California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

February 1, 2010

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Executive Summary

This quarterly report covers the fourth quarter of 2009 (October – December 2009), which corresponds to the third three-month period of the California Independent System Operator's (ISO) new nodal market. The report provides an overview of general market performance, as well as more detailed analysis of a variety of special market issues. The new ISO markets are generally continuing to perform well and improve:

- The fourth quarter (Q4) of 2009 was a period of relative grid and market stability, with improved convergence of prices in the ISO's different energy markets when compared to previous quarters.
- The day-ahead Integrated Forward Market (IFM) has continued to be stable and competitive, with a high proportion of load and supply being scheduled in the day-ahead market (e.g., typically 95 to 100 percent).
- Prices in the day-ahead and real-time ancillary services markets have been reasonable and competitive, with overall ancillary services costs totaling less than one percent of energy costs in Q4.
- Market activity in the Residual Unit Commitment (RUC) market continues to be minimal due to high levels of load scheduling in the IFM and sufficient Resource Adequacy (RA) capacity in RUC.
- Over the first nine months of the ISO's new market, Bid Cost Recovery (BCR) totaled about $66 million, or approximately 1 percent of total energy plus ancillary services costs. This indicates that BCR payments have been relatively low, and compare favorably with analogous payments in other ISOs, which have averaged from 1 percent up to almost 3 percent of total energy costs.

Provided below is a summary of the market issues and findings in this report, as well as follow-up on actions the ISO is taking to address several issues and short-term recommendations identified in the Department of Market Monitoring's (DMM) Q3 report. A more detailed analysis of Q4 performance and a wide range of key issues relating to the ISO's new market design will be provided as part of DMM's annual report scheduled for completion in April 2010.

Real Time Market Performance

The fourth quarter of 2009 was a period of relative grid and market stability:

- Prices in the five-minute Real-Time Dispatch (RTD) market increased by about 24 percent in Q4 compared to Q3. However, this increase was driven by an increase in spot market gas prices, which increased by about 43 percent in Q4 compared to Q3.
- Performance of the RTD market continued to improve in terms of a reduction in the frequency and magnitude of extremely high or low prices that are not reflective of actual real-time supply and demand conditions. This reduction in price spikes and volatility is likely due in large part to the more favorable supply and demand conditions during the Q4 months of October to December.

- Convergence of prices in the day-ahead and real-time energy markets at the major load aggregation points (LAPs) within the ISO have converged more closely in Q4 since Q3. Prices in the off-peak hours have shown the greatest degree of convergence in Q4 since the introduction of the new ISO market structure in April 2009.

Market Competitiveness

- Prices in the ISO's day-ahead IFM during each month of Q4 continued to be approximately equal to prices we estimate would result under perfectly competitive conditions. DMM simulates these competitive benchmark prices by re-running the IFM using Default Energy Bids, which reflect each unit's actual marginal cost, as a substitute for actual market bids.
- The frequency of prices in excess of the $500 bid cap in the RTD increased slightly in October, driving average real-time market (RTM) prices slightly above DMM's competitive benchmark prices for that month, but RTM prices returned to levels approximately equal to DMM's competitive benchmark prices in November and December.
- On September 29, 2009, the Federal Energy Regulatory Commission (FERC or the Commission) issued an order accepting modifications to the ISO's tariff provisions allowing increased bids for start-up and minimum load costs to be modified every month rather than every six months.[1] Following approval of these modifications, the portion of gas-fired capacity selecting the Registered Cost option – under which unit owners can bid start-up and minimum load costs in excess of fuel costs – increased from about 25 percent to 35 percent. However, as of December 2009, only about 16 percent of start-up bids and about 11 percent of minimum load bids for capacity under the Registered Cost option were submitted at prices at or near the 200 percent cap now in effect under this option.

Transmission Congestion

Transmission congestion was relatively low and occurred on a limited number of constraints in Q4.

- A relatively small number of all transmission constraints were managed during a significant number of hours by conforming the transmission limits based on observed differences in modeled versus actual flows – a practice referred to as "biasing" in our Q3 report. Most constraints that were conformed in the real-time market tended to be "conformed up" (i.e., adjusted in the upward direction). In such cases, the market limit was conformed up to reflect the true available capacity on the line in order to avoid "phantom" congestion in real time (i.e., congestion in the market model when actual physical flows were below limits).
- The number of constraints that have been conformed in the real-time market in a significant portion of hours has decreased since Q3. While some of this decrease may be attributable to changes in system conditions, modeling improvements made by the ISO in late Q3 appear to have significantly reduced the need for conforming a number of the constraints near the Bay Area that were most frequently conformed in Q3.

[1] Order Accepting Tariff Modifications, ER09-1529-000, 128 FERC ¶ 61,282 (September 29, 2009 Order) http://www.caiso.com/2439/243974b716500.pdf

- For several of the most frequently congested constraints, congestion was often not consistent between the day-ahead and real-time markets (e.g., a particular constraint may have been binding in the IFM, but not in the real-time market, or vice versa). This situation was observed more significantly for the Intermountain-Adelanto DC Branch Group (IPPDCADLN_BG), the SCE Import Percent Branch Group Limit (SCE Import Limit), and the La Fresa-Hinson 230kV line. We discuss some of the factors that may have contributed to these trends in Chapter 3 of this report.

Beginning November 11, the ISO began enforcing a constraint on the total volume of imports as a percentage of load into Southern California Edison service territory (the SCE Import Limit):

- The bulk of congestion on the SCE Import Limit in the IFM occurred during the first week that this constraint was added to the market model, without any prior notification to participants. The lower level of congestion on the SCE Import Limit in the IFM approximately one week following its implementation into the market optimization reflects changes in participants' scheduling and bidding, as well as changes in system conditions.
- During Q4, this constraint was binding in the IFM market in 7.4 percent of hours, and was only binding in the RTM in approximately 1 percent of hours. It was binding in both markets for simultaneous operating intervals in 0.4 percent of hours. The lower level of congestion in the RTM can be attributed in large part to the fact that (1) the volume of net imports scheduled into SCE typically decreases significantly in the hour-ahead scheduling process (HASP) market, and (2) the ISO frequently conformed this limit to a higher level (i.e., upwards by about 10 percent) in the real-time market based on the difference between scheduled and actual flows.
- As part of a recent stakeholder process on release of transmission information, the ISO is proposing to establish several new advance notifications that will inform stakeholders of significant changes to the transmission constraints included in the ISO's market systems.[2] Under these new policies, the ISO will seek to provide participants with advance notice when new constraints such as this are added, except when this may not be possible for reliability reasons.

On October 12, 2009, the ISO activated a software feature that is designed to manage variation between market and physical flows on the major inter-ties through an automated form of compensating injections at special nodes outside of the ISO system. 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 an increasing number of CPS2 violations. As a result, on November 4, 2009, the automated compensating injections were turned off until further refinements could be made in this software feature. The ISO is currently testing the enhancements to the compensating injection software, and anticipates testing and then re-activating this software feature in Q1 2010.

DMM is working with the ISO to develop metrics that can be used to monitor the impact of compensating injections on modeled flows on specific major constraints within the ISO that are

[2] See Draft Final Proposal, Data Release & Accessibility, Phase 1: Transmission Constraints, January 6, 2010, p.9. http://www.caiso.com/2718/2718ef3844a00.pdf

likely to be impacted by compensating injections.[3] DMM is recommending that this software feature not be re-activated until these metrics are completed and advance notice is provided to participants that compensating injection will be reactivated.

Follow-up on Prior Recommendations

The ISO is taking steps to address several of the short term recommendations in DMM's previous *Quarterly Report* (*Q3 Report*).[4]

- ***Ramping of Inter-tie Schedules in HASP.*** As discussed in our *Q3 Report*, a limitation of the HASP model is that it does not account for the fact that intra-hour changes in schedules of system resources (imports and exports) are ramped in over a 20-minute period each operating hour. This is likely to cause HASP to underestimate the actual ramping that will be needed in the RTD during this 20-minute ramping period. In Q4, as an initial step toward addressing these modeling differences, the ISO initiated development of enhancements that would modify HASP to account for the imbalance energy difference that arises due to the fact that HASP does not model how changes in net hourly inter-tie schedules are ramped in over a 20-minute period each operating hour. The ISO expects this modeling enhancement to be implemented in February 2010.

- ***Load Forecasting Improvements.*** Another factor identified in our *Q3 Report* that is likely to be contributing to systematic dispatch and price differences between the HASP and RTD is a systematic difference in the load forecast used in HASP and RTD. As noted in our *Q3 Report*, the ISO currently has a new short-term forecasting tool under development that is designed to provide a more accurate and consistent forecast for both HASP and RTM. 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 HASP and RTM.[5] Implementation of this new forecasting tool is still anticipated in early 2010.

- ***Explore and implement options for incorporating into the market model the reliability constraints driving exceptional dispatch.*** As noted in our *Q3 Report*, in July 2009 the ISO implemented capacity nomograms in the RUC process that reflect capacity needs incorporated in the G-217 (South-of-Lugo) and G-219 (Orange Country) operating procedures, which were found to be driving a large portion of unit commitments in the Southern California area. Since minimum load energy and other capacity from units committed in RUC is not available in the IFM market, DMM has recommended that these constraints be incorporated in the IFM market model if possible. This will reduce excess

[3] Modeled flows for constraints in the ISO provided by the market software do not differentiate between the portion of flow attributable to compensating injections and the portion of flow attributable to market schedules. Thus, the impact of compensating injections on constraints within the ISO must be calculated using data on the compensating injections values at each CNode outside of the ISO system, combined with shift factors for these CNodes relative to constraints within the ISO.

[4] *Quarterly Report on Market Issues and Performance*, October 31, 2009; covering July through September 2009 http://www.caiso.com/2425/2425f4d463570.html

[5] The ALFS forecasting tool currently being used actually produces a 30-minute forecast, so that the more granular 15- and 5-minute forecasts needed for the HASP and RTM software are developed by interpolating from this 30-minute forecast.

generation in the real-time markets (HASP and RTD) resulting from minimum load committed after the IFM, and will also provide resources needed for these constraints with additional opportunity for market revenues in the IFM. During Q4, the ISO developed and began testing procedures to incorporate these minimum online commitment constraints in the IFM. On January 26, 2010, the ISO issued a market notice announcing plans to implement minimum online commitment constraints for G-217 and G-219 on February 2, 2010.[6]

- ***Conforming Transmission Constraint Limits Based on Actual Flows.*** In our *Q3 Report*, DMM recommended that the ISO should continue to place a high priority on continuing to refine the use of conforming constraint limits (referred to as "biasing" in our *Q3 Report*) as it gains more experience and data in this area. Specifically, DMM suggested that more automated statistical metrics that correlate the degree of conforming and congestion in the various sequential markets may be helpful in tracking trends and identifying potential areas for improvement as conditions change, and that overall market transparency and the ability of participants to "self-manage" congestion can be improved by providing timely data to market participants on the application of conforming and the un-enforcement of constraints in market operations. In Q4, the ISO addressed this issue as part of a more comprehensive stakeholder process on public data release. The ISO's proposal for release of public data includes a provision to provide on a routine basis some of the same metrics that were provided by DMM in the *Q3 Report*.[7] DMM is working with the ISO to facilitate development of the ISO's capability to provide these data on a routine basis. In addition, as reviewed in Chapter 3 of this report, the number of constraints that have been conformed in the real-time market in a significant portion of hours has decreased since Q3. In many cases, this reduction in conformance of constraint limits can be attributed to improvements aimed at modeling net rather than gross loads at nodes with significant amounts of self-generation that were implemented at the end of Q3.

- ***Failures of LMPM in HASP*.** In our *Q3 Report*, DMM noted that there have been numerous hours in local market power mitigation (LMPM) procedures that were not reviewed for price impacts by the ISO's price correction team, and recommended that the ISO improve the price correction process to ensure that all hours in which LMPM procedures fail in HASP are thoroughly reviewed for price impacts. Although to total number of hours in which LMPM procedures have failed in HASP is small and has declined slightly (from about .9 percent of hours in Q3 to about .7 percent of hours in Q4), DMM is continuing to work with the ISO to ensure the process for reviewing LMPM failures and correcting prices is improved.

- ***Exceptional Dispatch.*** DMM continues to monitor the volume and reasons for exceptional dispatch. The volume of day-ahead unit commitments has declined measurably, averaging two to four resources per day throughout the fourth quarter, primarily for reasons relating to zonal capacity needs and transmission outages. Real-time exceptional dispatches for energy requirements have increased somewhat, for a variety of reasons, including dispatch in the Fresno area, system capacity, and transmission outages. Exceptional dispatches made for the La Fresa and SCE Import Limit are discussed in additional detail in Chapter 3.

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[6] http://www.caiso.com/272a/272aac691c650.html

[7] See pp.91-95 in *Quarterly Report on Market Issues and Performance*, October 31, 2009, http://www.caiso.com/2425/2425f4d463570.html

1 Real-Time Market

1.1 Price Convergence

One of the key measures of overall performance of the ISO's energy markets (IFM, HASP, and RTD) is the degree of price convergence across these markets. A high degree of price convergence is an indicator of market efficiency, as it suggests that resource commitment and dispatch decisions are being optimized across the day-ahead and real-time markets. As discussed in our *Q3 Report*, divergence in energy prices between the HASP and RTD markets can also result in significant excess costs that must be allocated to market participants through the Real Time Energy Imbalance Energy Offset.

Price convergence can be measured and analyzed in a variety of ways. One approach is to examine the extent to which average prices converge over a period of time. In the first few months of the ISO's new market, average IFM prices tended to be consistently lower than RTD prices, while average HASP prices tended to be consistently lower than both IFM and RTD prices. Since then, price convergence in these three markets has improved substantially. Q4 2009 was a period of relative grid and market stability and resulted in prices that were relatively similar across the ISO's energy markets when compared to previous quarters. Convergence of prices in the day-ahead and real-time energy markets at the major load aggregation points (LAPs) within the ISO improved in Q4 relative to Q3. Prices in the off-peak hours have shown the greatest degree of convergence in Q4 since the introduction of the new ISO market structure in April 2009.

All prices have generally trended upward, following the national price trend of natural gas, which is the most prevalent fuel for marginal resources. Prices in the five-minute real-time dispatch (RTD) market increased by approximately 24 percent in Q4 compared to those seen in Q3. This increase was driven primarily by an increase in gas prices, which increased by about 43 percent in Q4 compared to Q3.

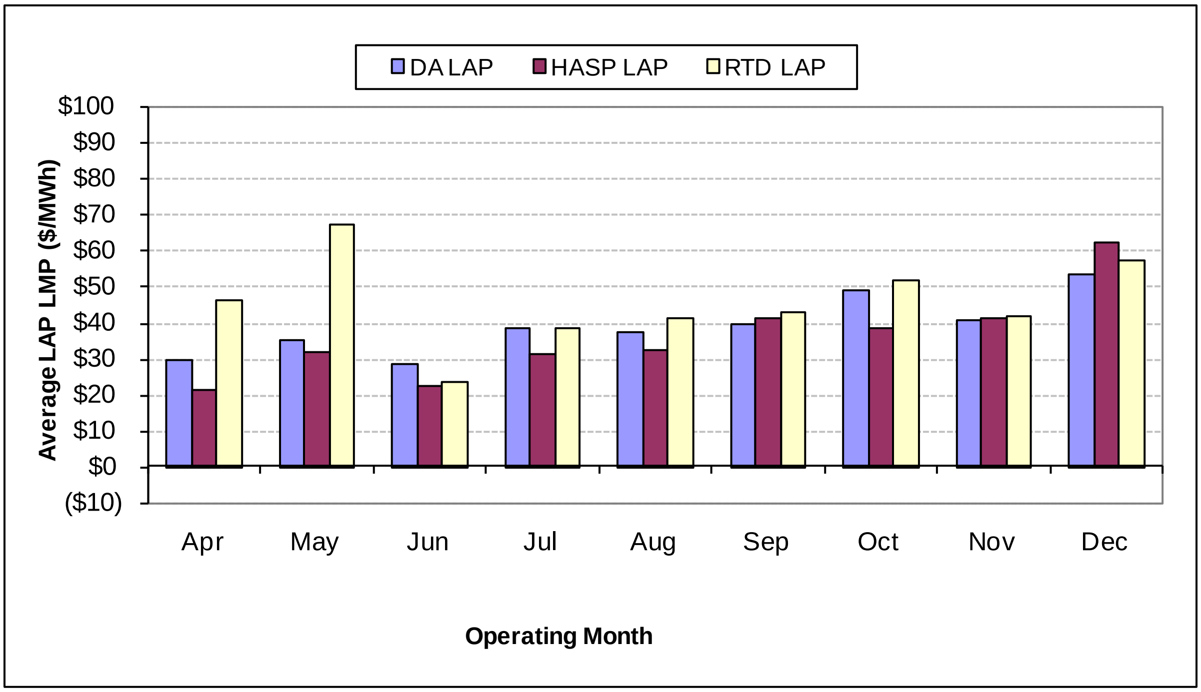
As shown in Figure 1.1, prices at the Southern California Edison (SCE) LAP maintained a relatively high degree of convergence since the start of Q3 (July), after diverging significantly during the first months of the ISO's new market design. In Q4, HASP prices were no longer systematically lower than both day-ahead and real-time prices,[8] and real-time prices were consistently slightly higher than day-ahead prices. Since July, monthly average peak-hour real-time prices have exceeded average day-ahead prices by no more than $4 per megawatt-hour (MWh). There has not been such a discernible trend in HASP prices, which have generally trended with day-ahead and real-time prices, but were $7 to $10 below RTD prices in July, August, and October, approximately equal in September and November, and approximately $9 higher in December.

The relatively low average HASP prices during peak hours in the SCE LAP during October can be attributed to a few unrelated events over five noncontiguous days in October, involving transmission derates and outages on internal and import constraints. In December, there were

[8] HASP prices are only binding for hourly imports and exports, and it is the inter-tie prices that bind for these transactions. The HASP LAP LMPs are not binding for ISO dispatches. However, the HASP market does optimize across both import/export bids as well as real-time bids for internal resources when determining dispatch at the ties. As a consequence, the LAP LMPs generated by the HASP market reflect grid and market conditions and are a good barometer for market efficiency when compared to the IFM and RTD LAP LMPs.

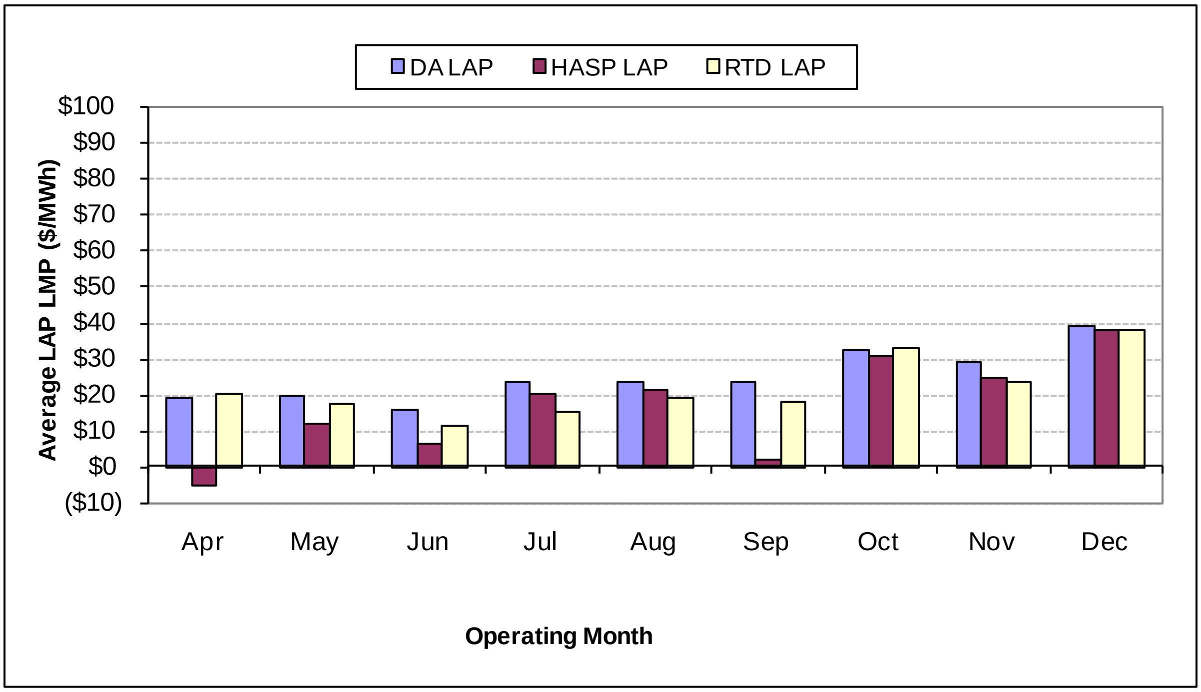
several incidences of the SCE Import Limit binding in HASP, which resulted in extreme price spikes in excess of $1000/MWh for the SCE area only and drove average HASP prices in the SCE LAP above IFM and RTD prices that month.

Figure 1.1 Comparison of SCE LAP Prices – Peak Hours



The convergence trend for SCE LAP prices are also observable in off-peak hours, with the exception that day-ahead prices tend to be slightly higher than real-time prices most of the time. All prices have converged significantly since Q2. The unusually low average HASP price in September was due to an anomalous event, and thus did not carry over into Q4. In peak hours, San Diego Gas and Electric (SDG&E) and Pacific Gas and Electric (PG&E) LAP prices were generally similar to those for SCE. Charts for SDG&E and PG&E LAP Price Comparisons can be found in the Appendix, in Figure A.1 through Figure A.4.

Figure 1.2 Comparison of SCE LAP Prices – Off-Peak Hours



1.2 Day-Ahead and Real-Time Prices

A second measure of price convergence is the distribution of the price differences between day-ahead and real-time markets. Figure 1.3 and Figure 1.4 below show the distribution of price differences between RTD and IFM LAP prices (LAP LMP_{RT} – LAP LMP_{IFM}) by month and period of day for SCE. Similar charts for SDG&E and PG&E can be found in the Appendix in Figure A.5 through Figure A.8.

In November and December, the distribution of price differences tends to have a larger tail below zero in off-peak hours, relative to peak hours. This reflects the fact that IFM prices tend to be higher than RTD prices in off-peak hours across LAPs, while RTD prices tend to be higher in peak hours. This trend can also be observed in Figure 1.1 which shows arithmetic means rather than medians.

This trend of RTD prices that are higher than IFM prices during peak hours and lower than IFM prices during off-peak may be explained in part by the nature of wholesale bulk power trading. Forward-purchased wholesale power is readily available in 16-hour peak-period and 8-hour off-peak-period blocks, while load moves smoothly across the day. This tends to result in day-ahead schedules that are short during the evening ramp, which results in higher hour-ahead and real-time incremental dispatch and higher real-time HASP and RTD prices. Meanwhile, day-ahead schedules tend to be in excess of load in early morning hours, when load is at its daily minimum. This typically results in decremental hour-ahead and real-time dispatch, with low or negative RTD and HASP prices. The brief but sharp evening peak of the winter load pattern tends to exacerbate this effect.

Figure 1.3 and Figure 1.4 show that the range of differences in IFM and RTD prices in the SCE LAP increased moderately since August and September, but still remains low when compared to earlier months. RTD prices on average were close to IFM prices, with fewer than 10 percent of intervals having RTD-IFM price differences large enough to be outside the range shown by the vertical orange bars. Notably, for months in Q4, the middle 50 percentiles of differences of RTD and IFM LAP prices were between -$6.03 and $4.18/MWh in peak hours, and between -$11.48 and $2.32/MWh in off-peak hours. In half of all peak-hour pricing intervals, the observed RTD price was within approximately $5 of the IFM price or less. In half of all off-peak intervals, the observed RTD price was within approximately $11 of the IFM price or less.

The distribution of differences in IFM and RTD prices in the SDG&E and PG&E LAPs in Q4 are similar to those seen in Q3, and not notably different from those observed in the SCE LAP. Charts for the SDG&E and PG&E LAPs may be found in Appendix A.

Figure 1.3 Distribution of SCE LAP Price Differences Between IFM and RTD – Peak Hours

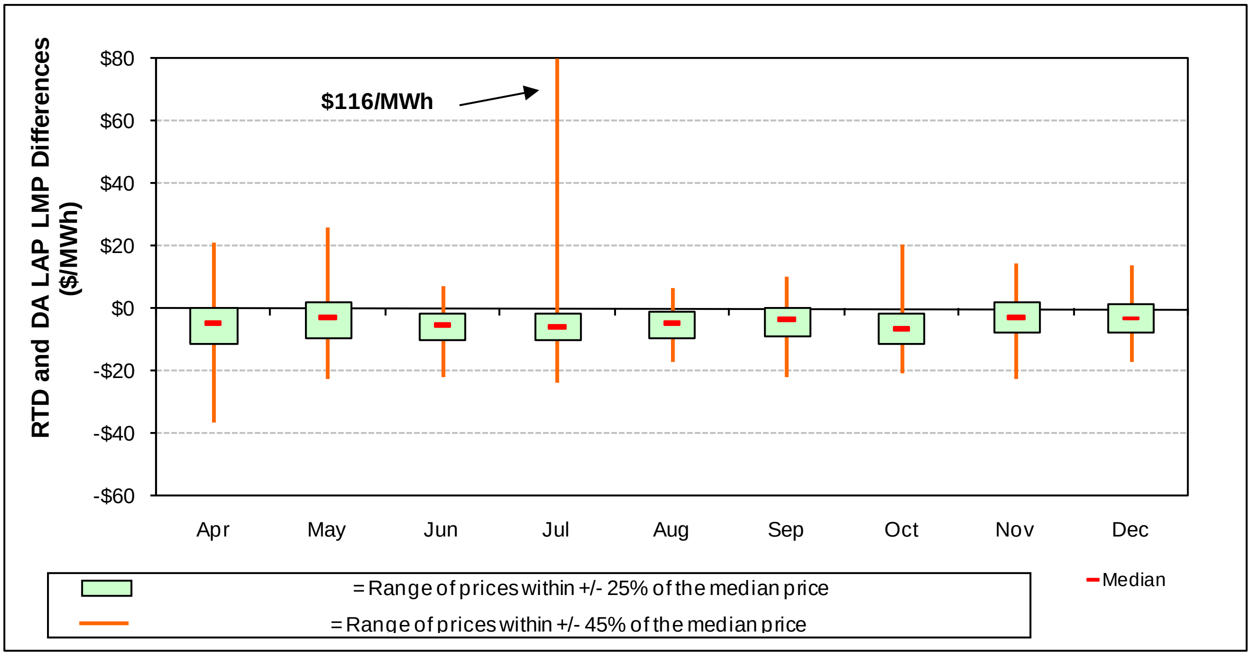
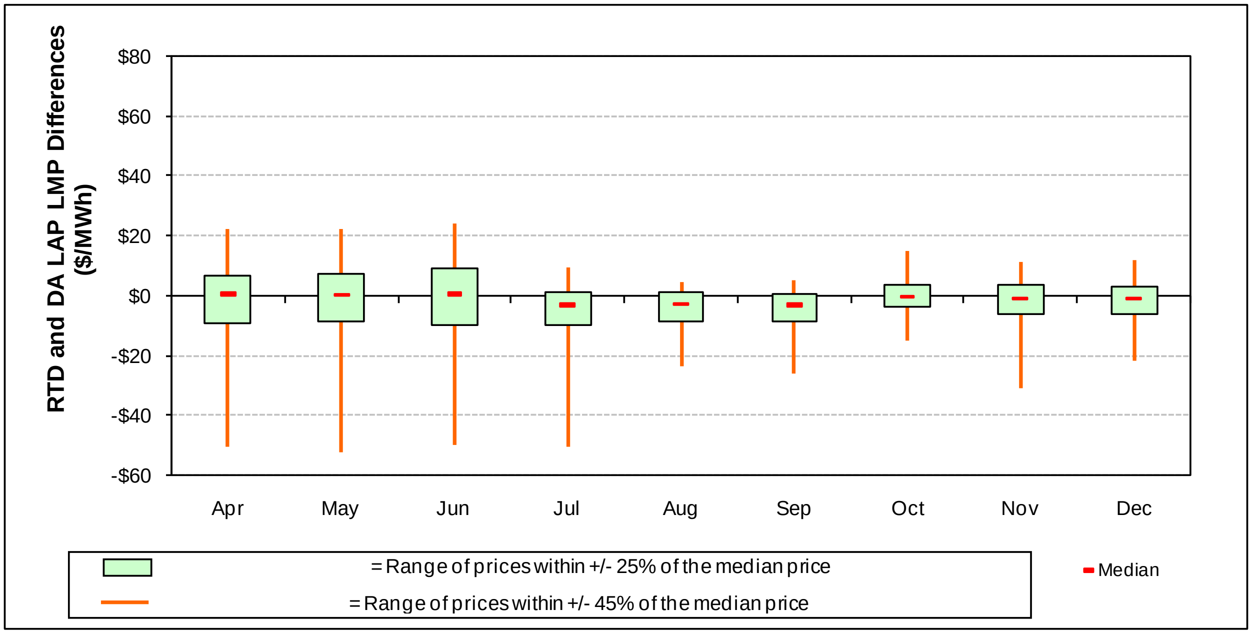


Figure 1.4 Distribution of SCE LAP Price Differences Between IFM and RTD – Off-Peak Hours



1.3 Price Volatility

Overall, prices have trended upward, reflecting the escalating price of natural gas. The day-to-day volatility of prices – as measured by the overall distribution of prices during Q4 – has also increased somewhat since Q3, as more localized constraints have been introduced and become binding into the software. In addition, outages, which typically are scheduled for the low-load shoulder and winter months, have resulted in congestion on transmission constraints that occasionally caused brief, localized price spikes, particularly within the SCE LAP.

Figure 1.5 shows the distribution of HASP LAP prices for the SCE area for April through September in peak hours. In Q4, HASP LAP prices were distributed more broadly than in previous quarters, with the middle 90 percent of prices ranging from approximately $20 to $60/MWh in October and November (as shown by orange vertical lines). December's prices were both higher and more volatile, as natural gas costs tended to increase prices. The large upper tail (75th to 95th percentiles) ranged from $60 to $94/MWh, and was affected by several incidences of the binding SCE Percent Import Branch Group limit that caused extreme price spikes in excess of $1000/MWh. This limit often binds during the evening ramp.

Figure 1.5 SCE HASP LAP Price Distributions – Peak Hours

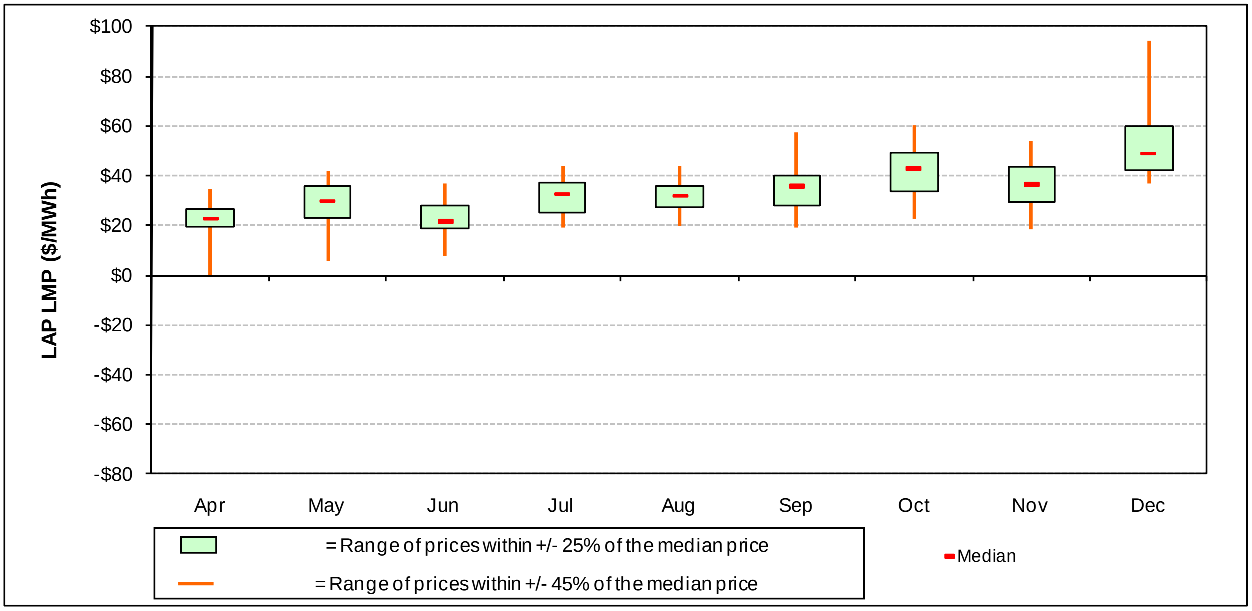
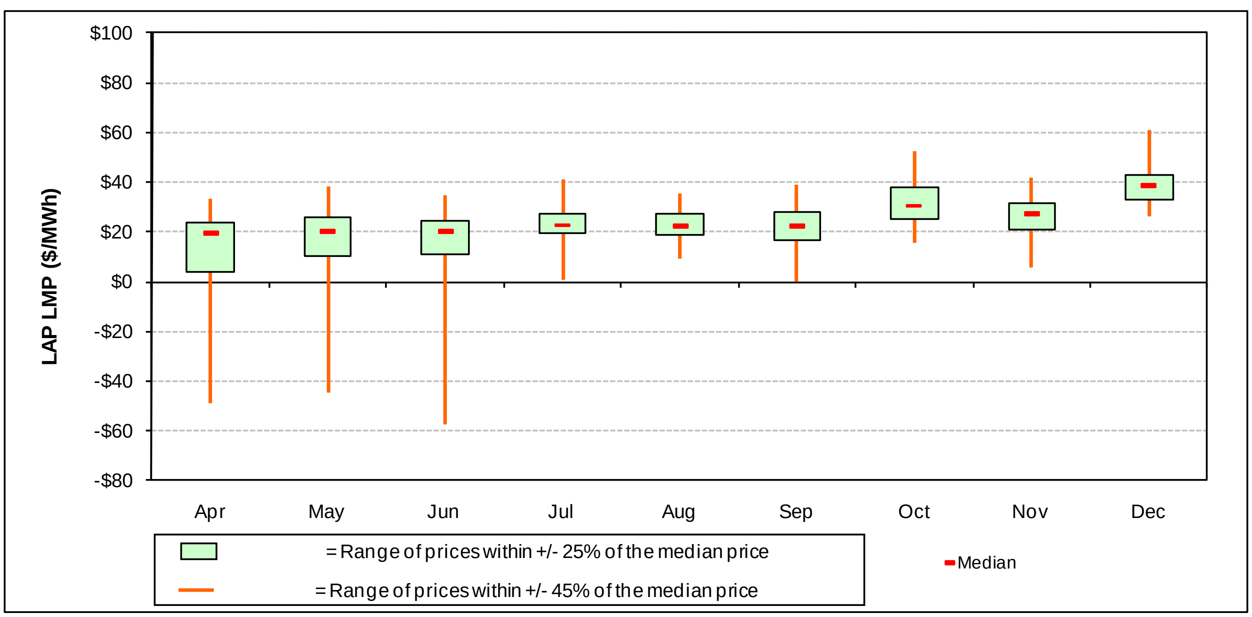


Figure 1.6 shows the SCE LAP HASP price distributions for off-peak hours. Off-peak prices in Q4 were lower and dispersed more tightly than those in peak hours. This may be due in part to the tendency for hour-ahead dispatches to be in the decremental direction in off-peak hours, as there is often a surplus of generation in the early morning (HE 3-5). The middle 90 percentiles ranged between $5 and $60 among the three months of the quarter. This continues the trend observed in Q3, which represented a departure from the large negative prices seen in Q2.

Figure 1.6 SCE HASP LAP Price Distributions – Off-Peak Hours



HASP price distributions for the PG&E and SDG&E LAPs are provided in Appendix A. Because the SCE area sustained the bulk of transmission congestion and binding constraints in Q4, few or none of which affected transmission between the SCE and other LAPs, the PG&E and SDG&E prices are similar. In peak hours, middle-quartiles' prices are similar to those observed in SCE, but the upper tails are shorter, in absence of the binding SCE Percent Import Branch Group limit.

PG&E and SDG&E LAPs' off-peak HASP price distributions are similar to those seen for SCE, in absence of the SCE Percent Import Branch Group limit that largely was binding only in peak hours. Aside from higher LAP energy prices due to the escalation in the natural gas price, the trend in volatility has been relatively constant since July.

Figure 1.7 and Figure 1.8 show box-whisker plot representations of RTD prices in the SCE LAP for peak and off-peak periods, respectively. The PG&E and SDG&E LAPs' off-peak prices' 5th percentiles in October and December were higher than in previous months at nearly $20/MWh. In these months, the real-time decremental dispatch of energy that had bid at or near the price floor of -$30 is now an unusual phenomenon, typically occurring in approximately 1 percent of hours, where it previously had been common. However, in the SCE and SDG&E LAPs, the 5th percentile of prices in off-peak hours in November was near zero. From mid-October to mid-November, a derate of Path 26 constrained generation within SP15 from being dispatched to meet loads north of Path 26. As load declined with seasonal weather changes, the ISO faced a surplus of energy in early morning hours, resulting in intermittent negative prices in the first two weeks of November.

Figure 1.7 SCE RTD LAP Price Distributions – Peak Hours

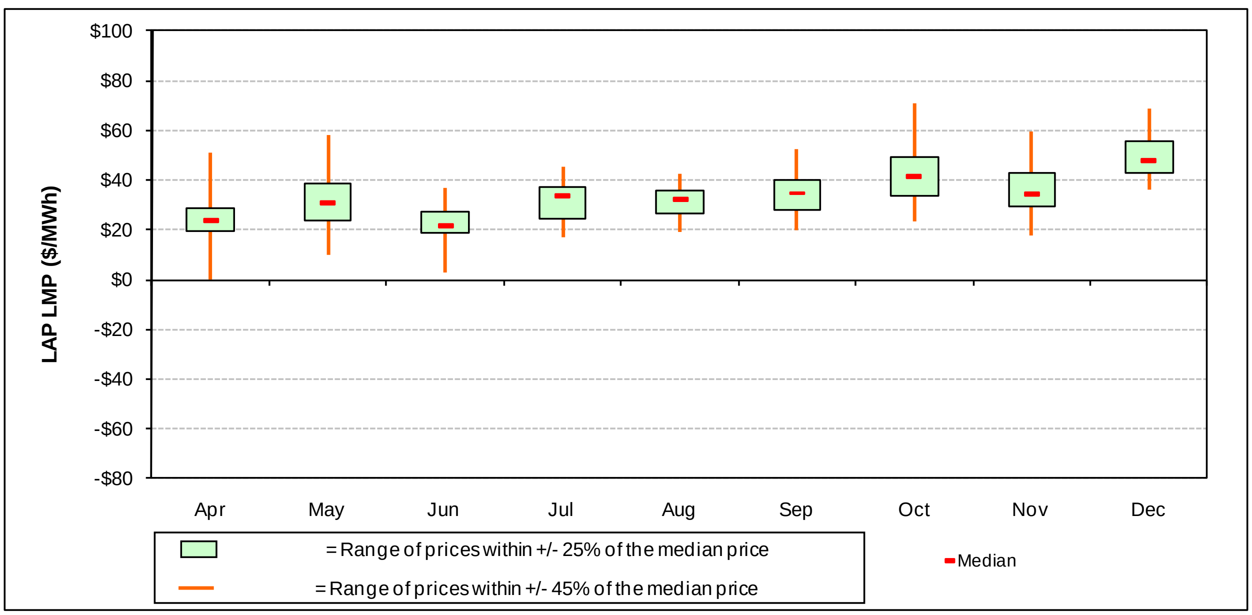


Figure 1.8 SCE RTD LAP Price Distributions – Off-Peak Hours

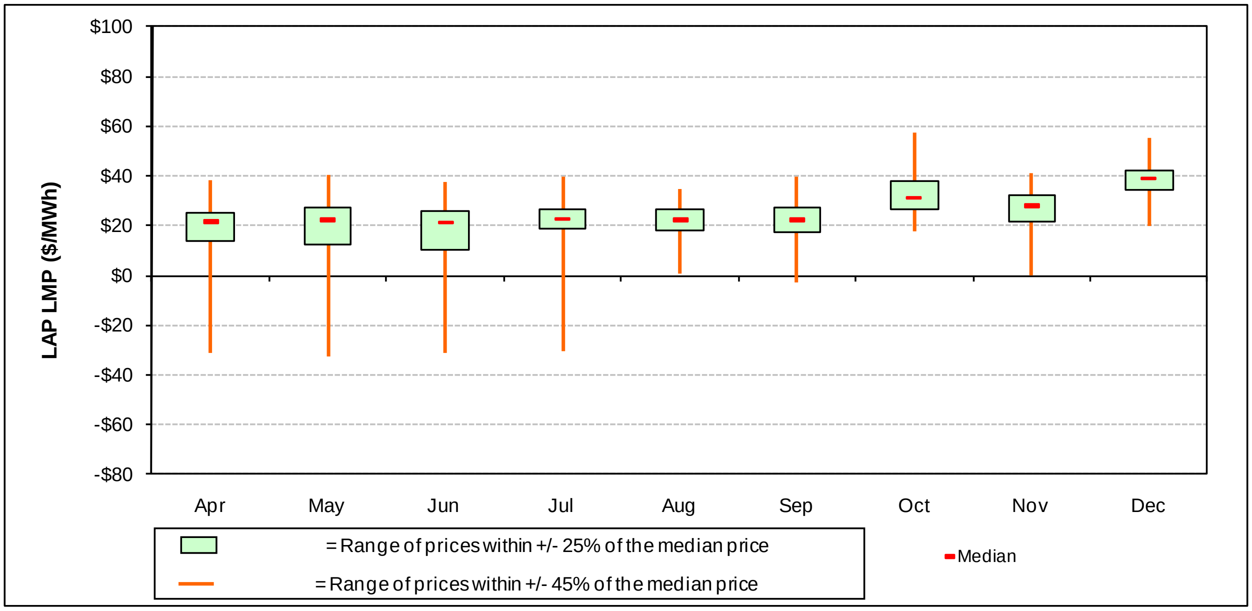
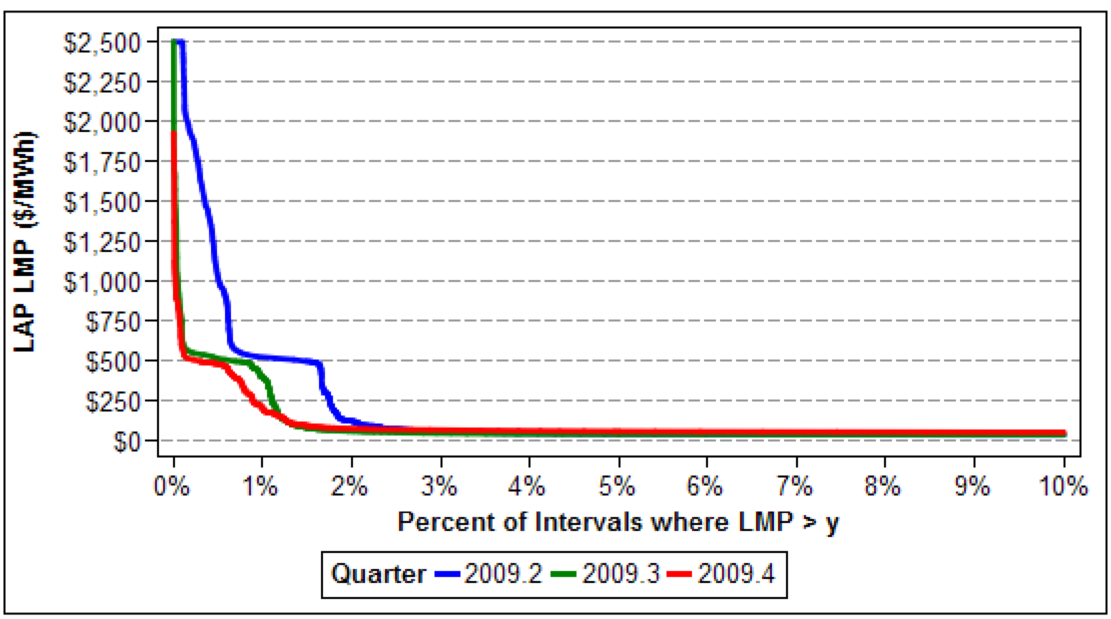


Figure 1.9 shows the top 10 percentiles of RTD LAPs by quarter as duration curves. In Q4, spikes in excess of $250/MWh occurred in 0.9 percent of intervals overall. October experienced price spikes in excess of $250/MWh in 1.3 percent of intervals, similar to the rates seen in Q3. November and December LMPs above $250/MWh respectively were 0.4 percent and 0.9 percent of intervals. The only month to have experienced a similarly low frequency of positive spikes was June, which had unseasonably mild weather. In comparison, Q2 and Q3 rates were 1.5 percent and 1.1 percent, respectively.

Figure 1.9 RTD LAP LMP Duration Curves by Month: Top 10 Percentiles



The frequency of price spikes in the negative direction in Q4 was lower than that seen in Q3. In Q4, LMPs below[9] the price floor of -$30 occurred in 0.9 percent of intervals overall. October and December LMPs below the price floor of -$30 were the lowest-frequency months seen in 2009, with prices below -$30/MWh occurring fewer than 0.6 percent and 0.5 percent of intervals. The November rate was similar to that seen in Q3, at 1.6 percent of intervals. In comparison, the Q2 and Q3 rates were approximately 3.3 percent and 1.3 percent, respectively.

Figure 1.10 RTD LAP LMP Duration Curves by Month: Bottom 10 Percentiles

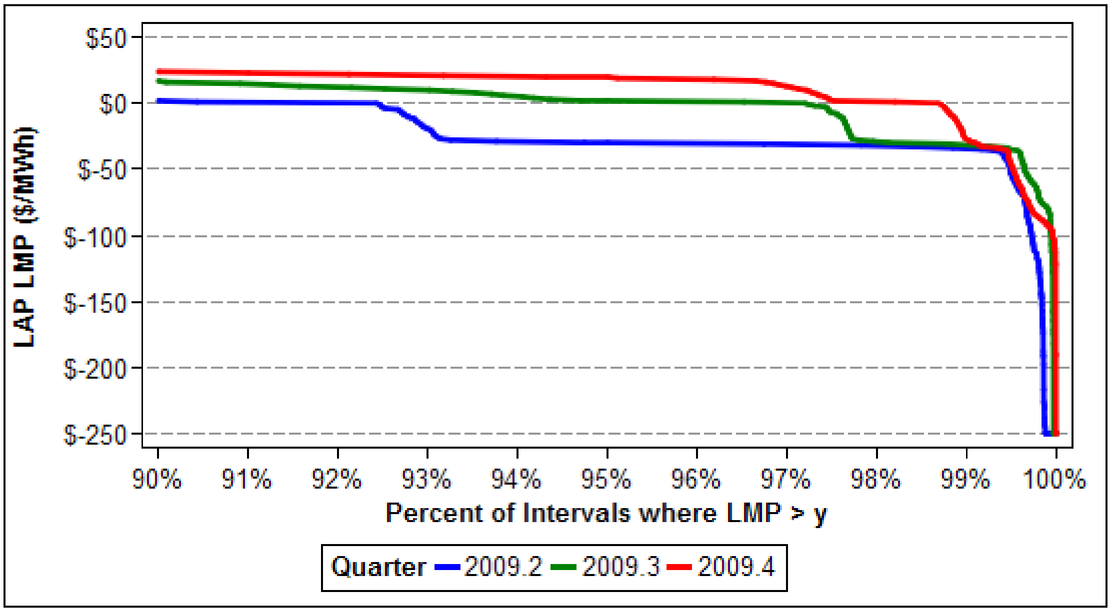


Figure 1.11 shows the daily average frequency of high prices, by price level, of RTD LAP LMPs, for each week since April 1, 2009. Extremely high prices have been rare since Q3. The four periods of prices above $1,000/MWh in Q4 occurred on October 14, October 16, December 3, and December 22, 2009. Spikes on October 2 were due to binding local area nomogram constraints in the SCE and PG&E areas. Spikes on the other three days were due to import-related congestion in the San Diego area. These situations coincided with transmission derates.

9 Does not include LMPs equal to the price floor.

Figure 1.11 RTD Positive LAP Price Spike Frequency

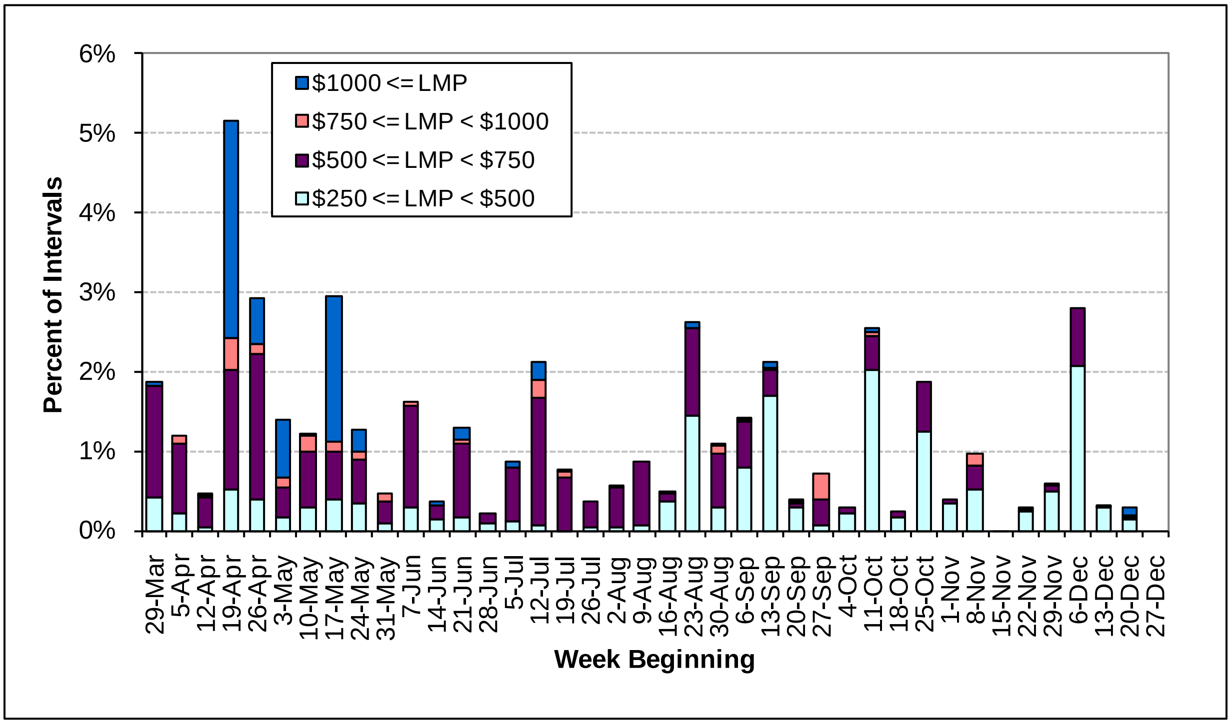


Figure 1.12 provides a different measure of price volatility which reflects the extent to which prices change from one 5-minute interval to the next in the real-time market. [10] This measure indicates that, after an initial period of very high price volatility from one 5-minute interval to the next following the introduction of the new market, this measure of price volatility is now in a range similar to that of other ISOs. The volatility metric for other ISOs ranges from roughly 5 percent (ISO New England) to 30 percent (Midwest ISO). The volatility metric for the California ISO is calculated two ways. The maroon portion includes the entire set of prices, and thus is more comparable to the metric used for other ISOs. The blue bars denote the contribution to volatility excluding extreme or outlier prices (i.e., only prices within the range of -$40/MWh to $550/MWh).

As shown in Figure 1.12, after a period of initial volatility, the total level of volatility had decreased to levels experienced in mature ISOs by Q4. Differences across ISOs may be explained by variations in each ISO's design, market software and optimization features, and fundamental supply and demand conditions. In light of these factors, we do not necessarily view the comparison across ISOs as an "apples-to-apples" comparison. However, the trend of decreasing volatility for the California ISO markets to levels within the range of that of other ISOs provides a clear indicator of improved and reasonable real-time market performance in terms of this aspect of price volatility.

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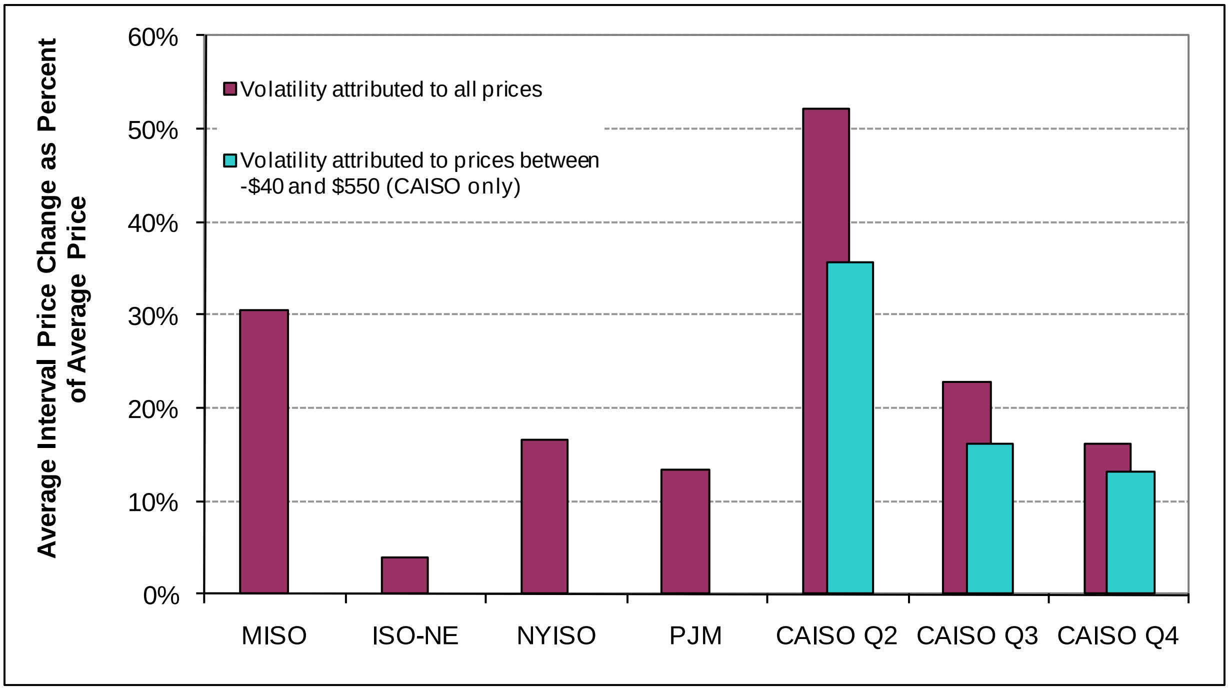
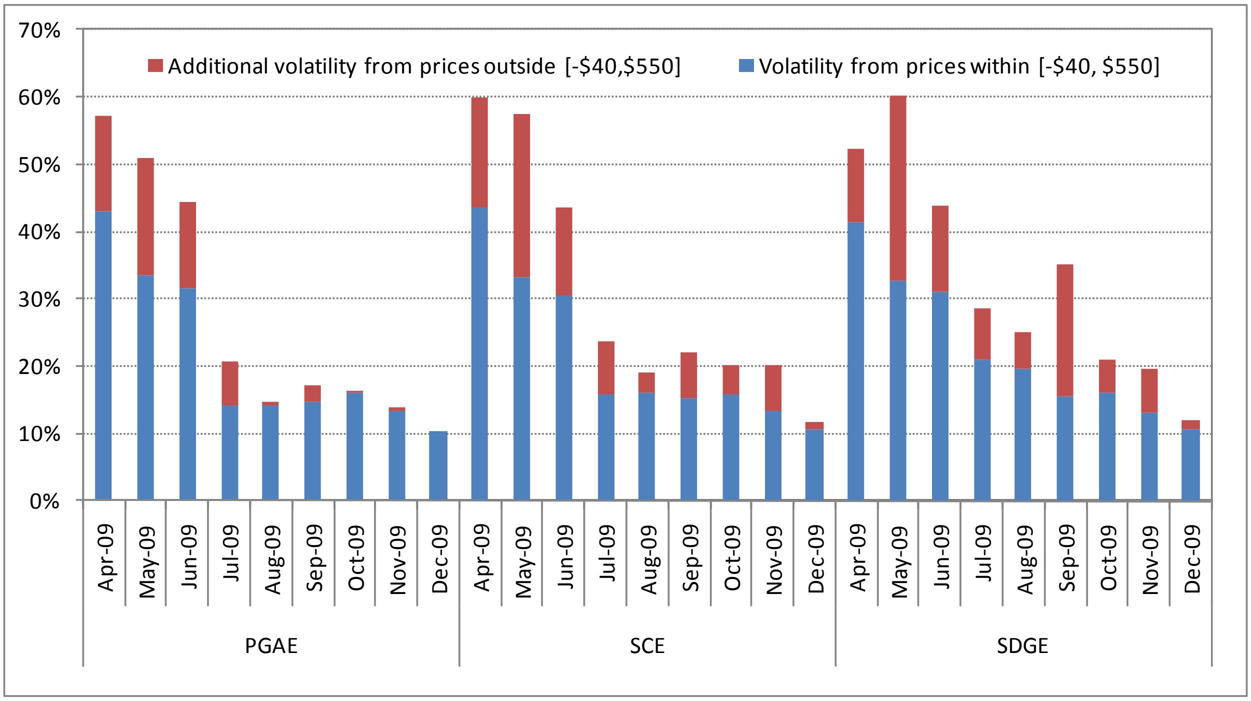
[10] This metric is a calculation of the average interval price change (in absolute value) expressed as a percentage of the average price. We calculate this metric by taking the arithmetic average of the three default LAP prices (SCE, SDG&E, and PG&E) across all intervals in each quarter, and comparing it to the same metric for other ISOs with nodal pricing for all of 2007.

Figure 1.12 5-minute Interval Real-Time LAP Price Volatility across ISOs



The same volatility metric is presented in Figure 1.13 for the three LAP areas separately, on a monthly basis. The overall trend in 2009 is a consistent decrease in volatility across all LAPs. The exception was an increase in the SDG&E LAP in September, due to fire-related and other outages. Aside from that anomaly, the trend continued into Q4. Price spikes have become so infrequent that the contribution to volatility from extreme outlier prices declined to below 2 percent of total volatility in December.

Figure 1.13 Monthly Average 5-minute Interval Real Time Price Volatility



2 Market Competitiveness and Mitigation

This chapter provides an assessment of the overall competitiveness of the ISO's Integrated Forward Market (IFM) and real-time market (RTM). In addition, we provide an analysis of start-up and minimum load bidding by gas-fired units, and overall Bid Cost Recovery costs over the first nine months of the ISO's new market. Key findings of this chapter 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).
- Prices in the ISO's IFM during each month of Q4 continued to be approximately equal to prices we estimate would result under perfectly competitive conditions, based on competitive baseline prices DMM develops by re-simulating the IFM with Default Energy Bids reflecting each unit's actual marginal cost.
- The frequency of prices in excess of the $500 bid cap in the RTM increased slightly in October, driving average RTM prices slightly above DMM's competitive baseline prices for that month, but RTM prices returned to levels approximately equal to DMM's competitive baseline prices in November and December.
- On September 29, 2009, the Federal Energy Regulatory Commission issued an order accepting modifications to the ISO's tariff provisions allowing increased bids for start-up and minimum load costs to be modified every month rather than every six months.[11] Following approval of these modifications, the portion of gas-fired capacity selecting the Registered Cost option – under which unit owners can bid start-up and minimum-load costs in excess of fuel costs – increased from about 25 percent to 35 percent. However, as of December 2009, only about 16 percent of start-up bids and about 11 percent of minimum load bids for capacity under the Registered Cost option were submitted at prices at or near the 200 percent cap now in effect under this option.
- Over the first nine months of the ISO's new market, Bid Cost Recovery (BCR) totaled about $66 million, or approximately 1 percent of total energy plus ancillary services costs. This indicates that BCR payments have been relatively low, and compare favorably with analogous payments in other ISOs, which have averaged from 1 percent up to almost 3 percent of total energy costs.

2.1 Day Ahead Scheduling of Load

As shown in Figure 2.1 and Figure 2.2, the level of load scheduled in the day-ahead market has been very high, with 95 to 100 percent of real-time load being scheduled in the IFM in Q4 2009. The level of load scheduled in the day-ahead IFM can represent a key indicator of overall market efficiency and competitiveness. If the level of load scheduled in the IFM is close to the actual level of load in real time, this generally allows for a more efficient commitment and scheduling of different supply resources to meet real-time demand. High levels of load

[11] Order Accepting Tariff Modifications, ER09-1529-000, 128 FERC ¶ 61,282 (September 29, 2009 Order) http://www.caiso.com/2439/243974b716500.pdf

scheduling in the IFM can also indicate that markets are competitive and that any market power is being effectively mitigated. Finally, when load scheduled in the IFM is near actual load, the impact of extremely high or low real-time prices is low, since a relatively small portion of demand and supply is actually being settled at the real-time price.

Figure 2.1 Day Ahead Load Scheduling by Operating Hour (Q4 2009)

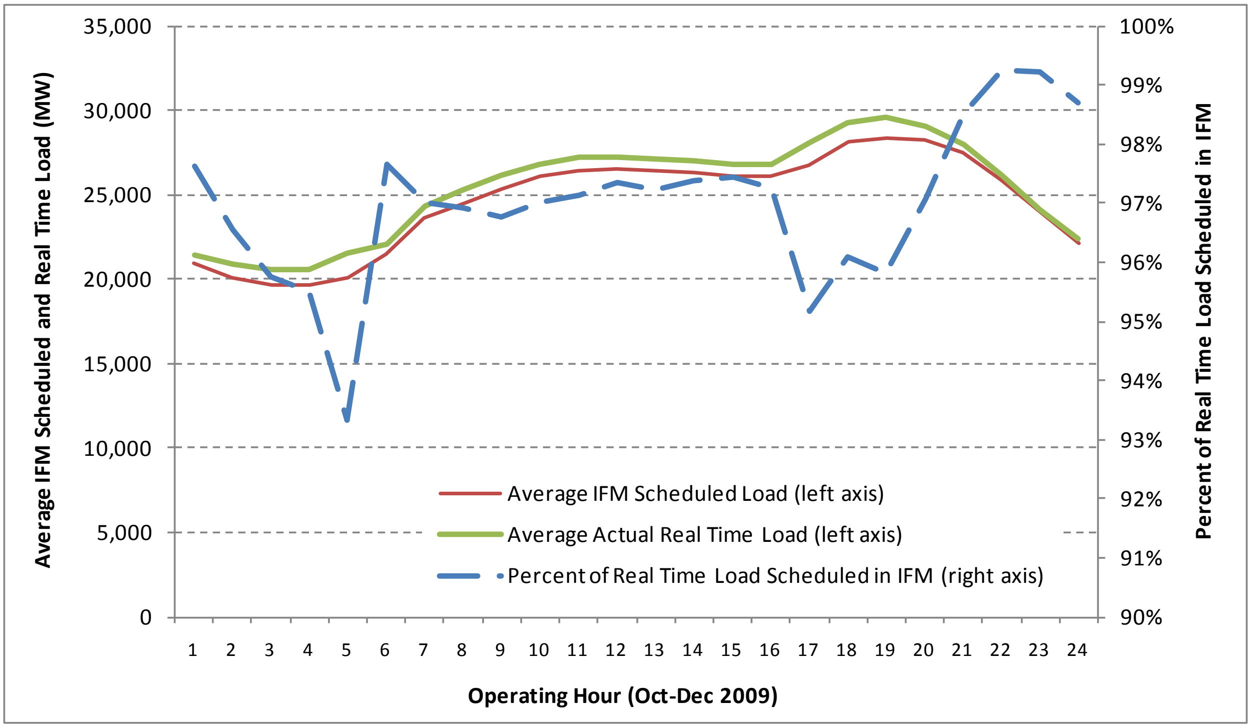
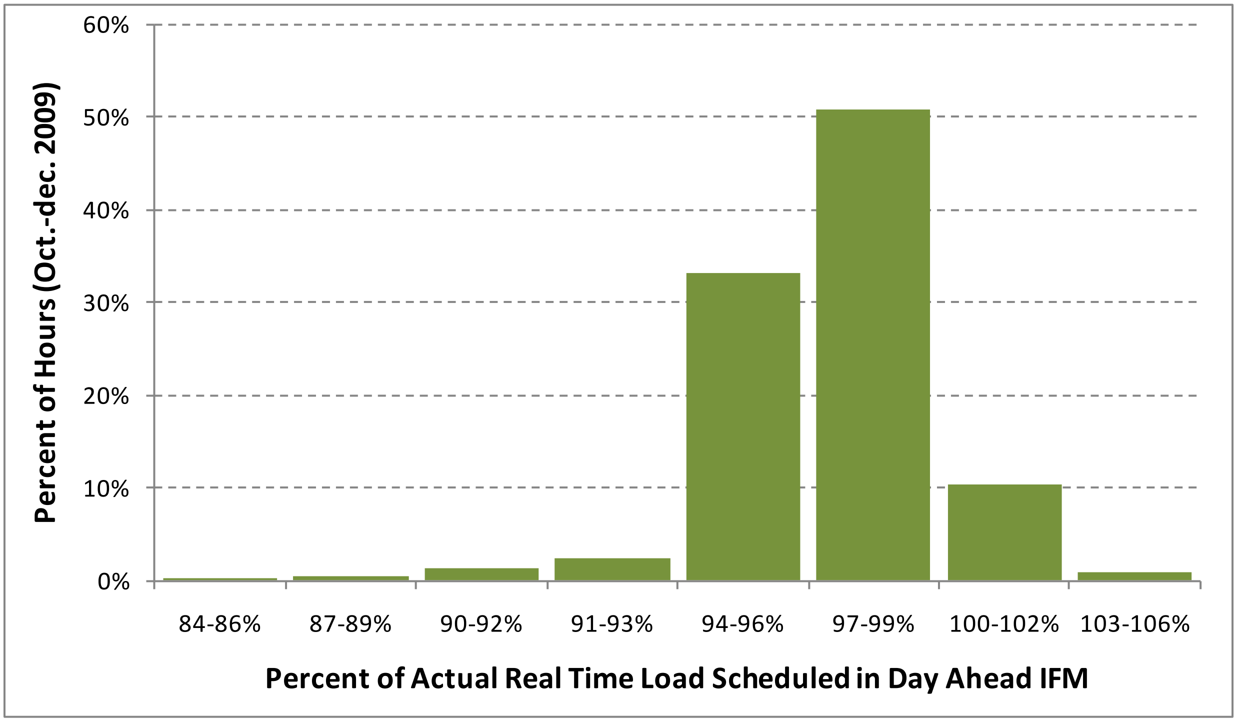


Figure 2.2 Percent of Real Time Load Scheduled in Day Ahead IFM (Q4 2009)



2.2 Market Competitiveness

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

- The first is a re-run of the IFM software using data for the applicable IFM Save Case (the ISO's archive of market and system inputs and settings saved after completion of the final IFM market run). Results of this initial re-run are benchmarked against actual IFM results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[12] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[13]

- The second run of the stand-alone IFM software is designed to represent a perfectly competitive scenario which provides a *competitive baseline* against which the re-run of actual IFM prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective Default Energy Bids (DEBs), which are designed to represent each unit's actual variable or opportunity costs.[14] 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 IFM. 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 2.3 through Figure 2.5 show monthly summary results of this competitive baseline analysis for each of the three LAPs in the system. The light blue bar (IFM Actual) represents the weighted average price for each LAP for the days that were re-run using actual IFM market inputs (see left vertical axis). The darker blue line (Competitive Baseline) shows the weighted average price for each LAP for these same days based on the re-run performed using DEBs for gas-fired generation. The red 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). As illustrated in these figures:

- In October, the monthly price-cost mark-up ranged from 0.1 percent to -0.8 percent across the three LAPs.

- In November, the price-cost mark-up was about -4 percent across all three LAPs.

- During December, the average mark-up ranged from -2.6 percent to -3.4 percent across the three LAPs.

Overall, the mark-up index indicates that monthly LAP prices are within competitive ranges through the first nine months of the ISO's new market. The mark-up index for Q4 of 2009

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

[13] For this fourth quarter 2009 report, results were excluded for 10 out of 31 days in October; 5 out of 30 days in November; and 7 out of 31 days in December. DMM expects the portion of re-runs that do not accurately replicate market outcomes (and are therefore excluded from such analyses) to decrease as updates to the IFM software decline, and DMM is able to successfully perform a greater portion of re-runs with a smaller lag time from the date of actual market operations.

[14] Under the market power mitigation provisions of the ISO's tariff, cost-based DEBs 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 DEBs are based (Section 39.7.1.1). Units such as use-limited resources may also have a DEB that reflects their opportunity costs under the negotiated cost option of the ISO 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).

shows slightly negative price-cost mark-ups, which are attributable to the fact that a significant amount of generators bid slightly below their DEBs. Since cost-based DEBs include a 10 percent adder above fuel and variable costs, these relatively small negative mark-ups are not indicative of uncompetitively low prices, and simply 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 DEBs.

Meanwhile, the increase in average cost during Q4 relative to Q3 in both the actual IFM and the competitive baseline scenario results can be explained by an increase in spot market prices for natural gas and the increase in demand during these periods. The Q4 average costs in both the actual IFM and competitive baseline scenario were generally higher than those in Q3 which can be explained by an increase of 43 percent in spot market prices for natural gas during Q4. Spot market prices for natural gas in Q4 averaged $5.20/mmBtu, while in Q3 natural gas prices averaged $3.63/mmBtu, representing an increase of 43 percent.

Figure 2.3 PG&E LAP Competitive Baseline Index (April – December, 2009)

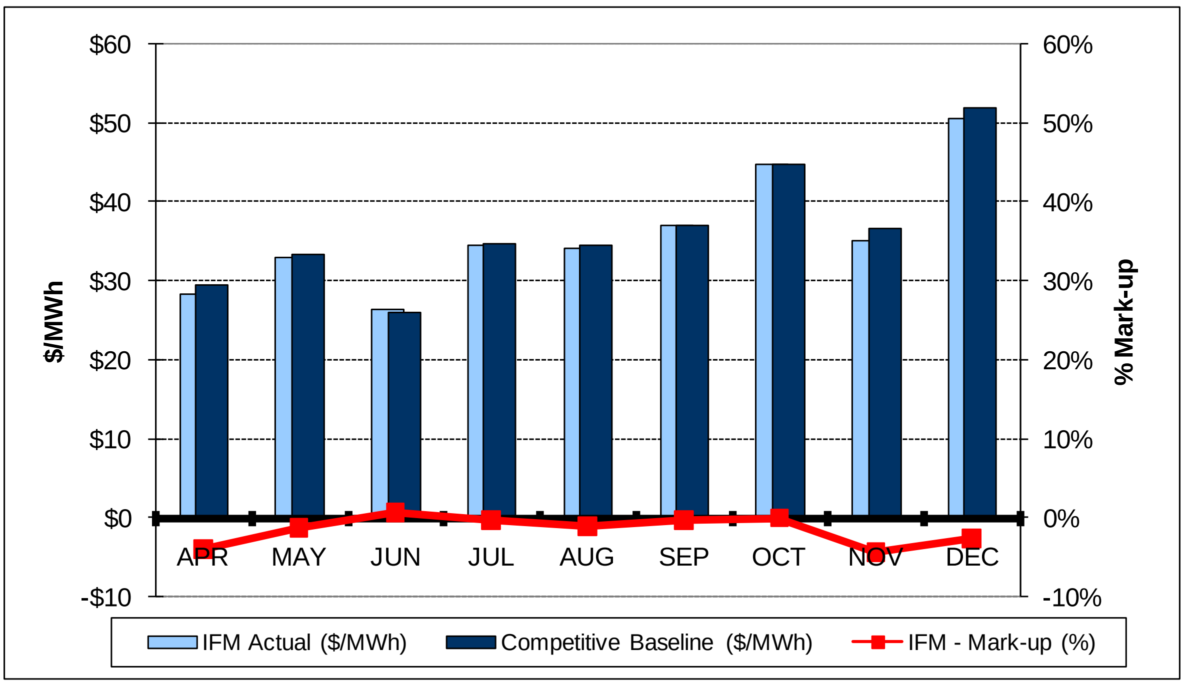


Figure 2.4 SCE LAP Competitive Baseline Index (April – December, 2009)

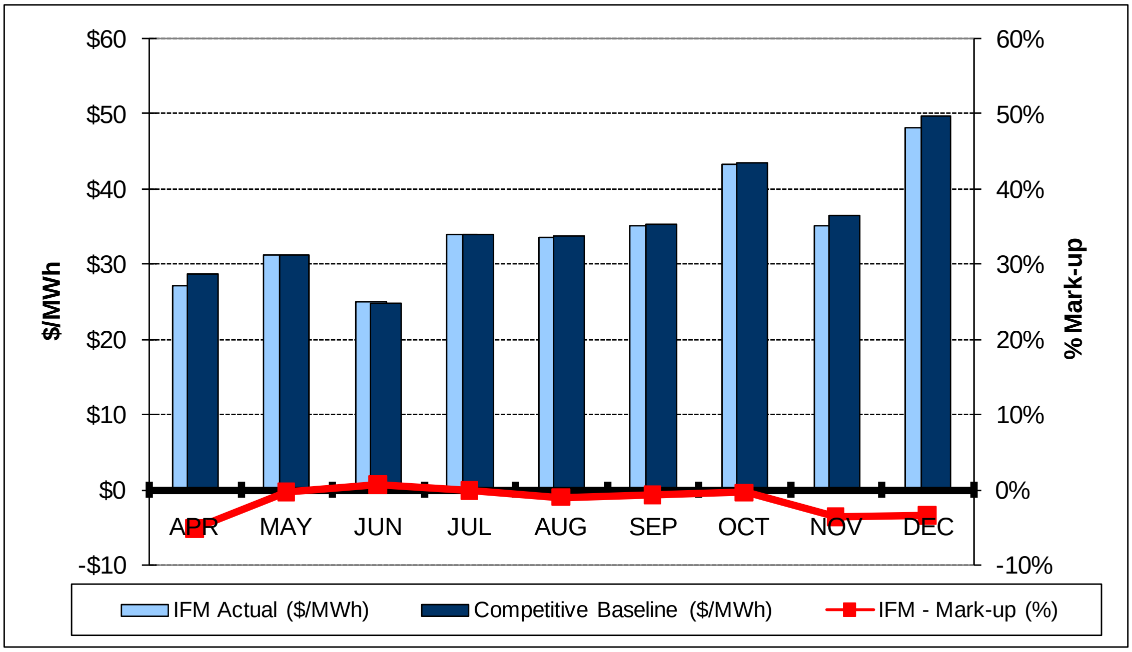


Figure 2.5 SDGE LAP Competitive Baseline Index (April – December, 2009)

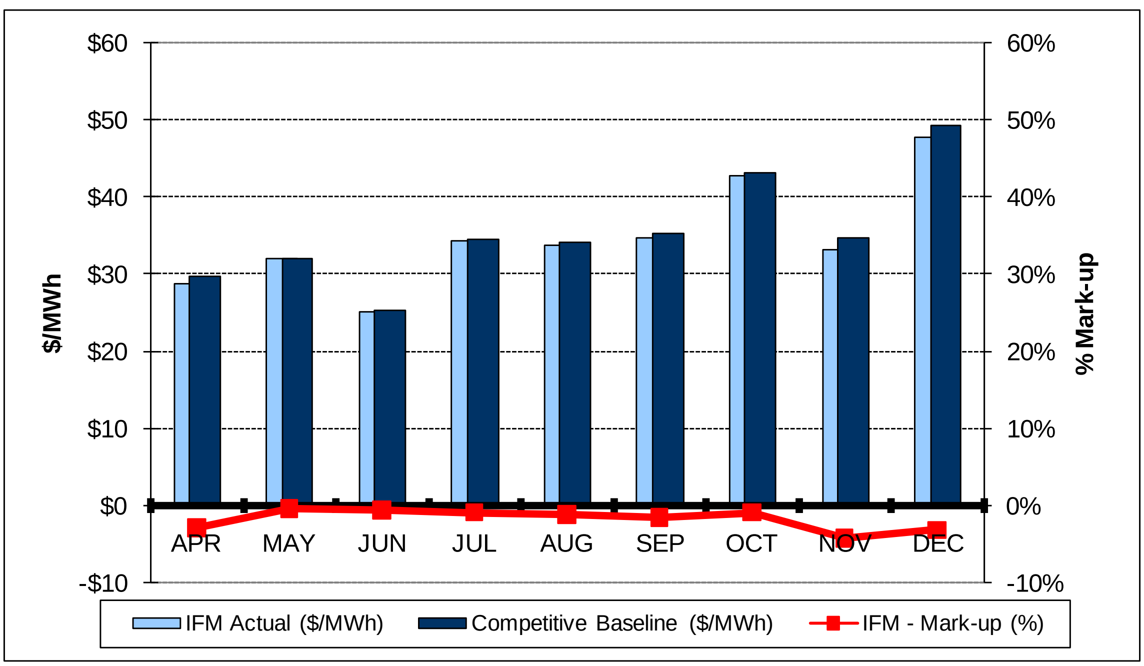
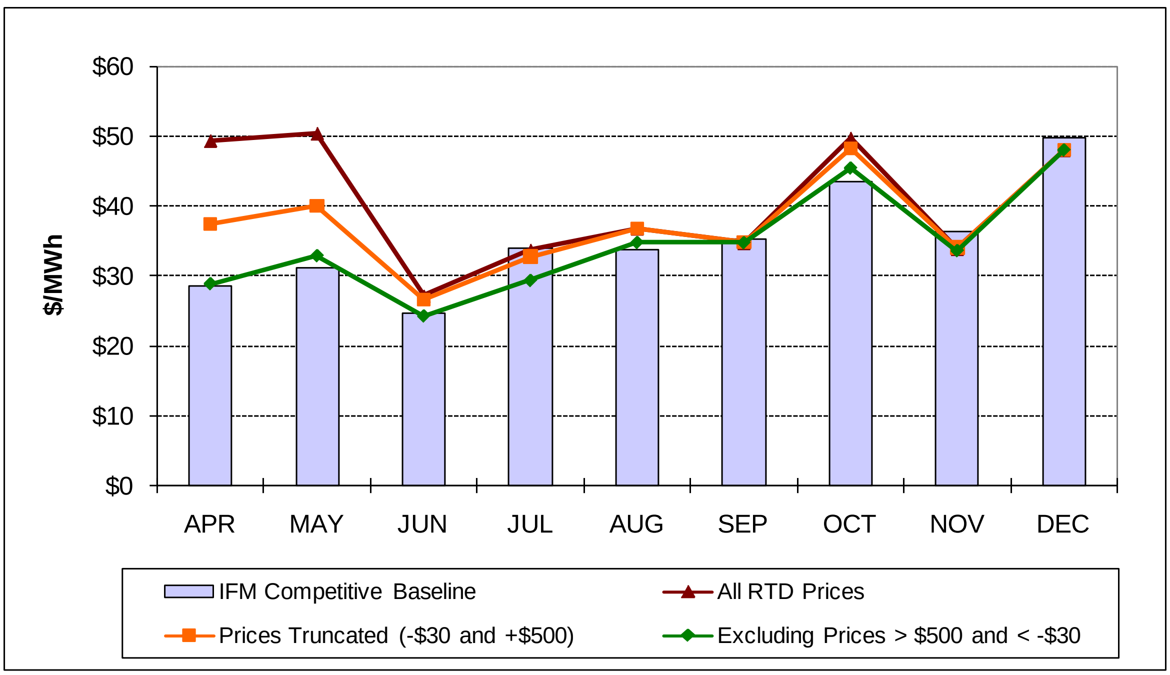


Figure 2.6 compares the competitive baseline price calculated by DMM using the IFM software for the SCE LAP to three different averages of 5-minute real-time SCE LAP prices. As shown in Figure 2.6, when extremely high or low 5-minute prices (greater than $500 or less than -$30) are excluded, average real-time prices for each of the three months are essentially equal to the competitive baseline estimate. For purposes of this comparison, DMM believes it is appropriate to exclude such extreme prices when making this comparison given that RTD prices reflect 5-minute operating constraints that cannot be captured in the competitive baseline estimate, which is produced using the day-ahead market software.

Figure 2.6 also provides two additional comparisons based on real-time prices with less screening of extreme prices, including one that includes all 5-minute prices but truncates extreme prices at the bid caps (orange line), and a second comparison that includes all 5-minute prices with no prices excluded or truncated (red line). As shown in Figure 2.6, these other two comparisons were significantly higher than the competitive baseline in April and May, then converged to the competitive baseline from June to December. This convergence of IFM and RTD prices reflects the fact that there were much fewer extreme real-time prices in the June to December months.

Figure 2.6 Comparison of SCE LAP Competitive Baseline to Real Time Prices



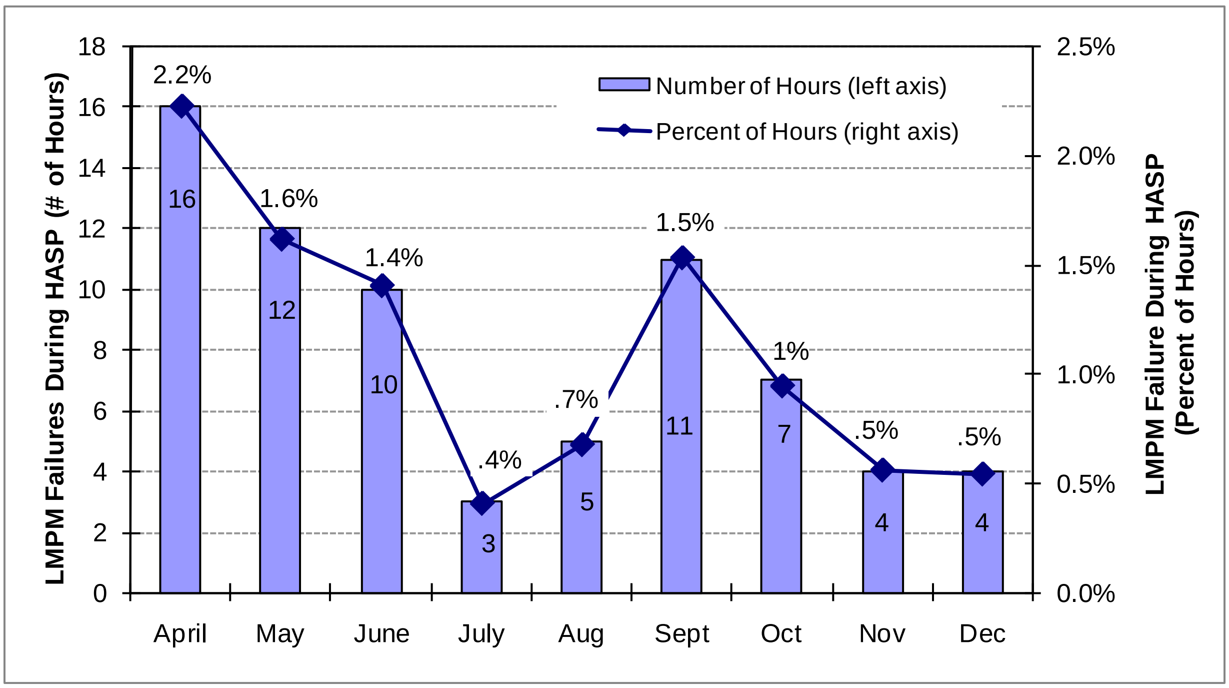
2.3 LMPM Failures During HASP

Prior to the start-up of the ISO's new LMP market, one of the major issues identified by DMM was the relatively high frequency with which the pre-RTM LMPM process was not run due to various problems or failures occurring during the HASP process – during which the pre-RTM LMPM process is performed. We recommended that the ISO closely monitor this issue and seek to reduce the frequency of pre-RTM LMPM failures due to problems in the HASP. In addition, we recommended that the ISO develop a process for assessing the market impact of any failures of the LMPM procedures on prices in the RTM and perform price correction, as appropriate.

As discussed in our *Q2 Report*, DMM worked with the ISO's price correction team to establish more automated and standard criteria for determining if price correction may be needed in cases when the pre-RTM LMPM procedures are not run. As noted in our *Q3 Report*, DMM recommended that the ISO improve the price correction process to ensure that all hours in which LMPM procedures in HASP fail are thoroughly reviewed for price impacts. DMM continues to work with the ISO to ensure that all failures of LMPM procedures are identified and thoroughly reviewed.

During the first nine months of the ISO's new market, the frequency of failures in the pre-RTM LMPM process has been relatively low, and has trended downward. As shown in Figure 2.7, the portion of hours that the LMPM process failed to run in the HASP continued to drop in Q4 2010. In addition, review by DMM and the ISO's price correction team indicates that the price impacts of failures in the pre-RTM LMPM procedures have been very limited.

Figure 2.7 Frequency of LMPM Failures During HASP



2.4 Start-up and Minimum Load Bids

2.4.1 Background

Under the ISO's new market design, owners of gas-fired generation can choose either a cost-based Proxy Cost option or a bid-based Registered Cost option for their start-up and minimum load costs.

- Under the Proxy Cost option, each unit's start-up and minimum load costs are automatically calculated each day by the ISO software based on each unit's start-up and minimum load fuel consumption as reported through the ISO's Master File, combined with an index of daily spot market prices for gas.

- Unit owners selecting the Registered Cost option submit fixed bids for start-up and minimum load costs to the ISO's Master File, which are then used by the ISO's market software. One of the key reasons for providing this bid-based option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs that were not covered under the Proxy Cost option.

At the start of the ISO's new market, Registered Cost bids were capped as follows:

- For units outside of Local Capacity Areas (LCAs), Registered Cost bids could not exceed 400 percent of the unit's projected actual start-up and minimum load fuel costs.

- For units within LCAs, Registered Cost bids could not exceed 200 percent of the unit's projected actual startup and minimum load fuel costs. The lower cap for units in LCAs was designed to reflect the fact that these units would be more likely to have potential local market power that might be exercised by submission of excessively high start-up and minimum load bids under the Registered Cost option.

Two other key provisions relating to start-up and minimum load bids at the start of the ISO's new market include the following:

- Registered Cost bids were initially required to be fixed for a six month period. Consequently, gas prices used for purposes of calculating the cap for each unit's Registered Cost bid were based on the maximum of monthly gas futures prices over the forward looking six month period that the Registered Cost bid would remain fixed. The requirement that Registered Cost bids remain fixed for six months was included to provide an additional disincentive for owners selecting this option to bid excessively high, since they would then face the risk of pricing themselves out of the market during more competitive conditions.

- Under the ISO tariff and Master File design, the unit owner's selection of either the Proxy or Registered Cost option is applied to both start-up and minimum load costs, so that a unit owner cannot select one of these options for start-up costs and the other option for minimum load costs.

After the first few months of the ISO's new market design, numerous participants raised concerns about the Proxy and Registered Cost options. Some suppliers that selected the Proxy Cost option indicated that certain units are being turned off and on more frequently than under the former market, causing extra wear and tear on the generating units. For units with start-up and emissions limitations, this could also make it difficult for the owner to seek to optimize use of a unit over the time period of these constraints. Although the Registered Cost option allowed generation owners to incorporate non-fuel costs in their bids, numerous generation owners indicated they felt the six month period that Registered Cost bids were required to remain fixed made it difficult to submit bids that accurately tracked changes in actual costs due to changes in gas prices over this six month period.

As a short term response to concerns about the Proxy and Registered Cost options initially incorporated in the ISO's tariff, on July 30, 2009, the ISO filed to modify these provisions as follows:[15]

- First, the six month restriction on changing between the Proxy and Registered Cost option or modifying Registered Cost bids was lowered to 30 days. This modification was designed

[15] http://www.caiso.com/23fc/23fcb61b29f50.pdf

to allow participants selecting the Registered Cost option to submit bids that would better represent their costs and help to more efficiently manage the way their units were being committed in the new markets.

- Second, the cap for bids under the Registered Cost option for units outside of LCAs was also lowered from 400 percent to 200 percent of projected actual start-up and minimum load fuel costs. This modification was included in response to concerns expressed by the Market Surveillance Committee (MSC) that a 400 percent cap – in combination with the option of modifying bids every 30 days – could allow a unit to exercise market power in cases where a unit outside an LCA might be needed for local capacity due to a temporary transmission outage or other extraordinary system condition.

When filing these tariff revisions with FERC, the ISO requested a waiver of the Commission's 60-day prior notice requirement so that the modifications could become effective August 1, 2009, and unit owners wanting to switch from the Proxy to Registered Cost option or modify Registered Cost bids could do so at that time. However, the Commission did not issue an order confirming acceptance of the ISO's July 30 filing until September 29, 2009.

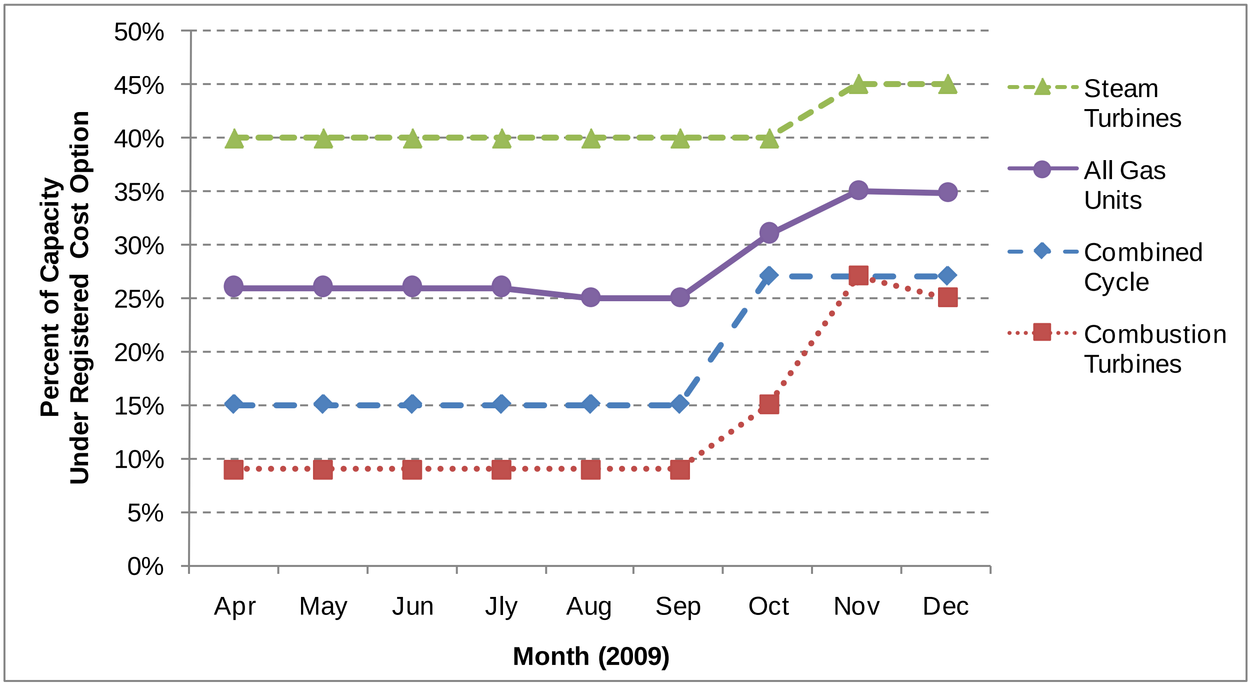
The following sections summarize trends in the portion of capacity selecting the Proxy and Registered Cost options since the start of the ISO's new market, and provide a summary of the general level of bids submitted under the Registered Cost option in Q4 2009.

2.4.2 Capacity Under Registered Cost Option

At the start of the new market in April 2009, about 25 percent of gas-fired capacity elected the Registered Cost option for start-up and minimum load bids. As shown in Figure 2.8:

- Steam units, which represent older generating capacity, were the most likely type of unit to select the Registered Cost option, with about 40 percent of steam capacity selecting this option.
- Only about 15 percent of combined cycle units and 10 percent of combustion turbines initially selected the Registered Cost option.
- There was no significant change in the amount of capacity under the Registered Cost option immediately after the ISO filed to reduce the six month selection period to just 30 days with an effective date of August 1, 2009.
- Following the Commission's September 29, 2009, Order accepting these tariff provisions, the portion of gas-fired capacity selecting the Registered Cost option increased from about 25 percent to 35 percent.
- The most significant change following acceptance of the new tariff provisions reducing the election period for the Registered Cost option from six months to 30 days was in the portion of gas turbines and combined cycle units that chose the Registered Cost Option, with the portion of capacity in these categories increasing from 10 percent and 15 percent, respectively, to over 25 percent.

Figure 2.8 Gas-Fired Capacity Under Registered Cost Option



2.4.3 Bids Submitted Under Registered Cost Option

A relatively limited portion of start-up and minimum load bids that have been submitted for capacity under the Registered Cost option have been at or near the 200 percent cap in effect under this option.

- As shown in Figure 2.9, in December 2009 about 71 percent of capacity under the Registered Cost option submitted start-up bids between 160 to 189 percent of start-up fuel costs, but only 16 percent submitted bids right at the 200 percent cap in effect under this option.
- Meanwhile, as shown in Figure 2.9, about 76 percent of capacity under the Registered Cost option submitted minimum load bids within 120 percent of minimum load costs, and only 11 percent submitted bids right at the 200 percent cap in effect under this option.

Figure 2.9 Start-Up Registered Cost by Generation Type - December 2009

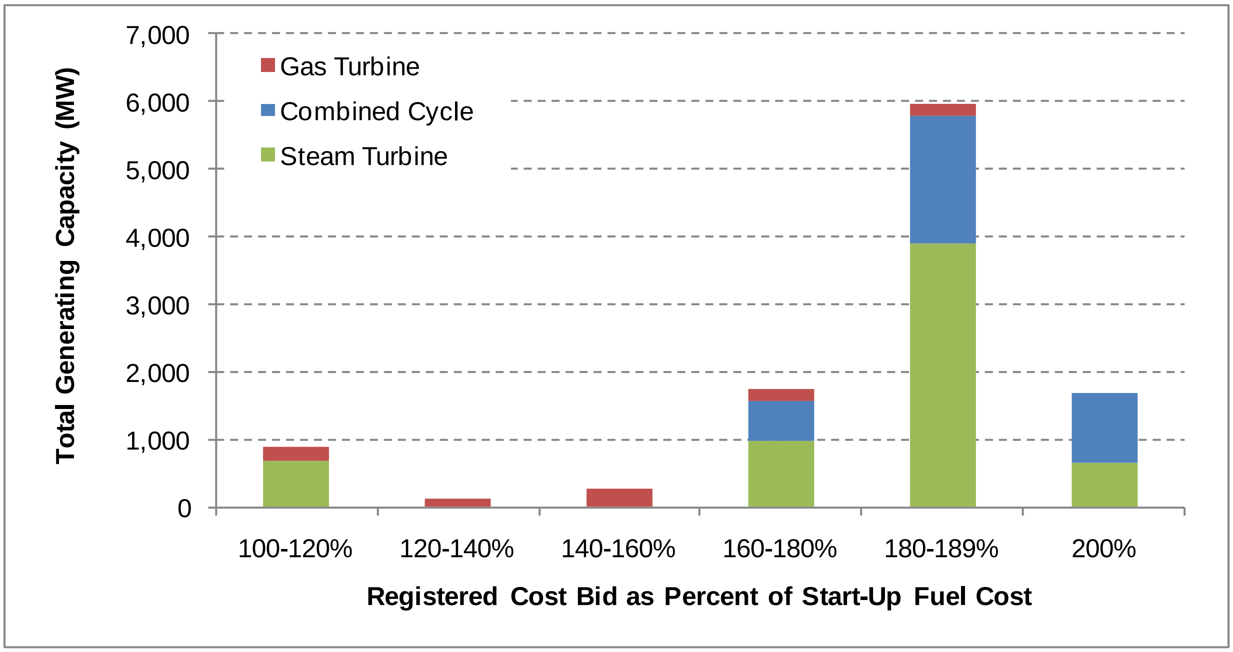
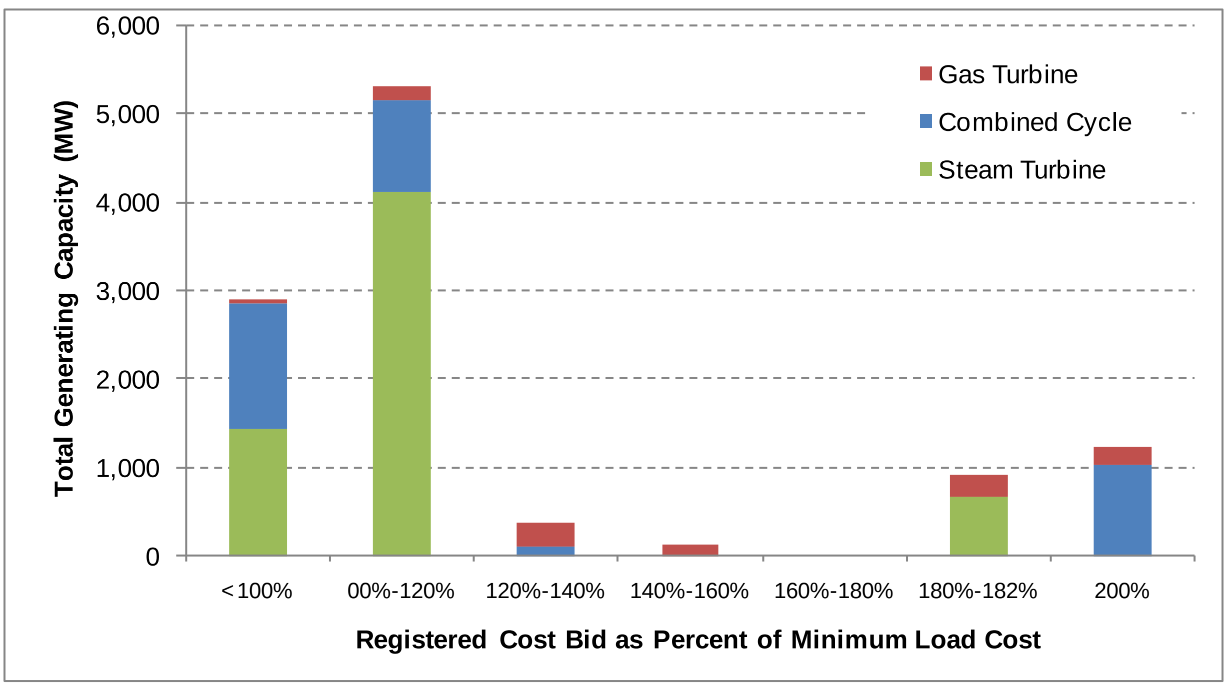


Figure 2.10 Minimum Load Registered Cost by Generation Type – December 2009



2.4.4 Conclusions

Overall, results of this analysis suggest that the 200 percent cap is not overly restrictive, and that owners of most gas-fired capacity under the Registered Cost option have been able to incorporate whatever non-fuel costs they may incur in bids within the 200 percent cap.

However, as shown in Figure 2.10, a relatively high portion of units under the Registered Cost option actually submitted bids below or just slightly over their projected actual minimum load operating costs. This is likely to reflect the fact that under the ISO tariff and Master File design, the unit owner's selection of either the Proxy or Registered Cost option is applied to both start-up and minimum load costs, so that a unit owner cannot select one of these options for start-up costs and the other option for minimum load costs. This suggests that a significant portion of unit owners selecting the Registered Cost option do so primarily in order to be able to submit start-up bids that include additional non-fuel costs, and then submit minimum load bids at or near their projected actual minimum load costs. Numerous stakeholders have indicated that this represents another aspect of the Registered Cost option that they would like to have modified. Specifically, they have suggested that rules be modified to allow them to submit start-up costs which include a fixed component for non-fuel costs, while having start-up and minimum load fuel costs calculated based on daily spot market gas prices. This represents a future design modification that the ISO has indicated it will seek to address in 2010.

2.5 Bid Cost Recovery Payments

Under the ISO's new market design, units are eligible to receive Bid Cost Recovery (BCR) payments in the event that the total market revenues earned by a generating unit over the course of an operating day do not cover the sum of all bids accepted by the ISO that day – including start-up, minimum load, ancillary services, RUC and energy bids. Thus, if units started up or committed at minimum load by the ISO are not dispatched for sufficient amounts of additional energy and/or do not earn sufficient revenues in excess of their bid costs, this may be reflected in higher BCR payments. In other ISOs, submission of high start-up and minimum load bids – coupled with other bidding and scheduling behaviors – has also been identified as a potential strategy for exercising local market power or "gaming" of market rules to profit through high BCR payments. Excessively high BCR payments can also be indicative of inefficient unit commitment or dispatch.

Table 2.1 provides a summary of total BCR payments based on a query of settlement records at the beginning of January 2010.[16] As shown in Table 2.1, the total amount of BCR payments over the first nine months of the ISO's new market has been about $66 million, or just about 1 percent of total energy and ancillary services costs.[17] This indicates that BCR payments have been relatively low since the start of the ISO's new market. For example, in other markets,

[16] Since further adjustments are made to BCR settlement data over the longer settlement window, data in Table 2.1 represent a "snapshot" that may change somewhat, particularly for the more recent months. However, DMM does not expect the magnitude of such changes to be significant.

[17] Total energy and ancillary service costs used in this analysis are based on preliminary calculations being performed to develop an "all-in-one" costs per MWh of load served to be included in the DMM annual report, and are therefore subject to further review and refinement.

analogous payments (such as revenue sufficiency guarantees) have ranged from about 1 percent up to almost 3 percent of total energy costs.[18]

The sub-totals for different markets that are provided in Table 2.1 represent the markets to which BCR payments made to generating resources were attributed for purposes of allocating BCR payments to Load Serving Entities. DMM is seeking to develop more detailed data and perform more detailed analysis of BCR payments at a generating unit level for DMM's *2009 Annual Report on Market Issues and Performance* and/or in future quarterly reports.

Table 2.1 Bid Cost Recovery Payments

	BCR Payments (by Market)				BCR as Percent of
Month	IFM	RUC	Real Time	Total BCR	Energy and A/S
April	$1,276,054	$9,191	$2,722,231	$4,007,475	0.8%
May	$7,707,961	$35,145	$5,791,919	$13,535,026	2.1%
June	$4,433,919	$19,662	$3,364,600	$7,818,181	1.5%
July	$5,116,894	$862,463	$3,695,812	$9,675,168	1.2%
Aug	$1,286,996	$3,062,506	$1,684,784	$6,034,286	0.8%
Sept	$5,714,362	$1,182,056	$2,328,789	$9,225,207	1.2%
Oct	$3,059,812	$1,214,660	$632,801	$4,907,272	0.6%
Nov	$2,832,239	$2,140,493	$190,557	$5,163,290	0.8%
Dec	$5,641,226	$189,649	-$38,202	$5,792,672	0.6%
Total	**$37,069,463**	**$8,715,824**	**$20,373,291**	**$66,158,578**	**1.0%**

[18] A more detailed comparison of BCR payments with analogous payments in other major ISOs (MISO, NYISO, PJM and ISO-NE) will be provided in DMM's *2009 Annual Report on Market Issues and Performance*.

3 Congestion and Transmission Management

3.1 Overview

This chapter provides a review of congestion of internal constraints and inter-ties in the fourth quarter of 2009 (Q4), as well as related topics, such as conforming transmission limits,[19] exceptional dispatch related to transmission reliability, and the use of automated compensating injections in the real-time market to reconcile observed differences in scheduled versus actual flows near major inter-ties. Key findings in this chapter include the following:

- In Q4, transmission congestion was relatively low and concentrated on a limited number of constraints, with congestion occurring on a total of 25 flowgates, nomograms and inter-ties at some point in the IFM and real-time markets.
- A relatively small number of all transmission constraints were managed during a significant number of hours by conforming the transmission limits based on observed differences in modeled versus actual flows – a practice referred to as “biasing” in our Q3 report. Most constraints that were conformed in the real-time market tended to be "conformed up" (i.e., adjusted in the upward direction). In such cases, the market limit was conformed up to reflect the true available capacity on the line in order to avoid "phantom" congestion in real time (i.e., congestion in the market model when actual physical flows were below limits).
- The number of constraints that have been conformed in the real-time market in a significant portion of hours has decreased since Q3. While some of this decrease may be attributable to changes in system conditions, modeling improvements made by the ISO in late Q3 appear to have significantly reduced the need for conforming a number of the constraints near the Bay Area that were most frequently conformed in Q3.
- For several of the most frequently congested constraints, congestion was often not consistent between the IFM and real-time market (e.g., congestion occurred in the IFM, but not in the real-time market, or vice versa). This situation was observed more significantly for the Intermountain-Adelanto DC Branch Group (IPPDCADLN_BG), SCE Import Branch Group, and La Fresa-Hinson 230kV line. We discuss some of the factors that may have contributed to these trends in this chapter.
- Beginning November 11, the ISO began enforcing the SCE Import Percent Branch Group Limit (SCE Import Limit), a constraint on the total volume of imports as a percentage of load into Southern California Edison service territory. The bulk of congestion on the SCE import limit in the IFM occurred during the first week that this constraint was added to the market model, without any prior notification to participants. As part of a recent stakeholder process on release of transmission information, the ISO is proposing to establish several new advance notifications that will inform stakeholders of any significant changes to the transmission constraints included in the ISO’s market systems.[20] Under these new policies,

[19] The operational term “Biasing” was used in Q2 and Q3 Reports. Going forward, the ISO has adopted the term “conforming transmission limits” to reflect the intent and nature of manual adjustment of the limits used by the market optimization software to conform to the physical operating characteristics of the grid in real time.

[20] See Draft Final Proposal, Data Release & Accessibility, Phase 1: Transmission Constraints, January 6, 2010, p.9. http://www.caiso.com/2718/2718ef3844a00.pdf

the ISO will seek to provide participants with advance notice when new constraints such as this are added except in cases when a constraint may need to be added or adjusted on an expedited basis for reliability reasons, prior to the time when market notice could be developed and issued.

- In Q4, the ISO activated a software feature that is designed to manage variation between market and physical flows on the major inter-ties through an automated form of compensating injections made at special nodes outside of the ISO system. 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 an increasing number of CPS2 violations. As a result, these automated compensating injections were turned off until further refinements could be made in this software feature. DMM is working with the ISO to develop metrics that can be used to monitor the impact of compensating injections on major constraints within the ISO system, and is recommending that this software feature not be re-activated until these metrics are completed and advance notice is provided to participants that compensating injections will be re-activated.

3.2 Transmission Congestion

3.2.1 Background

Under the ISO prior market design, congestion on inter-zonal flowgates was managed through the day-ahead and hour-ahead markets and priced explicitly. Congestion prices set by the congestion management market was charged explicitly to schedules across these flowgates (or paid for "counterflow" schedules in the opposite direction of congestion). Congestion on intra-zonal flowgates within the ISO system was managed through manual commitment and/or real-time re-dispatch of resources. Because intra-zonal congestion was managed outside the market, this form of congestion management was not priced in a transparent fashion.

Under the ISO's new nodal market design, congestion of inter-zonal and intra-zonal flowgates is managed in the day-ahead IFM, HASP and 5-minute RTD markets. When a constraint is congested, the market produces a shadow price that represents the system-wide bid cost savings that would occur if that constraint had one additional megawatt of transmission capacity in the congested direction.

Although shadow prices are produced for congested constraints, this price is only an indication of the cost impact of the economic cost of the binding constraint and is not directly charged to participants (or paid for "counterflow" schedules in the opposite direction of congestion). However, this congestion does affect the dispatch required to meet load at the various load points within the ISO and as a consequence also has an indirect impact on the price of energy at different nodes. The impact of congestion on the energy price at any location is calculated and published as the congestion component of the LMP for all locations where energy is priced. Thus, in the ISO's new nodal market, the cost of congestion is implicit in the energy price.

Congestion occurs when the physical constraints of transmission limit the ability of the market to move electricity freely across the grid and serve all load with the least-cost bids system-wide. As a consequence, costlier energy that is topologically closer to load must be substituted. For any time interval, the following relationship is true between the congested constraints and the congestion component of a LAP:

$$-\sum_{n=1}^{N} \text{Shift Factor}_{n}^{LAP} * \text{ Shadow Price}_{n} = \text{LMP}_{\text{Congestion Component}}^{LAP}$$

where, for all N constraints on the grid, the shift factor represents the proportion that the congested line impacts the LAP price, and the shadow price is the increase in cost due to substitution of costlier energy that an additional scheduled megawatt of energy on that line will cause. Uncongested lines have a shadow price of zero, since an additional unit of scheduled energy will not overflow the line and thus will not require substitution.

The following example in Table 3.1 will help to understand this formula more clearly. On November 25, trade hour ending 7, two internal constraints (24074_LA FRESA_230_24065_H INSON _230_BR_1_1 and LOSBANOSNORTH_BG) were binding in the IFM market.

Table 3.1 Construction of LMP Congestion Component, IFM Market November 25, 2009, Hour Ending 7

LAP	Flowgate Name	Shift Factor	Shadow Price	LMP	LMP Congestion
PGAE	24074_LA FRESA_230_24065_HINSON _230_BR_1_1	0.038	$14.27	$36.75	$2.08
PGAE	LOSBANOSNORTH_BG	-0.233510112	$11.24	$36.75	$2.08
SCE	24074_LA FRESA_230_24065_HINSON _230_BR_1_1	-0.061185739	$14.27	$30.48	-$1.41
SCE	LOSBANOSNORTH_BG	0.203	$11.24	$30.48	-$1.41
SDGE	24074_LA FRESA_230_24065_HINSON _230_BR_1_1	0.038	$14.27	$28.55	-$2.82
SDGE	LOSBANOSNORTH_BG	0.203	$11.24	$28.55	-$2.82

Using the data, we can decompose the $2.08 LMP congestion component of the PG&E LAP as follows:

$$-[(0.038 * \$14.27) + (-0.23351 * \$11.24)] = -[(\$0.54) + (-\$2.62)] = -\$2.08$$

This example shows how the shadow values on binding constraints, which are not directly used in settlement, impact the energy LMPs which are directly used in settlement. It is this relationship that makes congestion frequency and shadow values important in the new market.

3.2.2 Frequency and Consistency of Congestion in Day Ahead and Real Time Markets

This section provides analysis of the frequency of congestion as well as consistency in congestion on internal constraints between the IFM and RTD markets, and on inter-ties between the IFM and HASP markets.[21] The coincidence of congestion between the IFM and real-time markets is examined as a potential indicator of the degree to which the market and network model are reflecting similar conditions and efficiently managing congestion in both the day-ahead and real-time markets. For example, if a constraint is frequently not binding in the IFM market but is binding in the RTD market, this may warrant further review of how the constraint is being modeled in the IFM and RTD markets or other factors that may contribute to this trend

[21] In the new market model, RTD prices are only used in settlement of internal resources and dynamic system resources (five-minute dispatchable imports and exports), whereas LMPs at the inter-ties calculated in the HASP market only affect settlement of non-dynamic system resources (hourly imports and exports).

(such as loop flows, conforming of constraints, etc.). Analysis in this quarterly report is designed to provide an initial review of patterns of congestion across the day-ahead and real-time markets, and as a starting point for more detailed future monitoring and follow-up. A more detailed discussion of the reasons for this trend on the SCE Import Branch Group is provided in Section 3.5.

In Table 3.2 and Table 3.3, we compare the frequency and consistency of congestion on various constraints during Q4. Congestion in the RTD and HASP markets are based on 5-minute and 15-minute runs, respectively. For both comparisons, we have considered a transmission line to be congested for the complete hour if it is congested for at least one interval in that trading hour. We do this for ease of comparison between the IFM (an hourly market) and the two RTM markets that clear on a sub-hour level. Given this convention, the frequency of congestion reported below for both HASP and RTD markets is overstated compared to a measure that counts congestion on a sub-hour basis.

As shown in Table 3.2 and Table 3.3, there was not a high frequency of congestion on many constraints in Q4. As shown in Table 3.2, on internal constraints within the ISO:

- The IPPDCADLN_BG was congested the most in Q4. However, this particular branch group does not have a significant impact on electricity prices within the ISO nor at the inter-ties and will not be analyzed here.
- Congestion occurred on the SCE Import Limit in the IFM market only during 7.4 percent of hours, in the RTM market only during about 1 percent of hours, and in both the IFM and RTM only 0.4 percent. This constraint is discussed in greater detail below in Section 3.5.
- Congestion occurred on the La Fresa-Hinson constraint in the IFM market only during 3 percent of hours, in the RTM market only during about 8 percent, and in both the IFM and RTM about 4 percent. This constraint is discussed in greater detail below in Section 3.6.
- Congestion was relatively low and consistent on other internal constraints.

Table 3.2 Frequency of Congestion and Shadow Values for the Most Congested Flowgates and Nomograms (IFM and RTD)[22]

Constraint Name	Binding in IFM Only		Binding in RTD Only		Binding in Both IFM and RTD		
	Frequency of Congestion	Average Shadow Price	Frequency of Congestion	Average Shadow Price	Freq. of Cong.	Avg. SP IFM	Avg. SP RTD
IPPDCADLN_BG	22%	$4	3%	$69	6%	$4	$63
SCE_PCT_IMP_BG	7%	$10	0.5%	$141	0.4%	$19	$304
24074_LA FRESA_230_24065_HINSON _230_BR_1 _1	3%	$19	8%	$65	4%	$13	$94
32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	3%	$30	0.3%	$51	1%	$30	$54
33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 _1	2%	$14	0.5%	$468	0%	$0	$0
PATH26_BG	2%	$3	5%	$40	1%	$4	$29
BARRE-LEWIS_NG	2%	$24	0.3%	$1,332	0.1%	$20	$416
LOSBANOSNORTH_BG	1%	$16	3%	$82	1%	$10	$99
HUMBOLDT_BG	1%	$88	2%	$196	1%	$89	$141
VINCNT_BNKS_14_NG	0%	$8	1%	$267	0%	$0	$0
1051307-SOL3 (Potrero - Larkin Outage)	0%	$124	1%	$355	1%	$133	$513
IVALLYBANK_XFBG	0%	$2	13%	$39	1%	$3	$51

[22] The flowgates and nomograms which have been congested less than 1% of the time in any market have been eliminated from this analysis.

Table 3.3 shows the frequency of congestion of inter-ties in both IFM and HASP markets. Because the energy prices produced in the HASP run are used in settlement only for system resources, we compare only the congestion of inter-ties in the IFM and HASP markets in Q4.[23] As shown in Table 3.3, major ties between the Southwest and Southern California were more frequently congested than those between the ISO and the Northwest in Q4, consistent with historical patterns of congestion during the later fall and winter months. A discussion of congestion on key inter-ties shown in Table 3.3 is provided below:

- The Palo Verde ITC (PV), which represents a large transmission corridor that connects Arizona generation to Southern California load, incurred the bulk of its congestion in the IFM market. Between Monday, October 12, 2009, and Monday, November 30, 2009, the Navajo-Westwing 500kV line in Arizona was taken out of service, for the cut-in of the Dugas 500/69kV Substation. The PV was nominally de-rated slightly during this time. Between November 17 and 18, the Imperial Valley - North Gila 500kV line was also out, contemporaneously with the Navajo - Westwing 500kV outage, causing a further de-rate of PV. Again on December 8, the North Gila-Hassayampa 500kV line was forced out for several hours. It returned only after the IFM market results for trade date December 9 were already published. That forced outage resulted in a significant outage on the inter-tie for the trade date December 9.

- On November 13, 2009, the ISO created the new inter-tie transmission constraint MEAD_ITC as a companion to the combination of MEAD_MSL and MEADTMEAD_MSL scheduling limits, representing transmission between Hoover Dam in Nevada and Southern California, as well as other Hoover-area limits. This ITC includes schedules for the scheduling points MEAD230 and MEAD2MSCHD. In Q4 there were no major de-rates of this inter-tie. The congestion occurred primarily due to the daily fluctuation of ETCs.

- SUMMIT_ITC, which represents a small transmission path between Northern California and Sierra Power in Northern Nevada, was congested 16 percent and 18 percent of the time, in IFM and HASP markets, respectively. The line was derated for scheduled work on the Drum-Rio Oso#2 115kV line, from October 28 through November 8. In addition, the DRUM #1 Pump Hydro unit was undergoing scheduled work November 3 through 18. During the pump outage, the SUMMIT_ITC limit was de-rated to 0 MW only in the import direction. The export direction remained at its normal 100 MW capacity. During this time the market observed shadow prices on SUMMIT_ITC in both IFM and HASP markets, but no megawatt was scheduled on this inter-tie, so prices did not apply for settlement.

- NOB_ITC represents transmission limits faced by ISO schedules on the Pacific DC Inter-tie, also referred to as the NOB (North of Oregon Border), which connects the Sylmar substation, shared by SCE and the non-participating Los Angeles Department of Water and Power, directly to the Pacific Northwest at the Celilo substation in Oregon. As Table 3.3 indicates, NOB_ITC typically was congested in the HASP market but not in the IFM market. On October 1 and 2, and again from October 13 through 24, Celilo-Sylmar 1000kV Poles 3 and 4 were out for scheduled work, which made the NOB_ITC unavailable in both directions, as the tie was open.

[23] To better understand the results shown in Table 3.3, consider the congestion on the Palo Verde inter-tie. In 19 percent of the hours the inter-tie was congested only in the IFM market, in two percent of hours it was congested only in the HASP market, and in thirteen percent of hours it was congested in both the IFM and HASP. These numbers are additive such that this inter-tie was congested in 31 percent of the IFM hours (19+13=31) and 15 percent of HASP hours (2+13=15).

Table 3.3 Frequency of Congestion and Average Shadow Prices for the Most Frequently Congested Inter-Ties in IFM and HASP[24,25]

		Binding in IFM Only			Binding in HASP Only			Binding in IFM and HASP		
Inter-Tie name	Full (Import) Rating (MW)	Import Frequency	Export Frequency	Avg. Shadow Price	Import Frequency	Export Frequency	Avg. Shadow Price	Binding Frequency	Avg. SP IFM	Avg. SP HASP
PALOVRDE_ITC	3,328	19%		$12	2%		$47	13%	$15	$28
ELDORADO_ITC	1,555	11%		$7	3%		$64	4%	$11	$31
MEAD_ITC	1,460	6%		$5	5%		$24	34%	$9	$12
PACI_ITC	3,200	3%		$7	1%		$188	1%	$4	$13
ADLANTO-SP_ITC	1,217	2%		$7	0.5%		$68			
MERCHANT_ITC	797	2%		$5	0.1%		$34			
SUMMIT_ITC	80	2%		$24	4%		$45	14%	$36	$38
BLYTHE_ITC	217	1%		$34	0.9%		$15			
PARKER_ITC	220	1%		$17	1%		$28	1%	$20	$28
NOB_ITC	1,591	1%		$2	12%	3%	$42	2%	$11	$8
CASCADE_ITC	300				1.0%		$54	0.2%	$0.4	$30

Table 3.4 shows average shadow prices and average congestion LMPs on major inter-ties in the import direction. We show the average congestion component of the LMP at the inter-tie scheduling point to provide an indication of how this congestion has impacted the price paid to imports. For example, in hours where Palo Verde was congested only in the IFM, imports coming in over Palo Verde were paid on average $14 below the system marginal energy cost in that hour. This $14 also reflects the potential savings to load per MWh of additional lower cost imports that may have been imported if there was more transmission.

Table 3.4 Average Import Shadow Prices and LMP Congestion Components

	Congested in IFM		Congested in HASP	
Inter-Tie Name	Shadow Price	Congestion LMP	Shadow Price	Congestion LMP
PALOVRDE_ITC	$13	-$14	$31	-$29
ELDORADO_ITC	$8	-$9	$44	-$31
MEAD_ITC	$8	-$10	$13	-$16
PACI_ITC	$6	-$6	$67	-$41
ADLANTO-SP_ITC	$7	-$7	$68	-$24
MERCHANT_ITC	$5	-$9	$34	-$25
SUMMIT_ITC	$34	-$35	$40	-$42
BLYTHE_ITC	$39	-$40	$27	-$30
PARKER_ITC	$18	-$20	$27	-$81

24 Starting November 13, 2009, ISO created a new MEAD_ITC as a companion to the combination of MEAD_MSL and MEADTMEAD_MSL. This ITC includes schedules for the following scheduling points MEAD230 and MEAD2MSCHD.

25 The inter-ties which have been congested less than 1% of the time have been eliminated from this analysis.

3.3 Conforming Constraint Limits

In the *Q3 Report*, we describe the principles that drive the practice of conforming transmission limits in detail.[26] The two most common reasons for which ISO operators make adjustments to transmission limits are to:

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths, and
- Set prudent operating margins consistent with good utility practice to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility.

In conforming transmission limits, the operators seek in part to compensate for the time lag between first detecting imminent congestion and the response of resources to dispatch instructions that is inherent in the timing of the five-minute real-time dispatch. In setting reliability margins, the operators seek to ensure that the market software produces a solution that is reliable and consistent with good utility practice within the general state of the system including potentially unpredictable flow variability and changing congestion patterns.

As shown in Figure 3.1, a relatively small portion of all flowgates and nomograms were conformed in the RTD during a significant percentage of hours in Q4. Seven constraints were conformed over 80 percent of the hours, with another six being conformed between about 35 and 65 percent of the time. Figure 3.1 shows only conforming data for the RTD market. We have found that, consistent with Q3 analysis, there is generally no constraint conforming performed in the IFM market and the conforming that is performed in the HASP and RTD markets is very consistently applied across both markets.

Table 3.5 lists all flowgates and nomograms that were biased in the RTD in Q4, 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.[27] 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 level of conforming was maintained at a relatively constant level during the time period in which they were conformed.

As shown in Table 3.5, most constraints that were conformed in the real-time market tended to be "conformed up"; i.e., adjusted in the upward direction. In such cases, the market model experienced "phantom" congestion in real time (i.e., congestion in the market model when actual physical flows were below limits), so conforming was used to reflect the true available capacity on the line. Since there is no physical flow in the IFM or RUC, there is normally no need to conform downward in these markets.[28] If congestion appears in day-ahead runs, the ISO's Operations Engineers evaluate the validity of this congestion and recommend conforming or un-enforcement, as appropriate.

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[26] A July 13, 2009 technical bulletin on this topic can be found at **http://www.caiso.com/23ea/23eae8aef980.pdf.**

[27] For example, the La Fresa-Hinson 230kV line was conformed 63 percent of the time in the real-time market. However, the flowgate was binding during only about 9 percent of the time during conformed hours. Its average shadow price was $67/MWh.

[28] The exception was La Fresa, which required downward conforming to ensure the necessary market dispatch of ED-committed resources.

Table 3.5 also shows that a few constraints were actually "conformed down" in the real-time market. ISO operators normally adjust market limits downward to maintain adequate reliability margin, which ensures that line and path loads stay within their operating limits. These constraints are typically conformed in the day-ahead market to ensure that congestion and reliability issues are manageable in real-time. Examples of these include Path 26 and the SCE Import Limit.

In Q4, there was a significant trend towards a reduction in the frequency of hours during which constraints were conformed relative to Q2. One of the major reasons for the reduction in the conforming of constraints in Q4 was the implementation of modeling improvements at the end of Q3 (September 24, 2009) where nodes with significant self-generation (such as refineries) are now modeled based on net loads rather than gross loads. Table 3.6 provides a comparison of the conforming frequency between Q3 and Q4 for constraints that are most likely to be affected by this modeling improvement. As shown in Table 3.6, the frequency that the limit on most of these constraints was conformed dropped significantly.

Figure 3.1 Percent of Hours Conformed in RTD Market – 2009 Q4

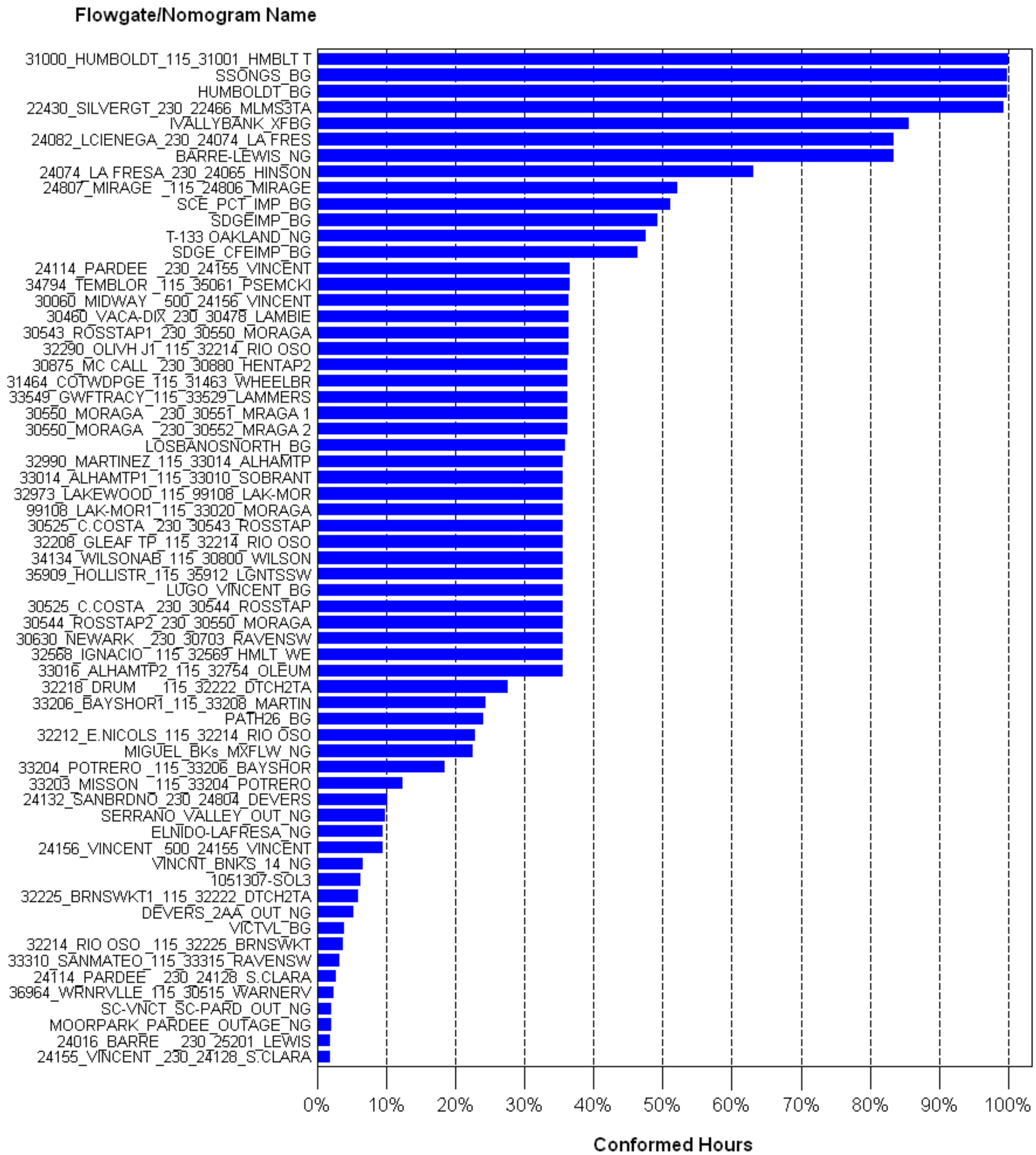

Table 3.5 Real-Time Congestion Frequencies and Conforming Limits for Flowgates in Q4[29]

Flowgate Name	Conforming Frequency (Pct. Of Hours)	Avg. Conformed Percent of Limit	Frequency of Binding During Conformed Hours	Avg. Shadow Price - Conformed Binding Hours
31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1	100%	110%	0.19%	$500
SSONGS_BG	100%	86%		
HUMBOLDT_BG	100%	133%	1.70%	$156
22430_SILVERGT_230_22466_MLMS3TAP_230_BR_1 _1	99%	120%		
IVALLYBANK_XFBG	86%	82%	9.50%	$36
24082_LCIENEGA_230_24074_LA FRESA_230_BR_1 _1	83%	110%	0.00%	$500
BARRE-LEWIS_NG	83%	105%	0.01%	$4,690
24074_LA FRESA_230_24065_HINSON _230_BR_1 _1	63%	90%	8.80%	$67
24807_MIRAGE _115_24806_MIRAGE _230_XF_4A	52%	120%		
SCE_PCT_IMP_BG	51%	111%	0.20%	$55
SDGEIMP_BG	49%	94%	0.17%	$29
T-133 OAKLAND_NG	48%	103%	0.01%	$500
SDGE_CFEIMP_BG	46%	94%	0.31%	$146
24114_PARDEE _230_24155_VINCENT _230_BR_1 _1	37%	150%		
34794_TEMBLOR _115_35061_PSEMCKIT_115_BR_1 _1	37%	120%		
30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2	36%	120%		
30460_VACA-DIX_230_30478_LAMBIE _230_BR_1 _1	36%	126%		
32290_OLIVH J1_115_32214_RIO OSO _115_BR_1 _1	36%	125%		
30543_ROSSTAP1_230_30550_MORAGA _230_BR_1 _1	36%	130%		
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	36%	115%		
31464_COTWDPGE_115_31463_WHEELBR _115_BR_1 _1	36%	110%		
33549_GWFTRACY_115_33529_LAMMERS _115_BR_1 _1	36%	112%		
30550_MORAGA _230_30552_MRAGA 2M_ 1.0_XF_2	36%	103%		
30550_MORAGA _230_30551_MRAGA 1M_ 1.0_XF_1	36%	103%		
LOSBANOSNORTH_BG	36%	83%	2.90%	$107
33014_ALHAMTP1_115_33010_SOBRANTE_115_BR_1 _1	36%	111%	0.10%	$500
32990_MARTINEZ_115_33014_ALHAMTP1_115_BR_1 _1	36%	111%	0.11%	$500
32973_LAKEWOOD_115_99108_LAK-MOR1_115_BR_1 _1	36%	111%	0.01%	$500
99108_LAK-MOR1_115_33020_MORAGA _115_BR_1 _4	36%	111%	0.01%	$500
30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	36%	125%		
LUGO_VINCENT_BG	36%	105%		
32208_GLEAF TP_115_32214_RIO OSO _115_BR_1 _1	36%	110%		
35909_HOLLISTR_115_35912_LGNTSSW2_115_BR_2 _1	36%	105%		
34134_WILSONAB_115_30800_WILSON _230_XF_1	36%	105%		
32568_IGNACIO _115_32569_HMLT_WET_115_BR_1 _1	35%	110%		
30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1	35%	112%		
30544_ROSSTAP2_230_30550_MORAGA _230_BR_2 _1	35%	113%		
33016_ALHAMTP2_115_32754_OLEUM _115_BR_1 _1	35%	111%		
30525_C.COSTA _230_30544_ROSSTAP2_230_BR_2 _1	35%	113%		
32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	28%	111%	0.69%	$56
33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 _1	24%	112%	0.03%	$500
PATH26_BG	24%	70%	3.10%	$36
32212_E.NICOLS_115_32214_RIO OSO _115_BR_1 _1	23%	150%	0.01%	$500
MIGUEL_BKs_MXFLW_NG	22%	94%	0.02%	$2,894
33204_POTRERO _115_33206_BAYSHOR1_115_BR_1 _1	18%	105%	0.04%	$147
33203_MISSON _115_33204_POTRERO _115_BR_1 _1	12%	112%	0.21%	$467
24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	10%	90%		
SERRANO_VALLEY_OUT_NG	10%	74%		
ELNIDO-LAFRESA_NG	9%	115%		
VINCNT_BNKS_14_NG	7%	104%	0.43%	$352
1051307-SOL3	6%	103%	1.30%	$470
32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	6%	116%	0.03%	$35
DEVERS_2AA_OUT_NG	5%	80%	0.47%	$411
24156_VINCENT _500_24155_VINCENT _230_XF_1 _P	5%	134%	0.20%	$240
24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	5%	137%		
VICTVL_BG	4%	107%	1.10%	$295
32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	4%	120%	0.00%	$40
33310_SANMATEO_115_33315_RAVENSWD_115_BR_1 _1	3%	109%	0.00%	$500
24114_PARDEE _230_24128_S.CLARA _230_BR_1 _1	3%	117%	0.06%	$273
36964_WRNRVLLE_115_30515_WARNERVL_230_XF_1	2%	112%	0.00%	$500
SC-VNCT_SC-PARD_OUT_NG	2%	87%		
MOORPARK_PARDEE_OUTAGE_NG	2%	92%	0.18%	$198
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	2%	130%		
24155_VINCENT _230_24128_S.CLARA _230_BR_1 _1	2%	110%		

[29] The time basis for the frequency statistics is based on all hours in the three month range and does not account for periods where the constraint was not enforced (and therefore would not be conformed). Consequently, the frequency statistics presented may understate the frequency for constraints that were not enforced throughout the period.

Table 3.6 Change in Frequency of Conforming Constraints in Q3 and Q4 2009

Line Name	Percent of Hours Conformed 2009 Q3	Percent of Hours Conformed 2009 Q4	Average Conformed Percent 2009 Q3	Average Conformed Percent 2009 Q4
30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2	71%	36%	111	120
30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	98%	36%	115	125
30525_C.COSTA _230_30544_ROSSTAP2_230_BR_2 _1	98%	35%	113	113
30543_ROSSTAP1_230_30550_MORAGA _230_BR_1 _1	36%	36%	119	130
30544_ROSSTAP2_230_30550_MORAGA _230_BR_2 _1	98%	35%	113	113
30550_MORAGA _230_30551_MRAGA 1M_ 1.0_XF_1	98%	36%	114	103
30550_MORAGA _230_30552_MRAGA 2M_ 1.0_XF_2	98%	36%	114	103
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	70%	36%	111	115
32568_IGNACIO _115_32569_HMLT_WET_115_BR_1 _1	84%	35%	110	110
32973_LAKEWOOD_115_99108_LAK-MOR1_115_BR_1 _1	25%	35%	111	111
32990_MARTINEZ_115_33014_ALHAMTP1_115_BR_1 _1	71%	35%	123	111
32990_MARTINEZ_115_33016_ALHAMTP2_115_BR_1 _1	22%	0%	128	
33014_ALHAMTP1_115_33010_SOBRANTE_115_BR_1 _1	69%	35%	116	111
33016_ALHAMTP2_115_32754_OLEUM _115_BR_1 _1	25%	35%	111	111
34794_TEMBLOR _115_35061_PSEMCKIT_115_BR_1 _1	98%	37%	120	120
99108_LAK-MOR1_115_33020_MORAGA _115_BR_1 _4	25%	35%	111	111

3.4 Compensating Injections

Compensating injections are positive or negative net power injections that can be automatically inserted into the Network Application (NA) portion of each real-time pre-dispatch (RTPD) run by a special algorithm incorporated in the real-time market software. Rather than being physical power injections, compensating injections are purely mathematical injections at numerous special CNodes outside of the ISO near major tie points. The purpose of compensating injections is to reduce the difference between the modeled market flows and actual physical flows over constraints near the inter-ties (e.g., due to loop flows), thereby reducing differences between modeled and actual flows throughout the network model. Thus, compensating injections are designed to be an automated, more accurate method of accounting for loop flows and other modeling discrepancies that would reduce the need for manual conforming or other actions operators may need to take to manage differences in modeled versus actual flows in real time.[30]

In Q4, the automated compensating injections feature was turned on intermittently for testing from October 3 to October 6, 2009, and then was turned on continuously from October 8 through November 4. 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 an increasing number of CPS2 violations. As a result, these automated compensating injections were turned off until further refinements could be made in this software feature.

The ISO is currently testing enhancements to the compensating injection software and anticipates testing and then re-activating this feature in the actual market software in Q1 2010. The ISO has indicated that prior to re-implementing this feature, the ISO will provide participants with advance notice. In addition, DMM is working with the ISO to develop metrics that can be used to monitor the impact of compensating injections on specific major constraints within the

[30] When automated compensating injections are not being utilized, the ISO mitigates the congestion impact of loop flows manually by “circulating” energy between the NOB DC and PACI ties, and/or by manually conforming (biasing) the limits on major internal constraints within the ISO near the inter-ties.

ISO that are likely to be impacted by this feature.[31] DMM is also recommending that automated compensating injections not be implemented until these metrics are completed and advance notice is provided to participants.

3.5 SCE Import Branch Group Limit

Starting November 11, the ISO began enforcing the SCE Import Percent Branch Group Limit (SCE Import Limit), a constraint on the total volume of imports as a percentage of load into SCE territory. Specifically, this limit ensures that SCE imports do not exceed 60 percent of its load, in order to avoid catastrophic outages in the event that the SCE system were to separate from the grid.[32]

Until late October 2009, system conditions were such that the SCE Import Limit had not been binding since the introduction of the new market, and in fact for the preceding several years. Prior to that time, no actions were necessary in the day-ahead or real-time markets to ensure that the limit was honored. However, starting on October 22, 2009, conditions were such that it was necessary to issue exceptional dispatches to ensure that real-time imports remain within the limit. As this became a recurring issue over the following days and weeks, the ISO began work to model the SCE Import Limit in the market optimization software. This was completed within approximately three weeks.

On November 11, the ISO began enforcing the import limit in the market software, so that the ISO congestion related to this limit was managed by the market optimization. Most hours in which the SCE Import Limit was binding occurred shortly after it was implemented in the software. However, after this period, congestion on this branch group diminished as the market scheduling and bidding adjusted to account for its impact.

As part of a recent stakeholder process on release of transmission information, the ISO is proposing to establish several new advance notifications that will inform stakeholders of any significant changes to the transmission constraints included in the ISO's market systems.[33] Under these new policies, the ISO will seek to provide participants with advance notice when new constraints such as this are added except when this may not be possible for reliability reasons.

3.5.1 Market Impact of SCE Import Limit

The binding limit of the SCE Import Limit averaged approximately 6,600 MW in Q4. In Figure 3.2, which provides a summary of congestion patterns on the SCE Import Limit:

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[31] Modeled flows for constraints in the ISO provided by the market software do not differentiate between the portion of flow attributable to compensating injections and the portion of flow attributable to market schedules. Thus, the impact of compensating injections on constraints within the ISO must be calculated using data on the compensating injection values at each CNode outside of the ISO system, combined with shift factors for these CNodes relative to constraints within the ISO.

[32] A technical bulletin was posted on December 1, 2009, and can be found on the ISO website at http://www.caiso.com/2479/247997c52e0f0.pdf.

[33] See Draft Final Proposal, Data Release & Accessibility, Phase 1: Transmission Constraints, January 6, 2010, p.9. http://www.caiso.com/2718/2718ef3844a00.pdf

- The blue bar shows the total hours in which the SCE Import Limit was binding only in the IFM market (11.8 percent of total congested hours).
- The pink bar shows the total hours which the branch group was binding only in the RTD market (0.9 percent of total congested hours).
- The green bar shows the total hours which the branch group was binding in both the IFM and RTD markets (0.7 percent of total congested hours).

As Figure 3.2 indicates, the SCE Import Limit was most frequently binding only in the IFM market, and was most frequently binding in the week immediately following its implementation in the software, after which market scheduling and bidding adjusted to moderate its impact. The average IFM shadow price in the first week in which the SCE Import Limit was modeled in the market optimization software was almost $12/MWh, compared to an average shadow price of $8/MWh across later periods.

Figure 3.2 Frequency of Congestion and Average Shadow Values for SCE Import Limit for IFM and RTD in Q4

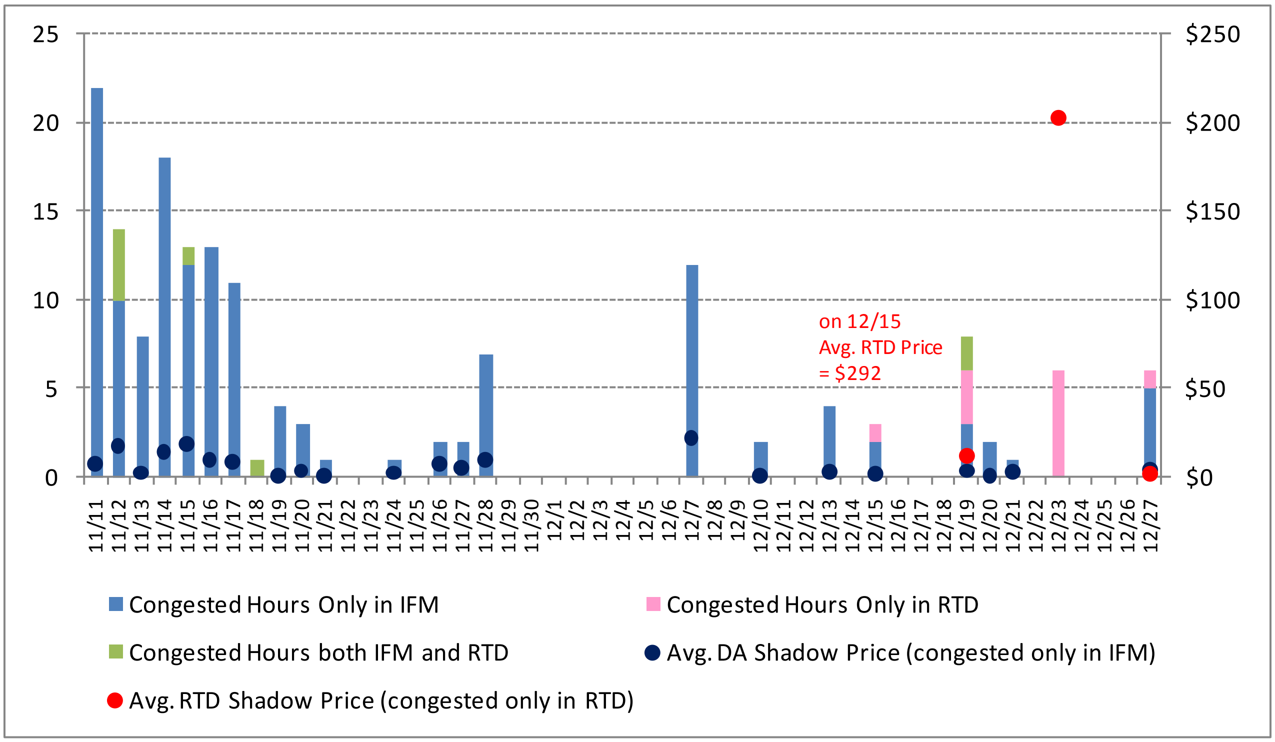


Figure 3.3 Frequency of Congestion, Average Shadow Values, and Average LAP LMP Congestion Component for SCE Import Limit (IFM)

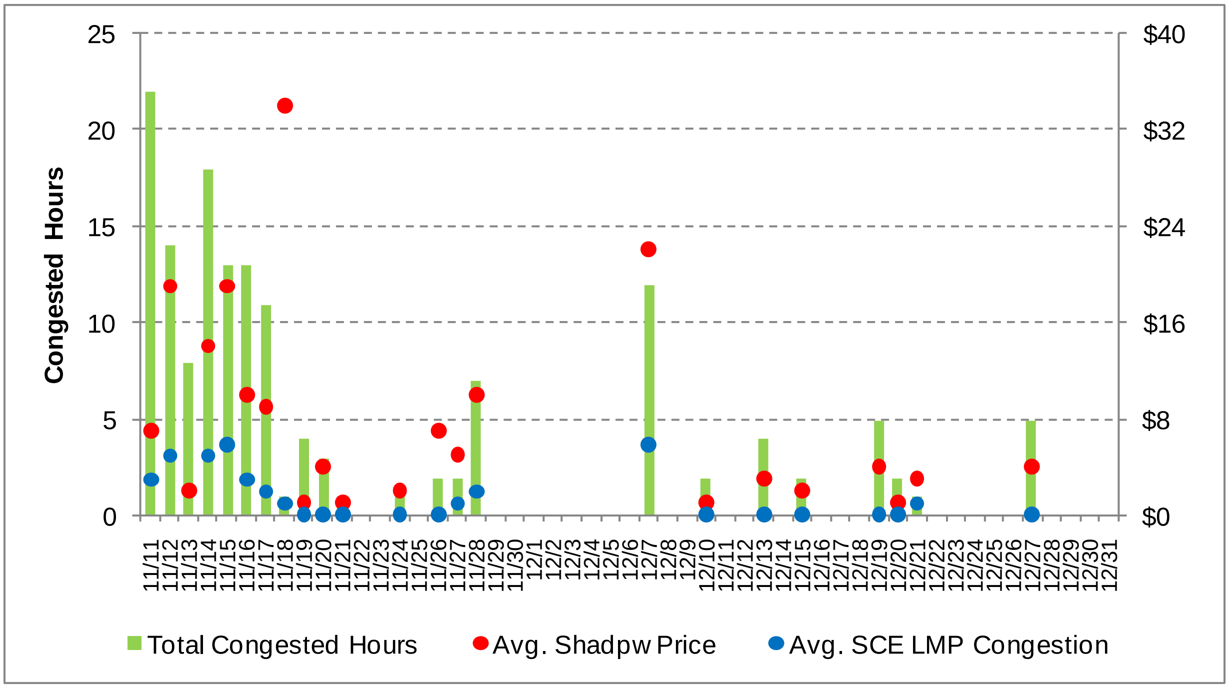


Figure 3.4 Frequency of Congestion, Average Shadow Values, and Average LAP LMP Congestion Component for SCE Import Limit (RTD)

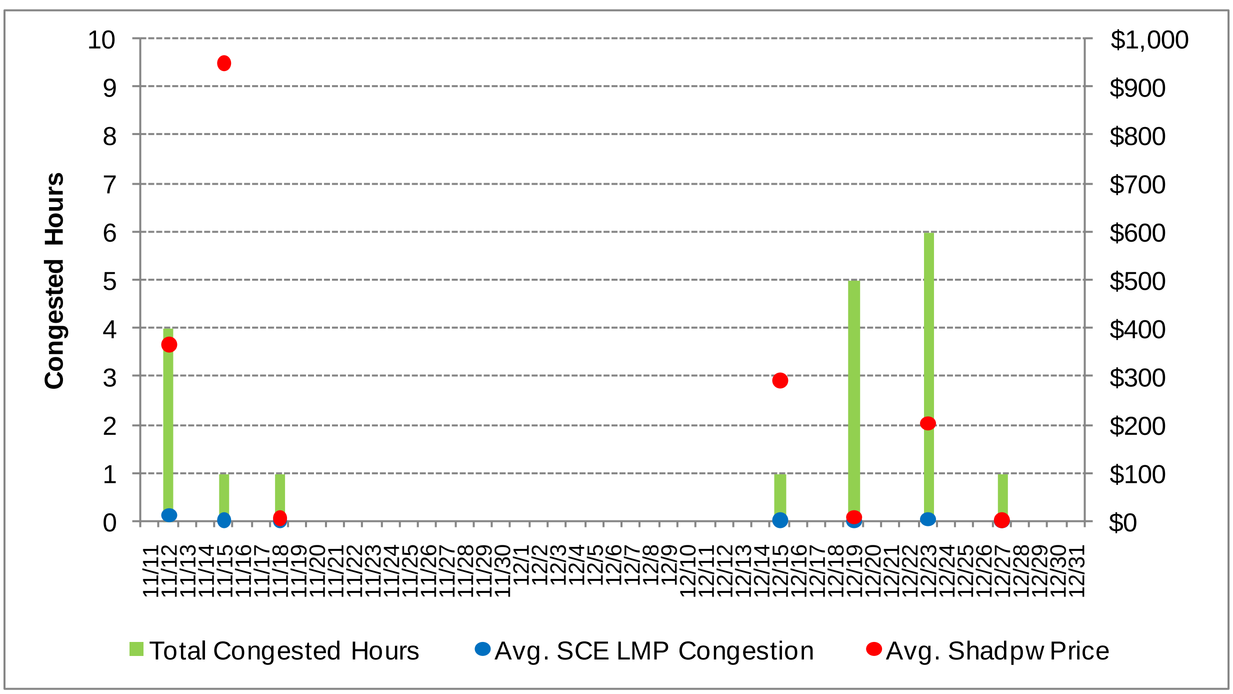
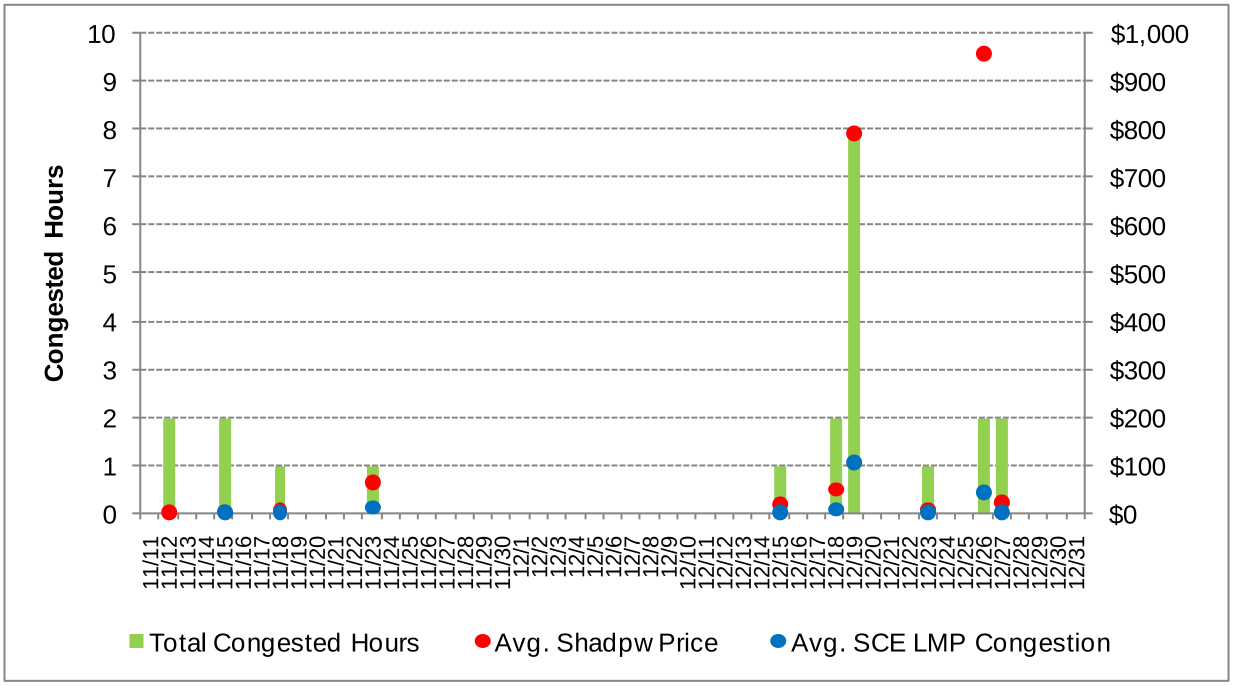


Figure 3.5 Frequency of Congestion, Average Shadow Values, and Average LAP LMP Congestion Component for SCE Import Limit (HASP)



As illustrated in Figure 3.3 through Figure 3.5, the frequency that the SCE Import Limit was binding is significantly less in the real-time markets than in the IFM. This can be attributed to at least two factors:

- First, the volume of net imports into the SCE area routinely decreased in the HASP due to a combination of increased exports and decreased imports. Figure 3.6 shows the change in net imports into SP26 in the HASP market. For example, on the trade date November 12 hourly final net imports were about 900 MW less than what was scheduled in the IFM market.

- In addition, as shown in Figure 3.7, the SCE Import limit was "conformed up" in real time to an average of 111 percent in roughly 90 percent of the hours between implementation on November 11th and the end of the quarter. In the IFM, the software uses the day-ahead load forecast of the SCE area to calculate the limit of this constraint. The hourly values for this limit that are calculated in the IFM are then passed to the real-time market software (no additional calculation of the limits is done for real time). Because of this, the limit is conformed in real time to account for changes in actual loads (versus the day-ahead forecast used to set the limit incorporated in the IFM and real-time software), as well as differences between scheduled and actual flows observed. As shown in Figure 3.7, based on real-time conditions the limit has generally been conformed upward in the real-time markets.

Figure 3.6 Net Change in Scheduled Imports to SP26 in HASP

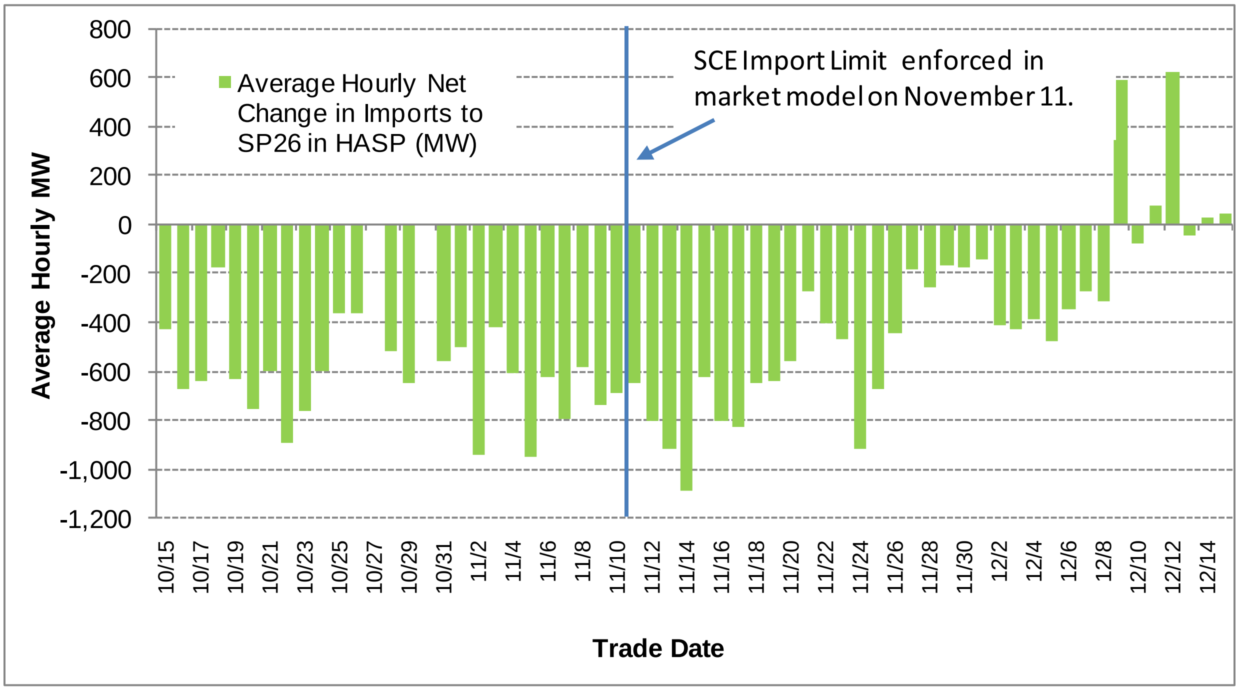
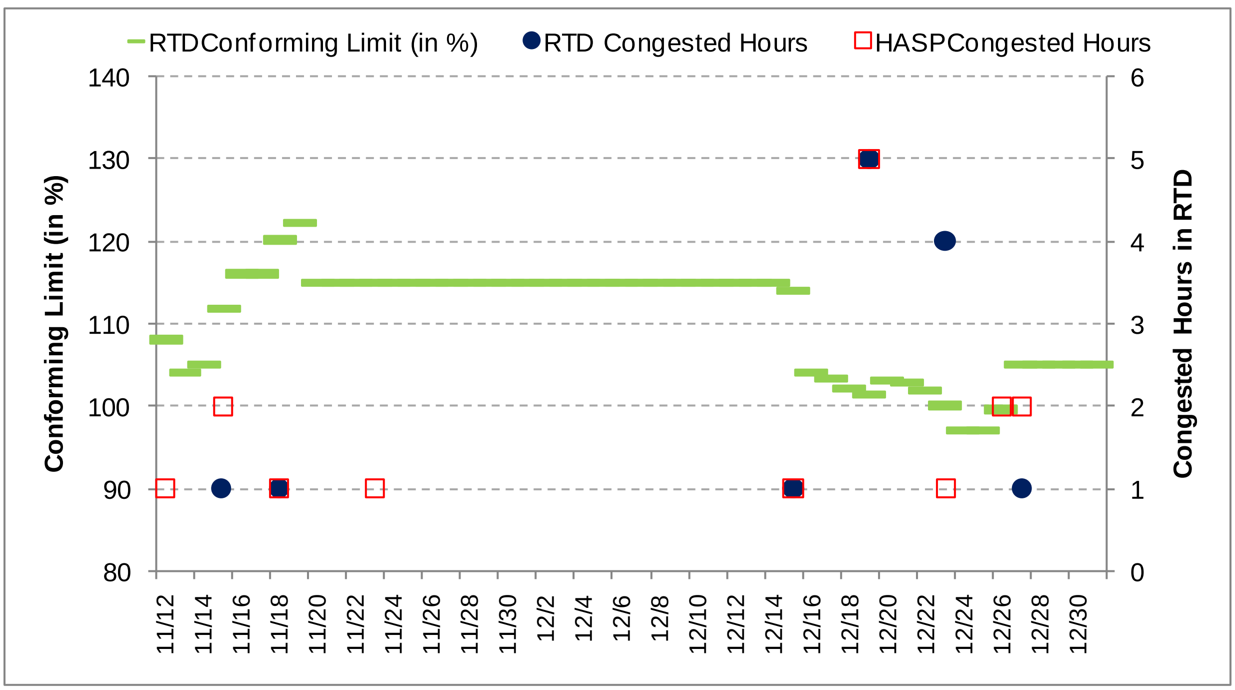


Figure 3.7 Frequency of Congestion and Average Conforming Percent for SCE Import Limit for IFM, RTD and HASP

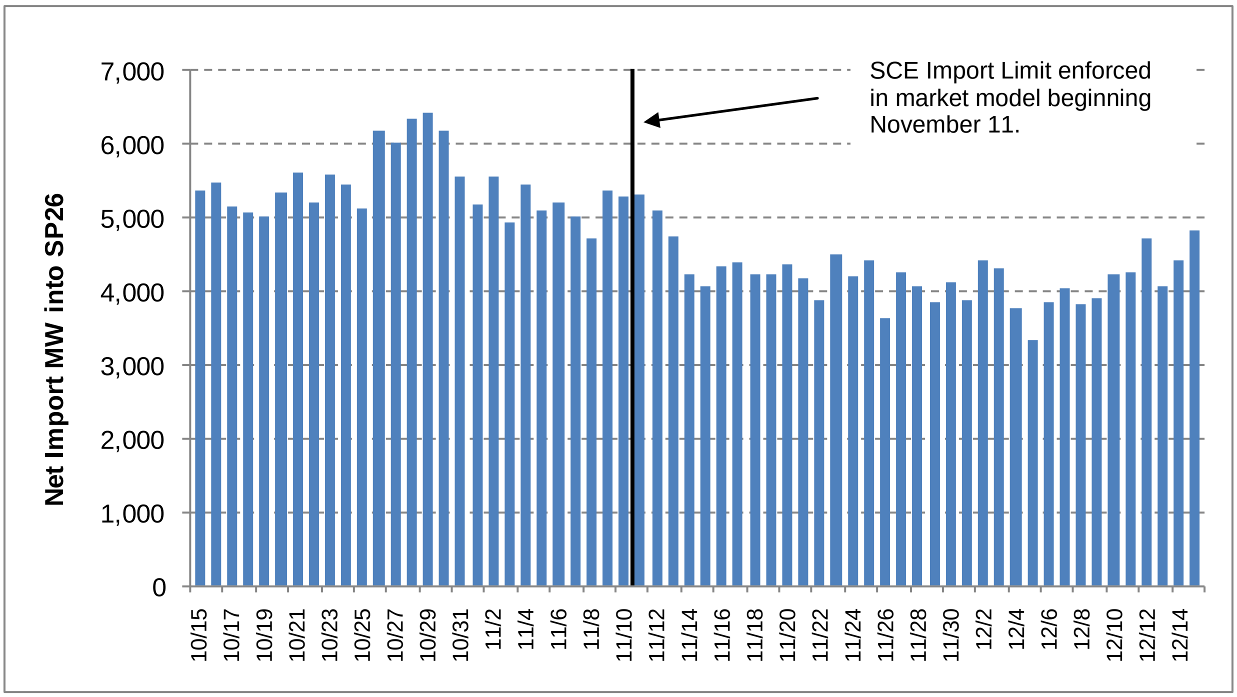


As previously illustrated in Figure 3.2, most of the hours for which the SCE Import Limit was binding occurred in the days immediately following its implementation in the software. After this period, market scheduling and bidding adjusted to moderate its impact. As shown in Figure 3.8:

- Prior to November 11, when the ISO began enforcing the import limit in the market software, the average daily imports into SP26 area were about 5,000 MW.
- After implementation of the constraint and the emergence of higher LAP LMPs as a result of congestion, imports into the SP26 area declined on average about 20 percent to around 4,000 MW.

While some of this may be accounted for by changes in load or other factors, the decline is coincident with realization of market impacts from high import levels and we believe reflects a market response to the price impacts that resulted from implementing the SCE Import Limit.

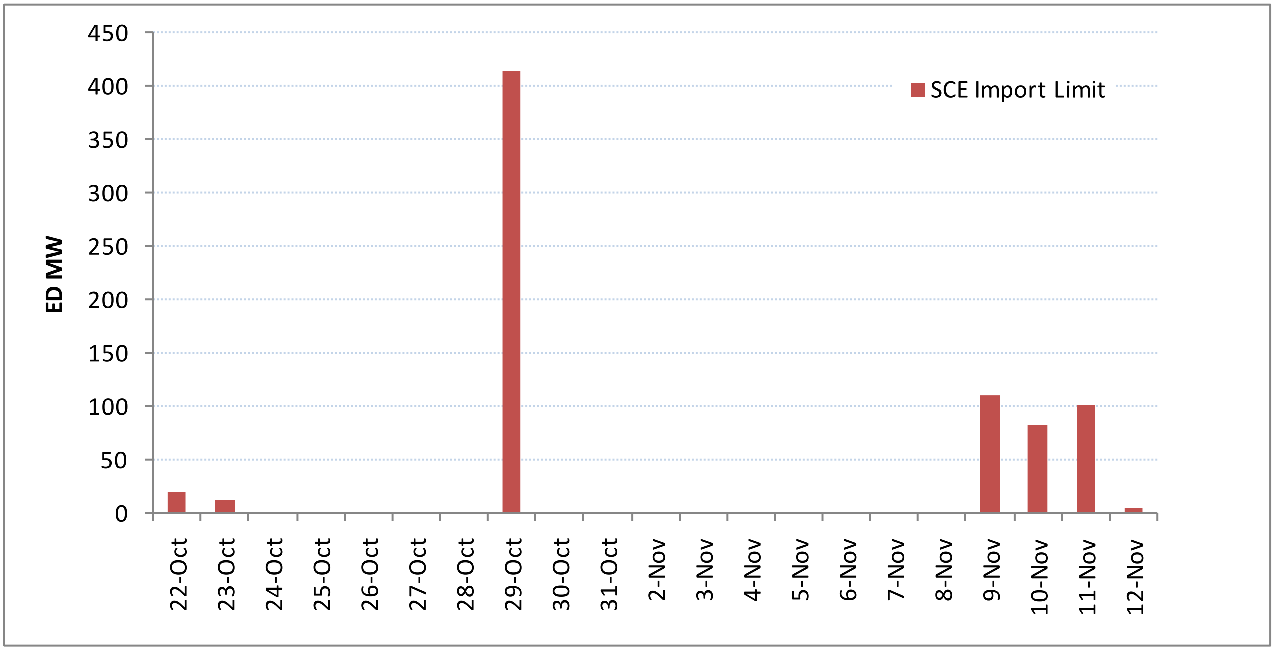
Figure 3.8 Net Import MW in SP26



3.5.2 Exceptional Dispatch for SCE Import Limit

DMM also reviewed exceptional dispatch (ED) records to examine the extent to which ED may have been used to manage the SCE Import Limit before and after the time this constraint was added to the market model. Figure 3.9 shows daily average instructed ED energy volume by reason, for all resources that received EDs for the purpose of managing the SCE Import Limit. Only three ED instructions were issued after the implementation of the SCE Import Limit in the market on November 11, 2009. Two of these ED instructions were real-time energy instructions on November 11, each for a single hour. One ED instruction for unit commitment to manage the SCE Import Limit occurred for trade day November 12. There were no other ED instructions specifically to mitigate for the SCE Import Limit after November 12.

Figure 3.9 Exceptional Dispatch Volume for SCE Import Limit



The application of the SCE Import Limit into the market model reflects the ISO's efforts to incorporate constraints into the market optimization. This permits the market to select the most efficient resolution of the constraint, andalso provides price signals that may help participants self-schedule a more efficient mix of imports and internal generation.

3.6 La Fresa – Hinson 230 kV line Congestion

Between November 23, 2009, and January 5, 2010, scheduled maintenance was performed on four 220 kV lines that limited transmission on the La Fresa-Hinson and Laguna Bell-La Fresa 230kV lines, in SCE territory near Los Angeles. The four 220kV lines subject to outage were La Fresa-Redondo No.1 and 2, Mesa-Redondo, and Lighthipe-Redondo.

Originally, the ISO intended to enforce a contingency in the market model to handle the planned outages of these lines. However, with the contingency enforced in the real-time market, operators were observing a significant deviation between the actual flows and the market flows that were expected based on off-line contingency studies. To correct for this, the ISO removed the contingencies from the market runs and enforced the expected contingency limits directly on the La Fresa – Hinson 230 kV line in both the IFM and real-time markets by conforming these transmission limits.

Since there are a very limited amount of resources that are effective at mitigating congestion and responding to any contingency impacting these lines, the ISO managed the La Fresa-

Hinson line by a combination of two actions. First, some units that are effective at mitigating this line were committed in the IFM through exceptional dispatch (i.e., up to 1 or 2 units were committed via exceptional dispatch). In addition, the ISO conformed transmission limits in the market to approximately 480 MW, and allowed units effective at mitigating this constraint that had been committed via the market or exceptional dispatch to be dispatched through the market for any additional energy to mitigate this constraint. In the real-time market, ISO operators conformed the transmission limits as needed so that market flows more closely matched actual flows.

3.6.1 La Fresa-Hinson Market Congestion Activity

As shown in Figure 3.10, which provides a summary of congestion patterns on the La Fresa-Hinson line:

- The blue bar shows the total hours in which the line was binding only in the IFM market (7.3 percent of total congested hours).
- The pink bar shows the total hours which the line was binding only in the RTD market (19.2 percent of total congested hours).
- The green bar shows the total hours which the line was binding in both the IFM and RTD markets (8.9 percent of total congested hours).

During this period, the average shadow price of this line when it was congested only in the IFM market was about $17/MW, compared $125/MW when it was congested only in the RTD market. When the constraint was binding in both the IFM and RTD, the average shadow price in the IFM was $23/MW compared to the $81/MW in the RTD market.

Figure 3.10 Frequency of Congestion and Average Shadow Values for La Fresa-Hinson line for IFM and RTD

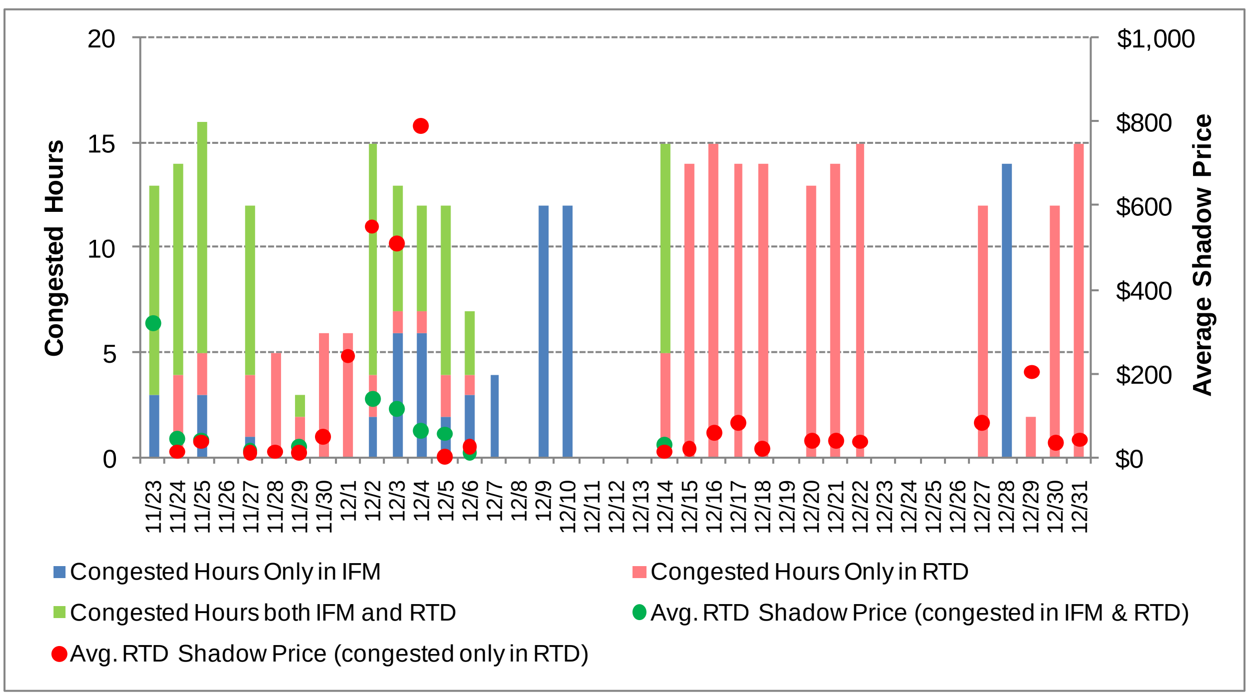
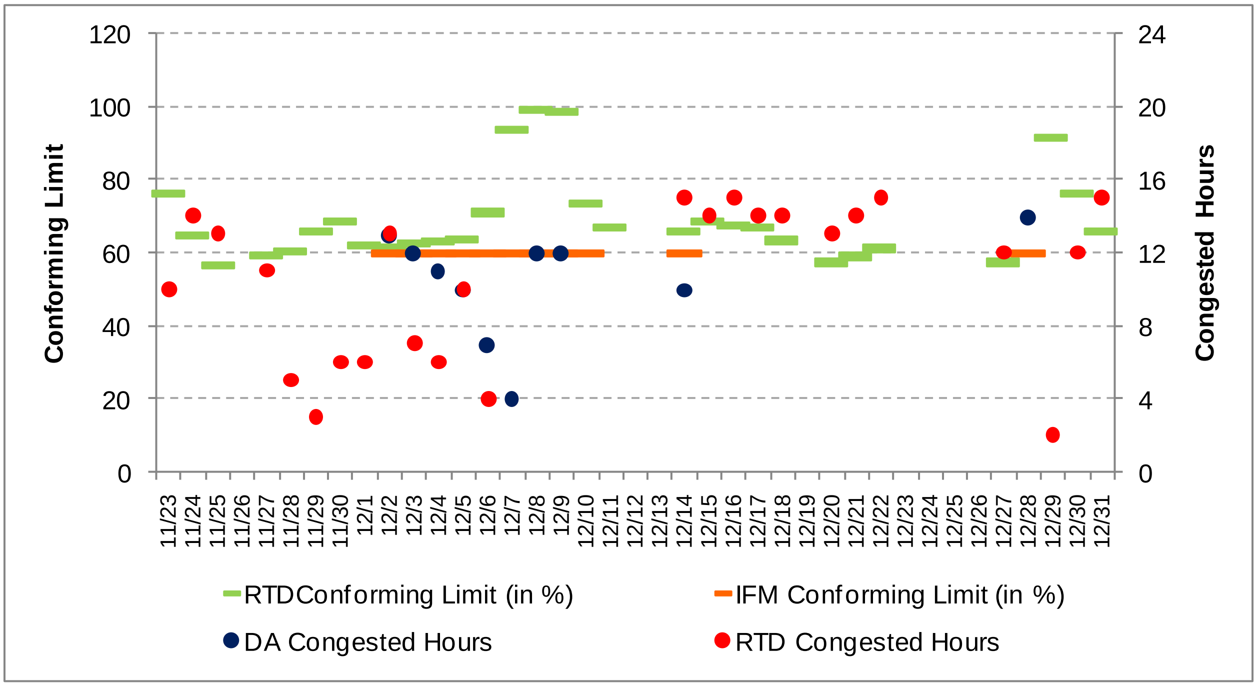


Figure 3.11 shows the frequency of congested hours and the average conforming level applied to the constraint. The flowgate was congested in 9 out of 10 days on which conforming was applied in the IFM market. In the RTD market, whenever the level of conforming exceeded 70 percent of the flowgate's normal operating limit, no congestion occurred.

Figure 3.11 Frequency of Congestion and Average Conforming Percent for La Fresa – Hinson 230kV line for IFM and RTD



3.6.2 Exceptional Dispatch for La Fresa Area Congestion

An extremely limited number of resources are available to mitigate the La Fresa area congestion. As a result, operators generally committed resources that were known to be needed to manage congestion or protect against contingencies prior to the IFM. From November 23 to December 31, a total of 34 exceptional dispatches[34] were issued to manage outages in the La Fresa area. Of these, 32 were issued to commit units prior to the IFM, as summarized in Table 3.7.

Figure 3.12 shows the average hourly minimum load energy instructed via exceptional dispatch for the La Fresa-area maintenance along with the average difference between PNode LMPs in the La Fresa area and the SCE LAP LMP by day. The amount of energy that resulted from exceptional dispatch was relatively low throughout the maintenance period, and (as noted in Table 3.7) the amount of energy resulting from real time exceptional dispatch was insignificant.

[34] Exceptional dispatches are counted by unit-market-day. That is, a single resource dispatched on a single day in a single market (Pre-IFM, Post-IFM, or Real Time) would be counted as one unit-market-day.

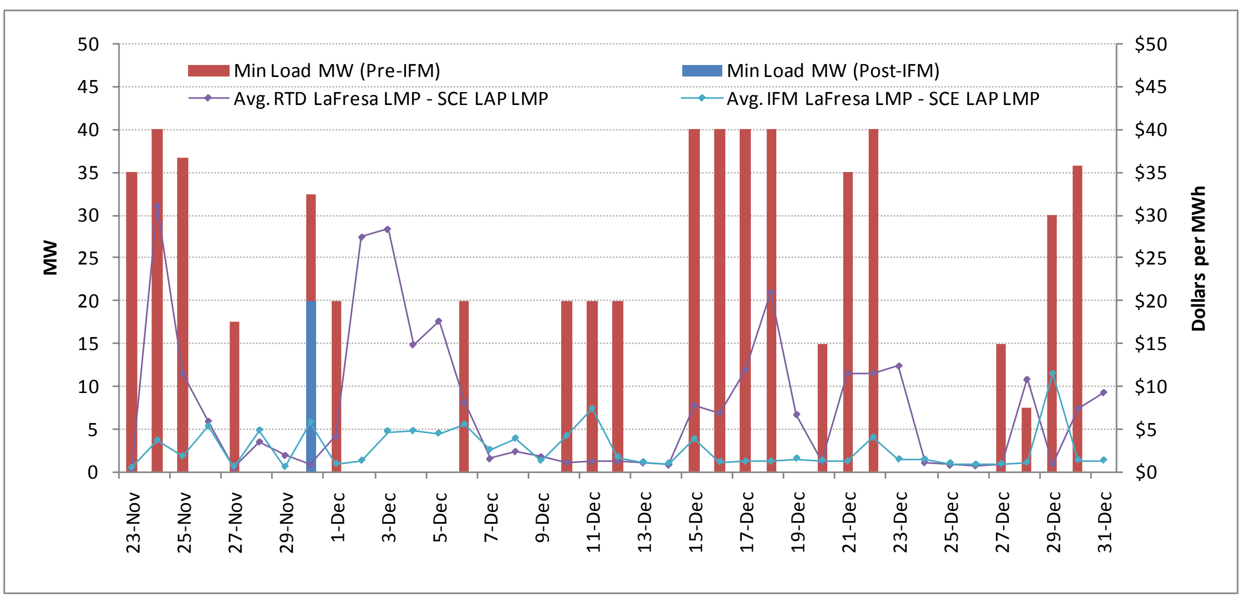
These commitments did result in additional capacity above minimum load that could be dispatched through the market to further manage congestion at La Fresa. Figure 3.12 also shows the average difference in local LMPs within the La Fresa area and the SCE LAP LMP for both IFM and RTD. These price differences indicate the impact of this congestion on prices in the La Fresa area and additional revenue to generation in that area that are dispatched to help manage congestion. Average price differences are at or below $5/MWh in the IFM, however in real time the La Fresa LMPs are as much as $28/MWh higher than the SCE LAP LMP.

No designations needed to be made under the Interim Capacity Procurement Mechanism (ICPM) in the ISO tariff for the SCE Import Limit or La Fresa-area reasons in Q4. Ten days prior to the effective date of new monthly Resource Adequacy (RA) designations that started on January 1, 2010, DMM worked with ISO operations to review the potential need for any ICPM designations to manage transmission outages in the La Fresa-area, given changes in RA designations taking effect in 2010. On January 5, 2010, an ICPM designation for 20 MW of a partial RA resource was made for planned transmission maintenance during January 2010.

Table 3.7 Exceptional Dispatch Instructions for La Fresa Area Congestion by Type and Line Outage

Commitment Period	La Fresa-Redondo No. 1	Lighthipe-Redondo	Mesa-Redondo	All Line Outages
Post-IFM			1	1
Pre-IFM	10	5	17	32
RT		1		1
All Commitment Periods	10	6	18	34

Figure 3.12 ED Instructions for La Fresa Area vs. RT Price Premium



Appendix A Real Time Market - Supplemental Charts for Section 1

Figure A.1 Monthly Average PG&E LAP Prices (Peak Hours)

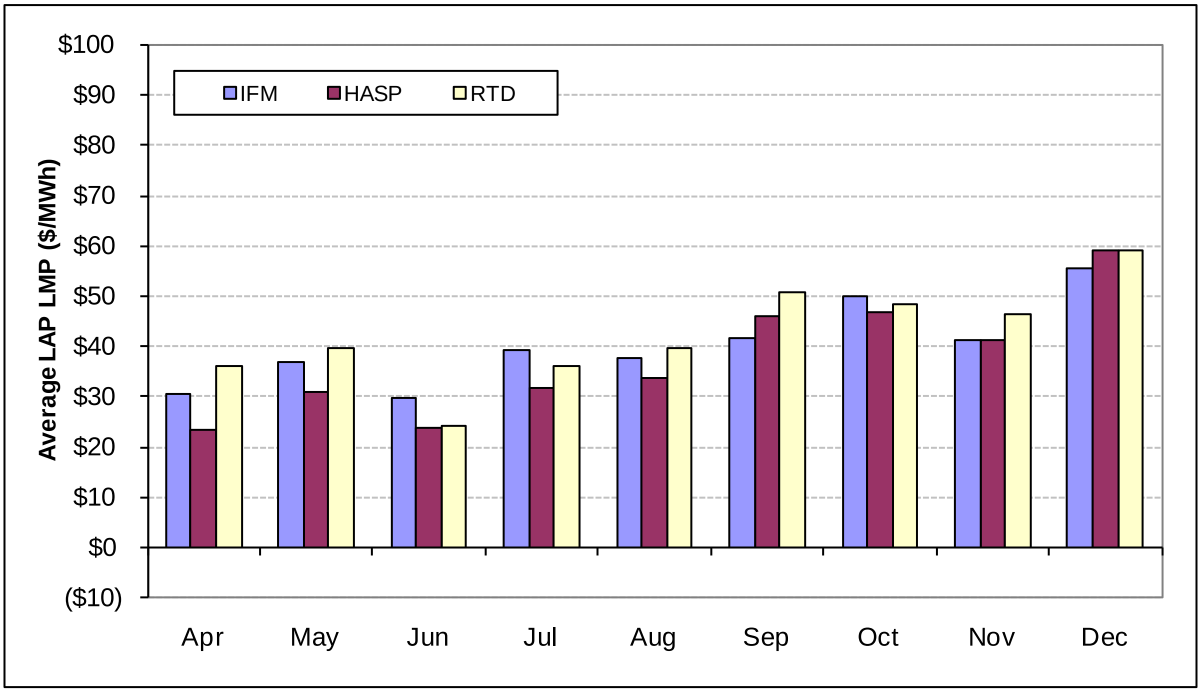


Figure A.2 Monthly Average PG&E LAP Prices (Off-Peak Hours)

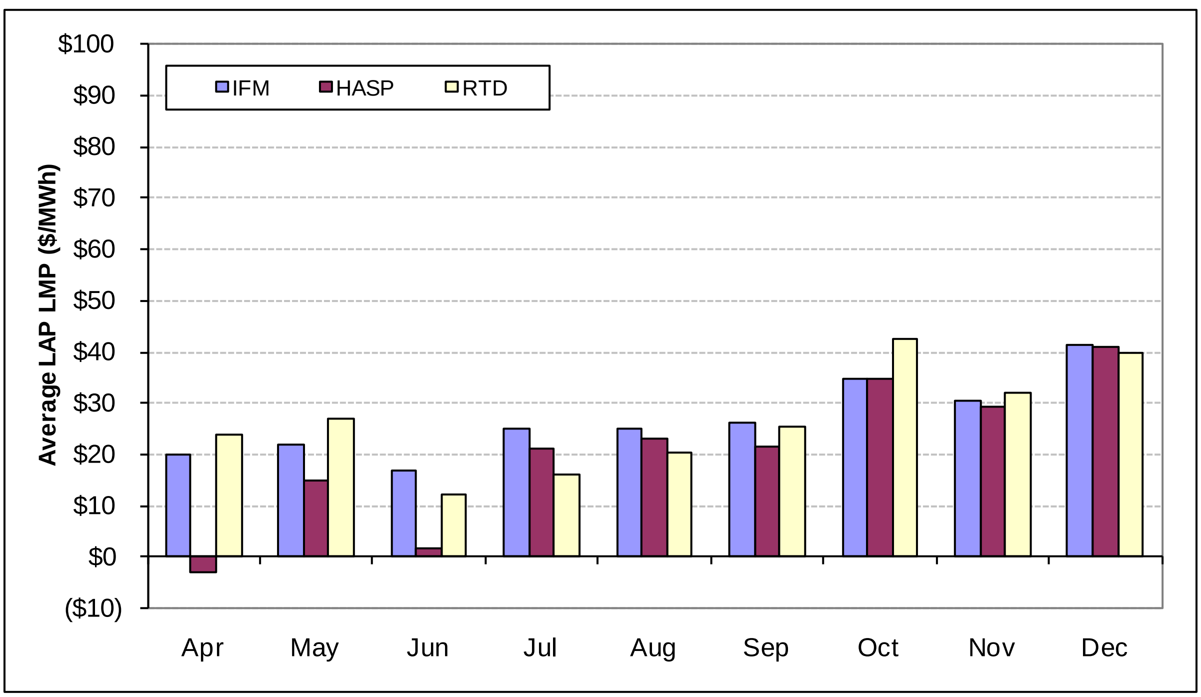


Figure A.3 Monthly Average SDG&E LAP Prices (Peak Hours)

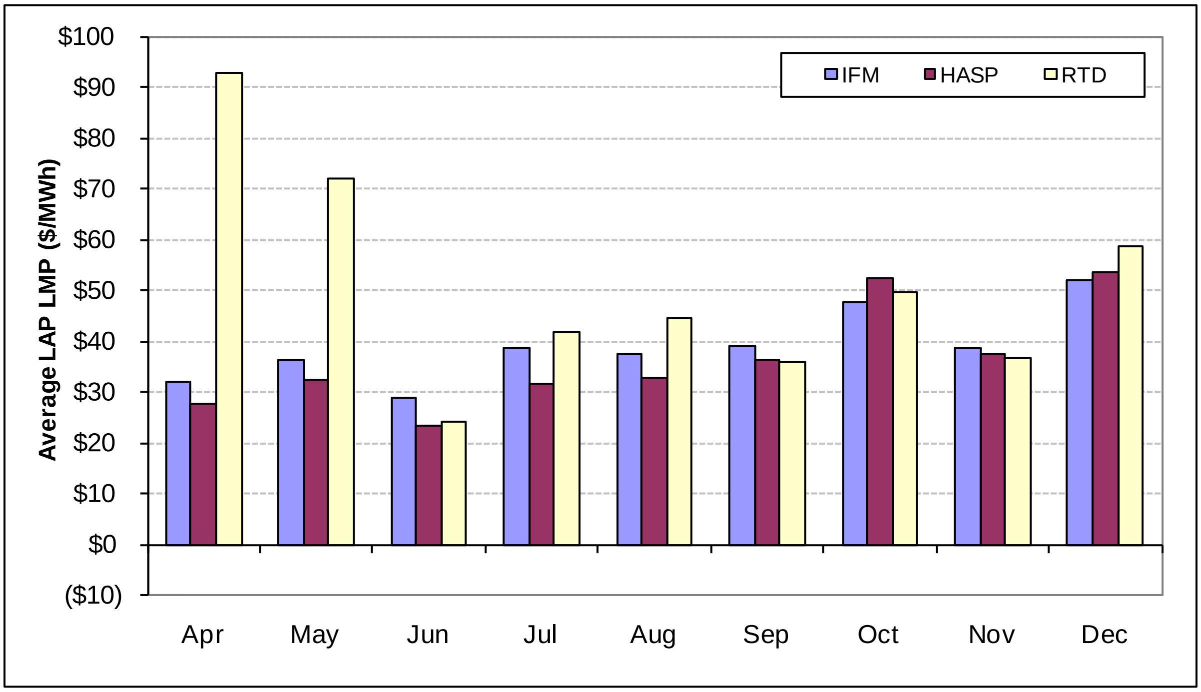


Figure A.4 Monthly Average SDG&E LAP Prices (Off-Peak Hours)

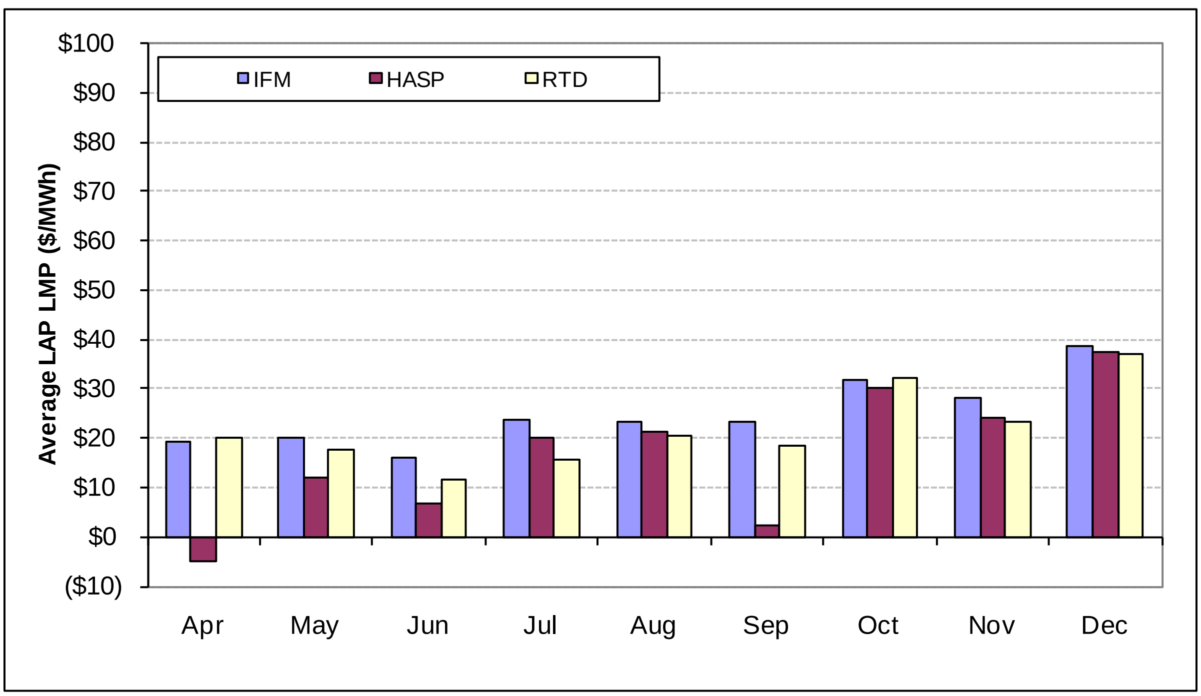


Figure A.5 Distribution of PG&E LAP Price Differences Between IFM and RTD (Peak Hours)

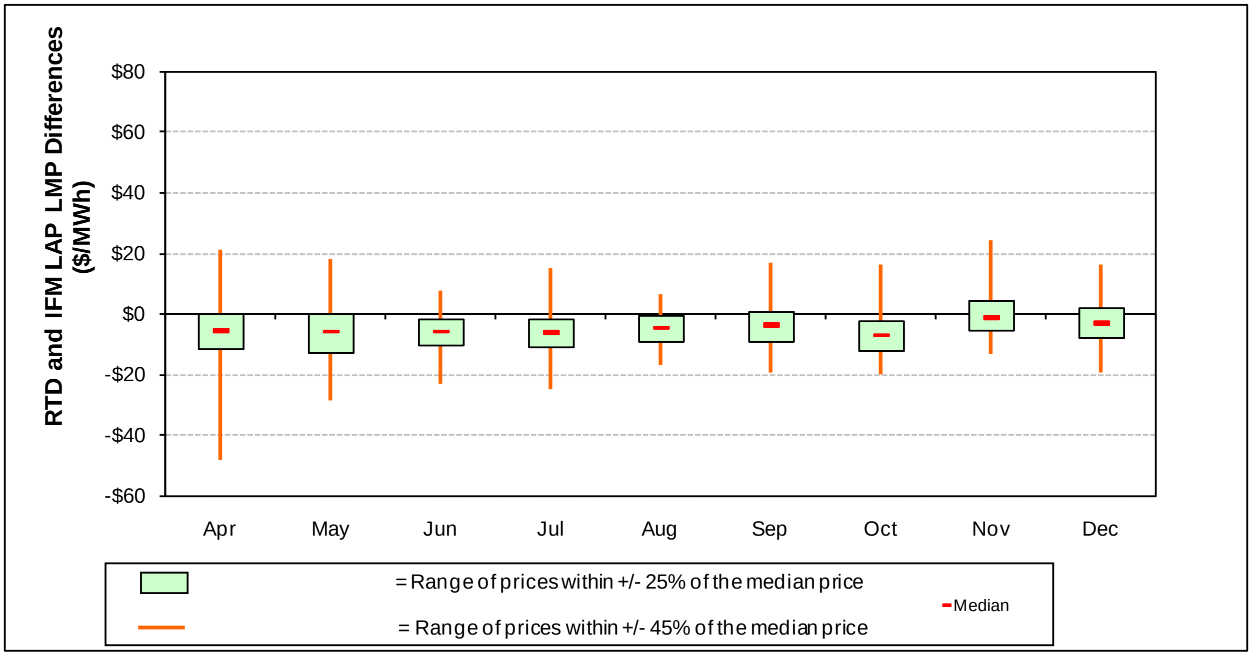


Figure A.6 Distribution of PG&E LAP Price Differences Between IFM and RTD (Off-Peak Hours)

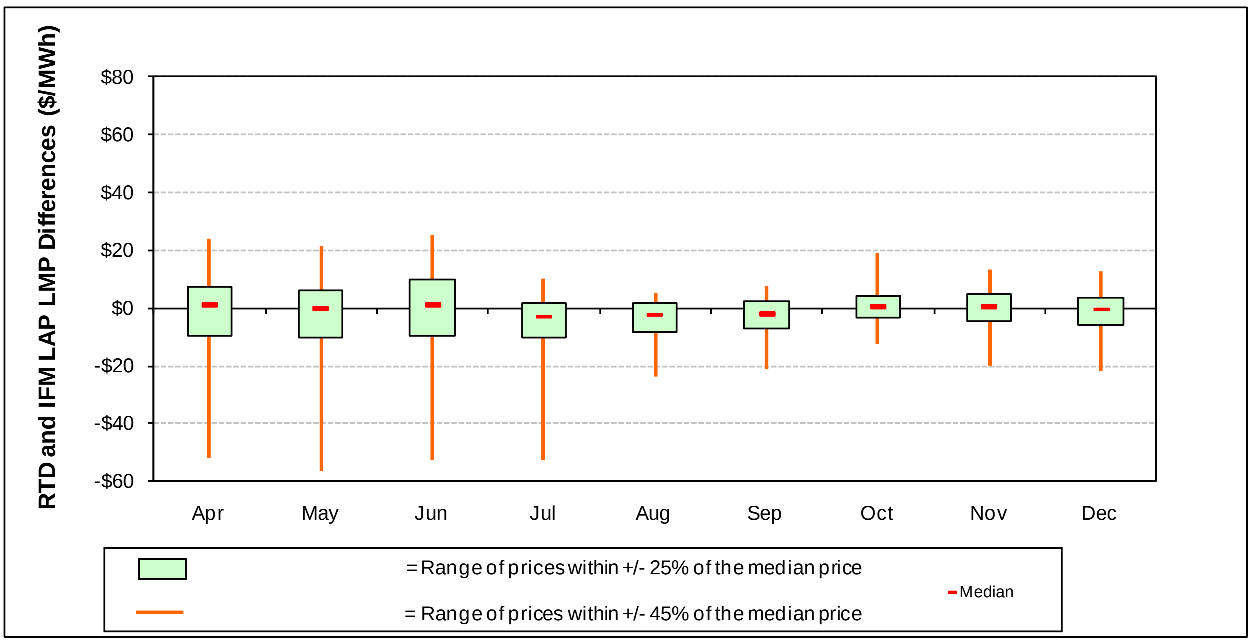


Figure A.7 Distribution of SDG&E LAP Price Differences Between IFM and RTD (Peak Hours)

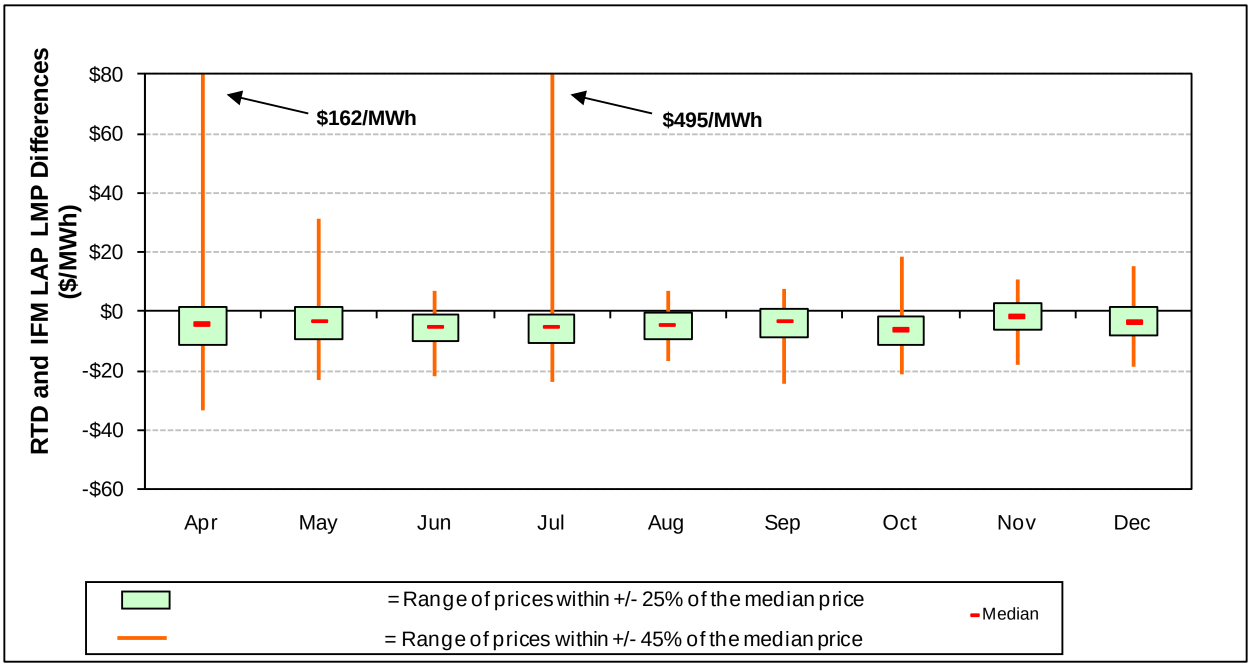


Figure A.8 Distribution of SDG&E LAP Price Differences Between IFM and RTD (Off-Peak Hours)

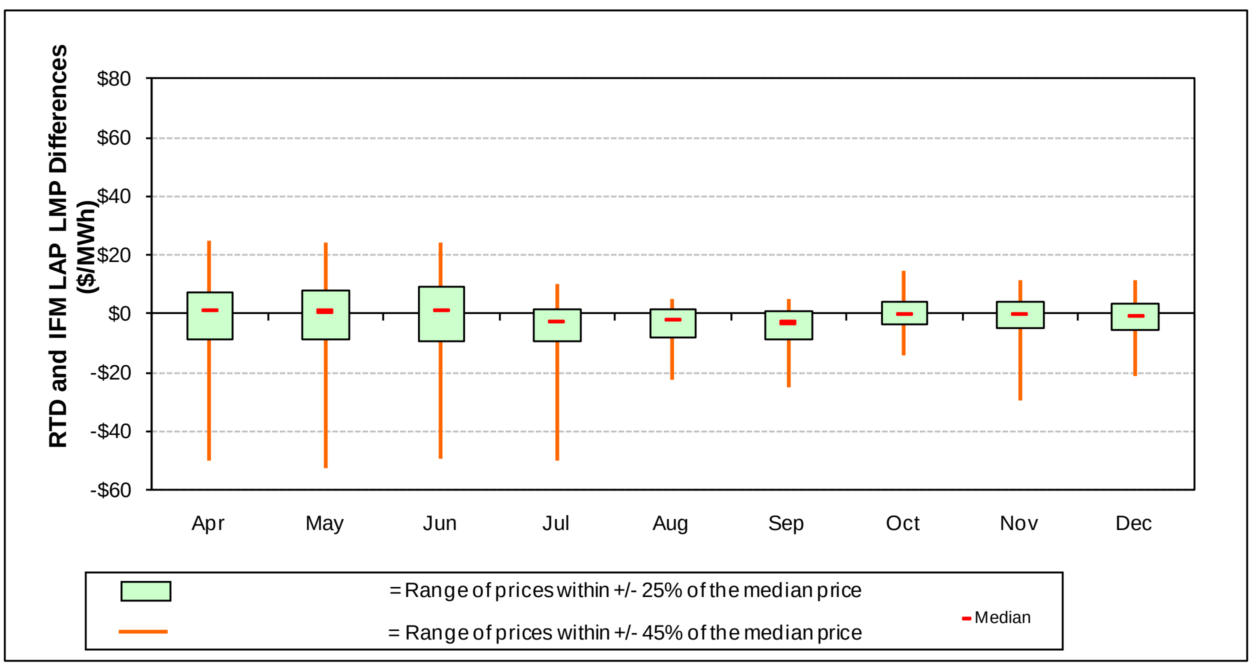


Figure A.9 PG&E HASP LAP Price Distributions (Peak Hours)

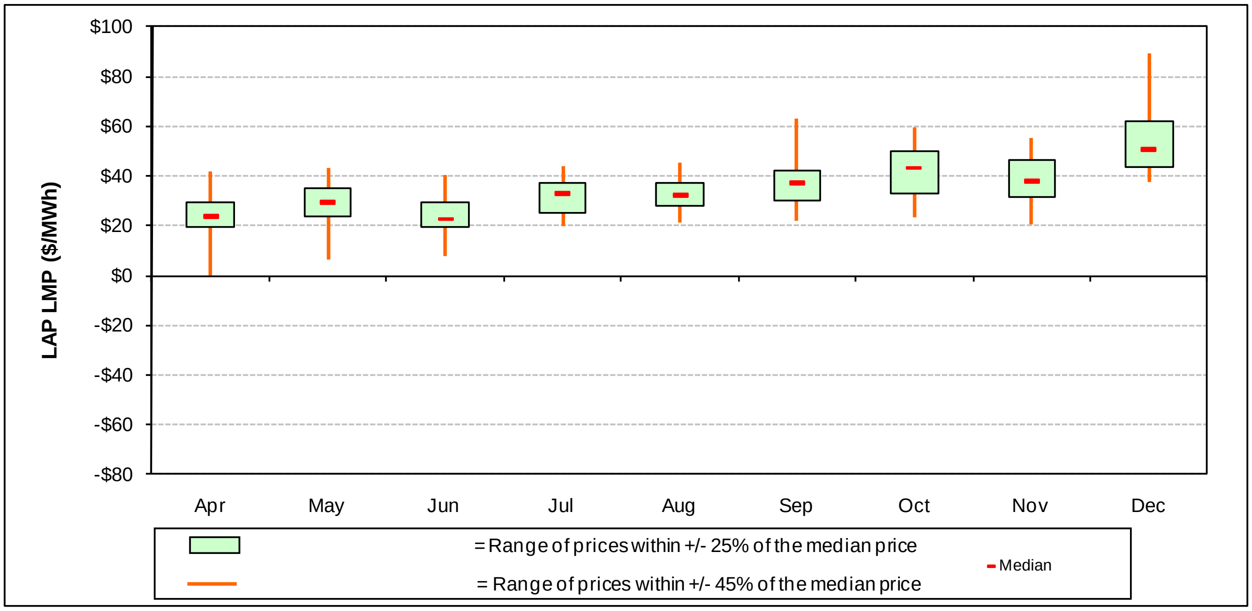


Figure A.10 PG&E HASP LAP Price Distributions (Off-Peak Hours)

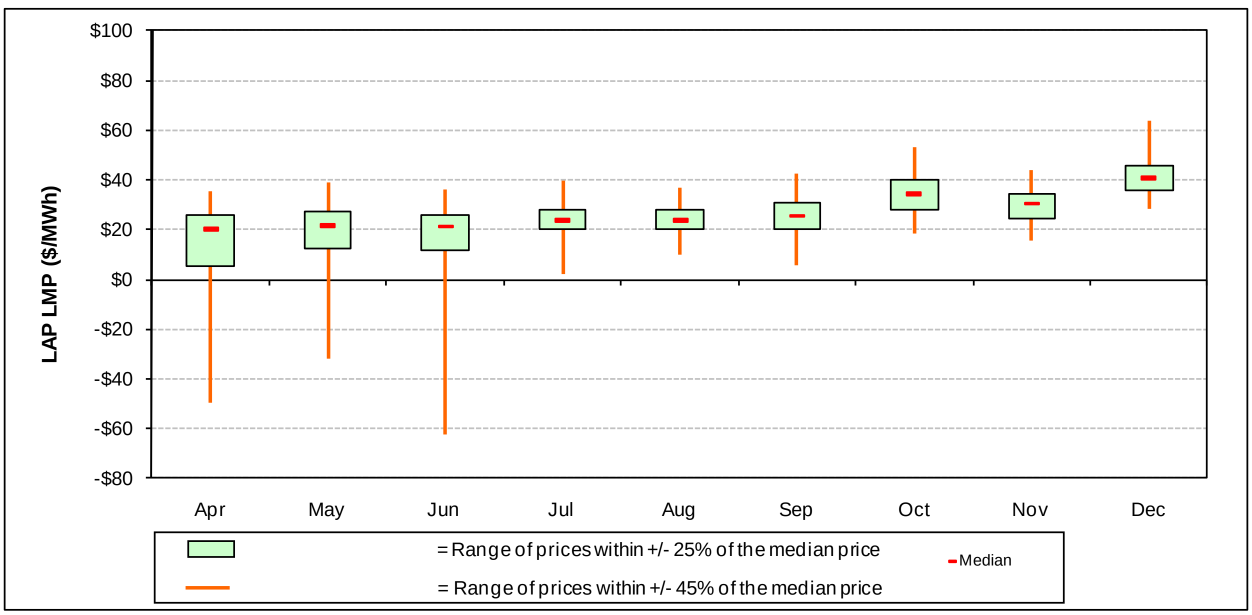


Figure A.11 SDG&E HASP LAP Price Distributions (Peak Hours)

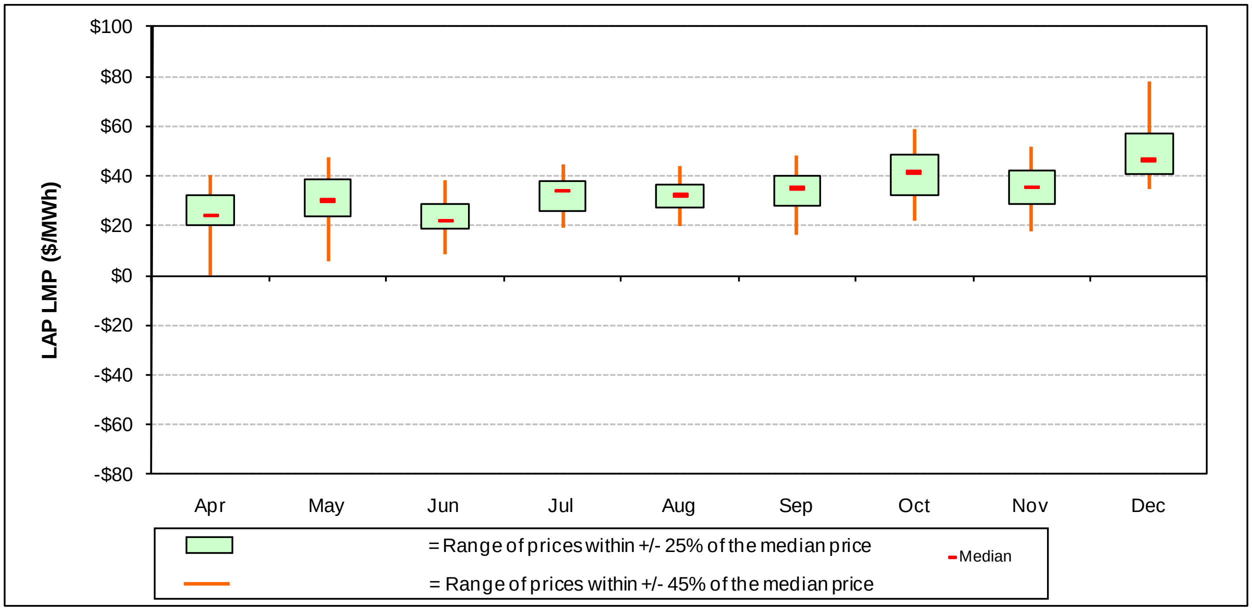


Figure A.12 SDG&E HASP LAP Price Distributions (Off-Peak Hours)

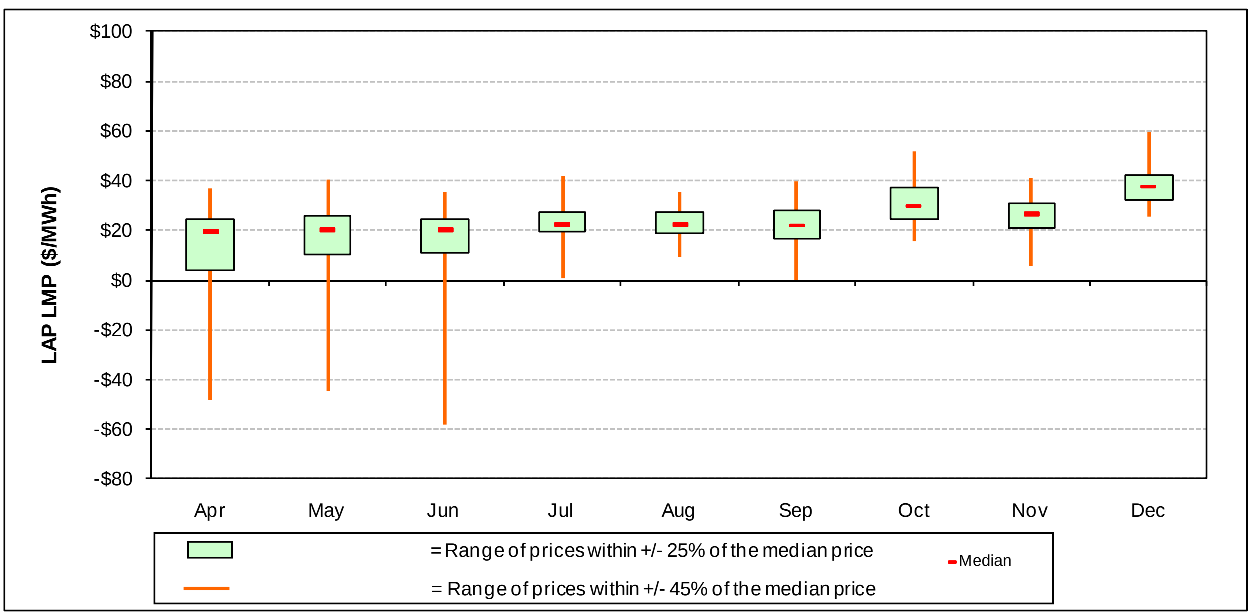


Figure A.13 PG&E RTD LAP Price Distributions (Peak Hours)

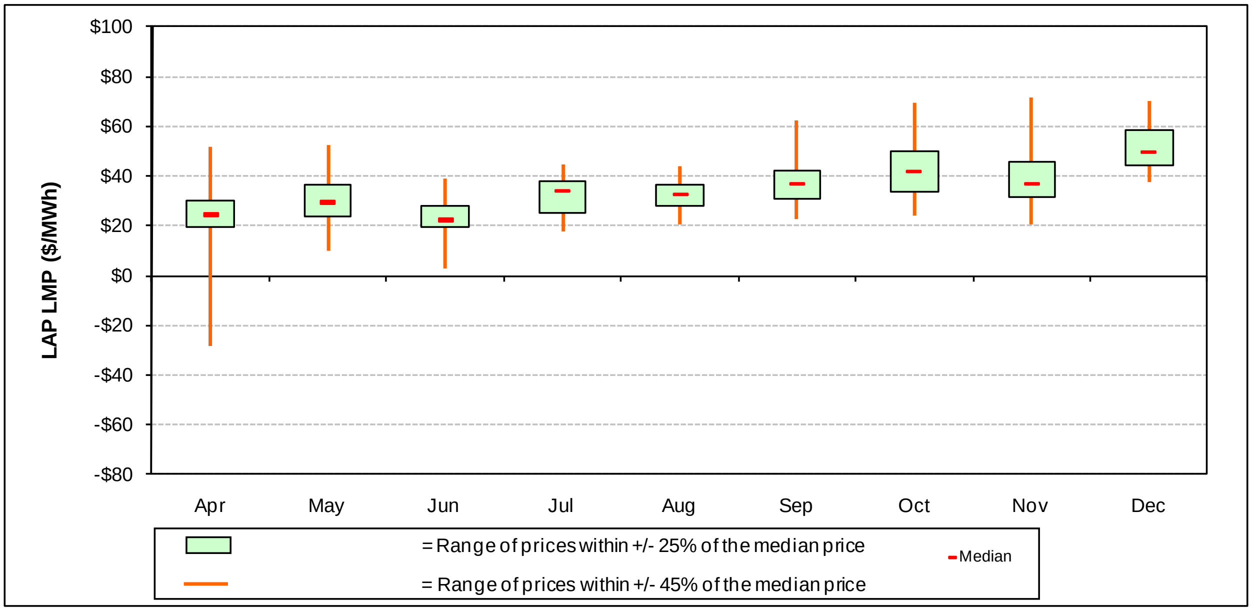


Figure A.14 PG&E RTD LAP Price Distributions (Off-Peak Hours)

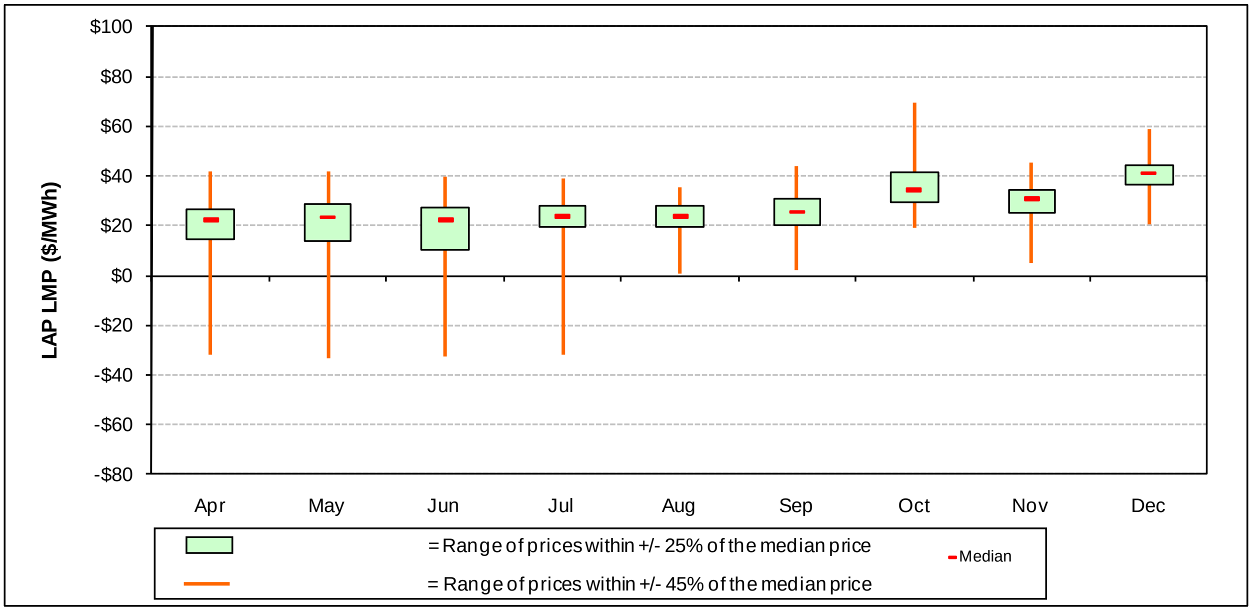


Figure A.15 SDG&E RTD LAP Price Distributions (Peak Hours)

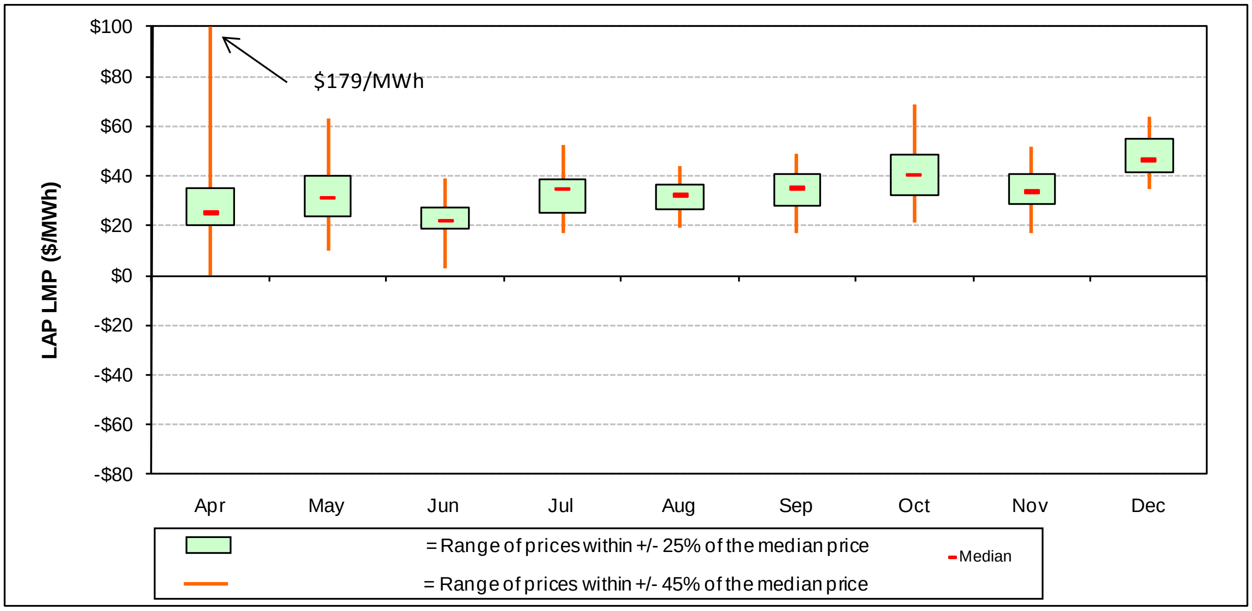


Figure A.16 SDG&E RTD LAP Price Distributions (Off-Peak Hours)