California ISO
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California Independent
System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

July 30, 2009

Prepared by: Department of Market Monitoring

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Executive Summary

On March 31, 2009, the California ISO (ISO) implemented its new Market Redesign and Technology Upgrade (MRTU). The new market was designed to address known deficiencies in the prior market, most notably: (1) the lack of a day-ahead energy market, and (2) a simplified zonal congestion management design that required numerous operator interventions to mitigate local reliability constraints within each zone. The MRTU design includes day-ahead and real-time energy markets based on locational marginal pricing (LMP) that produce prices at over 3,300 separate locations throughout the ISO control area.

This quarterly report, produced by the ISO Department of Market Monitoring (DMM), covers the first three months of the new market operation (April – June) and focuses on three main areas of market performance: (1) real-time market performance, (2) market competitiveness and effectiveness of the local market power mitigation (LMPM) procedures, and 3) exceptional dispatches – or manual dispatches issued by an ISO operator in cases where the market failed (or was expected to fail) to address a particular reliability need. In addition to this report, the ISO has produced a separate quarterly report that provides a comprehensive review of general market performance. Rather than replicate the content of the ISO quarterly report, we chose to focus our quarterly report on a more in-depth analysis of the specific market issues noted above. We selected these three topics because they were of primary concern and interest to us and numerous stakeholders. A brief summary of our analysis and findings on each of these three topics is provided below.

While the focus of this report is to provide a detailed analysis and assessment of these three specific topics, our overall observation is that the new ISO markets are performing well. Most notably:

- The Day Ahead Integrated Forward Market (IFM) has been very stable and competitive;
- Market activity in the Residual Unit Commitment (RUC) market has been minimal due to high levels of load scheduling in the IFM and sufficient Resource Adequacy (RA) capacity in RUC;
- The Real Time Market has been very competitive, but exhibited higher than expected levels of volatility, particularly during the first two months of the market; and
- The local market power mitigation procedures have been effective in both the Day Ahead IFM and Real Time Markets.

However, two key areas where we would like to see further improvements include 1) price volatility in the Real Time Market, and 2) use of exceptional dispatch. Our specific concerns and recommendations in both of these areas are summarized below.

Real Time Market Performance

While the ISO Real Time Market generally produces 5-minute prices that are at levels consistent with prevailing market conditions, it can be extremely volatile when stressed and produce relatively extreme prices. This was very evident during the first month of the new market operation and continued into May. Most of the 5-minute price volatility observed in the April to May timeframe was limited to the southern portion of the ISO control area and was due to a combination of congestion and limited 5-minute dispatch capability within constrained regions. In such situations, the market optimization has to resort to more inefficient and costly market solutions, the marginal cost of which can be well above the $500/MWh bid cap. While the 5-minute prices produced during these periods were at times at or near the $2,500/MWh price cap, the overall market cost of these prices spikes was relatively minor given their short duration and the relatively small amount of real-time load exposed to these prices.

The market conditions producing these extreme prices during the April to May period were caused by a combination of 1) physical grid limitations due to various transmission and generation outages and, at times, unusually high loads, and 2) certain deficiencies in the market model and input data such as inaccurate load forecasts or abrupt changes in transmission limits through operator adjustments.

The incidents of extreme 5-minute price volatility declined in June as most of the transmission and generation outages were completed and the ISO took various actions to improve its market model and input data. While real-time price volatility improved in June, we believe it is important to continue to investigate remaining incidents of extreme volatility to determine the root cause and whether there are further opportunities for improvement, particularly during the off-peak hours where we tend to see higher levels of price volatility.

Market Competitiveness and Effectiveness of Market Power Mitigation

The DMM has numerous metrics and tools for assessing the competitiveness of the market and effectiveness of local market power mitigation and has been routinely monitoring and assessing performance in these areas since the start of the new market. Our overall finding is that the new ISO markets are functioning competitively and the local market power mitigation (LMPM) procedures are working effectively to mitigate any uncompetitively high market bids when they are needed for resolving congestion on non-competitive transmission constraints.

One of our primary methods for gauging the overall competitiveness of the energy markets is to calculate "competitive benchmark" market prices by re-running the market software with cost-based bids used in place of submitted market bids. We then compare our competitive benchmark prices to what the actual market produced. In comparing our monthly average competitive day-ahead benchmark prices for the three major load aggregation points (LAPs) to the actual average day-ahead prices, we find them to be very close, with our average competitive benchmark price in April being slightly below the actual average LAP prices (approximately 5 percent lower) and within a fraction of a percent in the months of May and June. Similarly, when we compare our day-ahead competitive benchmark LAP prices to actual real-time average LAP prices, excluding extreme 5-minute scarcity prices,[1] we find that they also are very close (within 1 percent), indicating that real-time prices are also generally competitive.

We assess the effectiveness of the LMPM procedures by reviewing the frequency and level of bid mitigation occurring in the day-ahead and real-time markets and by examining cases where relatively high unmitigated market bids are dispatched to determine the extent to which these bids are being dispatched for non-competitive reasons. We also monitor the frequency with

[1] Extreme market prices (outside of the $500 and -$30 bids caps in effect) are excluded because these prices typically reflect real-time constraints that cannot be captured in the benchmarking analysis performed using the day-ahead market software. We do periodically review extreme 5-minute prices and find that they are typically set by a very complicated market dispatch where the marginal generators have moderate bid prices but are being dispatched in a very inefficient manner.

which the local market power mitigation procedures fail to run in the Hour Ahead Scheduling Process (HASP), so that no bid mitigation is performed for the Real Time Market. Our general conclusion from this analysis is that the local market power mitigation is working effectively. Due to the fact that significant volumes of generation within transmission constrained load pockets are being bid at competitive levels, the overall frequency and impact of LMPM procedures has been relatively limited.[2] However, uncompetitively high bids needed for local constraints are being effectively mitigated, and we see very few instances where high unmitigated market bids are being dispatched in the market for non-competitive transmission constraints. In addition, incidents of the LMPM procedures failing to run in the HASP are low and have trended down over the April to June period, dropping from about 16hours in April (2.2 percent of hours) to only 10 in June (1.4 percent of hours). Moreover, review performed as part of the ISO's price correction process found that during hours that LMPM procedures failing to run in the HASP, prices during only one hour needed to be lowered to correct for the lack of appropriate bid mitigation.

Exceptional Dispatch

Exceptional Dispatch (ED) is a term used to describe manual dispatches performed by an ISO operator in cases where the market failed (or was expected to fail) to address a particular reliability need. Since the start of the market, the use of exceptional dispatches has been higher than expected and this has raised concerns, particularly among generator owners, about the efficacy of the new market and impact these manual dispatches are having on market prices.

DMM has undertaken a comprehensive review of this issue that focused on identifying the primary reasons for ED and what actions could be taken to reduce the need for ED going forward. The results of this assessment are provided in Section 3 of this report. While we have observed a decline in the volume of ED in June relative to April and May, more recent observations suggest incidents of ED may have increased in July.

Our analysis does not include an assessment of the market impacts from ED because undertaking such an analysis would require knowing the counter-factual of what prices should have been if the reliability constraints driving ED were incorporated into the market model. However, since most exceptional dispatches are limited to committing units to their minimal operating level in the day-ahead market (about 95 percent) and such minimum load energy is not eligible to set price under any case, the market impacts of such dispatches may not be that significant. As long as there is a well-founded reliability need for having a unit on-line, the market outcome from having the operator manually force it on in the day-ahead market may not be appreciably different than what would occur if the constraint leading to this action was in the market causing the market to dispatch the unit automatically. However, to the extent exceptional dispatches are overly conservative or the reliability criteria driving the ED can be met by different combinations of unit commitments, having the constraint in the market model and managed by the market optimization will likely produce a more efficient and different market outcome. In this case, prices would be different but not necessarily higher relative to the ED case.

Exceptional dispatches for energy above the minimum operating level of the units, which are limited to the Real Time Market, can distort and suppress market prices if the original market

[2] For example, during peak hours the number of units having some portion of their IFM market bids lowered due to LMPM averaged only about 1.4 units in April, about two units in May (1.9), and less than one unit in June (.85). The increase in capacity scheduled in the IFM from these units that may be attributable to this bid mitigation averaged 52 MW in April, 73 MW in May, and just 32 MW during peak hours in June.

bids for this energy are at or above prevailing market prices. In this case, having the reliability constraint driving these EDs incorporated into the market model would likely lead to higher LMPs at location of the ED and the surrounding area that defines the reliability constraint. Fortunately, in May and June there have been very few real-time exceptional dispatches for energy above a unit's minimum output level, and thus the current market impact from these dispatches is likely minimal.

While it is unrealistic to think that ED can be entirely eliminated, we do think that concerted efforts by the ISO in the following areas, listed in order of short to longer term efforts, could significantly reduce the frequency of ED.

1. Undertake a comprehensive review of all operation procedures and other criteria for determining the need for ED to make sure the criteria and processes driving exceptional dispatch are well-founded, consistently followed, and not overly-conservative.

2. Explore and implement options for incorporating the reliability constraints driving ED into the market model.

3. To the extent ED is being driven by the need for contingency reserves, consider new market products that might mitigate the need for ED and more appropriately remunerate resources providing these reserve services.

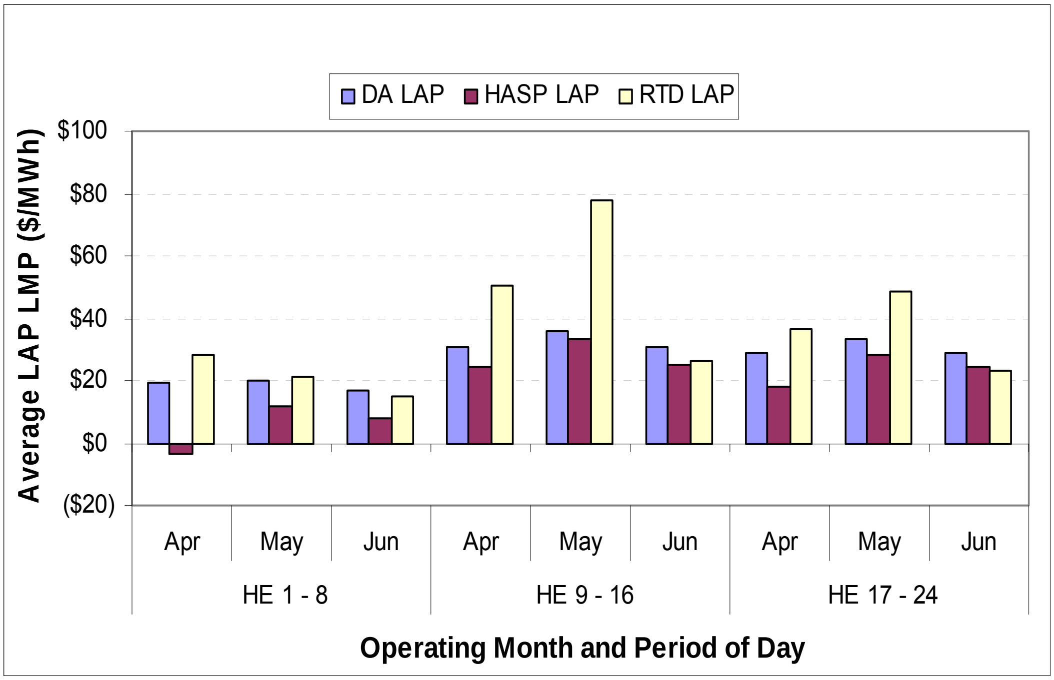
1 Real Time Market Performance

This section provides an assessment of price convergence across the three ISO energy markets: Day Ahead IFM, Hour Ahead Scheduling Process (HASP), and the 5-minute Real Time Dispatch (RTD). In addition, we provide a review of trends in RTD price volatility. Our analysis shows that while there has been a significant improvement in price convergence in June during the middle and later hours of the day, HASP prices continue to diverge during the early morning hours. Additionally, we show that while price volatility in May was similar to April, there was a significant improvement in June. This improvement is likely due to a combination of (1) the various actions the ISO has taken over the past two months to improve the quality of the real-time market model and associated input data, and (2) the fact that many of the planned generation and transmission outages that were driving some of the price volatility in April and May were completed in June. Despite these improvements, price volatility from one 5-minute interval to another is found to be much higher than what is observed in other ISOs. We will be working with ISO market operations to conduct further analysis of this observation and consider potential options for addressing it going forward.

1.1 Price Convergence

One standard measure of market performance is the degree to which prices across the ISO's inter-temporal energy markets (IFM, HASP, and RTD) converge. A high degree of price convergence can provide market efficiency benefits in markets that are otherwise competitive and well functioning. Price convergence can be measured and analyzed in a variety of ways. One approach is to examine how well average prices converge over an extended period. At the start of the new market, prices tended to diverge with HASP prices, on average, lower than IFM and RTD. However, as the market has had time to mature, prices have been trending towards convergence, most notably in June. The following three figures compare the (simple) average prices across markets by month and time of day for all three LAPs, Southern California Edison (SCE), San Diego Gas and Electric (SDGE), and Pacific Gas and Electric (PG&E).

Figure 1.1 Comparison of SCE LAP Prices[3]



Southern California Edison LAP prices are shown in Figure 1.1 above. In the morning hours (HE1-8), HASP prices were lower than day-ahead and real-time prices. While there was significant improvement in May, the morning hour HASP prices diverged again in June though not to the same extent as in April. The lower morning HASP prices tend to be a result of a few factors.

1. The load pattern across this period is relatively low but changes significantly from one hour to the next;

2. There is limited 5-minute dispatch capability (particularly in the decremental direction) due to units being off-line or at minimum operating levels; and

3. Load is typically scheduled at or near 100 percent of forecast.

To manage the load pattern across the morning hours, specifically to maintain enough 5-minute dispatchable energy for the morning load pull, operators are often biasing the HASP load forecast down to decrease net import schedules from day-ahead. The negative HASP load bias decreases net imports and therefore increases internal generation to meet demand. The increased internal generation moves units off of Pmin, providing more 5-minute dispatchable energy in both the incremental and decremental direction. While this practice helps manage the morning load pattern, it tends to produce a predictable price divergence with average HASP prices that are typically well below day-ahead and RTD prices.

Average real-time prices in the middle part of the day (HE 9 -16) were significantly higher than day-ahead and HASP prices for April and May. The high real-time prices in April and May are

[3] Averages represented in the figures in this section are all simple averages.

due primarily to price spikes during periods when Path 26 (the major transmission path between Northern and Southern California) is congested and the southern region runs out of 5-minute dispatchable supply. The frequency of real-time price spikes in June dropped resulting in average prices across the three markets that were more closely aligned. The latter part of the day (HE 17-24) shows a similar pattern but average RTD prices were not as extreme during April and May.

Figure 1.2 and Figure 1.3 below show the same charts for San Diego Gas and Electric and Pacific Gas and Electric respectively. SDGE and PG&E average prices in the morning hours show similar patterns to that of SCE, with HASP prices lower than day-ahead and real-time due to the aforementioned factors. SDGE real-time prices in the afternoon hours in April and May were significantly higher than HASP and day-ahead; PG&E real-time prices during the same time period for April and May were also higher than day-ahead and HASP but at a much lower magnitude. Congestion on Path 26 contributed to higher RTD prices in the southern LAPs during the mid-day hours in April and May, and congestion on the San Diego import limits contributed further to higher average mid-day RTD prices in the SDGE LAP during these months. Based on this metric, convergence between RTD and HASP prices in June improved during the mid-day hours for both PG&E and SDGE relative to April and May. The latter part of the day showed similar patterns as the afternoon for both SDGE and PG&E but real-time prices were much lower.

Overall, the average prices across markets have become more closely aligned since the start of the market, with the exception of the morning hours in June. All three LAPs have similar patterns, though the magnitude of real-time prices in SDGE and SCE were, on average, higher than PG&E.

Figure 1.2 Comparison of SDGE LAP Prices

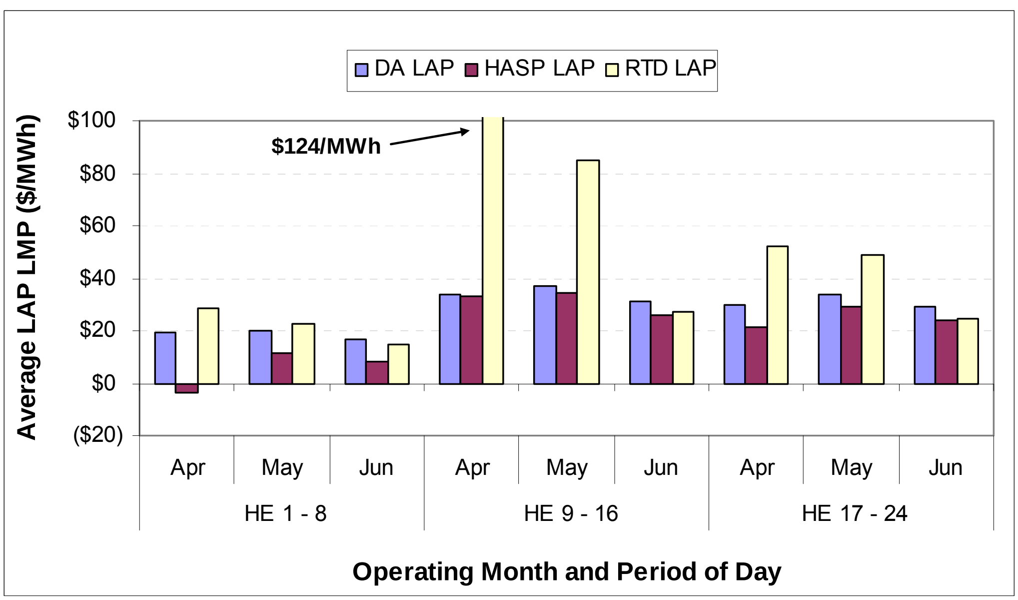
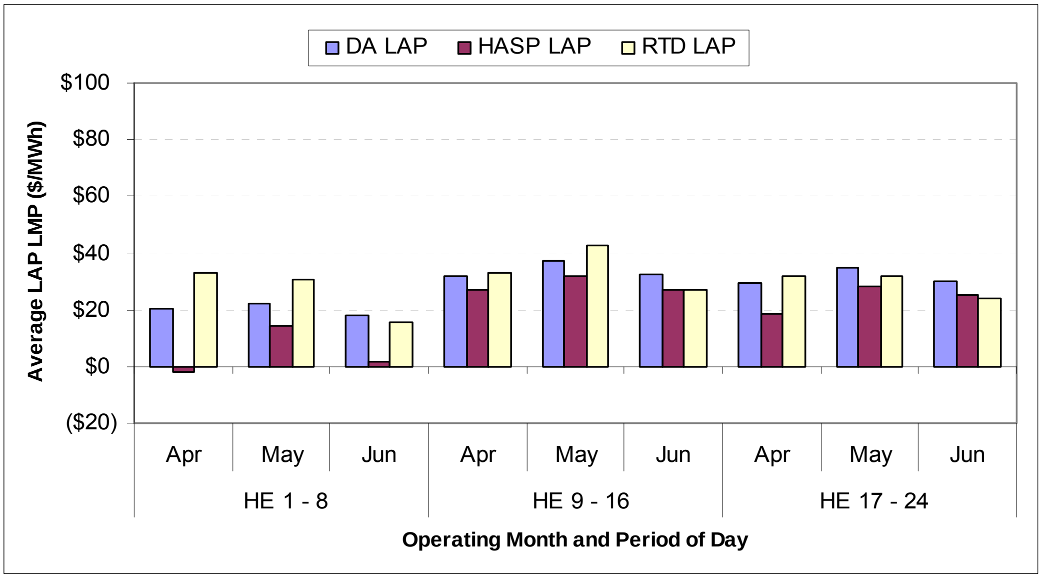


Figure 1.3 Comparison of PG&E LAP Prices



A second measure of price convergence is the distribution of the differences between temporal markets, in this case between real-time and day-ahead LAP prices. Figure 1.4 through Figure 1.6 below show the distribution of price differences between real-time and day-ahead LAP prices (LAP_{RT} – LAP_{DA}) by month and period of day for SCE, SDGE, and PG&E respectively. The results shown below are similar to the previous three charts in that each LAP has similar price patterns across the months and time of day.

The distribution of price differences in SCE is shown in Figure 1.4 below. The price differences in the morning hours have a wider distribution, ranging from approximately -$55 to $25 for all three months, than the afternoon and evening hours. Large price differences are less prevalent in the afternoon hours, especially in April and June. During the latter part of the day, the price differences in April were similar to that in the morning hours ranging from approximately -$55 to $30; May and June distributions during the latter part of the day are similar to the afternoon hours. Overall, the distribution of price differences slightly decrease in June from May and April, indicating better convergence of prices between the two temporal markets.

While the distribution of price differences in the afternoon and evening hours are less widespread than the morning hours, the median price differences are persistently slightly negative while the morning hour median price differences are slightly positive. A negative median price difference indicates that real-time prices are typically lower than day-ahead prices, which is initially counter-intuitive given the previous charts showing that monthly average real-time prices are generally higher than day-ahead prices. However, day-ahead prices more closely follow the load curve, starting off low ($15) and gradually climbing to a peak ($40-$45) in the afternoon or early evening hours. Real-time prices, on the other hand, generally remain below $40 with the exception of extreme price spikes in both directions which occur intermittently. Thus, in the morning hours real-time prices are typically higher than day-ahead due to intra-hour ramping for the morning load pull, which typically causes higher real-time prices in the latter part of each hour. As the load climbs, the day-ahead prices increase while real-time prices tend to remain lower than day-ahead throughout the afternoon and evening hours with the exception of intermittent price spikes.

Figure 1.4 Distribution of SCE LAP Price Differences Between RTD and DA

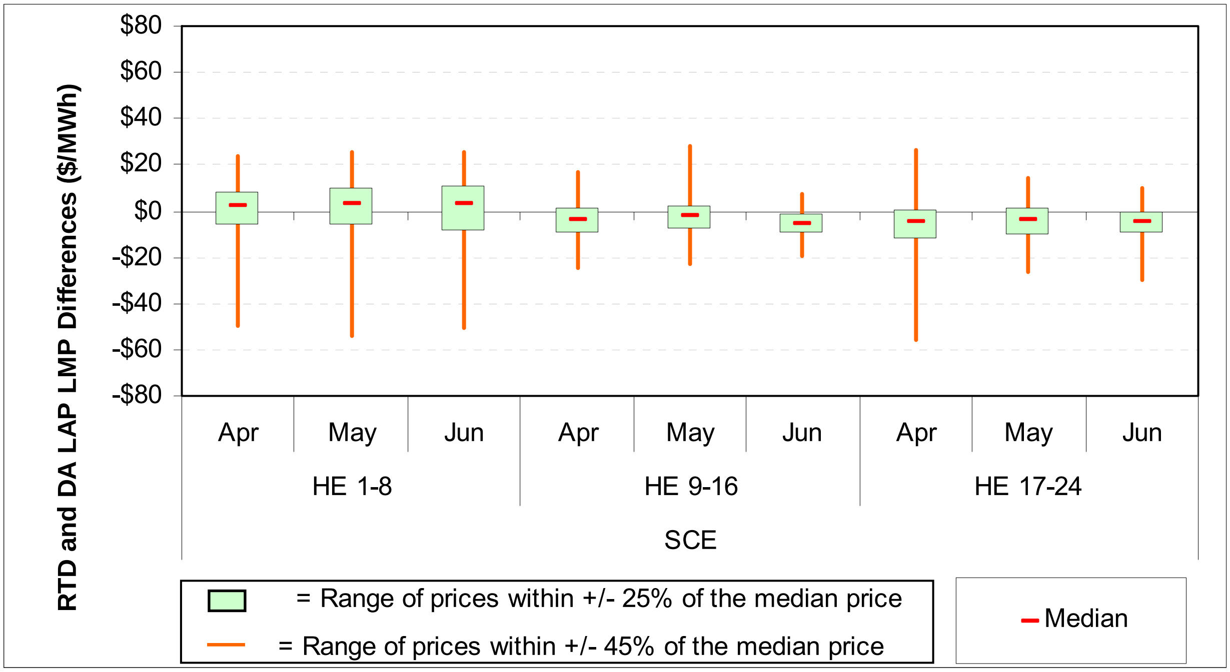


Figure 1.5 and Figure 1.6 below for SDGE and PG&E respectively, show the same distribution pattern as SCE. The distribution of price differences in the morning hours is wider with slightly positive median price differences. The afternoon and evening hour distributions are more compact, with the exception of SDGE prices in April from HE 9-16, and have slightly negative median price differences. The extreme tail end for April HE 9-16 in SDGE is primarily due to congestion on Path 26 and limited 5-minute supply available in the San Diego area.

Figure 1.5 Distribution of SDGE LAP Price Differences Between RTD and DA

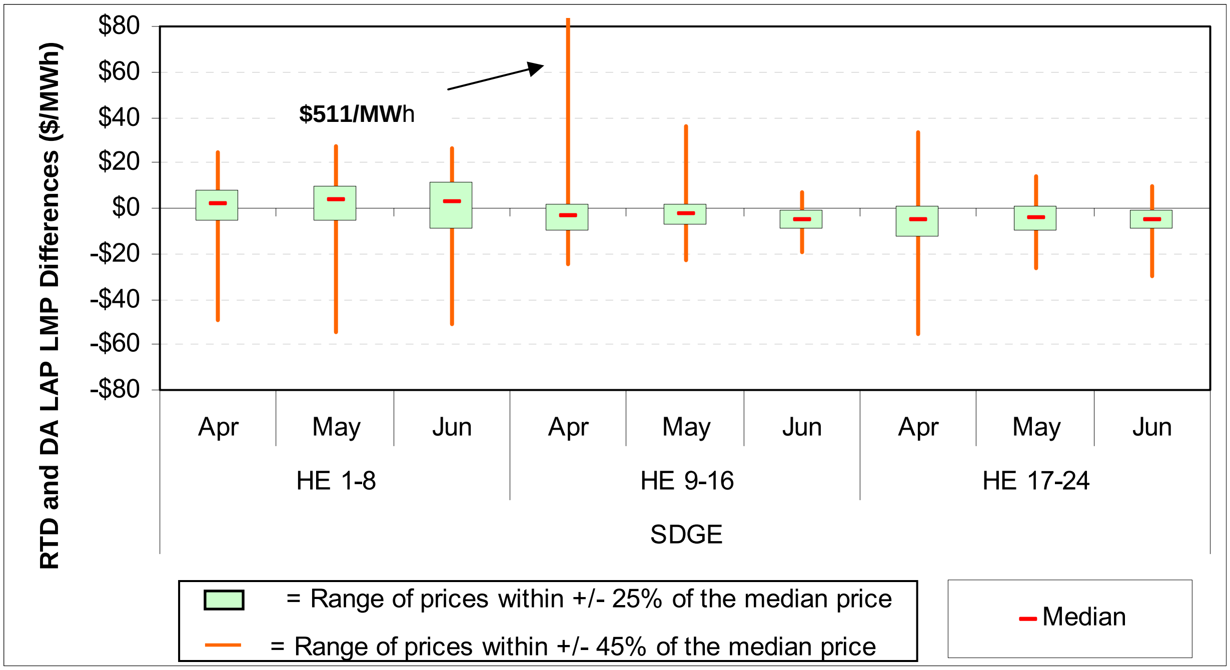
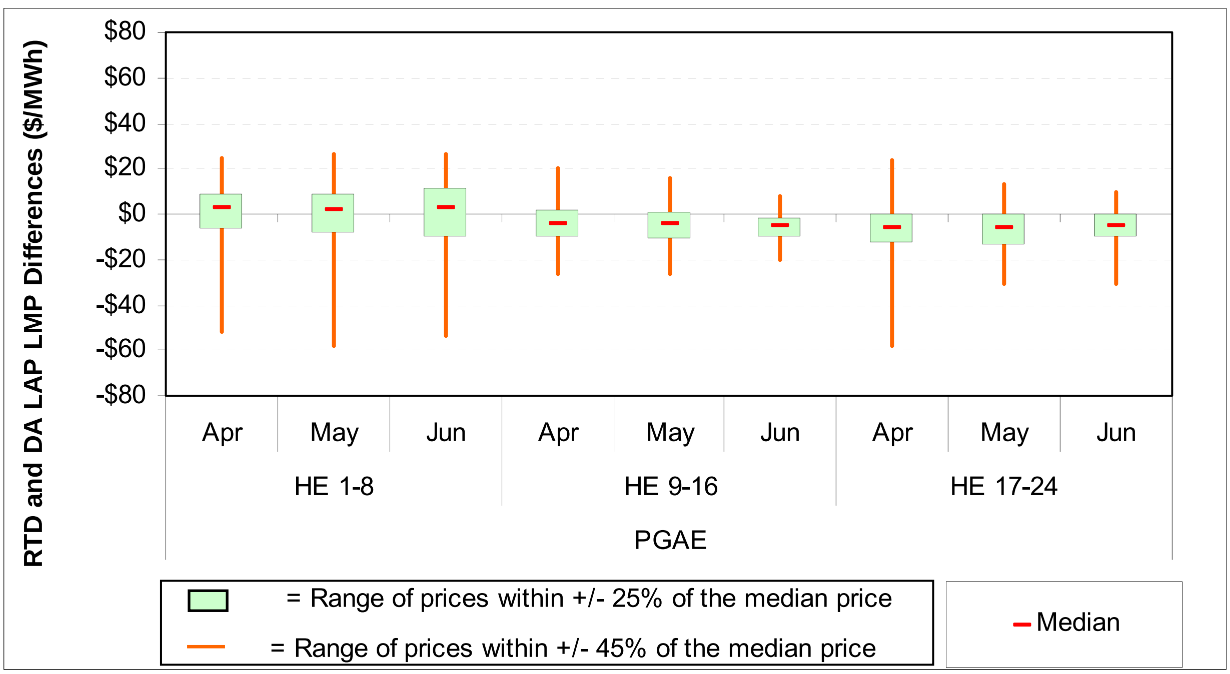


Figure 1.6 Distribution of PG&E LAP Price Differences Between RTD and DA



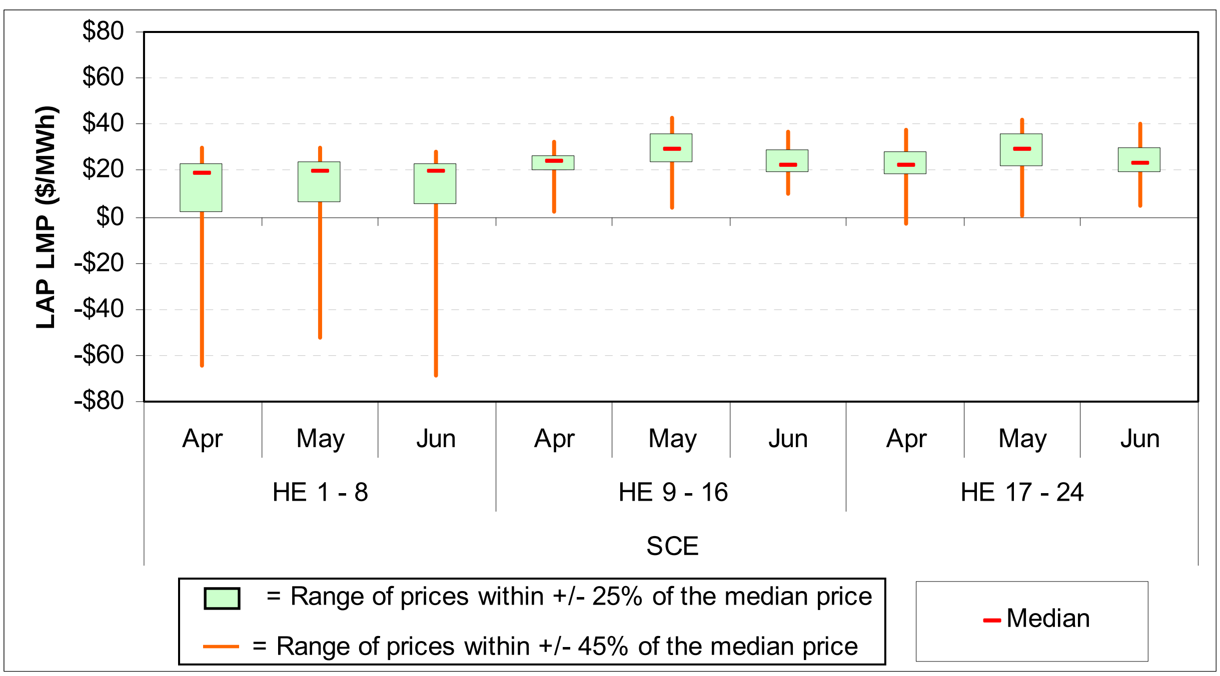
In summary, price convergence across inter-temporal markets can provide market efficiency benefits in markets that are otherwise competitive and well functioning. At the start of the new market, day-ahead, HASP, and real-time prices were divergent, especially HASP prices in the morning hours, but price convergence improved in June. The divergent prices in the morning hours are a result of the aforementioned factors which include the load pattern, limited supply of 5-minute energy in the decremental direction, and being over-scheduled in the day-ahead.

1.2 Price Volatility

This section provides a brief summary of some observed trends in price volatility. The real-time energy market in April was, at times, extremely volatile, with 5-minute prices exceeding \$2,500/MWh in some intervals. Some of this volatility was caused by an unusually early heat wave during the third week of April, which led to high loads in Southern California and congestion on some of the major south-to-north transmission paths. However, sporadic 5-minute price spikes continued through May but then moderated substantially in June.

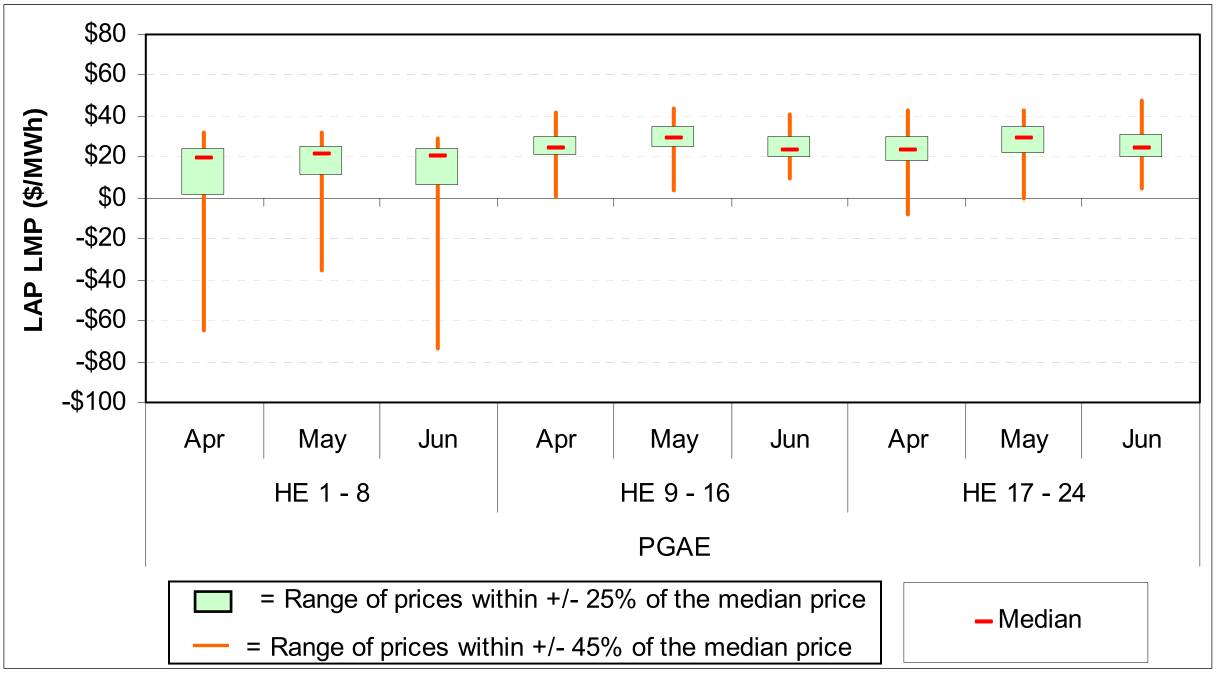
Figure 1.7 below reflects the distribution of HASP LAP prices for the SCE area for April through June. For afternoon and evening periods, HASP LAP prices have shown a fairly tight distribution, with the middle 90 percent of prices (orange lines) ranging from just below \$0/MWh to just above \$45/MWh. Prices in the morning hours, however, have had a much wider distribution and have often been negative.

Figure 1.7 SCE HASP LAP Price Distributions (April – June)



The majority (90 percent) of HASP LAP prices for SCE during the morning hours (1-8) have ranged from roughly -\$70 to \$30. The higher volatility and more frequent negative prices in these hours are driven by several factors. Grid operators often used a negative load bias in the HASP to reduce imports for both reducing over-scheduling in these off-peak hours as well as influencing the market to dispatch internal resources up off their minimum load to better accommodate the morning load ramp. Additionally, the HASP market may reduce net imports to move internal resources to accommodate ramping requirements in future intervals. Both of these actions result in lower and potentially negative prices in those intervals. There has been little or no trend in the HASP price distribution across the three months of the second quarter.

Figure 1.8 PG&E HASP LAP Price Distributions (April – June)



As seen in Figure 1.8 (above) and Figure 1.9, the distribution of LAP LMPs differs only slightly between the three LAP areas.

Figure 1.9 SDGE HASP LAP Price Distributions (April – June)

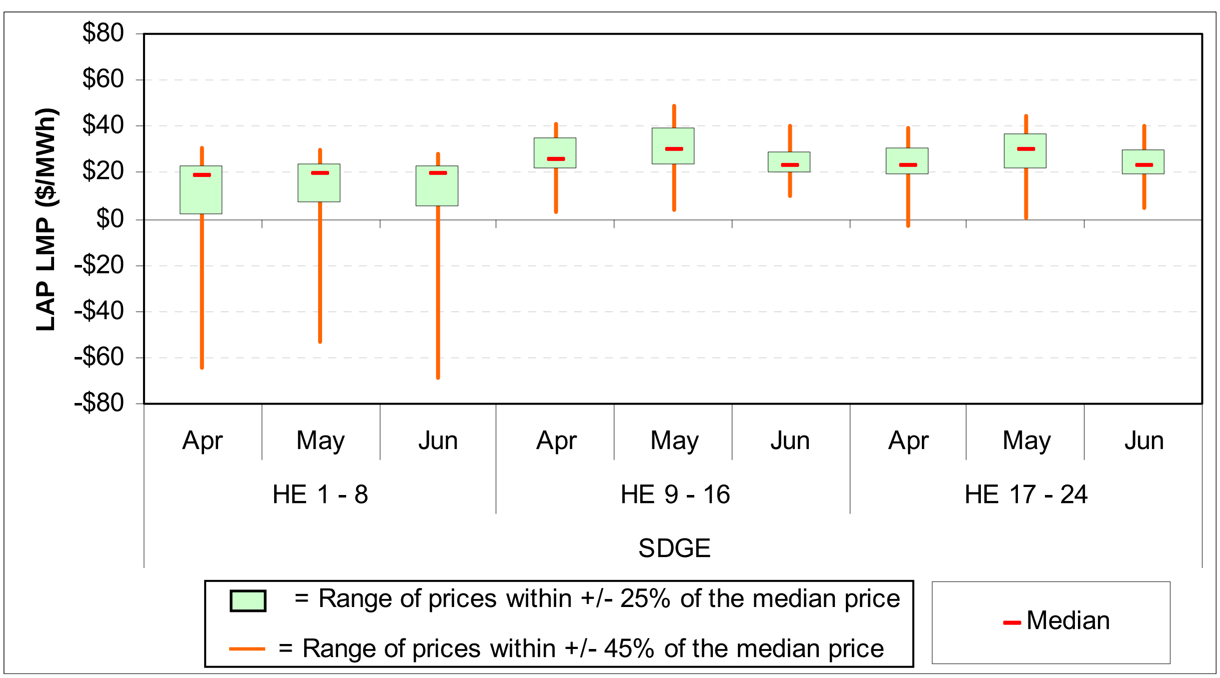
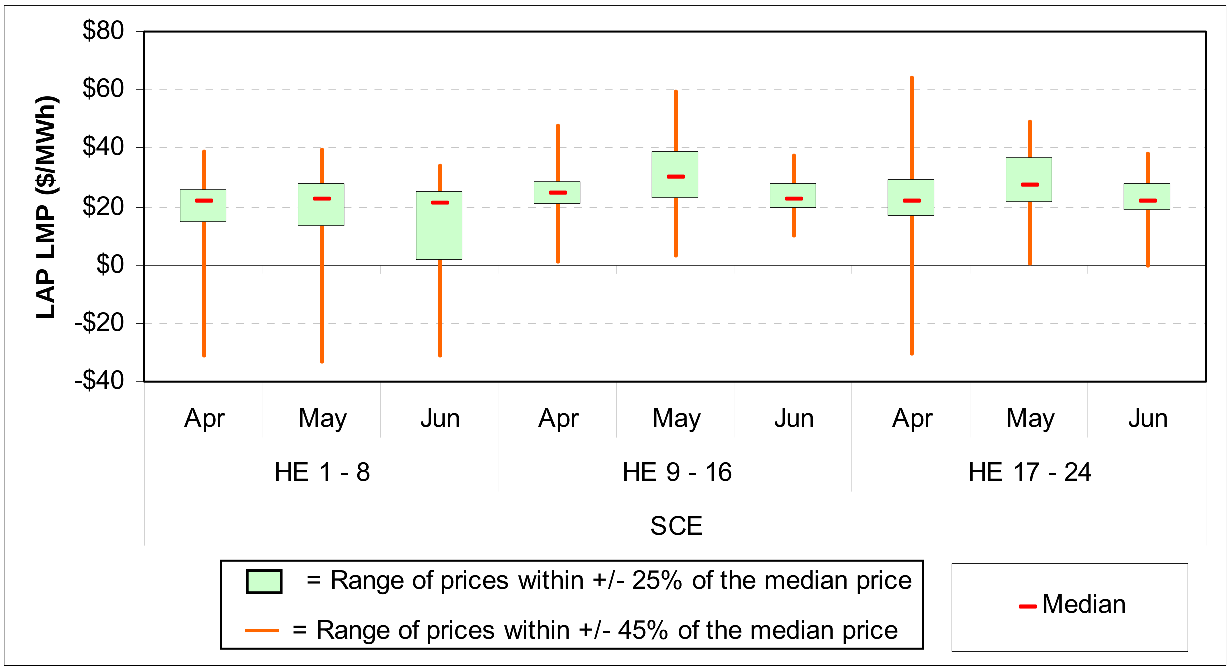


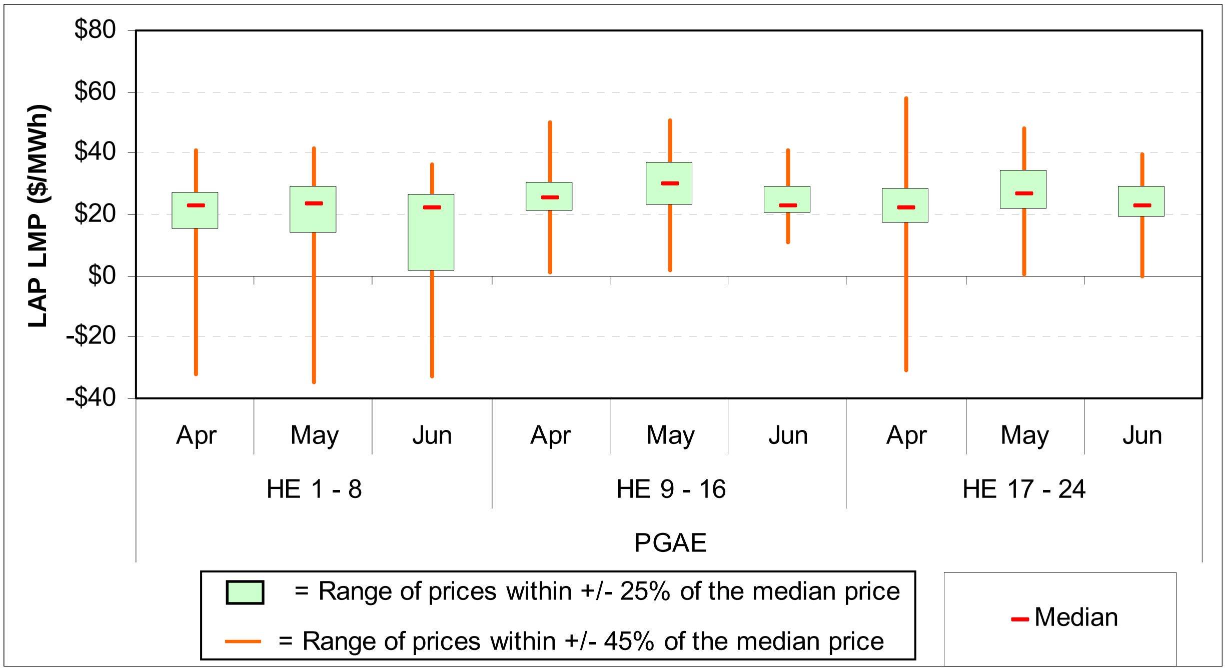
Figure 1.10 below provides a box-whisker plot representation of the distribution of SCE RTD LAP prices for the past three months. SCE RTD LAP prices tend to show the greatest volatility in the early morning, with 90 percent of the prices (+/- 45 percent of the median price) generally falling within a rather wide dispersion of approximately $70/MWh (-$30/MWh to $40/MWh). Price distributions were fairly spread out in the mid-day and late-day periods as well. However, the price distributions became significantly more consolidated in June during these same periods.

Figure 1.10 SCE RTD LAP Price Distributions (April – June)



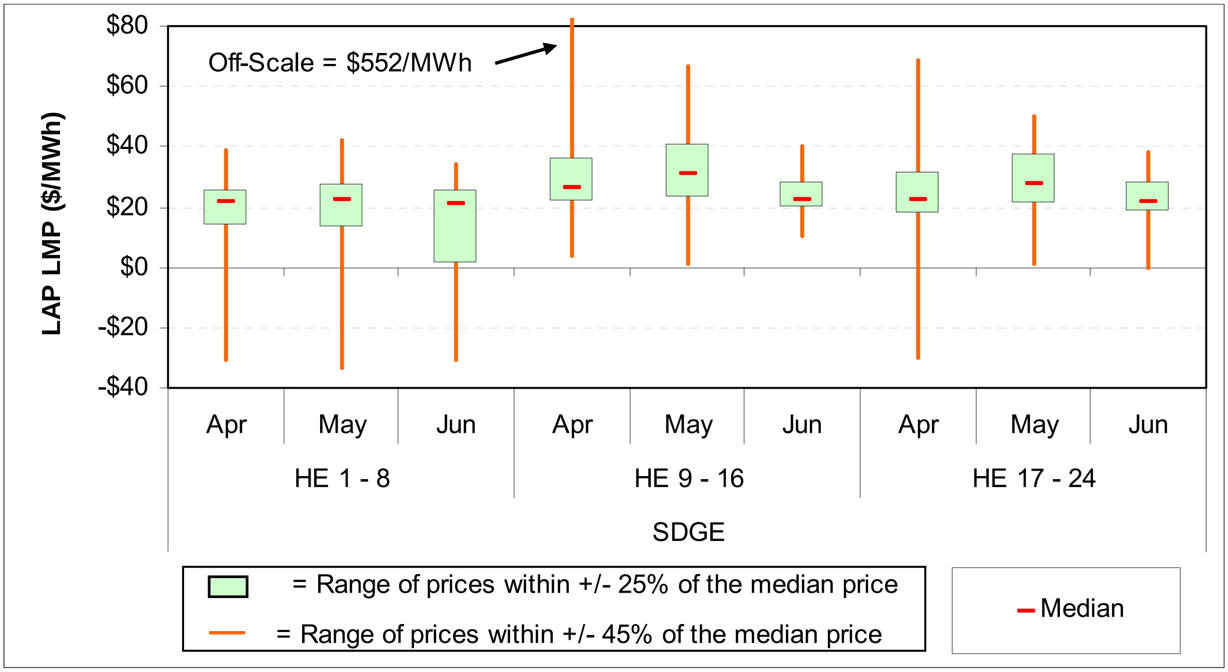
The RTD LAP price distributions for PG&E are very similar to SCE, as seen in Figure 1.11 below. One notable difference can be seen when comparing the price distributions for May, hours ending 9 – 16, where the 95th percentile for the PG&E LAP LMP distribution is about $5/MWh lower. This is due to lower prices in the north during periods in May when Path 26 was congested, causing higher LAP LMPs in the two southern LAP areas.

Figure 1.11 PG&E RTD LAP Price Distributions (April – June)



The SDGE LAP LMPs were also affected by the Path 26 congestion in May as well as congestion on import limits into the SDGE area. This is seen in Figure 1.12 below. The 95th percentile for mid-day hours during April and May is higher in SDGE compared to the other two LAP areas, and most notably in April at $552/MWh. The high prices in April were driven primarily by extreme high prices in the SDGE area during the unseasonable heat wave in late April. During this time, the San Diego import constraints were binding more frequently with high shadow values and resulted in extreme prices within the San Diego area.

Figure 1.12 SDGE RTD LAP Price Distributions (April – June)



To provide some context on how the price distribution plots shown above compare with other ISOs/RTOs with locational marginal pricing (LMP) markets, Figure 1.13 shows a similar plot of zonal 5-minute prices in ISO New England for the week of May 11-15, 2009. For this particular week, which was randomly selected, 90 percent of ISO New England load zone prices for Massachusetts and Connecticut were generally within a $30-$40/MW range, which is similar to the observed SCE LAP price distributions for the mid-day to late-day periods of June (Figure 1.10).

Figure 1.13 ISO New England Price Distribution

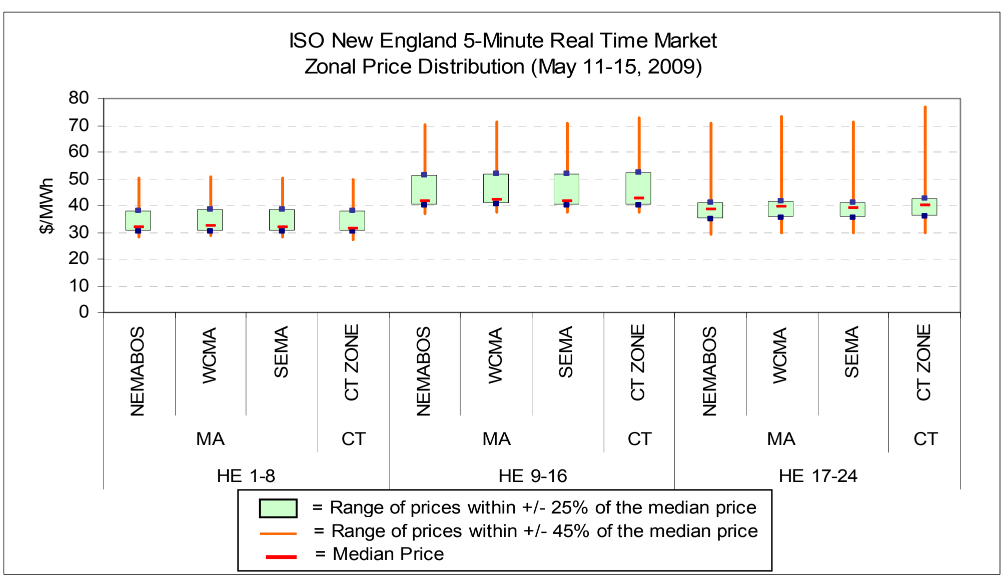


Figure 1.14 and Figure 1.15 provide some insight into the frequency and magnitude of extreme HASP prices. Specifically, Figure 1.14 shows that the frequency of extreme prices over $500/MWh has been very low (a fraction of a percent) across all months. Negative prices have been more prevalent in HASP (Figure 1.15) and, as discussed, occur primarily in the morning off-peak hours driven primarily by over-scheduling and downward ramp-limited conditions characteristic of this period of the day. Here, consistently about three percent of HASP LAP LMPs are at or below -$30 across the three months.

Figure 1.14 Monthly Duration Curves of HASP LAP Prices (High 20 Percentile)

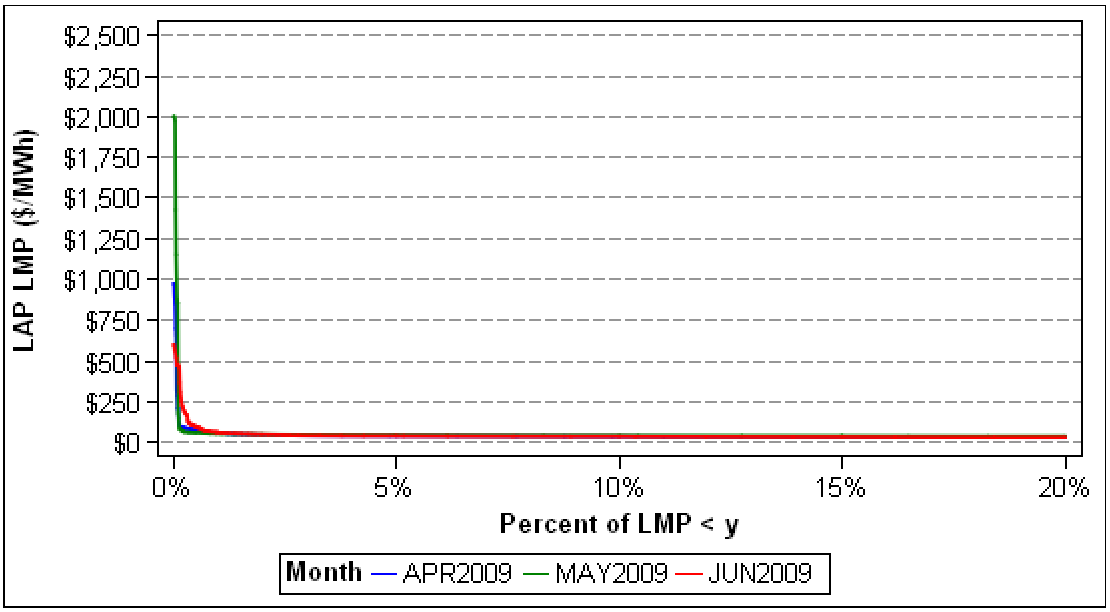


Figure 1.15 Duration Curve of HASP LAPs (Low 20 Percentile)[4]

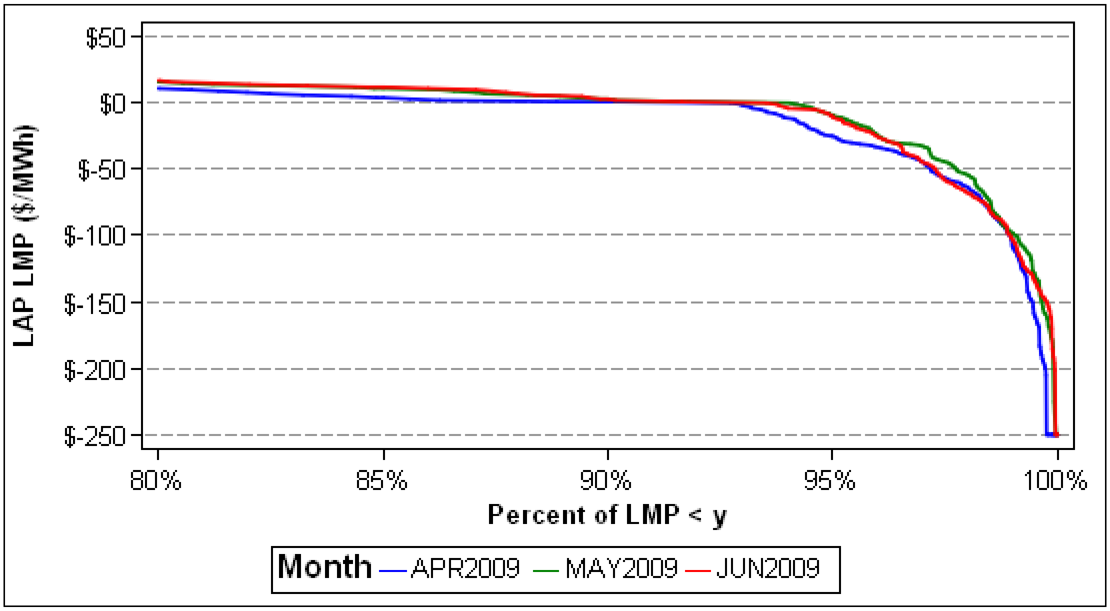
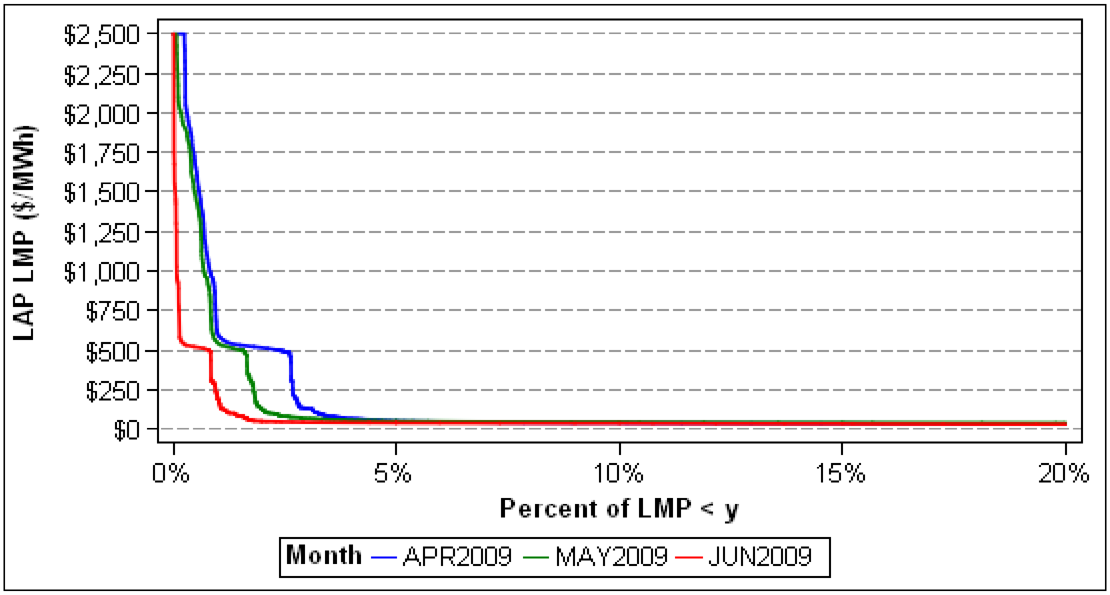


Figure 1.16 and Figure 1.17 show the same 20 percentile tails for the RTD LAP LMPs and provide some insights into frequency and magnitude of extreme RTD prices. Figure 1.16 shows that the frequency of extreme prices over $500/MWh has declined steadily from 2.3 percent in April to 1.4 percent in May and to 0.8 percent in June. This improvement is likely due to various enhancements the ISO has made to the real-time market such as improvements in the accuracy of the RTD load forecasts and in the use of load and transmission limit biasing. Additionally, many of the planned generation and transmission outages that were driving some of the price volatility in April and May were completed in June.

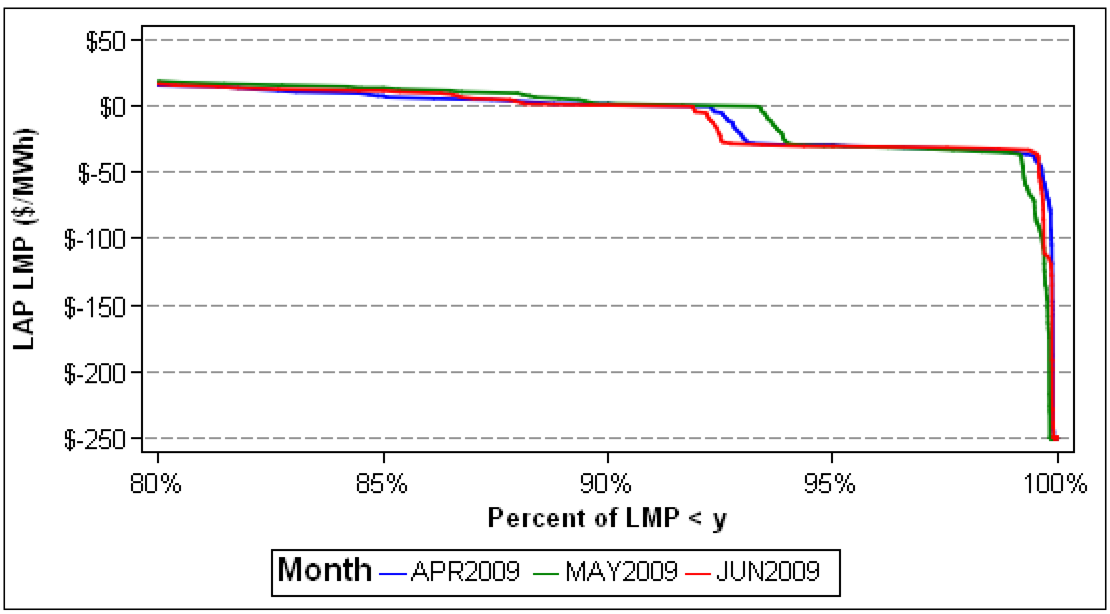
4 Prices represented in the chart are truncated at -$250 on the lower bound in order to scale the chart in a way that reveals differences in the monthly price distributions. The lowest values for the three months are -$2,413 for April, -$2,500 for May, and -$2,500 for June.

Figure 1.16 Duration Curve of RTD LAPs (High 20 Percentile)



For lower prices, Figure 1.17 shows that there has been little change in the lower five percent of prices over the three months, where four percent are at -$30/MWh and the lowest one percent of prices drop down further (figures are capped at -$250 to accommodate readable chart scaling).

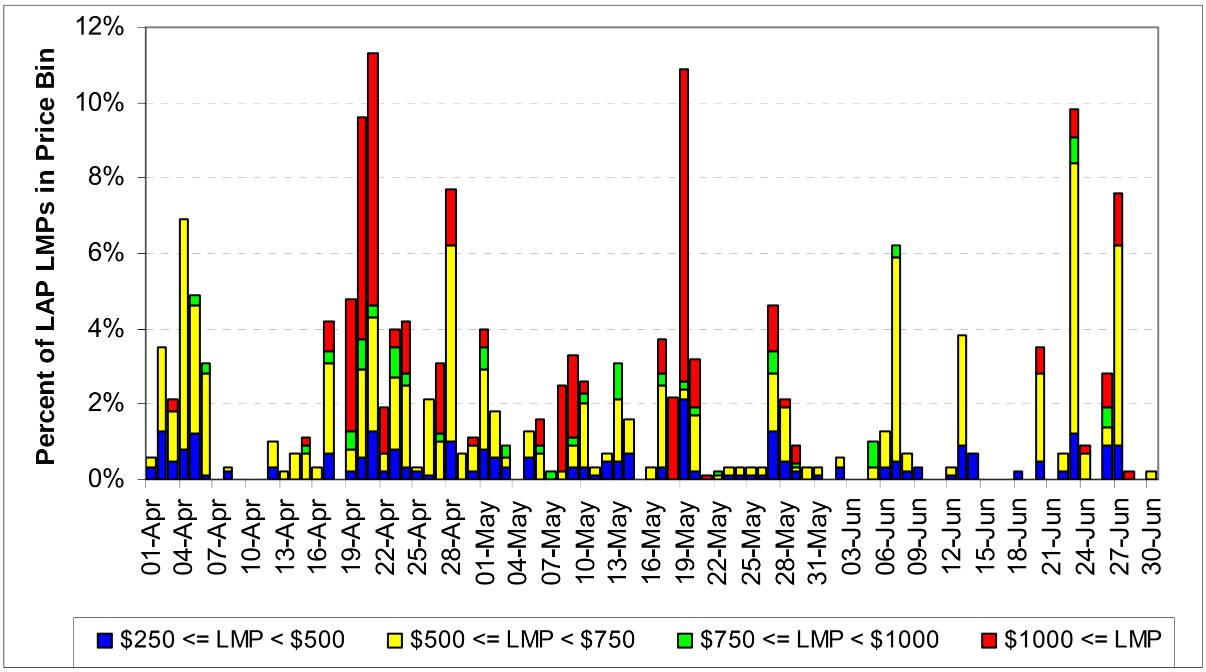
Figure 1.17 Duration Curve of RTD LAPs (Low 20 Percentile)[5]



[5] Prices represented in the chart are truncated at -$250 on the lower bound in order to scale the chart in a way that reveals differences in the monthly price distributions. The lowest values for the three months are -$1,996 for April, -$1,983 for May, and -$1,638 for June.

Figure 1.18 below shows the daily frequency of high prices, by price level, for RTD LAP LMPs. Fewer extreme prices (>= $1,000/MWh in red) occurred in late May through June. Also notable is the increase in June in the number of days where there were no high prices compared to April and May. As previously noted, some of the factors contributing to a decline in the frequency of extreme price spikes include 1) various improvements to real-time operation practices and input data[6] and 2) a reduction in scheduled generation and transmission outages, which reduced the frequency and severity of congestion.

Figure 1.18 RTD Positive LAP Price Spike Frequency



Conversely, we have seen an increase in negative LAP prices in June, driven primarily by imbalance and ramping issues in the morning off-peak hours (as discussed earlier in this section).

[6] Some of the specific enhancements to the operation of the real-time market include improvements in load forecasts, particularly the Load Distribution Factors (LDFs) used to distribute the load throughout the load nodes in the network, and improvements in the use of transmission biasing on constraints having market flows that diverge from actual flows. In using transmission biasing, operators are now phasing in the bias more gradually, which helps to reduce incidents of exhausting the 5-minute dispatch capability, which can occur if a binding constraint is biased downward too abruptly.

Figure 1.19 RTD Negative LAP Price Spike Frequency

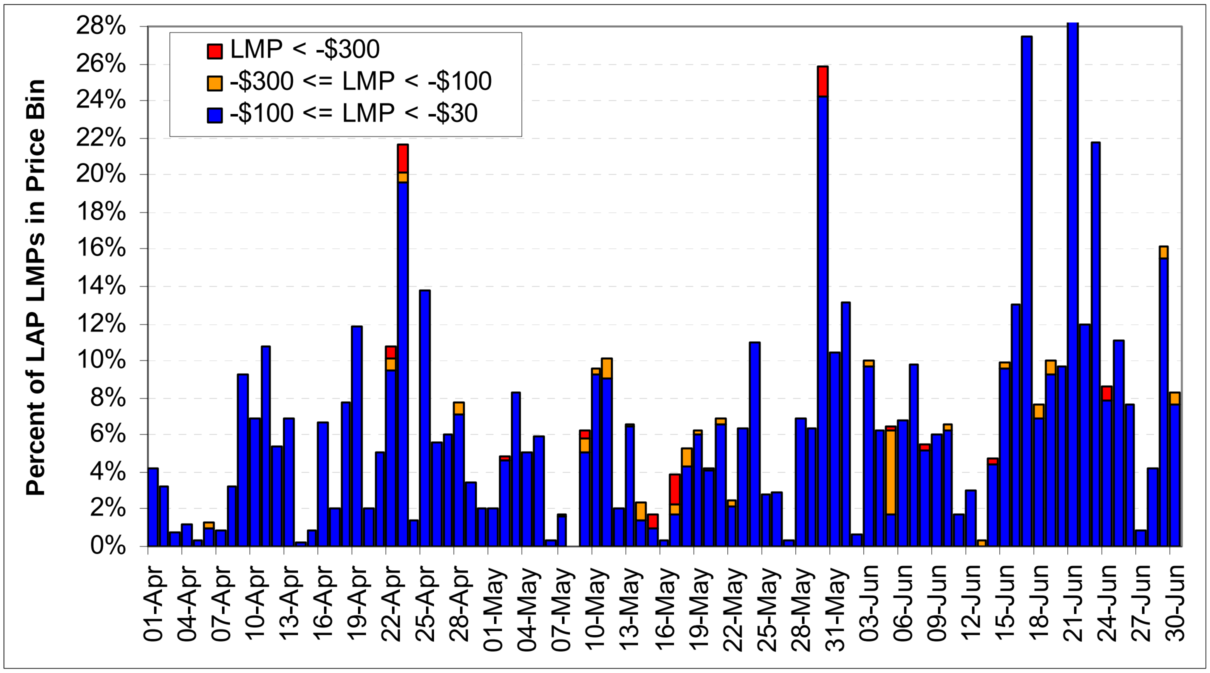
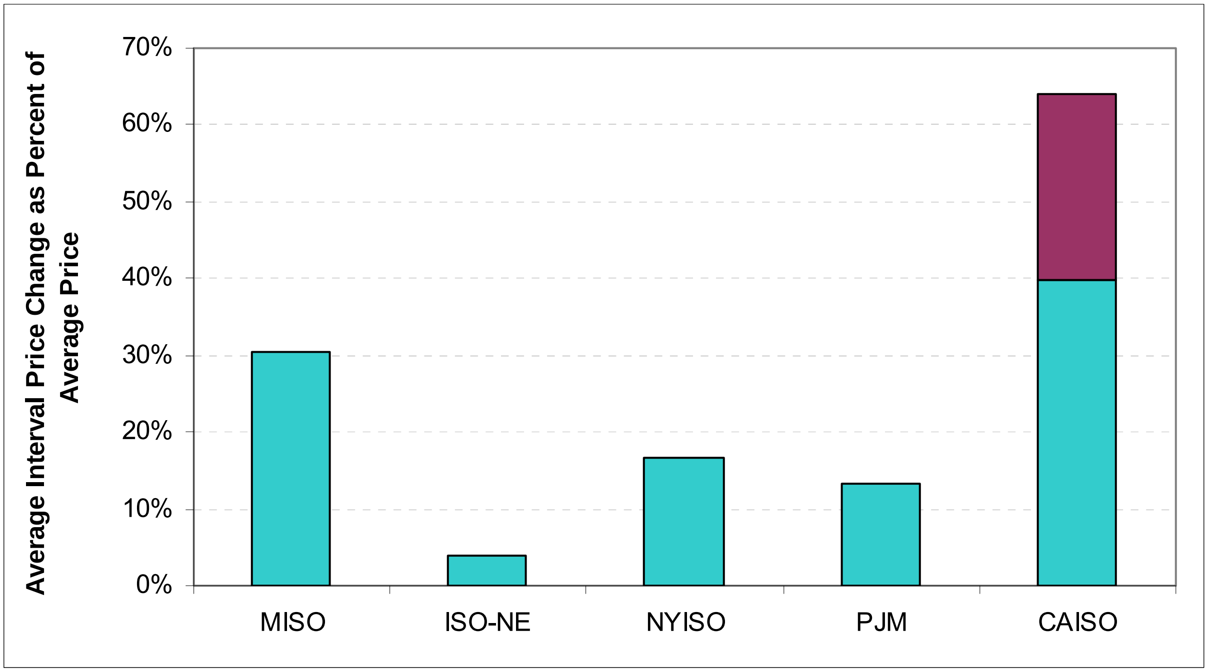


Figure 1.20 provides a different perspective on price volatility, which is to examine the extent to which prices change from one 5-minute interval to the next by calculating the average interval price change (in absolute value) and expressing it as a percentage of the average price. We calculated this metric separately for the three Default LAP prices (SCE, SDGE, and PG&E) and show the average along with a comparison of the same metric for other ISOs.[7] 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 divided into two contributing factors. The purple portion of the bar denotes the contribution to volatility of extreme or outlier prices, those outside the -$40/MWh to $550/MWh range,[8] The outlier contribution is roughly 24 of the total 64 percent for the volatility metric. The blue portion of the bar shows the contribution of prices within the "normal" range to the volatility metric, 40 of the total 64 percent.

[7] The data shown for other ISOs are from the 2007 State of the Market Report for the Midwest ISO, prepared by Potomac Economics. The metrics for the other ISOs is calculated using several hub prices for each ISO – see Figure 35, page 46 of the report.
(http://www.potomaceconomics.com/uploads/midwest_presentations/2007_State_of_the_Market_Report-Full_Text_07-08.pdf).

[8] These values were chosen to reflect the current minimum and maximum bid limits of -$30 and $500 plus some additional margin to account for losses and potential congestion impacts on the LMP.

Figure 1.20 Real Time LAP Price Volatility across ISOs



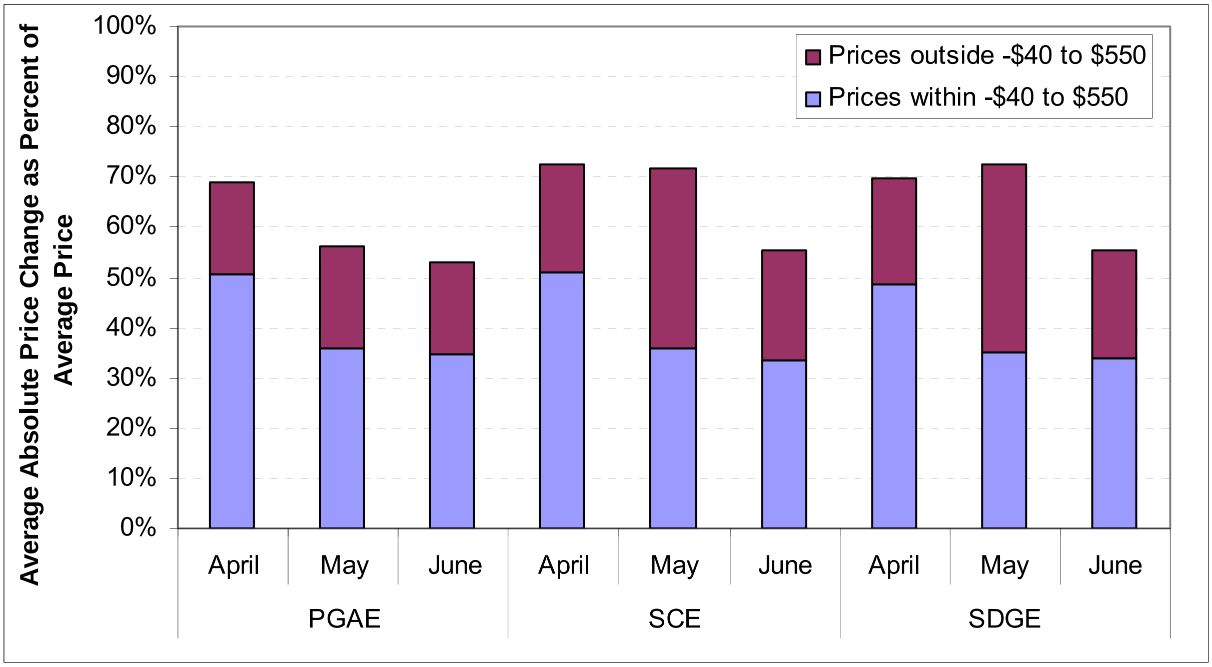
As evident in Figure 1.20, the interval-to-interval volatility of the California ISO 5-minute prices for the first three months of the new market is substantially greater than what has been observed in other ISOs. Comparing price volatility in the nascent California ISO market to price volatility in more mature LMP markets may not be a fair comparison but it nonetheless provides some important context and basis for gauging future trends. Moreover, differences in observed interval-to-interval price volatility across various ISOs are likely due to important differences in particular aspects of each ISO's real-time market design and optimization features as well as differences in market characteristics such as dependency on inter-tie schedules, daily load profiles, and internal resource mix. In light of these factors, we do not view the comparison of price volatility shown in Figure 1.20 as a simple "less is better" exercise. Instead, it should be used as a basis for examining what aspects of the California ISO real-time market design are contributing to higher price volatility and assessing whether these features are desirable or need to be modified in some fashion. [9]

The same volatility metric is presented in Figure 1.21 below for the three LAP areas separately by month. Focusing on the contribution of prices within the "normal" range, the level and trend from April through June are similar across the three LAPs. May and June are lower compared to April and are roughly equal to each other at 35 percent. Also, while the total volatility measure drops in May in the PG&E LAP area, it does not drop in either the SCE or SDGE LAP areas. This is due to Path 26 congestion that occurred more frequently in May, separating the southern LAPs from the PG&E LAP and creating more frequent extreme real-time prices in the

[9] For example, different ISOs have different means for utilizing energy from regulation reserves to manage periodic shortages of ramping energy. Many of the price spikes occurring in the ISO's 5-minute dispatch market (RTD) are due to shortages of ramping energy and therefore comparing how RTD utilizes energy from regulation reserves to practices in other ISOs might reveal opportunities for market enhancements that could appropriately reduce price volatility. In other cases, there may be differences in the California ISO real-time market design that produce greater price volatility but are desirable.

two southern LAP areas. The SCE and SDGE volatility measures do drop in June as those LAP prices were impacted less by high shadow values on Path 26.

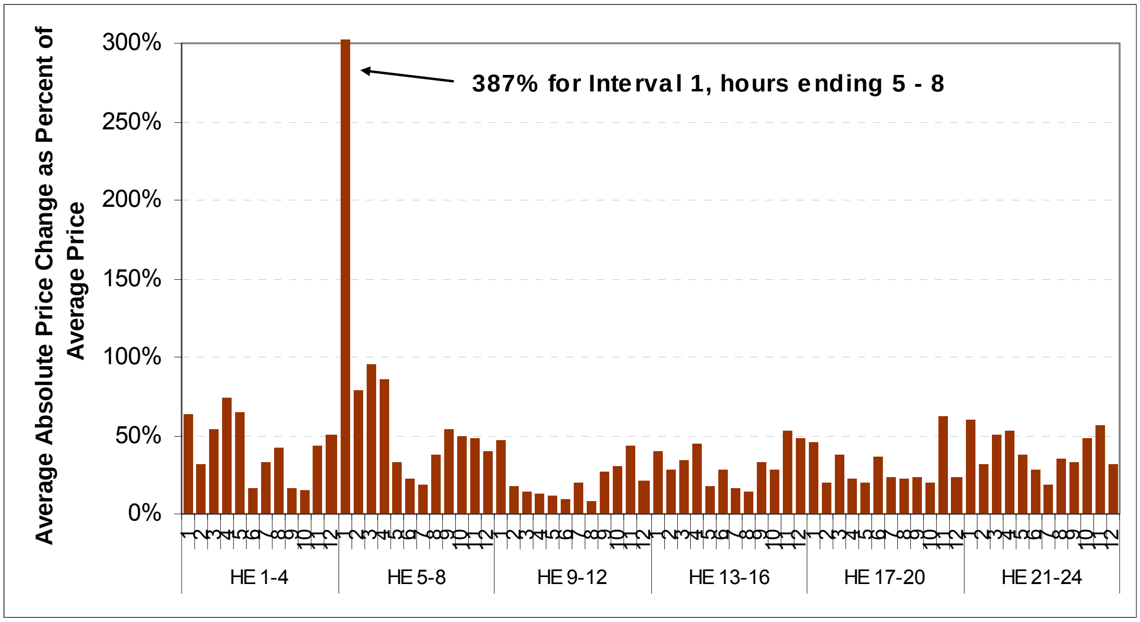
Figure 1.21 ISO Real Time Price Volatility by Month



Focusing on the volatility metric for the "normal" price range, the blue bars in Figure 1.21, ISO real-time prices exhibit a high level of interval-to-interval volatility. Looking at average volatility across the day, by interval, shows that much of the volatility shown in Figure 1.20 and Figure 1.21 is driven by prices in the morning hours. This is shown in Figure 1.22, which presents the same interval-to-interval volatility measure averaged for each 5-minute interval within a time period across the month of April. Prices used in Figure 1.22 through Figure 1.24 are RTD DLAP LMPs, with outlier prices removed to focus on volatility within the more normal price range.[10] Two characteristics of price volatility can be seen in this chart: volatility is higher in the morning hours and in the shoulder intervals within the hour. In April, the greatest single contributor to real-time price volatility was the first interval of hours-ending five through eight. This block of hours captures the change in direction in load ramp, where load is ramping down in hour-ending five and is ramping up by hour-ending eight. A primary driver of volatility in this interval, passing from the last interval of one hour to the first interval of the next hour, is the impact of inter-hour ramping of inter-tie schedules that all occur from ten minutes before the hour to ten minutes into the hour. This ramp schedule can result in a shift in imbalance from negative to positive and have a pronounced impact on imbalance prices in these four shoulder intervals.

[10] Any single volatility calculation where one or both of the interval prices was outside the range -$40/MWh to $550/MWh was removed from the final average presented in Figure 1.22 through Figure 1.24.

Figure 1.22 SCE LAP Real Time Price Volatility by Interval[11] (April)



There is no one interval that stands out in May as the primary driver of overall volatility; however, as seen in Figure 1.23 there is higher volatility in the morning hours compared to the rest of the day. For the remaining afternoon and evening hours, interval-to-interval price volatility in the real-time market was lower in May compared to April (also evident in the monthly averages presented in Figure 1.21).

[11] Excludes pricing intervals with LMPs less than -$40 or greater than $550.

Figure 1.23 SCE LAP Real Time Price Volatility by Interval[12] (May)

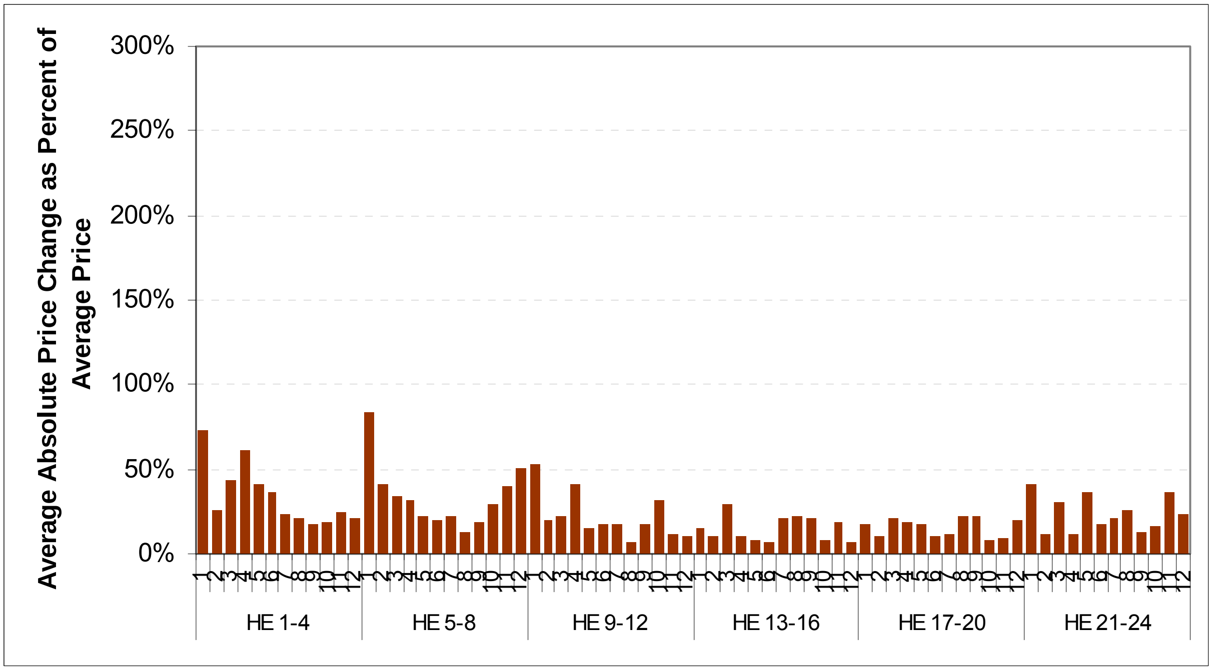
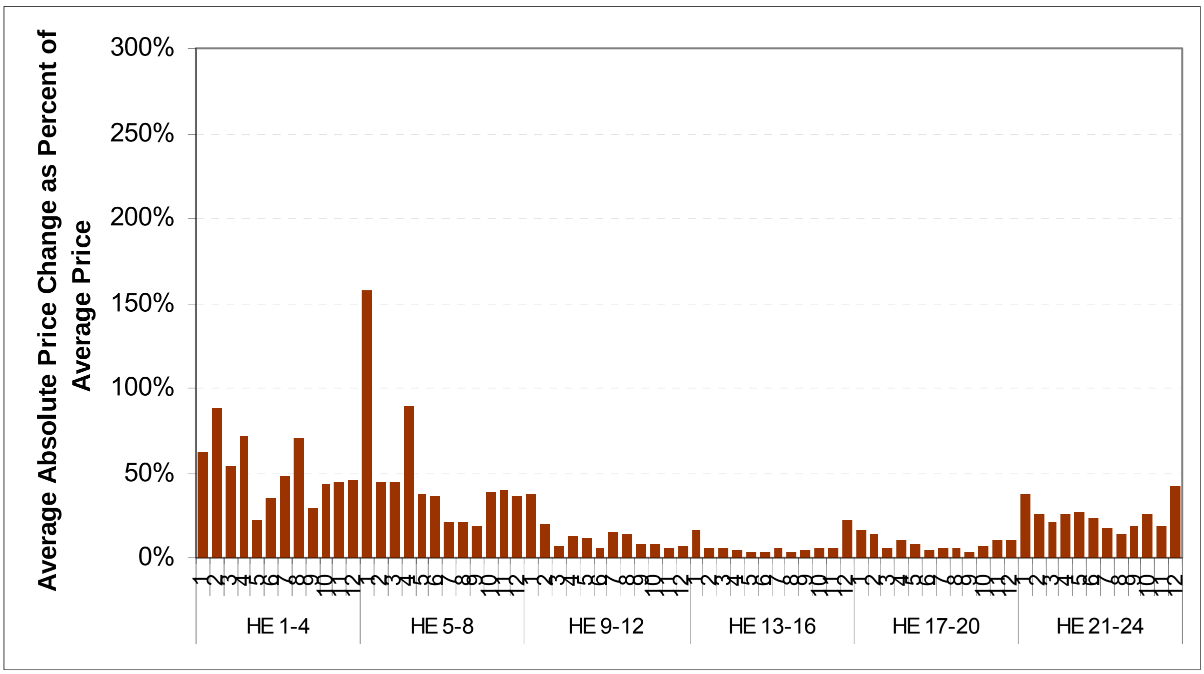


Figure 1.24 SCE LAP Real Time Price Volatility by Interval[13] (June)



[12] Excludes pricing intervals with LMPs less than -$40 or greater than $550.
[13] Excludes pricing intervals with LMPs less than -$40 or greater than $550.

In summary, this analysis shows that price volatility in the California ISO's real-ime market did improve in June relative to April and May. Specifically, RTD LAP prices in June showed a much tighter price distribution with fewer extreme prices. However, price volatility from one 5-minute interval to the next is found to be much higher than what is observed in other ISOs. We will be working with the ISO to conduct further analysis of this observation and consider potential options for addressing it.

2 Market Competitiveness and Mitigation

This section provides an assessment of the overall competitiveness of the ISO's Integrated Forward Market (IFM) and the effectiveness of the local market power mitigation (LMPM) provisions included in the ISO's new market design. In future quarterly reports, DMM will refine these metrics and include additional metrics and analysis of competitiveness and mitigation in the real-time market.

This section begins with a review of market competitiveness beginning with an analysis comparing actual market outcomes with simulated competitive benchmarks. We then examine the frequency and volume of bid mitigation. This is followed by an assessment of mitigation differences when the LMPM is based on bid-in demand as opposed to forecasted demand. Next, we examine the frequency and impact of LMPM failures during the Hour Ahead Scheduling Process (HASP). We conclude with an analysis of cases where high unmitigated bids were dispatched in the real-time market.

2.1 Competitive Benchmark

To assess the competitiveness of the day-ahead market, DMM runs two simulations using its standalone copy of the IFM software. The first run is a re-run of the IFM using data for the applicable IFM Saved Case, or the ISO's archive of market and system inputs and settings that were saved after completion of the final IFM market run. Results of this initial re-run are benchmarked against actual market results to validate that the DMM standalone system is accurately reproducing results of the actual market simulation software.[14] In cases where the standalone system does not produce comparable results, results for these days are excluded from the analysis.[15]

The second run of the standalone IFM software is designed to represent a perfectly competitive scenario which provides a *competitive benchmark* 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.[16] This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs. The

[14] Results of the market simulation software and DMM's standalone 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.

[15] Results were excluded for 6 out of 30 days in April; 8 out of 31 days in May; and 10 out of 30 days in June. DMM's goal is for 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.

[16] 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).

percentage difference between actual market prices and prices resulting under this competitive benchmark scenario represents the *price-cost markup* or *competitive baseline 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 2.1, Figure 2.2 and Figure 2.3 show monthly summary results of this competitive baseline analysis for each of the three LAPs in the system. The light yellow bar (left axis) represents the weighted average price for each LAP for the days that were re-run using actual IFM market inputs (IFM Actual). The darker blue line (left axis) shows the weighted average price for each LAP for these same days based on the re-run performed using DEBs for gas-fired generation (Competitive Baseline). The red line in each figure (right axis) represents price-cost markup, or the percentage difference between actual prices and the prices under the competitive baseline. As illustrated in these figures:

- In April, the monthly IFM competitive index across the three LAPs is between -3 and -5 percent.
- In May, the price-cost markup averaged about -1 percent across all three LAPs.
- During June, the average markup ranged from -1 to +1 percent across the three LAPs.

Overall, the competitive index indicates that monthly LAP prices are within competitive ranges for the first three months of the ISO's new market. The slightly negative price-cost markups during April and May can be largely attributed to large amounts of self scheduling of generation during the initial months of the new market, and the fact that many generators bid slightly below their DEBs. In addition, it should be noted that since cost-based DEBs include a 10 percent adder above fuel and variables costs, these relatively small negative mark-ups are not indicative of uncompetitively low prices. Rather, these lower market prices simply reflect the fact that actual bids for many units cover fuel and variables costs, but do not include the full additional 10 percent multiplier included in DEBs.

Meanwhile, the decrease in average cost from May to June in both the actual IFM and the competitive baseline scenario results can be explained primarily by a decrease in spot market prices for natural gas during this period. During June, spot market prices for gas averaged about 13 percent less than in May (about $3.40/mmBtu in June compared to $3.90/mmBtu in May), while actual IFM prices during the days included in the competitive baseline analysis dropped about 21 percent (about $25/MW in June compared to about $32/MW in May).

Figure 2.1 PG&E LAP Competitive Baseline Index (April – June, 2009)

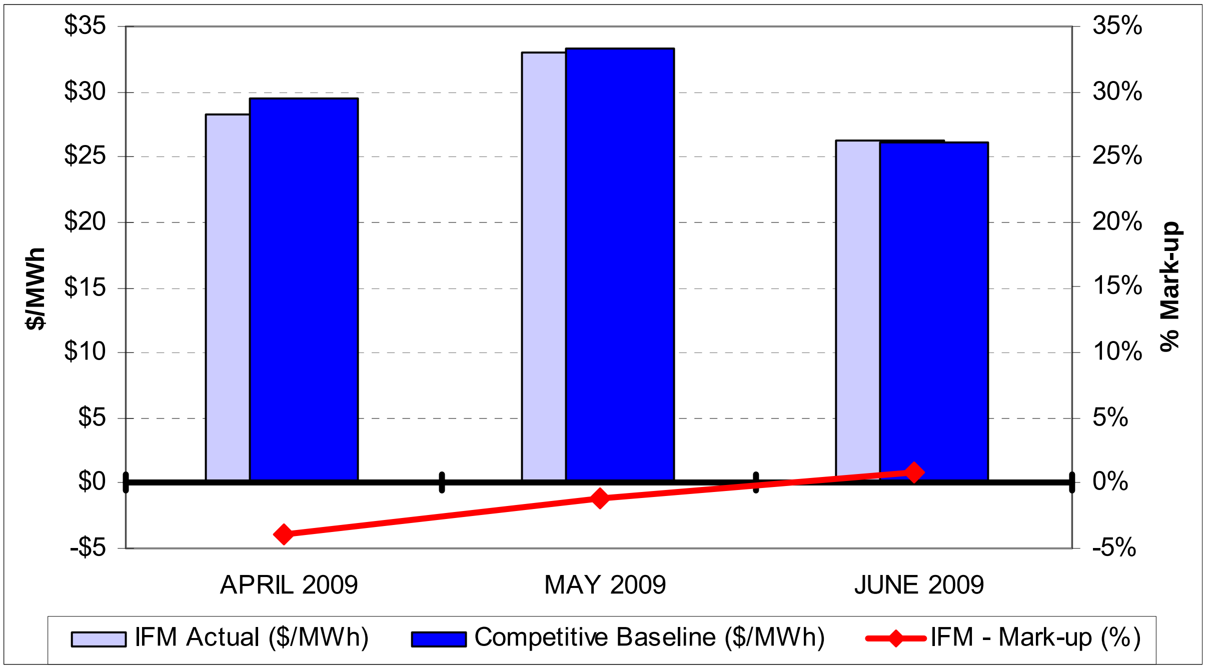


Figure 2.2 SCE LAP Competitive Baseline Index (April – June, 2009)

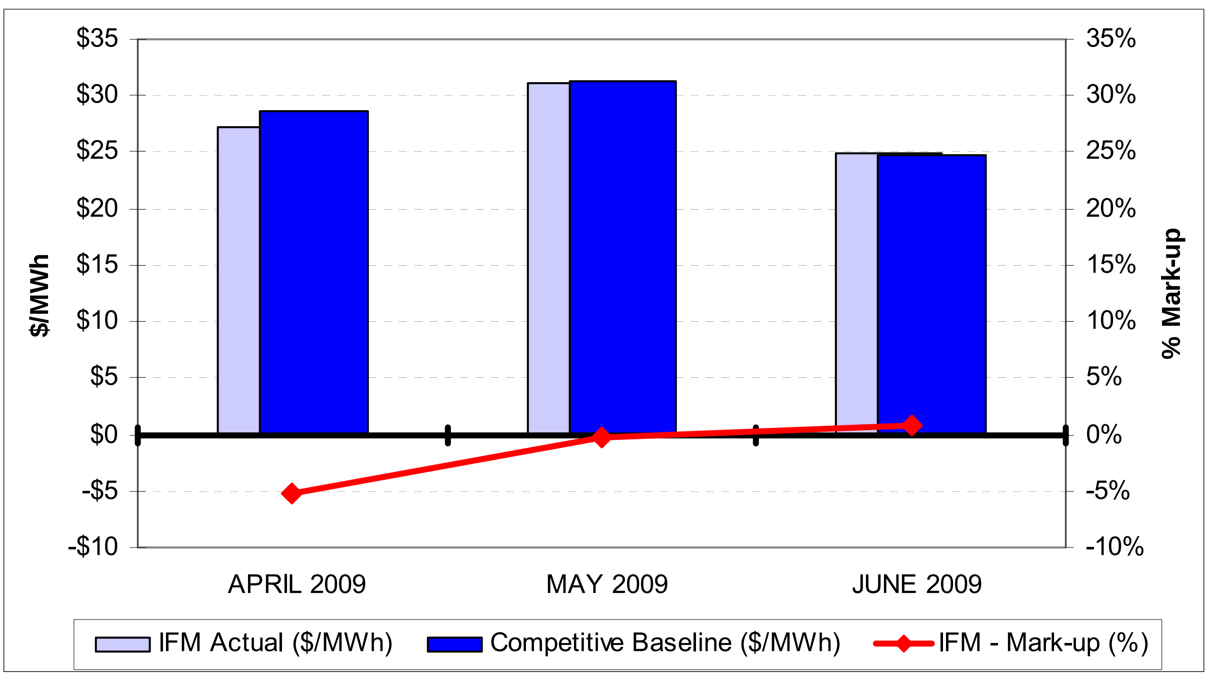


Figure 2.3 SDGE LAP Competitive Baseline Index (April – June, 2009)

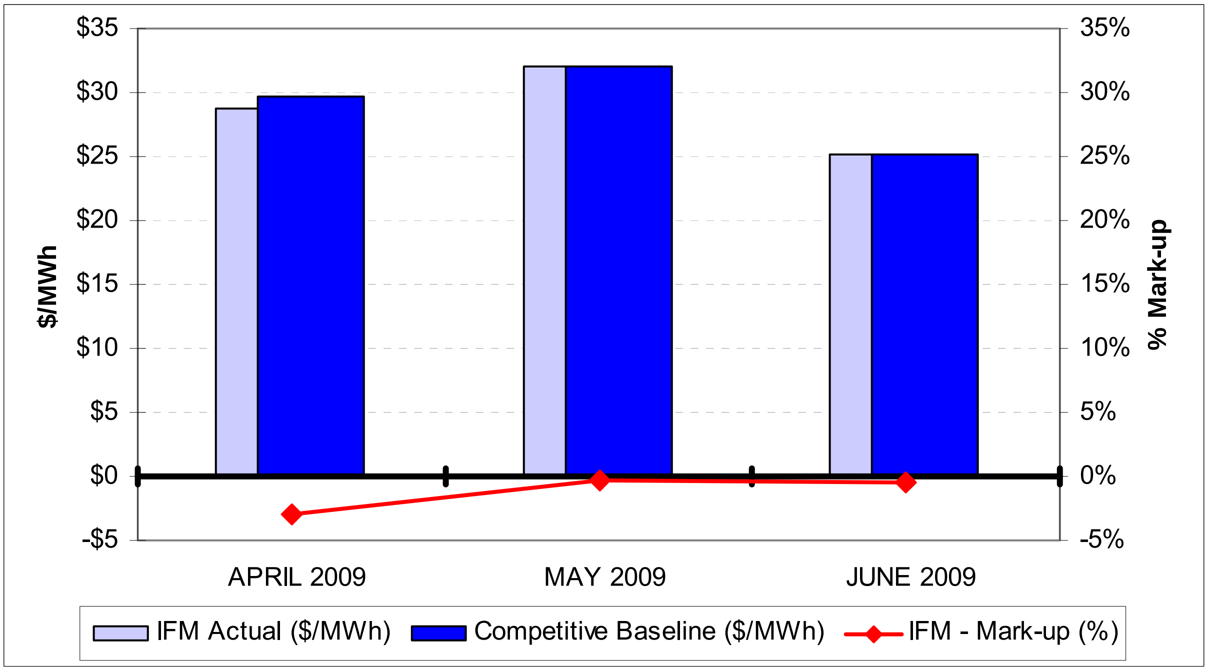
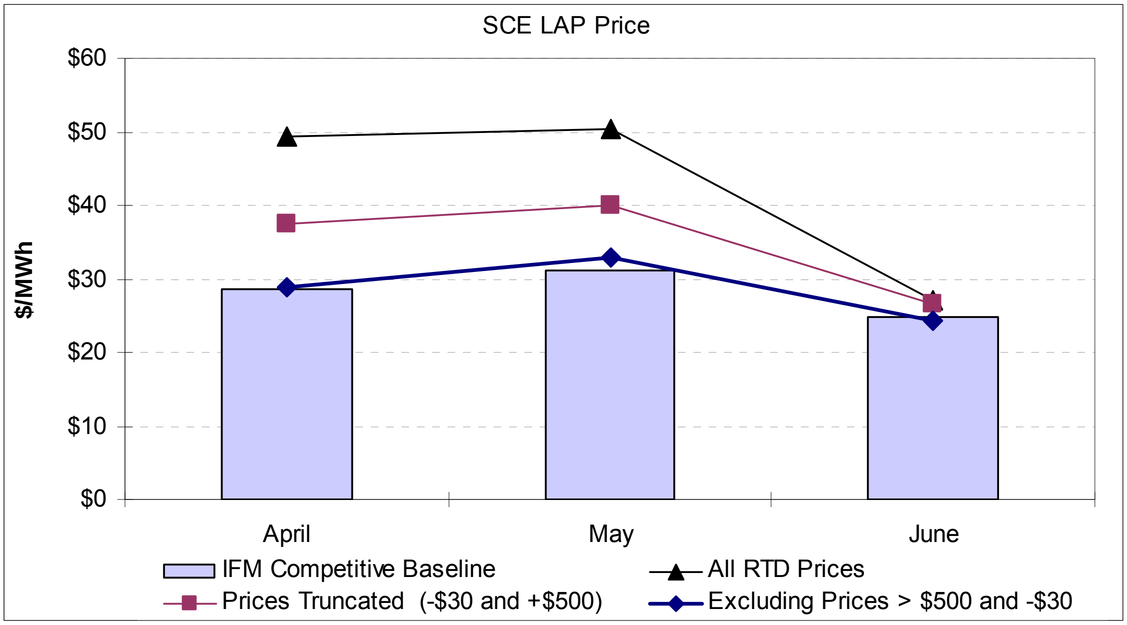


Figure 2.4 compares the SCE LAP competitive baseline price to three different averages of 5-minute real-time SCE LAP prices. It shows that when extreme 5-minute prices are excluded (prices greater than $500 or less than -$30), average real-time prices for each of the three months are essentially equal to the competitive baseline estimate. For purposes of this comparison, DMM believes it is appropriate to exclude such extreme prices on the grounds that they reflect 5-minute operating constraints that cannot be captured in the competitive baseline estimate, which is produced using the day-ahead market software. Figure 2.4 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 (purple line), and a second comparison that includes all 5-minute prices with no prices excluded or truncated (black line). As shown in Figure 2.4, these other two comparisons were significantly higher than the competitive baseline in April and May, then converged to the competitive baseline in June. This convergence reflects the fact that there were much fewer extreme prices in June.

Figure 2.4 Comparison of SCE LAP Competitive Baseline to Real Time Prices



2.2 Frequency and Volume of Bid Mitigation in IFM

As noted in the previous section, bidding by most generation resources has been highly competitive during the first three months of the ISO's new market design. As a result, the frequency and volume of bid mitigation occurring under the LMPM provisions of the ISO's new market have been relatively limited during each of these three months.

Figure 2.5 illustrates how the LMPM procedures are applied to a unit's IFM bid curve under the ISO's new market design. Prior to the IFM, the ISO's software is first run with only Competitive Constraints (CC) enforced. The CC run is performed by clearing unmitigated market bids with the ISO's day-ahead forecast of demand. A second run is then performed with All Constraints (AC) enforced. Units which are dispatched at a higher level in this AC run than in the first CC run are subject to bid mitigation. As illustrated in Figure 2.5, the unit's initial market bid is subject to mitigation since its dispatch in this second AC run (Q_{AC}) is greater than its dispatch in the first CC run (Q_{CC}). The unit's highest market bid dispatched in the CC run is used as a *floor* below which the unit's bid is not mitigated, even if this exceeds the unit's DEB (e.g., see the unit's final mitigated bid for capacity up to Q_{CC} in Figure 2.5). The unit's bid curve is only mitigated (i.e., lowered) to the extent that its market bid exceeds the maximum of this bid floor or the unit's DEB for energy above the unit's dispatch level in the CC run. This final mitigated bid is then used in the IFM. A similar LMPM process is performed prior to the real-time market during the HASP process.

Figure 2.5 and Figure 2.6 also illustrate several different metrics developed by DMM to assess the degree of bid mitigation occurring under these LMPM procedures.

- **Units With Market Bids Lowered Due to Mitigation.** As shown in Figure 2.5, the total quantity of a unit's initial unmitigated market bid that can potentially be lowered as a result of LMPM procedures extends from the unit's highest bid dispatched in the CC run (Q_{CC}) up to the unit's maximum bid capacity (Q_{Max}). However, in a substantial number of cases, bids for units subject to mitigation may not actually be lowered. One reason this can occur is that the highest priced unmitigated bid dispatched in the CC run (P_{CC}) is used as a *floor* below which other market bids are not lowered. In addition, this can occur since units may bid at or below their DEBs.

- **Bids from Mitigated Units Dispatched in IFM.** As shown in Figure 2.5, even if a unit has the bid price for a portion of its initial market bid curve *lowered* due to mitigation, only a portion of these bids may be dispatched in the IFM. Thus, a second measure of the degree to which mitigated bids may be dispatched in the IFM is to calculate the incremental amount that each unit having its bid curve lowered through LMPM procedures is actually dispatched in the IFM. As illustrated in Figure 2.5, this quantity is calculated based on the difference between each unit's dispatch in the CC run (Q_{CC}) and its actual IFM schedule (Q_{IFM}).
- **Increase in Dispatch due to Mitigation.** Finally, as shown in Figure 2.6, the actual increase in a unit's dispatch due to bid mitigation can be assessed even more precisely by estimating the portion of the unit's capacity that would have cleared the IFM if its bid had not been mitigated. In Figure 2.6, it is assumed that the unit's dispatch in the IFM (Q_{IFM}) is greater than its dispatch in the CC and AC runs due to the fact that its final mitigated bid used in the IFM is lower than its initial market bid. The increase in the unit's IFM schedule due to mitigation can be approximated by calculating the portion of the unit's initial unmitigated bid curve with a bid price equal to or lower than the clearing price in the IFM (Q_U). The difference between this level (Q_U) and its actual IFM schedule (Q_{IFM}) provides an indication of the magnitude of the actual impact of bid mitigation given actual IFM prices and the degree to which the unit's initial market bid was actually mitigated (lowered).[17]

Table 2.1 through Table 2.3 summarize the three various metrics described above in terms of system-wide hourly averages during each operating hour for the first three months of the ISO's new market design. Figure 2.7 provides a graphical comparison of these metrics in terms of monthly average for peak hours (HE 7 – 22). The bars in Figure 2.7 show the average number of non-RMR units in the ISO system having some portion of the market bids lowered due to LMPM each month (left axis), while the lines plot the average increase in capacity scheduled in the IFM from these units attributable to this bid mitigation (right axis). As shown in these results, the degree of mitigation has been relatively low in each of the first three months of the ISO's new market design. Specifically:

- During peak hours, only about 66 percent of units subject to mitigation actually have a portion of their bids *lowered* due to mitigation.[18]
- The number of units having some portion of the market bids lowered due to LMPM during peak hours averaged about 1.4 units in April, about 1.9 units in May, and less than one unit in June (.85).

[17] In practice, the unit's bid price at its actual dispatch level in the IFM (Q_{IFM}) can be lower than the unit's bid price due to the fact that the IFM is a 24-hour optimization. This could also create situations where the amount of the unit's unmitigated bid curve below the IFM price was less than the unit's dispatch in the CC run. To avoid any overestimation of the impacts of mitigation that could result from these conditions, the estimated dispatch of the unit with unmitigated bids was constrained to be not less than its dispatch in the CC run ($Q_U \geq Q_{CC}$). The net effect of this constraint is to simply prevent the measure of the increase in dispatch due to mitigation during any hour (Q_{IFM} - Q_U) from exceeding the actual increase in the unit's final IFM schedule over the unit's dispatch in the CC run based on its unmitigated bids (Q_{IFM} - Q_{CC}).

[18] Percentage based on average number of units subject to mitigation over all peak hours in April – June, 2009 (2.10), compared to average number of units with bids actually lowered due to mitigation during these hours (1.38).

- The increase in capacity scheduled in the IFM from these units that may be attributable to this bid mitigation averaged 52 MW in April, 73 MW in May, and just 32 MW during peak hours in June.

Figure 2.5 Bid Mitigation

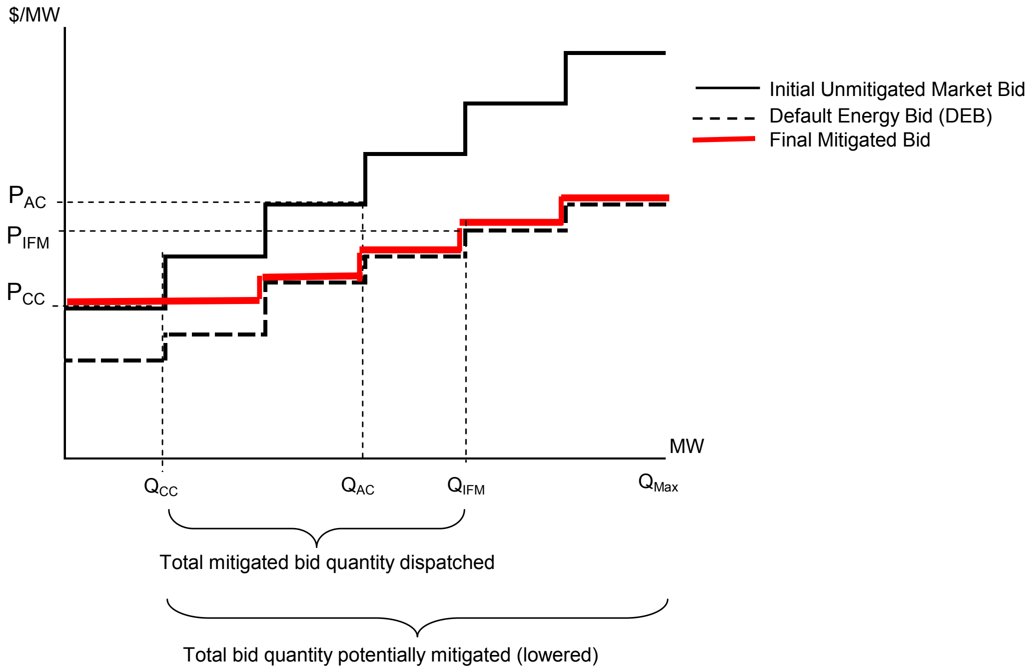


Figure 2.6 Measuring Impact of Bid Mitigation

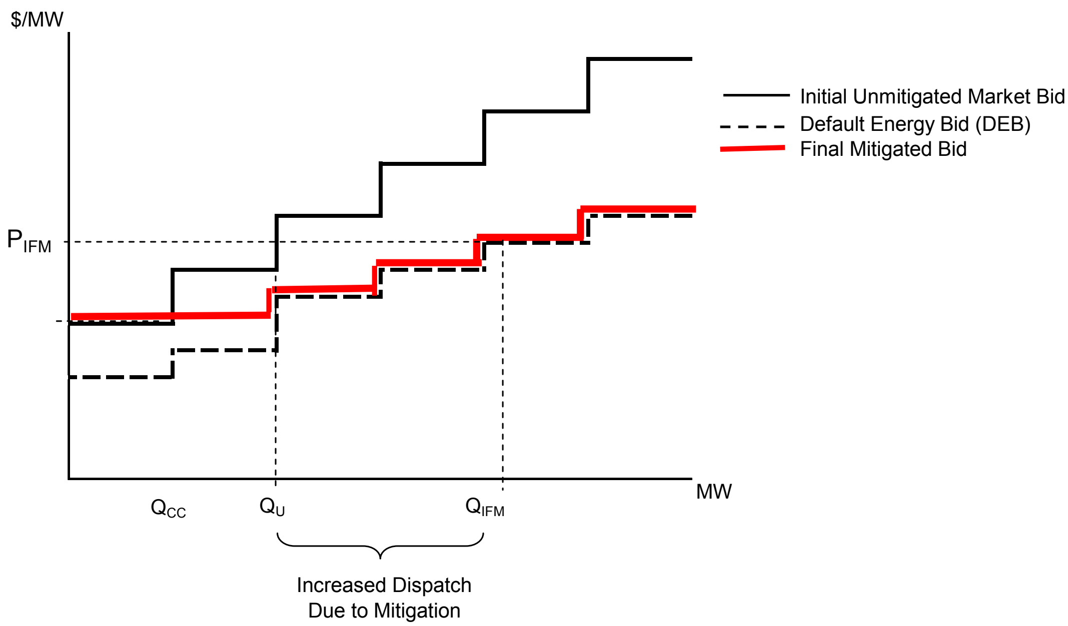


Table 2.1 Summary of IFM Bid Mitigation – April 2009 (Hourly Averages)

	Units Subject to Mitigation [1]	Units with Market Bids Mitigated (Lowered)		Potentially Mitigated Bids Dispatched [4]	Increased in Dispatch Due to Mitigation [5]
Hour	$Q_{AC} > Q_{CC}$	Units [2]	$Q_{MAX} - Q_{CC}$ [3]	$Q_{IFM} - Q_{CC}$	$Q_{IFM} - Q_{U^*}$
1	1.37	1.00	189	35	32
2	1.17	.90	176	34	31
3	1.23	1.03	190	33	33
4	1.43	0.97	167	37	34
5	1.63	1.07	182	33	33
6	1.93	1.30	245	43	42
7	1.83	1.17	224	46	41
8	2.17	1.57	270	53	49
9	2.17	1.53	253	61	55
10	2.33	1.57	235	65	50
11	1.83	1.37	212	82	61
12	2.07	1.33	197	80	63
13	2.03	1.20	173	71	48
14	2.03	1.40	211	75	57
15	2.13	1.43	185	72	49
16	2.27	1.27	178	63	46
17	2.13	1.37	171	64	45
18	2.10	1.43	222	82	50
19	1.57	1.17	174	42	42
20	2.13	1.23	192	62	55
21	2.53	1.47	179	77	61
22	2.33	1.60	286	83	66
23	2.77	1.87	343	68	57
24	1.97	1.57	340	45	43
Peak Avg.	2.10	1.38	210	67	52

Column Descriptions:

[1] Number of units dispatched at higher level in CC run (Q_{AC}) than in AC run (Q_{CC}).

[2] Units = Units with at least some portion of their market bids lowered as a result of mitigation.

[3] The amount of bids subject to mitigation for units having at least some portion of their market bids lowered. Includes the total amount of energy bids from each unit's dispatch in CC run (Q_{CC}) and their maximum bid capacity (Q_{MAX}). Therefore, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[4] The amount of bids that may have been lowered due to mitigation (Column 3) that were dispatched in IFM ($Q_{IFM} - Q_{CC}$). As with the total in Column 3, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[5] The estimated increase in bids dispatched due to bid mitigation. Calculated based on each unit's actual final IFM schedule (Q_{IFM}) and the amount of each unit's initial unmitigated bids with bid price ≤ the IFM price (Q_U).

Table 2.2 Summary of IFM Bid Mitigation – May 2009 (Hourly Averages)

	Units Subject to Mitigation [1]	Units with Market Bids Mitigated (Lowered)		Potentially Mitigated Bids Dispatched [4]	Increased in Dispatch Due to Mitigation [5]
Hour	$Q_{AC} > Q_{CC}$	Units [2]	$Q_{MAX} - Q_{CC}$ [3]	$Q_{IFM} - Q_{CC}$	$Q_{IFM} - Q_{U*}$
1	1.58	1.23	275	28	27
2	1.61	1.19	264	25	25
3	1.26	1.03	204	27	26
4	.97	.71	119	26	26
5	1.35	.94	171	28	27
6	1.35	1.00	175	34	35
7	1.55	1.19	226	61	45
8	1.74	1.23	212	60	46
9	2.06	1.29	231	59	40
10	2.45	1.65	268	74	63
11	2.77	1.74	283	75	66
12	3.48	1.94	262	78	66
13	3.23	1.87	233	86	66
14	3.87	2.45	261	118	90
15	3.71	2.32	240	136	104
16	4.45	2.90	284	156	109
17	4.16	2.65	286	138	104
18	3.45	2.26	264	125	97
19	2.61	1.68	209	75	64
20	2.29	1.71	253	81	74
21	2.94	1.74	230	93	68
22	2.94	1.74	259	90	72
23	2.52	1.71	303	86	57
24	1.81	1.39	281	47	43
Peak Avg.	2.98	1.90	250	94	73

Column Descriptions:

[1] Number of units dispatched at higher level in CC run (Q_{AC}) than in AC run (Q_{CC}).

[2] Units = Units with at least some portion of their market bids lowered as a result of mitigation.

[3] The amount of bids subject to mitigation for units having at least some portion of their market bids lowered. Includes the total amount of energy bids from each unit's dispatch in CC run (Q_{CC}) and their maximum bid capacity (Q_{MAX}). Therefore, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[4] The amount of bids that may have been lowered due to mitigation (Column 3) that were dispatched in IFM ($Q_{IFM} - Q_{CC}$). As with the total in Column 3, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[5] The estimated increase in bids dispatched due to bid mitigation. Calculated based on each unit's actual final IFM schedule (Q_{IFM}) and the amount of each unit's initial unmitigated bids with bid price ≤ the IFM price (Q_U).

Table 2.3 Summary of IFM Bid Mitigation – June 2009 (Hourly Averages)

Hour	Units Subject to Mitigation [1]	Units with Market Bids Mitigated (Lowered)		Potentially Mitigated Bids Dispatched [4]	Increased in Dispatch Due to Mitigation [5]
	$Q_{AC} > Q_{CC}$	Units [2]	Q_{MAX} – Q_{CC} [3]	Q_{IFM} – Q_{CC}	Q_{IFM} – Q_{U} *
1	.37	.17	27	9	9
2	.60	.40	77	11	10
3	.63	.40	83	10	10
4	.83	.60	109	13	13
5	.67	.47	80	9	9
6	.53	.40	67	10	10
7	.57	.40	80	14	14
8	.80	.63	140	24	23
9	1.27	.90	211	27	25
10	1.00	.70	152	35	34
11	.83	.60	141	39	37
12	1.37	.83	168	57	43
13	.93	.70	139	62	55
14	1.27	1.00	186	72	54
15	1.27	.83	131	50	33
16	1.30	.87	102	55	21
17	1.50	1.03	151	55	18
18	1.40	1.03	162	57	26
19	1.30	1.00	169	41	34
20	1.13	1.00	159	37	35
21	0.97	.77	138	38	33
22	1.43	1.30	224	56	32
23	1.03	.80	147	20	18
24	.73	.63	175	24	18
Peak Avg	1.15	.85	153	45	32

Column Descriptions:

[1] Number of units dispatched at higher level in CC run (Q_{AC}) than in AC run (Q_{CC}).

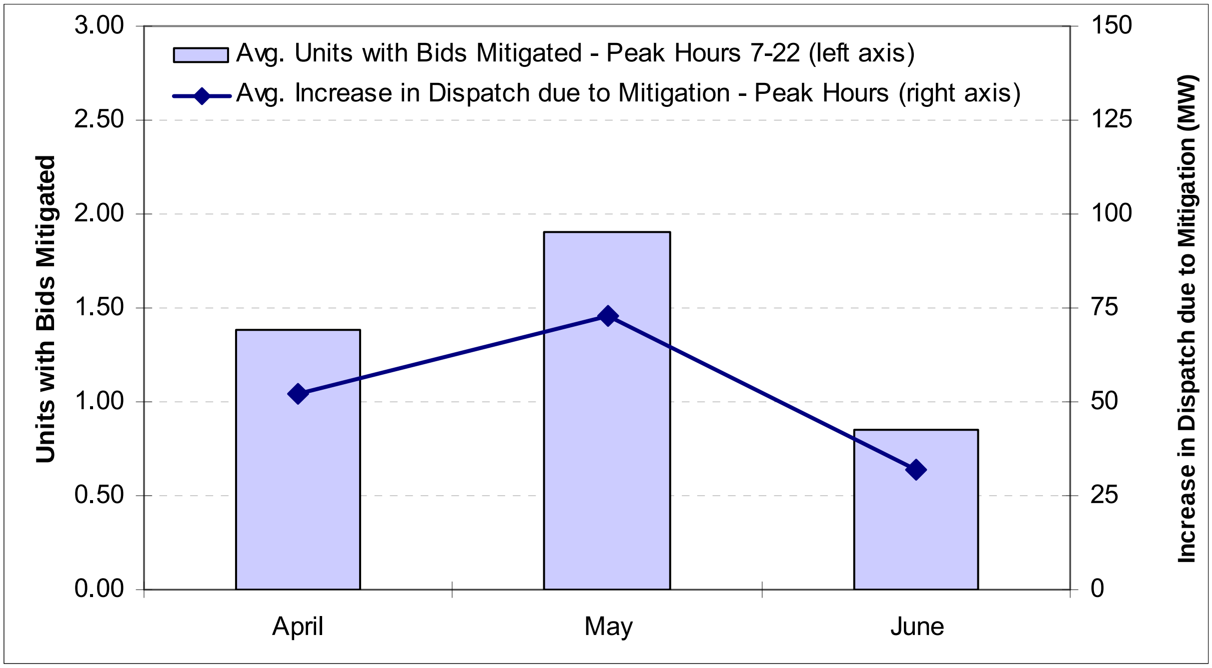
[2] Units = Units with at least some portion of their market bids lowered as a result of mitigation.

[3] The amount of bids subject to mitigation for units having at least some portion of their market bids lowered. Includes the total amount of energy bids from each unit's dispatch in CC run (Q_{CC}) and their maximum bid capacity (Q_{MAX}). Therefore, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[4] The amount of bids that may have been lowered due to mitigation (Column 3) that were dispatched in IFM ($Q_{IFM} - Q_{CC}$). As with the total in Column 3, this includes capacity for which the final mitigated bid price may not have been lower than the initial unmitigated bid price.

[5] The estimated increase in bids dispatched due to bid mitigation. Calculated based on each unit's actual final IFM schedule (Q_{IFM}) and the amount of each unit's initial unmitigated bids with bid price ≤ the IFM price (Q_U).

Figure 2.7 IFM Bid Mitigation – Hours Ending 7-22, April to June, 2009



2.3 Frequently Mitigated Units

The LMPM provisions incorporated in the ISO's new market design also provide the option for a bid adder to be included in cost-based DEBs for resources that are frequently mitigated. Resources that are mitigated in greater than 80 percent of the hours in which they are running are deemed to be Frequently Mitigated Units (FMUs).

The purpose of the FMU bid adder is to provide opportunity for supplemental revenue for recovery of going-forward fixed costs for those resources that are frequently mitigated to their cost-based levels, which may be at or near their marginal cost of production. Since resources with Reliability Must Run (RMR) agreements or full capacity Resource Adequacy (RA) contracts receive revenues for recovery of going-forward fixed costs, these units are not eligible for the FMU bid adder. Units with a portion of their capacity under RA contracts are eligible for a portion of the bid adder based on the proportion of each unit's capacity that is not covered under an RA contract.

The default FMU bid adder is $24/MWh. For units that have some but not all of their capacity contracted under the RA program, the FMU adder is adjusted pro-rata in proportion to the un-contracted capacity.[19] The bid adder, if elected by the FMU, can only be added to their cost-based DEBs. A negotiated option is available also for resources that believe the default of $24/MWh is not accurate in the context of recovering their going-forward fixed cost.[20]

[19] For example, a FMU with 90 percent of its capacity under a RA contract would be eligible for a $2.40 default bid adder.

[20] Section 39.8 of the ISO tariff at http://www.caiso.com/23d5/23d5cd07a480.pdf.

Calculating the Bid Adder Eligibility Criteria

Eligibility for the FMU bid adder is established on a monthly basis according to standard criteria. The Scheduling Coordinator submitting bids for generating units is eligible to have a bid adder applied to a generating unit for the next operating month if the criteria in Section 39.8.1 of the ISO tariff are met.

During the first twelve months after the start of the ISO's new market (April 1, 2009), the *mitigation frequency* used to determined eligibility for the FMU adder will be based on a rolling twelve month combination of data from the ISO's prior market design and this new market design.

- During the period prior to April 1, 2009, RMR and Out-of-Sequence (OOS) dispatches, which were used to manage the local congestion, serve as a proxy for being subject to Local Market Power Mitigation. The generating units' dispatched hours are counted as mitigated hours in their mitigation frequency. Run hours are those hours during which a generating unit has positive metered output.
- For the period after April 1, 2009, the mitigation frequency will be based entirely on a generating unit being subject to mitigation under the MPM-RRD procedures in Sections 31 and 33 of the ISO tariff. If a unit is subject to mitigation in either the IFM or the real-time market (RTM) during any hour, that hour is counted as a mitigated hour in their mitigation frequency. It is important to note that for purposes of this FMU calculation, a unit is considered to be *mitigated* if its dispatch in the All Constraints (AC) run of the market software is greater than the unit's dispatch in the Competitive Constraints (CC) run of the market software. In practice, as discussed in the previous section of this report, during peak hours when mitigation is highest, only about 70 percent of units subject to mitigation actually have a portion of their bids *lowered* due to mitigation (see Table 2.1 through Table 2.3).

Frequently Mitigated Units in Q2 2009

Every month, DMM provides Potomac Economics, an independent entity contracted by the ISO to calculate DEBs, with a list of generating units which have been mitigated in at least 80 percent of their run hours during the last twelve months prior to the next operating month. Potomac Economics uses this information to determine if these generating units are eligible for a $24/MWh adder to their cost-based DEBs.

Figure 2.8 shows the monthly count of FMUs categorized by unit type: RMR, RA, partial RA, and non-RMR/RA units. During each month of the second quarter of 2009, a total of seven units have been mitigated in at least 80 percent of their run hours during the prior twelve month period. In both the months of April and May:

- Five of the seven units that met the mitigation frequency criteria were either under RMR or had all of their capacity under RA contract and thus were not eligible for the FMU bid adder.
- The remaining two resources were relatively small (~50 MW) units with over 96 percent of their capacity contracted under the RA program, so that they were eligible for a very small portion of the $24/MWh default adder (~4 percent).

In June, four resources were eligible for the bid adder:

- As in April and May, the two partial-RA resources eligible for FMU status in June were relatively small units with over 97 percent of their capacity contracted under the RA program, so that they were eligible for a very small portion of the $24/MWh default adder.
- The two non-RA units becoming eligible for FMU status in June were relatively small units, which had been under RA contracts in previous months, but were ineligible for RA status in June due to outages for maintenance scheduled to occur in June. The mitigation frequency of these two units during the first two months of the ISO's new market design (April and May) was actually extremely low (< 1 percent of hours). This indicates that these units had a much higher level of mitigation frequency in the twelve months prior to the start of the ISO's new markets, and that their mitigation frequency has actually dropped substantially during the first few months of the ISO's market design.

In future months, the amount of capacity eligible for the FMU adder will be increasingly determined based on the frequency of mitigation resulting from the ISO's new LMPM procedures. As previously noted, the overall frequency of mitigation has been relatively limited during the second quarter of 2009. This trend is further illustrated in Figure 2.9, which shows the mitigation of the most frequently mitigated generating units, by contract status, during the April to June 2009 period. As shown in Figure 2.9, a total of 15 units were mitigated at least 20 percent of their run hours during the first three months of the ISO's new market design. Seven of these units are RMR units, three are fully contracted under the RA program, and five are partial RA resources.

Figure 2.8 Resources That Exceeded Mitigation Frequency for Prior 12 Months

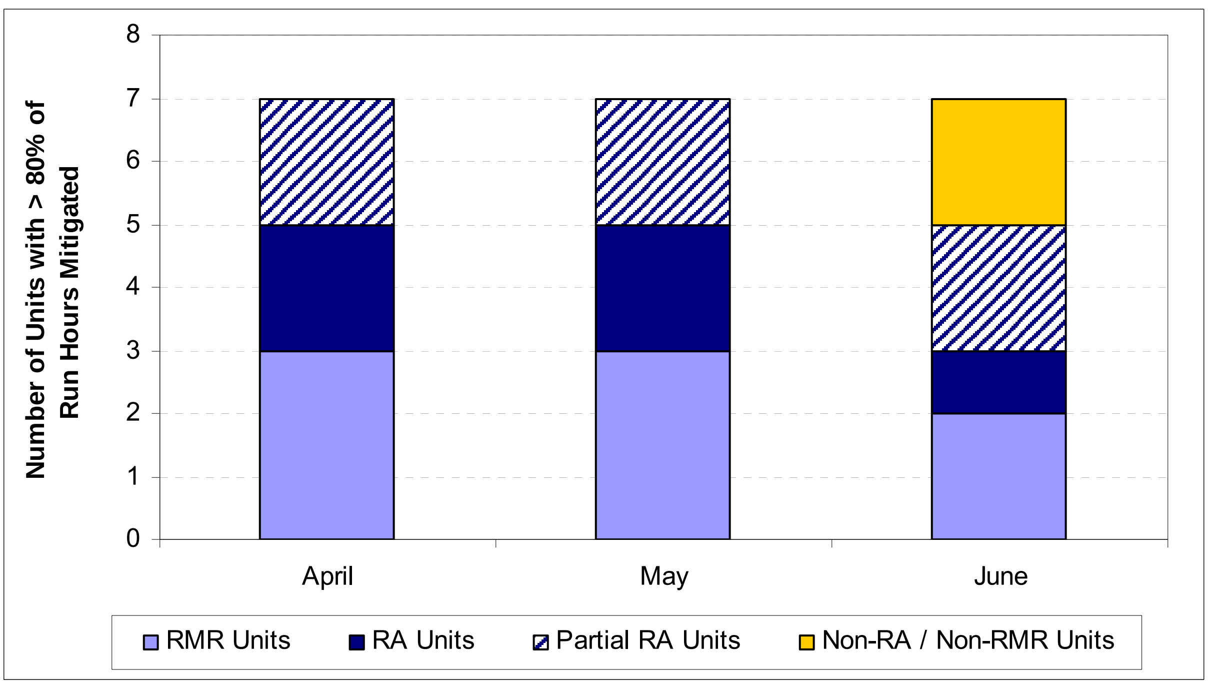
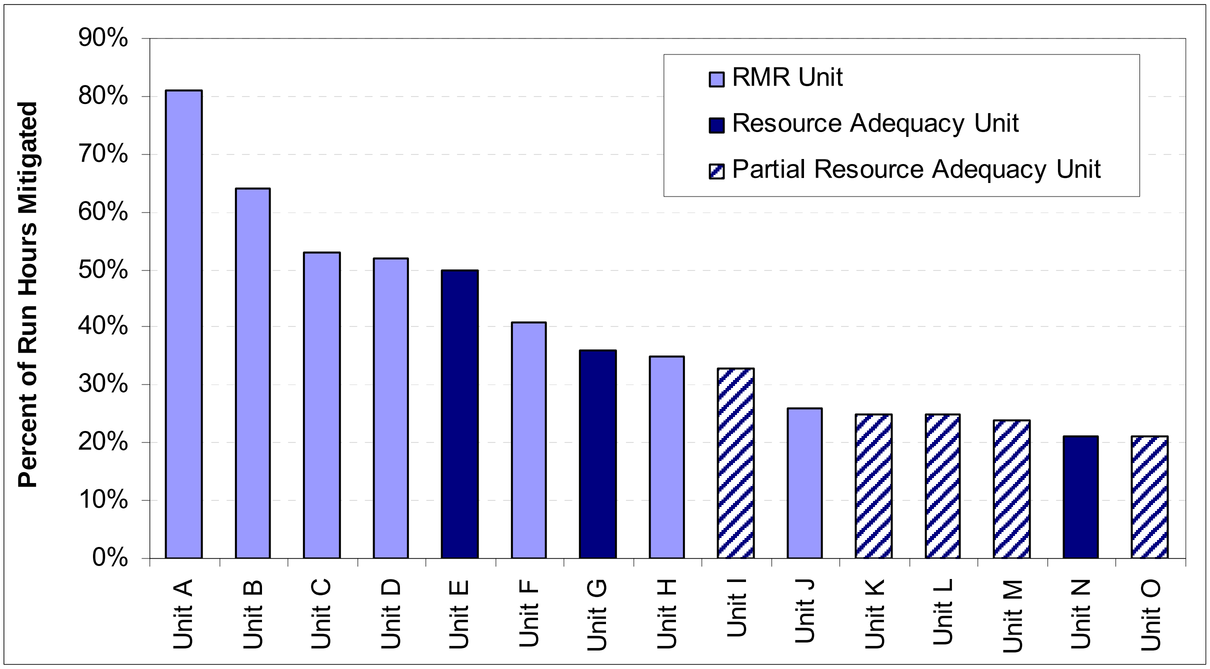


Figure 2.9 Mitigation Frequency of Resources Based on 2009 Q2 Activity



2.4 Mitigation Based on IFM Demand Bids Rather than ISO Forecast

In the ISO's May 2005 MRTU filing with the Federal Energy Regulatory Commission (FERC or the Commission), the ISO proposed to base the pre-IFM MPM runs on its forecast of demand, rather than demand bids submitted to the IFM. The Commission initially approved this approach, but, in its September 2005 Order on Rehearing, later directed the ISO to base the pre-IFM MPM runs on bid-in demand, citing concerns by some stakeholders that use of forecasted demand could result in over-mitigation of supply in the IFM.[21] In a subsequent filing, the ISO requested that the Commission allow the ISO to base the pre-IFM MPM runs on forecasted demand rather than bid-in demand, noting that changing the IFM software to use bid-in demand in MPM could substantially delay implementation of the new market design.

In its September 2006 Order, FERC granted rehearing to allow the ISO to use forecast demand, rather than bid-in demand, for the pre-IFM MPM process, but directed the ISO to develop systems and tariff language so that bid-in demand can be implemented no later than Release 2.[22] In its April 2007 Order, FERC also directed the ISO's market monitor to monitor the effects of market power mitigation in the day-ahead using the ISO's load forecasts instead of bid-in demand, including a comparison with an estimate of what the amount of mitigation would have been with bid-in demand, and include these findings in the ISO quarterly status reports.[23]

As described in Section 2.1, DMM has the capability to re-run the IFM using a standalone copy of Siemens' market simulation software used in the ISO's new day-ahead market. However, the pre-IFM MPM process incorporated in the standalone IFM software cannot be modified by DMM

[21] September 2005 Order, 112 FERC ¶ 61, 310 at 69.

[22] September 2006 Order, 116 FERC ¶ 61, 274 at P 1089.

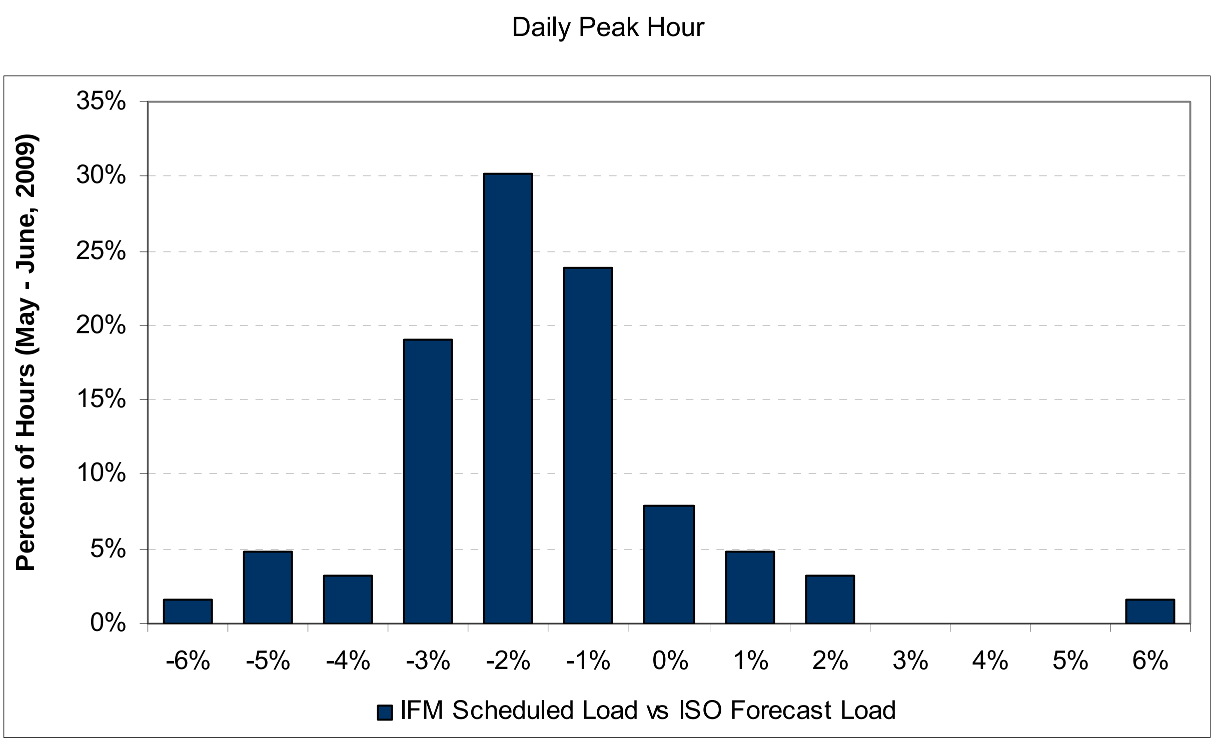
[23] April 2007 Order, 119 FERC ¶ 61, 076 at P 496.

to actually run based on bid-in demand rather than forecasted demand. In order to provide an indication of the level of mitigation that may occur if the software was modified to base MPM on bid-in demand, DMM has developed the capability to modify the load forecast used by the software to approximately equal the level of demand that actually cleared the IFM (i.e., given actual bid-in demand). Results of this re-run of the IFM can then be compared to actual market results to provide an indication of the impact of basing the pre-IFM MPM process on bid-in rather than forecasted demand.

Since re-running the IFM software in this manner is relatively time intensive, DMM needed to select a limited sample of days for this analysis. Since the primary concern with the use of forecasted demand cited by the Commission and some stakeholders is that this would result in over-mitigation when demand bid into or clearing the IFM was less than forecasted demand, DMM selected a sample of days that encompass the range of under- or over-scheduling of demand in the IFM (relative to the ISO's forecast) that has occurred over the first three months of the IFM.

Figure 2.10 shows the percentage difference between load scheduled in the IFM and the ISO's day-ahead load forecast for the peak hour of each day during May and June 2009. As shown in Figure 2.10, the amount of load clearing the IFM has generally been only about one to three percent lower than the ISO's forecast of load. This trend indicates that the use of forecasted rather than bid-in demand is likely to have a very limited impact on the level of mitigation that has occurred due to any under-scheduling in the IFM. Data shown in Figure 2.10 were also utilized by DMM to select a sample of four different days for more detailed analysis using the DMM's standalone IFM software, as described below.

Figure 2.10 Difference Between Load Scheduled in IFM and ISO Forecast



Results for the four sample days analyzed for this report are summarized in Table 2.4. As shown in Table 2.4, these results further indicate that use of bid-in rather than forecast demand in the pre-IFM MPM procedures could be expected to have a very negligible impact on the level of mitigation in the IFM, and on final IFM schedules and prices. For example:

- On the two sample days with typical levels of under-scheduling in the IFM relative to the ISO's load forecast (2 percent on June 12 and 26), the analysis showed that use of bid-in demand had a negligible impact on the degree of mitigation in the IFM. On these days, case study results show that use of bid-in demand instead of the forecast would have no effect during the peak hour on final IFM schedules of units with any portion of their bid curves lowered due to mitigation.[24] Moreover, on these two sample days, average prices in the IFM actually decreased by about one percent under the scenario used to estimate the impacts of basing MPM on bid-in demand. Such results are counterintuitive, since basing MPM on a lower level of demand would be expected to decrease mitigation and decrease the pool of resources considered in the IFM.[25] Such counterintuitive results simply reflect the "margin of error" that is involved in trying to assess the impact of a very small change in IFM market inputs, such as a small change in bid prices due to mitigation.[26]

- On the sample day with the highest level of under-scheduling in the IFM relative to the ISO's load forecast (5 percent on June 18), the analysis showed that use of bid-in demand may have decreased the number of units having a portion of their bid curve mitigated (lowered) during the peak hour (would be reduced from four units to one unit). Again, however, such counterintuitive results simply reflect the "margin of error" that is involved in trying to assess the impact of a very small change in IFM market inputs, such as a small change in bid prices due to mitigation.

- On the one sample day with significant over-scheduling (5 percent on June 21), the analysis showed that use of bid-in demand would have a slight increase on the level of mitigation in the IFM, with prices decreasing by about 6 percent. However, analysis of results for this day indicates that this decrease in price is not attributable to bid price mitigation, and is instead due to the fact that the pool of units considered in the IFM is greater under this scenario, since additional resources are dispatched in the pre-IFM AC run.[27]

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[24] See final right most column in Table 2.4, labeled "Impact of Mitigation during Peak Hour, MW (Q_{IFM} - Q_U)". For a description of these metrics, see Figure 2.5 and Figure 2.6 and the related discussion in Section 2.2 of this report.

[25] Under current market rules, the pool of bids considered in the IFM is limited to resources that are dispatched in the AC run of the pre-IFM MPM (ISO Tariff Section 31.2).

[26] Such counterintuitive results can be attributed to the fact that relatively small changes in resources and bids considered in the IFM can cause the software to take a different "search path", which can result in different solutions at the point that the minimum MIP gap requirements are met and the software stops. The MIP gap (or Mixed Integer Programming gap) is a measure of the optimality of a solution relative to a theoretical optimal that could be achieved without integer constraints. The MIP gap is measured in two ways. The absolute MIP gap is calculated based on the difference in the objective function value of a given solution (i.e., total bids costs of resources dispatched to meet load) and the minimal value of the objective function that could be achieved without integer constraints. The MIP is also measured on a percentage basis (i.e., the absolute MIP gap as a percentage of the minimal value of the objective function that could be achieved without integer constraints).

[27] DMM is currently monitoring the impact of the rule limiting bids considered in the IFM to bids that are dispatched in the AC run, rather than all resources. However, DMM has found that to date modifying this rule would have negligible impact on IFM results due to the very limited degree of over- or under-scheduling that has occurred. See *Initial Recommendation on Potential Changes in Market Design Rule Limiting the Pool of Resources Considered in Integrated Forward Market*, Department of Market Monitoring, July 2, 2009, at the following link: http://www.caiso.com/23df/23dfb81a48990.pdf.

Table 2.4 Analysis of Mitigation Based on Forecast Rather than Bid-in Demand

	Daily Avg Cost	Units with Bids Lowered due to Mitigation			Impact of Mitigation during Peak Hour	
		Total Unit/Hours Mitigated	Units Mitigated in Peak Hour	Bids Subject to Mitigation in Peak Hour (Q_{MAX} - Q_{CC}) *	Units with Higher Dispatch	MW (Q_{IFM} - Q_U)*
5% Underscheduling / Peak Forecast = 36,970 MW (June 18)						
Base	$28.25	41	4	173	1	37
MPM w/IFM MW	$28.34	32	1	105	1	105
Change	**0%**	**-10**	**-3**	**-68**	**0**	**68**
2% Underscheduling / Peak Forecast = 29,316 MW (June 12)						
Base	$24.56	12	1	270	0	0
MPM w/IFM MW	$24.27	7	0	0	0	0
Change	**-1%**	**-5**	**-1**	**-270**	0	0
2% Underscheduling / Peak Forecast = 35,040 MW (June 26)						
Base	$30.35	9	0	0	0	0
MPM w/IFM MW	$30.15	10	0	0	0	0
Change	**-1%**	**1**	**0**	**0**	**0**	**0**
5% Overscheduling / Peak Forecast = 26, 961 MW (June 21)						
Base	$30.58	5	1	281	1	150
MPM w/IFM MW	$28.75	7	3	391	1	112
Change	**-6%**	**2**	**2**	**110**	**0**	**-38**

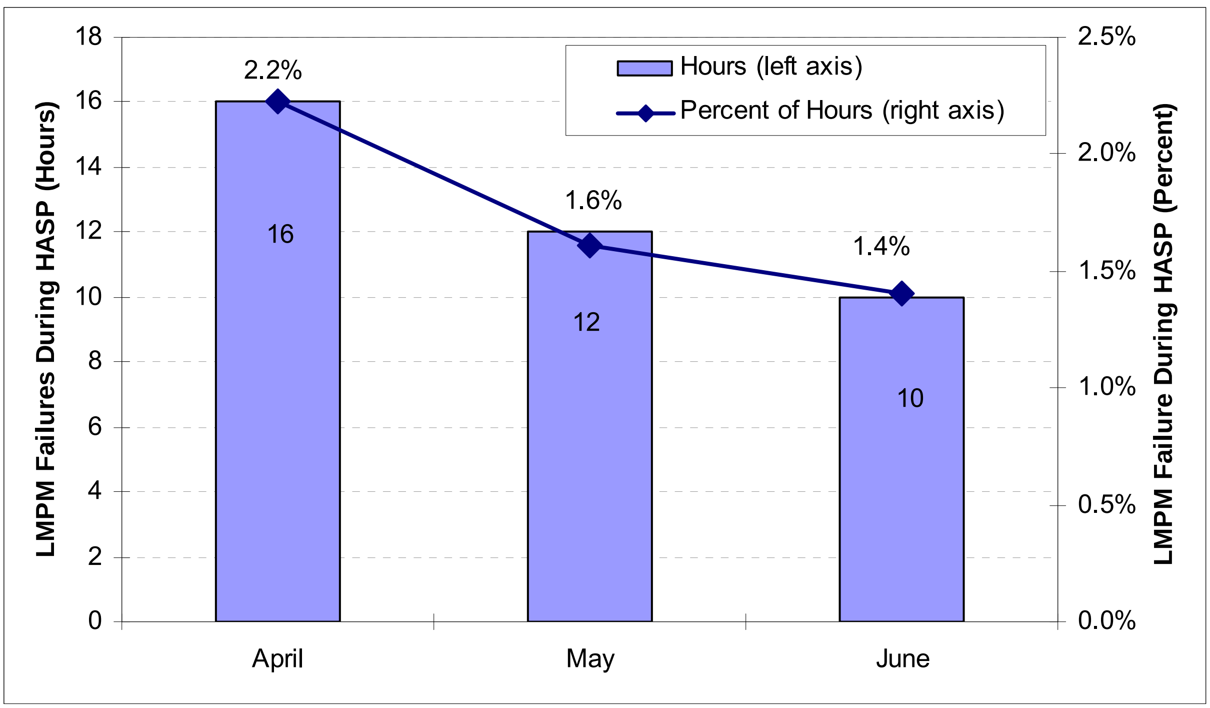
* For a description of these metrics, see Figure 2.5 and Figure 2.6 and the related discussion in Section 2.2 of this report.

2.5 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 performing price correction, as appropriate.

During the first three months of the ISO's new market, the frequency of failures in the pre-RTM LMPM process has been relatively low, and has decreased each month. As shown in Figure 2.11, the portion of hours that the LMPM process has failed to run in the HASP has dropped from about 2.2 percent in April to 1.4 percent in June. This compares to an average rate of about 5 percent during market simulations prior to the opening of the ISO's new LMP markets.

Figure 2.11 Frequency of LMPM Failures During HASP



In addition, due to the relatively low frequency and volume of bid mitigation that is occurring under the LMPM provisions, the impacts of pre-RTM LMPM procedures has been very limited. When LMPM failures have occurred during the HASP, the ISO's Market Operations department performs a review to determine if the failure may have had a significant impact on LMPs, so that price correction may be applied. The basic process employed by Market Operations includes the following:

- First, the hours before and after the hour of the LMPM failure are reviewed to see if any units had any portion of their bids mitigated (i.e., lowered) during these hours. If no units have bids mitigated in the hours before and after the hour of the LMPM failure, no further review is performed since it is unlikely that mitigation would have occurred during the hour of the LMPM failure.

- Second, for each resource that was mitigated in any of the hours before and after the hour of the LMPM failure, the unit's RTD dispatches for the hour of the failure are examined to determine whether – if bid mitigation had occurred – it was likely to have affected each unit's dispatch level. For this step, the mitigated bid(s) for the unit during the hour(s) before and after the hour of the LMPM failure are used to estimate what the unit's final market bid would have been if the unit was subject to mitigation during the hour of the LMPM failure. If the unit's LMP is *lower* than its estimated mitigated bid at its RTD dispatch level or *higher* than the unit's unmitigated bid level, then it is assumed that the unit's dispatch would not have changed even if mitigation had occurred and the unit did not affect the LMP.[28]

- Finally, any units that are not screened out using the steps above are subject to a more detailed review to assess the extent to which the unit would have been dispatched at a higher level if its bid had been mitigated, and what impact this may have had on market prices.[29]

Table 2.5 lists all 38 hours in the second quarter of 2009 during which the pre-RTM LMPM procedures failed to run during the HASP process. As shown in Table 2.5, about 10 of these 38 hours could be screened out based on the first two standard impact screens described above. Of the remaining hours, based on more detailed manual review of potential price impacts by Market Operations, it was determined that price correction was appropriate for one interval of one of the hours during which LMPM failed to run in the HASP.[30]

We are continuing to work with Market Operations staff to refine and automate the general approach described above for determining if price correction is appropriate when LMPM failed to run in the HASP. For example, we believe that it may be appropriate and efficient to incorporate some additional screening criteria based on LMPs during the period before, during, and after any LMPM failures in HASP to determine whether or not any lack of mitigation significantly impacted market prices.

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[28] Resources that are ramp constrained are also screened at this stage, since lack of mitigation of these units is not likely to have affected the LMP.

[29] For example, in some cases this can be assessed by estimating the total amount of additional energy that may have been dispatched from mitigated units (or "upward movement"), and then examining the bids and dispatch level of the marginal units that actually set LMPs during each interval to determine if this "upward movement" by units that would have been mitigated would have reduced the dispatch of higher priced bids enough to create a significant decrease in the LMP.

[30] See log for May 29, 2009, Interval 10 in *Price Correction Report, Week of May 18-24, 2009,* http://www.caiso.com/23c7/23c7a47a730f0.doc.

Table 2.5 Hours When RTM Market Power Mitigation Procedures Failure to Run

Date	Hour	Standard Impact Screens*	Price corrected based on more detailed review
4/1/2009	18		No
4/1/2009	20		No
4/1/2009	21		No
4/1/2009	22		No
4/4/2009	20	No Impact	
4/4/2009	21	No Impact	
4/9/2009	1		No
4/11/2009	8		No
4/12/2009	1	No Impact	No
4/14/2009	20		No
4/15/2009	11		No
4/16/2009	20		No
4/17/2009	15		No
4/22/2009	17		No
4/28/2009	5	No Impact	
4/28/2009	18		No
5/1/2009	8		No
5/3/2009	14		No
5/5/2009	17		No
5/5/2009	20		No
5/9/2009	15		No
5/9/2009	16		No
5/9/2009	18		No
5/10/2009	16		No
5/20/2009	**10**		**Yes**
5/21/2009	2	No Impact	
5/25/2009	22		No
5/30/2009	4	No Impact	
6/4/2009	18		No
6/5/2009	4	No Impact	
6/5/2009	5	No Impact	
6/7/2009	2		No
6/10/2009	4		No
6/11/2009	4	No Impact	
6/16/2009	1		No
6/18/2009	8		No
6/25/2009	1		No
6/25/2009	2	No Impact	

* The standard impact screens are described in the first two bullets on the previous page.

2.6 Analysis of High Unmitigated Bids Dispatched in Real Time Market

This section describes results of one of the processes that have been developed by DMM to review the effectiveness of LMPM procedures in the real-time market. Under the ISO's new market design, LMPM procedures are run as part of the hourly HASP process, approximately one hour prior to the start of the RTM for each operating hour. Thus, bid mitigation in the RTM is determined based on the software's forecast of demand and supply conditions about one to two hours in advance of the actual operating intervals for which mitigation is being determined. This creates the potential for LMPM procedures to be ineffective at mitigating local market power if demand and supply conditions are incorrectly forecasted or unforeseen events occur between the HASP and RTM (such as forced unit outages, uninstructed deviations, etc.).[31] Specifically, such differences create the potential that relatively high bids (which were not projected to be needed in the HASP and were therefore not subject to mitigation) need to be dispatched in the RTM to relieve congestion on uncompetitive constraints and thereby set relatively high LMPs in the RTM. Consequently, one of the processes that we have developed for assessing the effectiveness of LMPM focuses specifically on assessing the degree to which this scenario may occur. The remaining portions of this section provide a description of this methodology, along with results for a variety of the highest priced periods during the first three months of the ISO's new market design that we have analyzed using this approach.

Figure 2.12 outlines the key steps in one of the approaches used to assess the effectiveness of LMPM procedures in the RTM. A more detailed description of this process is provided below:

- Step 1: In order to focus monitoring efforts on detecting cases when the LMPM process is least likely to have been effective in the RTM, DMM performs this review for hours with relatively high LMPs. For example, Figure 2.13 and Figure 2.14 show the sample of relatively high priced hours during the months of May and June, respectively, for which more detailed results are summarized in this report.
- Step 2: This step involves further analysis of all resources with bids over $100 dispatched in the RTM during the hours selected for analysis.[32] The $100 bid price level is used since virtually all DEBs are less than $100, and this level allows the analysis to focus on cases where any lack of mitigation could have a significant impact on LMPs. These resources are then further categorized based on two factors: (1) their dispatch level and (2) the congestion component of their LMP.
    - o As shown in Figure 2.12, all resources dispatched at this maximum available capacity are excluded from further review since these units are *not marginal,* so that any lack of bid mitigation for these units had *no impact* on prices due to local congestion (or local market power).
    - o As further shown in Figure 2.12, units that are partially dispatched (i.e., below their full available capacity) and could therefore be marginal are then screened based on the congestion component of their LMP, as described below.
    - o Units that are partially dispatched, but for which the congestion component of their LMP is $0 are screened from further review, since this indicates that lack of bid mitigation for these units had *no impact* on prices due to local congestion.

[31] As noted in Section 1 of this report, various forecasting and modeling differences between the HASP and RTM software have been identified as a significant contributing factor to RTM price volatility and lack of price convergence between the HASP and RTM.

[32] Units that were subject to mitigation but still have bids over $100 could be excluded at this step of the analysis. However, given the structure of ISO data, it is computationally much more efficient to examine whether units were subject to mitigation as part of the final step of this analysis. In practice, DMM has found that virtually all units subject to mitigation get screened out by the other various screens used in this approach.

  - o Similarly, any partially dispatched resources for which the congestion component of their LMP is lower than $5 are also screened from further review, since this indicates that lack of bid mitigation for these units had – at most – a *minimal impact* on prices due to local congestion.

  - o Remaining resources that are partially dispatched for which the congestion component of their LMP is greater than $5 are subject to further review to determine if lack of bid mitigation for these units may have had a significant impact on prices due to local congestion.

- Step 3: The congestion component of the LMP for all resources not screened out in Step 2 is then decomposed to determine the portion of congestion cost attributable to different constraints.

  - o If most or all of the congestion component is attributable to congestion on *competitive* constraints, the actual competitiveness of the constraint under actual system conditions may be assessed. For example, this can be done by examining the "effective supply" of bids that can provide counterflow on the congested constraint.[33] Although the LMPM provisions of the ISO's new market design are specifically designed not to mitigate resources dispatched to resolve congestion on constraints deemed to be competitive through the ISO's Competitive Path Analysis (CPA),[34] this type of review is performed to ensure that the CPA methodology reflects the actual competitiveness of constraints under actual system and market conditions.

  - o If a significant portion of the congestion component is attributable to congestion on *non-competitive* constraints, further review of HASP and RTD Saved Case conditions and results may be performed to try to determine whether and why the relatively high unmitigated bid was dispatched to resolve congestion on a non-competitive constraint. Potential factors that may explain the need to dispatch relatively high unmitigated bids include:

    - A significantly higher RTM load forecast than the load forecast used in HASP;

    - Differences in the bias used to adjust the scheduling limit of transmission constraints in the HASP and RTM; and

    - Generating unit outages or major deviations from schedules which may occur between the HASP and RTM.

[33] The "effective supply" of bids that can provide counterflows on a constraint includes the set of bids from resources with a negative shift factor relative to that constraint. The quantity of effective supply from each resource equals its bid quantity multiplied by this shift factor.

[34] For a description of the CPA methodology and most recent results, see *Competitive Path Assessment for MRTU: Final Results for MRTU Go-Live*, February 2009 (http://www.caiso.com/2365/23659ca314f0.pdf). DMM is developing other metrics to assess the competitiveness of constraints under actual operating and market conditions. Results of this analysis will be provided in future reports as more data and analysis are available.

Figure 2.12 Process for Assessing LMPM Effectiveness in RTM

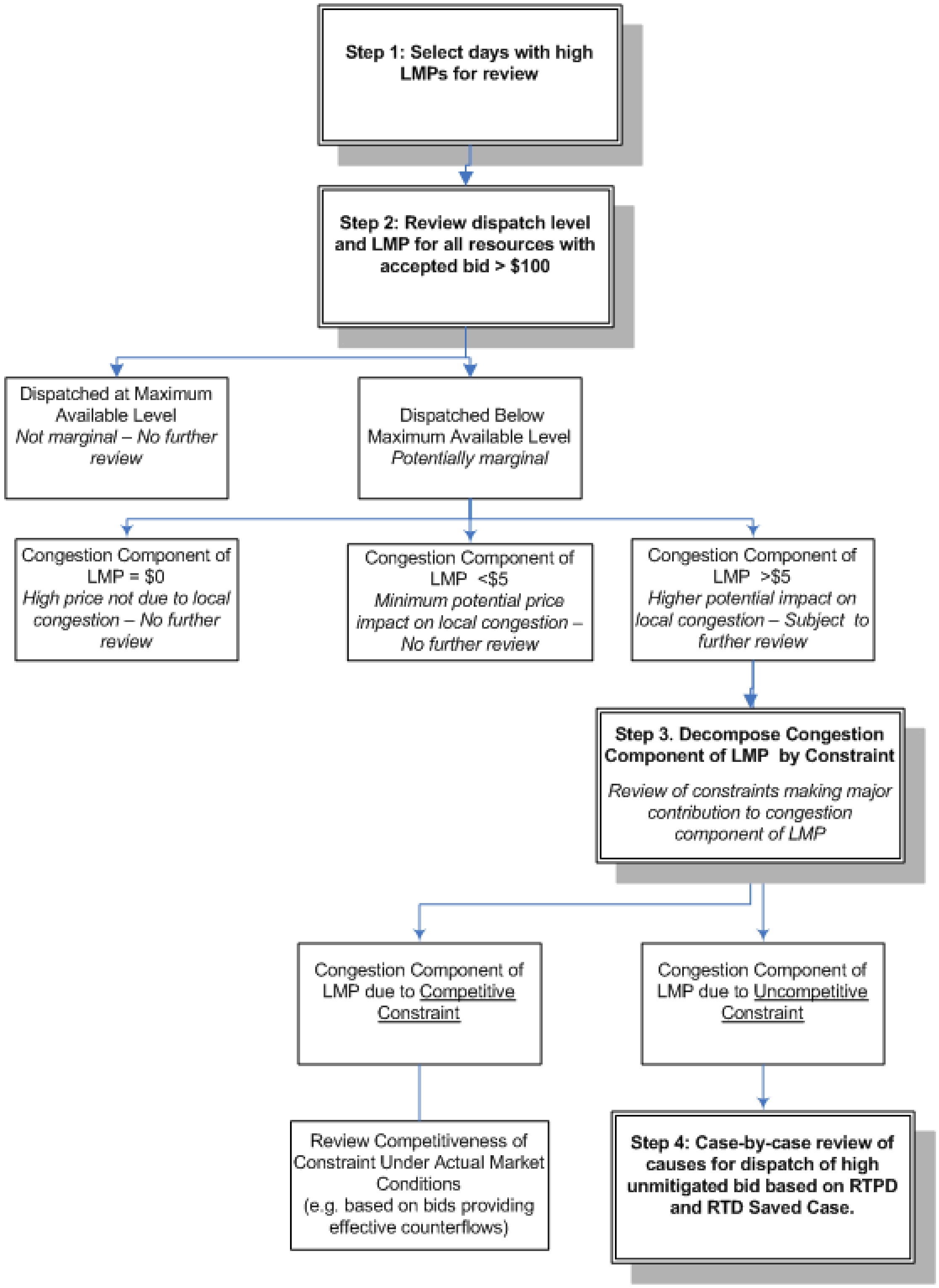


Figure 2.13 Sample Day (May 2009)

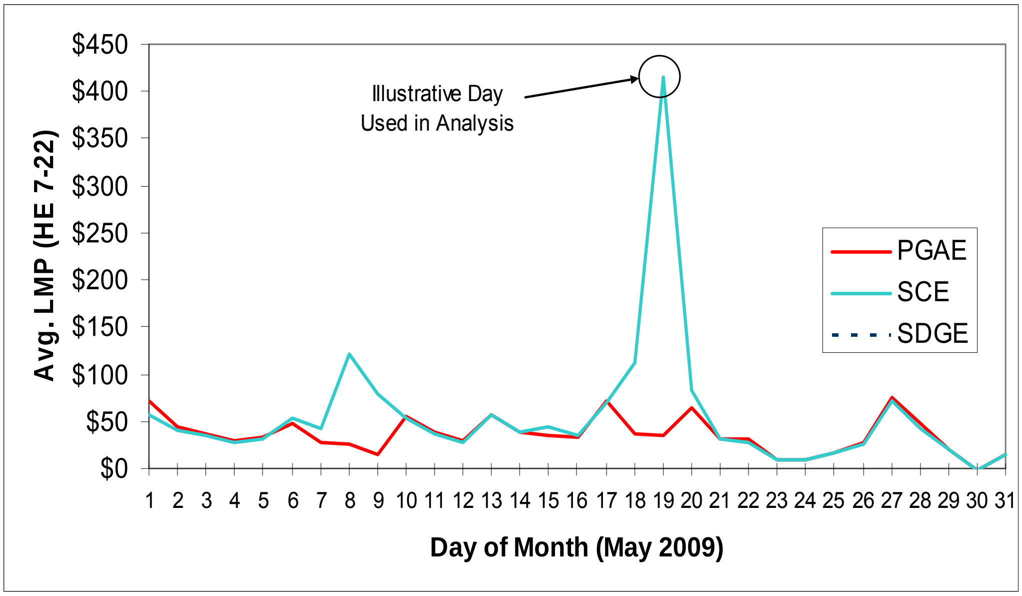
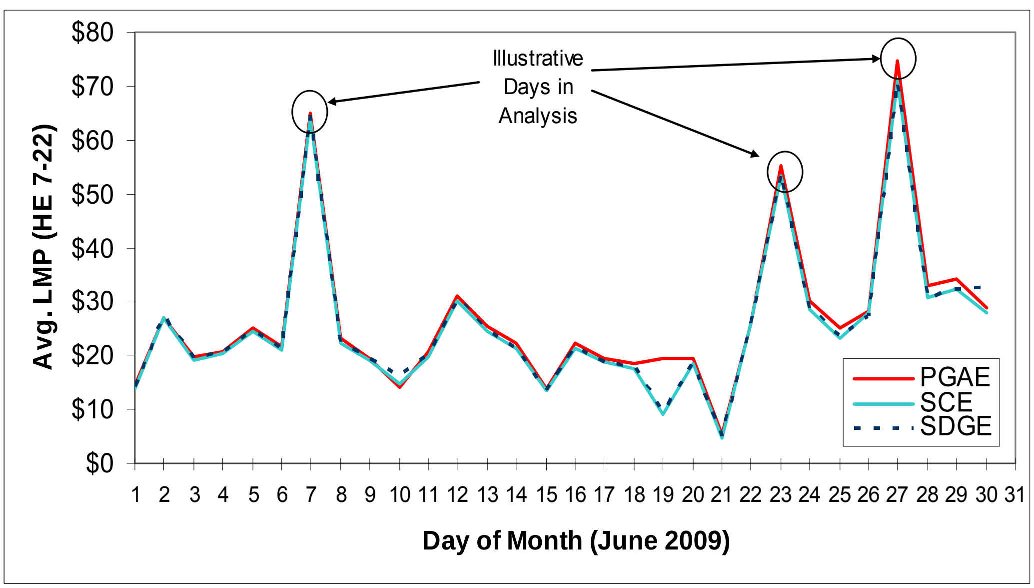


Figure 2.14 Sample Days (June 2009)



It should be noted that this final case-by-case review is more "art-than-science" and may in some cases not provide a definitive explanation of the reason why the unmitigated bid was dispatched. However, the process is designed to provide an indication of the overall degree to which LMPM is effective, and identify the basic trends or factors that may undermine its effectiveness.

Table 2.6 provides results of this analysis for the four high priced days highlighted in Figure 2.13 and Figure 2.14. As shown in Table 2.6:

- For these four days, the automated screens incorporated in Step 2 of this approach reduce the units and intervals subject to further case-by-case review to a total of only 10 units/intervals: eight units/intervals on May 19, and just one unit/interval on June 23 and June 27.
- As further shown in Table 2.6, nine of these ten units/intervals involve resources that may have been dispatched to relieve congestion on competitive constraints (see Step 3 results for May 19 and June 23). All eight of these units/intervals on May 19 involved congestion on Path 26, while the remaining unit/interval on June 23 involved congestion on the Humboldt branch group.
- Review of the ISO's pricing review logs for the one remaining unit/interval on June 27 indicated that during this hour the LMP was corrected due to a "corrupted case" resulting from a "timing issue between RTPD and RTD". This suggests that the dispatch of a relatively high-priced unmitigated bid during this interval likely resulted from precisely the type of software problem that could be expected to affect the effectiveness of LMPM in the RTM. However, as shown by these overall results, the impact of this type of problem on the effectiveness of LMPM in the RTM appears to have been extremely limited during the first three months of the ISO's new market design.

Table 2.6 Summary of Results

	High Price Dates			
	19-May	7-Jun	23-Jun	27-Jun
Total # of units/intervals with dispatched bid > $100	134	105	76	234
Step 2 (Categorized by dispatch and congestion)				
2a) Dispatched at Full Available Capacity	121	94	46	186
2b) Partially Dispatched - No Congestion	3	11	28	47
2c) Partially Dispatch - Congestion <$5	2	0	1	0
2d) Partially Dispatch - Congestion >$5	8	0	1	1
Step 3 (Detailed review of units/intervals from Step 2d)				
Congestion due to Competitive Constraint	8	0	1	0
Congestion due to Non-Competitive Constraint	0	0	0	1*

* Price in this hour was corrected due to a corrupted case resulting from a timing issue between RTPD and RTD.

3 Exceptional Dispatch

Exceptional Dispatch (ED) is a term used to describe manual dispatches performed by an ISO operator in cases where the market failed (or was expected to fail) to address a particular reliability need. EDs are issued for a variety of reasons, including constraints that are not properly modeled by the software, software execution errors, and others, as discussed below. EDs are often in the form of unit commitments, usually issued in the day-ahead, or for real-time exceptional dispatch energy (EDE), in which a resource that is already available to the market is constrained to be above or below a certain level of output. Decisions regarding ED are based on physical requirements specified in established Operating Procedures, power flow analysis of transmission outages, or to mitigate the result of market application failure.

Grid operators have discretion in issuing EDs, subject to authority of the ISO Tariff Section 34.9[35] and in accordance with ISO Operating Procedure M-402 (Exceptional Dispatch), M-401 (Day-Ahead Market Operations), and M-403 (Real-Time Market Operations).[36] This authority and settlement details are summarized in an ISO *Technical Bulletin* issued May 5, 2009.[37] Operators also have at their disposal a tool that assists them in selecting resource(s) for ED that are under RA contract whenever possible.

Since the start of the market, the use of exceptional dispatches has been higher than expected, and this has raised concerns, particularly among generator owners, about the efficacy of the new market and impact these manual dispatches are having on market prices. This section provides a comprehensive review of the primary reasons for ED and what actions could be taken to reduce the need for ED going forward. It begins with some additional background on exceptional dispatches and notes some of the data limitations and challenges with conducting this assessment. We then discuss the major trends in exceptional dispatches over the April to June period and discuss their potential market impacts. Next, we provide a more in-depth analysis and explanation of the more frequent exceptional dispatch reasons, which is followed by a discussion of potential market power concerns with ED. We conclude with some recommendations for reducing ED.

3.1 Background

Day-Ahead ED Commitment Instructions

ED commitments typically are issued for non-modeled reliability requirements, such as voltage and capacity requirements. An ISO grid operator issues an ED day-ahead commitment to bring a relatively long-start generator online to operate at its minimum generation capacity (or “minimum load”) so that the unit will be available for dispatch when needed. According to Operating Procedure M-402, ED day-ahead commitments are initially issued after the day-ahead market is completed. If specific resources that grid operators and transmission

[35] CAISO Tariff Section 34.9, http://www.caiso.com/23d5/23d5ccbb9800.pdf.

[36] CAISO Market Operating Procedures, http://www.caiso.com/thegrid/operations/opsdoc/marketops/index.html.

[37] CAISO Technical Bulletin on Exceptional Dispatch, http://www.caiso.com/23ab/23abf0ae703d0ex.html.

engineers deem necessary for reliability were not committed in the market, operators will commit them with an ED startup instruction. In this case, the ED appears as a self-schedule at minimum load in the hour-ahead scheduling process (HASP) and real-time dispatch (RTD) markets. However, as of April 16, 2009, if a particular resource "is the only unit that can meet the reliability requirement and there is a reasonable basis for believing that the unit will not receive a Day-Ahead Schedule", the grid operator can commit the resource prior to running the day-ahead market.[38] In this case, the ED commitment appears as a self-schedule at minimum load in the day-ahead IFM market, so that the energy that the exceptionally dispatched resource generates will be accounted for in the optimization, resulting in more accurate system dispatch and price signals.

Real-Time ED Energy Instructions

An ISO grid operator issues an exceptional dispatch energy (EDE) instruction to constrain a resource within a particular range of output. For example, a resource that receives a day-ahead ED commitment may have a very slow ramp rate at its minimum load level. The grid operator may issue an EDE instruction to raise the resource to a minimum level at which it can be responsive to market instructions. EDE instructions are also used to keep multi-stage combined-cycle units in particular generation configurations; that is, with a particular combination of turbines and heat-recovery steam generators on. The specific configuration is not currently modeled by the market software, and an instruction that would require the startup or shutdown of a turbine can be very costly if it remains in that configuration for a short time.[39]

The EDE instruction is passed to the market software as a minimum or maximum output constraint. That is, the software would interpret the EDE minimum or maximum constraint megawatt output level respectively as the resource's effective minimum or maximum load. There is also a seldom-used "fixed" constraint option, which holds a resource fixed at a specific level of output.

Occasionally, grid operators may commit short-start units as real-time EDE instructions. These are typically fast-start resources that do not require day-ahead commitment, and are used, for example, to work around isolated modeling errors in the presence of transmission outages.

Mitigation and Cost Allocation

Presently, all ED energy instructions for RA units beyond start-up and minimum load are subject to market power mitigation, which must be administered outside the market software's processes. Units committed by ED are compensated for start-up and minimum load costs as part of bid cost recovery.[40] Beginning August 1, 2009, the only EDs that will be subject to bid mitigation are (1) those that resolve transmission-related modeling limitations, in which the transmission path that requires a workaround is deemed non-competitive in the DMM's Competitive Path Assessment; and (2) those that are in support of the Delta Dispatch requirement. The tool that was developed to assist operators with these requirements was recently enhanced to include functionality that assists operators in determining whether a particular path requiring an ED is competitive.

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[38] Operating Procedure M-402, p. 5.

[39] Multi-Stage Generation Unit Modeling is an ongoing CAISO stakeholder process, http://www.caiso.com/2078/2078908392d0.html.

[40] Start-up and minimum load bids for resources within a Local Capacity Requirement Area are capped at 200 percent of the cost-based levels. For resources outside of these areas, bids are capped at 400 percent of the cost-based levels.

Explicit costs for ED energy dispatches are intended to be allocated using cost causation principles. In the event that a transmission owner (TO) fails to provide information that otherwise would enable market selection and dispatch, the costs of EDs in excess of LMP that the ISO incurs to resolve those transmission-related modeling issues are allocated to that TO. Costs that cannot be allocated to a particular TO are spread across all load.

Logging and Measurement Issues

Exceptional dispatches were originally intended as a workaround mechanism for real-time energy dispatches only and were presumed to be infrequent – an exception to the rule of automated market dispatch. As of April 1, 2009, the ISO had in place a process for logging real-time ED energy dispatches, but not for day-ahead ED unit commitments. The ability to issue unit commitments was a modification developed after the April 1 go-live date. Thus, early ED commitments are less clearly distinguishable in data from ED energy instructions. The ISO is making changes to improve these processes, but existing data still have some problems.

As described in Operating Procedure M-402, operators use the ISO's SLIC logging tool, to record exceptional dispatches, and they also enter instructions in the market software. The SLIC ED template provides for manual entry of an extensive set of information regarding the instruction. Due to the dynamic use of the ED process and manual nature of the SLIC entries, data fields are often left blank or miscoded. ED entries are reviewed in a post-market process and corrected as appropriate.

For this report, we have compiled data from SLIC records specified in exceptional dispatch reports between April 1 and June 30, 2009. These records include information on all internal ED commitments and energy instructions but do not include information on EDE instructions to system resources (inter-ties). We selected these data because they have a richer set of information than data generated by the market software and downstream applications which are used for dispatch and settlement. Only the SLIC data can provide a clearer picture of dispatch patterns, particularly with respect to reasons for which ED instructions are being issued. However, readers should note that they are from manually written logs, and thus are also non-standard and subject to error, both in entry and in after-the-fact reporting.

In order to conduct analysis, we have had to make some assumptions when data are missing or questionable.[41] For example:

- If no entry is issued for start or end time, we assume the start or end time is HE 1 or 22, respectively.[42]
- Only day-ahead ED instructions issued prior to the market are explicitly coded as day-ahead. If the issue date for an instruction coded as real-time is prior to the date of operation, we assume the instruction is a day-ahead commitment.

[41] The CAISO has filed with FERC several reports specific to ED under FERC Docket Nos. ER08-1178-??? and EL08-88-???. The figures presented in the monthly ED filings may differ from those presented in this report due to: timing of data preparation for reports compared to the data correction process; omission (in the present report) of ED for system resources and other intentional omissions, primarily to avoid double-counting and other errors; use of data from the ED logging tool (in the present report), compared to use of pre-settlement data (in reports filed under aforementioned dockets).

[42] HE 22 was used as the default end hour based on our best judgment following several interviews with grid operators. Operators noted that they often enter start times for real-time EDE instructions without knowing exactly when the EDE will end.

- Volumes of real-time dispatch above minimum generation capacity are excluded, in order to avoid double-counting of commitments to minimum load that had already been committed in the day-ahead. Approximately 28 percent of real-time ED energy dispatches were instructions to minimum generation capacity for at least one hour.
- Approximately 20 percent of real-time ED energy instructions hold resources at maxima, rather than at minima. We include GOTO maximum instructions for the purposes of instruction counts, but exclude all GOTO maximum instructions in calculating volumes. These are tantamount to decremental energy exceptional dispatches, which we are not analyzing in this report.
- EDE energy instructions to system resources are not included. These are issued almost exclusively for HASP market failures but are currently processed manually and were not available in the data.
- For simplicity, we treat all ED energy instructions as having a single begin time and a single end time, with the GOTO MW quantity as the average of all GOTO MW quantities.
- Reliability must-run (RMR) dispatch instructions are excluded, as they are not exceptional dispatches under the ISO tariff.

As internal procedures and systems are refined and improved over the coming months, these logging issues will decrease and reporting quality should improve.

3.2 Summary of Exceptional Dispatch

The ISO issued approximately 770 day-ahead ED commitments during the quarter. The most frequently cited reasons for day-ahead ED commitments were in support of transmission outages. Clearances for planned work required approximately 39 percent of day-ahead ED commitments during the quarter. Local requirements for voltage support, identified by the procedures G-206, G-219, and G-233, together comprised approximately 20 percent of day-ahead ED commitments. South of Lugo (G-217) and SCIT (T-103) requirements together comprised approximately 12 percent of day-ahead ED commitments. SP26 capacity day-ahead commitments totaled approximately 9 percent of instructions.

The ISO issued approximately 849 real-time EDE instructions during the quarter. The most frequently cited reasons for real-time EDE were also to manage transmission outages, totaling approximately 20 percent of instructions. Software limitations accounted for approximately 19 percent of real-time EDE instructions. Instructions to move resources to output levels with dispatchable ramp rates accounted for approximately 15 percent of the total volume of real-time EDE instructions. The figures below show the overall distribution of most prevalent reasons for exceptional dispatch for the quarter, for both unit commitment and real-time ED energy.

Figure 3.1 Frequency of ED for Day Ahead Commitment by Reason

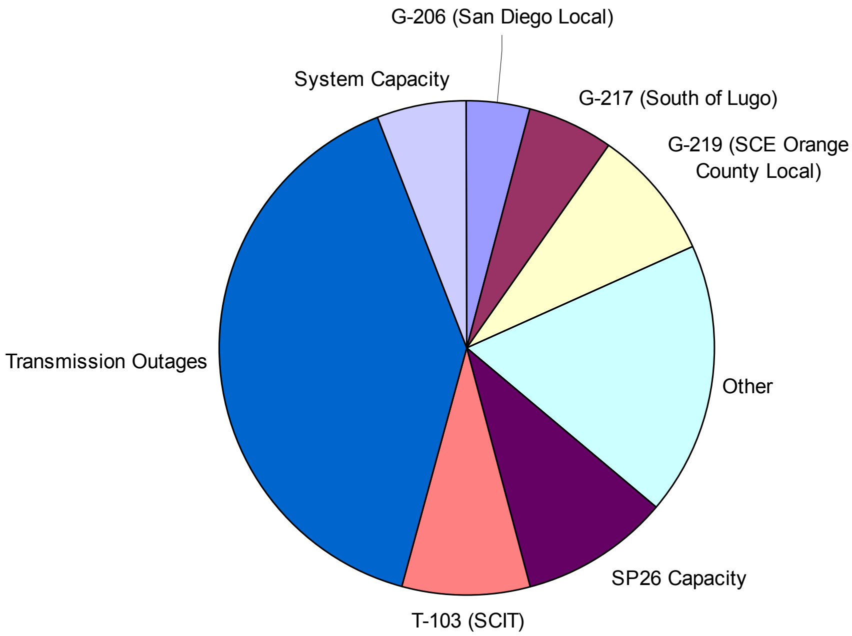
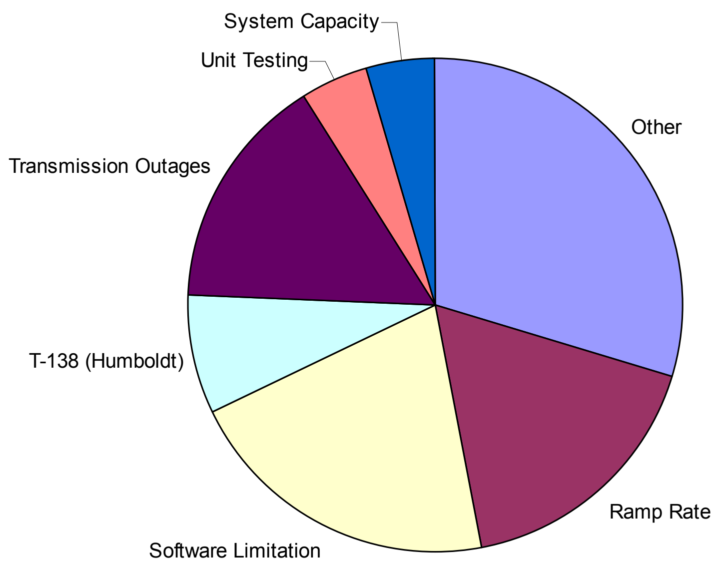


Figure 3.2 Frequency of ED for Real Time Energy by Reason



The dominant reason for ED unit commitment was for transmission outages. Between April and May, multiple clearances for maintenance required that resources be committed via ED. Other reasons include regional capacity requirements and local generation requirements (specifically, California ISO Operating Procedures G-206, G-217, G-219, and G-233).

Figure 3.3 and Figure 3.4 show weekly trends in exceptional dispatches by reason. Figure 3.3 shows the weekly number of day-ahead commitments through ED (unit days) and Figure 3.4 shows the weekly energy volumes stemming from day-ahead ED. These figures do show a decline in the day-ahead ED in the first two weeks of June but an increase in the last two weeks. The increase in "Other" is primarily due to system capacity requirements in anticipation of a heat wave during the weekend of June 27-28. These reasons are explained in greater detail in Section 3.5.

Figure 3.3 Frequency of Day Ahead Exceptional Dispatch by Reason

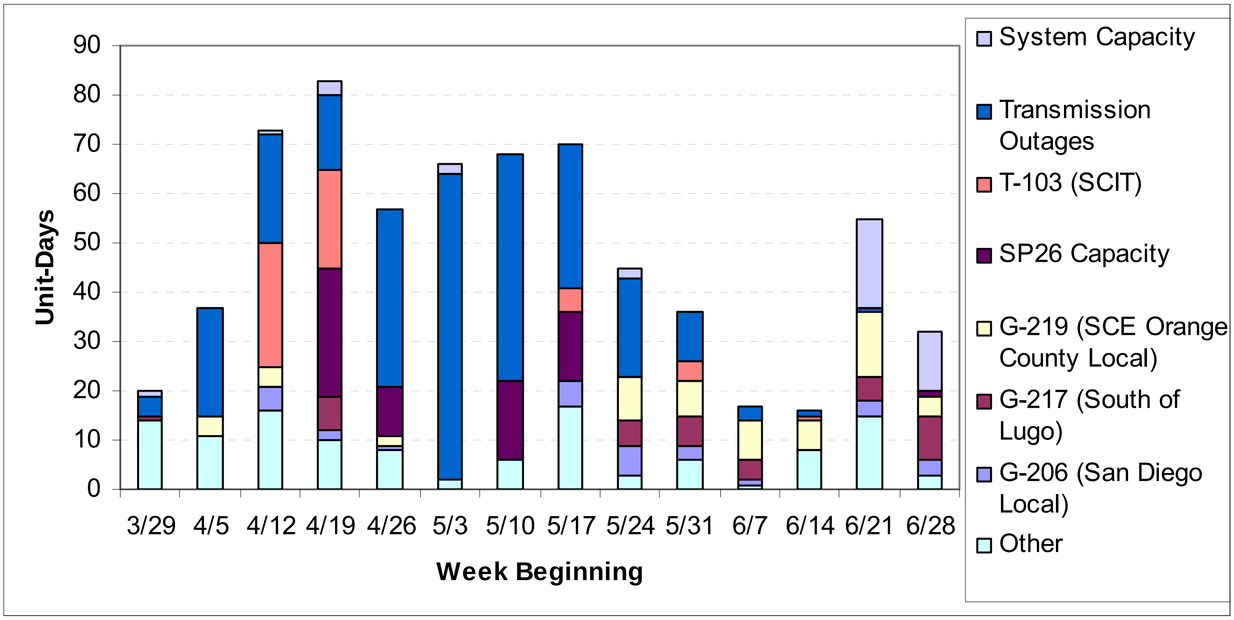
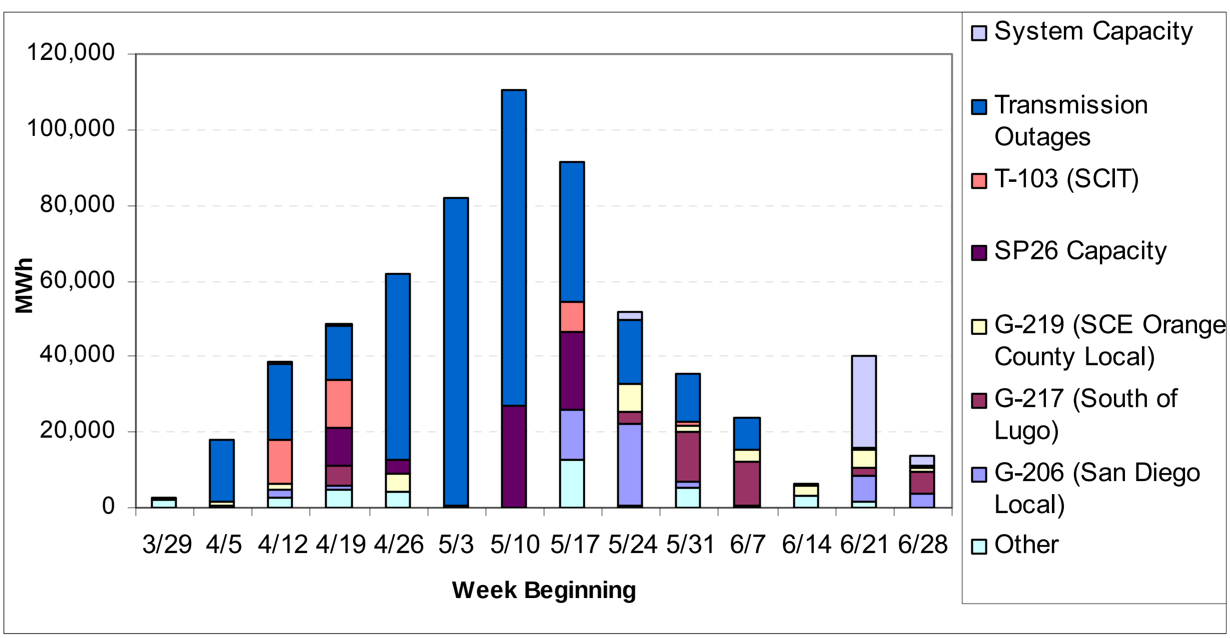


Figure 3.4 Energy Volume of Day Ahead Exceptional Dispatch by Reason



The most prevalent reason for real-time ED energy dispatch was "Ramp Rate" dispatch. This refers to resources that are committed at minimum load, in this case for the transmission outages noted above, but have ramp rates too slow at that level of output to be dispatched by the market software, and thus are raised to output levels at which they are more responsive and are a more viable solution for the market software. Other reasons include transmission-related voltage requirements (operating procedures T-103, T-138, and T-165 in particular); software limitations, which are overrides of erroneous dispatches primarily to pump load resources; and unit testing, which is required of new or enhanced resources prior to participating commercially in the markets. The increase in "Other" in late June is explained by several smaller concurrent transmission requirements. These are also explained in greater detail in Section 3.5.

Figure 3.5 Frequency of Real Time Exceptional Dispatch Energy by Reason

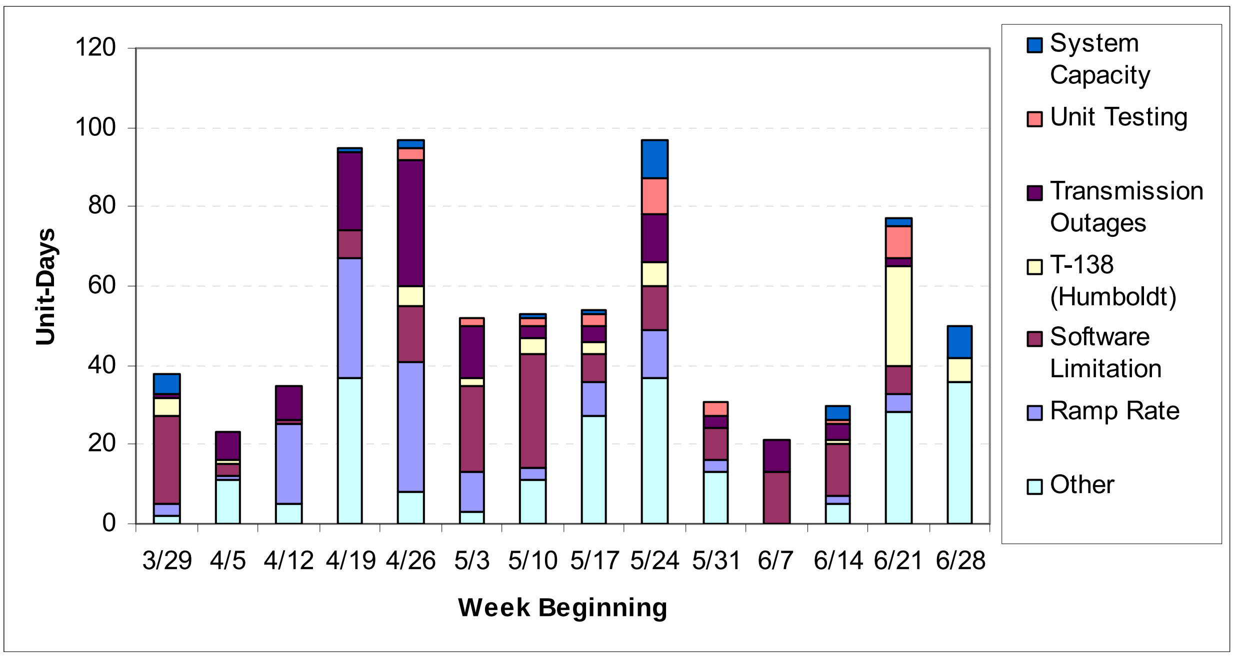
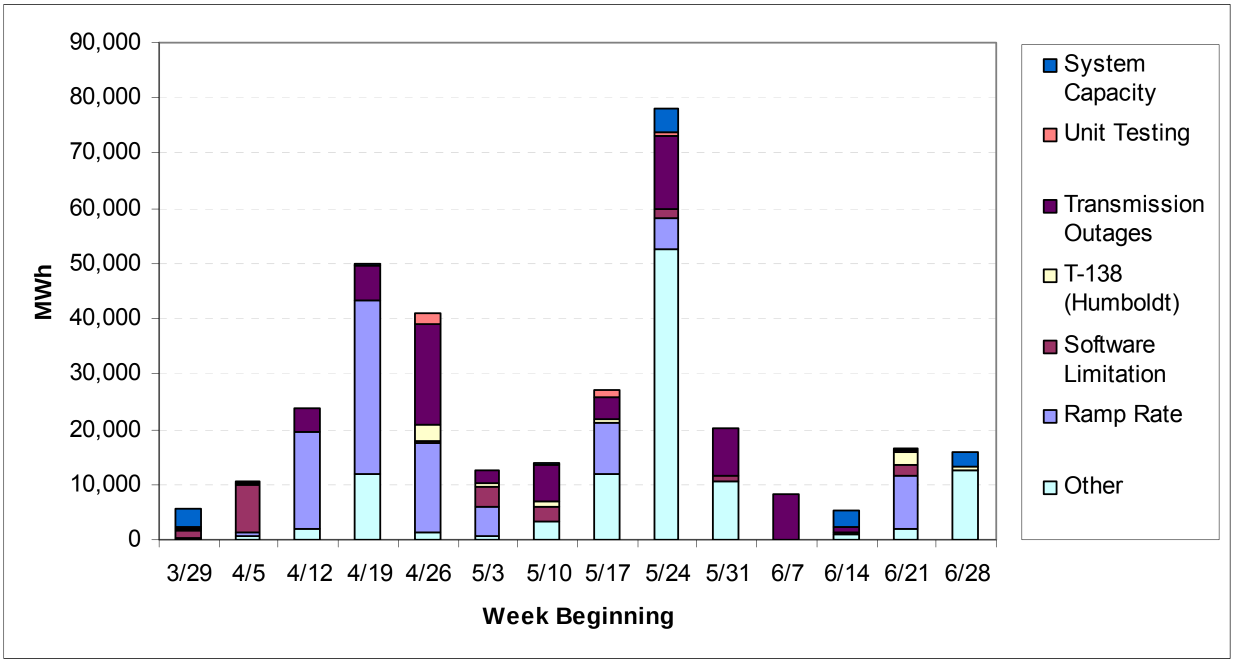


Figure 3.6 Energy Volume of Real Time Exceptional Dispatch Energy by Reason



The high volume of "Ramp Rate" dispatches in April were to resources that had been committed in the day-ahead through ED for outages. The spike in "Other" the week of May 24 was largely a series of same-day unit commitments, primarily for capacity requirements. Other real-time dispatches were typically real-time commitments to minimum load and decremental dispatches, for which volumes are not counted.

Many resources were committed via ED repeatedly. Some reasons, such as the voltage support procedures (G-206, G-217, G-219, G-233), identify specific units for commitment that meet requirements. For example, the nearly 70 unit-day commitments for outages the week of May 3 were made to 19 distinct resources. Similarly, the real-time ED instructions to resources for Ramp Rate and Software Limitation dispatches often repeated units. Meanwhile, instructions for "Other" were spread across a larger number of resources as this bin represents many different small categories. Figure 3.7 shows the number of distinct day-ahead ED commitments for each reason by week; Figure 3.8 shows the number of distinct real-time ED energy dispatches for each reason by week.

Figure 3.7 Number of Resources Committed for Day Ahead ED by Reason

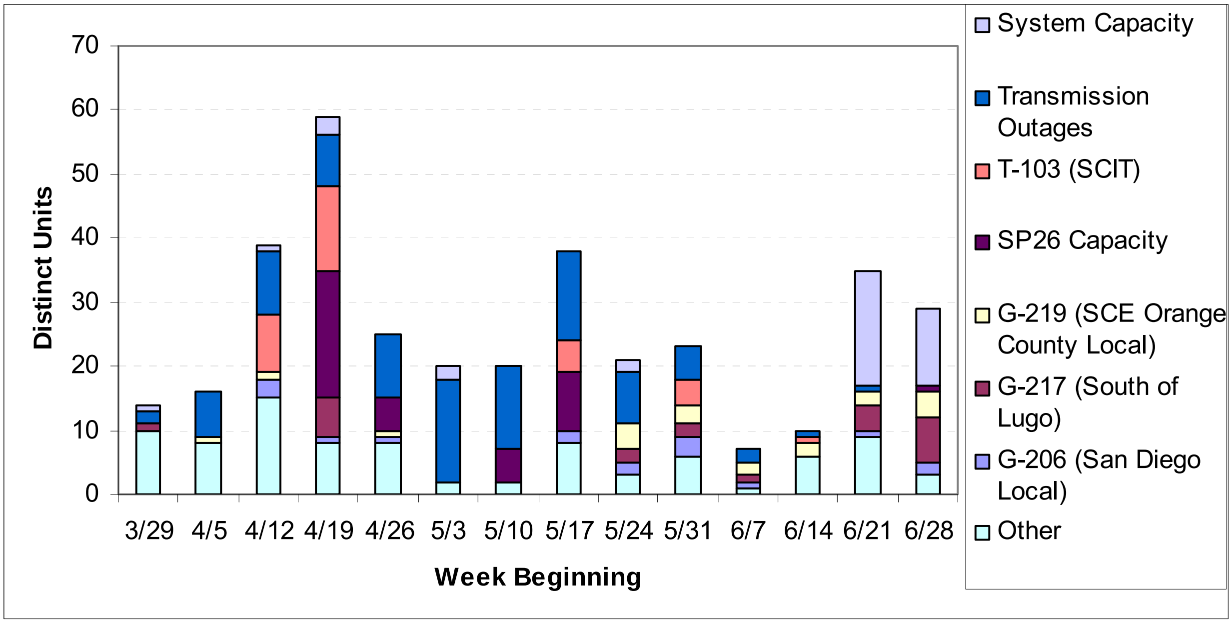
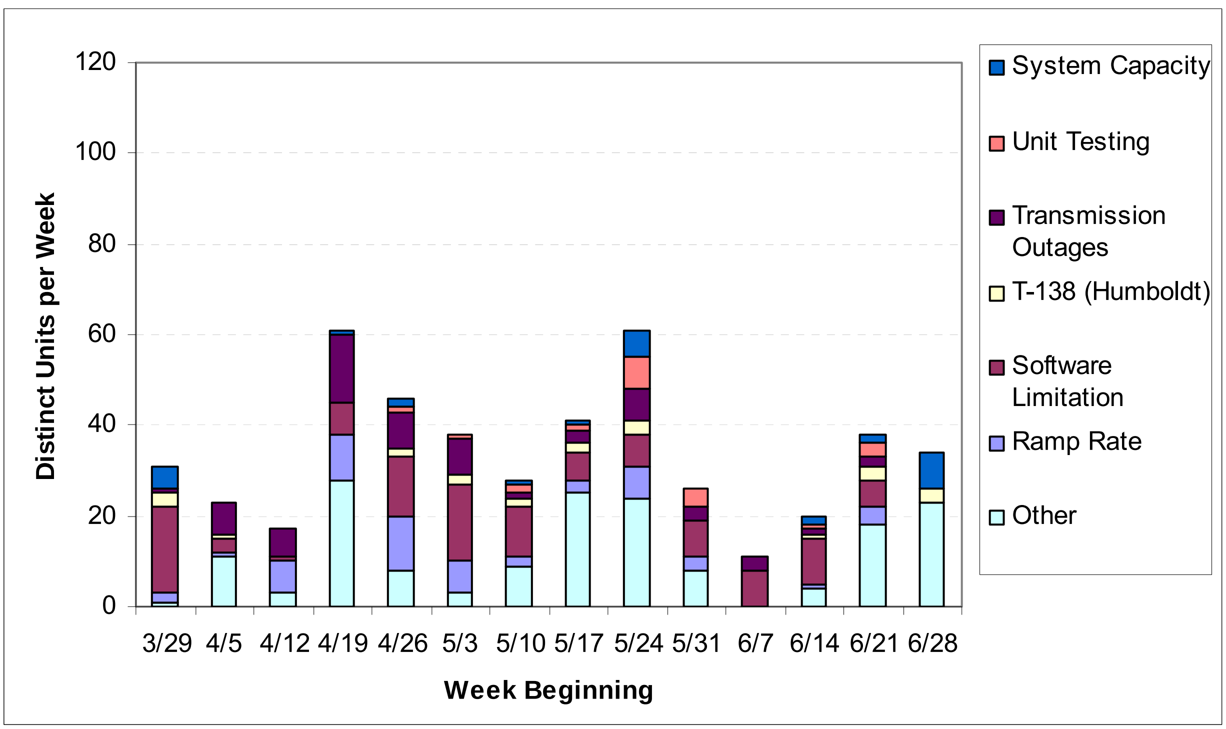


Figure 3.8 Number of Resources Dispatched for Real-Time ED by Reason



3.3 Market Impact of Exceptional Dispatch

It is not possible to directly estimate the market impact of ED because undertaking such an analysis would require knowing the counter-factual of what prices should have been if the reliability constraints driving ED were incorporated into the market model. If that were possible, those issues would already be modeled by the software, obviating the need for the ED in the first place.

We can, however, discuss the potential impacts conceptually. Since most exceptional dispatches are limited to committing units to their minimal operating level in the day-ahead market and such minimum load energy is not eligible to set price under any case, the market impacts of such dispatches may not be that significant. As long as there is a well-founded reliability need for having a unit on-line, the market outcome from having the operator manually force it on in the day-ahead market may not be appreciably different than what would occur if the constraint leading to this action was in the market causing the market to dispatch the unit automatically. However, to the extent exceptional dispatches are overly conservative or the reliability criteria driving the ED can be met by different combinations of unit commitments, having the constraint in the market model and managed by the market optimization will likely produce a more efficient and different market outcome. In this case, prices would be different but not necessarily higher relative to the ED case.

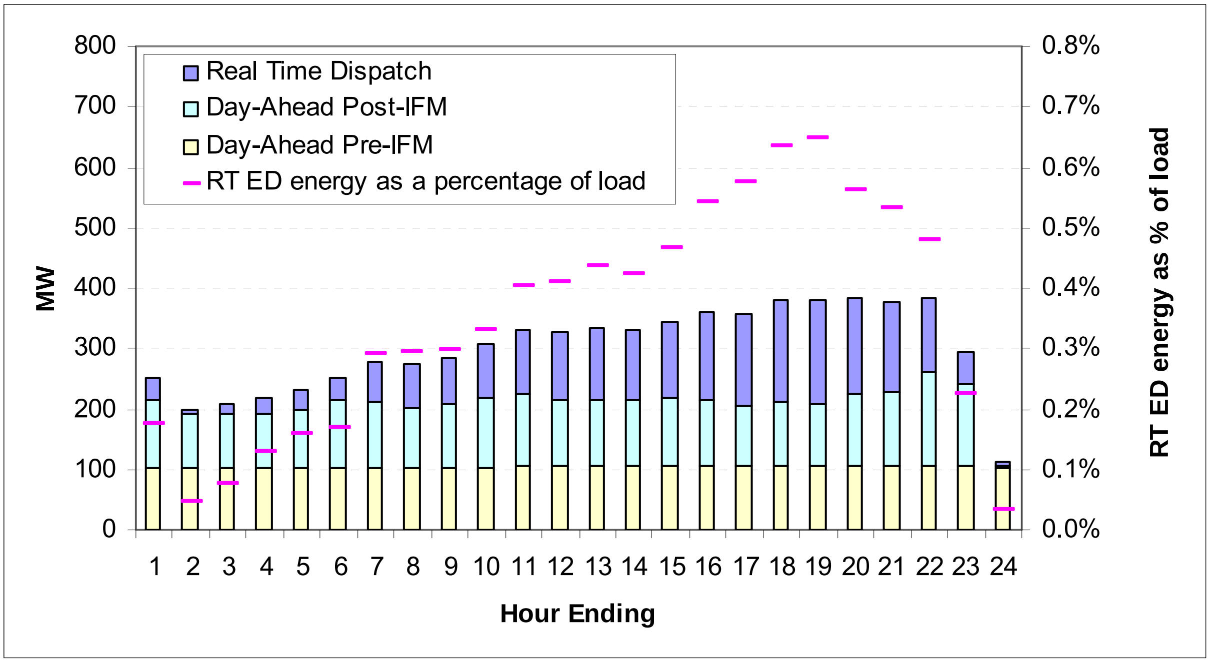
Exceptional dispatches for energy above the minimum operating level of the units, which are limited to the real-time market, can distort and suppress market prices if the original market bids for this energy are at or above prevailing market prices. In this case, having the reliability constraint driving these EDs incorporated into the market model would likely lead to higher LMPs at the location of the ED and the surrounding area that defines the reliability constraint.

To get a sense of the potential for price impact on the real-time market, we have considered the volume of energy above a unit's minimum operating level that is inserted into the market by ED. If the volume is large (e.g., more than 5 percent of total market volume), ED may have had an impact on market prices depending on how much of that energy had market bids that were higher than prevailing LMPs. If the volume is small, energy from ED is likely to have less of an impact if any at all.

The charts below indicate that energy from ED unit commitment and real-time ED energy dispatch represent, on average, a relatively small share of the market. The share was largest in April, when it approached 0.7 percent across the peak, but was below 0.5 percent for most hours of the day on average in April. Average real-time ED market shares for May were below 0.4 percent across the day, and below 0.2 percent across the day in June. Again, these figures do not consider system resources, decremental dispatches, or real-time commitments to minimum load.

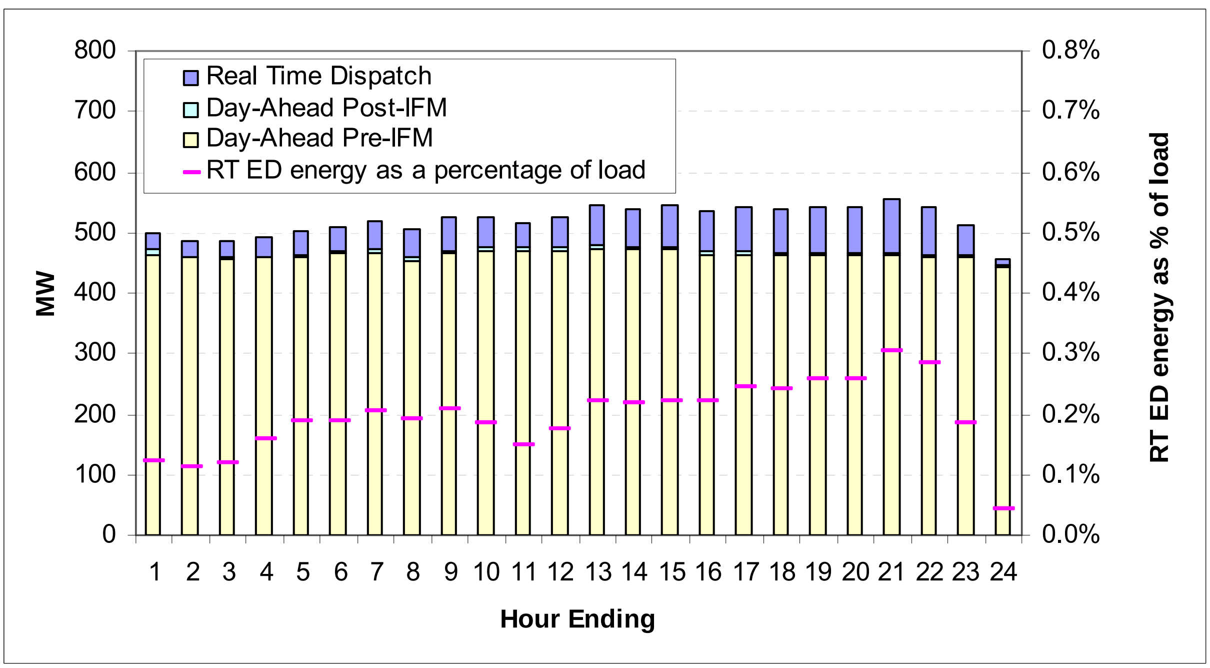
Operating Procedure M-402 was amended to allow operators to issue pre-IFM ED unit commitments as of the April 21 trade date. This allows the ED market volumes to be included in total dispatch, and avoids the over-commitment of resources that would result from commitment of IFM resources after the completion of the market. On average in April, Hour Ending 18 saw approximately 211 MW from resources committed at minimum load and an additional 168 MW of real-time ED energy.

Figure 3.9 Hourly Average Volume of ED Energy and Percent of Load (April)



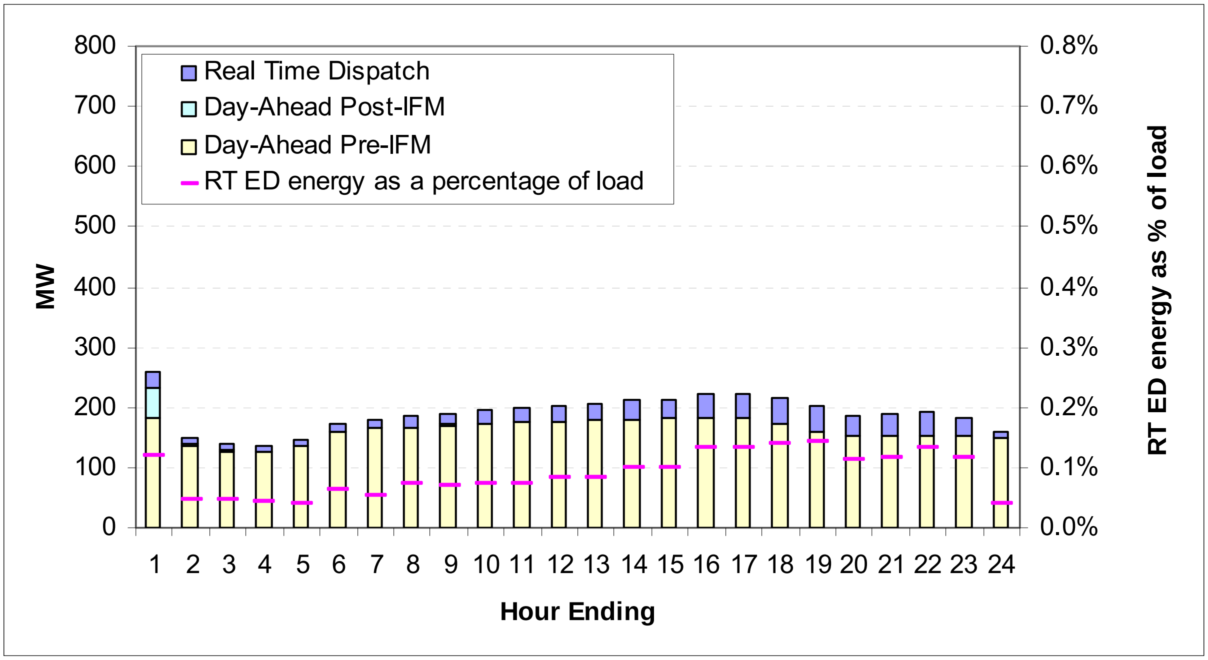
In May, the multiple transmission outages required additional unit commitment, with volumes fairly stable across the day, as resources committed to minimum generation capacity typically are committed for the full 24-hour day. On average, Hour Ending 18 exhibited 463 MW of energy from pre-IFM commitment and 3 MW from post-IFM commitment, with 72 MW of real-time ED energy dispatch.

Figure 3.10 Hourly Average Volume of ED Energy and Percent of Load (May)



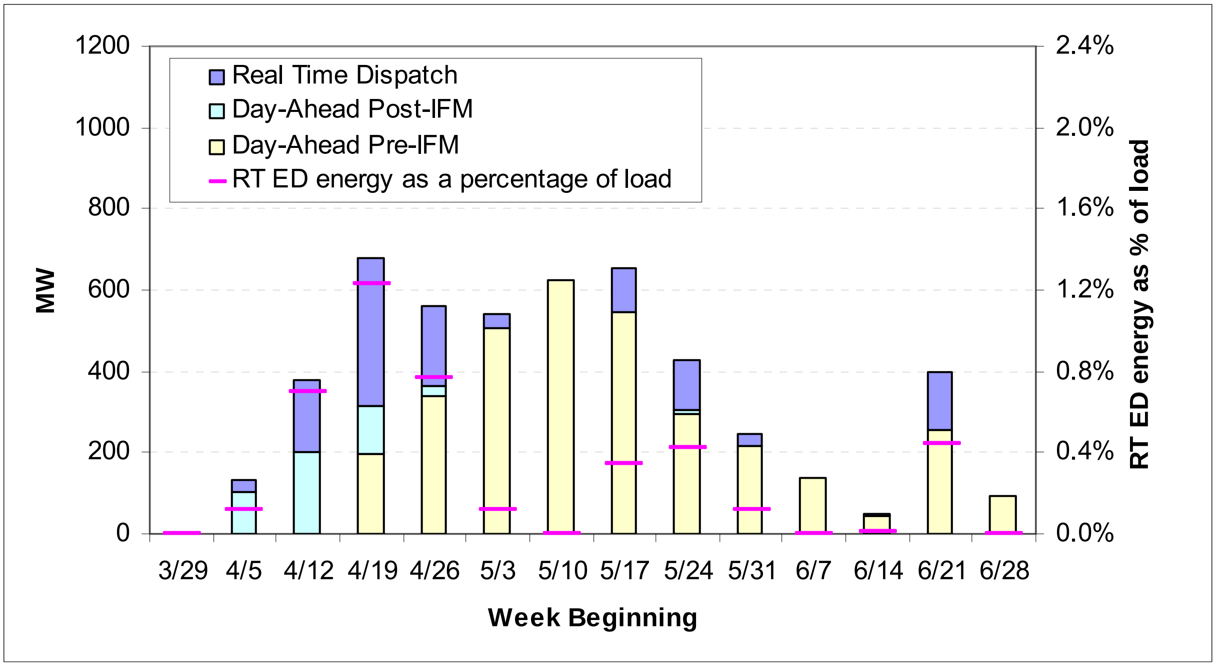
Volumes dropped in June to levels even below that seen in May, on average. Hour Ending 18 saw 174 MW of pre-IFM unit commitment energy, and no post-IFM unit commitment energy at all. Real-time ED energy dispatch averaged 42 MW in that hour.

Figure 3.11 Hourly Average Volume of ED Energy and Percent of Load (June)



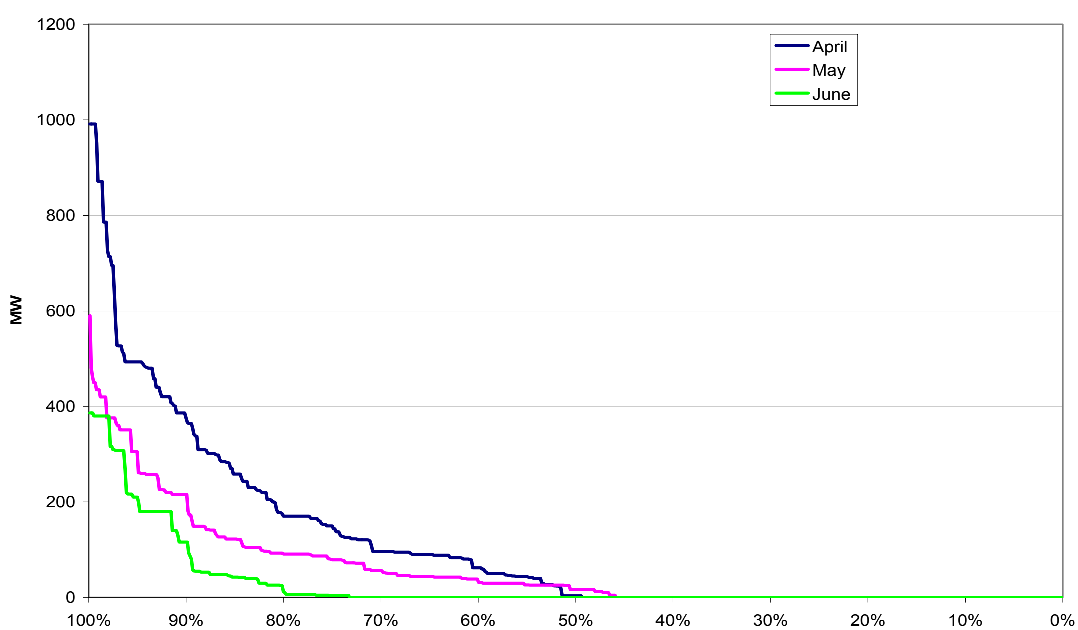
Many of the pre-commitments in April and May were due to the outages that occurred between the weeks of April 19 and May 17. The chart below shows the same indicators, but for weekly averages of Hour Ending 18. In the highest-volume weeks, energy attributed to real-time ED never exceeded 1.3 percent of load.

Figure 3.12 Weekly Average Volume of ED Energy and Percent of Load (Hour 18)



One can also observe that volumes of energy from real-time ED dispatch are following a downward trend by looking at monthly volume duration curves, depicted below in Figure 3.13. For example, consider the proportion of hours with real-time ED dispatch of at least 200 MW. This proportion has declined between April and June from approximately 20 percent of all hours to approximately 5 percent of hours.

Figure 3.13 Duration Curves of Hourly Real-Time ED Energy Dispatch Volumes



3.4 Utilization of Resources Committed at Minimum Load via ED

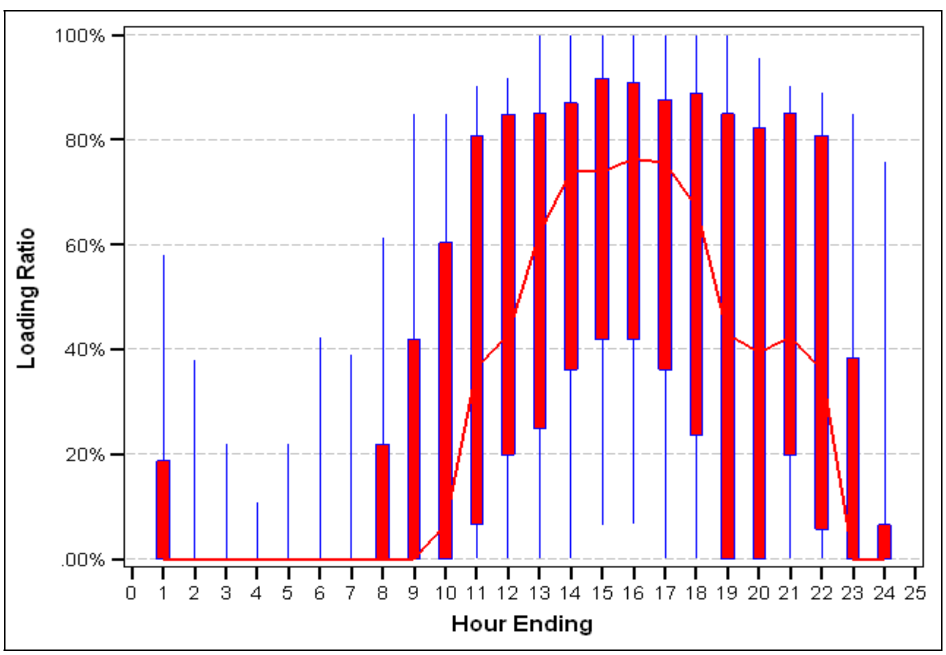
Some market participants have expressed concern that resources committed at minimum load by way of ED and remain at minimum load throughout the day are not earning additional revenues from energy and Ancillary Service sales.. We have investigated this concern in an aggregated analysis and found that these resources largely do get dispatched above minimum generation capacity in the day-ahead IFM, particularly across the super-peak hours of the day. To consider resources' average dispatch between minimum and maximum generation capacity, this analysis defines a "Loading Ratio" metric as the ratio of dispatch above minimum capacity divided by the range between minimum and maximum capacity:

$$LoadingRatio = \frac{DayAheadSchedule - P\min}{P\max - P\min}$$

In other words, when a resource is scheduled in the day-ahead market at minimum generating capacity, its loading ratio is 0; when it is scheduled to maximum capacity, its loading ratio is 1 (or 100 percent loaded).

Figure 3.14 shows statistical dispersions of aggregated day-ahead loading ratio by hour of day for the month of June 2009 for resources that were committed in the day-ahead via ED. Resources committed at minimum load largely remain there until the late morning hours, in which case their dispatch patterns follow load patterns on an aggregated basis. Across the mid-day peak hours, the median resource was 76 percent loaded. Note that roughly 95 percent of day-ahead ED unit commitments were instructions to minimum load.

Figure 3.14 Dispersions of Day-Ahead Loading Ratio among Resources Committed to Minimum Load via ED in June



Red bars indicate 25th to 75th percentiles of resources. Blue lines indicate 10th-25th and 75th-90th percentiles of resources. The red horizontal line depicts the 50th percentile.

Figure 3.14 illustrates the extent to which units committed via ED in the IFM were economic and were awarded provision of additional energy above their ED amount through the market. Additional revenue is also available through ancillary services and the imbalance energy market. Assuming these resources were not economic for unit commitment and would not have been committed through the IFM without an ED instruction, these additional revenues, resulting from bid-based market participation, would not have been available to this set of resources. Given this, and the evidence from Figure 3.14 regarding revenue opportunities, there are some units among those that are committed through ED that, in some months, have not sold much if any ancillary service or energy above their minimum load, The vast majority of units, however, have received additional revenues for provision beyond minimum load.

3.5 Analysis of Most Frequent Exceptional Dispatch Reasons

General Description of Situations that Require Exceptional Dispatch

Adequate reactive power is needed at all times in proximity to various load pockets in order to prevent instantaneous voltage collapses and to ensure grid reliability. Transmission equipment is rated by its ability to withstand prolonged excess load, and these equipment ratings are incorporated into capacity limits for transmission facility networks, known as *nomograms.* In addition to simply needing units online for their reactive power, these requirements specify that unloaded real power capacity be available throughout the grid, to ensure that transmission components can return to their thermal rated limits within a time frame of roughly 15 to 30 minutes, in the event those limits are exceeded. Voltage stability and thermal limit reliability problems can arise as a result of unexpected deviations of load from local, regional, and system-wide load forecasts, as well as from unexpected generator and transmission component contingencies. Outside of spinning and non-spinning reserves, the ISO's market software does not dispatch capacity for handling contingencies. Spinning and non-spinning reserve markets do not adequately specify the required locations of capacity for all of the system's reliability needs.

Beyond the broad zonal designations of spinning and non-spinning reserves, the market software's ability to dispatch resources to prevent reliability problems in the face of contingencies or load forecast errors is limited to what can be modeled as flow limit constraints. Nearly every transmission system component has its thermal flow limit modeled as a constraint by the market software. Under normal operating conditions, the software is able to ensure that no thermal constraints are violated. If a generator or transmission system component fails, however, thermal constraints may change and can be violated. Given that the software does not know how to commit the locational generation capacity that would be required to avoid the reliability problems that would arise as a result of contingencies, flow limits must be constrained to levels that would protect many of the major transmission components if a contingency were to occur. The software directly models many major transmission system contingencies, constraining all pre-contingency dispatches so that major transmission components would not be overloaded if any single "modeled contingency" were to occur. Engineers have also defined hundreds of nomograms that limit the flows over combinations of transmission system components in order to protect those components from suffering thermal limit violations after many possible system contingencies.

While we believe that the ISO may take a variety of steps to reduce the frequency and volume of ED, it is unrealistic to expect that these flow limit nomograms and modeled contingencies can fully replace EDs for several reasons:

- First, the nomogram constraints and modeled contingencies are limited to major transmission components due to the desire for the software to complete its optimizations in a reasonable amount of time. Nomograms cannot reasonably be created to keep real-time flow limits of all minor transmission lines at levels such that an outage of a particular small transmission line would not overload some other nearby small transmission line. Moreover, the software does not model generation contingencies at all.
- Second, the energy dispatch that satisfies the flow limit nomograms may not satisfy either the voltage or thermal constraint capacity needs for specific load pockets. The software does not consider at all the reactive power needed to maintain voltage stability within the system's various load pockets. Nomograms and modeled contingencies can help to ensure that there is enough energy within the load pockets to prevent thermal violations after a contingency. However, that energy could, for example, be from a single large unit, rather than the variety of units needed for voltage support in locations throughout a load pocket. Similarly, available capacity may be needed in more specific locations to protect against potential thermal constraint violations of "smaller" components.
- Furthermore, the software only does limited modeling of neighboring balancing areas. Therefore, it cannot accurately model the actual flows over many inter-ties or transmission system components that receive a large percentage of their flows from an inter-tie. Nomograms in the software or modeled contingencies can only commit capacity and dispatch energy to limit *market* flows. When these market flows are known to differ substantially from actual flows, the related nomograms and modeled contingencies are not defined in the software. Instead, day-ahead actual flows are estimated outside of the software and exceptional dispatches may be needed to provide corrective generation capacity in various ISO regions in order to protect the system's reliability from outages of inter-ties or nearby transmission components.
- Finally, while the capacity of a derated transmission line can be input to the software for the real-time unit commitment (RTUC) run following the derate, in practice, the nomograms for surrounding lines take some time to be updated after a forced transmission outage, as this necessarily involves manual work. In rare cases, EDs for both capacity and energy are used as proxies for the nomograms until the outages are entered. Even with planned transmission outages, the software still has the same limitations concerning the modeling of reactive power and the inability to dispatch capacity to correct possible thermal constraint violations. Therefore, EDs must be issued after planned transmission outages for the same reasons they are issued under normal operating conditions. There will be a need for *more* EDs after planned transmission outages, however, because the components being protected from the new set of "next" possible contingencies are more heavily loaded due to the original planned outage.

Transmission Outages

The most frequent reason for ED capacity and dispatch energy, as logged by operators, is for "Transmission Outages". EDs of units for capacity labeled as Transmission Outage serve as workarounds for the same reactive power and corrective capacity modeling limitations of the software discussed in the previous section.

Only a small fraction of EDs for energy that are logged as being for a Transmission Outage are for mitigating actual violations of thermal constraints.[43] When there is a transmission outage, the RTM software is updated to dispatch energy in accordance with the line's outage by the very next RTUC run. Therefore, there is generally no need to issue an ED to commit a unit to provide energy in response to a transmission outage, except when nomograms that would limit pre-"next"-contingency flows on surrounding lines are not defined in the software.[44]

Based on discussions with Operations staff and DMM's review of ED data, most EDs for Transmission Outages are issued to commit capacity for known Transmission Outages. For the duration of a scheduled outage, many next credible contingencies (single or double) would cause voltage violations. The voltage impacts of the next contingency cannot be simulated by the market software. Therefore, EDs may be needed to commit enough capacity to maintain voltage stability. On the other hand, an outage may result in concern over nearby transmission system components (whose market flow after contingencies has not been constrained by nomograms or modeled contingencies) having their thermal limits violated after the "next" contingency. Most Transmission Outage EDs for capacity were due to planned outages of inter-ties or lines that received a significant portion of their flows from inter-ties. According to Operations staff, most of those EDs provided corrective capacity for post-"next"-contingency thermal constraint violations.

Similarly, most Transmission Outage EDs for dispatch energy are during planned transmission outages of transmission components that are electrically close to an inter-tie. Due to the inability to accurately model the actual flows on these and nearby lines, some nomograms for limiting pre-"next"-contingency actual flows to levels that would be safe post-"next"-contingency are not entered into the software. Instead, actual flows are monitored by operators who issue EDs if the actual flows violate the nomogram.[45]

ISO operators issued exceptional dispatches to work around several key transmission outages in April and May, as they deemed necessary to maintain reliability. These instructions are primarily day-ahead unit commitments, but also include some real-time instructions. The following outages required the most commitments during the quarter:

- The Devers-Valley 500kV line, which connects the Devers substation near Palm Springs to the Valley substation near Perris, was out from April 6 through 29 for circuit breaker work (Outage 928990). This required daily commitments of up to eight resources per day between April 17 and 29.

- The Devers-Palo Verde 500kV line, which connects Devers to the Palo Verde substation in Arizona, was out of service for related work at the Devers substation between May 2 and 6 (Outage 952092). This required daily commitments of up to 12 units during this outage.

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[43] A minor exception to this general rule occurs immediately after a forced transmission outage occurs when a nomogram to preventatively limit the impacts of the outage is not already being enforced. In this situation, the operator may issue an ED for energy to mitigate real-time thermal constraint violations of lines if the operator feels that waiting for the next RTUC run to mitigate the thermal constraint violation threatens reliability.

[44] Or when there is a forced outage in real time that requires energy before the next RTUC run.

[45] Another reason for Transmission Outage EDs for dispatch energy concerns forced outages when the nomogram flow limits are entered into the software. After a forced outage occurs, energy is sometimes exceptionally dispatched to reduce flow limits to sufficiently low levels for preventing thermal constraint violations should the "next" contingency occur. Such EDs of dispatch energy will occur in the short time period before the appropriate nomograms are updated in the software.

- The Southwest Power Link, which brings power along the California-Mexico Border to San Diego from Arizona, was out for maintenance between May 8 and 18 (Outages 946641 and 946648). This outage required up to 11 unit commitments per day.
- The Pittsburg 230kV bus was out from May 18 through 21 (Outage 1013118) and required one commitment per day.
- A section of the Contra Costa-Lone Tree 230kV line, in the East Bay Area, was out from March 23 through June 10 for reconductoring (Outage 954095). This required commitments of up to three units per day.
- The Ignacio-Sobrante 230kV line, also in the East Bay, was out for upgrade work at the Sobrante substation, between May 30 and June 6 (Outage 1014198). This work required commitments of up two units per day.

Figure 3.15 shows the frequency of EDE instructions for transmission outages. “Post-IFM” instructions are day-ahead commitments issued after the IFM market is complete. “Pre-IFM” instructions are day-ahead commitments issued before the IFM market begins; these began after a procedural change effective Trade Day April 21, which requires that the commitment was made the previous day and is not expected to be cleared in the market. Note that once the Pre-IFM procedure was put into place, most of the ED related to transmission outages have been placed into the day-ahead market and were reflected in the optimization. Also of note in Figure 3.15 is the high reliance in May on ED to mitigate reliability issues stemming from transmission outages, the decline in frequency and estimated MWh through June and the impact this has had on overall ED. This decline is due to the end of the outages that required ED, as outages typically are completed prior to the summer.

Figure 3.15 Weekly Frequency of ED for Transmission Outages

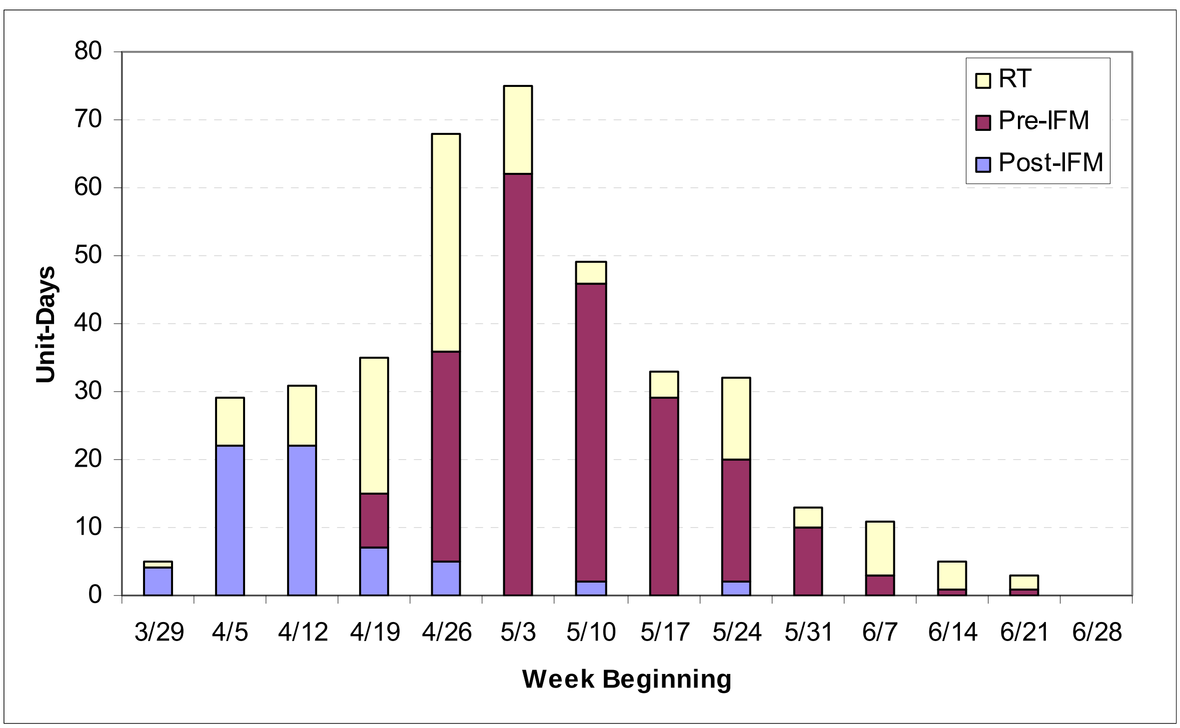
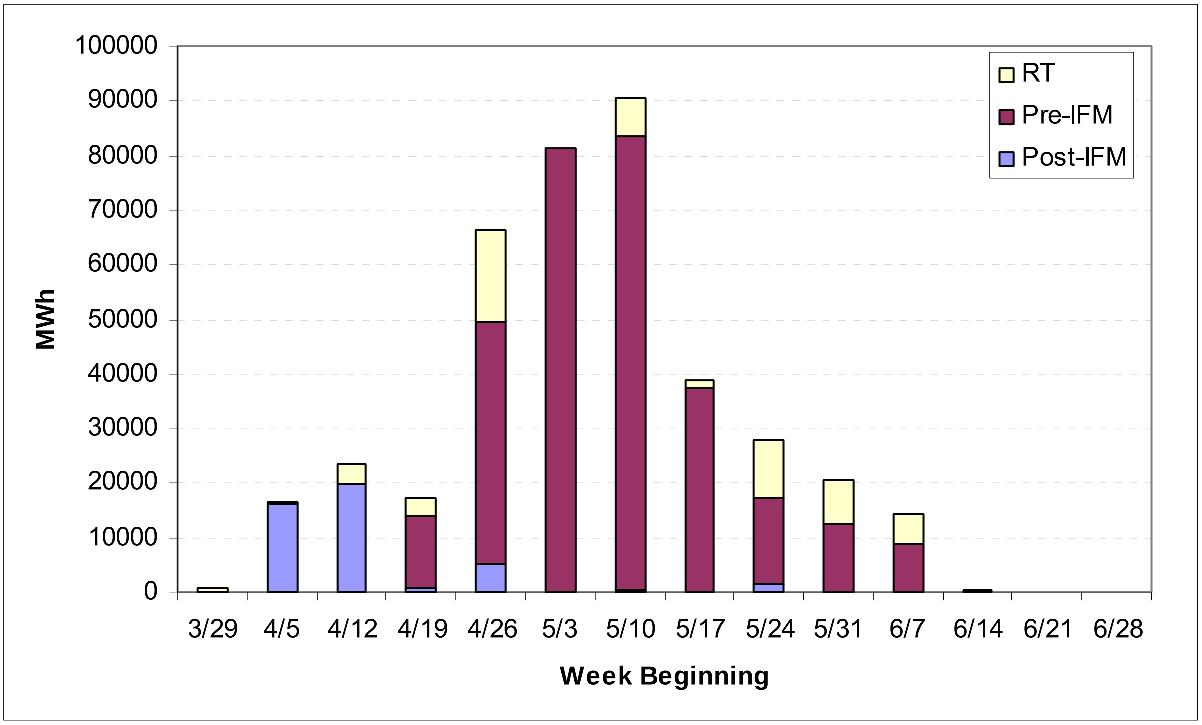


Figure 3.16 Weekly Energy Volume of ED for Transmission Outages



Capacity Reasons

The following reasons are primarily used by operators to log EDs that commit units to their Pmins. EDs are issued for the following capacity reasons to manually account for the software's limitations in dealing with capacity for voltage stability and thermal constraints as described above. The specific reason mainly designates the load pocket or region whose reliability may be threatened without the ED. The reasons are roughly grouped in order of the size of the region. Operators will first exceptionally dispatch resources to meet the more local reliability requirements. If the unit commitments and capacity needed to meet the more local reliability requirements are not sufficient for meeting the broader region's reliability requirements, EDs will be issued for the more regional reasons, such as System Capacity. EDs for the more local reasons, such as G-206, will have more units committed for local voltage stability than will the broader regions that encompass those localities. The regional reasons, such as T-103 and System Capacity, are almost always capacity commitments for thermal constraints, as adequate units should always be committed within the entirety of the broader regions to meet the regional reactive power requirements. Capacity reasons tend to require more commitments during periods of high loads and/or outages.

G-206 (San Diego Area Support)

G-206 is an ISO operating procedure that defines the generation requirements for the San Diego area. This procedure is used only to make day-ahead unit commitments; if such committed resources are to be moved by ED energy dispatches in real-time, they would be moved under other applicable reason codes, such as "Ramp Rate." The defined generation requirements protect the area from the potential voltage stability and thermal constraint problems discussed above at the beginning of Section 3.5. Specifically, G-206 defines the units that need to be committed for various San Diego area load levels when the region's import limit has been reached. It lists the set of possible substitutions among San Diego area units that operators can use in considering costs. It also defines a minimum proportion of total load that must come from internal units. According to Regional Transmission Engineers, voltage stability is particularly essential in the San Diego area.

The charts below respectively show the weekly frequency and total volume (in MWh of energy) of ED commitments for G-206. Ongoing clearances for transmission work in the San Diego area required repeated ED commitments in April and May. After the procedural change effective trade day April 21, the ongoing nature of the outages enabled Operators to commit resources before the running of the IFM market, so that energy from those resources could be included in the power optimization and the market would not double-commit resources. A heat wave that occurred the final weekend of June 27-28 also required that the ISO issue ED commitments.

Figure 3.17 Weekly Frequency of ED for G-206 San Diego Support

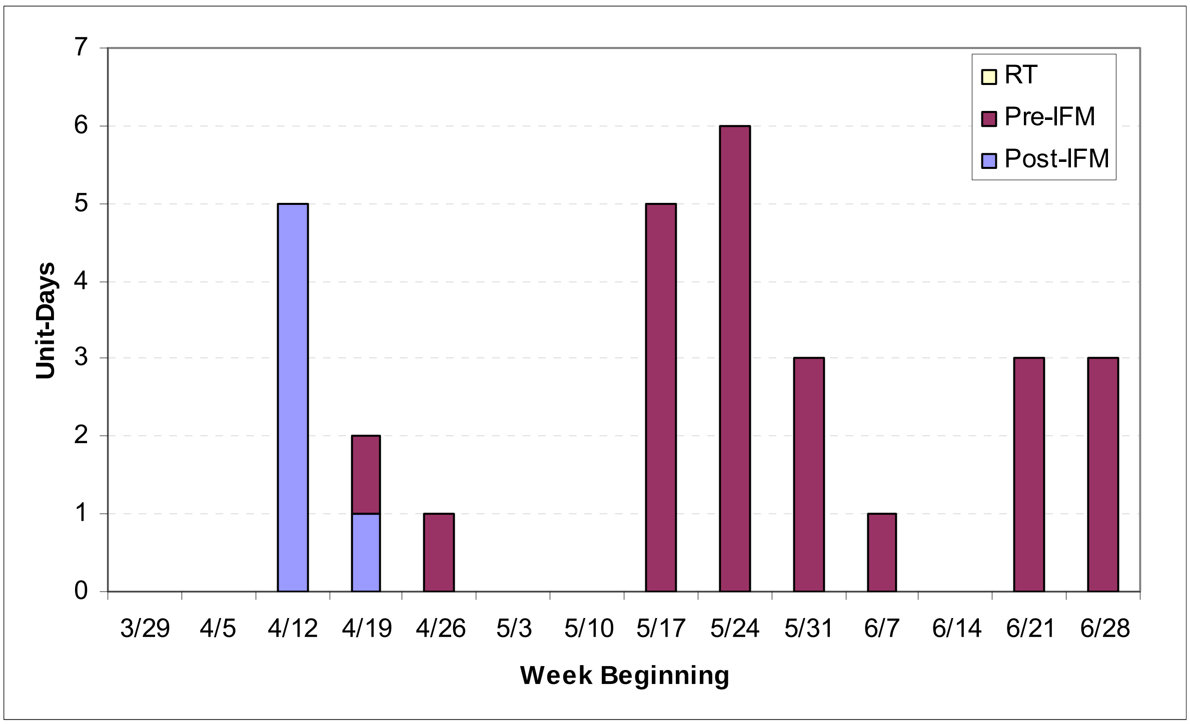
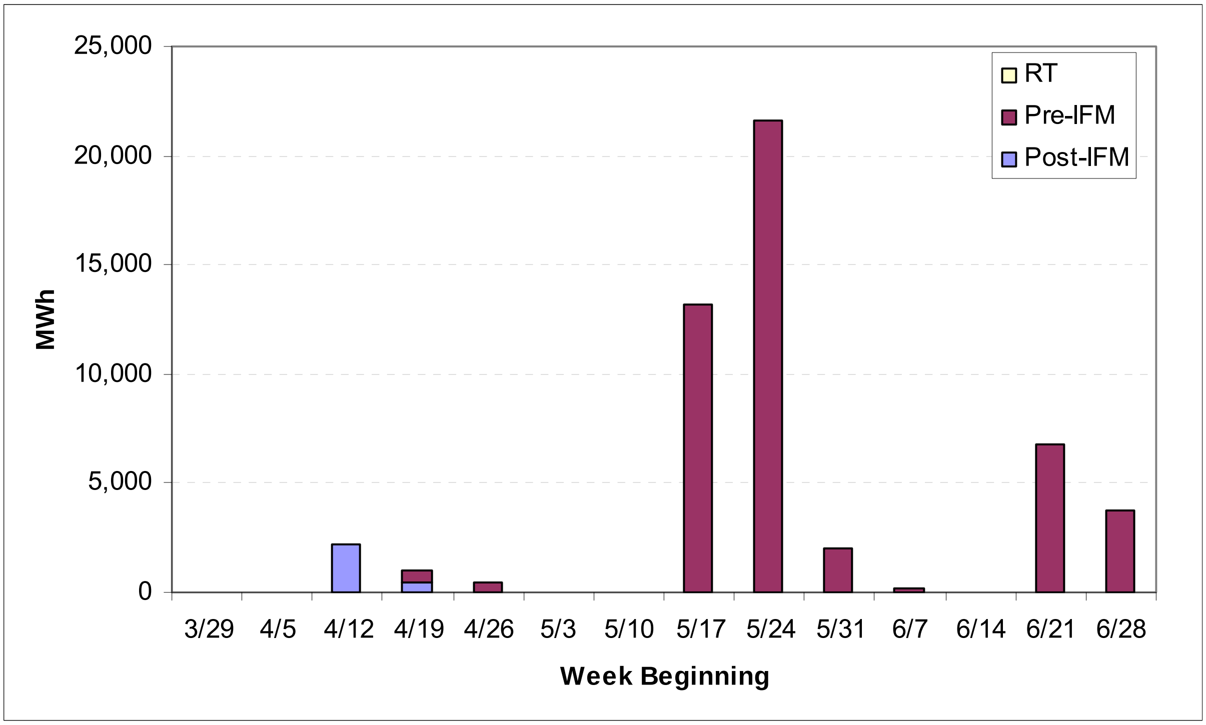


Figure 3.18 Weekly Energy Volume of ED for G-206 San Diego Support



G-233 (Bay Area Support)

G-233 is an ISO operating procedure that defines the generation commitment requirements for the San Francisco Bay Area. G-233 is for day-ahead commitments. The defined generation requirements protect the area from the potential voltage stability and thermal constraint problems discussed above. Forced generation outages are emphasized as more of a reliability concern in the Bay Area than in the other two local areas. Like G-206, G-233 defines a minimum amount of capacity that must come from internal resources. This minimum internal resource requirement varies with the local load levels. Unlike G-206, G-233 identifies groups of generators within the Bay Area. For various load levels, each group provides a required amount of committed capacity. Capacity nomograms define the amount of capacity that can be substituted among nearby generation groups for different load levels.

The exceptional dispatches with reason specified to be G-233 in previous DMM presentations have largely been reclassified as RMR dispatches, as they were dispatches of RMR resources for a local reason. Fewer than ten dispatches during the quarter remain as exceptional dispatches. Thus, these are grouped within the "other" category in Figure 3.3 through Figure 3.5.

G-219 (SCE Orange County Area Support)

G-219 defines the generation commitment requirements for the third and final local area, the Orange County area, a large load pocket within Southern California Edison territory. The defined generation requirements protect the area from the potential voltage stability and thermal constraint problems discussed above. Like the other two local area procedures, G-219 specifies a few major contingencies from which its generation requirements are explicitly designed to protect reliability. G-219 specifies the minimum internal generation capacity for specific load levels in the Orange County area. It defines the maximum effective capacity for each generator in meeting the above internal generation capacity requirement. It also specifies the effectiveness factors to use for each internal unit when using a unit to replace another in meeting the internal capacity requirement. The maximum effective capacities and effectiveness measures in replacing some generating units with others in G-219 and G-233 defines sub-regions within each of these localities that require a certain amount of reactive power for various load levels. Unlike the distinct local areas, however, these sub-regions are connected enough to the other sub-regions that generation commitment from one nearby sub-region can replace generation commitment from another, but with a diminished effectiveness. As indicated by the higher volumes in the last several weeks of the quarter, G-219 requirements specify more commitments during high-load periods.

Figure 3.19 Weekly Frequency of ED for G-219 (Orange County)

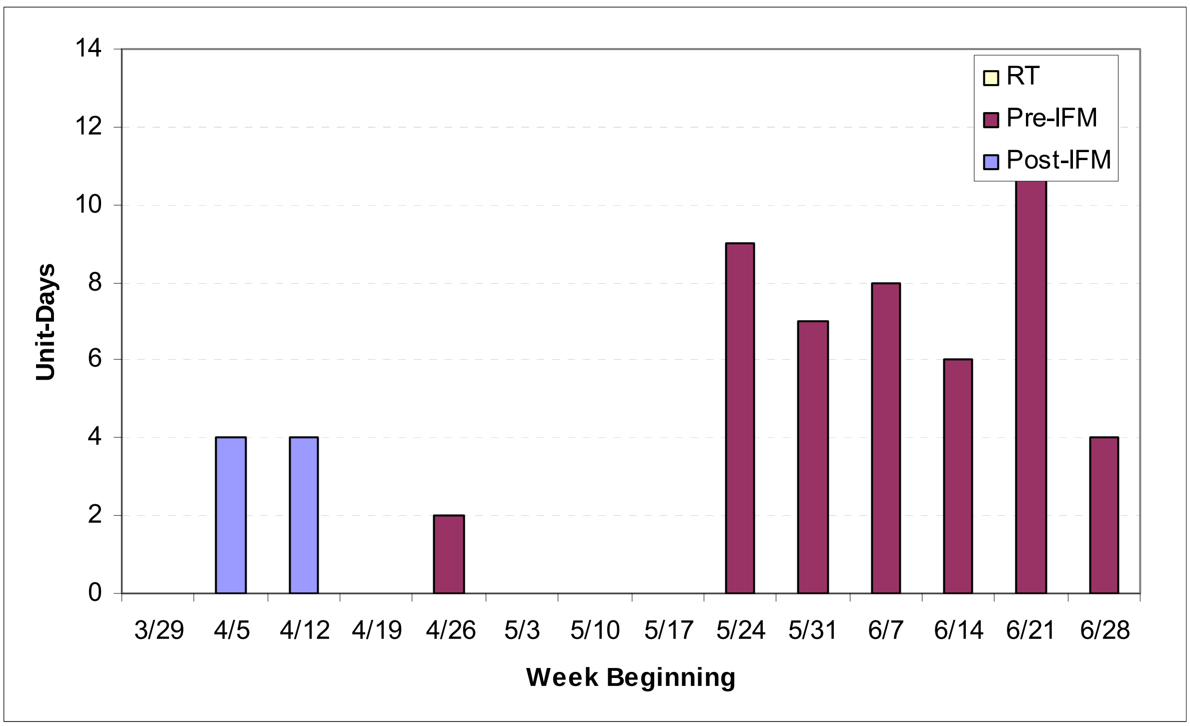
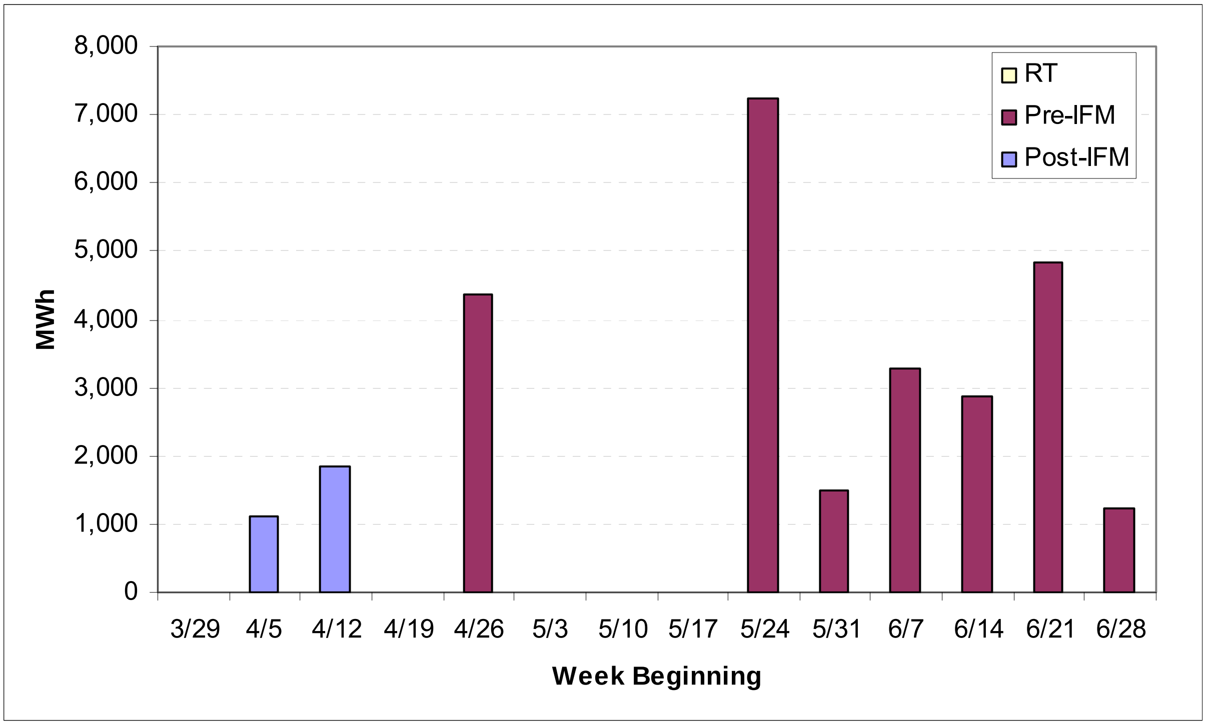


Figure 3.20 Weekly Energy Volume of ED for G-219 (Orange County)



G-217 (South of Lugo Support)

These are day-ahead commitments and real-time congestion management to provide generation requirements on the SCE side of the Lugo Substation, which is a gateway for transmission of power from Nevada to California. Day-ahead ED commitments for G-217 are only necessary if the G-219 Orange County commitments are not sufficient to meet the requirements of the procedure. Starting with G-217, the Capacity Reasons now define the generation commitment requirements for ISO regions that encompass one or more of the above local reliability regions. Together with G-219, G-217 defines generation requirements for the SCE area. As with all of these nested generation commitment procedures, generation is committed for the more local procedure (G-219) before assessing whether more generation needs to be committed in different areas for the more regional procedure (G-217). The defined generation requirements of G-217 protect the region from the same general potential voltage stability and thermal constraint problems discussed above. G-217 defines generator groups for different South of Lugo (SOL) sub-regions, much as G-233 does for the Bay Area. G-217 specifies how much capacity must be committed from each of the groups for all forecasted SOL load levels. Furthermore, it defines the effectiveness factors to use when substituting generators from one group for generators from another.

The charts below show weekly frequency and energy volume of ED for G-217. The peak in late May was due to unseasonably warm weather in Southern California that week; another spike that required commitments occurred over the weekend of June 27-28. As indicated by the higher volumes in the last several weeks of the quarter, G-217 requirements specify more commitments during high-load periods. The real-time ED energy dispatches were decremental or were commitments to minimum load, and were thus calculated to be of zero volume,

Figure 3.21 Weekly Frequency of ED for G-217 (South of Lugo)

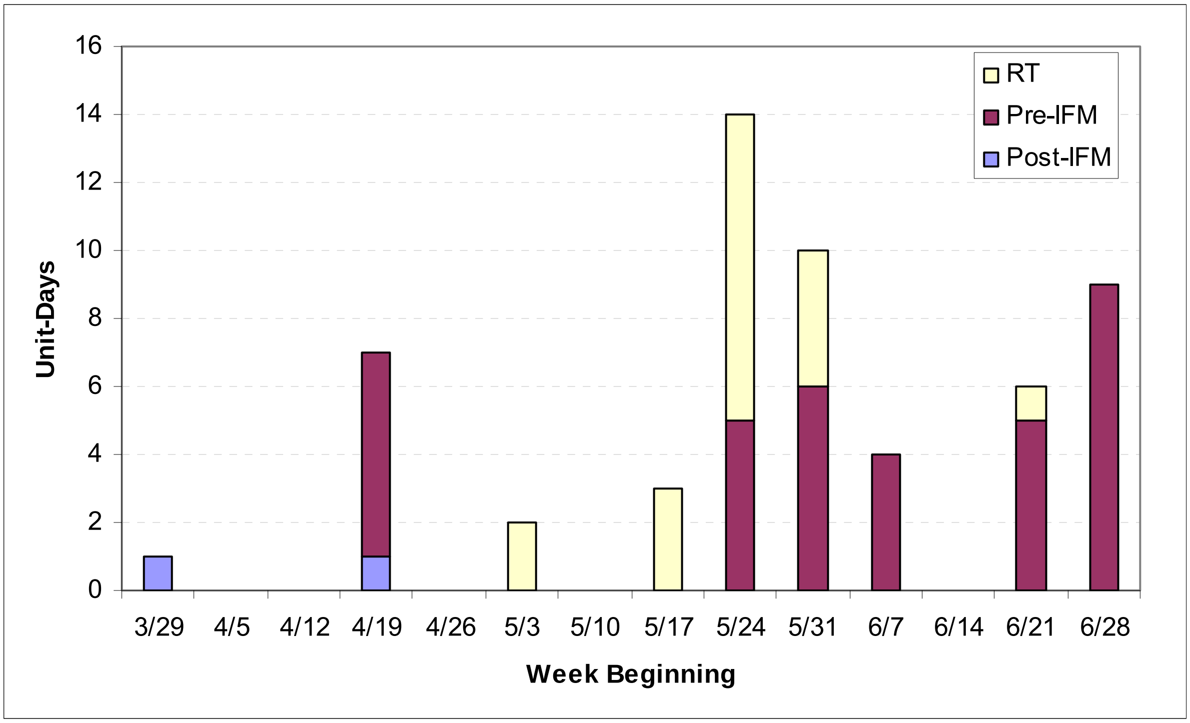
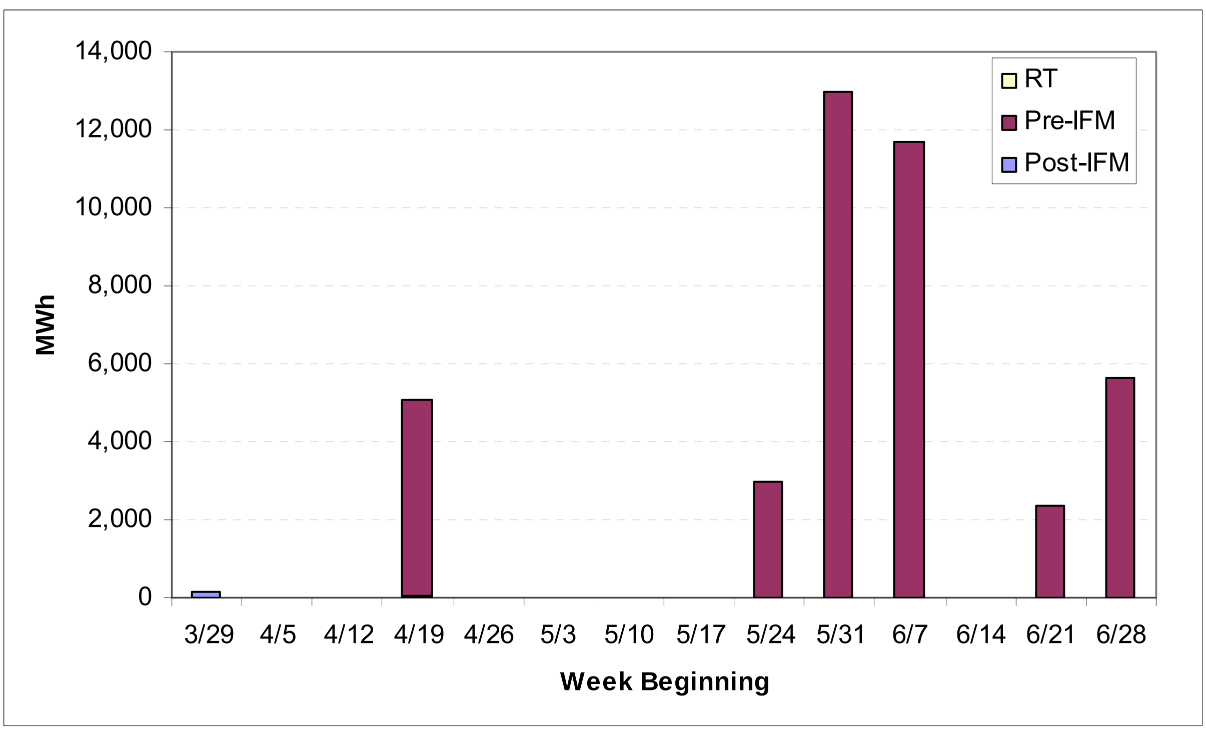


Figure 3.22 Weekly Energy Volume of ED for G-217 (South of Lugo)



T-103 (SCIT)

This is the *Southern California Import Transmission Nomogram,* a technical limit on the volume of power that can be instantaneously imported into Southern California at a given moment, and requires a certain level of generation relative to imports and load within Southern California. Many SP15 units can help to meet this requirement.

In practice, T-103 defines generation requirements for the Southern California region. Technically, T-103 defines a nomogram that specifies the maximum SCIT import versus the East-of-River flow for all Southern California region load levels. It also specifies how the nomogram changes for outages on dozens of lines, paths, inter-ties, and other transmission components in the region. The procedure specifies that generating units will be committed so that the nomogram will not be violated within 20 minutes of the worst single contingency. This commitment specification has turned T-103 from a procedure that mitigates transmission path constraints into a procedure that commits generation capacity for corrective action on a potentially violated nomogram constraint, just like the G-procedures described above. The data shows that in the second quarter, T-103 was not listed as the reason for any ED of dispatch energy other than “Ramp Rate” for units whose capacity had been issued an ED for capacity for the same trade date. So, T-103 is used for committing enough generation capacity in the Southern California region so that if there is a contingency, the SCIT-East-of-River nomogram will cease to be violated within 20 minutes of the contingency. Of course, if a contingency did take place that violated the nomogram, T-103 could be logged as the reason for the ED that dispatched the incremental energy for mitigating the constraint. “Transmission Outage SCE or SDGE” could also be logged as the reason for the ED of dispatch energy after the contingency, however.

The charts below show weekly frequency and volume for SCIT. The spike in April was due to the requirement in the presence of the Devers-Valley outage, which ended April 29. The real-time dispatches that do not show up in the volume chart were in the decremental direction, or were commitments to minimum load.

Figure 3.23 Weekly Frequency of ED for T-103 (SCIT)

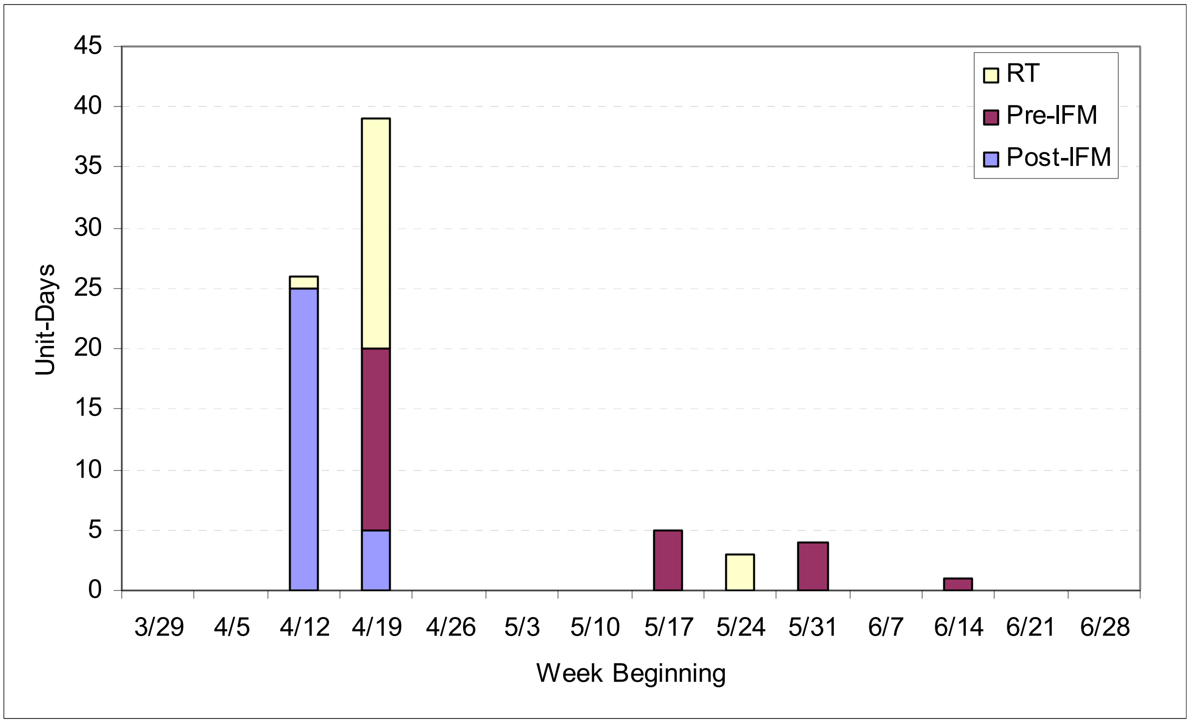
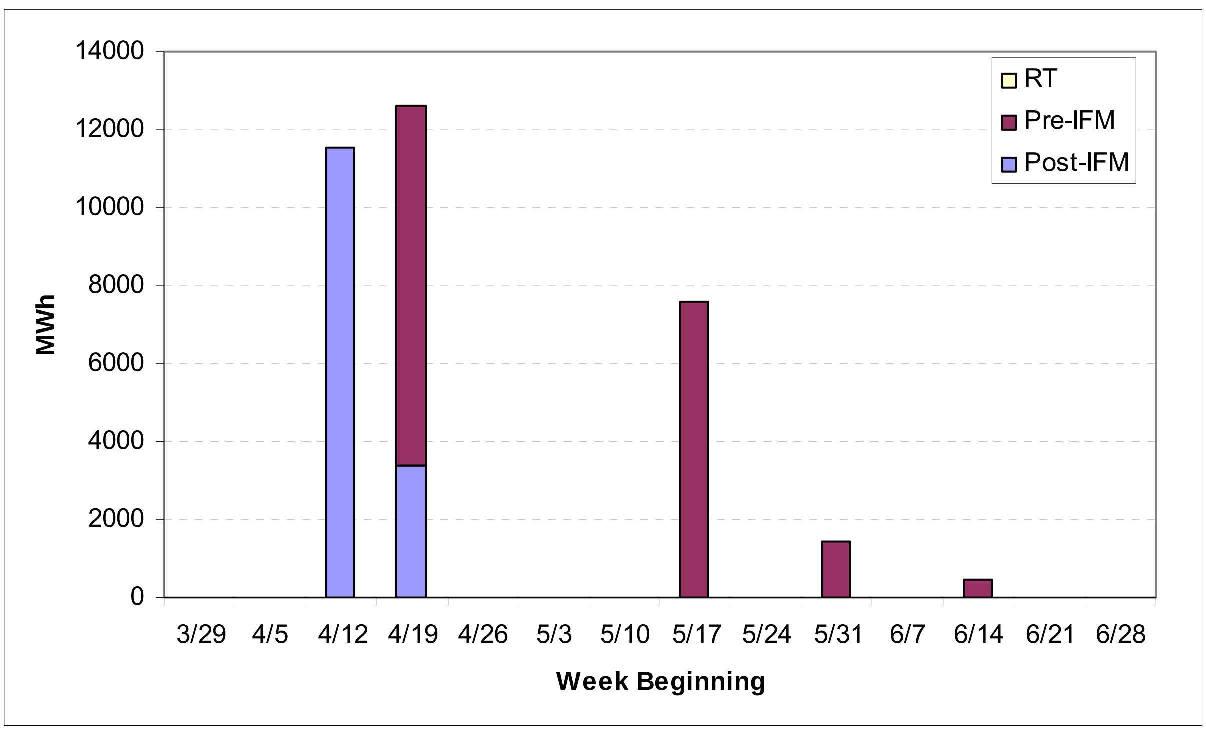


Figure 3.24 Weekly Energy Volume of ED for T-103 (SCIT)



SP26 Capacity

This is a zonal requirement based on forecast load for SP26 for which the ISO commits units in the day-ahead market. Nearly any resource within Southern California can contribute to meeting this requirement.

The SP26 Capacity reason is logged when an ED is issued to commit a unit to meet capacity requirements in the area south of Path 26 (Southern California). The capacity requirements are to protect that area against loss of the Pacific DC inter-tie. As discussed above, the current software lacks the capability to dispatch resources to accurately address contingencies on many inter-ties. Therefore, exceptional dispatches must be issued to ensure there is enough online capacity to mitigate any thermal constraints in the region within 20 minutes of the inter-tie outage. There is clearly considerable overlap between this reason and the T-103 reason above. The SP26 capacity requirement was driven by the concurrent transmission outages in April and May and also to protect against inaccurate load forecast, which was an issue at that time.

Figure 3.25 Weekly Frequency of ED for SP26 Capacity

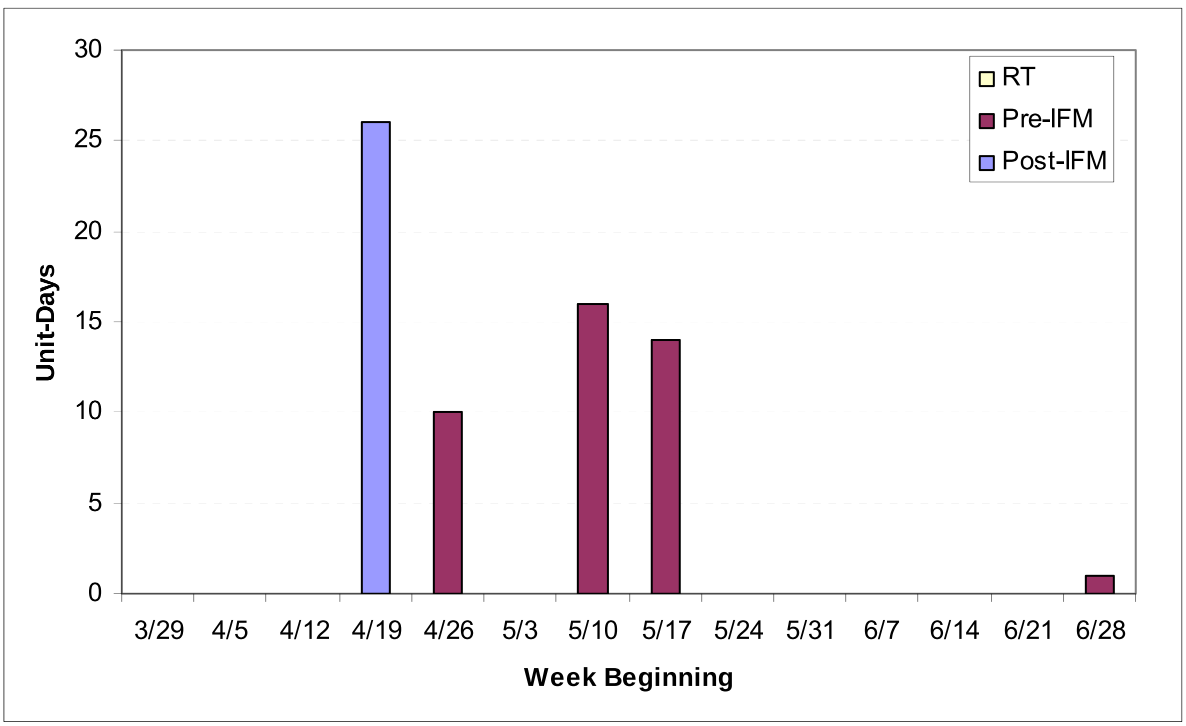
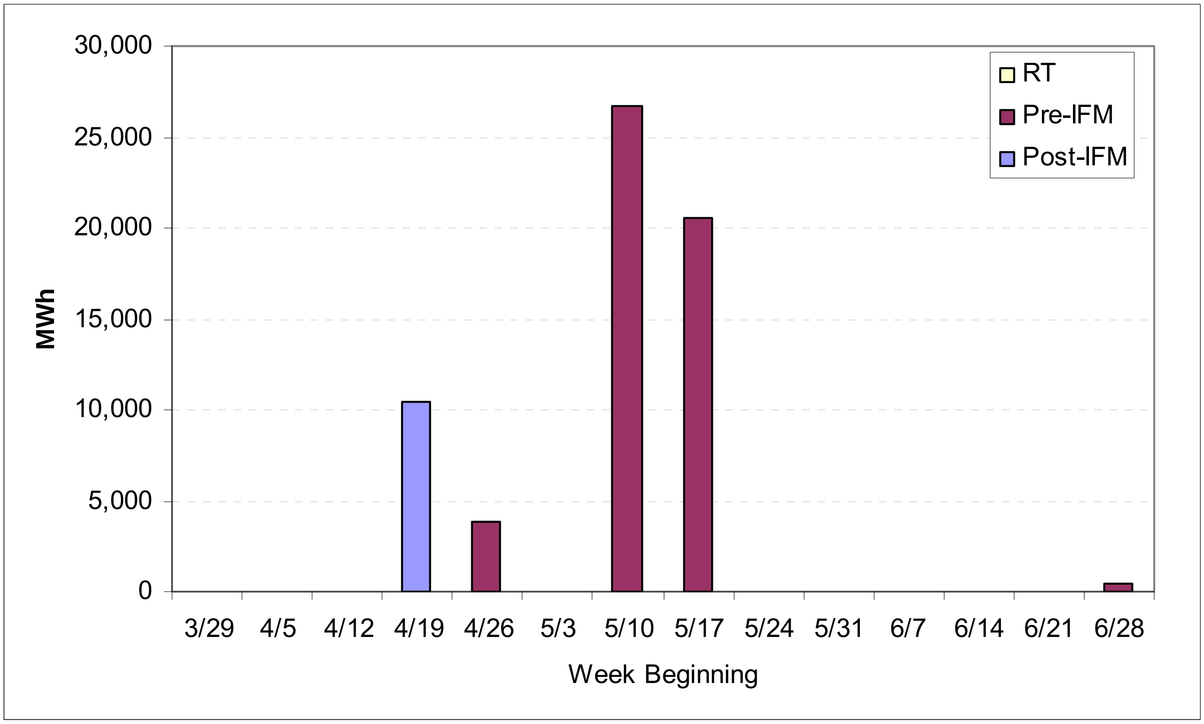


Figure 3.26 Weekly Energy Volume of ED for SP26 Capacity



System Capacity

EDs for System Capacity help to meet generation capacity requirements for the entire ISO region. The defined generation requirements protect the area from the potential voltage stability and thermal constraint problems faced by smaller regions, as discussed in the previous subsections. The ISO should retain online generation capacity sufficient to avoid a system-wide voltage collapse. System Capacity is only used in practice for ensuring there is enough online capacity in California to meet demand in the event of a series of worst-case scenarios simultaneously occurring. The charts below show that real-time ED energy dispatches were issued during unseasonably warm and above-forecast periods in late May and late June. As noted in other sections, the June spike occurred in anticipation of a weekend heat wave. The real-time ED dispatches depicted in Figure 3.27 not accounted for in Figure 3.28 refer to decremental dispatches or commitments to minimum load.

Figure 3.27 Weekly Frequency of ED for System Capacity

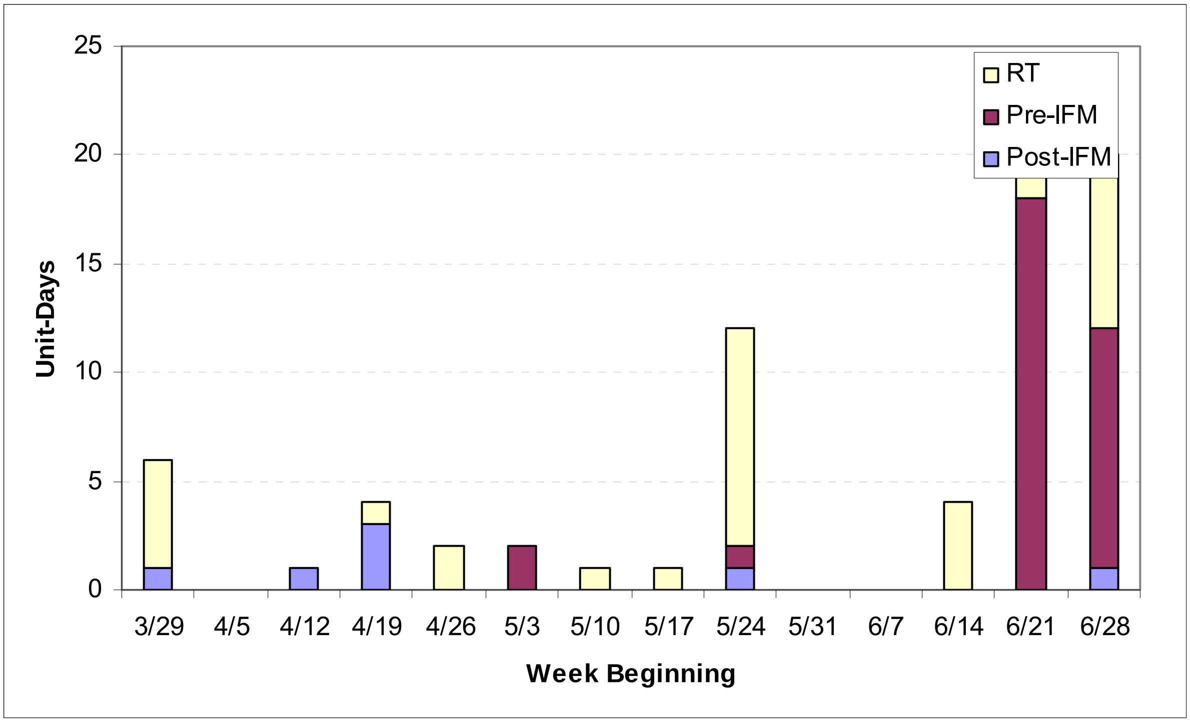
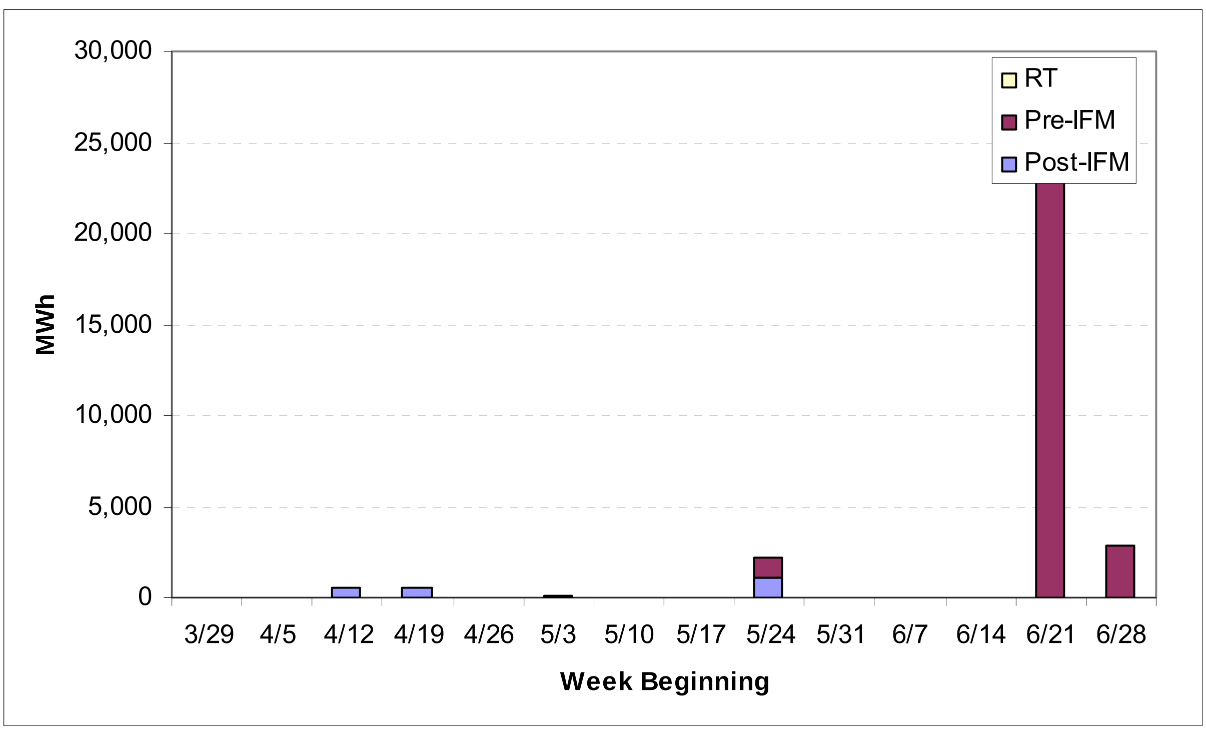


Figure 3.28 Weekly Energy Volume of ED for System Capacity



Ramp Rate

When the ISO issues a day-ahead ED commitment, the resource is turned on and will sit at minimum load, unless it is economic and participates in the market. At minimum load, most resources that receive EDs have very low ramp rates; that is, they take a long time to move from their minimum levels of output upward to respond to dispatch instructions. In order to ensure that committed units are responsive, ISO operators can issue *Ramp Rate* EDE instructions, which instruct units to ramp up to higher levels of output, where they can be moved up and down quickly by the market software. All Ramp Rate EDE instructions are issued in real-time.

The majority of energy from exceptional dispatches above Pmin comes from this Ramp Rate, or Dispatchability, reason. Unlike the dispatch energy requirements described above under Transmission Outages, and below under T-Procedures, dispatches for Ramp Rate have little to do with the energy that is dispatched. Instead, they are dispatches for getting the unit to an output level at which the unit has more available capacity for mitigating thermal constraint violations from possible "next" contingencies.

Some generating units have ramp rates that vary with the unit's current MW output level. For example, a unit may only be able to ramp 1.6 MW/min when it is operating at its Pmin of 20 MW. However, when the unit is operating at an output level in the range of 70-150 MW, then its ramp rate is 6.4 MW/min. As described above, the software currently cannot dispatch capacity for correctively responding to a possible "next" contingency. However, unloaded capacity is needed in regions of various sizes to mitigate violations of thermal constraints after a potential "next" contingency. This unloaded capacity is specifically needed for lines whose flows after possible contingencies are not limited pre-contingency via nomograms or "modeled contingencies". The effective 20 minute unloaded capacity of a unit with a 6.4 MW/min ramp rate is 128 MW, four times the same unit's effective 20 minute unloaded capacity when the unit is operating at its Pmin. Therefore, when a unit is operating at a level where it has a low ramp rate and the system needs the unit's capacity for the thermal limit reliability reasons described above, the operator will issue an ED to just get the unit into its maximum ramp rate output range. We will refer below to the MW output level at which a unit's maximum ramp rate output range begins as the unit's "dispatchable Pmin".

The charts below show real-time ramp rate ED energy dispatch frequency and volume. These were primarily to resources that were committed on for transmission outages. As those outages ended, ramp rate ED dispatches were no longer needed.

Figure 3.29 Weekly Frequency of ED for Ramp Rate

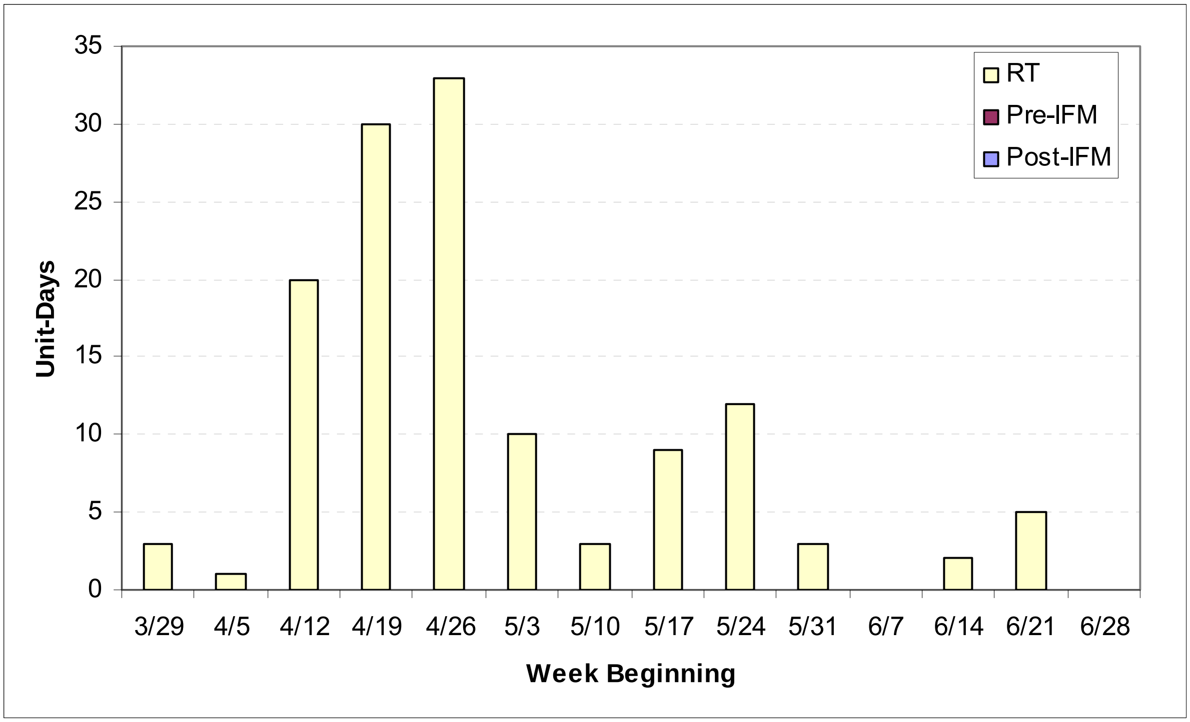
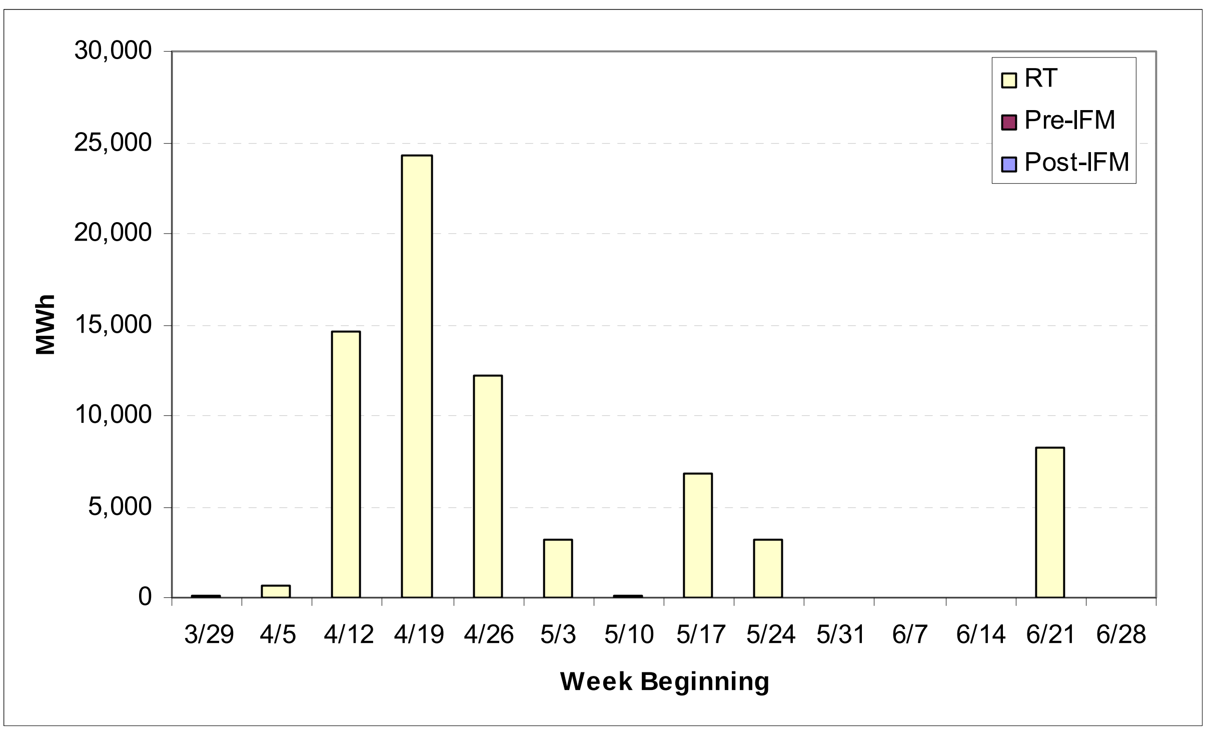


Figure 3.30 Weekly Energy Volume of ED for Ramp Rate



T-Procedures

T-Procedures, such as T-132 and T-133, describe the measures that should be taken when a transmission system component in or into a particular region has its thermal constraint violated. Each T-Procedure is for the transmission system of a certain region. For example, T-132 is for the San Diego area, T-133 is for the Bay Area, T-138 is for the Humboldt area, and T-129 is for the Fresno area.

T-Procedures specify the actions that should be taken when various components are overloaded or when particular contingencies occur. The T-Procedures also specify the effectiveness of generating units in the area for mitigating congestion on a particular component. Furthermore, T-Procedures define many of the nomograms for limiting the simultaneous flows on many transmission components so that, as described above, if certain contingencies occur, the components will not be overloaded. Many T-Procedures also specify the acceptable voltage ranges of many buses within the T-Procedure's area, as well as the effectiveness of voltage control equipment for mitigating voltages going outside the acceptable ranges of the buses.

In general, T-Procedures are logged as the reason for an ED that is needed in real-time to dispatch energy to mitigate a violated thermal constraint. T-Procedures may also be logged as the reason for a real-time dispatch of energy needed, after one contingency has occurred, to manually simulate a nomogram defined by the T-Procedure that would keep flow limits low enough to avoid a thermal constraint violation upon the occurrence of a possible "next" contingency. There is significant overlap between the "Transmission Outage" reason for dispatch energy and a T-Procedure reason for the same region.

T-138 (Humboldt Area Transmission)

Humboldt County is a small load pocket in the northwest corner of California, and is connected to the NP15 grid by a 60kV transmission line. This line is frequently congested, and thus the ISO must issue EDE instructions to the small fleet of units within the Humboldt region. Transmission work and generation outages on or near the area has required particularly frequent issuances of EDE instructions since April. Transmission clearances in the Cottonwood area and a planned outage of a Humboldt-area resource both contributed to the late June peak.

Figure 3.31 Weekly Frequency of ED for T-138 (Humboldt)

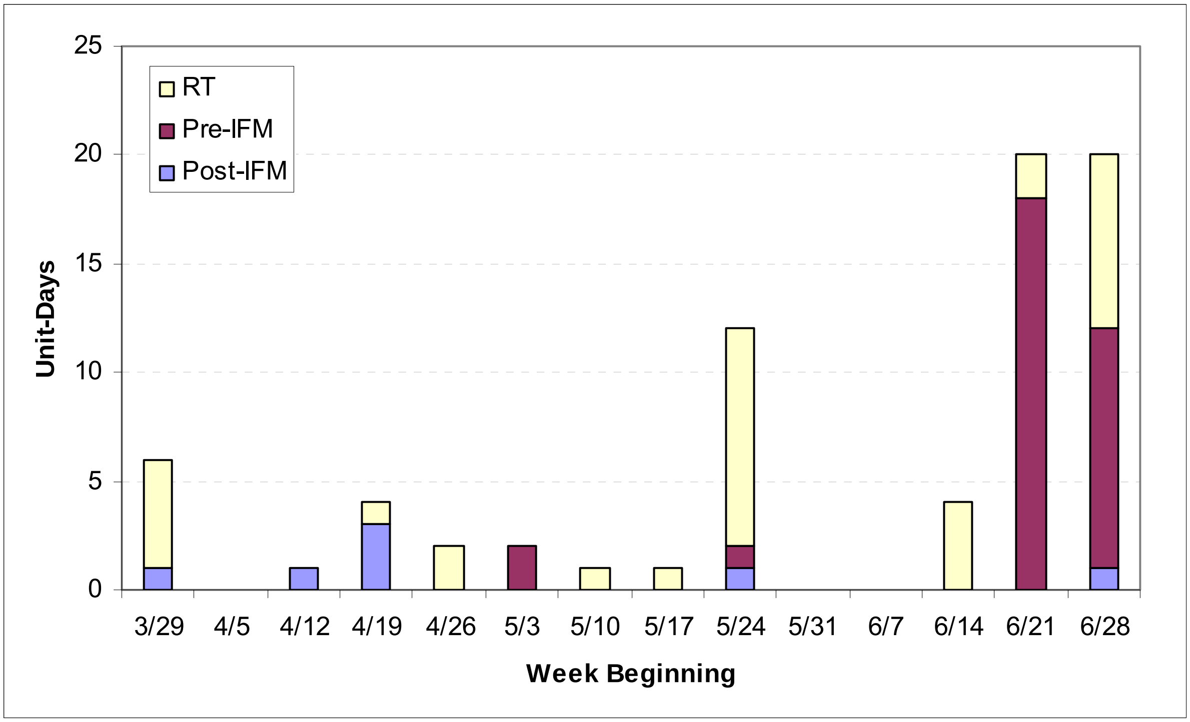
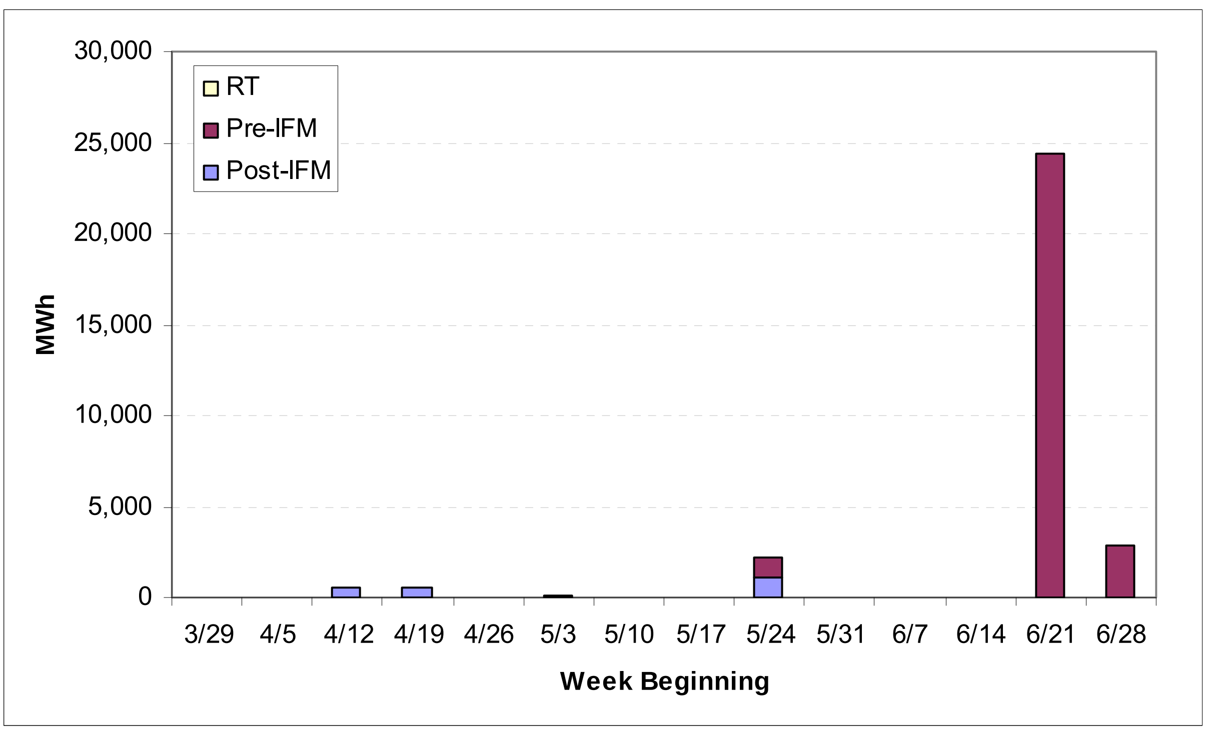


Figure 3.32 Weekly Energy Volume of ED for T-138 (Humboldt)



Software Limitation

Operators log “Software Limitations” as the reason for exceptional dispatches that must be issued as a result of the system software not performing a function that it is supposed to be able to do and that it normally does for most generators. One could of course view every exceptional dispatch as a “Software Limitation”, but the software is not designed to be able to dispatch capacity for corrective reliability reasons, or for voltage stability. The software is, however, designed to respect generator characteristics (besides Forbidden Regions) such as minimum run times or minimum down times. Sometimes the software will dispatch a unit with a minimum run time of an hour for a single 5-minute interval. Or, the software may dispatch a unit that has a minimum down time of 4 hours to start-up an hour after shutting down. In these cases, EDs will be issued to force the dispatch to comply with the generators’ physical characteristics. Because these are characteristics that the software is designed to recognize in its automated dispatches, the operators will log the ED as being due to “Software Limitations”.

These refer to situations in which the software fails and must be manually overridden. Many of these ED instructions were to pump storage units that did have some modeling issues, as well as to isolated areas that are poorly modeled. The pumps tend to be large and receive frequent ED “fixed” go-to or “shutdown” instructions. Some of them have no ramping capability and frequently get EDs to their single generating capacities or zero. Downward dispatches, including those to zero, are recorded in the frequency chart but show up as zero volume in the MWh chart.

Figure 3.33 Weekly Frequency of ED for Software Limitation

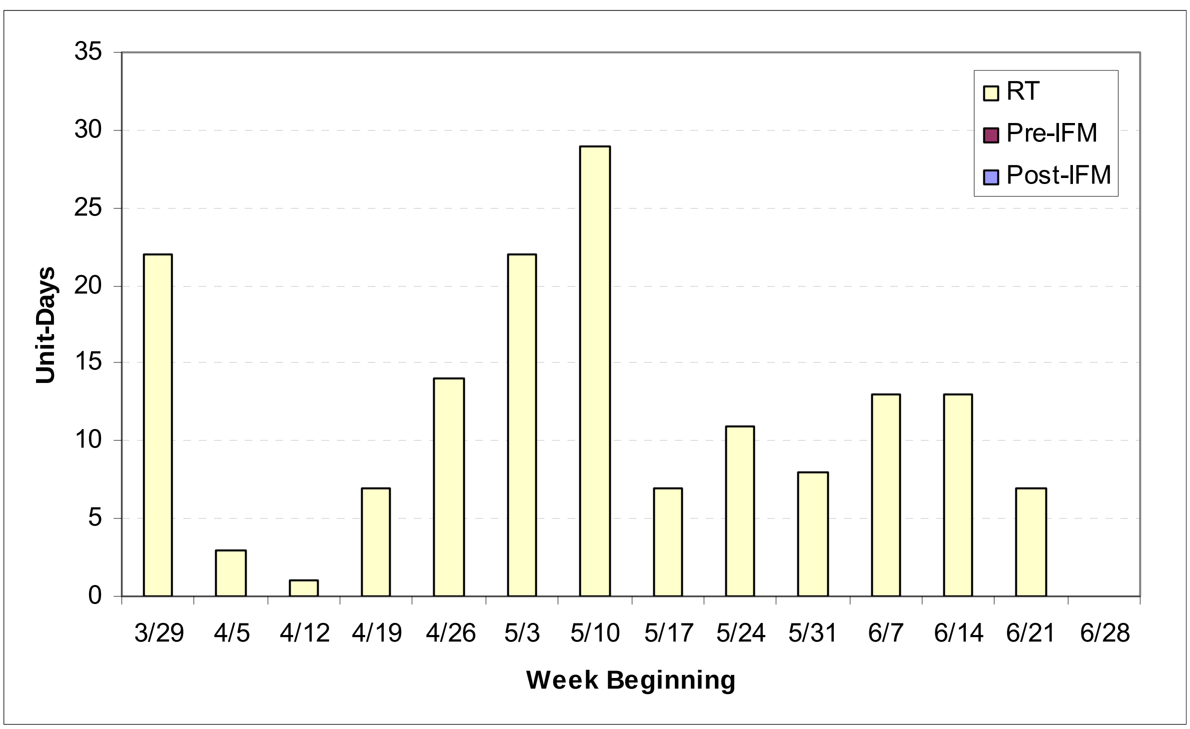
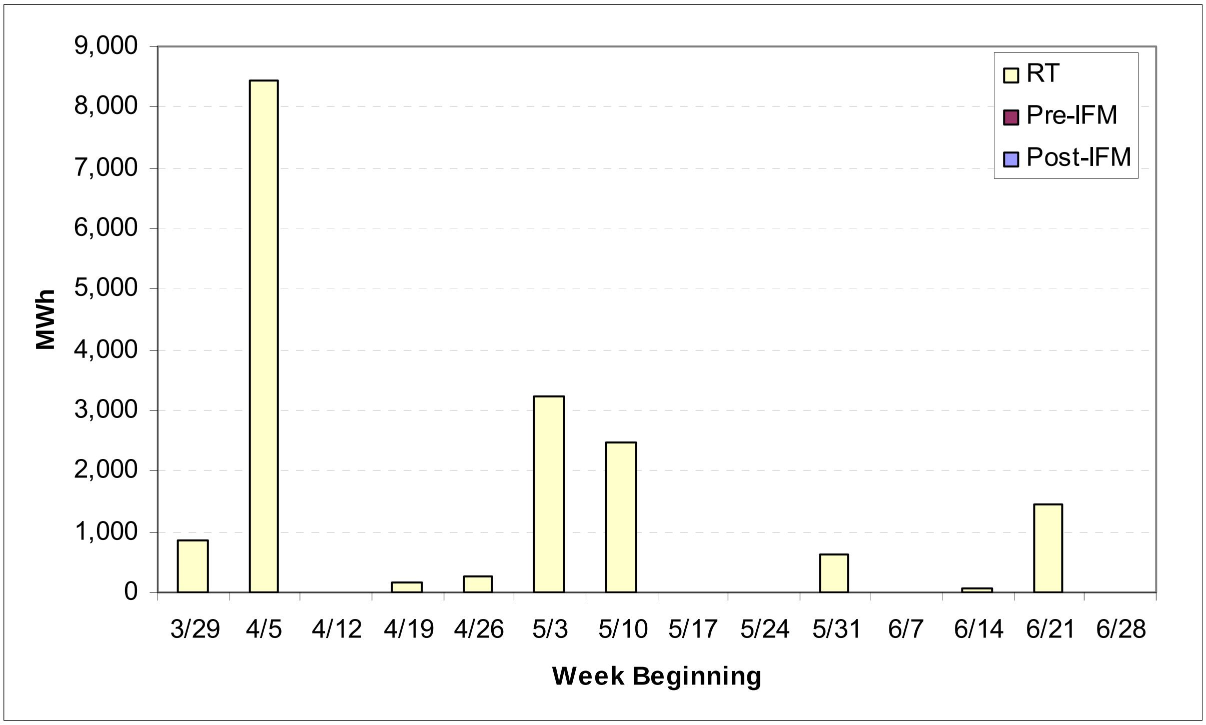


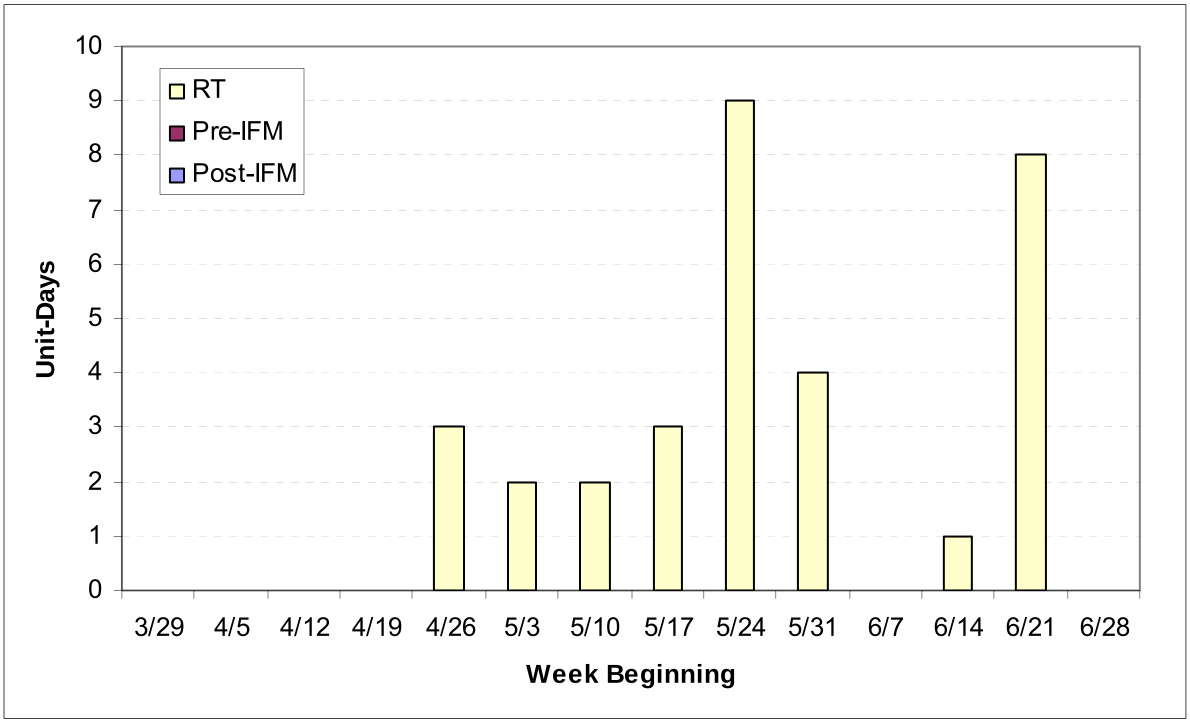
Figure 3.34 Weekly Energy Volume of ED for Software Limitation



Unit Testing

Generators that are new, are adding capacity, or are requesting qualification to provide a new ancillary service, must first undergo a testing phase to become certified as commercial before participating in the ISO markets. Since these resources are not yet participating in the markets, but do provide power to the grid, ISO grid operators issue EDE instructions so that the software recognizes these units as generating and/or providing ancillary services. All Unit Testing EDE instructions are issued in real-time, which is when measurement of ramping and delivery of energy from ancillary services is possible. There is no figure for energy from unit testing. Testing was for products other than incremental dispatch, and thus is quantified as zero volume.

Figure 3.35 Weekly Frequency of ED for Unit Testing



3.6 Market Power Concerns

Unit Commitments

As indicated in the previous sections of this report, the greatest portion of total energy dispatched through ED instructions results from unit commitments made on a day-ahead basis. In such cases, the exercise of local market power by units needed for local reliability is limited by caps in effect on units' start-up and minimum load bids. Under current rules, start-up and minimum load bids for all resources within Local Capacity Areas (LCAs), where local market power is most likely to exist, are either cost-based or are limited to 200 percent of each unit's startup and minimum load costs.[46] In addition, we note that many RA resources are under tolling contracts or other contractual agreements with load-serving entities (LSEs) that would also limit the degree to which any market power might be exercised by units through excessively high start-up and minimum load bids.

Any resources not under a RA or RMR contract that are committed via ED are eligible for additional compensation. However, over the first three months covered in this report, a total of only 16 MW of non-RA/non-RMR capacity was committed via ED, representing a total of less

[46] For units submitting bids rather than the cost-based option, bids cannot be changed for six months. The 200 percent limit on bids is based on a projection of gas costs based on the gas futures price for the month with the highest gas futures price within this six month period. For resources outside of LCAs, the six month bid-based option is limited to 400 percent of the unit's start-up and minimum load costs. The ISO is planning on submitting a proposal to modify this bid-based option so that units may update the bid on a 30-day basis, with all units subject to a cap of 200 percent of projected costs based on gas futures prices for the month in which the bid would be in effect.

than $25,000 in capacity payments.[47] We expect that due to minimum RA requirements that are set for each LCA, the ISO should continue to always be able to meet localized capacity requirements through commitment of RA units.

Incremental Energy

In its February 20 Order,[48] FERC ruled that ED instructions to RA units for energy (above minimum operating levels) would be subject to mitigation for the first four months of the ISO's new nodal markets. Thus, for all three months covered in this quarterly report, RA units dispatched for incremental energy via ED will be paid the higher of the market LMP or their DEB. However, FERC's February 20 Order directed that after the initial four month period, mitigation would only be applied to two categories of ED for incremental energy:[49]

- ED to mitigate congestion on constraints deemed to be "non-competitive" under the Competitive Path Analysis (CPA) performed by the ISO as part of its local market power mitigation procedures; and
- Dispatches for Delta Dispatch.

Thus, starting on August 1, 2009, all other categories of ED for incremental energy will not be subject to bid mitigation, and will be eligible to be paid the higher of the market LMP or their market bid price.[50]

Based on the ED trends for the first three months of the ISO's new nodal markets reviewed in this report, we remain concerned about the potential for the exercise of local market power by units receiving ED instructions for incremental energy after mitigation is reduced on August 1, 2009. However, we cannot draw any conclusions at this time as to the extent to which such local or temporal market power may in fact exist and be exercised, for several reasons:

- First, as noted in previous sections of this report, limited data are currently available on the specific constraints for which ED energy instructions were issued. Equally important, data are not available on the other available supply that could have been used to meet these constraints under actual operating conditions. Such basic supply and demand data would be needed to assess the degree to which suppliers receiving ED instructions are pivotal, as suggested in FERC's February 20 Order.[51] This is particularly true of ED instructions for temporary transmission outages and to ramp units for up to their dispatchable Pmin levels to meet various potential contingencies. However, as the constraints driving ED are better defined and tracked, it may be possible to assess any market power that is observed using the type of pivotal supplier analysis suggested in FERC's February 20 Order.
- We also note that since ED trends are likely to change with load patterns and market conditions, the primary sources of the exercise of any local market power may significantly change from month to month.

[47] http://www.caiso.com/237a/237ac93c2a6c0.html

[48] February 2009 Order, 126 FERC ¶ 61, 150.

[49] February 2009 Order at P 74.

[50] Any units without market bids will be paid the higher of the LMP or their DEB).

[51] February 2009 Order at P 77, 80-81.

- In addition, to the extent a supplier receiving ED instructions for energy may have had local market power during the initial three month period covered in this report, the supplier would have no incentive to exercise that market power due to the mitigation that has been in effect over this period. Thus, when mitigation is relaxed on August 1, DMM will closely monitor actual bidding behavior and ED patterns for indications of potential local or temporal market power that will no longer be subject to bid mitigation.
- Finally, another factor complicating any assessment of local market power based on ED data for this initial three months is the fact that in some cases, ED instructions for additional real-time energy needed from specific units may not have been issued since these units were already dispatched through the market to levels sufficient to meet reliability requirements. However, if these units were not subject to mitigation and sought to exercise market power by raising their bid prices, as noted above, it is possible that additional ED instructions may need to have been issued to these units.

One specific type of localized or temporal market power that we remain concerned about involves situations where units are committed at minimum operating levels via ED on a day-ahead basis, and then receive an ED instruction to their dispatchable Pmin level in real-time. Our analysis of ED data indicates that this type of ED accounts for about 65 percent of the total ED energy above minimum load during the second quarter of 2009.[52] When a unit with the dispatchable Pmin level is committed at minimum operating level via an ED, the unit knows that its commitment is for mitigation of voltage support and/or a possible post-“next”-contingency thermal constraint violations. If such a unit then receives an ED to move above its minimum operating level to its dispatchable Pmin, the unit owner then knows that its capacity is required for mitigating possible post-“next”-contingency thermal constraint violations. In many cases, limited competition may exist to provide the required level of “effective capacity” from other nearby units that are already committed and also have the dispatchable Pmin characteristic. Therefore, when a unit receives an ED to move its unit’s output level to its dispatchable Pmin, this may provide the unit owner with a good indication that the unit’s energy could be bid at an extremely high price (up to the $500/MWh bid cap) for the rest of the trading day and still receive an ED instruction. Under the ISO’s market design, the deadline for real-time bids is about two hours prior to the start of each operating hour. Thus, a unit receiving an ED in one hour could respond by submitting extremely high energy bids that would begin to be effective by the third operating hour after this initial ED.

As a practical matter, much of the potential market power that may arise when units are ramped to their dispatchable Pmin via ED will be mitigated by the fact that many of the units that are needed to meet these reliability requirements are under tolling contracts with LSEs or similar contractual arrangements that give LSEs control over the bidding of these units. Data on the control of each generating unit is routinely collected by DMM as part of its CPA studies. Based on these data, we estimated that over 75 percent of the energy dispatched via ED for Ramp Rate issues was issued to units owned or under contracts with LSEs that would effectively mitigate this market power. However, for the remaining ED for Ramp Rate energy we remain concerned about the potential for market power once mitigation is eliminated for these dispatches. In addition, we note that while these contractual arrangements reduce the cost of such market power in the short term, over the longer term units that might expect to receive ED to their dispatchable Pmins may be expected to seek to exercise this potential market power by demanding a higher price in negotiations of future contracts.

[52] Just under 62 percent of this represents ED energy above minimum load logged as being dispatched due to the unit’s “Ramp Rate”, while another 3.5 percent includes ED energy logged as being dispatched for “NP15 Capacity”.

The second single largest category of ED energy during the second quarter involved ED energy logged as being attributable to various transmission outages, which accounts for almost 17 percent of ED energy. Over the three month period covered in this report, the level of detail included in ED logging has often been insufficient to quantitatively assess the degree to which such ED instructions may be specifically due to uncompetitive constraints and would therefore continue to be subject to mitigation after August 1. For example, while logging may indicate the transmission line on which the outage occurred, the log may not indicate the specific constraints or contingencies for which additional ED energy was needed as a result of the reported transmission outage. However, our review of various ED logs suggests that most of this ED energy would be attributable to non-competitive constraints.[53] After August 1, this additional level of detail will need to be routinely logged in order to establish whether or not mitigation will be applied.

3.7 Recommendations for Actions to Reduce Exceptional Dispatch

Most exceptional dispatches occur as a result of the software not being able to optimally commit units and capacity that would ensure instantaneous voltage stability and mitigation of thermal constraints within 20 minutes of the "next" generator or transmission component contingency. Redesigning the software for "corrective" capacity dispatches and to perform an AC power flow solution that considered reactive power would currently not be cost-effective. It is doubtful that the computing capacity exists to perform such optimizations within the time frames required for running the markets.

In the absence of automated calculations of the optimal capacity dispatches that consider all system conditions at every interval, however, power system operators have made do with engineering studies that define the locational requirements of commitment for voltage stability and capacity for thermal constraint mitigation. The procedures, or reasons, of Section 3.5 describe the commitment and capacity requirements that Regional Transmission Engineers and Grid Operators use to determine the units they commit for all system conditions. The rules and procedures currently used by the Engineers and Operators are actual capacity constraints that are required for system reliability. Because they are not modeled in the software, the operators enforce the constraints manually through exceptional dispatch.

While it is unrealistic to think that ED can be entirely eliminated, we do think that concerted efforts by the ISO in the following areas, listed in order of short to longer term efforts, could significantly reduce the frequency of ED:

- Undertake a comprehensive review of all operating procedures and other criteria for determining the need for ED to make sure the criteria and processes driving exceptional dispatch are well-founded, consistently followed, and not overly-conservative;
- Explore and implement options for incorporating the reliability constraints driving ED into the market model; and

[53] In many cases, it appears that ED energy in this category may result from real-time dispatches made to mitigate constraints or contingencies not modeled in the system. Since any constraint that is not modeled in the network model cannot be assessed using the CPA methodology, any such constraints are by default deemed to be non-competitive. To the extent these constraints are incorporated in the ISO model at a later date, they would be included in future CPA studies and explicitly examined.

- To the extent ED is being driven by the need for contingency reserves, consider new market products that might mitigate the need for ED and more appropriately remunerate resources providing these reserve services.