California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

August 11, 2010

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TABLE OF CONTENTS

Executive summary

This report provides an overview of general market performance during the second quarter (Q2) of 2010 (April – June). The report also provides more detailed analysis of two special issues:

- The impact of the increase in the energy bid cap from $500/MWh to $750/MWh starting in April 2010.
- The costs incurred due to the continuing trend of decreased net imports in the hour-ahead market, which exacerbates the need to increase procurement of imbalance energy in the 5-minute real-time market at higher prices.

Energy markets

- The day-ahead integrated forward market has continued to be very stable and competitive, with a very high portion of load and supply being scheduled in the day-ahead market (e.g., typically 95 to 100 percent).
- Average energy prices in the day-ahead market during each month of the second quarter of 2010 continue to be approximately equal to average benchmark prices estimated under perfectly competitive conditions.
- Average real-time market prices in April 2010 were close to average competitive baseline levels. However, the frequency of real-time energy prices in excess of the $750/MWh bid cap taking effect in April increased in Q2 2010, particularly during May and June of 2010.[1] This increased the average real-time prices significantly above the competitive baseline prices for the day-ahead market for these months, as shown in Figure E.1.
- Because most energy is scheduled in the day-ahead market and such a small portion of overall energy is procured in the real-time market, higher average real-time prices have had minimal impact on overall wholesale energy costs.

Increase in bid cap

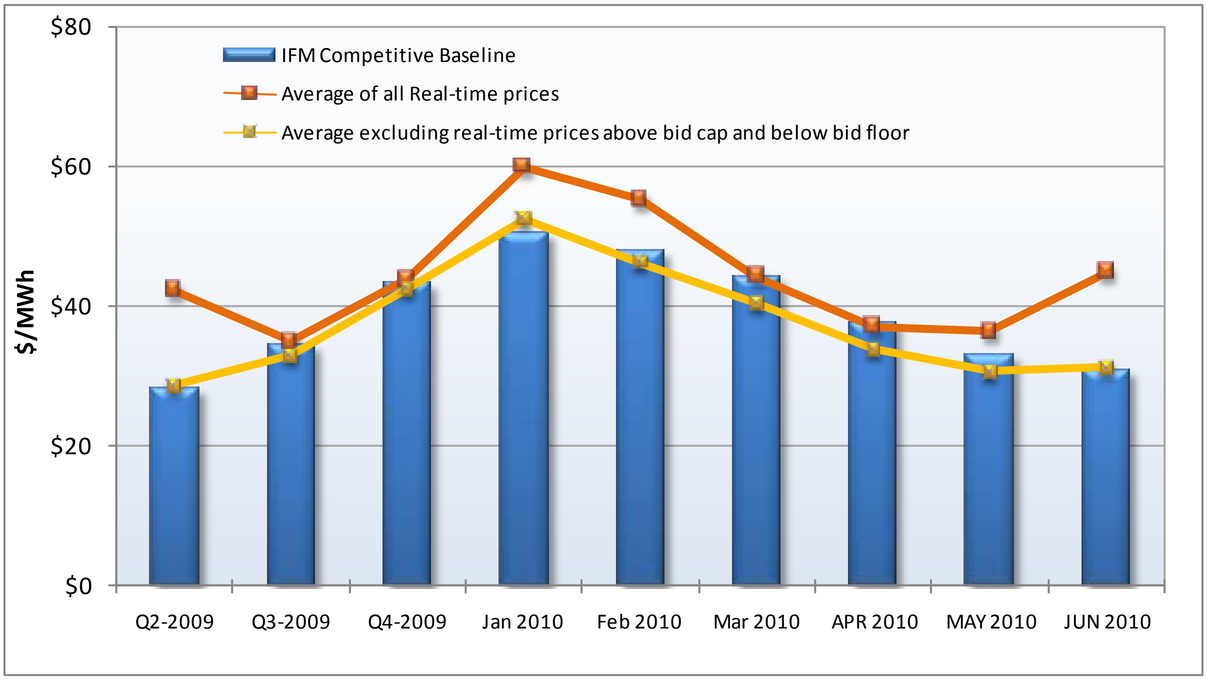
The ISO's energy bid cap increased on April 1 from $500/MWh to $750/MWh. The frequency of high prices increased after this change in the bid cap. However, not all high locational marginal prices (LMPs) are caused by the dispatch of high-priced bids. Two other primary drivers of high LMPs include violations of the power balance constraint (typically due to relatively short-term ramping limitations in real-time) and congestion on transmission constraints. Both of these types of constraints have penalty prices associated with them that can result in high shadow prices on the constraint and can impact LMPs. The penalty prices for both types of constraints are a function of the energy bid cap.[2] When the

[1] The ISO increased the energy bid cap from $500/MWh to $750/MWh on April 1, 2010, as specified by the Federal Energy Regulatory Commission (FERC). The energy bid cap will increase again to $1,000/MWh on April 1, 2011. There are no other mandated or planned increases once the energy bid cap reaches $1,000/MWh.

[2] Penalty prices of these constraints in the pricing run are set at 100 percent of the energy bid cap.

bid cap changes, so does the penalty price for these constraints. To the extent these penalty prices drive high energy prices, the increase in the bid cap will have an indirect effect on energy prices.

Figure E.1 Comparison of SCE LAP competitive baseline to real-time prices



Analysis in this report shows that increasing the energy bid cap from $500/MWh to $750/MWh in April had a negligible effect on bidding behavior and a minimal impact on market outcomes.

- A very small portion of bids (.01 percent) were submitted above the prior bid cap of $500/MWh after the bid cap was raised to $750/MWh.
- In addition, most of the high LMPs were driven by violations of the power balance constraint and binding transmission constraints (together totaling 98 percent of high priced real-time intervals), rather than high energy bid prices (representing 2 percent of high priced real-time intervals).

Thus, increasing the energy bid cap from $500/MWh to $750/MWh in April had a negligible direct effect on bidding behavior. Furthermore, while the increase in penalty prices associated with the increase in the bid cap had an indirect impact on market prices, price spikes that may have been exacerbated by these increased penalty prices were still limited to a small number of intervals in the real-time market.

The energy price cap was also changed on April 1, 2010. Previously, energy LMPs were restricted to be between ± $2,500/MWh. These minimum and maximum price limits were eliminated on April 1, 2010. Since these price limits were eliminated at the beginning of Q2:

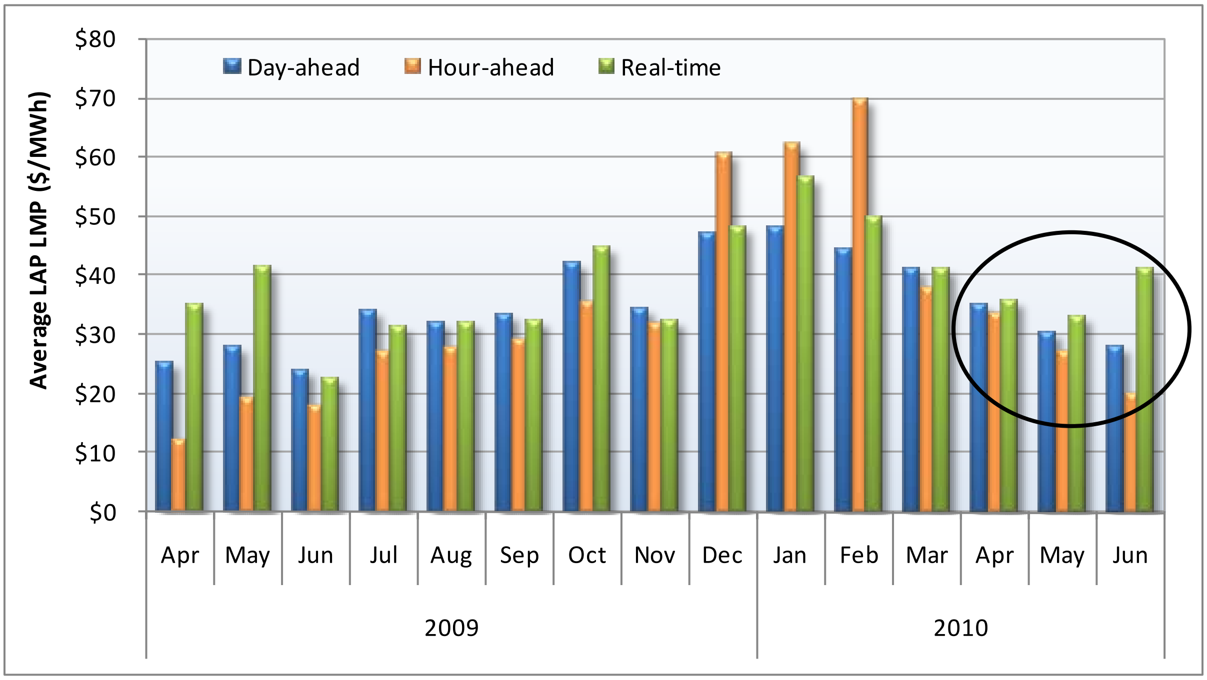
- There were no instances in the day-ahead market where nodal prices were outside the ± $2,500/MWh limits previously in place.

- There were 5 hours in the second quarter where nodal prices exceeded the former caps in the real-time market.[3] Because of the extremely locational nature of the high prices, the load aggregation point LMPs were not heavily impacted by these prices and did not exceed the former price cap levels in these instances. The estimated incremental cost of real-time nodal LMPs outside the ± $2,500/MWh limits previously in place is less than $20,000.

Divergence in hour-ahead scheduling process and real-time dispatch prices

As shown in Figure E.2, prices in the hour-ahead scheduling process (HASP) were significantly lower than prices in the 5-minute real-time dispatch (RTD) market in Q2 2010. A combination of factors contributed to this change in price convergence in Q2, which was most notable in June. These include: real-time derates on transmission capacity from the Northwest, steep load ramp in the evening hours, resource deviations by both renewable and other generation resources in real-time, unscheduled flows, and good hydro-electric generation in California.

Figure E.2 Monthly average prices (All hours, SCE LAP)



As discussed in the quarterly report prepared by the Department of Market Monitoring (DMM) for the third quarter of 2009, divergence in the hour-ahead scheduling process and real-time dispatch can create substantial uplifts that must be recovered from load-serving entities through the Real-Time Imbalance Energy Offset charge (Charge Code 6477).[4] These additional costs are incurred when price divergence is coupled with a trend for the ISO to export relatively large quantities of additional energy in

[3] These instances occurred on June 10 (one 5-minute interval), June 12 (15 5-minute intervals across three hours), and June 21 (one 5-minute interval). There were between 1 and 20 generation nodes in each interval that had high prices.

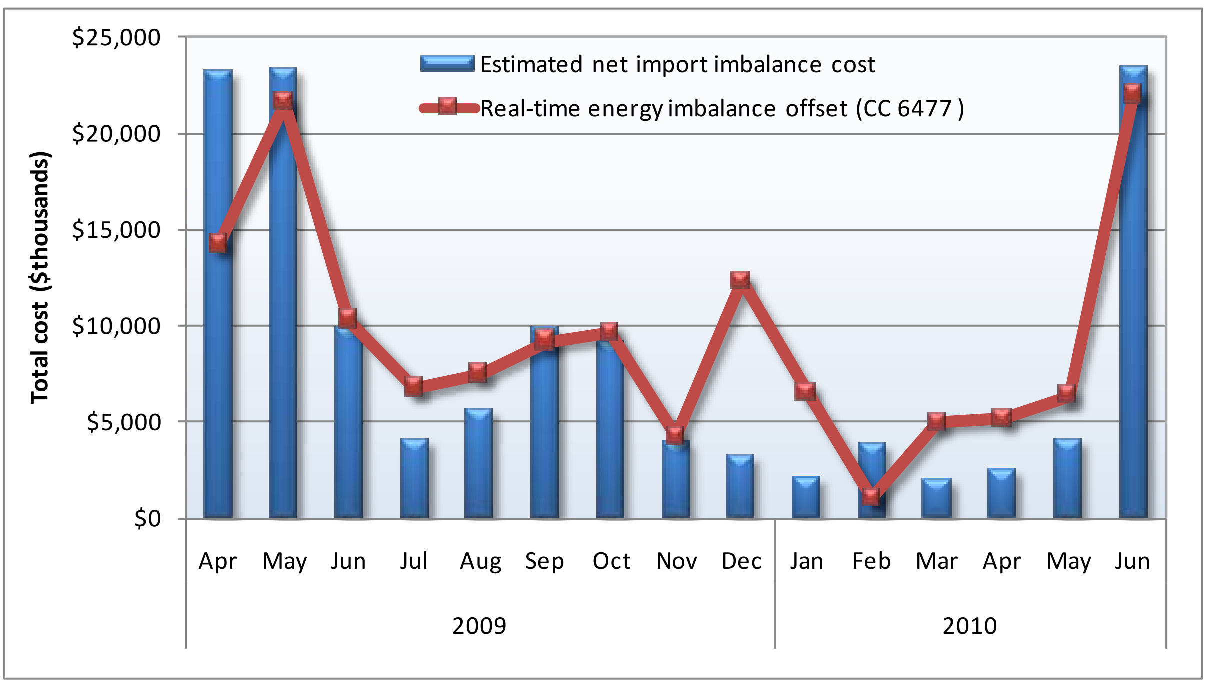
[4] *Quarterly Report on Market Issues and Performance*, Revised December 23, 2009; covering July through September, 2009: http://www.caiso.com/2425/2425f4d463570.html

the hour-ahead scheduling process (at low prices), and then dispatch additional energy within the ISO in the real-time dispatch (at significantly higher prices). As shown in Section 3 of this report, during Q2 2010, the amount of import/export energy that is reduced in the hour-ahead and then re-procured in the 5-minute real-time market has increased from an average of about 300 MW per hour in April to over 900 MW per hour in June 2010.

Figure E.3 shows the estimated costs of additional imbalance energy as a result of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at a higher price.[5] Figure E.3 also shows the actual Real-Time Imbalance Energy Offset charges from the ISO settlement system for each month. Since other factors can increase or decrease these settlement charges, these actual settlement charges and DMM's estimate of the costs associated with decreased net imports in the hour-ahead are equal and vary in some months.

As shown in Figure E.3, actual charges under Charge Code 6477 and DMM's estimate of costs due to "selling low" in hour-ahead and "buying high" in real-time are highly correlated, and increased substantially in June to over $23 million. This compares to an average of about $5 million per month in the prior 12 months, and represents the largest cost in any month since the start of the new market.

Figure E.3 Estimated imbalance costs due to decreased net HASP imports reprocured in RTD market at higher price



[5] 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.

Congestion

- Congestion on inter-ties from balancing areas adjacent to the northern half of California increased in Q2 2010 relative to Q1 2010 and Q2 2009. This is consistent with the seasonal snowpack melt in the Northwest and was coupled with increased wind generation, transmission outages and derates, and low prices in the Northwest.
- Congestion on inter-ties from balancing areas adjacent to the southern half of California generally decreased. Congestion on Palo Verde – the major inter-tie between California and the Southwest – dropped due to a decrease in the frequency and duration of scheduled outages compared to previous quarters.
- The frequency of day-ahead congestion on constraints within the ISO was very low, and had a minimal impact on overall day-ahead energy prices in Q2 2010. The SCE import limit – which was frequently binding in prior winter months – was rarely binding as the portion of load within Southern California met by imports from the Southwest decreased due to changes in load and as the amount of on-line generation within Southern California increased.

Ancillary services

- Ancillary service costs in Q2 2010 totaled $26 million, an increase of 57 percent from Q1 2010 and an increase of 5.5 percent from Q2 2009. The increase from prior quarters can be attributed to higher upward regulation and spinning reserve prices. However, as seen with the smaller increase compared to Q2 2009, a significant increase in ancillary service prices is common during the spring when hydro-electric units favor providing energy rather than ancillary services to avoid spilling water, and other non-hydro resources are selected to provide ancillary services. The effect in Q2 2010 was compounded by the fact that hydro conditions in California were better than normal.
- Ancillary service costs in Q2 2010 were about 5.5 percent higher than the same period last year, which represented the first three months of the new market design. In terms of costs per MWh of load served, ancillary service costs increased from $0.44/MWh of load in Q2 2009 to $0.48/MWh of load in Q2 2010. This increase can again be attributed to higher upward regulation and spinning reserve prices. The increase in these prices from last year can be attributed to decreased supply of these ancillary services from hydro units and increased reliance on thermal units.

Compensating injections

As noted in DMM's Q4 2009 report, in October 2009, the ISO activated a software feature designed to manage variation between market and physical flows on the major inter-ties by adding *compensating injections* at special nodes outside of the ISO system.[6] However, it was determined that during periods of high interchange ramping or inadvertent flows, these automated compensating injections were contributing to inaccuracies in the forward looking imbalance energy forecast and causing the ISO to exceed the limits of metrics that measure balancing supply and demand. In November 2009, the automated compensating injections were turned off until further refinements could be made in this software feature.

[6] Technical Bulletin 2010-07-01, *Compensating Injection in the ISO Real-time Market*, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf

The ISO then began developing and testing enhancements to the compensating injection feature. While these enhancements were developed and tested, DMM recommended that this software feature not be re-activated until automated metrics to monitor key potential operational and market impacts of compensating injections were in place and advance notice was provided to participants that the compensating injection feature will be reactivated. DMM worked with the ISO to ensure that these metrics included monitoring of the effects on modeled flows on specific major constraints within the ISO that are likely to be affected by compensating injections.

In late July 2010, the ISO re-implemented the functionality of compensating injections in the real-time pre-dispatch and 5-minute real-time market software. Prior to re-implementing compensating injections, the ISO took steps to ensure that a variety of automated metrics were in place that can be used to monitor key potential operational and market impacts of compensating injections. The ISO also issued a technical bulletin on compensating injections as well as a market notice indicating when the ISO anticipated re-activating this software feature.

DMM plans to include an update on the operational and market impacts of compensating injections based on these metrics in its next quarterly report.

Recommendation:

Improve the consistency of hour-ahead and real-time prices and dispatches.

The pattern of selling relatively large quantities of import/export energy in the hour-ahead scheduling process and then re-purchasing additional energy in the 5-minute market at higher prices remains one of the most critical areas for further improvement in the new market software and processes.

Many of the changes identified in DMM's Q3 2009 report that might address this issue are still under development by the ISO. In several cases, implementation of these modifications was initially anticipated in the end of 2009 or early 2010, but implementation is now anticipated in Q3 2010. The status of these changes as well as other ISO actions is outlined below.

- As reported in DMM's Q3 2009 report, the ISO is developing a new short-term forecasting tool that is designed to provide a more accurate and consistent forecast for both the hour-ahead scheduling process and the real-time market. In addition, this new forecast will specifically be designed to provide forecasts at the 15-minute and 5-minute level of granularity over the approximately two hour forecasting timeline needed for the hour-ahead and real-time markets. Implementation of this new forecasting tool is anticipated in the third quarter of 2010.

- In the interim, before the new tool is operational, the ISO has taken steps to improve the current forecasting tool to better forecast loads during ramping periods. A fix was implemented early in 2010. The fix was further tuned in June 2010 to better align the average 15-minute forecast with respect to the average 5-minute forecast values to reduce forecast differences between the hour-ahead and the real-time forecasts.

- In Q3 2009, the ISO assessed a variety of options that might mitigate the impacts of the differences in ways that inter-tie schedules and ramping of resources are modeled in hour-ahead compared to real-time. As an initial step, the ISO is developing enhancements that would modify the hour-ahead scheduling process to account for the imbalance energy difference that arises due to the fact that it does not model how changes in net hourly inter-tie schedules are ramped in over a 20-minute period each operating hour. Testing of this enhancement is currently in progress. The target for release is also during the third quarter of 2010.

- The ISO is continuing to look for opportunities to improve how and when to bias the system. As part of this effort, the ISO is developing a more systematic procedure that gives the operators more guidance to the maintenance of load biasing to determine whether a bias should be removed or continued.

- As previously noted, in late July 2010, the ISO implemented the capability to produce automated compensating injections in the hour-ahead and 5-minute real-time market software. This feature is designed to automatically align flows produced by the market software with actual observed flows. Thus, this feature is expected to decrease the need for manual conforming of transmission limits, and may help to improve price convergence between the hour-ahead and 5-minute markets.

- The ISO has begun a process to evaluate what products, if any, may be necessary to support renewable integration. These products could potentially address some of the issues related to low ramping capability which can affect price convergence.

While implementation of the changes identified above may improve convergence of prices in the hour-ahead and 5-minute markets, DMM believes the ISO should continue to seek to identify other potential sources of the divergence between prices and dispatches in these markets and how these may be addressed.

1 Review of market performance

1.1 Energy market

Overall performance

This section provides an assessment of the overall performance of the integrated forward market and real-time energy market. Key findings include the following:

- The day-ahead integrated forward market has continued to be very stable and competitive, with a very high portion of load and supply being scheduled in the day-ahead market (e.g., typically 95 to 100 percent).
- Energy prices in the day-ahead market during each month of the second quarter of 2010 continue to be approximately equal to benchmark prices estimated under perfectly competitive conditions.
- Real-time market prices in April 2010 were close to competitive baseline levels. However, the frequency of real-time energy prices in excess of $500/MWh and the $750 bid cap taking effect in April increased in Q2 2010, particularly during May and June 2010.[7] This increased the average real-time prices significantly above the competitive baseline prices for the day-ahead market for these months.

Day-ahead scheduling of load

Load scheduled in the day-ahead market continues to be very high. As shown in Figure 1.1 and Figure 1.2, 95 to 100 percent of real-time load was scheduled in the day-ahead market in Q2 2010. This is consistent with levels of day-ahead scheduling in Q1 2010.

The level of load scheduled in the day-ahead market can represent a key indicator of overall market efficiency and competitiveness. If the amount of load scheduled in the day-ahead market is close to the actual level of load in real-time, this generally indicates sufficient supply was made available and load bids effectively reflected market and system conditions. This generally allows for more efficient unit commitment and energy scheduling. High levels of load scheduling in the day-ahead market can also indicate that markets are competitive and that market power is being effectively mitigated. Finally, when load scheduled in the day-ahead is near actual load, the effect of extremely high or low real-time prices is low, because a relatively small portion of demand and supply is actually being settled at the real-time price.

Off-peak hours generally have higher scheduling percentages compared to on-peak hours, as shown in Figure 1.1. This is due to excess energy from online resources running at minimum load, which are committed in order to be available during higher load hours. During the evening load ramp (typically hours ending 19 to 20), the percentage of scheduling is lower due to the sudden increase in load, which can be up to 3,000 MW in an hour during winter months. This increase in load, and the subsequent

[7] The ISO increased the energy bid cap from $500/MWh to $750/MWh on April 1, 2010, as part of the 2010 Spring Market Simulation Release.

move up the supply curve, causes price sensitive load bids to clear at a lower level of actual demand at these higher prices.

Figure 1.1 Day-ahead load scheduling by operating hour (Q2 2010)

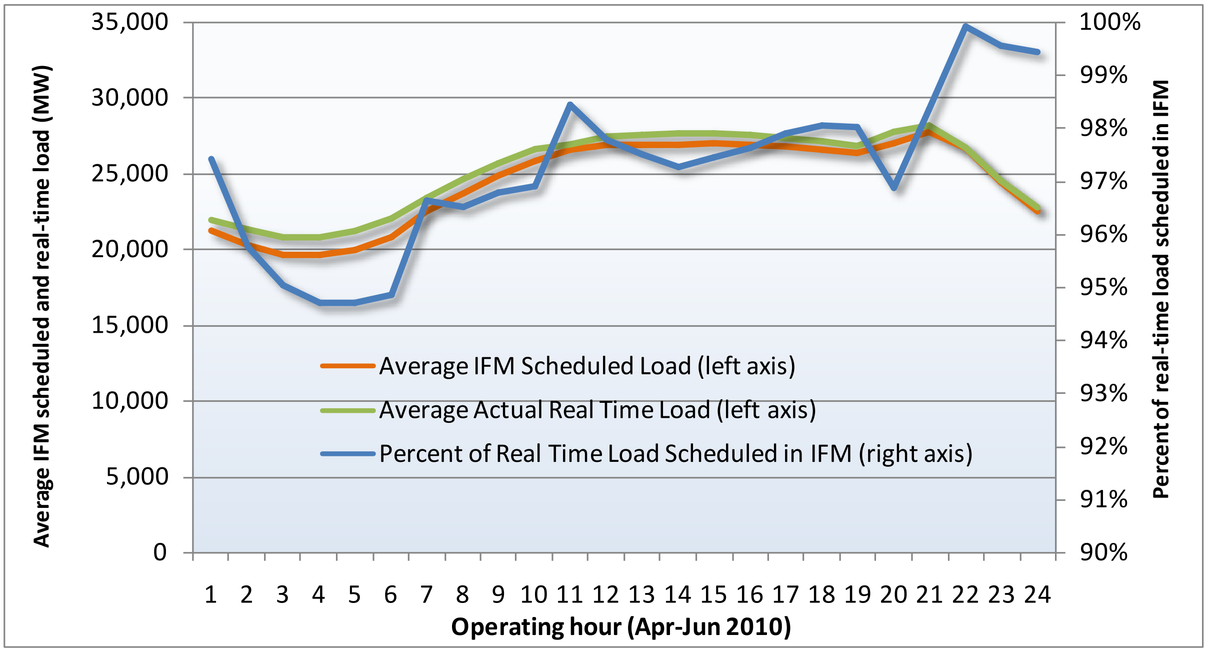
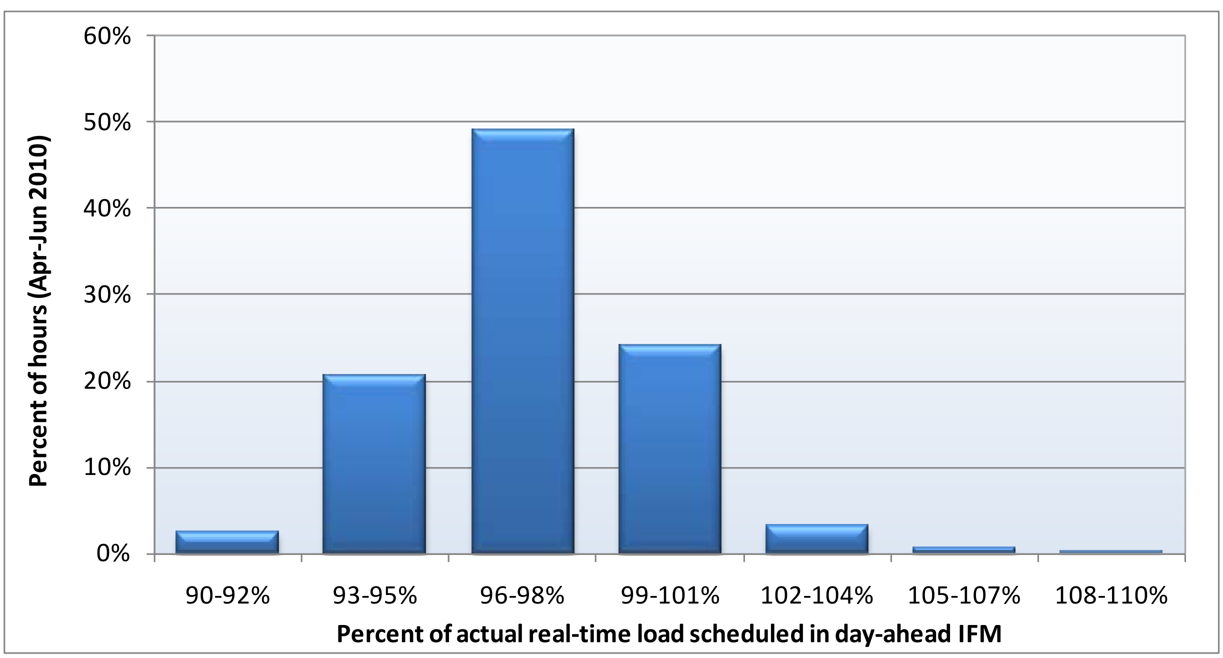


Figure 1.2 Percent of real-time load scheduled in the day-ahead IFM (Q2 2010)



Market competitiveness

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

- The first is a re-run of the market software using data for the applicable Save Case (the archive of market and system inputs and settings saved after completion of the final day-ahead market run). Results of this initial re-run are benchmarked against actual market results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[8] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[9]

- The second run of the stand-alone day-ahead market software is designed to represent a perfectly competitive scenario which provides a competitive baseline against which the re-run of actual market prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective default energy bids, which are designed to represent each unit's actual variable or opportunity costs.[10] This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs.

- 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 1.3 through Figure 1.5 show monthly summary results of this competitive baseline analysis for each of the three load aggregation points in the system.[11] As illustrated in these figures, the monthly price-cost mark-up ranged from -1 percent to -5 percent across the three months of Q2 2010 and the three load aggregation points.

Overall, the mark-up index indicates that monthly load aggregation point prices are within competitive ranges through all of the first 15 months of the new market. The mark-up index for Q1 and Q2 2010

[8] Results of the market software and DMM's stand-alone version can vary for several reasons. First, because these two systems are managed and updated independently, the DMM system may sometimes be running with a somewhat previous version of the actual market software. In addition, differences may occur due to changes in one or more settings that may have been made between the pre-IFM market power mitigation, integrated forward market and residual unit commitment runs. Data archived in Save Cases represent settings used in the final residual unit commitment run. Thus, if any changes in settings (such as the mixed integer programming (MIP) gap, for example) are made between the pre-IFM market power mitigation, integrated forward market and residual unit commitment runs during actual market operations, a re-run based on the settings used in the final residual unit commitment run that are archived in the Save Case data may not duplicate the actual day-ahead market results.

[9] For this second quarter 2010 report, results were excluded for 7 out of 30 days in April; 11 out of 31 days in May; and 9 out of 30 days in June.

[10] Under the market power mitigation provisions of the 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 (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 tariff (Tariff Section 39.7.1.3, and *Business Practice Manual for Market Instruments*, Version 1, Revised: Mar 26, 2009, D-3 to D-4).

[11] The green bar (IFM Actual) represents the weighted average price for each load aggregation point for the days that were re-run using actual market inputs (see left vertical axis). The blue bar (Competitive Baseline) shows the weighted average price for each load aggregation point for these same days based on the re-run performed using default energy bids for gas-fired generation. The orange line in each figure represents price-cost mark-up, or the percentage difference between actual prices and the prices under the competitive baseline (see right vertical axis).

shows slightly negative price-cost mark-ups, which are attributable to the fact that a significant amount of generators bid slightly below their default energy bids. Because cost-based default energy bids include a 10 percent adder above fuel and variable costs, these relatively small negative mark-ups are indicative of a competitive market and reflect the fact that actual bids for many units are designed to cover fuel and variable costs, but do not include the additional 10 percent multiplier included in default energy bids.

Meanwhile, average prices were generally lower during Q2 2010 relative to Q1 2010 in both the actual day-ahead market and the competitive baseline scenario results. This decrease can be explained by a decrease of 18 percent in spot market prices for natural gas and also by an increase in hydro-electric generation during Q2 2010 compared to Q1 2010.

Figure 1.3 PG&E LAP competitive baseline index (Q2 2009 through Q2 2010)

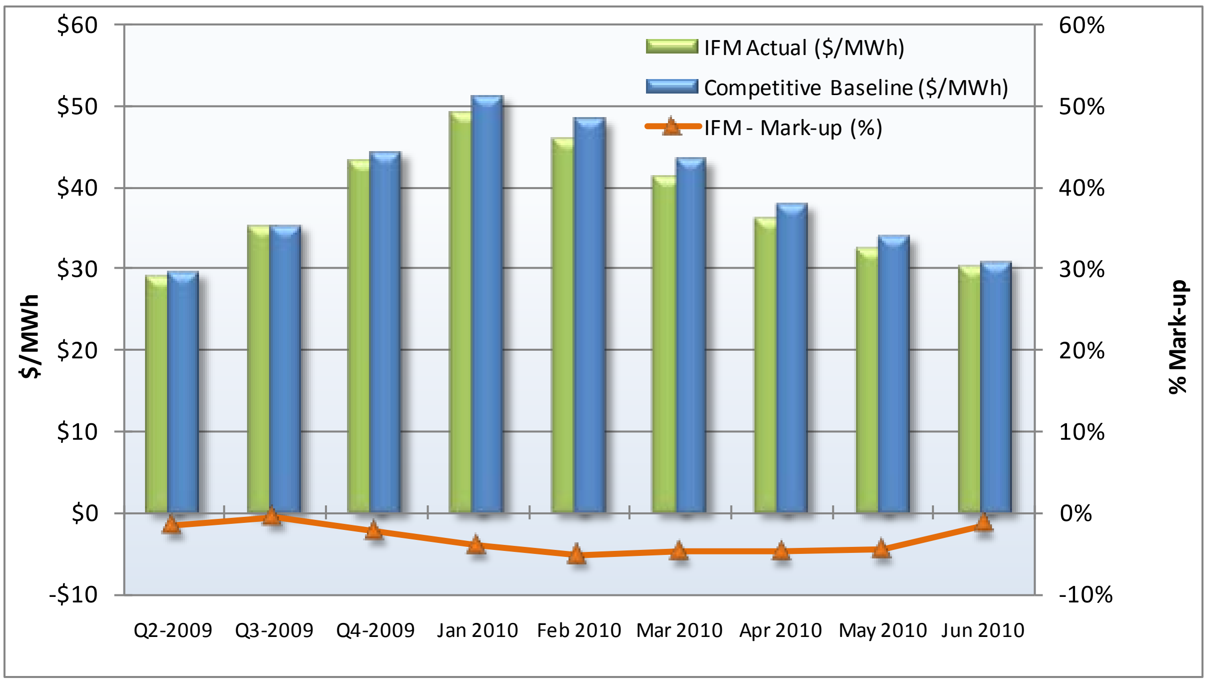


Figure 1.4 SCE LAP competitive baseline index (Q2 2009 through Q2 2010)

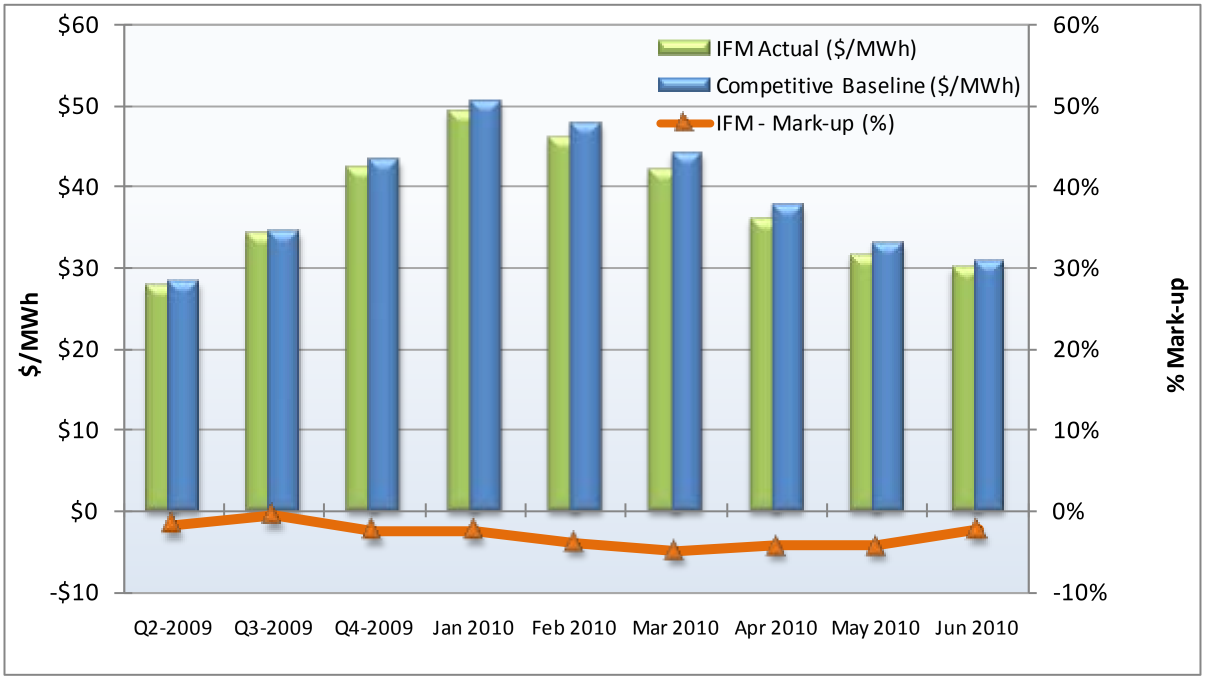
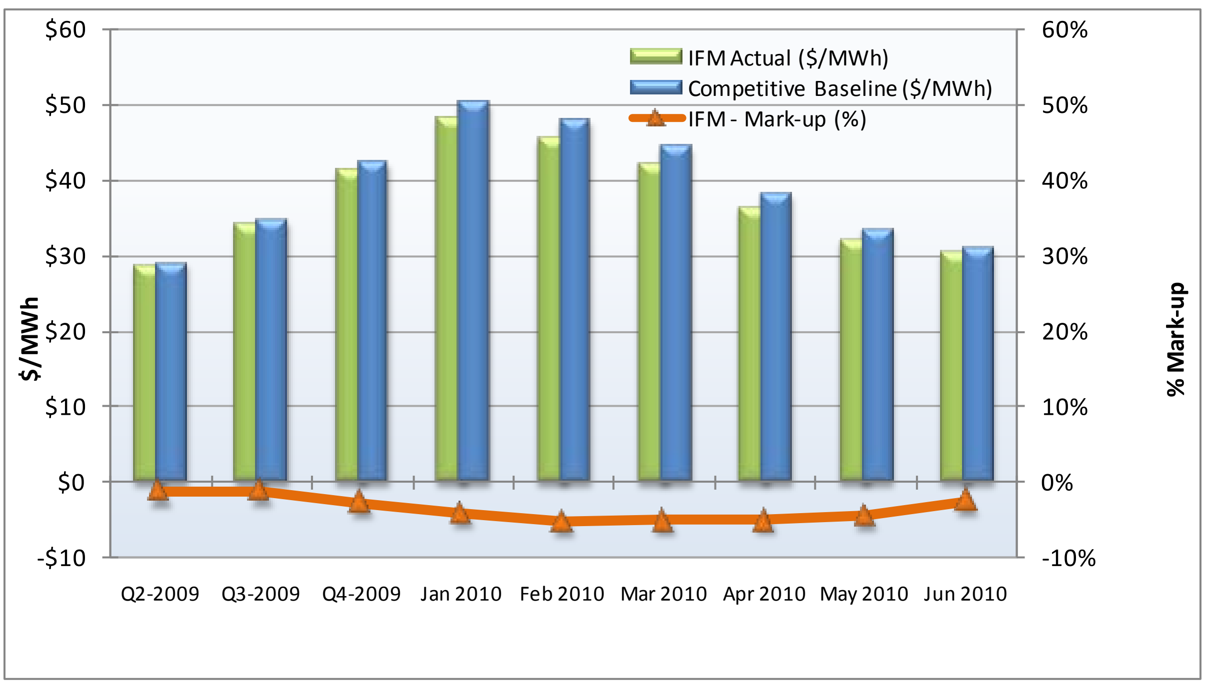


Figure 1.5 SDG&E LAP competitive baseline index (Q2 2009 through Q2 2010)



Real-time price spikes

Real-time price spikes increased in Q2 2010 from previous quarters (see Figure 1.6). The percent of intervals with real-time prices above $250/MWh increased from 0.6 percent of intervals in Q1 2010 to 1.5 percent of intervals in Q2 2010. The overall frequency for Q2 2010 was driven up by June 2010, the highest month since the new market start-up in April 2009.

The increase in price spikes was due in part to transmission derates in the Pacific Northwest and tight ramping availability in real-time. While low loads and high hydro-electric generation can decrease overall prices, these conditions can also reduce the amount of thermal generation committed and thereby create hours when limited upward ramping capability is available in real-time. Other factors included steep ramp periods in the evening hours and resource deviations, such as wind resource changes from hour-ahead to real-time and other uninstructed generation deviations. As explained in Section 2, when extremely high prices occurred in the real-time market, these prices were primarily due to the power balance constraint and congestion, rather than high priced bidding behavior.[12]

Figure 1.6 Real-time LAP price spike frequency by month

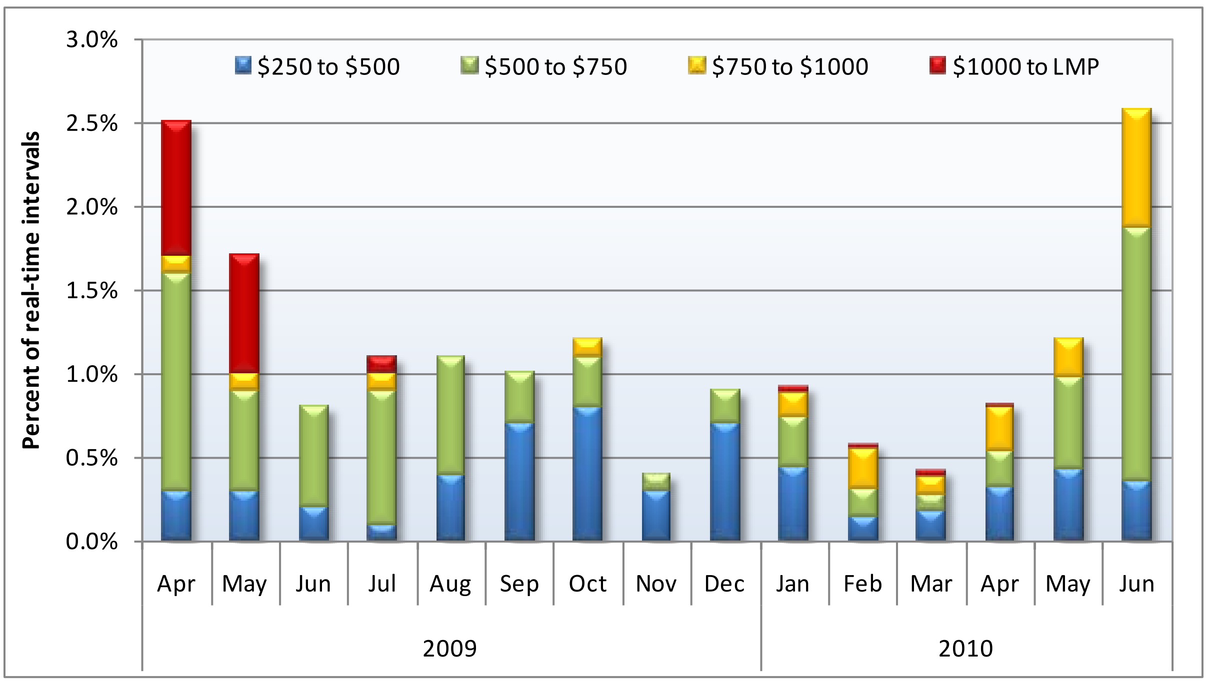


Figure 1.7 compares the competitive baseline price calculated by DMM using the day-ahead market software with three different averages of 5-minute real-time prices: (1) the average of all 5-minute prices (orange line), (2) the average with extreme 5-minute prices truncated at the relevant bid cap (green line), and (3) the average with all prices above or below the bid caps excluded (yellow line).[13] Comparing real-time prices with average prices with extreme prices truncated or excluded highlights the impact of extreme price spikes (or negative prices) which occur in a very small number of intervals on

[12] While May and June were not addressed in Section 2, the power balance constraint and congestion remained the main factor contributing to the high price levels throughout the quarter.

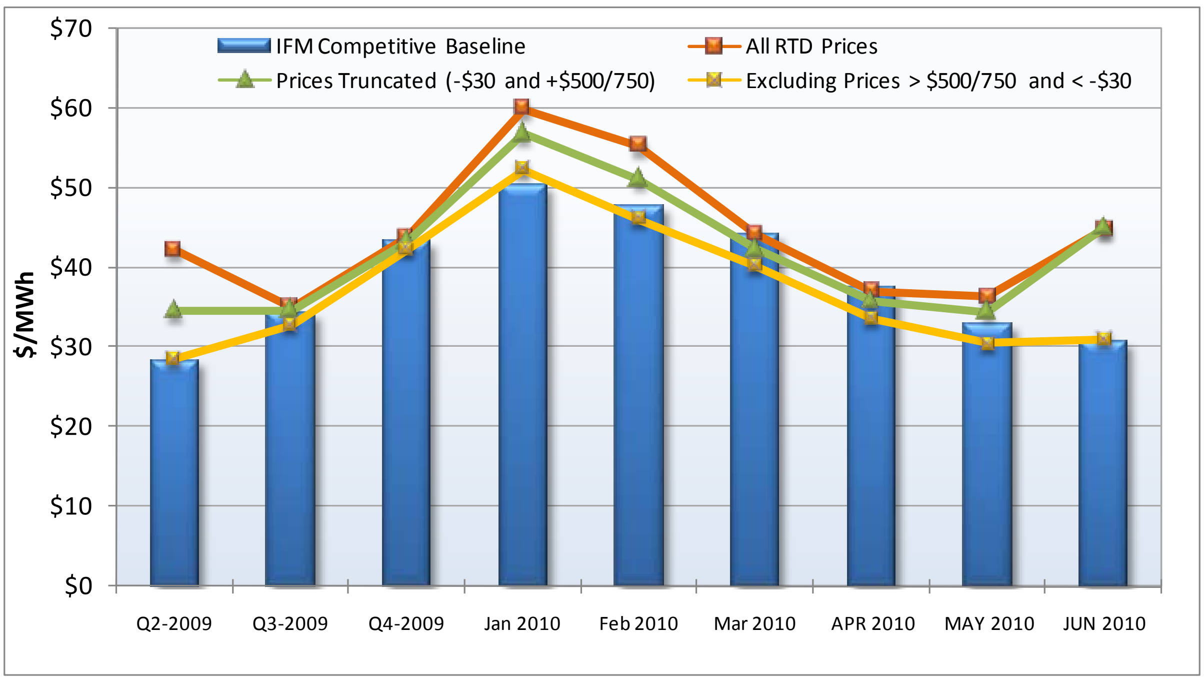
[13] Prior to April 1, 2010, prices above the $500/MWh energy bid cap in effect during this period are truncated or excluded. After April 1, 2010, prices above the $750/MWh energy bid cap are truncated or excluded.

overall average prices. In addition, when comparing real-time prices to the competitive baseline prices computed by DMM, we believe it is appropriate to exclude such extreme prices given that real-time prices reflect 5-minute operating constraints that cannot be captured in the competitive baseline estimate produced using the day-ahead market software.

As shown in Figure 1.7, all three of these price comparisons were relatively close to the competitive baseline in April and May 2010. However, in June 2010, average real-time prices rose significantly above the competitive baseline (except when extreme prices outside of the bid caps were excluded). This reflects the increased frequency of extreme real-time prices above the $750/MWh bid cap in June. As discussed in Section 2 of this report, the increase in the energy bid cap from $500 to $750/MWh contributed to the higher average real-time price by increasing the magnitude of extreme price spikes in some intervals.

As shown in Figure 1.7, when extremely high or low real-time prices (greater than the respective bid cap of $500/$750[14] or less than -$30) are excluded, average real-time prices for each of the three months are essentially equal to the competitive baseline estimate. While Figure 1.7 shows the comparisons for the SCE load aggregation point only, the PG&E and SDG&E load aggregation points exhibit similar trends.

Figure 1.7 Comparison of SCE LAP competitive baseline to real-time prices

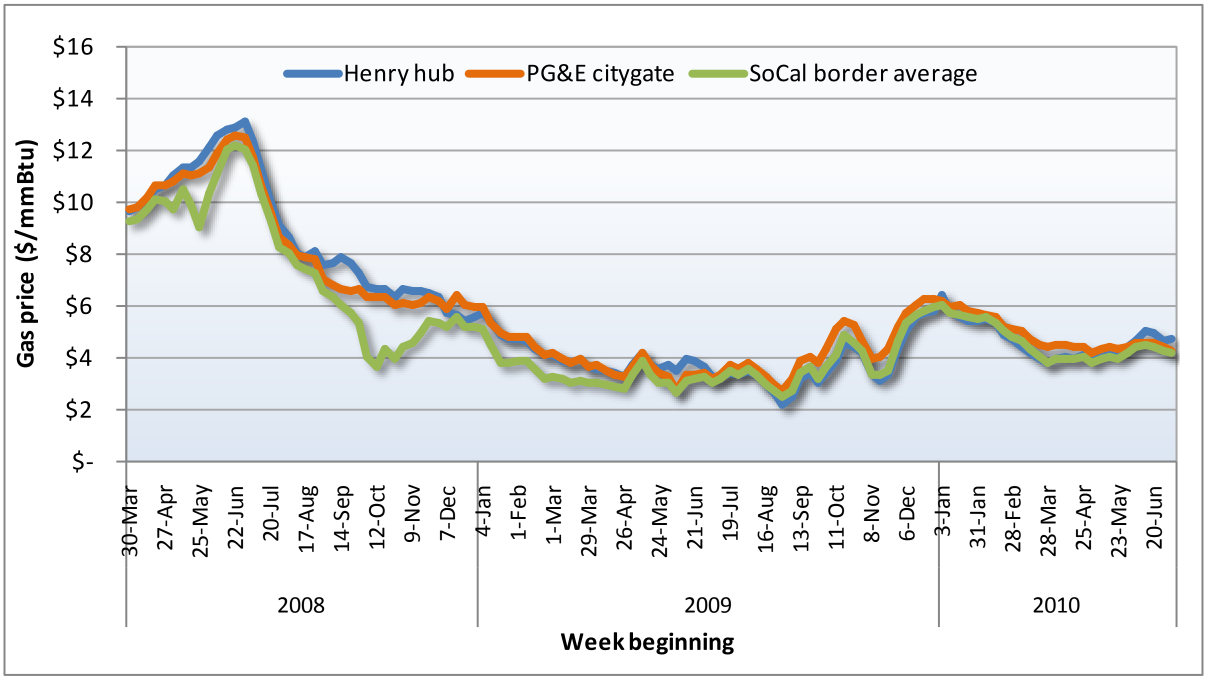


Natural gas prices

By the end of December 2009 natural gas prices reached $6/MMBtu. In early January, natural gas prices began to decline, and fell steadily throughout the first quarter. In Q2 2010, natural gas prices remained in a fairly tight range of $4-5/MMBtu for most of the quarter.

[14] Please refer to footnote 7.

Figure 1.8 Natural gas prices for Q2 2008 through Q2 2010



Monthly average prices

Average prices at the SCE load aggregation point were lower in the second quarter of 2010 than in the first quarter of 2010, as illustrated in Figure 1.9 and Figure 1.10.

In the SCE load aggregation point, monthly average peak prices in the day-ahead and hour-ahead markets were lower than prices in the real-time market. Peak prices in the day-ahead and real-time markets trended down in April and May before increasing slightly in June. This trend reflects the changes in natural gas prices shown in Figure 1.8. In addition, better than normal hydro-electric generation availability also played a role, as discussed further below.

Monthly average prices in the SCE area during off-peak hours were significantly higher for the real-time market than prices in the day-ahead and hour-ahead markets. Day-ahead and hour-ahead prices trended down compared to Q1 2010, while prices in the real-time market increased in May and noticeably in June. Energy prices in the PG&E and SDG&E load aggregation points experienced a similar trend across the quarter as the SCE load aggregation point for the three markets.

The increase in hydro-electric supply in California and from the Northwest in May and June had a dampening effect on prices in the day-ahead and hour-ahead markets. Most of these hydro resources are self-scheduled or bid as price takers. However, the increase in self-scheduled energy – coupled with low loads – also created tight ramping conditions, which in turn increased price volatility in the real-time markets. When ramping capacity is limited, prices can increase significantly when any incremental ramping capacity is needed in real-time. As a result, real-time prices were at a premium relative to both day-ahead and hour-ahead prices. This effect was more pronounced in the off-peak hours in both May and June, but also influenced the June peak prices as well.

Figure 1.11 shows price convergence between the hour-ahead and real-time markets for the PG&E load aggregation point. Overall, price convergence was significantly worse in Q2 2010 compared to the last few quarters, particularly in May and June. Real-time prices increased and hour-ahead prices decreased as a result of tight ramping conditions caused by low seasonal loads and high hydro-electric availability. This resulted in considerable price divergence between the two markets in the off-peak hours.

In June, the difference in average off-peak prices in the hour-ahead versus 5-minute real-time market was larger than in any month since the beginning of the new market in April 2009. Price differences during peak hours in June 2010 were more pronounced than April or May and second only to the peak price divergence in April 2009.

Section 3 of this report provides more discussion of factors contributing to price divergence in the day-ahead, hour-ahead and 5-minute real-time markets.

Figure 1.9 Monthly average LAP LMPs for the SCE LAP (peak hours)

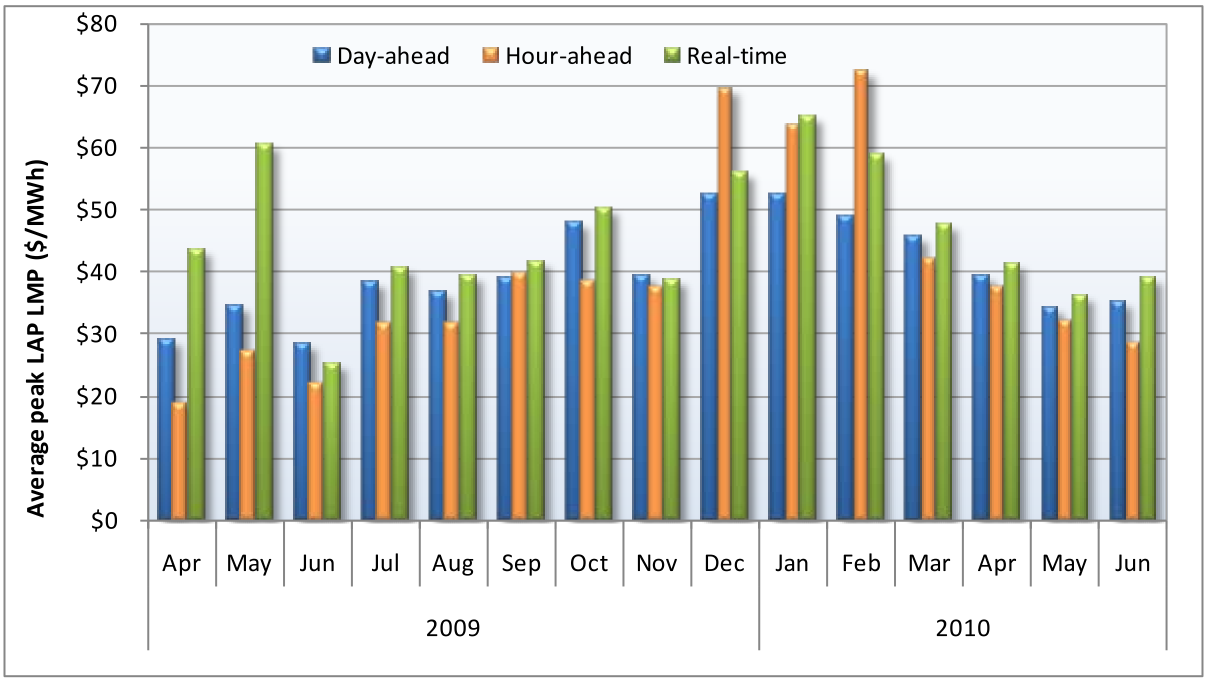


Figure 1.10 Monthly average LAP LMPs for the SCE LAP (off-peak hours)

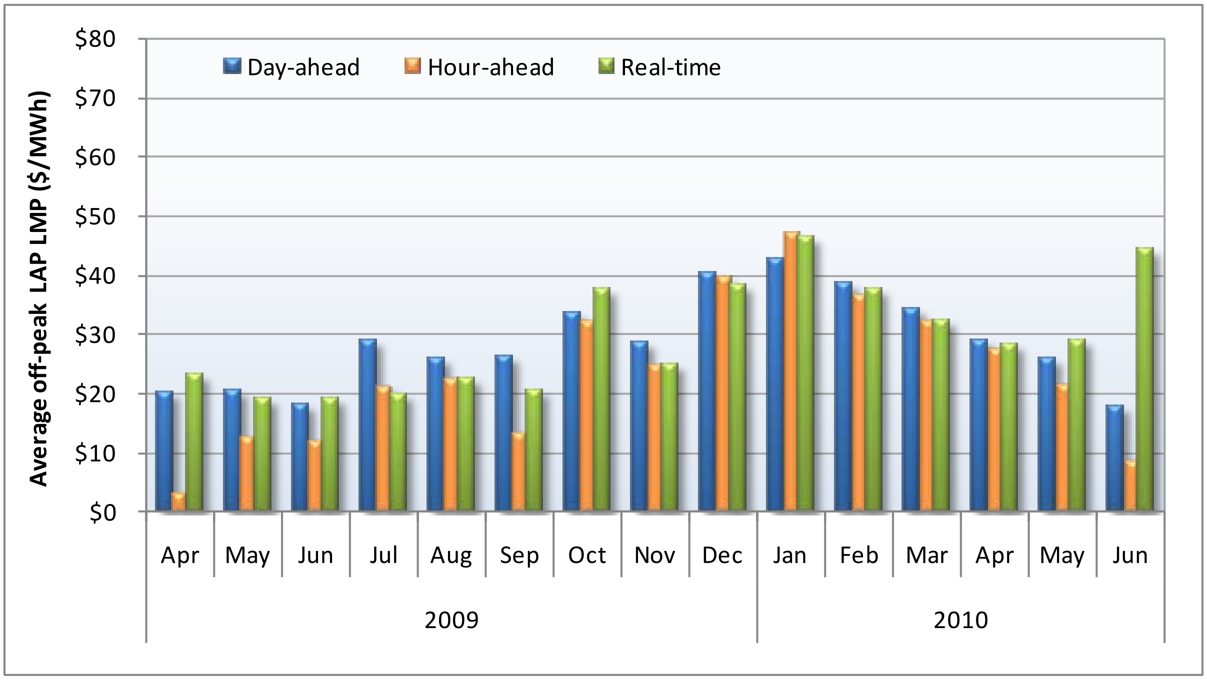
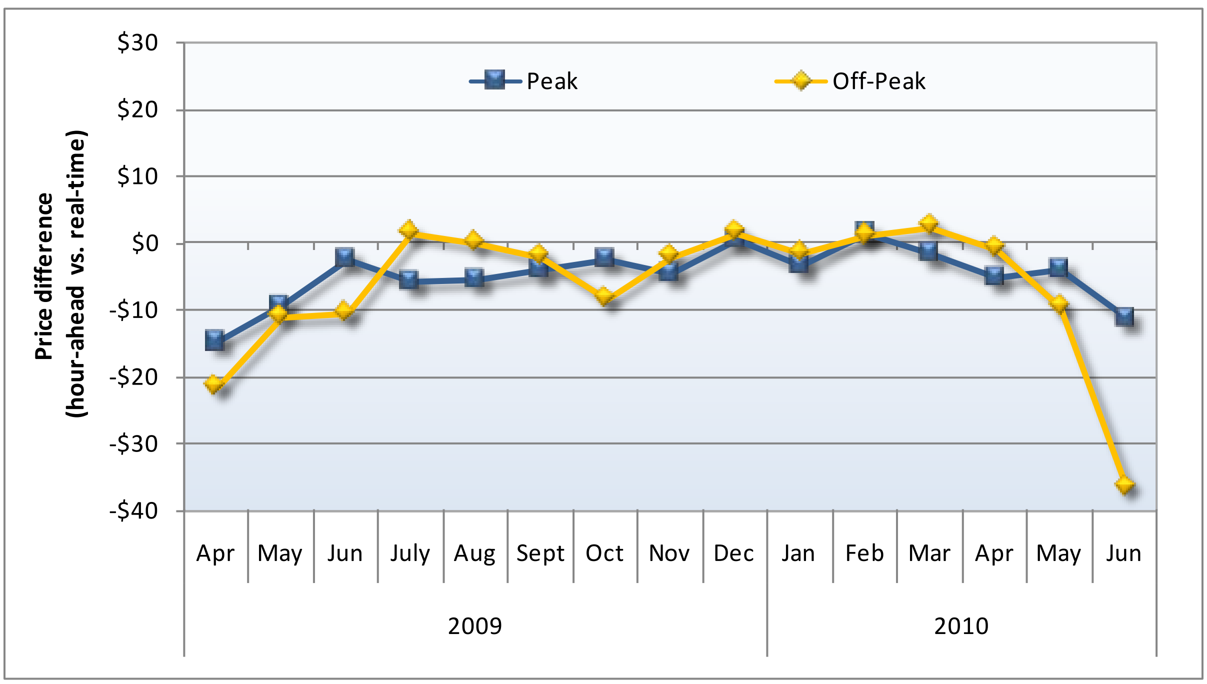


Figure 1.11 Convergence between hour-ahead and real-time LAP LMPs – PG&E LAP



1.2 Congestion

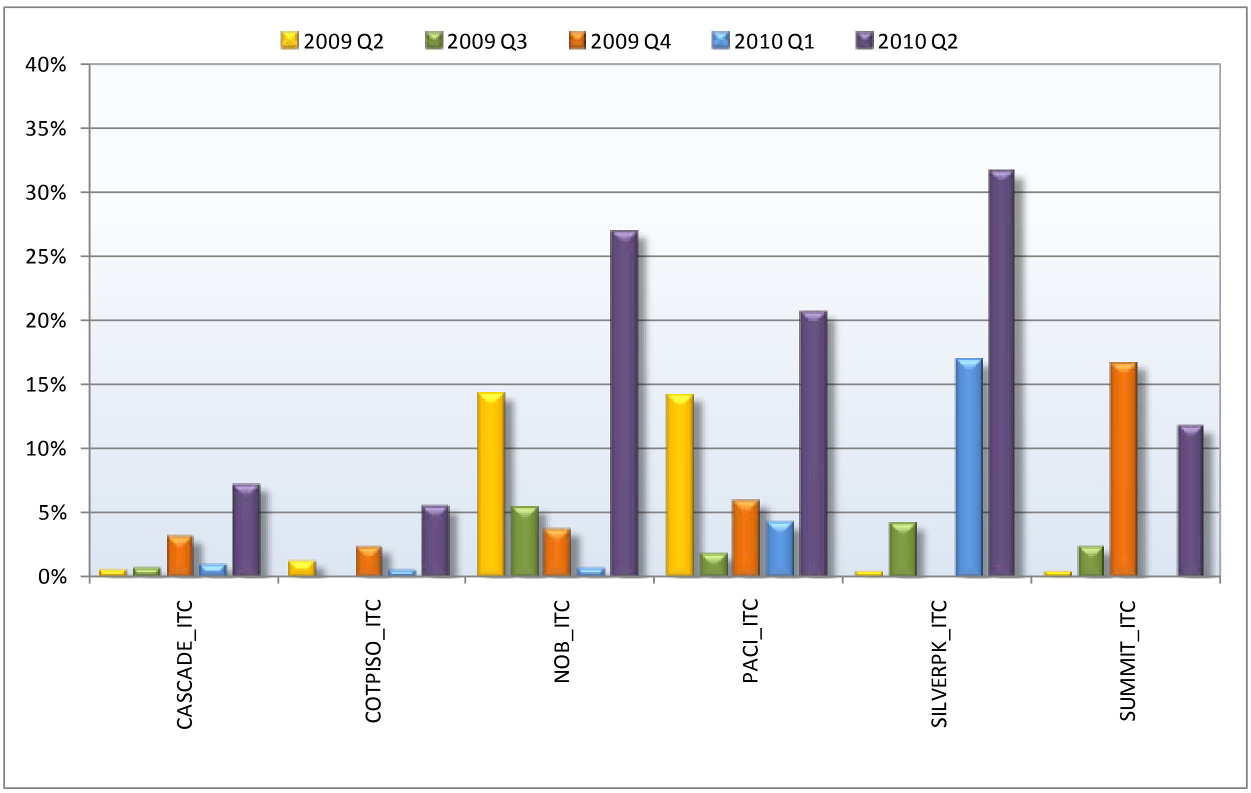
Congestion on external interfaces and scheduling limits

Figure 1.12 and Figure 1.13 provide a comparison of the hours of day-ahead congestion, in the North and South respectively, on major inter-ties on a quarterly basis from Q2 2009 through Q2 2010. Table 1.1 provides the frequency of congestion and average shadow price on the inter-ties and scheduling limits in the day-ahead market in Q2 2010.

In this section we focus on congestion in the day-ahead market in Q2 2010. Discussion of congestion that occurred in 2009 is reviewed in the *2009 Annual Report on Market Issues and Performance*.[15] The frequency of congestion on inter-ties with other regions was mixed, with some increasing and others decreasing, in Q2 2010 compared to previous quarters.

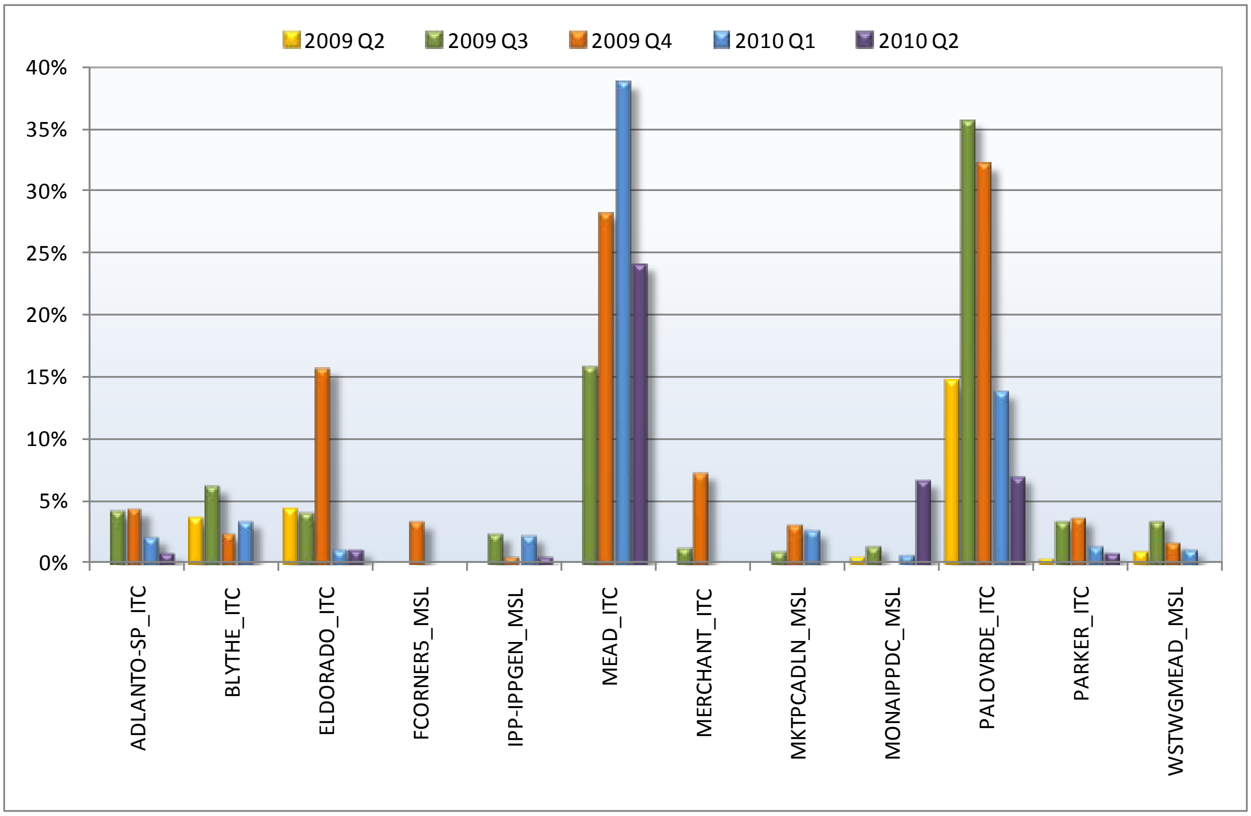
- In the North, the frequency of congestion in Q2 2010 significantly increased for the Silver Peak inter-tie, NOB, PACI and Summit inter-ties compared to Q1 2010.
- In the South, the frequency of congestion in Q2 2010 significantly decreased for Palo Verde and Mead inter-ties compared to Q1 2010.

Figure 1.12 Frequency of day-ahead congestion on major northern inter-ties



[15] *2009 Annual Report on Market Issues and Performance*, http://www.caiso.com/2777/27778a322d0f0.pdf.

Figure 1.13 Frequency of day-ahead congestion on major southern inter-ties



Key trends in Table 1.1 include the following:

- The **Mead inter-tie** was congested 23 percent of the time in the day-ahead market in the second quarter of 2010. The congestion occurred mostly during the peak hours. The average shadow price on this inter-tie was relatively low at $6/MWh. The frequency of day-ahead congestion on Mead in Q2 2010 was significantly higher than Q2 2009, which had no congestion,[16] but significantly lower than in Q1 2010 and Q4 2009. Even when congestion occurred on the Mead inter-tie, there were often significant quantities of unused capacity reserved for existing transmission contracts (ETCs) and transmission ownership rights (TORs). These transmission rights are reserved until after the completion of the hour-ahead market unless they are released by the participant prior to the running of the market. The participant may choose to schedule or not schedule power on the reserved transmission. This reduces the amount of transmission capacity available for the market, regardless of whether the capacity is used by the participant or not.

- The frequency of the **NOB inter-tie** day-ahead congestion increased in Q2 2010 compared to all previous quarters in the new market. During Q2 2010, NOB was congested approximately 27

[16] Starting November 13, 2009, the ISO created a new constraint, MEAD_ITC, as a companion to the combination of the two market scheduling limits MEAD_MSL and MEADTMEAD_MSL. This inter-tie constraint includes schedules for the following scheduling points: MEAD230 and MEAD2MSCHD.

percent of the time, with an average shadow price of $8/MWh. The **PACI inter-tie** was congested 15 percent of the time in the day-ahead market, with an average shadow price of $8/MWh. Scheduling increased at the NOB and PACI inter-ties starting in June, likely due to summer contracts in association with late spring run-off and increased hydro-electric generation in the Northwest. The congestion would also have been influenced by good renewable generation conditions in the Northwest along with transmission outages and derates, negative prices at the Mid-Columbia trading hub, and from increased hydro-electric generation in California.

- The **Silver Peak inter-tie** was congested 31 percent of the time in the day-ahead market in Q2 2010. In mid-February, scheduled work on the Miller 55kV substation limited the Silver Peak inter-tie to 0 MW in the import direction and 13 MW in the export direction. The derate lasted until the end of May 2010. The average shadow price on this inter-tie was $12/MWh.

- The **Mona inter-tie** was de-energized for scheduled work, which contributed to the congestion in the day-ahead market. Mona was congested 6.5 percent of the time, with an average shadow price of $2.70/MWh in Q2 2010. This is a substantial increase from previous quarters where congested hours were no greater than 1.2 percent, and can be mainly attributed to scheduled maintenance and line work.

- The frequency of day-ahead congestion on **Palo Verde** decreased to its lowest levels in Q2 2010 compared to all previous quarters in the new market. During Q2 2010, Palo Verde was congested 7 percent of the time, with an average shadow price of $11/MWh. Congestion in Q2 2010 decreased compared to previous quarters as a result of a decrease in the frequency and duration of several scheduled outages on Palo Verde.

Table 1.1 Frequency of IFM congestion and average shadow prices of inter-ties (Q2 2010)

Name	Congestion Frequency	Avg. Shadow Price ($/MWh)
ADLANTO-SP_ITC	1%	$5
CASCADE_ITC	7%	$11
COTPISO_ITC	5%	$14
ELDORADO_ITC	1%	$3
IID-SCE_ITC	0.5%	$57
IPP-IPPGEN_MSL	0.3%	$6
MEAD_ITC	24%	$6
MONAIPPDC_MSL	6%	$3
NOB_ITC	27%	$8
PACI_ITC	20%	$8
PALOVRDE_ITC	7%	$11
PARKER_ITC	1%	$31
POTRERO_MSL	0.4%	$1
SILVERPK_ITC	31%	$12
SUMMIT_ITC	12%	$27

Congestion on internal constraints

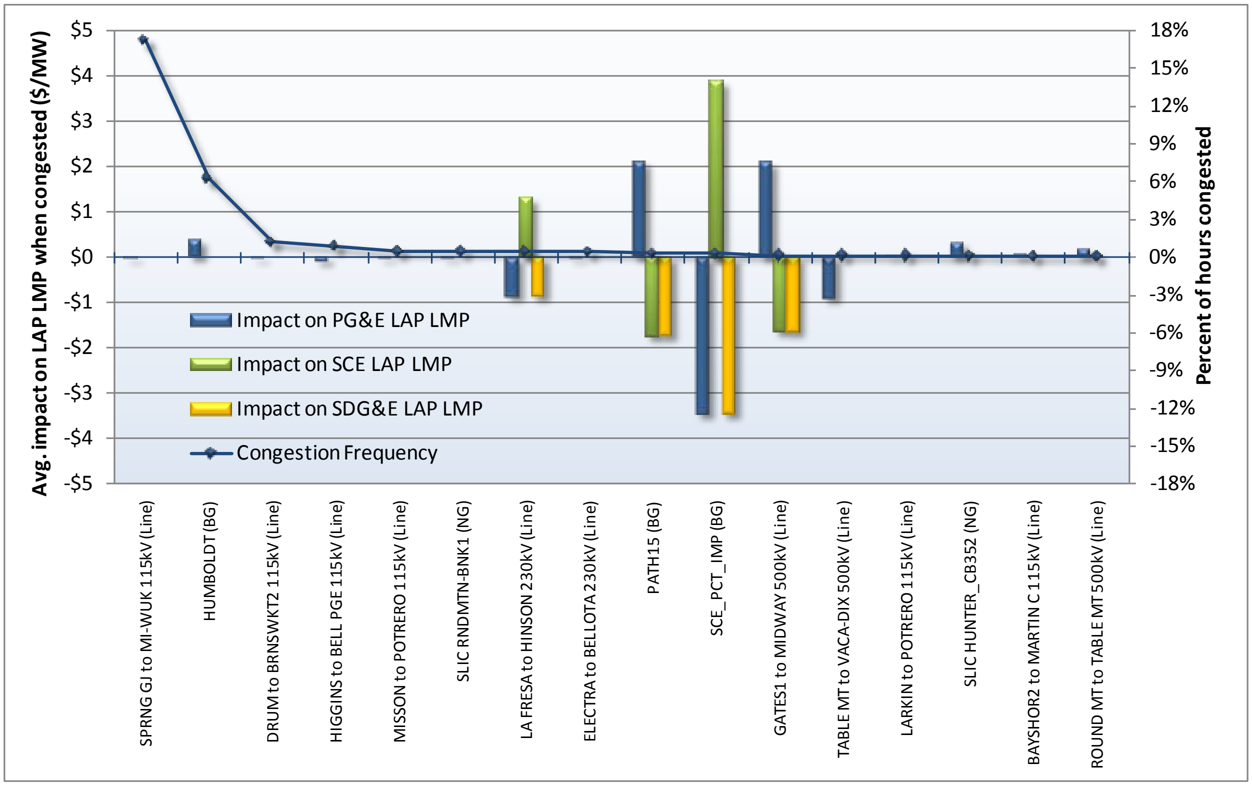
Figure 1.14 shows the impact of congestion on specific internal constraints on average day-ahead LMPs for the three load aggregation points during the hours when congestion occurred. Constraints shown in Figure 1.14 include either the most frequently congested internal flowgates and nomograms in the day-ahead market, or those that had an impact on an LMP of at least $0.01/MWh.

As shown in Figure 1.14, congestion on some constraints had a significant impact on prices in the different load aggregation points during hours of congestion. However, because the frequency of this internal congestion was very low, congestion had a minimal impact on overall day-ahead energy prices in Q2 2010. Other findings include:

- The SCE import percent branch group limit was congested 0.3 percent of the time. This is a constraint on the percent of SCE load that is met by imports into that area.[17] Congestion on this constraint averaged $3.87/MWh at the SCE load aggregation point LMPs during hours when this constraint was binding. The PG&E and SDG&E load aggregation point LMPs were negatively affected when the constraint was binding, indicating that the prices in PG&E and SDG&E areas were lower relative to both the SCE area LMP and the system marginal energy cost.
- The Path 15 branch group was congested 0.3 percent of the time. This is primarily due to a planned outage on the Los Baños to Midway #2 500kV line. The effect of this constraint on the PG&E load aggregation point LMPs during congested hours averaged $2.11/MWh. The effect on the load aggregation point LMPs for SDG&E and SCE was negative, indicating that when this constraint was binding the price in SDG&E and SCE was lower relative to both the PG&E area LMP and the system marginal energy cost.
- Spring Mi-Wuk 115kV (Line) was congested approximately 17 percent of the time. While this constraint was frequently binding in Q2 2010, this constraint had only a minimal effect on the load aggregation point congestion. This line is a radial generation tie with capacity less than that of the hydro generation tied to it. During the hydro runoff season, which occurs in the second quarter, generation becomes trapped behind the Spring Mi-Wuk flowgate. When the flowgate is congested, the hydro units can respond to prices, or, in the extreme, spill water when backed down. The nodal LMP on the generation side of the flowgate is low even when the system marginal energy component is high, resulting in a high LMP congestion component.
- La Fresa to Hinson 230kV (Line) was congested 0.5 percent of the time due to the La Fresa-Laguna Bell 220kV Line being de-energized due to inadequate relay protection in June. The effect of the constraint on the SCE load aggregation point LMPs averaged $1.32/MWh during congested hours. The effect on the load aggregation point LMPs for SDG&E and PG&E was negative.
- Gates1 to Midway 500kV (Line) was congested 0.2 percent of the time due to planned station work in May. The effect of the constraint on the PG&E load aggregation point LMPs averaged $2.10/MWh during congested hours. The effect on the load aggregation point LMPs for SDG&E and SCE was negative.

[17] A technical bulletin was posted on December 1, 2009. See http://www.caiso.com/2479/247997c52e0f0.pdf.

Figure 1.14 Effect of congestion on internal constraints on LAP LMPs (Q2 2010)



Conforming transmission constraint limits

Constraint limits in the market software are sometimes adjusted or conformed to account for differences in flows calculated by the market model and actual flows observed in real-time. Although the total number of conformed transmission constraints handled by the operators was small, the total number of hours conformed was high. Constraints tended to be conformed in the upward direction in real-time, increasing the limit on those constraints. This is typically done when the flow calculated by the market is significantly above the actual flow indicated through the energy management system (EMS). In such cases, the market is indicating a higher degree of scarcity of transmission capacity than actually exists. Grid operators will conform the constraint limit upward to more accurately reflect the available transmission capacity on the constraint. This practice avoids instances where the constraint artificially binds in the market and impacts prices when transmission was not in fact scarce.

Operation engineers review congestion in the day-ahead market on a regular basis to identify the potential need for conforming. However, transmission constraints were rarely conformed in the day-ahead market. Table 1.2 lists all flowgates and nomograms that were conformed in the day-ahead market, along with the percentage of hours that each flowgate or nomogram was conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. As shown in Table 1.2:

- Only five constraints were conformed in the day-ahead market more than one percent of the time.

- Two constraints were conformed down, on average, to 93 percent and 73 percent of their operating limits, primarily to sustain a safe reserve margin.
- Three constraints were conformed up to avoid inappropriate congestion.

Table 1.2 Day-ahead conforming limits and congestion frequencies for flowgates for Q2 2010

Flowgate Name	Conformed Hours	Average Conformed Limit	Congested Intervals	Average Shadow Price
SANBRDNO to DEVERS 230kV (Line)	3%	93%		
DEVERS_VALLEY_OUT (NG)	2%	73%		
BARRE to ELLIS 230kV (Line)	1%	115%		
DRUM to BRNSWKT2 115kV (Line)	1%	110%	0.6%	11
BRNSWKT1 to DTCH2TAP 115kV (Line)	1%	110%		

Table 1.3 lists flowgates and nomograms that were conformed in the real-time market, along with the percentage of hours that each were conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. The statistics presented in this table are calculated only for intervals in which the conforming action moved the effective limit from the actual limit. For most of these transmission lines, the conforming level was maintained at a relatively constant level during the period in which they were conformed. There was strong consistency in conforming within the real-time markets (hour-ahead scheduling process and real-time dispatch) in both frequency and level of adjustment.

Table 1.3 Real-time congestion frequency and conforming limits for flowgates (Q2 2010)

		Conformed Upward				Conformed Downward		
Flowgate Name	Conformed Intervals	Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price	Conformed Interval	Average Conformed Limit	Congested Intervals
HUMBOLDT (BG)	99%	99%	160%					
SCE_PCT_IMP (BG)	97%	97%	121%	0.04%	$611			
SPRNG GJ to MI-WUK 115kV (Line)	55%	0.1%	101%	0.02%	$5	55%	94%	41%
SDGEIMP (BG)	36%					36%	86%	0.3%
VICTVL (BG)	19%	19%	115%					
LARKIN to POTRERO 115kV (Line)	17%	17%	118%					
STANISLS to RVRBK J2 115kV (Line)	17%	17%	110%					
HIGGINS to BELL PGE 115kV (Line)	15%	15%	110%	0.02%	$1,075			
MISSON to POTRERO 115kV (Line)	12%	12%	111%					
LOSBANOSNORTH (BG)	8%					8%	82%	0.2%
COTWDPGE to WHEELBR 115kV (Line)	7%	7%	105%					
MIDWAY to VINCENT 500kV (Line)	6%	6%	110%					
SSONGS (BG)	6%	0.04%	105%			6%	84%	0.1%
PATH15 (BG)	5%	0%	102%			5%	89%	0.6%
ELIS_SANT_JOH_SANT_DERATE (NG)	4%	2%	102%			2%	95%	0.04%
MIDWAY to NAVY 35R 115kV (Line)	3%	3%	120%					
GRN VALY to MOSSLD 115kV (Line)	3%	3%	114%					

Of the 17 constraints listed in Table 1.3, operators conformed only 11 constraints (65 percent) in the upward direction in order to avoid congestion occurring in the market that was not actually occurring based on observed flows. Operators conformed some of the major branch groups (SDGE import limit, Los Baños North, Songs and Path 15) as well the Spring Mi-Wuk 115kV line downward. Operators tend to conform down the operating limit of these major transmission lines in order to maintain an adequate reliability margin. The reliability margin ensures the flow on the grid line stays within the line's operating limits even when sudden unpredictable changes in flows occur.

Table 1.3 shows that constraints were rarely congested during the intervals that their operating limits were conformed upward. Most of the congestion occurred when downward conforming was applied. The level of congestion during these instances was low overall, with the exception of congestion on the Spring Mi-Wuk 115kV line. When ratings were conformed down, the actual real-time flows were approaching the constraint operating limit more rapidly than the market real-time flow, and in some cases even exceeded the limit. In these circumstances, operators conform the constraint limit downward to get the market to manage flows by dispatching resources to relieve the constraint at a lower limit.

1.3 Exceptional dispatch

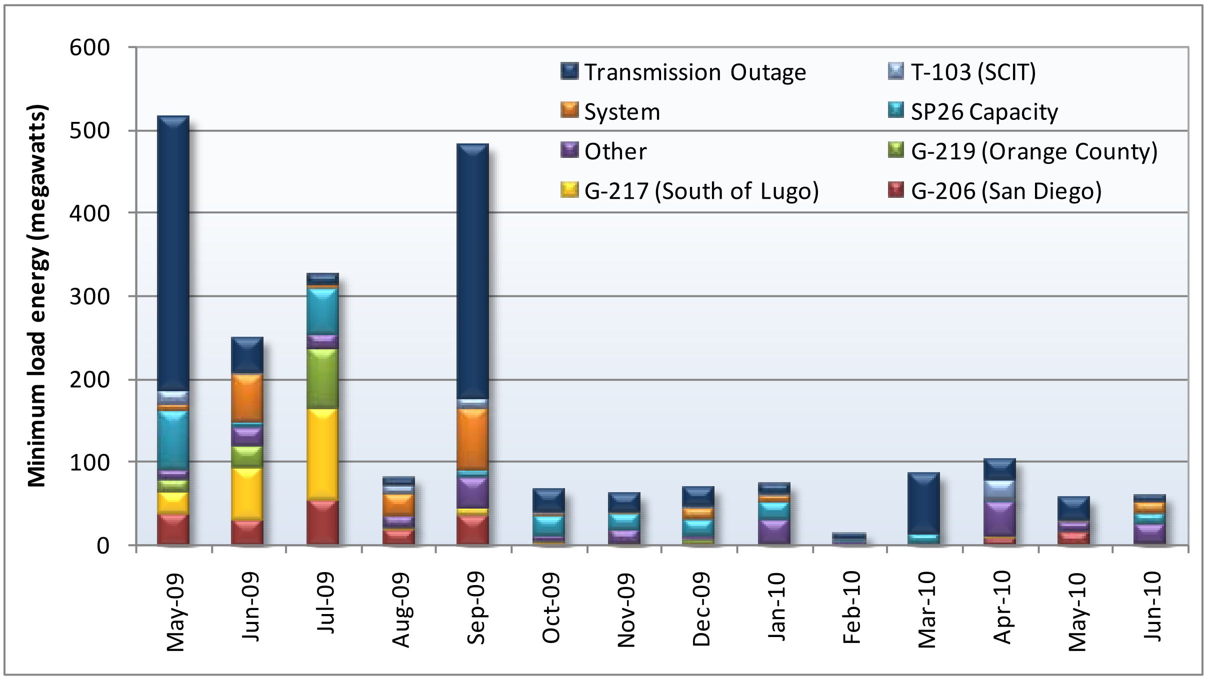
Minimum-output energy from generation committed through exceptional dispatch increased[18] somewhat, averaging approximately 73 MW each hour across the quarter. This was more than the levels seen in the previous quarter, but considerably less than most of 2009. Minimum-output energy from resources committed via exceptional dispatches ranged in the quarter from a maximum per month of approximately 102 MW and a minimum of approximately 56 MW in each hour.

Figure 1.15 shows monthly average energy from minimum-output generation committed through exceptional dispatch. The primary drivers of exceptional dispatch during the quarter were to support requirements for transmission outages as well as other factors, including the T-132 procedure (San Diego area limits).

The transmission outages in May occurred in connection to work related to the Devers-Valley 500kV Line and the Los Baños – Midway #2-500kV Line. An outage of the North-Gila-Hassayampa 500kV Line also required unit commitment in April to support reliability requirements. Also in April an outage of the Imperial Valley – North Gila Transmission Corridor required unit commitment to meet generation requirements.

[18] Enhancements have been made to the collection, collation and compilation of the exceptional dispatch data. The enhancements include augmenting the data to include both day-ahead and real-time data, clarifying resource-must-run categorization, and refining minimum load commitment levels. These enhancements have been applied to all months and have resulted in changes to the data and graphic compared to versions reported in previous quarterly reports.

Figure 1.15 Monthly average minimum-output energy from generation committed through exceptional dispatch



1.4 Ancillary services

Ancillary service costs in Q2 2010 totaled $26 million, an increase of almost 5.5 percent compared to the $24 million cost in Q2 2009 and a 57 percent increase from $16.6 million in Q1 2010. This increase in ancillary service prices is common during the spring when hydro-electric units favor providing energy rather than ancillary services to avoid spilling water, and other non-hydro resources are selected to provide ancillary services.[19]

Figure 1.16 shows the total cost of procuring all four products by region and month over the first 15 months of the new market.[20] Key trends in the ancillary service market over this 15-month period include the following:

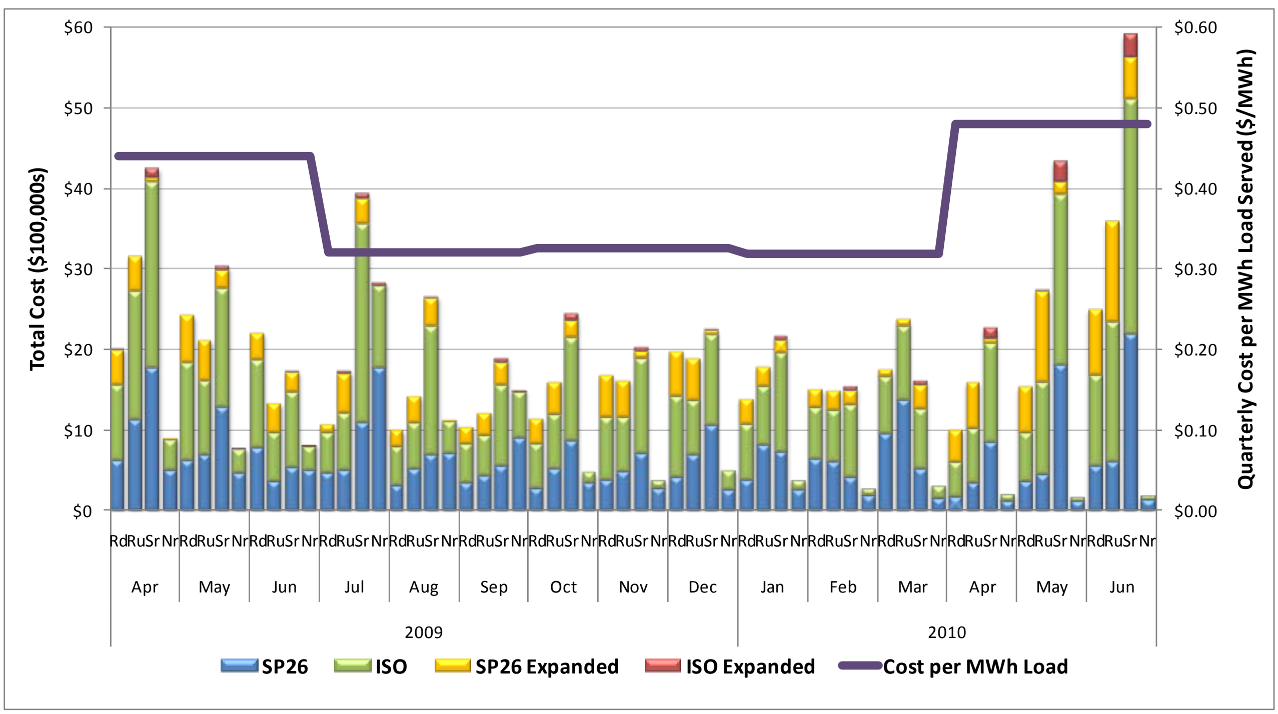
- Most of the ancillary service capacity was procured from capacity within the ISO. In Q2 2010, the cost of procuring from internal capacity was 76 percent of the total ancillary services costs, compared to 88 percent of similar costs in Q1 2010; external capacity costs in Q2 2010 were 24 percent of total costs compared to 12 percent in Q1 2010.

[19] *2009 Annual Report on Market Issues and Performance*, http://www.caiso.com/2777/27778a322d0f0.pdf.

[20] The total cost figures from April 2009 through March 2010 account for day-ahead capacity that is unavailable in real-time and charged back to the specific unit(s) at the average of the real-time price. Resources that sell ancillary services receive the prices for all regions within which they are located. For example, a resource located in SP26 and selling spinning reserve will receive the ancillary service price for the SP26, ISO, SP26 Expanded, and ISO Expanded regions. Ancillary services have been procured from four of the 10 pre-defined regions, ISO, ISO Expanded, South of Path 26, and South of Path 26 Expanded regions, in the day-ahead and real-time pre-dispatch markets.

- In May and June, the market observed an increase in the cost of procuring ancillary service capacity from the ISO expanded regions, most notably from SP26 expanded.
- Quarterly ancillary service costs increased from $0.31/MWh of load served in Q1 2010 to $0.48/MWh of load served in Q2 2010. Quarterly ancillary service costs were $0.44/MWh in Q2 2009.
- The total costs for procuring spinning reserves and regulation up in Q2 2010 increased 86 percent from Q1 2010 due to a combination of factors. The main contributing factor was the reduction of upward reserve capacity from hydro units bid in at relatively low prices due to favorable hydro conditions for serving energy. The capacity that was generally available from hydro units were either bid at a higher price or procured from other units at a higher price. The effect in Q2 2010 was compounded by the fact that hydro conditions in California were better than normal. There was also a slight increase, approximately 4 percent, in ancillary service requirement that also contributed to higher prices and costs.
- The cost for procuring regulation down totaled $2.5 million in June 2010, the most costly month for regulation down since the start of the new market in April 2009. The average monthly regulation down cost from April 2009 to May 2010 was $1.6 million.

Figure 1.16 Ancillary service cost by region



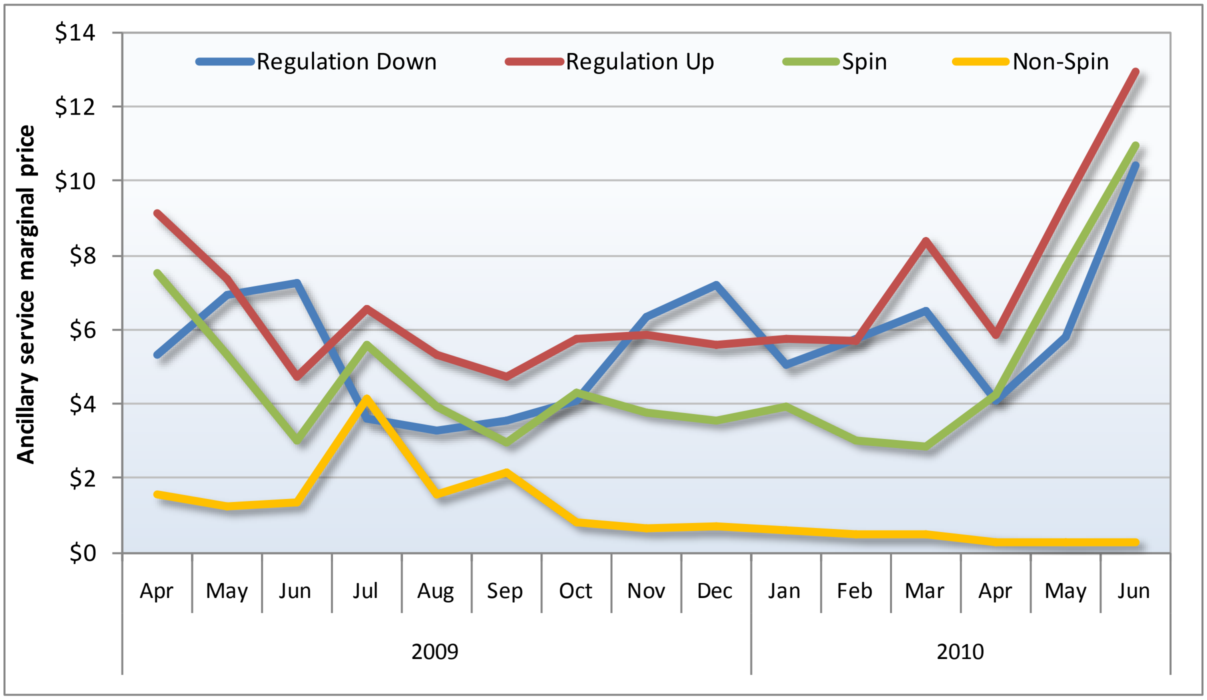
Resources providing ancillary services receive a market clearing price in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 1.17 shows the weighted average market clearing prices for each ancillary service product by month in the day-ahead market. Day-ahead prices ranged from approximately $0.30/MW to $13.00/MW. Key findings from Figure 1.17 include the following:

- The average day-ahead prices of regulation up in May and June increased to $9.45/MW and $12.94/MW, respectively. The average spinning reserve clearing prices were higher in May and June as well, reaching $7.70/MW and $10.95/MW, respectively. The reduction in regulation up and spinning reserve capacity available from hydro units, due to California's favorable hydro conditions for energy, in conjunction with higher bid prices contributed to the higher prices.
- The monthly average prices for regulation down in April and May were $4.10/MW and $5.80/MW. However, in June the monthly average price for regulation down increased to $10.40/MW, the highest price since the beginning of the new market. This increase in June was driven both by the increase in opportunity cost to provide regulation down in the early morning off-peak hours[21] as well as higher bid prices.
- Non-spin reserve prices in Q2 2010 remained low, averaging $0.33/MW for the quarter. The low clearing prices were mostly due to more capacity being bid in at lower prices when compared to the higher quality upward reserves. In addition, units providing non-spin are not required to be online, and therefore generally are not providing energy and have no opportunity cost added to the bid price.

Ancillary services prices in the real-time market were low and stable, with monthly average prices for all services ranging from $0.18/MW to $6.13/MW. The market procures 100 percent of the ancillary service requirement in the day-ahead. As a result, ancillary service volumes in the real-time market are low.

[21] During those hours, the system was experiencing light loads and most of the units were dispatched at their minimum operating levels, which were also their economic operating levels. In order to provide regulation down, some of the units were dispatched above their economic operating point. Whenever a resource is dispatched above its economic operating point to provide regulation down, it loses money in the energy market most notably during hours with negative energy prices, which is termed as the unit's opportunity cost. The resource that is awarded regulation down receives a payment equal to or greater than its regulation down bid price and opportunity cost arising from its dispatch in the energy market.

Figure 1.17 Day-ahead ancillary service market clearing prices



2 Impact of increasing energy bid cap to $750/MWh

Overview

The ISO's energy bid cap increased on April 1 from $500/MWh to $750/MWh. This section evaluates the impact of the increase in the energy bid cap on bidding behavior and market prices.

The frequency of high LMPs at load aggregation points (e.g., > $475/MWh) increased in April compared to March.[22] However, not all high LMPs are caused by the dispatch of high-priced bids. Two other primary drivers of high LMPs include congestion on transmission constraints and violations of the power balance constraint. Both of these types of constraints have penalty prices associated with them that can result in high shadow prices on the constraint and can impact LMPs. The penalty prices for both types of constraints are a function of the energy bid cap.[23] When the cap increases, so does the penalty price. To the extent these penalty prices drive high energy prices, the increase in the bid cap will have an indirect impact on energy prices.

Analysis in this section shows that most of the high LMPs were driven by violations of the power balance constraint and binding transmission constraints, rather than high energy bid prices. However, since penalty prices for the power balance constraint and binding transmission constraints are set at the energy bid cap, the increase in the energy bid cap to $750/MWh did have an indirect impact on market prices by increasing the penalty price used in the pricing run of the market software when these constraints were violated.

Bidding behavior

Figure 2.1 shows day-ahead energy bids for a typical day in May after the energy bid cap was increased to $750/MWh. As shown in Figure 2.1, an extremely small portion of energy (<1%) is bid at the bid cap in the day-ahead market. Figure 2.2 and Figure 2.3 show the average hourly percentage of real-time bids by bid category for on and off-peak hours, respectively. The bids are shown as a percentage of supply bid in between -$30/MWh and $750/MWh, and excludes all supply that was self-scheduled. As illustrated in Figure 2.2 and Figure 2.3:

- For both on-peak and off-peak hours, the percentage of supply bids offered between $400 and $475/MWh remained relatively consistent near 0.25 percent.
- Supply bid in between $475 and $500/MWh fluctuated around another 0.25 percent.
- Thus, the total supply bid in between $400 and $500/MWh in March and April before and after the increase in the bid cap was consistently 0.50 percent.

[22] This analysis focuses on the effect on energy prices at the load aggregation point LMPs. Dispatch of high-priced bids and congestion also can have an impact on individual nodal LMPs; however, individually these may not have a material impact on the price paid by load. Thus, the analysis focuses on the LAP LMPs to better highlight the effects, direct or indirect, the increase in the energy bid cap may have had on prices ultimately paid by load.

[23] The shadow price on a constraint is related to the penalty price up to a pre-determined allowance above the binding limit, currently 5 MW in real time and 0.01 MW in day ahead, after which the shadow price is no longer associated with the penalty price and can become quite large.

- In April, after the energy bid cap was raised to $750/MWh, no supply was bid in between $500 and $675/MWh, and less than 0.01 percent was bid in between $675 and $750/MWh.

The minimal quantity of bids above the previous bid cap of $500/MWh indicates that the potential effect changes in bidding behavior could have had on market prices was minimal. The remaining potential for impact is related more as a result of tight system conditions and the need to dispatch through the available bid stack than on changes in bidding behavior to leverage the higher energy bid cap.

Figure 2.1 Supply bids in day-ahead market: May 19, 2010, hour ending 13

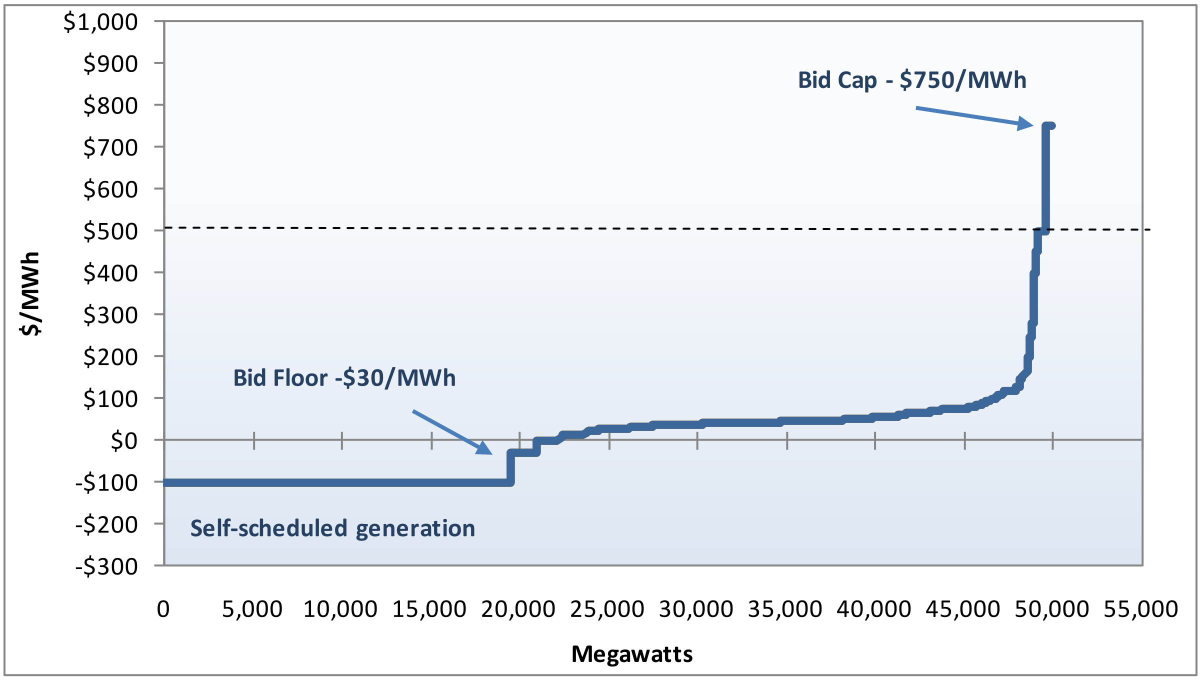


Figure 2.2 Real-time bids by price bin: On-peak hours

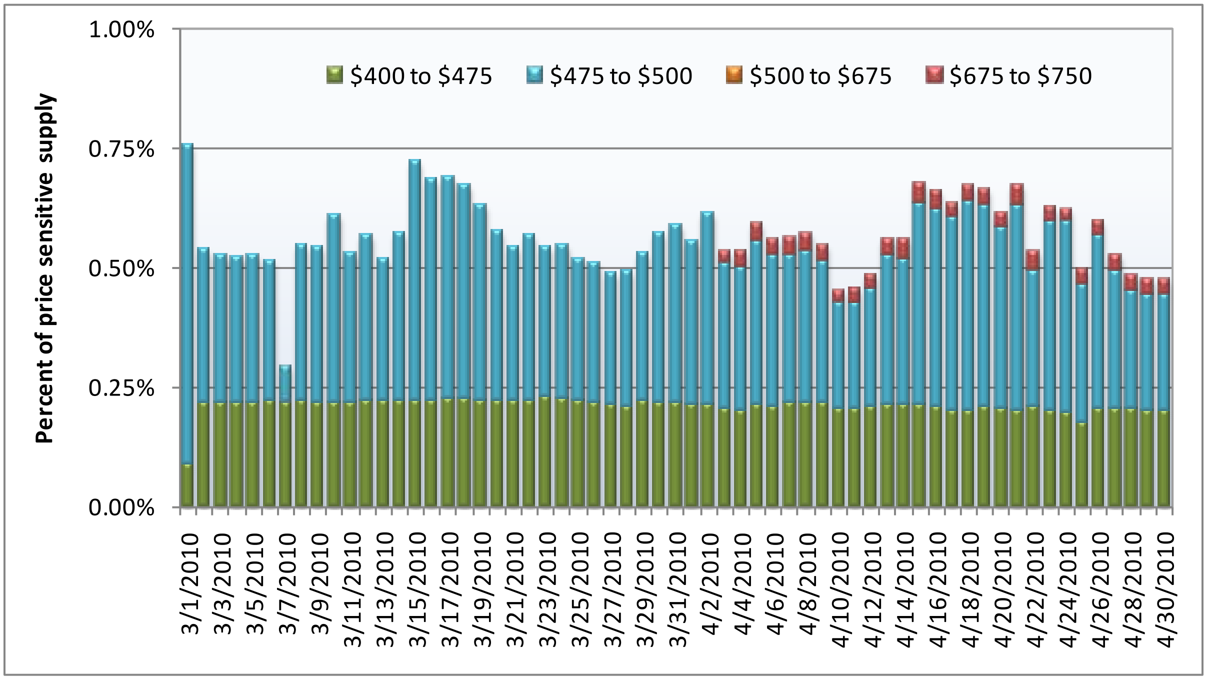


Figure 2.3 Real-time bids by price bin: Off-peak hours

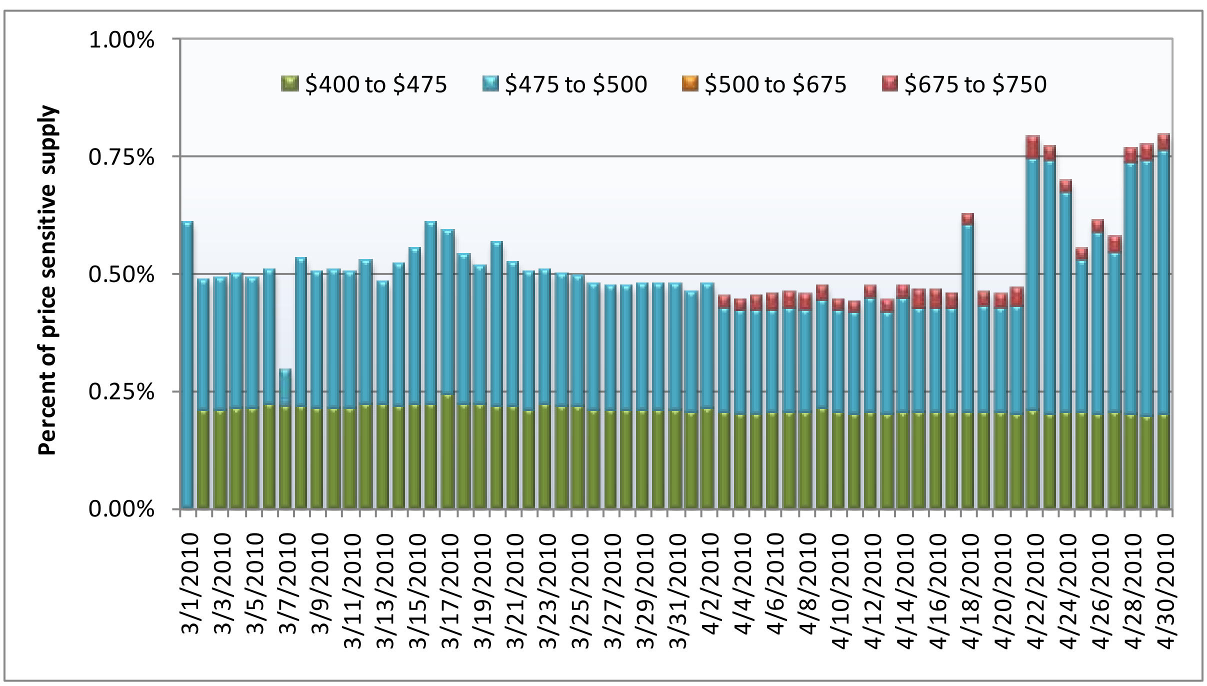
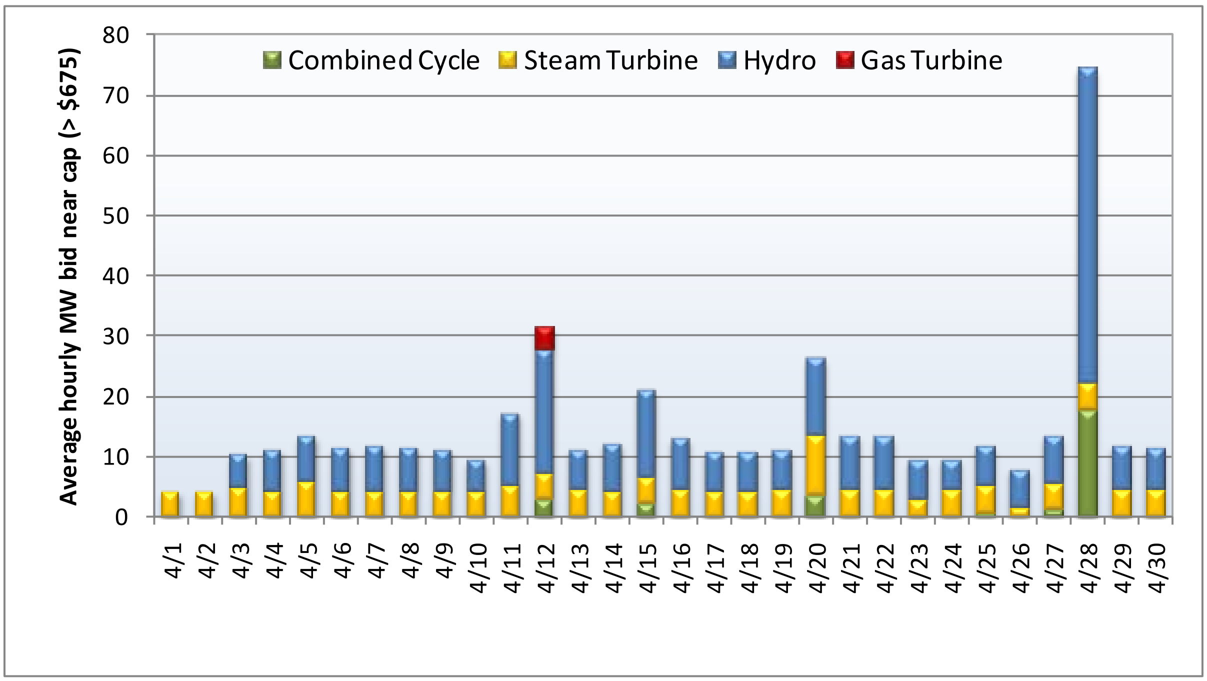


Figure 2.4 shows the average hourly supply bid in at a price greater $675/MWh for April 2010 by technology type. This figure shows the types of resources that are bidding in at or near the new energy bid cap. About 93 percent of the high-priced supply for the entire month of April was bid in by hydro or steam turbine units. On average, only about 10 to 12 MW were bid in each hour at or near the cap (above $675) with the exception of five days during which additional resources submitted 18 to 75 MW of high-priced bids.

Overall, real-time bidding behavior from March to April before and after the increase in the energy bid cap does not seem to have changed significantly. Of the minimal supply at or near the new energy bid cap, most of the supply is offered by hydro and steam turbine units.

Figure 2.4 Real-time supply at higher bid prices by generator technology (April 2010)



Market impact of higher bid cap

Real-time energy prices can increase up to, and beyond, the energy bid cap for various reasons. The main driving factors include: (1) violations of the power balance constraint, (2) binding transmission constraints, and (3) dispatch of higher priced bids.

When the power balance constraint is violated, the system energy component of the LMP, which is consistent for all LMPs in a given interval, is set by a high penalty price and results in high LMPs. Congestion on the system impacts LMPs differently depending on the direction of congestion and proximity of a pricing node to the location of congestion. The congestion component of the LMP will reflect the effect congestion had on the price of energy at that location.

Both the power balance constraint and transmission constraints have penalty prices that are invoked when the constraints are violated. These penalty prices are functions of the energy bid cap and increase as the cap increases.[24] This creates an indirect effect of the increase of the energy bid cap on energy prices through the constraint penalty price (when the constraint is violated).

Increasing the energy bid cap, and consequently the constraint penalty price, does not change the frequency of when these constraint violations influence prices. However, it does increase the *magnitude* by which such constraints will affect prices when violations occur.

Lastly, absent violations of the power balance constraint and transmission constraints, a high LMP may result from dispatching a high priced bid, which would most likely be reflected in a high system energy component. The frequency of high LMPs as a result of dispatching high priced bids would be an indication of the market effect the new energy bid cap has had on real-time energy prices.

Figure 2.5 shows the frequency of real-time prices greater than $475/MWh by load aggregation point.[25] As shown in Figure 2.5, the frequency of high real-time prices increased around April 1 and continues through the end of the month. Following the increase in the energy bid cap on April 1, the frequency of high priced load aggregation point-level LMPs slightly increased, from about 0.03 percent of load aggregation point LMPs in March to 0.05 percent in April.

In many – if not most – cases, the precise cause of high LMPs at the nodal or load aggregation point cannot be determined. In many cases, high LMPs result from a combination of different constraints and bid prices. However, DMM developed the following method to assess the extent to which higher bid prices submitted after the bid cap was raised to $750/MWh in April may have contributed to higher LMPs. With this approach, each of the intervals with a relatively high LMP depicted in Figure 2.5 were categorized as being primarily a result of (1) the power balance constraint, (2) the power balance constraint and congestion, (3) congestion, or (4) dispatch of a high priced bid.

- If the power balance constraint was violated as a result of a shortage and the congestion component of the LMP was less than $200/MWh[26] (i.e., congestion was not the major component of the LMP), then the power balance constraint was identified as the primary cause of the high price.
- If the power balance constraint was violated and the congestion component of the LMP was greater than $200/MWh, then the power balance constraint and congestion were identified as the primary causes of the high price.
- If the congestion component was greater than $200/MWh, then congestion was identified as the primary contributing factor.

[24] The power balance constraint in the market model ensures supply is equal to demand. When the constraint is violated during an under-generation condition, the system energy component is set by a $750 penalty price and thus impacts all pricing nodes equally. In some cases, DMM has found that even though the power balance constraint is violated, the system energy component is set at a price less than the $750 penalty price. The ISO has recognized this as a software issue and is pursuing a fix.

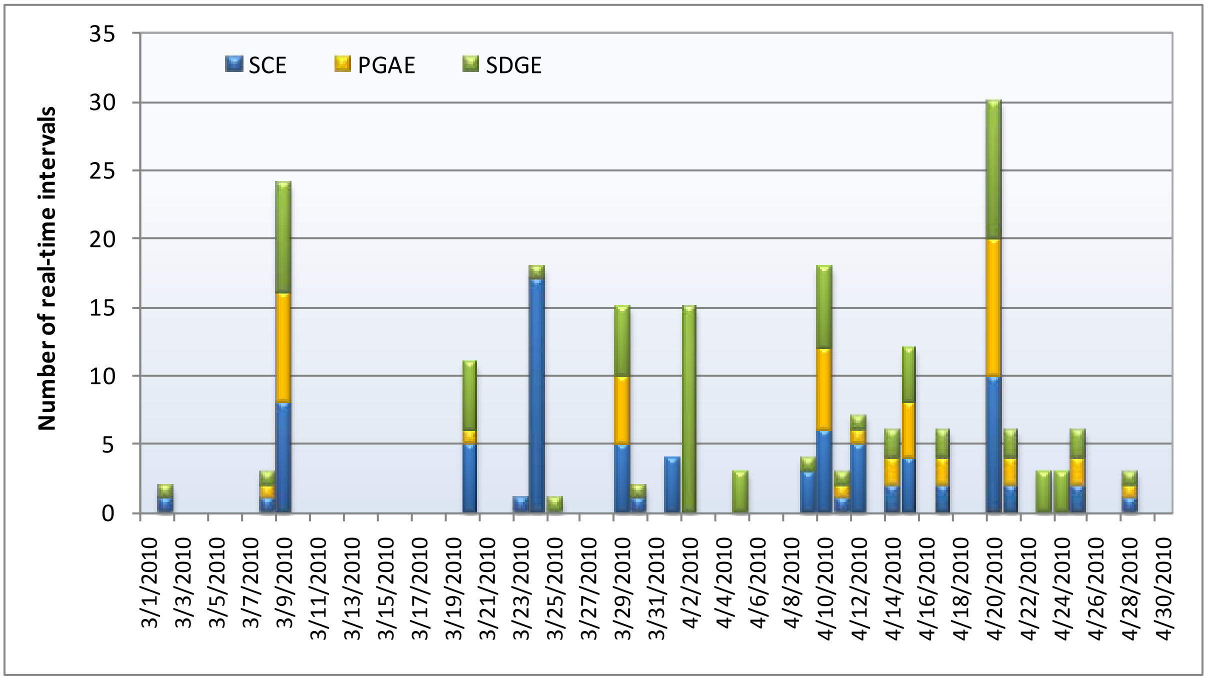
[25] For each load aggregation point, the frequency represents the number of 5-minute intervals in a day with a real-time energy price greater than $475/MWh. Thus, each load aggregation point had the potential for 288 high priced intervals. Dispatch of high-priced bids and congestion can also have an impact on individual nodal LMPs. However, price spikes at individual nodes may not have a material impact on the price paid by load. Therefore, this analysis focuses on the load aggregation point LMPs to better highlight the effects, direct or indirect, the increase in the energy bid cap may have had on prices ultimately paid by load.

[26] In all intervals during which the power balance constraint was violated, the congestion component at the load aggregation points was either $0/MWh or greater than $200/MWh, with the exception of one LAP LMP at $100/MWh; therefore, $200/MWh was determined to be a natural breaking point.

- Otherwise, if a high priced bid was dispatched during that interval, then the bid price was identified as the likely cause.[27]

The results of this analysis are shown in Table 2.1 and Figure 2.6.

Figure 2.5 Frequency of real-time prices greater than $475/MWh by LAP



[27] If an interval was not categorized as one of the three above categories, then the factor was identified as "other." For March and April, there were no high priced intervals that fell into the "other" category.

Figure 2.6 Causes of LAP-level real-time prices greater than $475/MWh

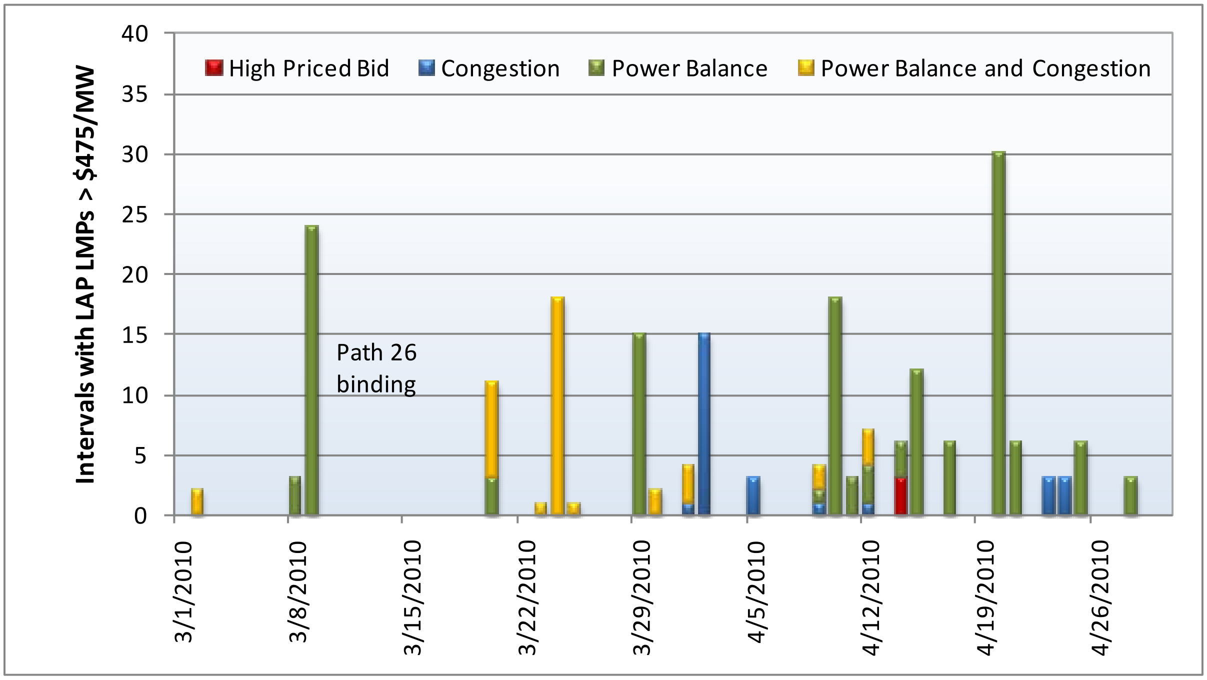


Table 2.1 Cause of high real-time prices (LAP LMP > $475/MWh)

Cause of high price	March Intervals	March Percentage	April Intervals	April Percentage	Total Intervals	Total Percentage
Power Balance Constraint	45	58%	91	71%	136	66%
Congestion and Power Balance Constraint	32	42%	8	6%	40	19%
Congestion	0	0%	27	21%	27	13%
High priced bid dispatched	0	0%	3	2%	3	1%
Total	77	100%	129	100%	206	100%

As shown in Table 2.1 and Figure 2.6, the majority of the high-priced intervals identified were due to violating the power balance constraint and/or congestion.

- Violations of the power balance constraint resulted in 136 high priced load aggregation point LMPs. A total of 91 of these instances occurred in April, representing a 102 percent increase from March. Both March and April experienced power balance constraint violations during the peak hours. April, however, experienced more violations during the evening ramping hours.

- During an additional 40 intervals, high priced load aggregation point LMPs were caused by a combination of the power balance constraint and congestion.

- During another 27 intervals, high priced load aggregation point LMPs were caused by congestion only. Thus, of the 206 high priced load aggregation point LMPs, a total of 67 were impacted by congestion.[28]
- Approximately 2 percent (three intervals) of the high priced load aggregation point LMPs in April were identified as potentially being a result of dispatching a high priced bid. No load aggregation point LMPs in March were identified as potentially being a result of higher priced bids.

Thus, the potential direct market impact the higher energy bid cap had on the real-time energy market was minimal. However, the high energy bid cap also has an indirect impact on the market in terms of the magnitude of price spikes rather than the frequency. When the power balance constraint is violated, the penalty price for this constraint is invoked at the energy bid cap and the energy cost component is set at that value. Therefore, a violation would have resulted in a $500/MWh energy cost component in March and a $750/MWh value in April due to the increased cap.

The energy price cap was also changed on April 1, 2010. Previously, energy LMPs were restricted to be between ± $2,500/MWh. These caps were eliminated on April 1, 2010. There were no instances in the day-ahead where nodal prices were outside the former caps in the period after they were removed. There were five hours in the second quarter where nodal prices exceeded the former caps in the RTD market. These instances occurred on June 10 (one 5-minute interval), June 12 (15 5-minute intervals across three hours), and June 21 (one 5-minute interval). There were between 1 and 20 generation nodes in each interval that had high prices. Because of the locational nature of the high prices, the load aggregation point LMPs were not heavily impacted by these prices and did not exceed the former price cap levels in these instances. The estimated incremental cost of having the nodal LMPs outside former price caps in these instances is less than $20,000.

In conclusion, increasing the energy bid cap from $500/MWh to $750/MWh in April had a negligible effect on bidding behavior and on market outcomes. Furthermore, despite the minimal increase in higher priced bids, the potential impact they had on the real-time energy prices in terms of more frequent price spikes was limited to only three real-time load aggregation point LMPs in April. The increase in price spike frequency in April was mostly due to more congestion on the system and violations of the power balance constraint during the evening ramping hours.

[28] Path 26 was binding in the north-to-south direction on March 20, increasing the LMPs in Southern California Edison and San Diego Gas and Electric load aggregation points. On March 24, the SCE Percent Import limit was binding, resulting in high prices in SCE. The San Diego Import branch group was binding on April 2, April 23, and April 24, resulting in high prices in San Diego.

3 Price convergence

One of the key measures of overall performance of the energy markets (integrated forward market, hour-ahead scheduling process, and real-time dispatch) is the degree to which prices across these markets converge. A high degree of price convergence is an indicator of potential market efficiency, as it suggests that resource commitment and dispatch decisions are being optimized across the markets within the ISO, as well as between the ISO and neighboring control areas.

As discussed in DMM's quarterly report for the third quarter of 2009, divergence in the hour-ahead scheduling process and real-time dispatch can create substantial uplifts that must be recovered from load-serving entities through the Real-Time Imbalance Energy Offset charge (Charge Code 6477).[29] This occurs when price divergence is coupled with a trend for the ISO to export relatively large quantities of additional energy in the hour-ahead scheduling process (at low prices), and then dispatch additional energy within the ISO in real-time dispatch (at significantly higher prices). This pattern of "selling low" in the hour-ahead and "buying high" in real-time has created substantial revenue imbalances that were recovered based on each participant's metered loads through Real-Time Imbalance Energy Offset charges.

DMM's Q3 2009 report included a discussion of some of the potential root causes of these trends, and some of the potential solutions being implemented or explored by the ISO to reduce these price divergences. DMM concluded that the price divergence between the hour-ahead and real-time represented one of the most critical areas for further improvement in the ISO's new market software and processes.

This report updates the analysis of price convergence through the second quarter of 2010. Price divergence among the integrated forward market, hour-ahead scheduling process, and real-time dispatch markets remains a problem, particularly with respect to the divergence of hour-ahead and real-time prices. In the most recent months of May and June 2010, the prices in the three markets diverged significantly. Hour-ahead prices are typically the lowest of the three markets, whereas real-time prices are typically the highest. Overall, price divergence is more pronounced during ramping periods as both hour-ahead and real-time prices become more volatile during these times.

3.1 Price divergence

Figure 3.1 shows monthly average prices for on-peak periods and Figure 3.2 shows monthly average prices for off-peak periods for the PG&E load aggregation point LMP. Prices at the PG&E load aggregation point are representative of the system as a whole as well as the SCE and SDG&E load aggregation points.

Price data in this section exclude extreme prices, which are typically caused by non-systematic events that can skew the underlying trends in the data. Thus, interval prices for hour-ahead and real-time greater than $1,000/MWh and less than -$500/MWh have been removed. These limits are high enough to capture prices set by participant bidding behavior, but exclude extreme prices that can only be the result of penalties within the pricing model and other modeling intricacies.

[29] *Quarterly Report on Market Issues and Performance*, Revised December 23, 2009; covering July through September, 2009. http://www.caiso.com/2425/2425f4d463570.html

For the 15 months since the new market started, hour-ahead prices have been lower than the day-ahead prices in both on-peak and off-peak periods for 13 months. The largest difference between hour-ahead and day-ahead prices was in April 2009, at $8.34/MWh for on-peak prices and $9.08/MWh for off-peak hours. Price convergence improved between the hour-ahead and day-ahead during the fall and winter, but again began to diverge in the spring, most significantly in June 2010 when the difference was back over $6/MWh for both on- and off-peak periods.

Real-time prices have shown the most divergence with the day-ahead and hour-ahead prices. The largest divergences occurred during June 2010 for both on-peak and off-peak prices. June real-time on-peak prices were $12.26/MWh higher than hour-ahead and $6.21/MWh higher than the day-ahead. Even more pronounced were off-peak price differences, where real-time prices in June 2010 were $33.20/MWh higher than hour-ahead and $26.90/MWh higher than day-ahead prices.

Unlike the hour-ahead scheduling process, prices in the real-time dispatch frequently fluctuate between being higher and lower than the day-ahead market. Real-time on-peak prices were higher than the day-ahead in 9 of the 15 months; off-peak real-time prices were lower than day-ahead in 8 of the 15 months. Real-time on-peak prices were higher than hour-ahead prices in all but one month, February 2010, and were higher than hour-ahead off-peak prices in 8 of the 15 months of the new market.

Figure 3.1 Comparison of PG&E load aggregation point LMPs – On-peak

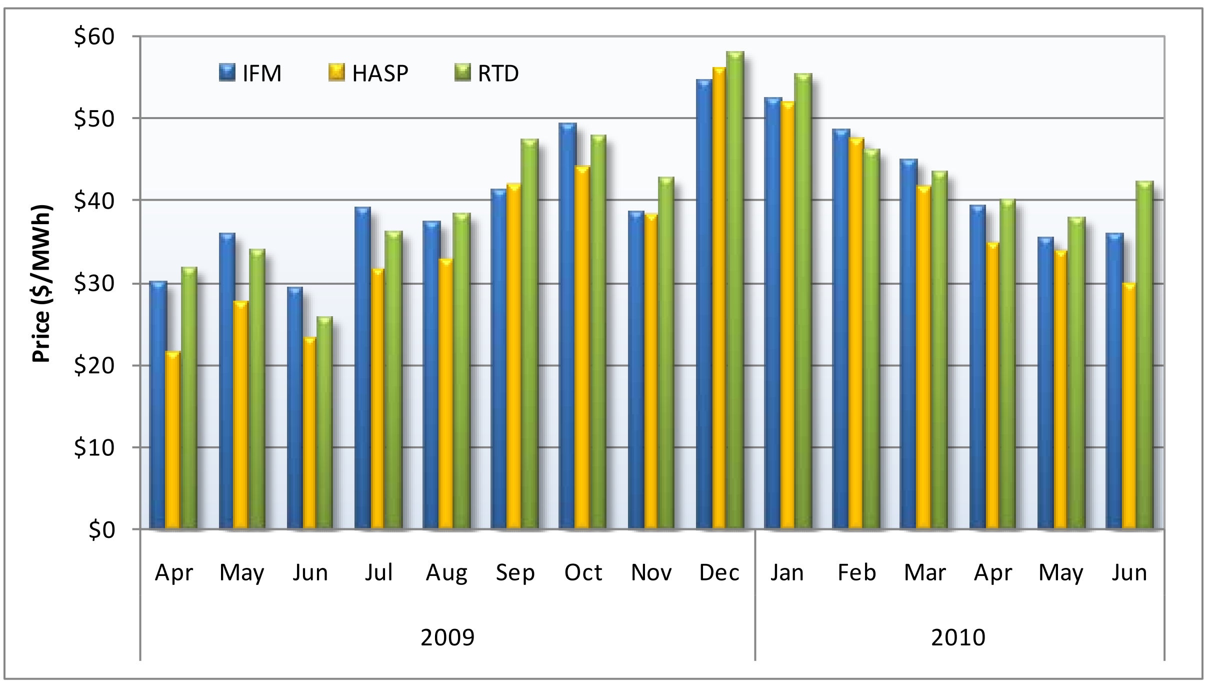


Figure 3.2 Comparison of PG&E load aggregation point LMPs – Off-peak

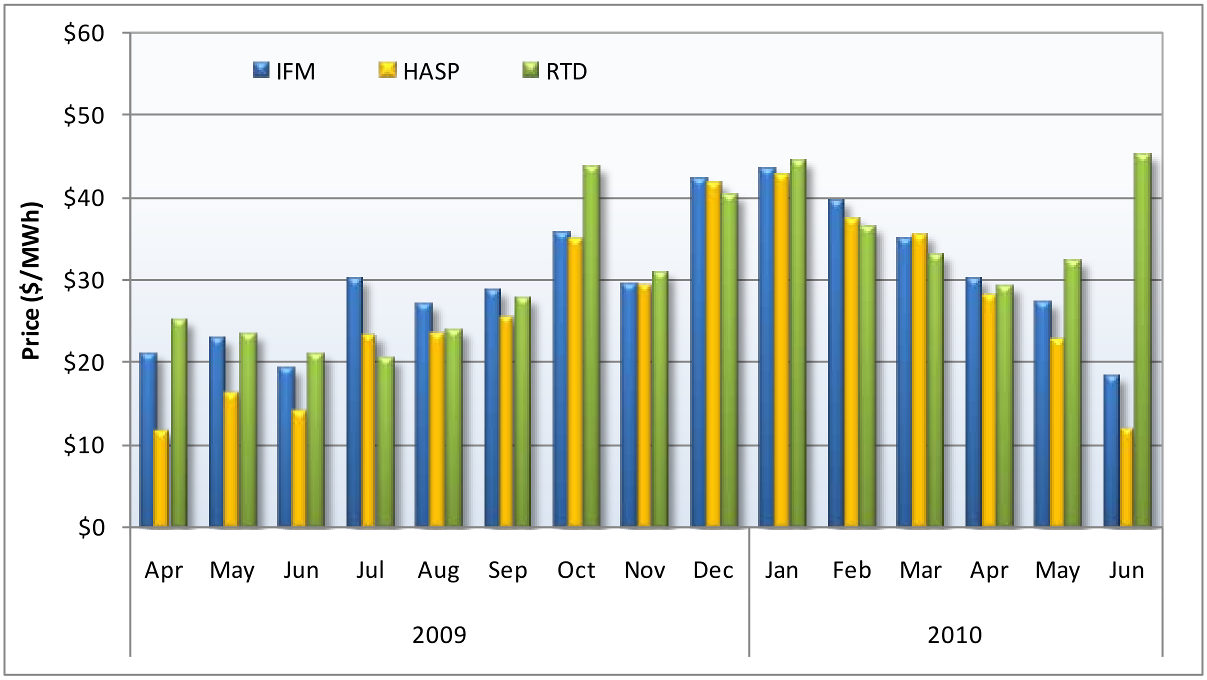


Figure 3.3 shows the average hourly prices in Q2 2010 at the PG&E load aggregation point. Hour-ahead prices in this quarter were on average lower than day-ahead prices in every hour. The largest differences between hour-ahead and day-ahead prices were in hour ending 7 and also later in the day in hours ending 20 through 24; the largest difference was in hour ending 7 at $9.09/MWh. Both of these periods are during periods of high load ramping.

Real-time prices were higher than both the day-ahead and hour-ahead prices in many hours, particularly in hours ending 1 to 3 and then again from 20 through 24. The largest differences in these hours between real-time and the day-ahead and hour-ahead were in hour ending 24 at $35.99/MWh and $45.08/MWh, respectively. Real-time dispatch was lower than both the hour-ahead and day-ahead in hours ending 5, 6, and 8 and again in hour ending 13. Hours ending 5, 6 and 8 are during the early morning ramping hours as units turn on in preparation for the steep morning ramp and the contractual on-peak period starting point in hour ending 7.

The trends in Q2 2010 do not hold in all quarters. Figure 3.4 shows the average hourly prices in previous quarters at the PG&E load aggregation point. Hour-ahead scheduling process prices are almost always lower than the day-ahead integrated forward market prices. However, 9 of the 24 hours in Q4 2009 had hour-ahead prices higher than day-ahead prices. The largest difference was in hour ending 19 at $7.51/MWh, near the peak load hour of the day during the late fall months. In Q3 2009, real-time dispatch prices were higher than hour-ahead and day-ahead prices during hours ending 16 and 17, the peak hours of the day during the summer months. Prices were frequently divergent in Q2 2009 as the new market started and as issues were resolved with the software. Even so, the patterns in Q2 2009 are somewhat similar to those in Q2 2010, particularly in the early morning hours.

Figure 3.3 Hourly comparison of PG&E load aggregation point LMPs – Q2 2010

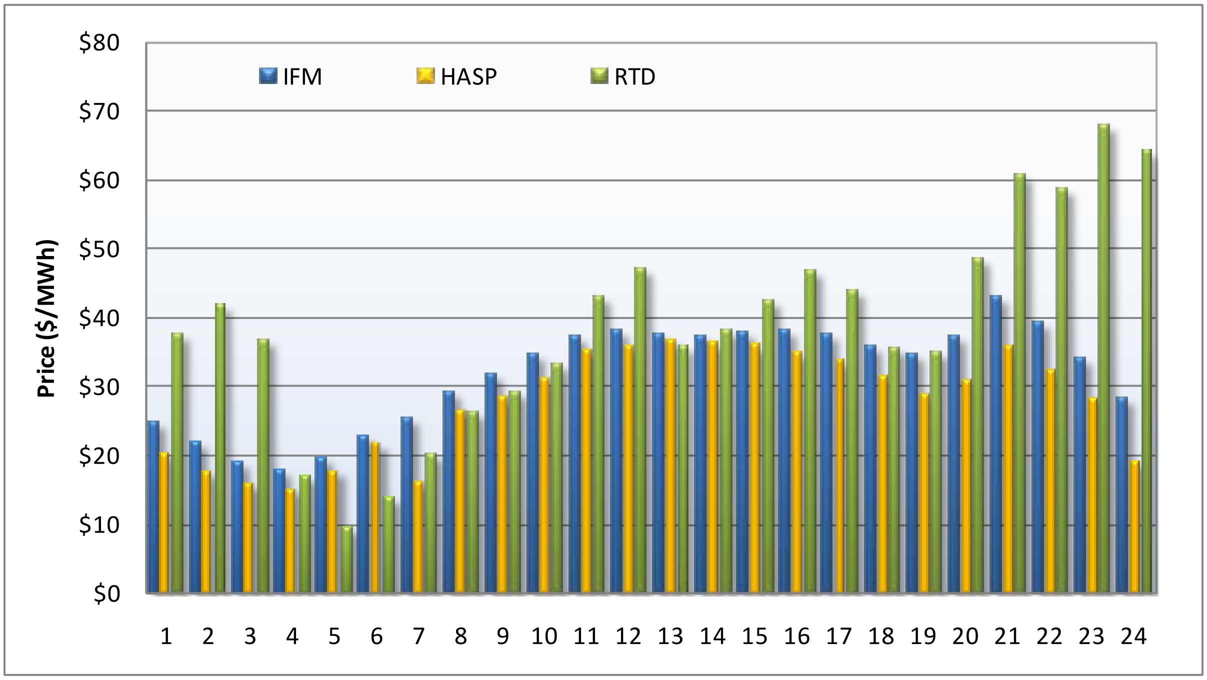
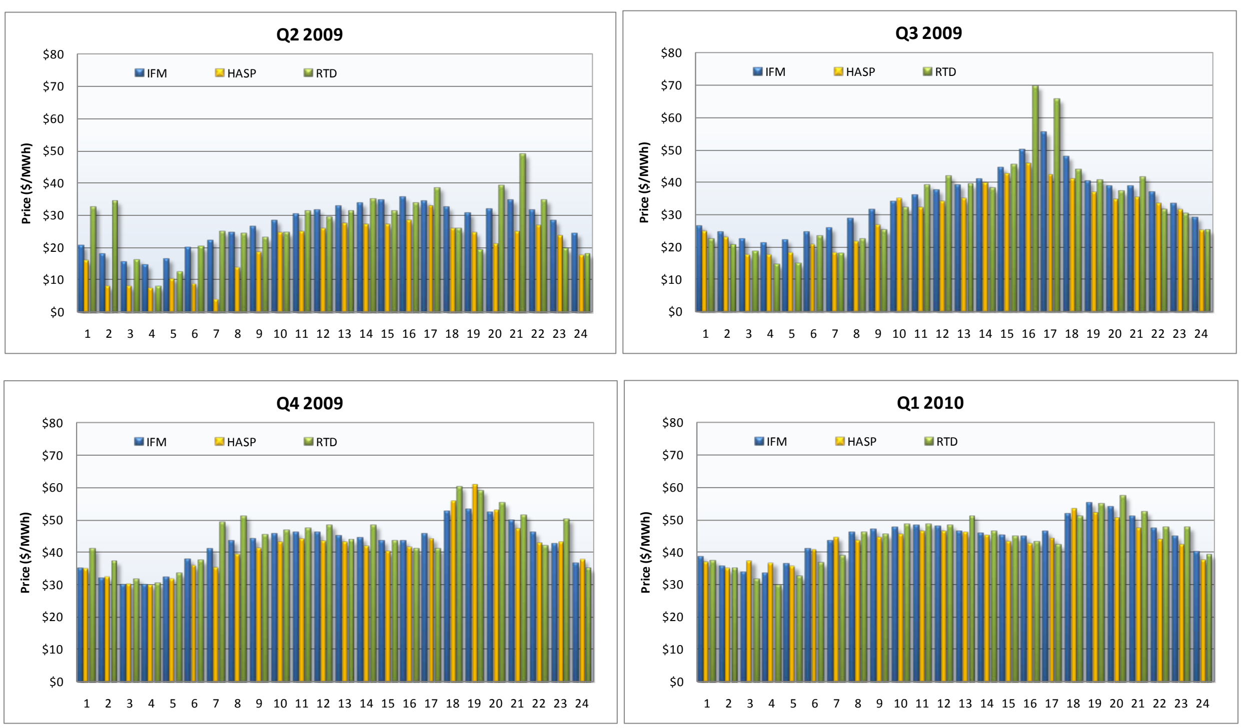


Figure 3.4 Hourly comparison of PG&E load aggregation point LMPs by quarter



3.2 Costs associated with price divergence

When the prices in the markets diverge, they can pose unnecessary additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead scheduling process, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[30] Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is "selling" energy in the hour-ahead at a low price and then purchasing additional energy in real-time at a higher price. This can also create substantial "uplifts" that must be recovered from load-serving entities through the Real-Time Imbalance Energy Offset.[31]

Decreased net imports in the hour-ahead scheduling process

When hour-ahead prices are systematically below day-ahead prices, holding all else constant, net imports will decrease in the hour-ahead scheduling process. In the hour-ahead scheduling process, participants can directly increase or decrease their final day-ahead import/export schedules, increase or decrease their import/export bid prices, and submit additional new import/export bids. However, even if participants do not modify their day-ahead import or export 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, and additional exports that did not clear in the day-ahead may clear in the hour-ahead.

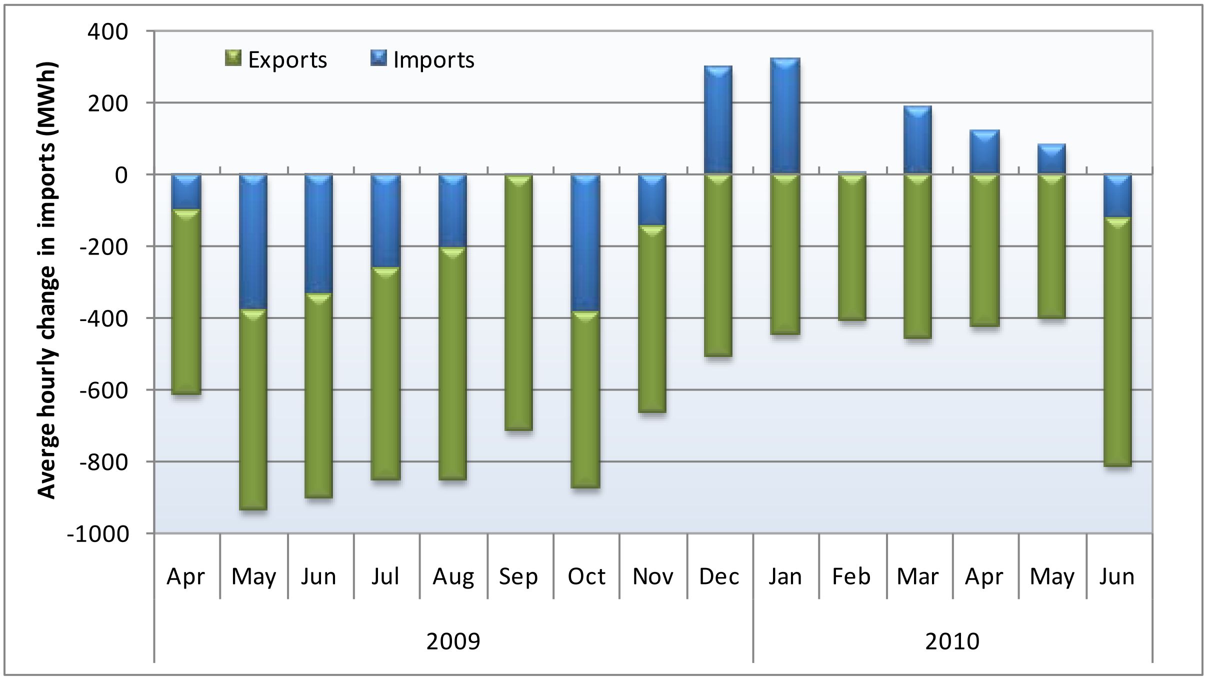
Since hour-ahead prices have often been lower than day-ahead prices under the new market design, the amount of imports originally scheduled in the day-ahead that "re-clear" the hour-ahead scheduling process often decreases and the amount of additional exports that clear increases in the hour-ahead. In addition, additional export bids (beyond those submitted in the day-ahead market) have tended to be submitted and cleared in the hour-ahead. 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.

Figure 3.5 shows that, on average, hourly net imports decrease in the hour-ahead from day-ahead levels in every month, mostly as a function of increased exports. The increase in exports in the hour-ahead from the day-ahead in June 2010 was second only to the increase in exports in September 2009.

[30] 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.

[31] 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 3.5 Change in net imports in hour-ahead relative to final day-ahead schedules



Costs of decreased net imports in the hour-ahead scheduling process

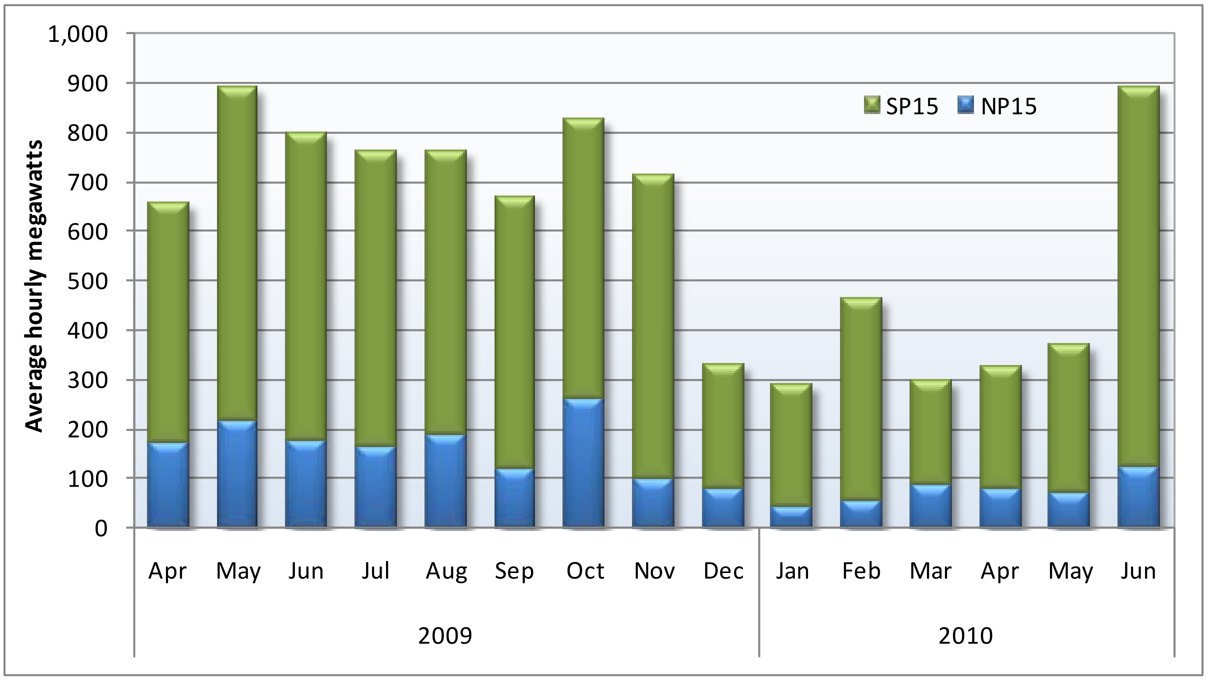
When net imports are decreased in the hour-ahead, but real-time imbalance energy increases, this indicates that the decreased imports in the hour-ahead are likely to have increased the need to dispatch imbalance energy in real-time.[32] Figure 3.6 shows DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month.[33] From April through November 2009, the average decrease in imports in the hour-ahead, which were subsequently re-procured by the real-time dispatch with imbalance energy, was roughly 750 MW. This figure then fell to roughly 350 MW from December 2009 through May 2009, and then increased again in June 2010 to around 900 MW. As shown in Figure 3.6, the average decrease in net imports was several times greater in the southern zone (SP15) than into the northern zone (NP15).

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

[33] 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.

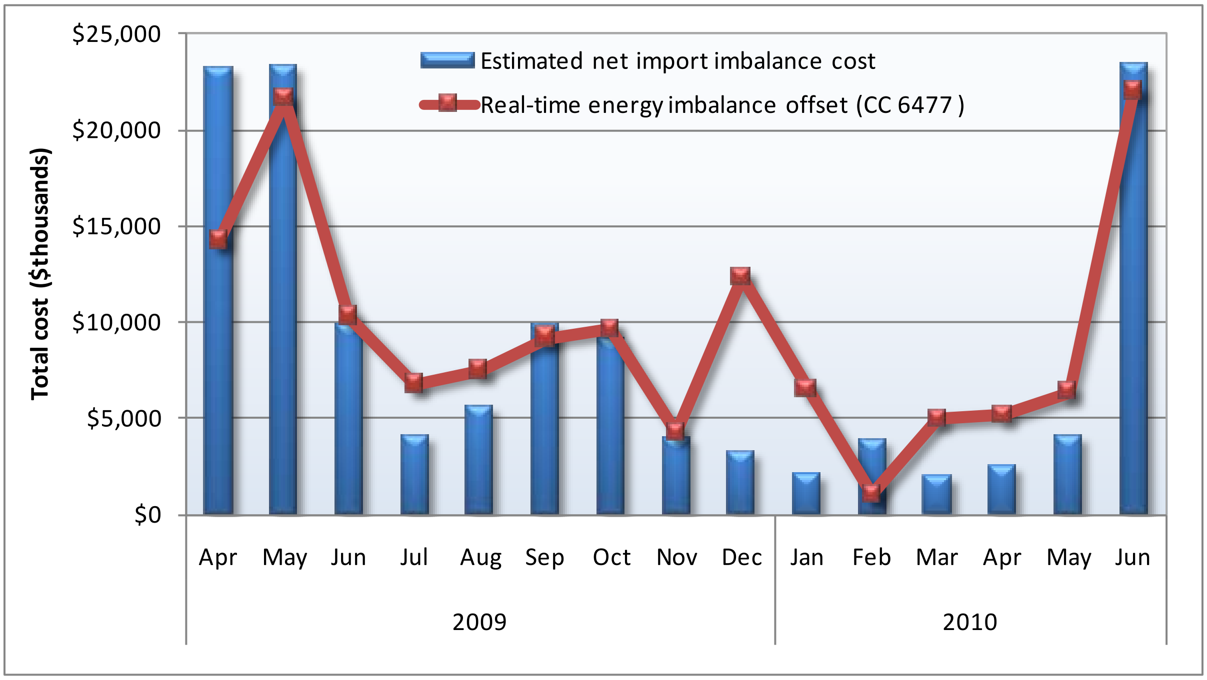
Figure 3.7 shows the estimated costs of additional imbalance energy as a result of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at a higher price.[34] The largest values were at the very start of the new market and again in June 2010. From June 2009 through May 2010 the estimated costs averaged roughly $5 million per month. This cost jumped to just under $23.5 million in June 2010, almost five times larger than the average of the preceding 12 months and the largest cost in any month including April and May 2009.

Figure 3.6 Comparison of imbalance energy increases due to decreasing net imports in HASP



[34] 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.

Figure 3.7 Estimated imbalance costs due to decreased net HASP imports reprocured in RTD market at higher price



3.3 Factors affecting divergence of hour-ahead and real-time prices

Prices can diverge for many reasons and, in most instances, several factors combine to cause the price divergence. These factors include ramping limitations, unexpected generation and transmission outages, differences in load levels, operator intervention, uninstructed deviations, inter-tie activity, and mismatches in scheduling and load. While some of these factors are systematic, others are unpredictable and beyond the control of the ISO without developing forecasting mechanisms to predict such conditions. For instance, unexpected generation and transmission outages, the level of self-scheduled generation, loop flow, and the level of uninstructed deviations are beyond ISO control though they all can influence price convergence.

The effects on prices when these events and limitations occur are often asymmetric. When an event or limitation causes prices to increase, prices often increase to higher levels than when an event causes prices to decrease. This is a function of the bid curve and the bid caps.

- For example, Figure 2.1 shows the bidding phenomenon commonly referred to as the hockey stick or hockey stick bidding, which are bids at the very end of the supply curve that increase sharply after a large section of relatively flat bids.
- In addition, the bid caps themselves are asymmetric. At the start of the market on April 1, 2009, the bid caps were set to $500/MWh for positive bids and -$30/MWh for negative bids. On April 1, 2010, the positive bid cap was raised to $750/MWh, but the negative bid cap remained the same.

Thus, the shape of the bid curve and nature of the bid caps cause price events to be larger in the positive direction than in the negative direction.[35]

3.4 Actions taken to mitigate root causes of systematic price divergence

Many of the changes identified in DMM's Q3 2009 report are still under development by the ISO. The status of these changes as well as other ISO actions is outlined below.

- As reported in DMM's Q3 2009 report, the ISO is developing a new short-term forecasting tool that is designed to provide a more accurate and consistent forecast for both the hour-ahead scheduling process and the real-time market. In addition, this new forecast will specifically be designed to provide forecasts at the 15-minute and 5-minute level of granularity over the approximately two hour forecasting timeline needed for the hour-ahead and real-time markets. Implementation of this new forecasting tool is anticipated in the third quarter of 2010.

- In the interim, before the new tool is operational, the ISO has taken steps to improve the current forecasting tool to better forecast loads during ramping periods. A fix was implemented early in 2010. The fix was further tuned in June 2010 to better align the average 15-minute forecast with respect to the average 5-minute forecast values to reduce forecast differences between the hour-ahead forecast and the real-time forecast.

- In Q3 2009, the ISO assessed a variety of options that might mitigate the impacts of the differences in ways that inter-tie schedules and ramping of resources are modeled in hour-ahead compared to real-time. As an initial step, the ISO is developing enhancements that would modify the hour-ahead scheduling process to account for the imbalance energy difference that arises due to the fact that it does not model how changes in net hourly inter-tie schedules are ramped in over a 20-minute period each operating hour. Testing of this enhancement is currently in progress. The target for release is also during the third quarter of 2010.

- The ISO is continuing to look for opportunities to improve how and when to bias the system. As part of this effort, the ISO is developing a more systematic procedure that gives the operator more guidance to the maintenance of load biasing to determine whether a bias should be removed or continued.

- In late July 2010, the ISO implemented the capability to produce automated *compensating injection*s in the hour-ahead and 5-minute real time market software.[36] This feature is designed to automatically align flows produced by the market software with actual observed flows. This feature is expected to decrease the need for manual biasing of transmission limits, and may help to improve price convergence between the hour-ahead and 5-minute markets.

[35] There are times when large negative prices occur as a result of system penalties. For instance, in hour ending 7 on June 20, negative prices around -$1,600/MWh occurred in the hour-ahead scheduling process as a result of system penalty prices related to cutting self-scheduled units.

[36] Technical Bulletin 2010-07-01, Compensating Injection in the ISO Real-time Market, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf.

- The ISO has begun a process to evaluate what products, if any, may be necessary to support renewable integration. These products could potentially address some of the issues related to low ramping capability which can affect price convergence.

Improving price convergence, particularly with respect to the hour-ahead and real-time markets, remains one of the most critical areas for further improvement in the new market software and processes. While implementation of the changes identified above may improve price convergence, DMM believes the ISO should continue to seek to identify other potential sources of the divergence between prices and dispatches in the hour-ahead and real-time markets and how these may be addressed.