California ISO
Shaping a Renewed Future

California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

May 24, 2011

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TABLE OF CONTENTS

Executive summary

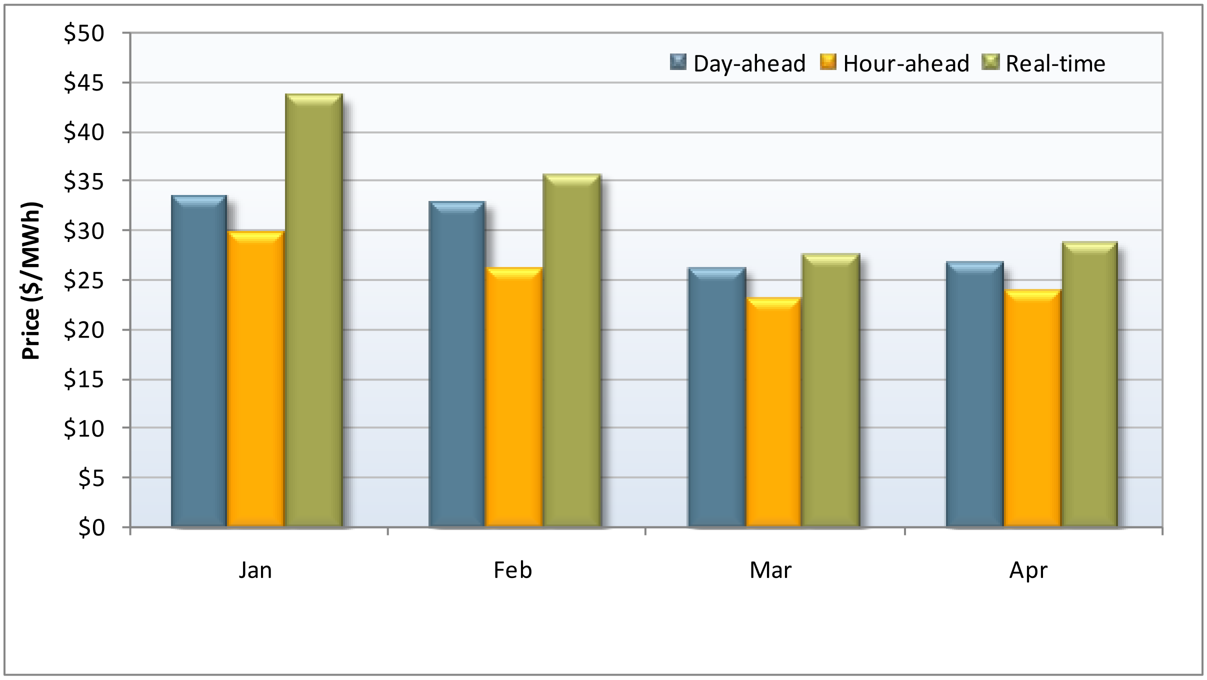
This report provides an overview of general market performance during the first quarter of 2011 (January – March). This report also includes additional analysis for price convergence and convergence bidding in April.

Energy market performance

- DMM continues to evaluate the competitiveness of the day-ahead integrated forward market in the first quarter of 2011.[1]
- In the 5-minute real-time market, average prices remained significantly above prices in the day-ahead and hour-ahead markets for much of the first four months of the year (as seen in Figure E.1). Higher average real-time prices continued to be driven by short but extreme price spikes. Most of these high prices were attributable to minor shortages of upward ramping capacity during these intervals.
- These high real-time price spikes generally do not reflect an underlying shortage of total potential capacity or uncompetitive bidding by suppliers, and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches. The ISO has been developing several such improvements that appear to have the potential to lower the frequency of such extreme price spikes and improve hour-ahead and real-time market performance. Indeed, starting in mid-April and continuing through mid-May, price convergence has improved significantly as modeling improvements have been deployed.
- The divergence of 5-minute real-time prices from hour-ahead market prices also continues to impose unnecessary additional inefficiencies and costs on the system. This occurs as a result of net imports and virtual supply at inter-ties decreasing in the hour-ahead market at low prices, which increases the additional incremental energy not offset by virtual demand at internal nodes, that is then purchased in the 5-minute real-time market at higher prices. The net cost of "selling low" in the hour-ahead market and "buying high" in real time must be recovered from load-serving entities and exports through the real-time imbalance energy offset charge. DMM estimates that this trend accounted for as much as $55 million in real-time imbalance energy offset charges for the first four months of 2011. DMM has noticed that these costs have fallen with the convergence of prices at the end of April. The costs have remained at low levels in May.
- Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion increased, particularly on constraints relating to imports into the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. This increase in day-ahead congestion coincided with the implementation of virtual bidding on February 1, 2011. DMM continues to evaluate the effects of convergence bidding and outages on this congestion.

[1] As noted in prior reports, DMM has previously had the ability to rerun the ISO market software to assess the competitiveness of the ISO day-ahead market. However, DMM has not been able to conduct this analysis so far in 2011 due to problems with the software system provided by the ISO to DMM for this analysis. DMM continues to flag this as an issue on which enhanced support is needed from the ISO.

Figure E.1 2011 average monthly PG&E load aggregation point prices – all hours



Convergence bidding

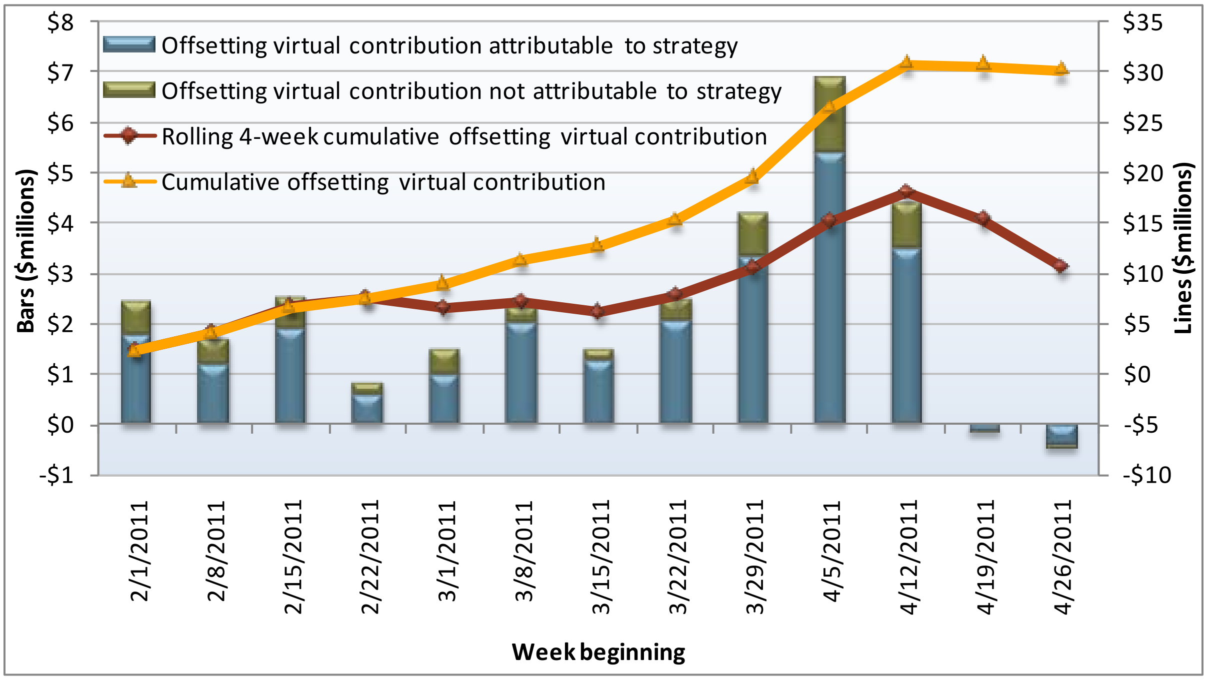
The ISO implemented functionality for convergence bidding in the day-ahead market for February 1, 2011. Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the ISO's day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

In theory, these participants profit by arbitraging the difference between day-ahead and real-time prices. As participants see opportunities to profit through convergence bids, this activity should drive real-time and day-ahead prices closer.

Price convergence did appear to improve in the first weeks after implementing convergence bidding as total virtual bid volumes continued to increase. However, DMM does not attribute this improvement in price convergence to convergence bidding, but rather to operational improvements by the ISO as well as some minor software enhancements. Specifically, DMM identified improvements in operator use of load adjustments in its daily review of operator logs, which resulted in improved price convergence starting in early February. However, improved operational practices did not resolve all price convergence issues. In mid-April, the ISO implemented additional software enhancements that further improved price convergence.

Over the course of the first two and a half months after implementation, the levels of convergence bids increased each week. However, the increase in volumes provided little system value because virtual demand was met with virtual supply. Specifically, individual scheduling coordinators bid in positions at inter-ties that offset their positions at internal nodes. Thus, even though total volumes increased, these positions essentially offset each other, and substantially contributed to real-time energy imbalance charges as shown in Figure E.2.

Figure E.2 Weekly offsetting virtual supply and demand contribution to real-time imbalance charges



Net revenues for convergence bidding entities averaged over $8 million over the first three months of this new market feature (February through April). DMM's assessment is that over this initial three month period convergence bidding has had little or no benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. Meanwhile, convergence bidding has added to energy imbalance offset costs that are ultimately allocated to load serving entities.

Recommendations

- **Modeling enhancements to improve price convergence**. DMM believes each of the ISO initiatives to address price convergence between the hour-ahead and real-time markets represent important steps that will help reduce extreme price spikes due to short-term shortages of ramping capacity. Convergence bidding has not resolved the issue of real-time price convergence. Therefore, resolving the convergence through modeling and operational enhancements remains a crucial approach to addressing this problem.

- **Manual load adjustments.** DMM supports the ISO efforts in modifying operational procedures, increasing operator training, and developing new tools to assist operators in understanding how and when to adjust load. DMM has identified manual load adjustment as one of several factors that contributes to price divergence. While DMM has observed that the consistency of adjustments has improved, the ISO is also undertaking efforts to improve the transparency of projected ramping capabilities to operators. This transparency will further improve how operators adjust loads to deal with system conditions.

- **Address offsetting virtual bidding strategy**. DMM supports the ISO in its stakeholder process to address the practice of offsetting virtual positions by scheduling coordinators. The strategy involves scheduling coordinators taking offsetting positions at inter-ties and internal locations. The strategy provides minimal value to the ISO as offsetting positions do not add day-ahead commitment. Rather, the strategy benefits from price divergence in real-time. As long as participants can bid in offsetting virtual supply bids on the inter-ties and virtual demand bids on internal nodes, this strategy will likely continue to lead to real-time energy imbalance charges when price divergence occurs between the hour-ahead and real-time markets.

1 Energy market performance

Day-ahead market

DMM continues to evaluate the competitiveness of the day-ahead integrated forward market in the first quarter of 2011.[2]

Real-time market

In the 5-minute real-time market, average prices remained significantly above prices in the day-ahead and hour-ahead markets for much of the first four months of the year. Higher average real-time prices continued to be driven by short but extreme price spikes. Most of these high prices were attributable to minor system level shortages of upward ramping capacity during one or two consecutive 5-minute intervals. These price spikes generally do not reflect an underlying shortage of total potential capacity and may be avoided by further modeling and dispatch improvements that increase the accuracy and flexibility of real-time dispatches.

Congestion

Congestion within the ISO system had minimal impact on overall prices. Yet, the frequency of day-ahead congestion increased, particularly on constraints relating to imports into the Southern California Edison and San Diego Gas and Electric area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. This increase in day-ahead congestion coincided with implementation of virtual bidding on February 1, 2011. DMM continues to evaluate the extent that this increase in congestion was attributable to convergence bidding versus a large number of generation and transmission outages during the quarter.

1.1 Energy market prices

The hour-ahead and real-time markets price divergence continued even after implementing virtual bidding, particularly in the off-peak hours as load ramps down.[3] Figure 1.1 and Figure 1.2 show monthly average prices for on-peak periods and off-peak periods for the PG&E load aggregation point, respectively. As shown in these figures:

- Hour-ahead market prices tended to be typically lower than peak and off-peak prices in the 5-minute real-time market, although they were higher in April. Hour-ahead market prices are used to settle physical imports and exports as well as virtual supply and demand bids on the inter-ties.

[2] As noted in prior reports, DMM has previously had the ability to rerun the ISO market software to assess the competitiveness of the ISO day-ahead market. However, DMM has not been able to conduct this analysis so far in 2011 due to problems with the software system provided by the ISO to DMM for this analysis. DMM continues to flag this as an issue on which enhanced support is needed from the ISO.

[3] Price convergence has improved significantly in the second quarter starting in mid-April and has continued into May as the ISO implemented new software and procedures to address price convergence.

Figure 1.1 Average monthly on-peak prices - PG&E load aggregation point

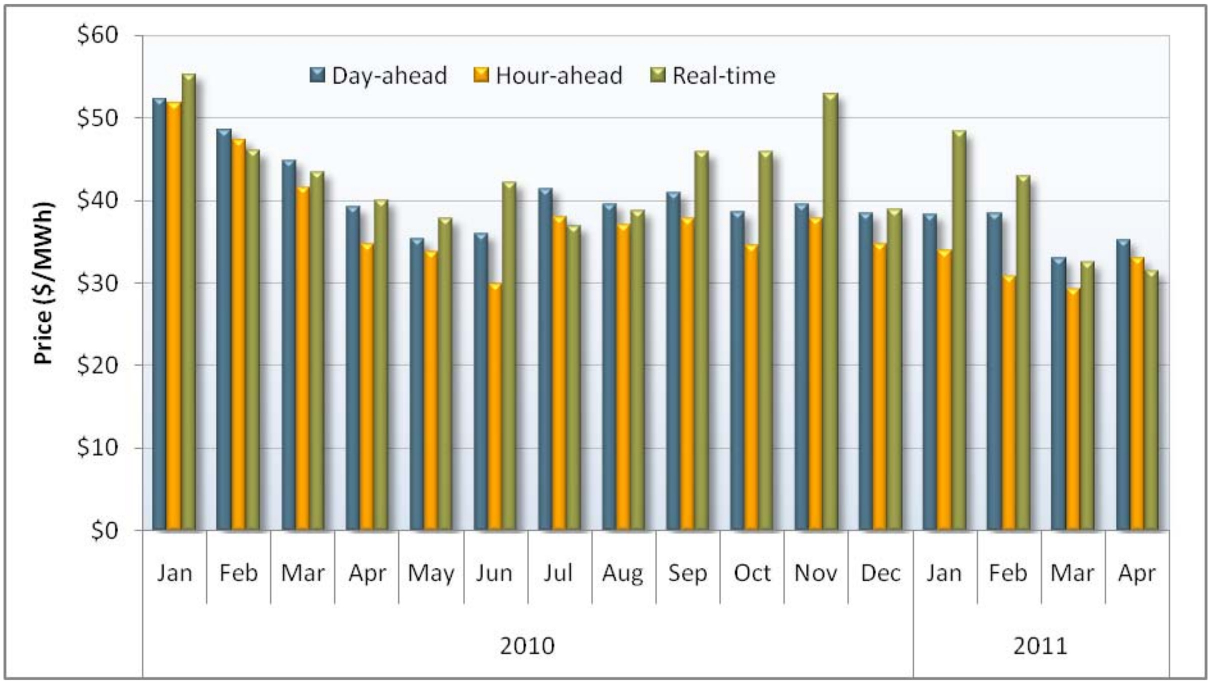
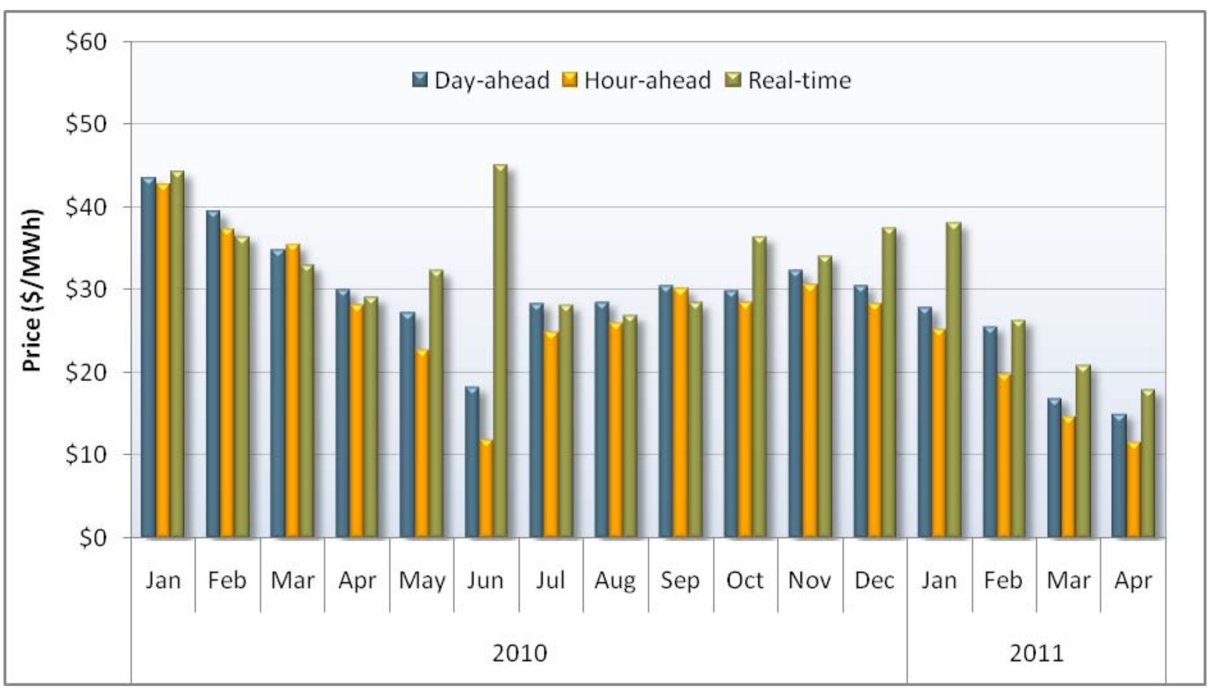


Figure 1.2 Average monthly off-peak prices - PG&E load aggregation point

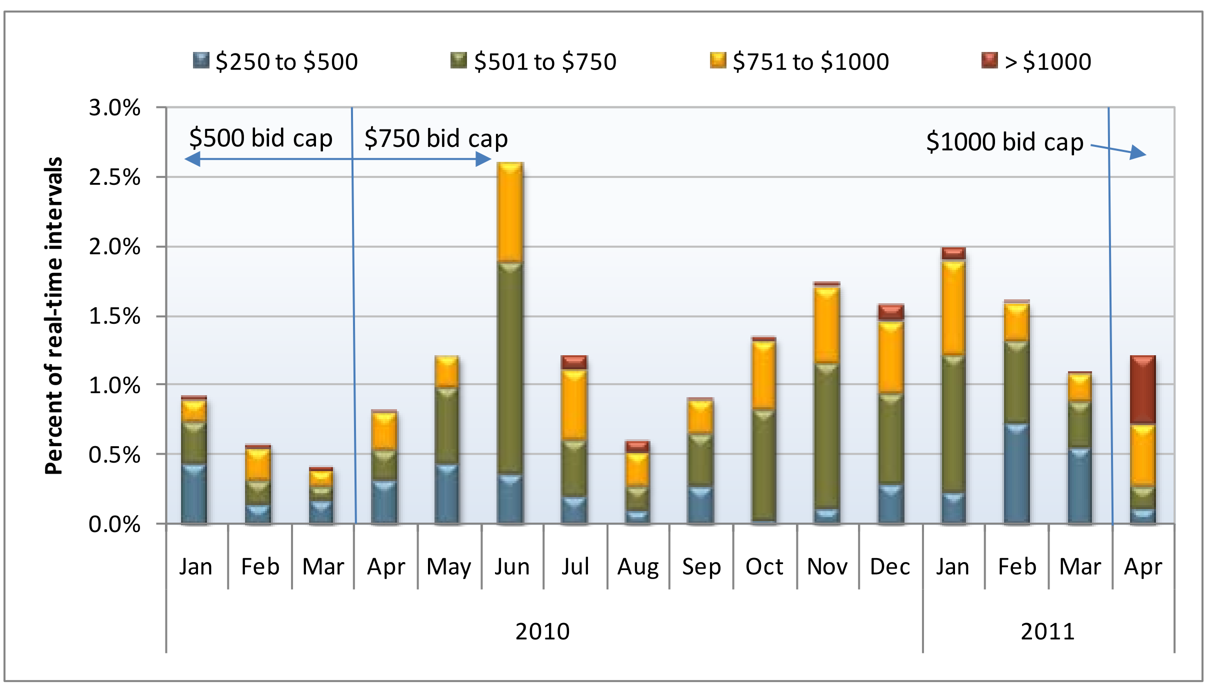


- During peak hours, average prices in the 5-minute real-time market were significantly higher than day-ahead prices in January and February. Real-time prices tracked day-ahead prices closely during March, and were lower than day-ahead prices in April.
- During off-peak hours, prices in the 5-minute real-time market were significantly higher than day-ahead prices in the first four months of the year.

Extreme price spikes near or above the bid cap continued to drive the average real-time energy market prices in the first four months of 2011.[4] As summarized in Figure 1.3, these price spikes occurred in less than 2 percent of hours in January. The frequency of these prices dropped in February and again in March. As shown in Figure 1.3, price spikes also decreased in these months in 2010. Moreover, such as in the previous year, the price spike frequency increased in April, which may reflect a seasonal trend.

The magnitude of price spikes changed in the first quarter of 2011. For instance, real-time price spikes above $750/MWh were highest in January when compared to all months over the previous year. In February and March, the frequency of the price spikes increased in the $250 to $500/MWh bin and decreased in all bins above $500/MWh. This change was coincident with the implementation of convergence bidding. This trend did not last, as the frequency of price spikes above $750/MWh was the highest in April 2011 since the nodal market began in April 2009. This change was coincident with the increase of the bid cap from $750/MWh to $1,000/MWh.

Figure 1.3 Frequency of price spikes (All LAP areas)

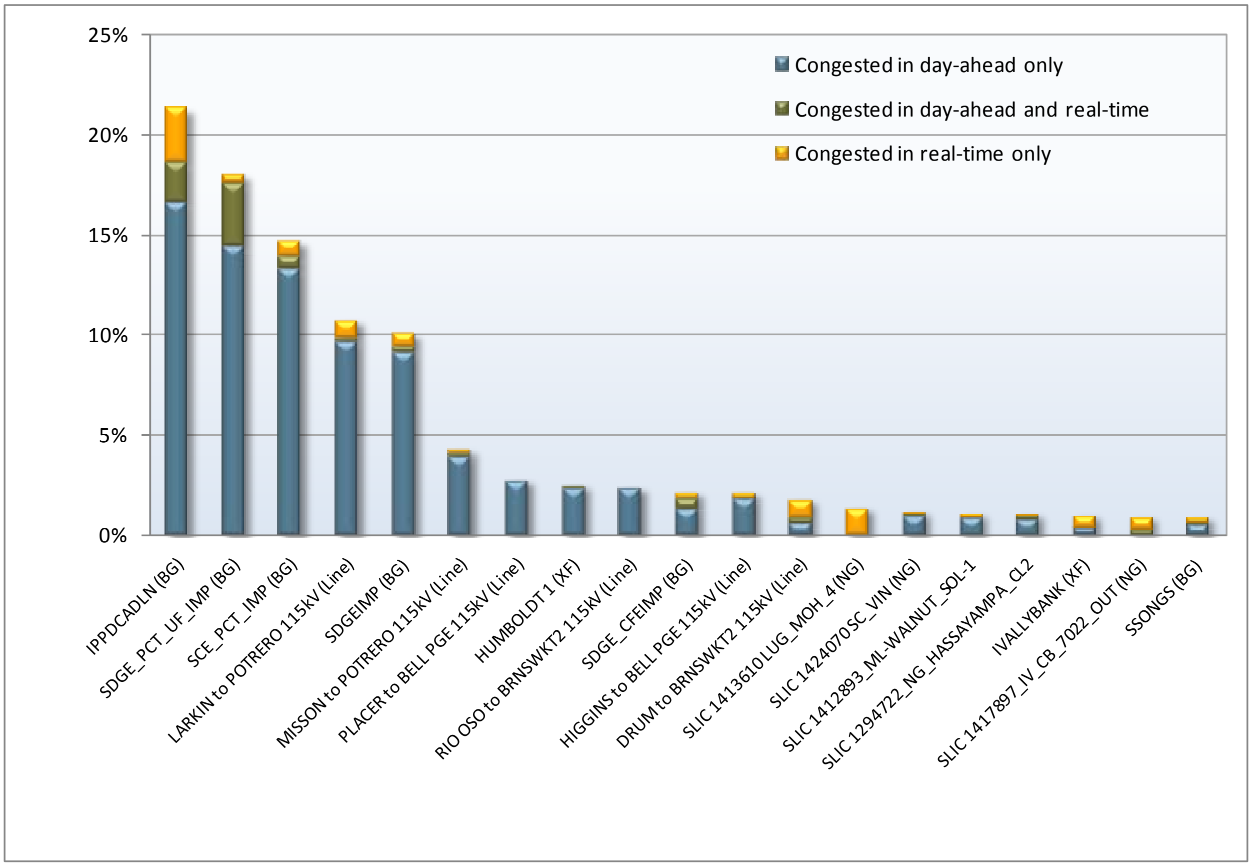


4 The bid cap for the first three months of the year was set to $750/MWh. The bid cap increased from $750/MWh to $1,000/MWh on April 1, 2011. The bid cap is not currently set to increase further.

1.2 Congestion

Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion increased, particularly on constraints relating to imports into the Southern California Edison and San Diego Gas and Electric area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. This increase in day-ahead congestion coincided with implementation of virtual bidding on February 1, 2011. DMM continues to evaluate the extent that this increase in congestion was attributable to convergence bidding versus a large number of generation and transmission outages during the quarter.[5]

Figure 1.4 Consistency of congestion in day-ahead and real-time markets (January – April 2011)



The IPP DC Adelanto branch group was the most frequently congested constraint because of line outages. Because this constraint is located near the ISO interface with neighboring control areas, congestion on this particular branch group does not have a significant impact on electricity prices within the ISO system or at the inter-ties.

Outages on the South West Power Link (SWPL) (Hassayampa-North Gila and Imperial Valley –Miguel) contributed to congestion into the SCE and SDG&E areas. When outages occur on SWPL, the internal San Diego percent of generation requirement increases to 30 percent from 25 percent. Limits are also placed on South of Songs transmission lines. Congestion in San Diego was also increased by manual

[5] DMM has limited ability to assess the impact of virtual bidding on congestion due to problems with re-running the day-ahead market software, as noted in footnote 1.

reductions (or conforming) made in transmission limits for reliability reasons, and by local outages (e.g. Mission –Old Town – Silvergate 230 kV line).

Congestion on the Larkin to Potrero 115 kV and Mission to Potrero 115 kV constraints was related to a number of outages in connection with work on the Potrero Station, Belmont Station the Martin H-Y#1 115 kV cable.

1.3 System power balance constraint

The system-wide power balance constraint continues be a significant factor in contributing to high real-time prices as well as negative prices.[6] Figure 1.5 and Figure 1.6 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software since the first quarter of 2011. The power balance constraints have never been relaxed in the day-ahead or the hour-ahead markets.

- Figure 1.5, the power balance constraint was relaxed due to insufficiencies of dispatchable incremental energy in about 1 percent of all 5-minute intervals during the first four months of 2011. This represents a decrease from the last months of 2010. Interestingly, there was a decrease in the number of insufficiencies starting in February and then again in March. This may appear to be a result of convergence bidding. The pattern in the first quarter of 2011, though, is consistent with the pattern that occurred in the first three months of 2010. Moreover, April 2011 results show an increase in insufficiencies when compared to February and March.

- As shown in Figure 1.6, the first four months of 2011 had an increase in the frequency of the power balance constraint relaxations in the 5-minute intervals because of insufficiencies of dispatchable decremental energy when compared to the final quarter of 2010.[7] This change appears to be partially attributable to increasing shares of hydro-electric and wind generation in total supply, which increased by 29 and 32 percent, respectively, over the last quarter of 2010. Net virtual demand[8] and increased net imports in the hour-ahead market (as highlighted in Section 2) also could have contributed to over-generation in real-time.

[6] For further detail on the system-wide power balance constraint, please refer to pages 11-12 of the *Quarterly Report on Market Issues and Performance*, February 8, 2011, http://www.caiso.com/2b1f/2b1f838819910.pdf.

[7] Insufficient decremental generation refers to over-generation that causes negative penalty prices at -$35, which is the penalty price for power balance relaxations in the scheduling run. Because of data issues, DMM was not able to calculate over-generation in such intervals for the first quarter of 2011. Instead, DMM reports the count of intervals with -$35 penalty prices in the scheduling run, which indirectly reflects over-generation.

[8] In certain hours, the system clears net virtual demand. Net virtual demand can potentially cause higher commitment levels in the day-ahead market that can increase the potential for over-generation.

Figure 1.5 Relaxation of power balance constraint due to insufficient upward ramping capacity

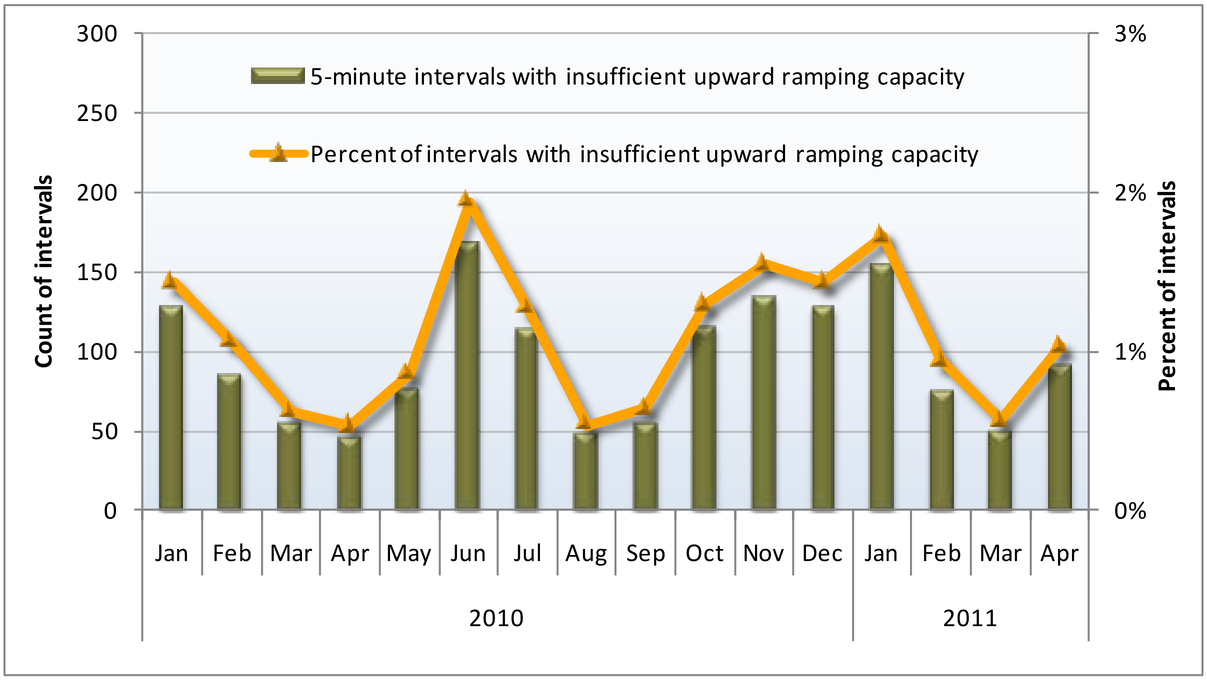


Figure 1.6 Relaxation of power balance constraint due to insufficient downward ramping capacity

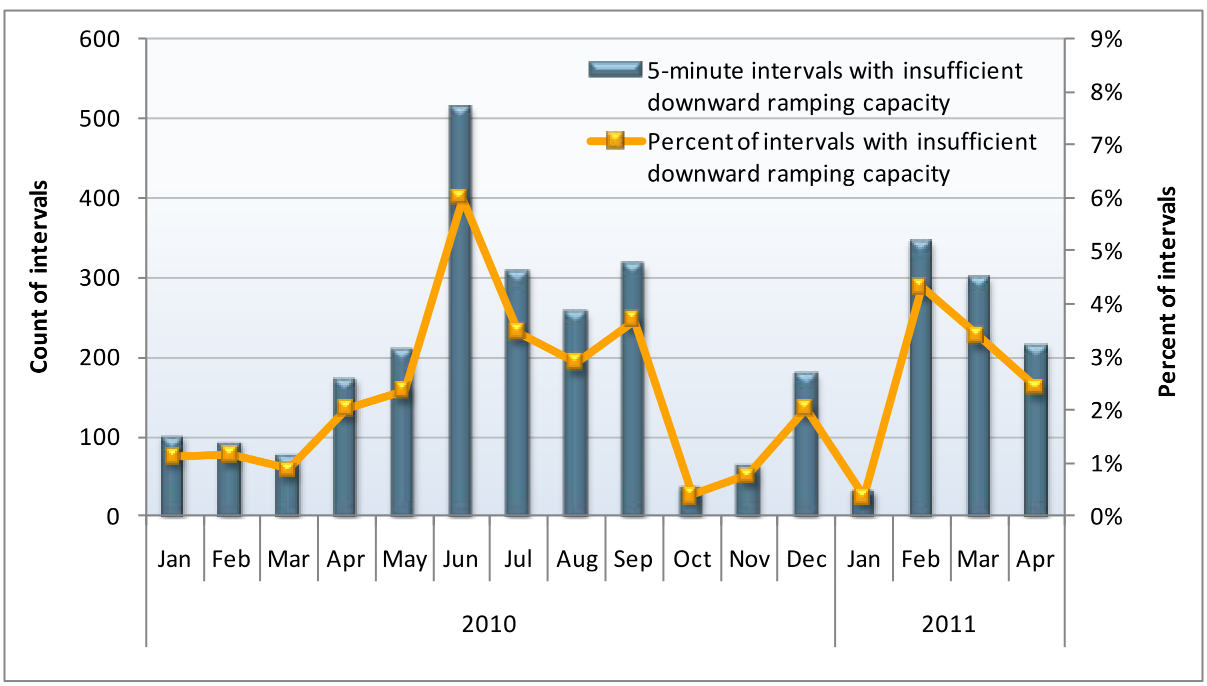


Figure 1.7 and Figure 1.8 provide more detailed information on the intervals in which the power balance constraint was relaxed because of insufficient upward ramp in the first quarter of 2011. Figure 1.7 shows the percentage of intervals that the power balance constraint was relaxed by hour. As shown in Figure 1.7:

- Shortages of upward ramping capacity caused the power balance constraint to become relaxed most frequently during morning and evening ramp hours when system loads were changing at a relatively high rate.
- Overall, the power balance constraint was relaxed because of shortages of upward ramping in about 1 percent of intervals during the first quarter of 2011. During the ramp hours of 7 and 8, upward ramping deficiencies constituted about 3 to 5 percent of intervals.

Figure 1.8 shows the number of consecutive 5-minute intervals that shortages of upward ramping capacity existed in the first quarter of 2011. As shown in Figure 1.8:

- About 82 percent of price spikes because of shortages of upward ramping capacity persist for only one to three 5-minute intervals (or 5 to 15 minutes).
- During intervals when price spikes occurred because of these short-term shortages of upward ramping capacity, the system energy prices averaged $660/MWh. This compares to an average system energy price of $138/MWh in the intervals before and after these price spikes.

Figure 1.7 Relaxation of power balance constraint by hour (January – March 2011)

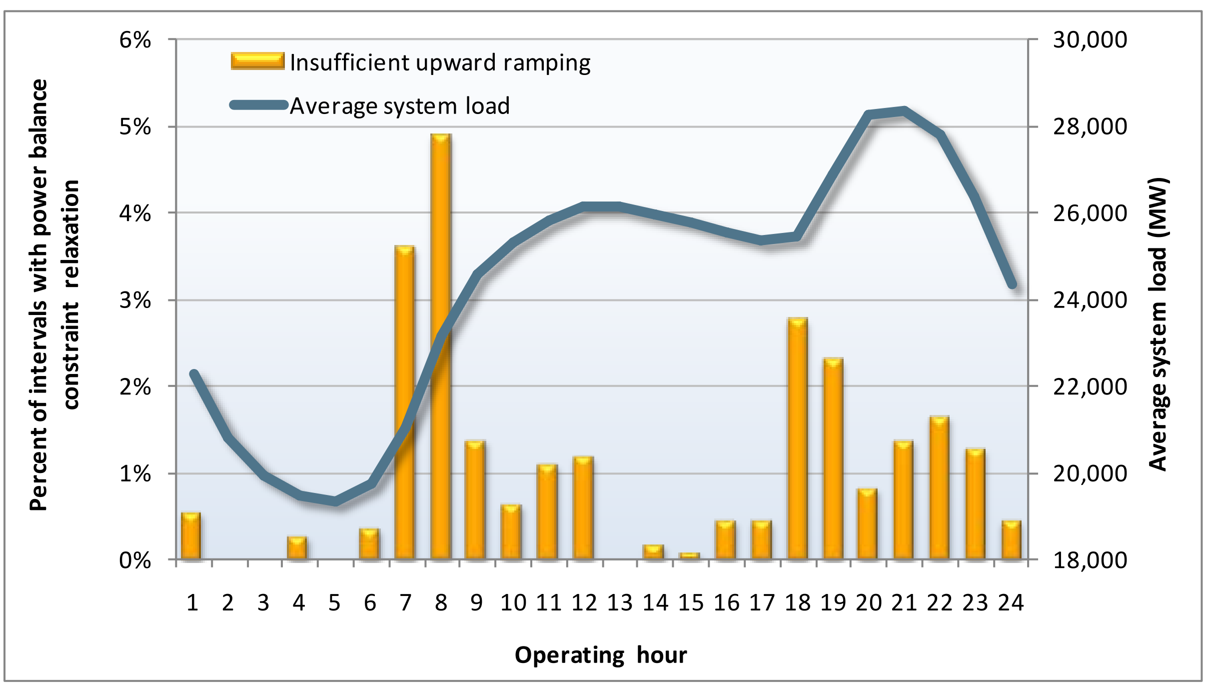
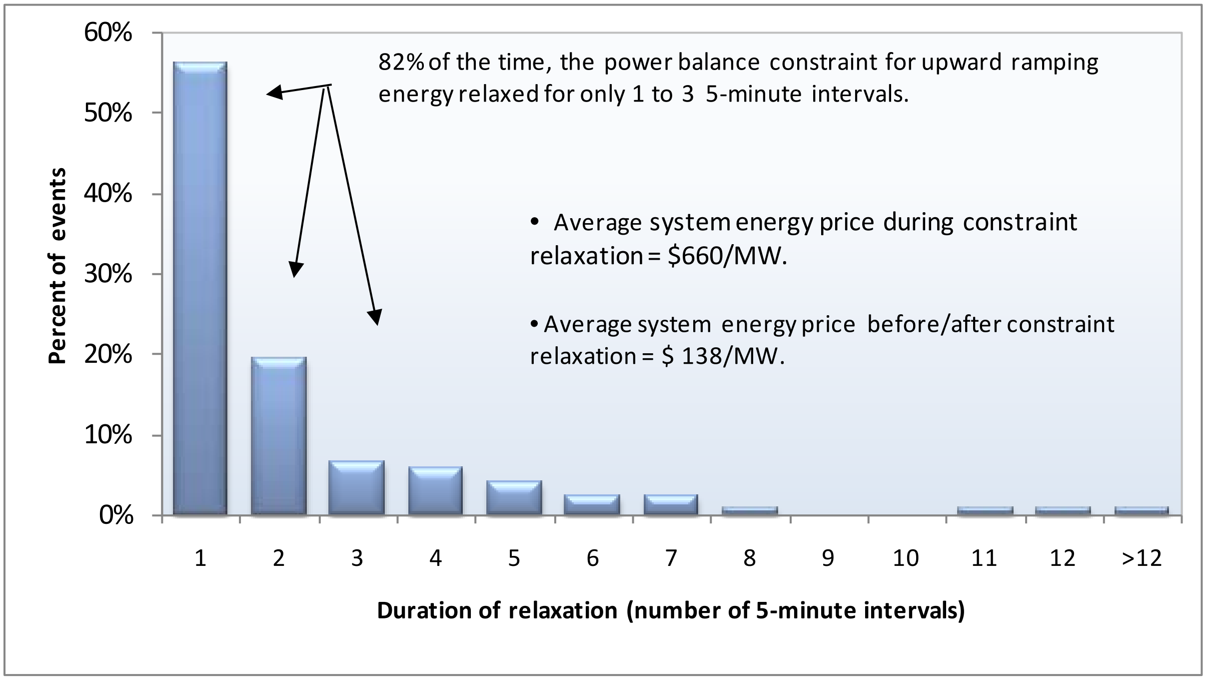


Figure 1.8 Duration of energy balance constraint relaxation of events (January – March 2011)



1.4 Load forecasting and manual adjustments

One of the contributing factors to divergence of prices in the hour-ahead and 5-minute real-time markets involves the difference in load forecasts used in these two markets. For example, if system demand is under-forecasted in the hour-ahead market, the market software may dispatch imports and exports in a way that decreases the supply of available upward ramping capacity within the ISO during the 5-minute market. Similarly, if the load forecast is suddenly increased in the 5-minute real-time market, this can create a brief shortfall in the upward ramping energy available to meet the increased load forecast.

Some of the differences in these forecasts may be due to changing conditions between the execution of the hour-ahead market and the real-time market. However, operators can also manually adjust load forecasts used in the software. This is known as a *load adjustment*.

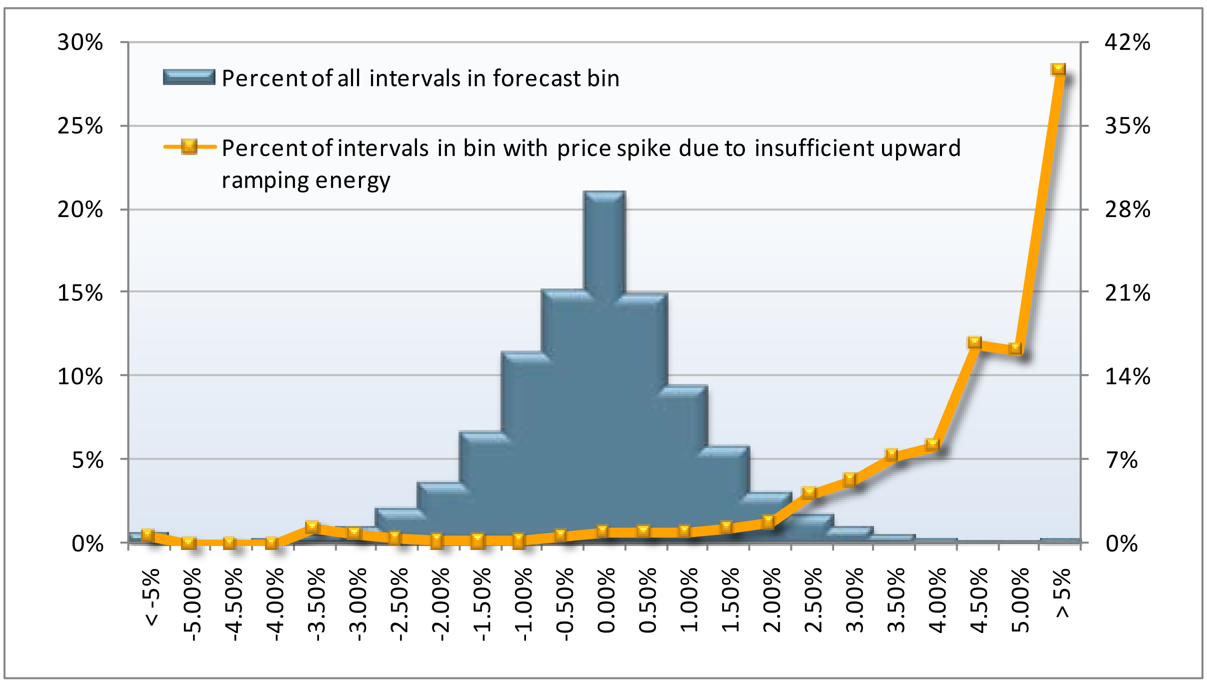
Load adjustment levels are not necessarily consistent between the hour-ahead and real-time forecasts. This can contribute to differences in price results between the hour-ahead market and the real-time market and short but extreme price spikes in the 5-minute market.

Figure 1.9 provides a histogram of the difference in the load forecast used in the hour-ahead market and the 5-minute load forecast in the first quarter of 2011. The bins represented by the blue bars show the distribution of this difference as a percentage of the real-time forecast. The line shows the percentage of intervals within each of these bins that the energy balance constraint was relaxed due to insufficient upward ramping energy. Load forecast data include manual adjustments. As shown in Figure 1.9:

- During most hours (91 percent), the load forecast used in the hour-ahead market was within ±2 percent of the 5-minute load forecast. During these hours, shortages of upward ramping capacity rarely occurred.
- 38 percent of upward ramping capacity shortages occurred when the 5-minute load forecast exceeded the load forecast used in the hour-ahead market by 5 percent or more.
- As the degree to which real-time loads were under-forecasted in the hour-ahead market increases, the incidence of price spikes due to shortages of upward ramping capacity also increases significantly.

DMM has identified some cases in which it appears that manual load adjustments may have contributed to the shortages of upward energy resulting in relaxation of the power balance constraint and extreme price spikes. For example, this can occur when the hour-ahead load forecast is adjusted significantly downwards, or when the real-time forecast is suddenly adjusted upwards. The more extreme differences in the hour-ahead and real-time forecasts in Figure 1.9 are likely to reflect cases in which such adjusting occurred.

Figure 1.9 Difference in hour-ahead and real-time forecast (January – March 2011)



As a result of these identified forecasting issues, the ISO has developed more systematic procedures, tools and training that have given operators additional guidance to determine whether a load adjustment should be removed or continued and at what magnitude. DMM attributes these changes to helping to improve price convergence in February and March. DMM is supportive of these changes and continues to recommend that the ISO seek to improve how and when to adjust the load forecasts used in the hour-ahead and 5-minute real-time markets.

Furthermore, the ISO is continuing to develop a new short-term forecasting tool that will provide a more accurate and consistent forecast for the hour-ahead and the real-time markets. This tool will provide forecasts at the 15-minute and 5-minute levels. The current load forecasting tool provides 30-minute forecasts, from which more granular forecasts are developed by simple interpolation. This new forecasting tool was expected in 2010, but implementation is now scheduled for 2011. The latest estimated release is scheduled for the end of May 2011.

When the ISO implements this tool, DMM recommends that the ISO keep a database of manual adjustments made to this forecast in the hour-ahead and real-time software.[9] DMM believes this data may provide a basis for more systematic analysis and improvements of manual load adjustment practices and perhaps the load forecasting tool itself. Also, these data will be needed to determine the extent to which any new load forecasting tool reduces the need for manual adjustments and its accuracy prior to any such adjustments.

1.5 Impact of the power balance constraint

As noted in Section 1.3, the power balance constraint was relaxed due to insufficient incremental energy around 1 percent of intervals in the first four months of 2011. Price spikes during these intervals had a significant impact on overall average real-time prices due to the bid cap and penalty prices used in the pricing run when this relaxation occurs.

Figure 1.10 and Figure 1.11 highlight the degree to which the divergence of monthly average real-time prices during all hours were caused by extreme prices during the small percentage of intervals when power balance constraint relaxations occur. With these intervals excluded, real-time prices were approximately equal to hour-ahead prices in most cases. However, in April, once these intervals are controlled for, hour-ahead prices were a premium to the real-time prices.

[9] The ISO has begun to systematically capture this data and has developed a tool to show operators a brief history of how the system has been adjusted. Moreover, the ISO has developed a ramp estimation tool that will be used to determine the upper bounds of how the system can be adjusted without creating a deficiency of incremental dispatchable energy.

Figure 1.10 Change in monthly prices excluding hours when power balance constraint relaxed (PG&E LAP, all hours)

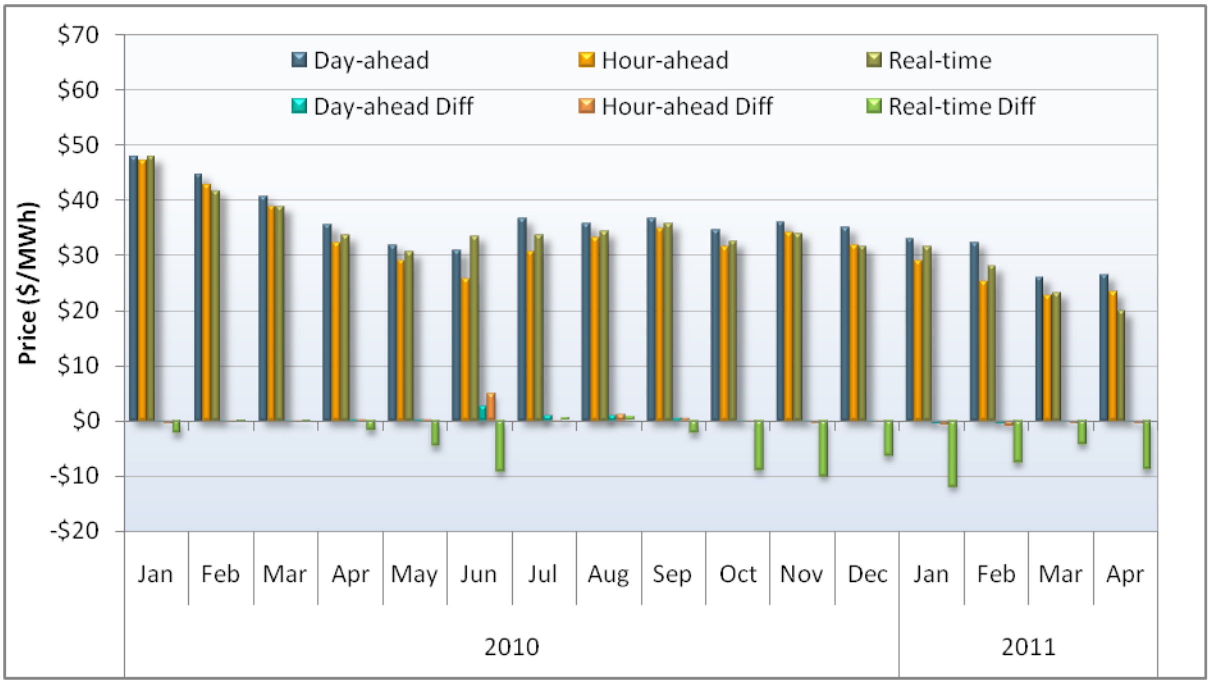
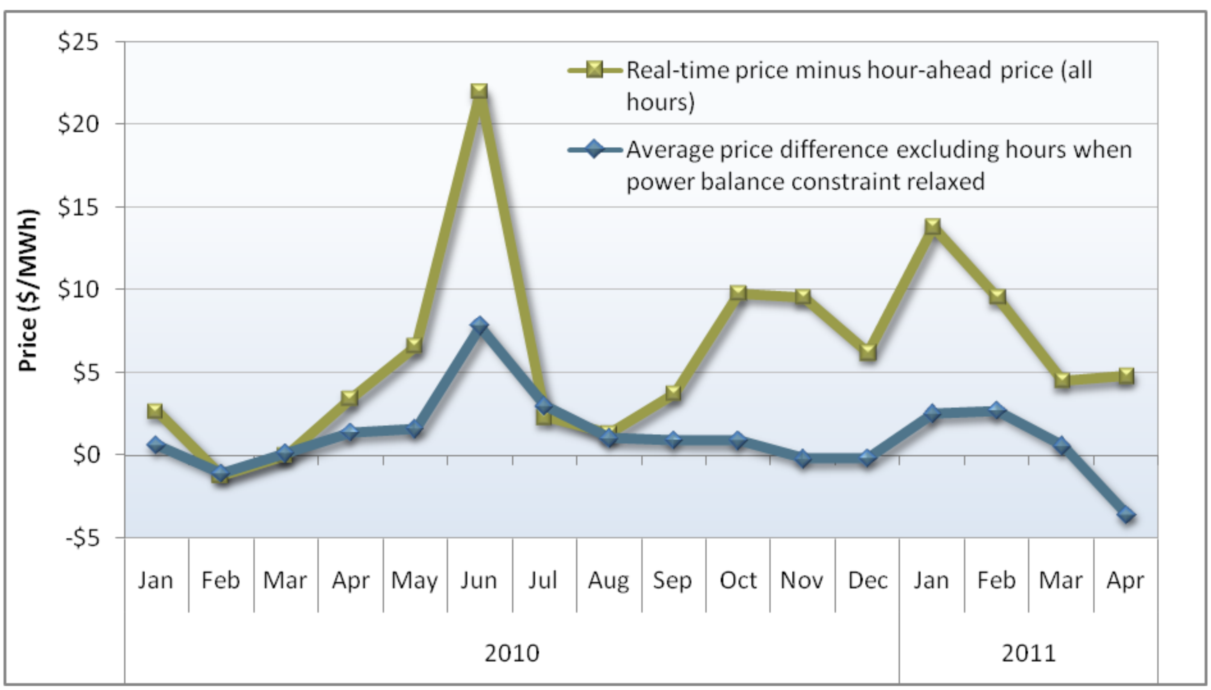


Figure 1.11 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraint relaxed (PG&E LAP, all hours)



1.6 Initiatives to improve market performance

The ISO is in the process of implementing several key measures aimed at improving the consistency of hour-ahead and real-time prices and reducing the incidence of ramping capacity shortages in the 5-minute market. Although many were delayed for an early 2010 deployment, many now appear closer to final implementation. An update on these items is provided below:

- **Providing improved guidance to the operators regarding manual load adjustment practices.** As previously noted, the ISO has improved the procedures, training and tools relating to how adjustments are made to load forecasts used in the hour-ahead and 5-minute real-time markets. As part of this effort, the ISO has provided additional training and guidance to market operators on using load adjustments. The ISO is further developing systematic training and tools to assist the operators on when and how to adjust the load. In addition, the new load forecasting tool should reduce the need for manual adjustments.

- **Improving the forecast used in the hour-ahead and 15-minute pre-dispatch processes.** As previously noted, the ISO is developing a new short-term forecasting tool designed to provide a more accurate and consistent forecast for the hour-ahead and the real-time markets. This new forecasting tool was expected in 2010, but is now rescheduled for May 2011.

- **Adding a new flexible ramping capacity constraint.** The ISO has been evaluating adding a flexible ramping constraint in the day-ahead residual unit commitment process, the hour-ahead process and potentially the 15-minute pre-dispatch process. The flexible ramping constraint will require that the software optimization results include a pre-specified amount of additional ramping capacity (beyond levels needed to simply meet the energy forecast). This new constraint is designed to ensure that sufficient upward and downward ramping capability from 5-minute dispatchable resources is committed and available to balance loads and supply on a 5-minute basis, taking into account the potential variability in actual system conditions. When applied in the day-ahead residual unit commitment process, this constraint may trigger commitment of long start units when additional ramping capacity is needed. When applied in the hour-ahead market, this constraint may help better align net import levels with internal ramping energy needs. When applied in the 15-minute pre-dispatch process, this constraint may trigger commitment of fast start units when additional upward ramping capacity is needed.

- **Unit start-up and shut down profiles.** Currently, when a generating unit is scheduled to start up, the market software does not account for the energy generated while the unit is ramping up to its minimum load level. The software also does not account for the energy generated when resources are ramping down from their minimum load levels to zero.[10] On a system-wide basis, this can create several hundred megawatts of unscheduled energy during the early morning hours when the load starts climbing up and in the evening hours when the load starts decreasing. Operators currently seek to compensate for this through manual load adjustments. The ISO is developing software enhancements to model the unscheduled energy and expects to implement this enhancement before the end of the second quarter of 2011.

[10] Before a more systematic approach can be developed for shut down profiles, the ISO has temporarily incorporated an automated real-time load adjustment mechanism that adjusts the load to account for additional generation related to units shutting down.

- **Adaptive control enhancements.** The ISO has a mid-term initiative in 2011 to develop adaptive control enhancements that will predict and account for other various specific sources of uninstructed deviations. A simpler feature incorporated in the new market software to account for uninstructed deviations was disabled due to performance issues. Operators now must make uninstructed deviations adjustments, as appropriate, by using manual load adjustments.

DMM believes each of these initiatives represent important steps that will help reduce extreme price spikes because of short-term shortages of ramping capacity, which in turn will help promote convergence of average hour-ahead and real-time prices. DMM recommends that the ISO continue to address the factors contributing to price divergence directly through these types of modeling and operational improvements, especially after the implementation of convergence bidding.

As is discussed in Section 2, convergence bidding has not necessarily reduced the divergence between hour-ahead and real-time prices. Indeed, convergence bidding may exacerbate the costs of price divergence. Therefore, modeling and operational enhancements appear to be the only approaches available for reducing extreme price variations, divergences and the costs associated with them.

2 Convergence bidding

Convergence bidding was implemented in the day-ahead market for February 1, 2011. Net revenues for convergence bidding entities averaged over $8 million over the first three months of this new market feature (February through April). However, DMM's assessment is that over this initial three month period convergence bidding has had little or no benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. Meanwhile, convergence bidding has added to energy imbalance offset costs that are ultimately allocated to load-serving entities.

As shown in Section 1, price convergence did appear to improve in the month of March. However, when breaking down the monthly prices into weekly prices, they began to diverge at the end of March and in early April, even though the absolute levels of convergence bids continued to increase.

DMM does not attribute this improvement in price convergence to convergence bidding, but rather to operational improvements by the ISO as well as some minor software enhancements. Specifically, DMM identified improvements in operator use of load adjustments in its daily review of operator logs, which resulted in improved price convergence starting in early February. Improved operational practices did not resolve all price convergence issues. In mid-April, the ISO implemented additional software enhancements that further improved price convergence.

Background

Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the ISO day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

In theory, these participants profit by arbitraging the difference between day-ahead and real-time prices. As participants see opportunities to profit through convergence bids, this activity should drive real-time and day-ahead 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 MW.

- 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, or potentially even the displacement of additional unit commitment.[11] This reduction in physical commitment would

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

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 MW.

The California market does have a unique feature that makes it different from most other ISOs and RTOs. California's market design re-optimizes imports and exports in an hour-ahead market. These inter-tie resources settle against hour-ahead prices rather than 5-minute real-time prices. The same is true for convergence bids on the inter-ties. These bids also settle against hour-ahead prices and not 5-minute real-time prices.

As shown in Section 2.1.2, this feature of the ISO market design has led to a particular convergence bidding strategy that has been exploited when prices diverge between the hour-ahead and real-time market. While this virtual bidding strategy has been highly profitable and has increased revenue imbalances allocated to load-serving entities, it does not appear to have provided any significant benefits in terms or helping to converge prices in the hour-ahead and 5-minute real-time markets.

2.1 Convergence bidding activity

Convergence bidding has had two distinct patterns over the course of the first few months. First, volumes have increased steadily over the first few months up until the second half of April. Second, the vast majority of virtual supply positions are found on inter-ties, whereas virtual demand positions are most often on internal locations. This activity is outlined below.

2.1.1 Increase in convergence bidding volumes

Convergence bidding volumes increased steadily from the start of convergence bidding on February 1 unit mid-April. 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, roughly 70 percent of virtual supply cleared and 60 percent of virtual demand bids cleared in the first three months of convergence bidding.
- With the exception of the very first week of convergence bidding, virtual supply has outweighed virtual demand by over 625 MW.

As shown in Figure 2.2**:**

- Virtual demand exceeds virtual supply in the early morning ramping hours ending 8 and 9 as well as the late evening ramp down hours ending 20 through 24.
- The total volume of offered and cleared virtual bids is consistent for much of the day with the exception of the early morning hours ending 2 through 6.

Figure 2.1 Weekly average offered and cleared virtual activity

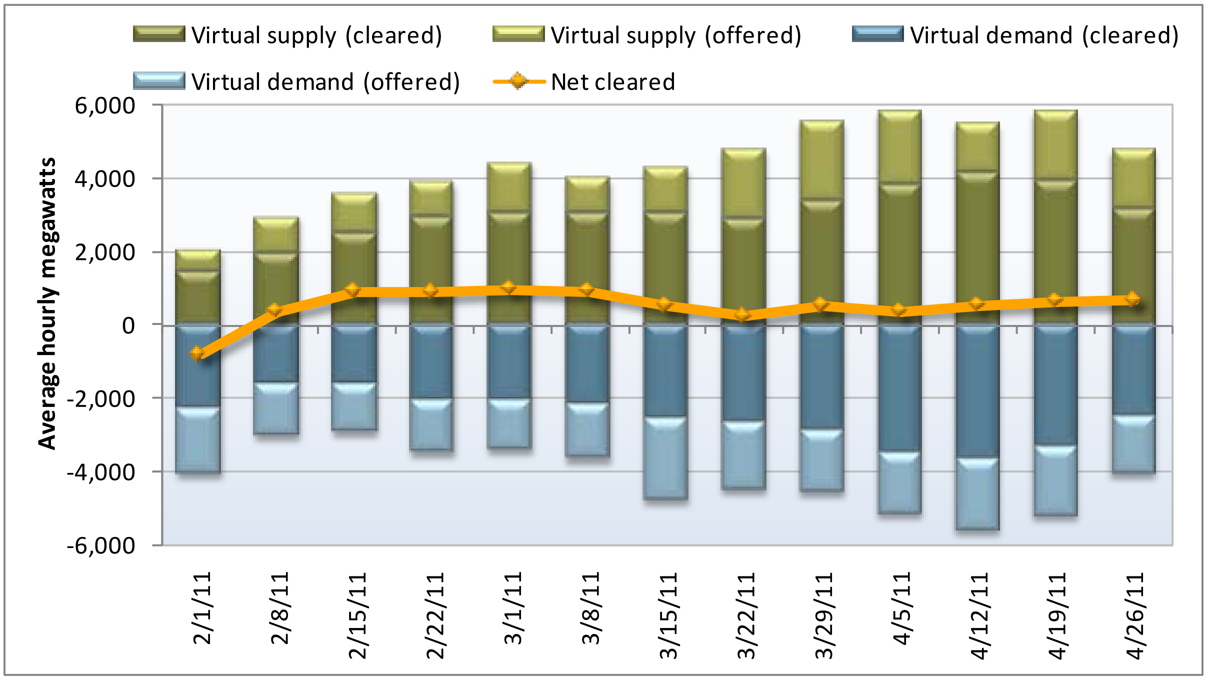
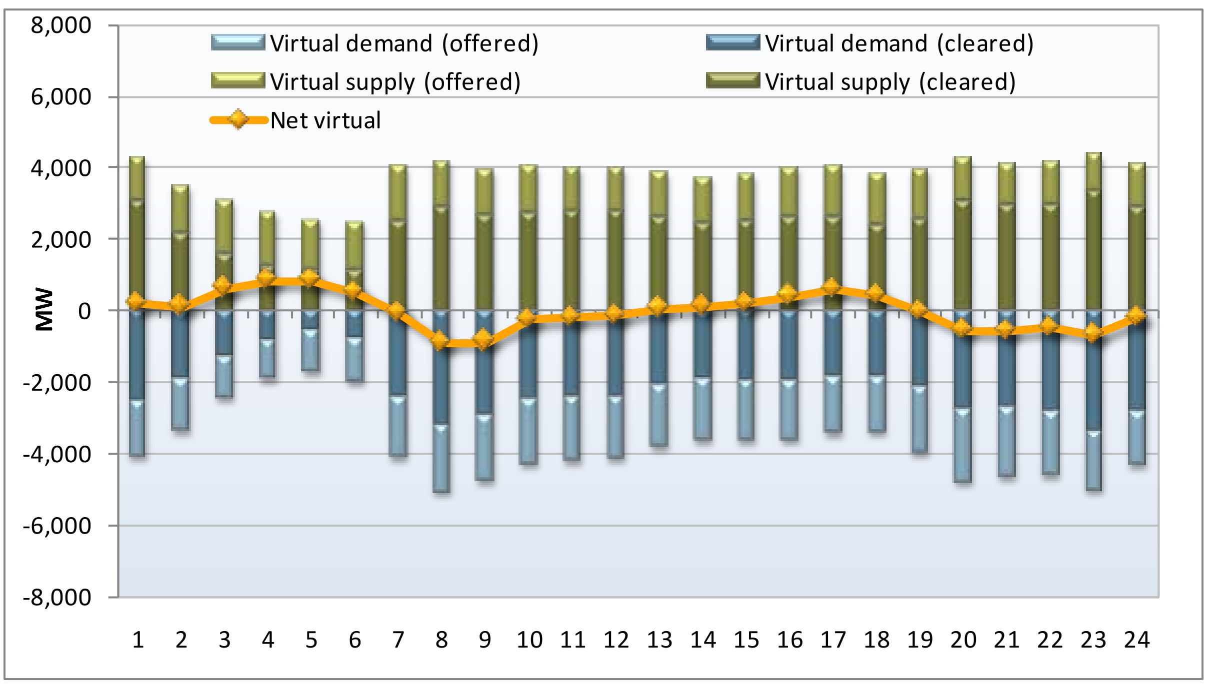


Figure 2.2 Hourly offered and cleared virtual activity (February – April 2011)



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

The difference between convergence bidding positions at the inter-ties and at internal nodes shows a distinctive pattern. As shown in Figure 2.3, convergence bidding on inter-ties (shown in green) is weighted towards virtual supply and convergence bidding on internal locations (shown in blue) is weighted towards virtual demand.

Numerous market participants are employing a strategy where they place virtual supply positions at the inter-ties and then place an equal and opposite virtual demand position at internal locations. Figure 2.3 shows the volume of these overlapping positions. The blue bars represent the weekly average MW associated with this strategy, whereas the green bars represent offsetting positions attributable to different convergence bidding entities placing offsetting positions.

Figure 2.3 Weekly net cleared inter-tie and internal positions

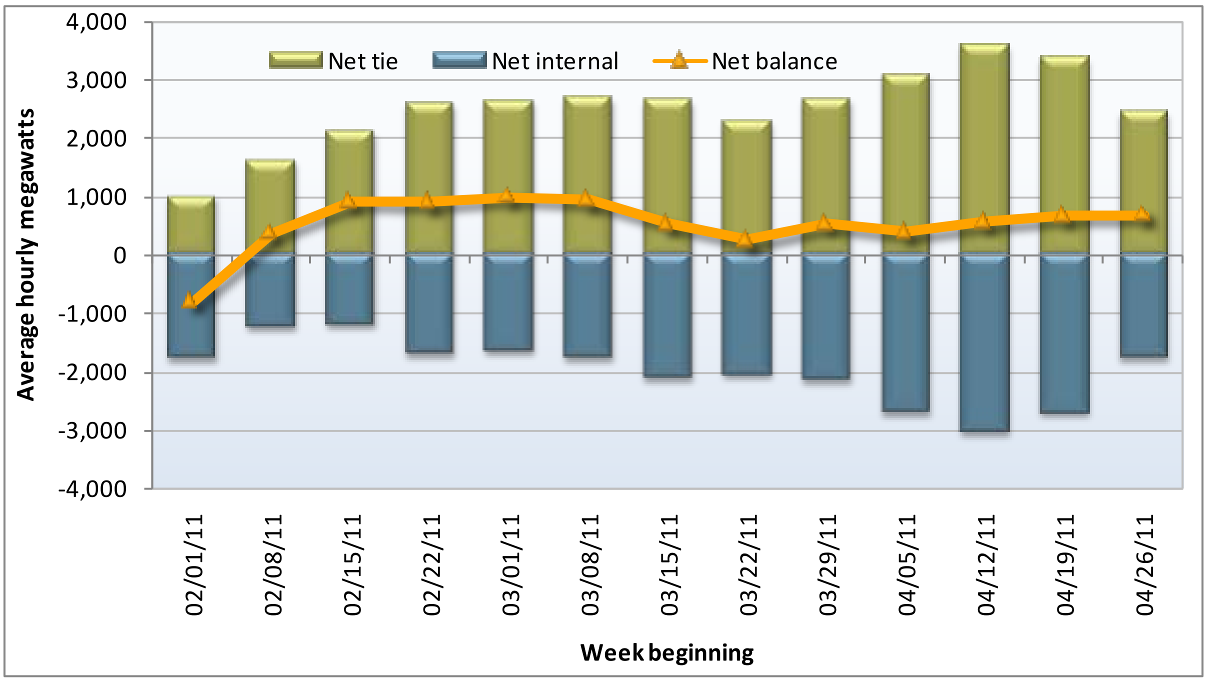
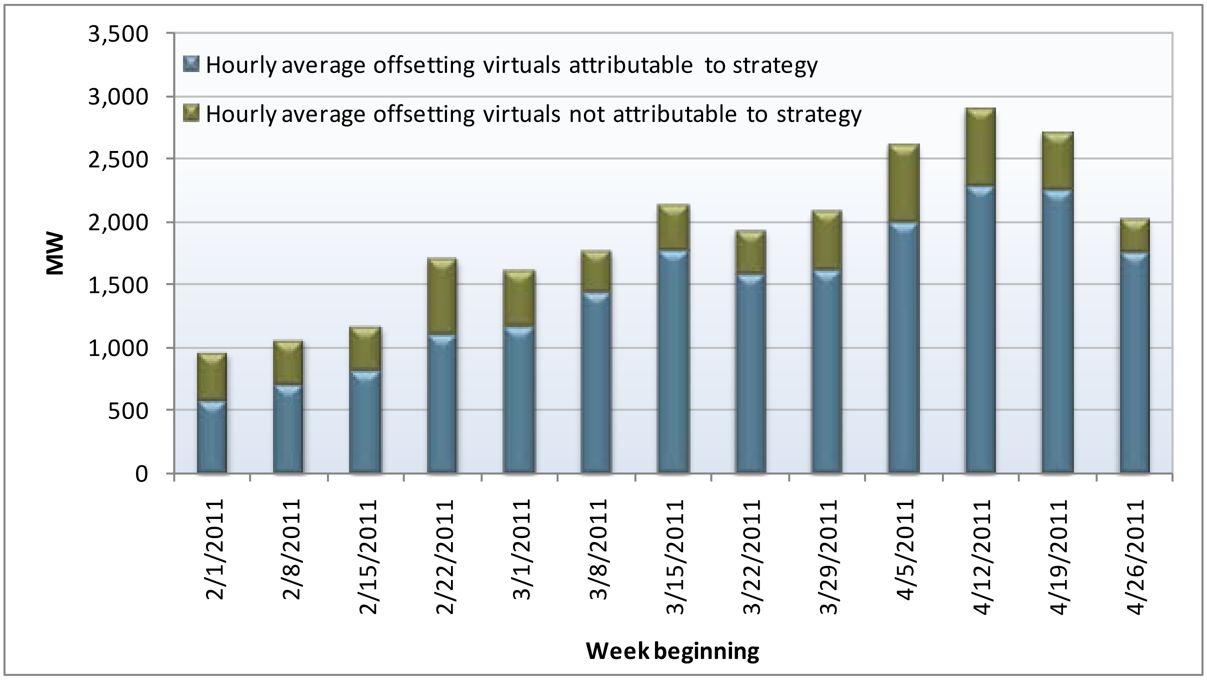


Figure 2.4 Weekly positions with offsetting virtual supply and demand megawatts



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 this would not create cause for concern. Yet, as shown in the next section, prices between these markets have been markedly different for much of the first three months. This has led to substantial uplifts that are outlined further in Section 2.2.3.

2.2 Convergence bidding effects on market

If convergence bidding is working as intended, day-ahead, hour-ahead and 5-minute real-time market prices should converge. Figure 2.5 shows weekly average prices at the PG&E load aggregation point.

- In February and March there appears to be signs of price convergence as real-time prices (green line) become closer to the day-ahead prices (orange line), while the hour-ahead prices (blue line) come close to the day-ahead prices.
- At the end of March and into early April, prices diverged even though the volumes of convergence bids increased. Contributing factors for the price divergence include increased frequency of power balance constraint relaxations and the increase in the bid cap from $750/MWh to $1,000/MWh, as well as generation and transmission outages.

Figure 2.6 compares the difference between prices in the hour-ahead and 5-minute real-time markets for peak and off-peak periods. Figure 2.6 shows that the price difference fell in February and was near zero for much of March. Prices diverged again at the end of March and into April. By the end of April, off-peak price differences were near zero and hour-ahead prices exceeded real-time prices.

Figure 2.5 Weekly average prices PG&E load aggregation point – all hours

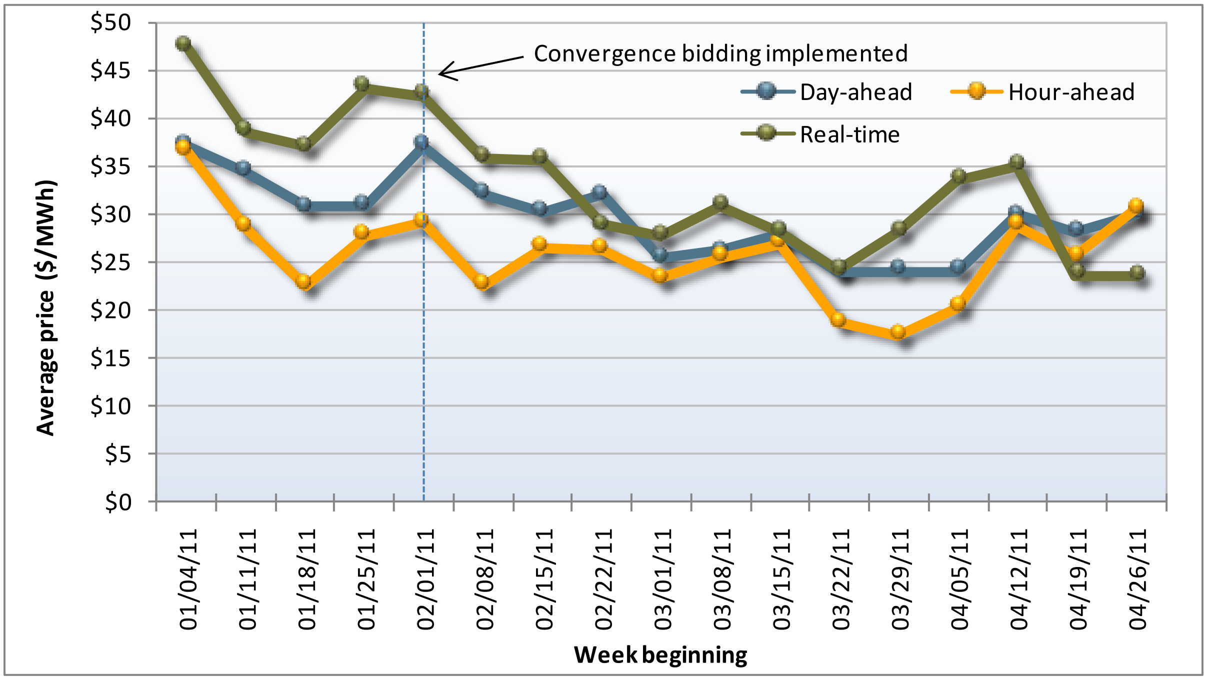
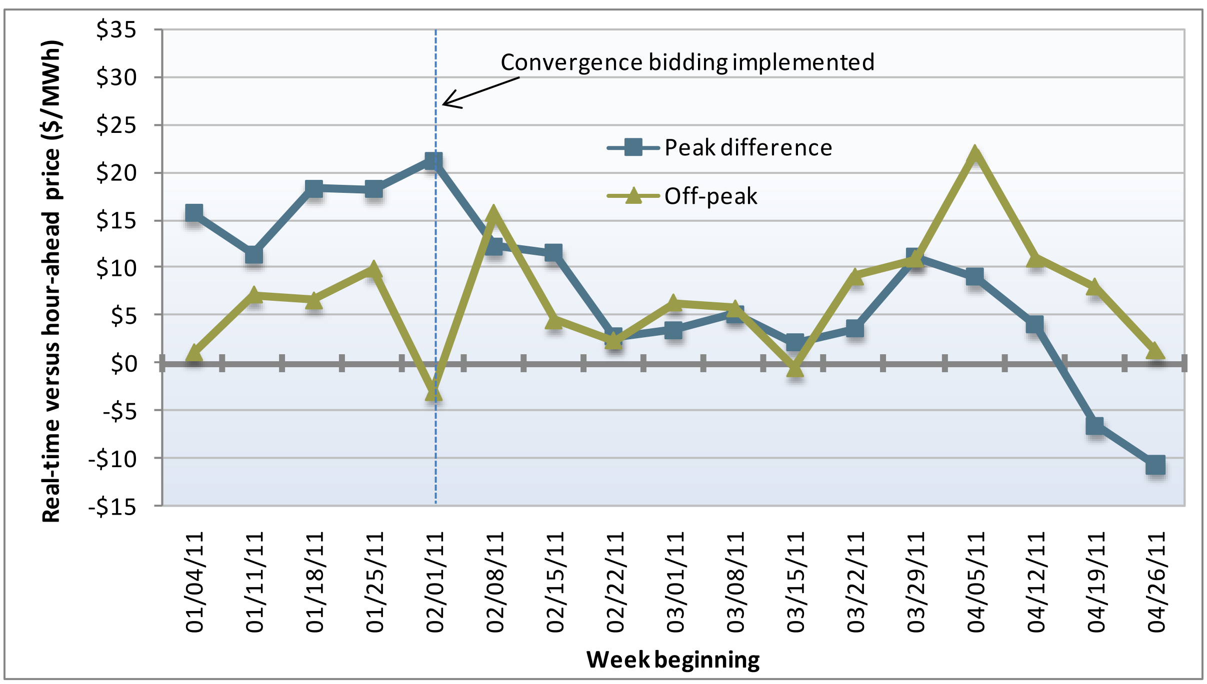


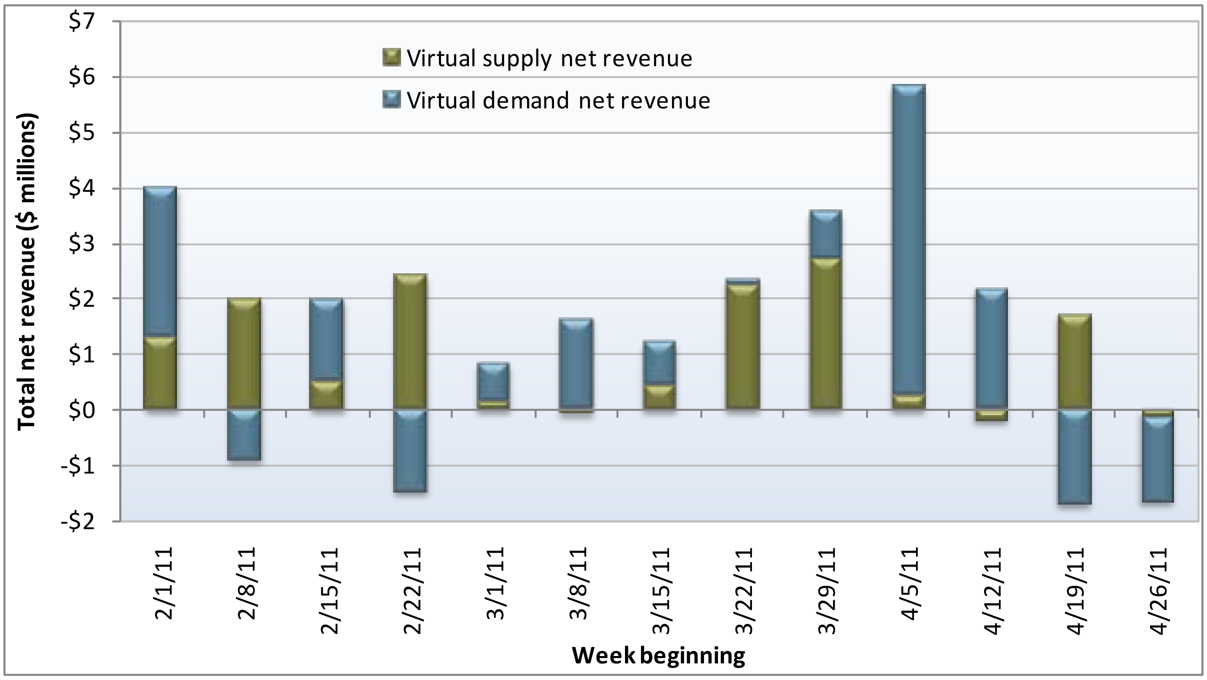
Figure 2.6 Weekly average difference between real-time and hour-ahead prices (PG&E LAP)



2.2.1 Net profits from convergence bidding

With the exception of the end of April, the total net profits paid to entities submitting virtual bids have been positive. Over the course of the first three months since convergence bidding was implemented, net revenues paid out to convergence bidding entities have totaled over $24 million. Figure 2.7 shows weekly convergence bidding net revenues for both virtual demand and virtual supply positions. Both virtual supply and virtual demand positions have led to positive net revenues. This is because inter-tie bids and internal bids settle against hour-ahead and 5-minute real-time market prices, respectively. Moreover, these prices most often move in different directions relative to day-ahead prices. As shown above, hour-ahead prices are often lower than day-ahead prices and real-time prices are above day-ahead prices.

Figure 2.7 Total weekly convergence bidding net revenues

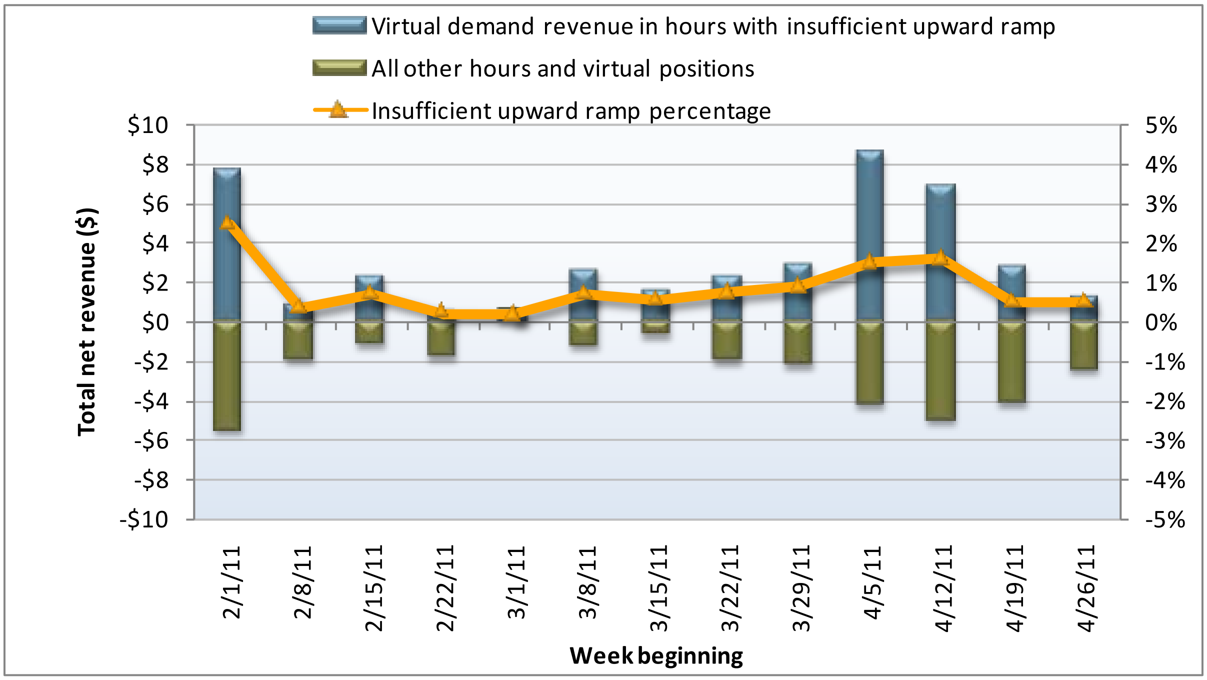


Net revenues on internal nodes

Roughly 85 percent of virtual demand bids clear at internal locations. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Specifically, intervals when the system power balance constraint relaxes account for almost all of the positive revenues for internal virtual demand positions, as seen in Figure 2.8. As noted in Section 1, 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 was increased to $1,000/MWh on April 1. Net revenues received from these brief but extreme price spikes are typically 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 spikes yields enough aggregate income to compensate losses in the remaining intervals of the hour (also shown in Figure 2.8).

As noted in Section 1, 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 issues. Moreover, in the event of over generation, real-time prices can be negative, but they never go below the bid floor equal to -$30/MWh. 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.

Figure 2.8 Convergence bidding revenues at internal nodes



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. This capacity ensures that enough committed capacity is available and on-line to meet the forecasted demand as well as any forecasted shortfalls of minimum generation requirements.

Given that cleared virtual supply generally has outweighed cleared virtual demand, more units have been committed in the residual unit commitment market.[12] This is because net virtual supply can displace physical supply in the day-ahead market. As a result, more residual unit commitment capacity is needed to replace the net virtual supply with physical supply.

This has led to the increase in the direct costs as well as in bid cost recovery payments associated with residual unit commitment. In the first quarter of 2011, total direct residual unit commitment costs

[12] Due to technical issues, DMM has not yet been able to determine what commitments, if any, have been related to cleared virtual demand outweighing cleared virtual supply.

totaled $141,000 compared to a 2010 total of $83,000. While the direct costs have increased, they remain small overall.

Bid cost recovery payments for the residual unit commitment capacity amounted to around $850,000 from February to April.[13] These bid cost recovery costs have occurred at a faster rate than any three month period in 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.[14] 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. This can create substantial uplifts that must be recovered from load-serving entities through the real-time imbalance energy offset charge.[15]

Physical net imports in the hour-ahead market relative to day-ahead market

Over much of the first two years of the market, when hour-ahead prices are low, physical net imports have typically decreased in the hour-ahead market. In the hour-ahead market, participants can directly increase or decrease their final day-ahead import and export schedules and bid prices, and submit additional import and export bids. Even if participants do not modify their bids in the hour-ahead, net imports may decrease if the hour-ahead price is lower than the day-ahead price. If hour-ahead prices are lower, fewer imports that cleared the day-ahead market may "re-clear" in the hour-ahead scheduling process. Additional exports may also clear in the hour-ahead when prices are low.

Since hour-ahead prices have been systematically lower than day-ahead prices, the amount of physical imports originally scheduled in the day-ahead that "re-clear" the hour-ahead market often decreases and the amount of additional exports that clear increases in the hour-ahead. Additional export bids (beyond those submitted in the day-ahead market) have also tended to be submitted and cleared in the hour-ahead market. This likely reflects participants' expectation that during many periods prices will be relatively low in the hour-ahead compared to prices in the day-ahead market or the regional bilateral markets. This additional demand for exports tends to increase the hour-ahead price relative to a case where no additional exports were made. However, despite this additional demand for exports, hour-ahead prices have tended to be significantly lower than day-ahead and 5-minute real-time prices.

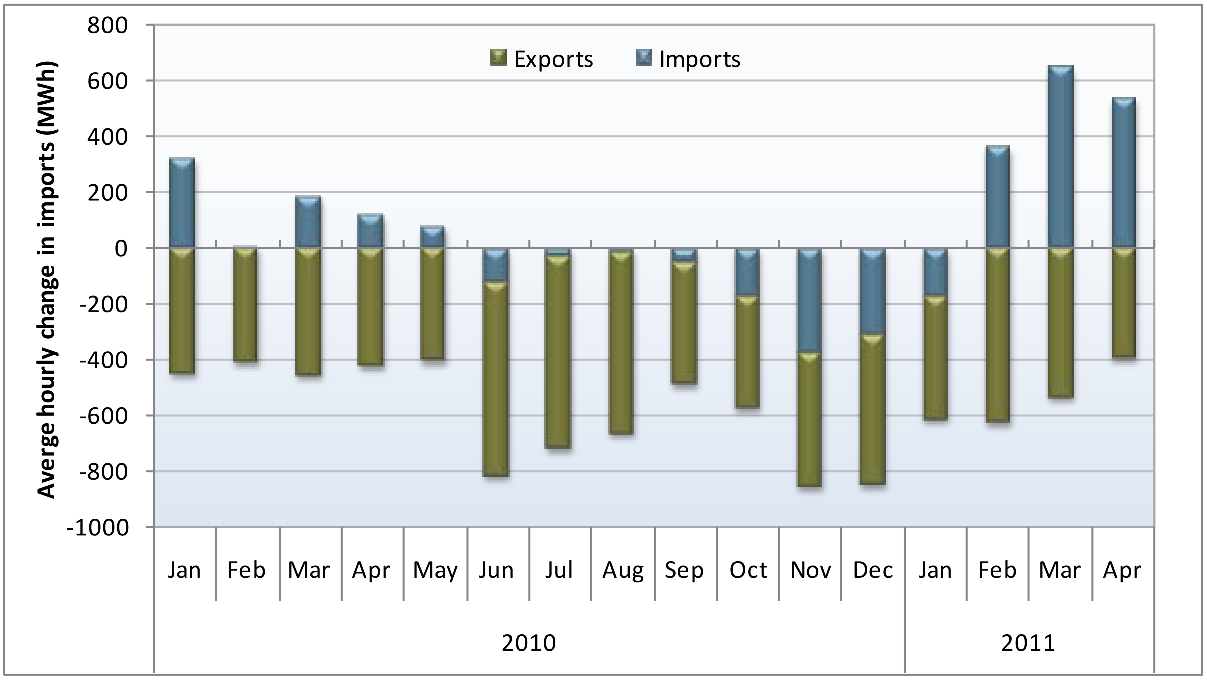
[13] Approximately $1 million bid cost recovery costs were realized in January. Most of the payments were awarded to multi-stage generation units. DMM and the ISO are investigating these payments further.

[14] 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.

[15] More information about the Real-Time Imbalance Energy Offset charge can be found on the ISO website at http://www.caiso.com/2406/2406e2a640420.html.

Figure 2.9 shows hourly average differences of scheduled physical hour-ahead market imports and exports from the scheduled day-ahead imports and exports. The figure indicates that, on average, physical hour-ahead imports relative to the day-ahead scheduled imports increased after the start of convergence bidding. Moreover, for the first time since the nodal market began in April 2009, average physical net imports increased in the hour-ahead market. The increase in average physical net imports was for over 100 MW in March and roughly 150 MW in April. In 2010, net imports decreased by over 500 MW on average each hour in the hour-ahead market.

Figure 2.9 Change in net imports in hour-ahead relative to final day-ahead schedules



Costs of decreases in net imports and in the hour-ahead market relative to real-time market

When net imports decrease in the hour-ahead and real-time imbalance energy increases, the decreased imports in the hour-ahead are likely to have increased the need to dispatch imbalance energy in real-time.[16] The green bars in Figure 2.10 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month. The lines in Figure 2.10 compare the corresponding weighted average prices at which this decrease in net imports was settled in the hour-ahead market and the weighted average prices for additional energy procured in

[16] In some cases, reductions in net import may be necessary in the hour-ahead scheduling process to manage congestion or reduce supply because of energy not scheduled in the day-ahead market, such as renewable generation or unscheduled start-up or minimum load energy from thermal units. The hour-ahead software should take this energy into account and seek to optimize prices between imports and exports adjusted in the hour-ahead and subsequent dispatches and prices in the 5-minute real-time market.

the real-time market during each month.[17] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are ultimately determined by the quantity that is reduced in the hour-ahead market and then re-procured in the 5-minute real-time market, combined with the difference in prices in these two markets.

As shown in Figure 2.10, there has been a slight increase in the price divergence between hour-ahead and 5-minute real-time market prices, averaging around $18.60/MWh with a diminished average quantity of about 370 MW in 2011.

Figure 2.10 Monthly average quantity and prices of net import reductions in hour-ahead scheduling process and resulting increase in real-time energy dispatched

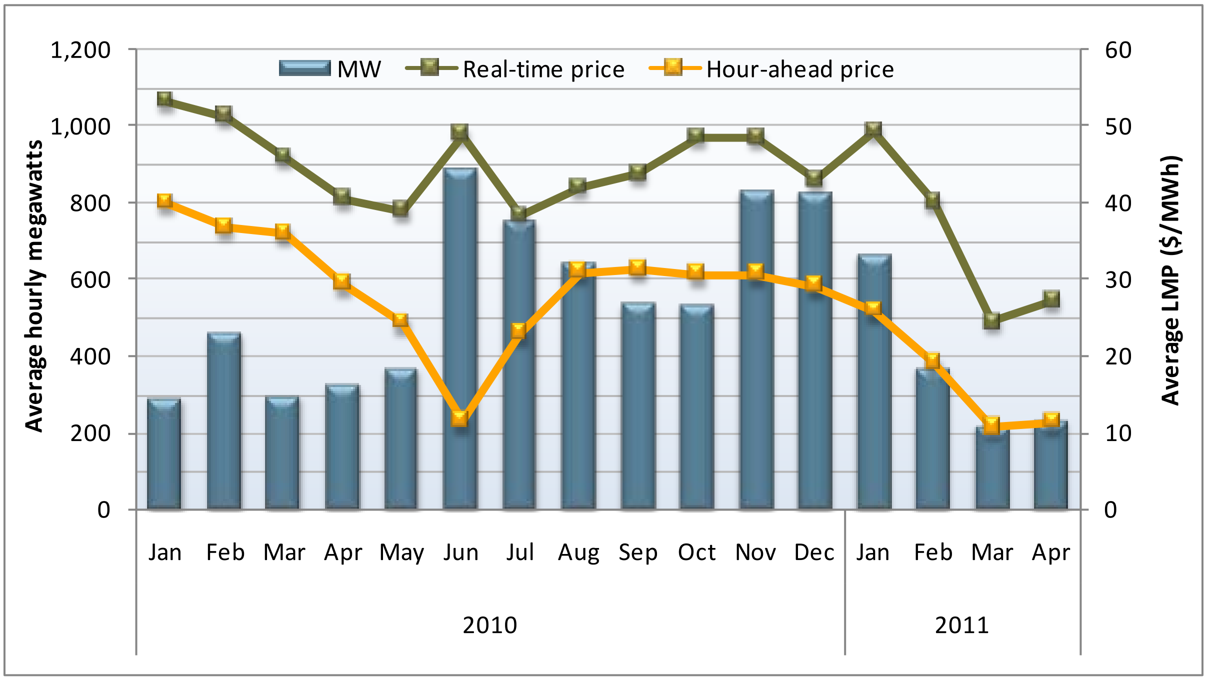


Figure 2.11 shows the estimated costs of additional imbalance energy because of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at a higher price.[18]

[17] DMM estimates the hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month based on the difference between the decrease in net imports each hour with the amount of energy dispatched in the 5-minute market during that hour. For instance, if the net imports were decreased by 500 MW in the hour-ahead, and 700 MW of net incremental energy was dispatched in the 5-minute market that hour, the entire 500 MW decrease of net imports in hour-ahead was re-procured in the 5-minute market. If net imports were decreased by 500 MW in the hour-ahead, but only 200 MW of net incremental energy was dispatched in the 5-minute market that hour, then only 200 MW of the decrease of net imports in hour-ahead was counted as being re-procured in the 5-minute market.

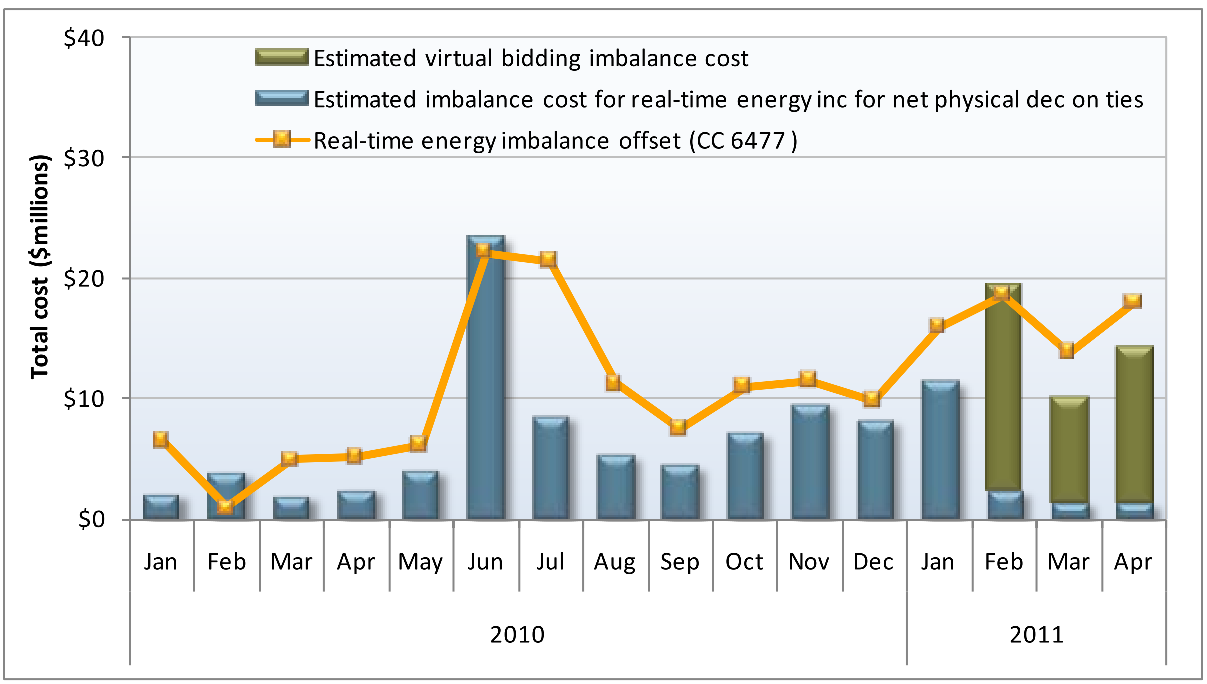
[18] DMM estimates these costs based on (1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time, and (2) the difference in hour-ahead versus real-time prices during the corresponding hour. This estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

With the introduction of convergence bidding in February 2011, these costs decreased substantially and have been replaced by a virtual bidding imbalance cost. This virtual bidding imbalance cost is related to liquidating virtual supply positions on the inter-ties at prices lower than virtual demand in the 5-minute real-time market.

The total convergence bidding imbalance cost during the first three months (February – April) was roughly $39 million. In comparison, the total estimated cost for real-time imbalance energy of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at higher prices was just over $5 million for the same period. This decrease represents roughly a 75 percent decrease from in physical import imbalance costs from pre-convergence bidding levels. However, overall imbalance costs have continued to trend upward as a result of the imbalance costs associated with virtual bidding.[19]

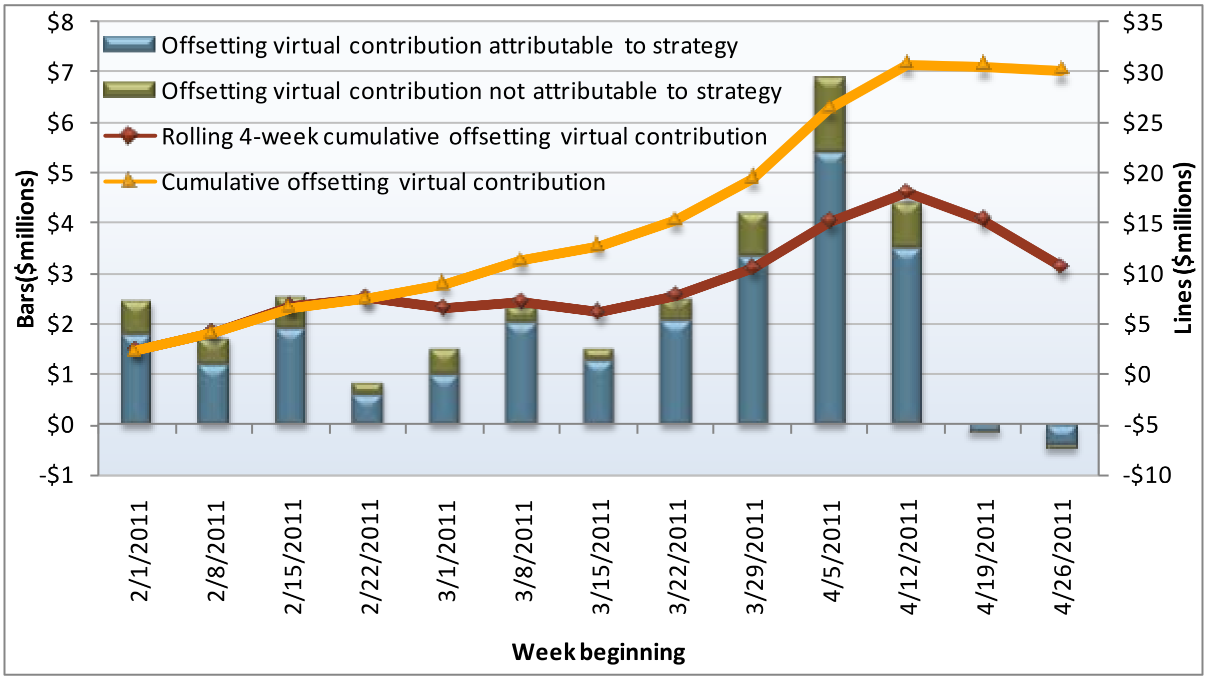
Figure 2.12 shows the breakdown of the estimated real-time imbalance cost associated with offsetting virtual supply on inter-ties and virtual demand at internal locations. Indeed, the vast majority of the real-time imbalance created by convergence bidding is associated with offsetting virtual positions. Over the course of the first three months of convergence bidding, this strategy has resulted in roughly $30 million in real-time imbalance charges.

Figure 2.11 Estimated imbalance costs because of decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at higher price



[19] DMM has noticed that starting in mid-April and continuing into May, the real-time energy imbalance changes have decreased with improvements in real-time price convergence. As a result of the improved convergence, the real-time energy imbalance costs associated with virtual bidding have also decreased.

Figure 2.12 Weekly offsetting virtual supply and demand contribution to real-time imbalance charges



2.2.4 Congestion revenue right settlement rule

The congestion revenue right (CRR) settlement rule was implemented to help deter the potential use of virtual bidding to increase payments for congestion revenue rights. The rule limits revenues from CRRs that have been increased by the strategic use of convergence bids.[20] This rule was put into place to recapture, where warranted, the increase in CRR revenues to CRR holders that are attributable to that participant or affiliates convergence bidding strategy. There is a four step approach to determine if the settlement rule will be applied:[21]

1. Calculate combined impact of participant's portfolio of virtual bids on flows of constraint for each hour;
2. Determine hours where participant's portfolio of virtual bids significantly impacted constraint;
3. Compare constraint's impact on day-ahead value of participant's CRR portfolio to the constraint's impact on real-time value of participant's CRR portfolio;
4. Apply CRR payment adjustment (netted by constraint, period — peak and off-peak — and day).

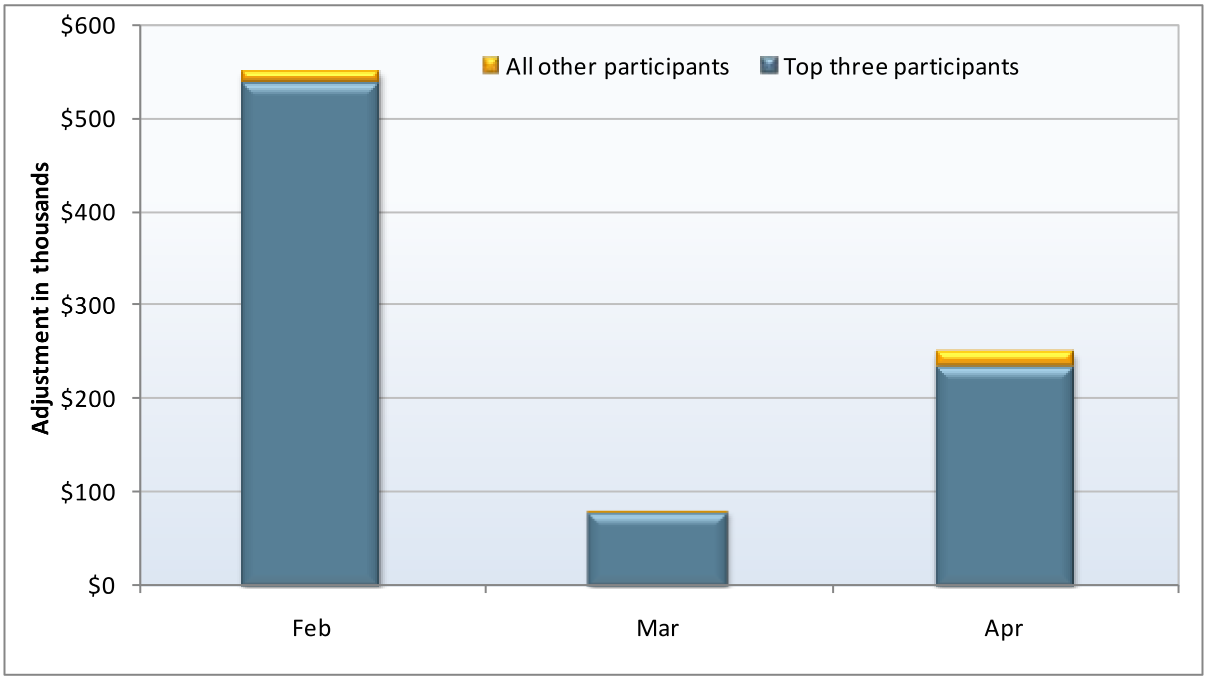
[20] This rule is very similar to the rules in other RTOs and ISOs used to limit the effects of virtual bidding on financial transmission rights (FTRs).

[21] *External Business Requirements Specification, Convergence Bidding*, December 01 2009, http://www.caiso.com/2478/24788f756dfc0.pdf.

From February through April, DMM estimates the total sum of revenue attributed to the settlement rule was approximately $884,000. These payments were removed from the congestion revenues paid to the specific congestion revenue rights holders that impacted the congestion. In total, these revenues represented roughly 1 percent of all revenues to congestion revenue rights for the period.

Figure 2.13 shows the monthly combination of peak and off-peak periods. Moreover, this figure highlights that almost all of the revenues associated with the settlement rule were concentrated on three market participants. The top three highest ranking market participants were similar over the period but their ranking varied month by month.

Figure 2.13 Congestion revenue right settlement rule: peak and off-peak periods



2.3 Recommendations

DMM recommends that the ISO place a priority on improving and maintaining convergence of hour-ahead and real-time prices though modifications to both modeling and operations of the real-time market. As noted in DMM's quarterly report for the third quarter of 2010, the costs of systematic and predictable price divergences could be magnified once convergence bidding was implemented.[22] Indeed, convergence bidding has not resolved the issue of real-time price convergence. Moreover, as long as participants can bid in offsetting virtual supply bids on the inter-ties and virtual demand bids on internal nodes, this strategy will likely continue to lead to real-time energy imbalance charges when price divergence occurs between the hour-ahead and real-time markets.

[22] *Quarterly Report on Market Issues and Performance*, November 8, 2010; covering July through September, 2010, http://www.caiso.com/2848/2848983817680.pdf.