3 Real Time Market Performance

3.1 Overview

2006 marked the second full year of operation under the new Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing or BEEP).

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA sets generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches (i.e., dispatches prior to the operating hour) hourly inter-tie bids.

This chapter reviews the performance of the CAISO Real Time Market in 2006. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. One significant driver on Real Time Market volumes is the level of forward energy scheduling, which is influenced by the CAISO 95 Percent Day-Ahead Scheduling Requirement (Amendment 72). Section 3.3 provides a review of load scheduling practices under Amendment 72. Section 3.4 provides a more detailed assessment of several aspects of RTMA beginning with a review of overall price volatility (Section 3.4.1). One element of RTMA that has not been implemented is the penalty provisions for deviations from dispatch instructions (Uninstructed Deviation Penalty (UDP)). This element has not been implemented because uninstructed deviations have been relatively moderate since RTMA was implemented. An analysis of uninstructed deviations under RTMA is also provided in Section 3.4.2. Another important aspect of RTMA is a load bias feature that allows operators to manually adjust the load forecasts that are used to determine optimal dispatch in RTMA. A review of the relationship between the use of load bias and the use of regulation energy is also examined in Section 3.4.3. Finally, 2006 is the first complete operating year of Amendment 66 for import/export bids over inter-ties with neighboring areas, which was an amendment to the CAISO tariff to correct problems with the prior settlement rules for pre-dispatched inter-tie bids that lead to excessive uplift payments. The impact of Amendment 66 is examined in Section 3.4.4.

3.2 Real Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy and both in and out-of-sequence (OOS) dispatches for 2005 and 2006. Monthly average prices for incremental energy in 2006 were stable, averaging between $60 and $80/MWh with the exception of $88/MWh in January due to the remaining effect of the dramatic increase in natural gas prices resulting from the Gulf Coast hurricanes. Average monthly prices for decremental energy were relatively low during the first half of 2006 at around $20/MWh, mainly due to abundant hydroelectric generation, but increased to around $40/MWh for the rest of the year. Average monthly prices for OOS incremental prices were lower than the in-sequence prices in most months of 2006, with the exception of July when California experienced the record-breaking heat wave and some relatively higher cost OOS dispatches were required to maintain the reliability of the grid. As in 2005, in-sequence dispatch volumes were overwhelmingly decremental in most months of 2006, especially during the spring and summer months. The preponderance of decremental dispatches in 2006 can be attributed to:

- Unusually high levels of hydroelectric output in northern California and the Pacific Northwest which resulted in over-generation conditions as well as inadvertent loop flows.
- An extremely high level of forward energy scheduling – driven in part by the CAISO day-ahead load scheduling requirement (Amendment 72).

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2005-2006)

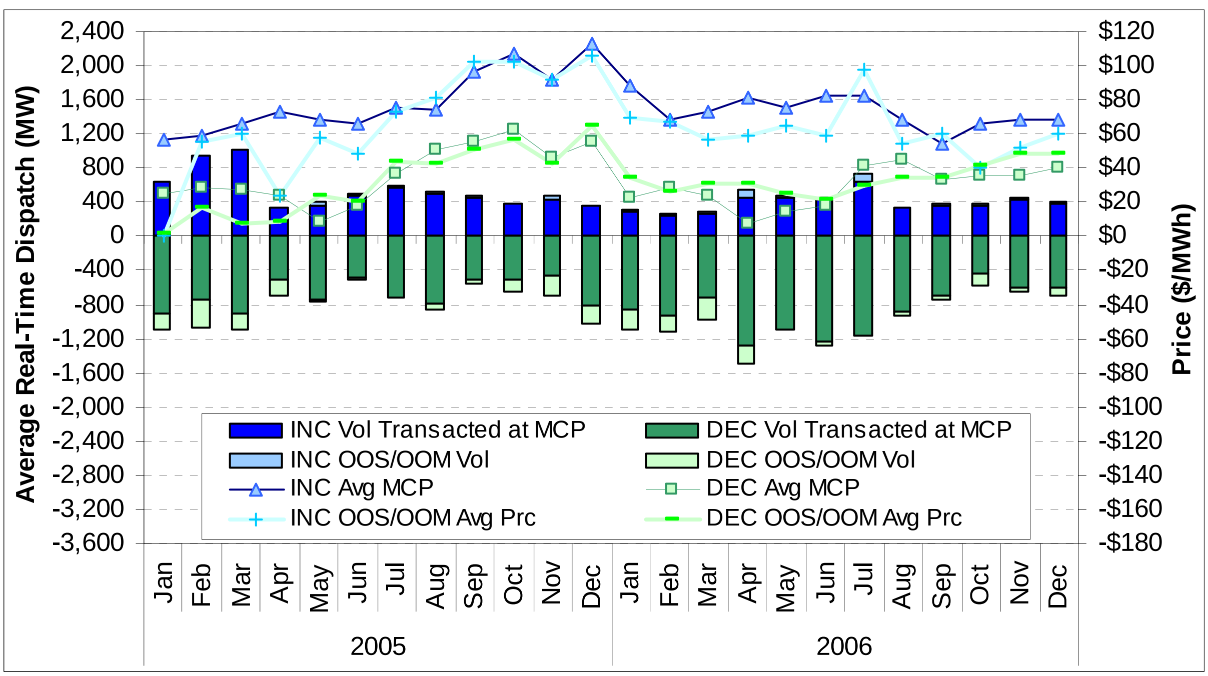


Figure 3.2 and Figure 3.3 show the same metrics presented in Figure 3.1 but separately for peak and off-peak hours, respectively. As can be seen in these figures, the average monthly market volume trends across the two years are fairly similar for peak and off-peak hours. However, there were generally higher decremental volumes during the peak hours in the spring of 2006, which as noted above can be attributed to high levels of forward scheduling and unscheduled over-generation due to high levels of hydroelectric generation. As expected, average monthly prices were generally higher in the peak hours.

Figure 3.2 Monthly Average Dispatch Prices and Volumes in Peak Hours (2005-2006)

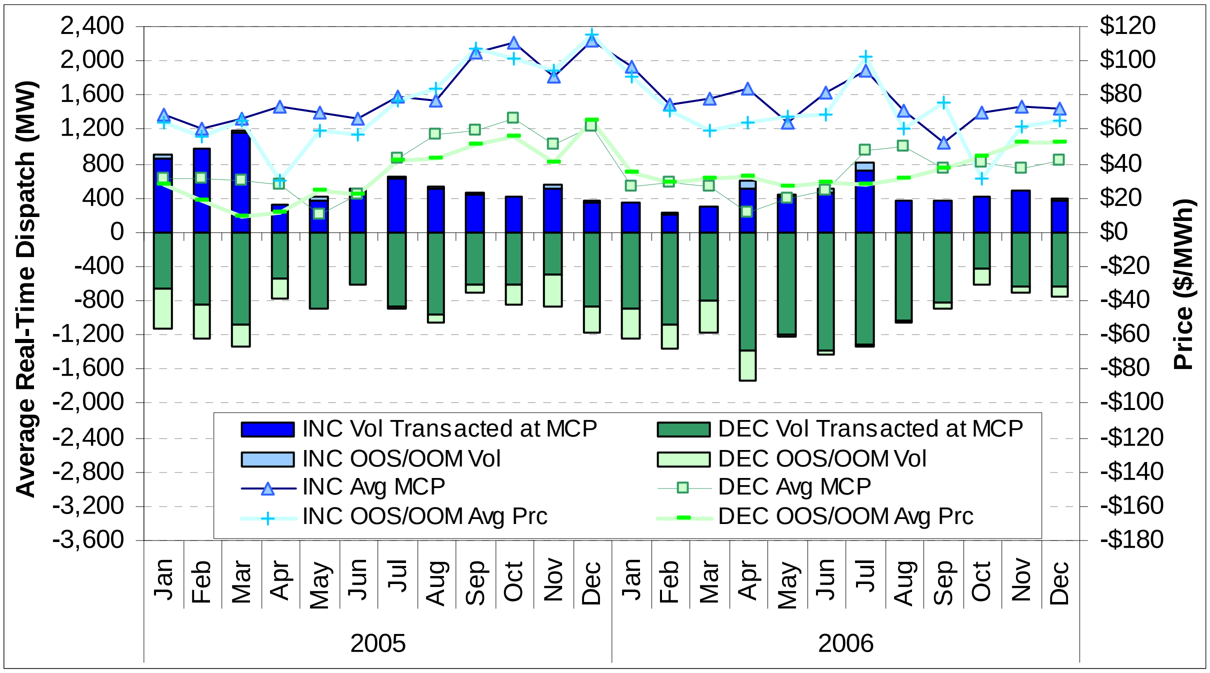


Figure 3.3 Monthly Average Dispatch Prices and Volumes in Off-peak Hours (2005-2006)

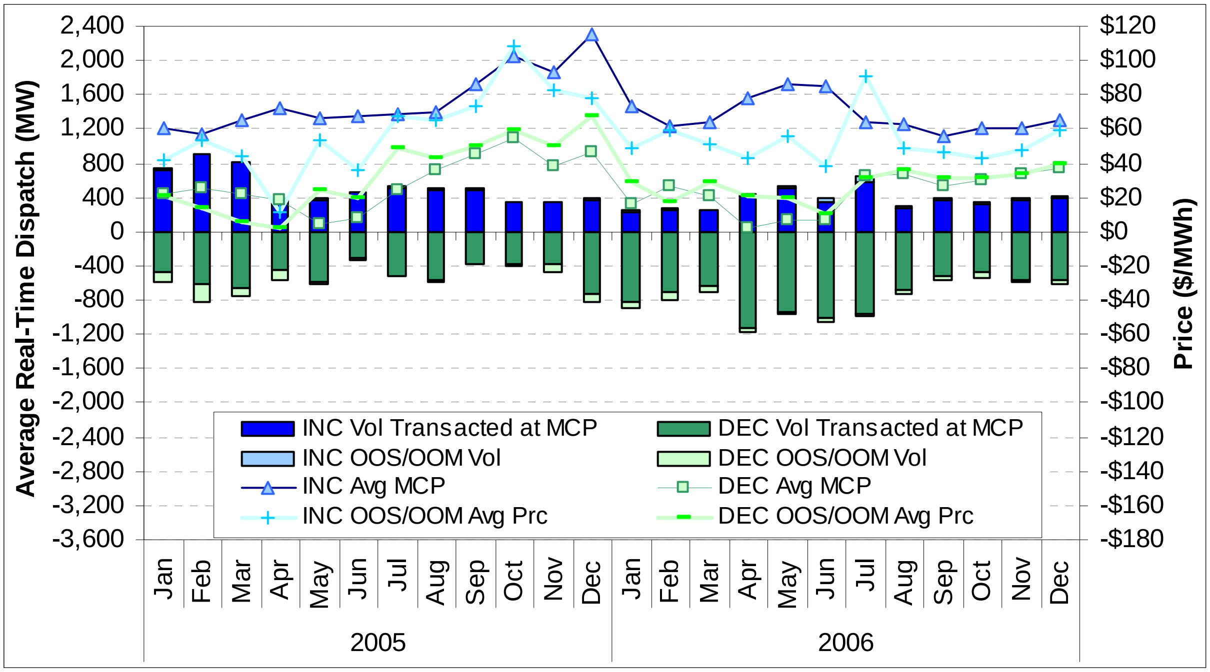


Figure 3.4 compares average annual Real Time Market prices by zone (NP26, SP15) for 2002 through 2006. Congestion on Path 26 in the north-to-south direction has resulted in consistently higher prices in SP15 than in NP26. This congestion was largely responsible for the zonal crest in prices in 2004, whereas natural gas prices accounted for system-wide increases into 2005. As natural gas prices decreased, new transmission and generation was deployed across the control area, and there was robust hydroelectric production in 2006, prices moderated. However, because much of the hydroelectric power is sourced in NP26 and the Pacific Northwest, Path 26 congestion persisted, and continued to result in higher SP15 prices.

Figure 3.4 Average Annual Real-Time Prices by Zone (2002-2006)[1]

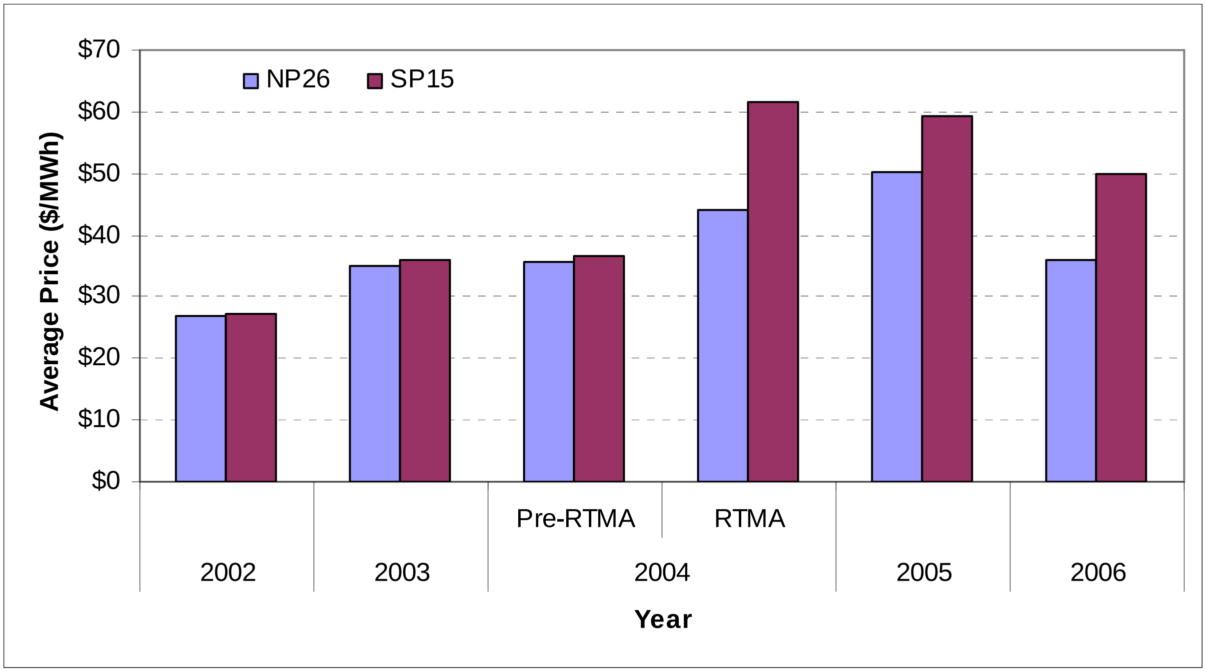


Figure 3.5 shows SP15 real-time 5-minute interval price duration curves for 2003 through 2006 and indicates that real-time interval prices in 2006 were generally lower than in 2005 with the exception of the very extreme end of the distribution (i.e., 1.8 percent of 5-minute price intervals), predominately because of an increase in the bid cap from $250/MWh to $400/MWh and an increase in the frequency of 5-minute price spikes. On the lower end, 2006 experienced more negative prices for about 2.5 percent of 5-minute intervals, which was the highest in four years. The increase in negative prices in 2006 is predominately attributable to high levels of hydroelectric generation and high levels of forward scheduling, both of which increased demand for decremental energy bids, and, under severe conditions, resulted in exhausting the supply of decremental bids.

[1] Chart incorporates most recently available information and may differ from prices reported in previous years. Averages are real-time volume-weighted.

Figure 3.5 SP15 Price Duration Curves (2003-2006)

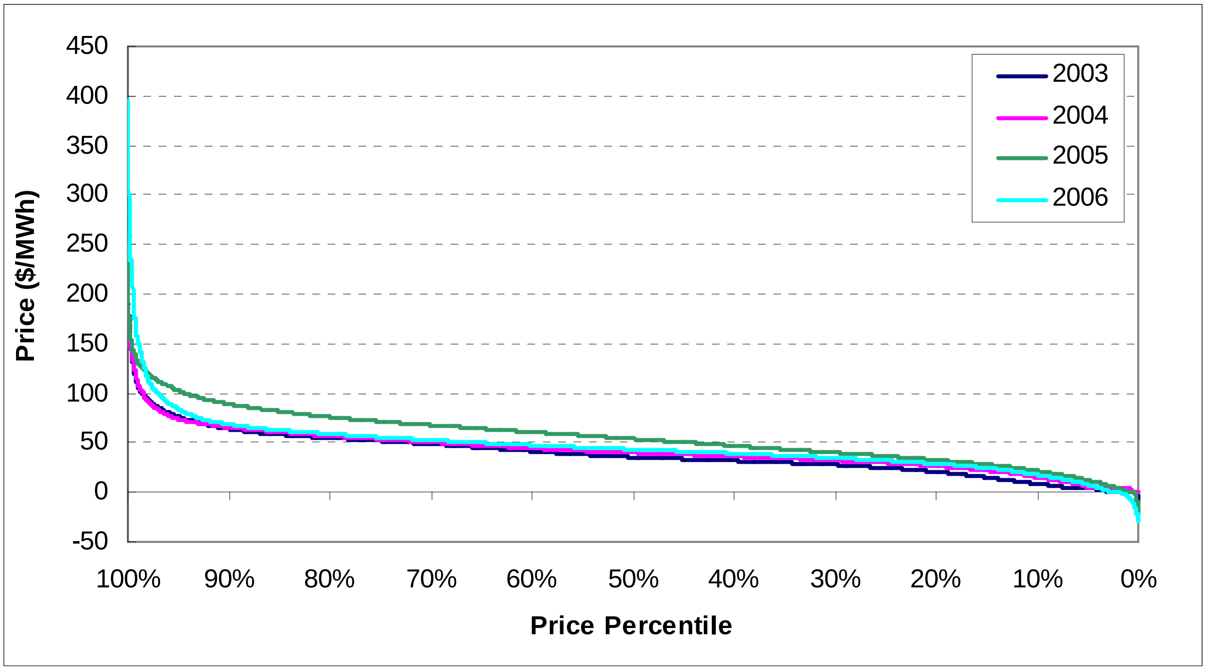
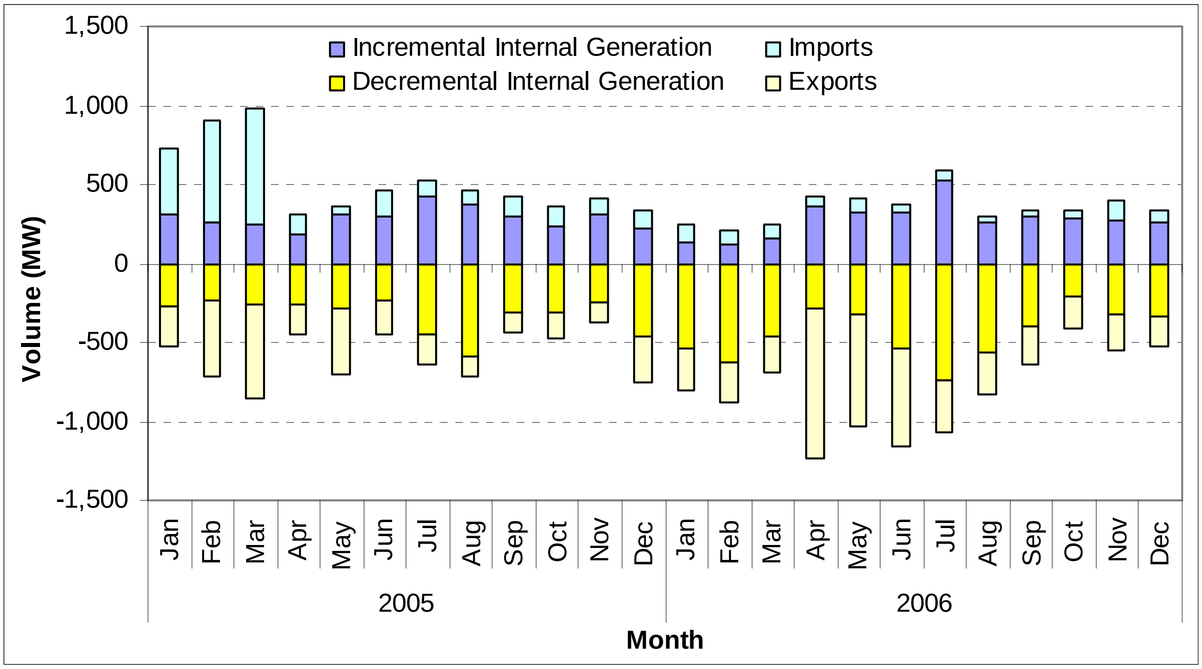


Figure 3.6 shows the monthly average dispatch volumes for internal generation, imports and exports for 2005 to 2006. With the exception of the three-month period of January 2005 - March 2005, internal resources constituted the majority of RTMA dispatches. The increase in inter-tie dispatches during the January 2005 - March 2005 time period is attributed to the “bid or better” settlement rules for inter-tie bids that are pre-dispatched under RTMA. This rule, coupled with the increasing volume of market clearing inter-tie bids, created significant market uplifts and resulted in a modification to the CAISO tariff that replaced the “bid or better” settlement with an “as-bid” settlement rule. The impact of this rule change can be seen in Figure 3.6 by the highly pronounced decrease in inter-tie dispatch volumes beginning in April 2005. This issue is discussed in greater detail in Section 3.4.4. Most notable in 2006 is the high level of export bids dispatched in the April to June timeframe. These dispatches were to address over-generation conditions as well as potential loop-flow problems exacerbated by the high level of hydroelectric generation.

Figure 3.6 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2005-2006)



3.2.2 Price Spikes

For the period January 1, 2005, through January 13, 2006, during which the price cap was $250, the SP26 price came within $1 of the price cap in 163 of 108,864 5-minute pricing intervals, or approximately 0.1 percent of all 5-minute intervals. Between January 14 and December 31, 2006, SP26 prices exceeded the $250 threshold in approximately 1,006 of 104,964 5-minute intervals, or just under 1 percent of all 5-minute intervals.

The sharp increase in Real Time Market price spikes in 2006, shown in Figure 3.7 for the March to May timeframe, is primarily attributable to an abundance of hydroelectric generation, which resulted in less thermal resources being on-line and available to the Real Time Market. Because of water management constraints and other operational considerations, hydroelectric resources are not always offered to the Real Time Market and are not subject to the same must-offer requirements as thermal resources. As a result, the supply of 5-minute dispatchable bids was limited during this period, particularly during critical ramping hours when demand for incremental energy is greatest. As a consequence, 5-minute interval price spikes in the spring occurred with greatest frequency during these ramping hours. In contrast, price spikes during the June to July period occurred more frequently during the peak hours of the day. This trend can be seen in Figure 3.8.

Figure 3.7 Price Cap Hit Frequencies by Month, During Periods of $250 and $400 Price Caps, 2005-2006[2]

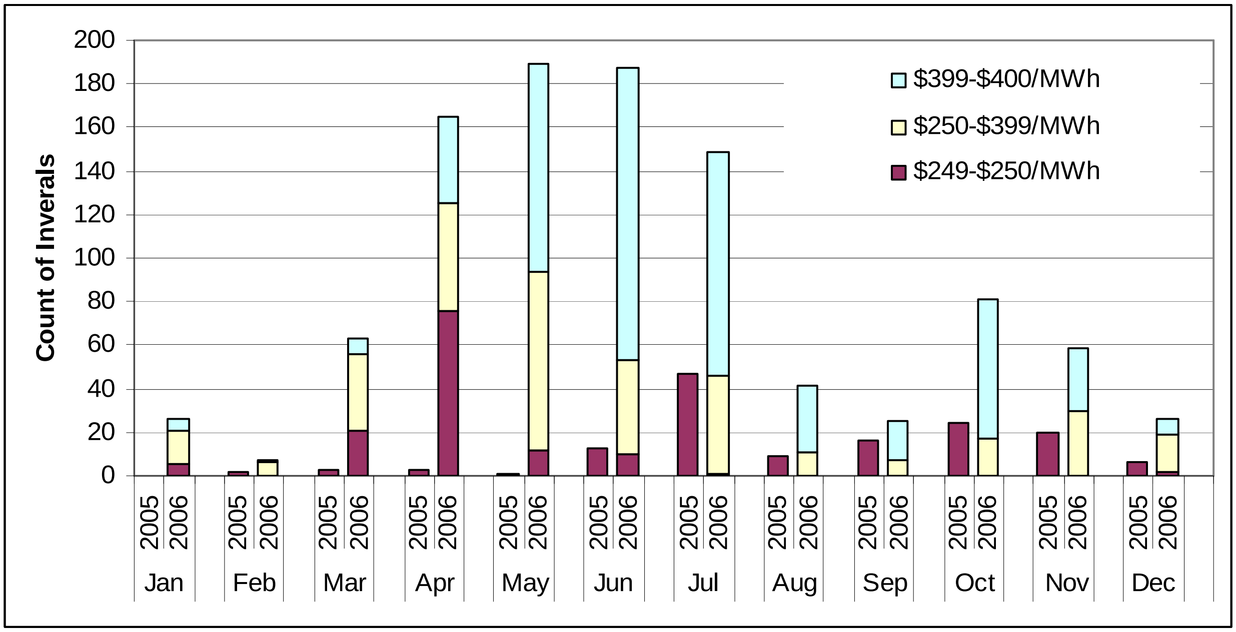
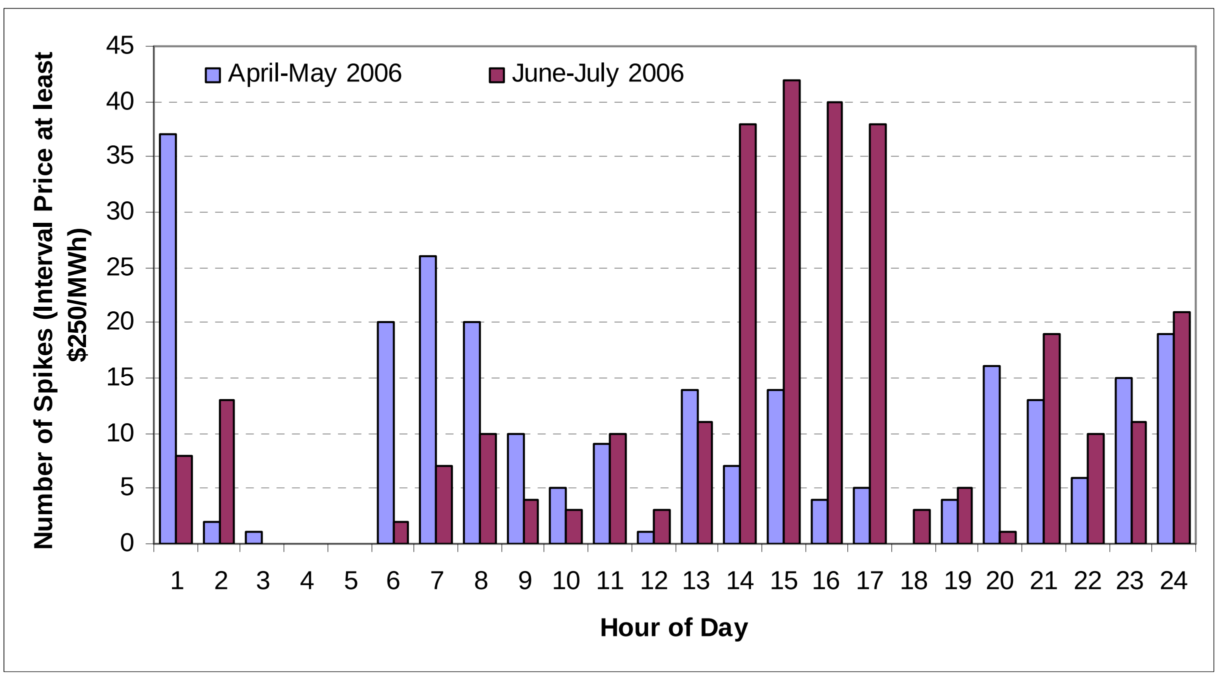


Figure 3.8 Spikes by Hour of Day: April-May and June-July 2006[3]



[2] Price cap was raised from $250 to $400/MWh on January 14, 2006. Data from January 1-13, 2006, prior to the price cap increase, are not shown.
[3] Time periods are actually April 1 through June 2 and June 3 through August 4, 2006, in order to normalize for days of the week.

While price spikes were significantly more prevalent in 2006 compared to 2005 and occurred at higher price levels due to the increase in the bid cap, the cost impact to load from these spikes was relatively minor given the low market volumes settled at these prices and the fact that a significant share of that volume is utility owned or contracted generation.

It is not possible to determine the actual cost impact of the higher bid cap as this would require knowing what the bids and market volumes would have been had the bid cap remained at $250/MWh. For example, the soft-bid cap increase may have resulted in lower Real Time Market volumes and more 5-minute dispatchable supply than would have been the case under a $250 soft-bid cap since market participants would have a greater incentive to reduce their exposure to real-time purchases and increase their opportunities for real-time sales. However, not knowing what the counter-factual market bids and volumes would have been under the $250 soft-cap and prevailing market conditions makes it impossible to precisely assess the impact. Given this limitation, a simplified approach to estimate the impact is to assume that the only change from raising the soft-cap to $400 is the occurrence of some 5-minute interval prices in excess of $250/MWh that would have otherwise been $250/MWh had the $250 soft cap remained in place.

In a prior report to the CAISO Board of Governors, DMM used the simplified methodology described above to estimate the impact of the higher bid cap for the period of January 15 through April 30, 2006. That analysis is shown below to provide an indication of the relative impact of the higher cap. Specifically, Table 3.1 provides the estimated market impacts of price spikes over $250 in the Real Time Market for the January 15 – April 30 period. As shown in Table 3.1, total net costs to Load Serving Entities (LSEs) due to 5-minute interval prices over $250 for this period are estimated at about $1.3 million, or about 2.3 percent of the total cost of Instructed Incremental Energy during this period.

Table 3.1 Estimated Market Impact of MCPs over $250 (Jan-Apr 2006)

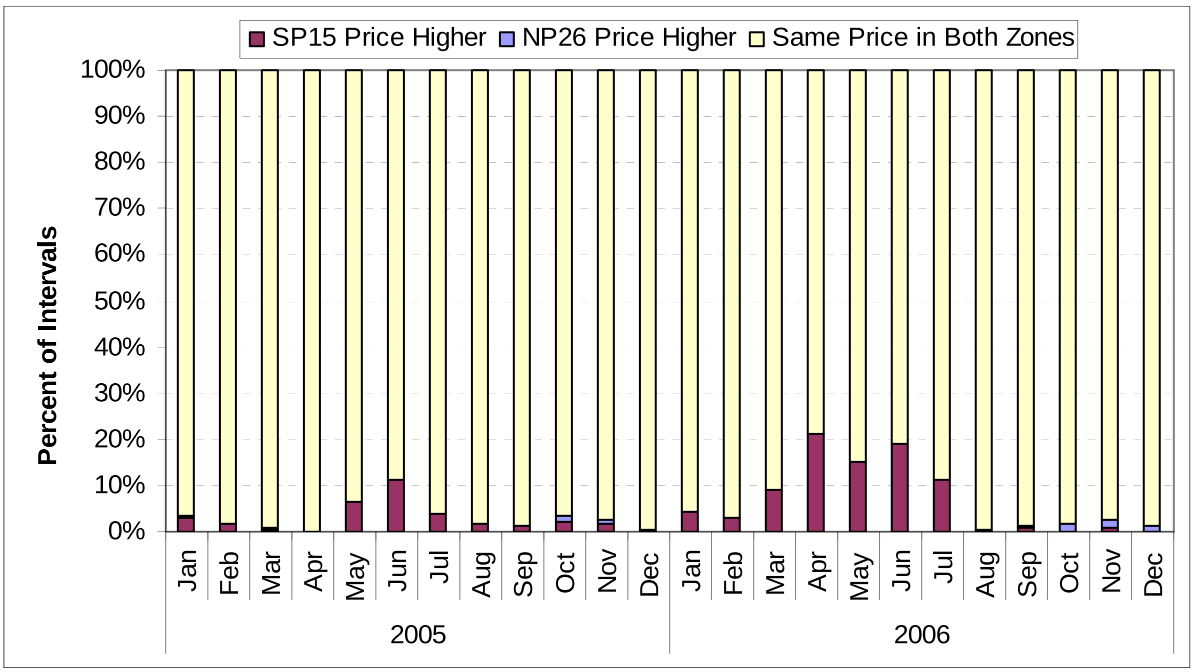
	Instructed Incremental Real Time Energy (IE)			Estimated Net Costs to LSEs	
Month	**Total Costs**	**Cost Due to MCP > $250**	**% of Total IE Costs**	**Total**	**% of Total IE Costs**
Jan 15-Feb	$17,981,783	$405,469	+ 2.3%	$380,445	+ 2.1%
March	$12,421,817	$310,298	+ 2.5%	$56,483	+ .5%
April	$26,489,610	$1,313,784	+ 5.0%	$846,560	+ 3.2%
Total	**$56,893,209**	**$2,029,551**	**+ 3.6%**	**$1,283,488**	**+ 2.3%**

Net costs include estimated uninstructed generation and excludes energy provided by resources owned or under contract to LSEs. Estimated costs do not account for the fact that in some cases, if prices had not exceeded $250, generators would have received higher daily uplift payments, which are paid in cases when a unit's total daily instructed energy payments (based on MCPs) are less than the total bid price of this instructed energy over the course of the day. Thus, data in Table 3.2 may somewhat overestimate the impact of the higher bid cap.

3.2.3 Real-Time Inter-Zonal Congestion

Figure 3.9 shows the monthly count of market splits in 2005 and 2006. Despite an increase in the north-to-south rating for Path 26 of 300 MW (3,700 to 4,000 MW) on June 1, 2006, real-time north-to-south congestion increased on Path 26 in 2006, mainly in the spring and early summer of 2006 when an abundance of hydroelectric generation resulted in significant north-to-south flows on Path 26. Prices differed between NP26 and SP15 in approximately 7.9 percent of 5-minute intervals in 2006, compared to 2.9 percent of intervals in 2005. Another operational issue that can result in splitting the Real Time Market is the Southern California Import Transmission Nomogram (SCIT). The SCIT constraint can be mitigated either by splitting the Real Time Market or by using OOS dispatches within SP15 (intra-zonal congestion management). On other occasions, the CAISO market experienced real-time congestion in the south-to-north direction on Path 15, especially in the fourth quarter of the year, due to derates necessitated by transmission reconductoring work on the Gates-Gregg 230kv line and installation of a switch on the Gates-Midway 500kv line.

Figure 3.9 NP26-SP15 Market Price Splits (January 2005 - December 2006)



3.2.4 Bidding Behavior

Figure 3.10 and Figure 3.11 show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for 2005 and 2006. Notable in Figure 3.10 is the significant increase in the percentage of higher priced incremental energy bids (over $100/MWh) beginning from September 2005 to January 2006. This trend is largely attributed to the increase in natural gas prices that occurred during this period. Also notable is the increase in incremental bid prices in the $0-$50/MWh range, beginning in January 2006 and increasing throughout most of the year. This trend can be attributed to both lower natural gas prices as well as an abundance of hydroelectric energy. With respect to decremental bids, Figure 3.11 shows that some resources bid very low prices for decremental energy (e.g., below $0/MWh). In

2005, this trend occurred predominately during April – July of 2005 when hydro generation is abundant and demand for decremental bids tends to be greatest. In 2006, this trend occurred through most of the year and included a small proportion of extreme negative bids (i.e., bids below -$10). The category in Figure 3.11 representing bids in the range of -$1/MWh to $0/MWh consisted largely of the hydroelectric bids.

Figure 3.10 SP15 Incremental Energy Bids by Bid Price Bin (January 2005-December 2006)

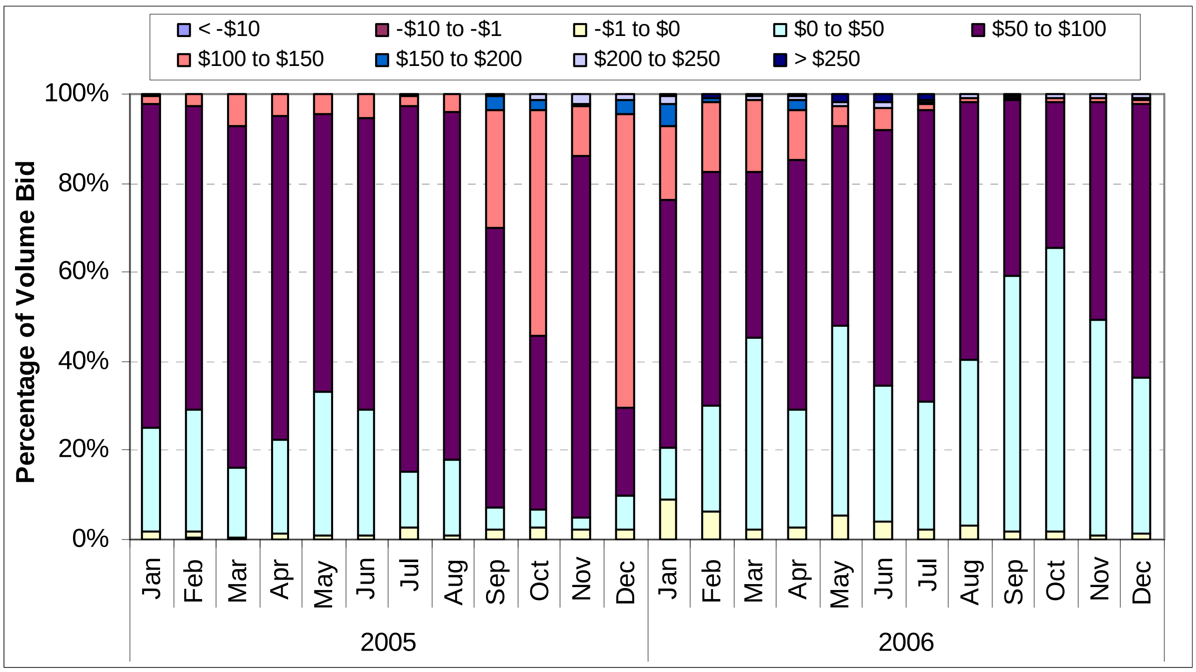
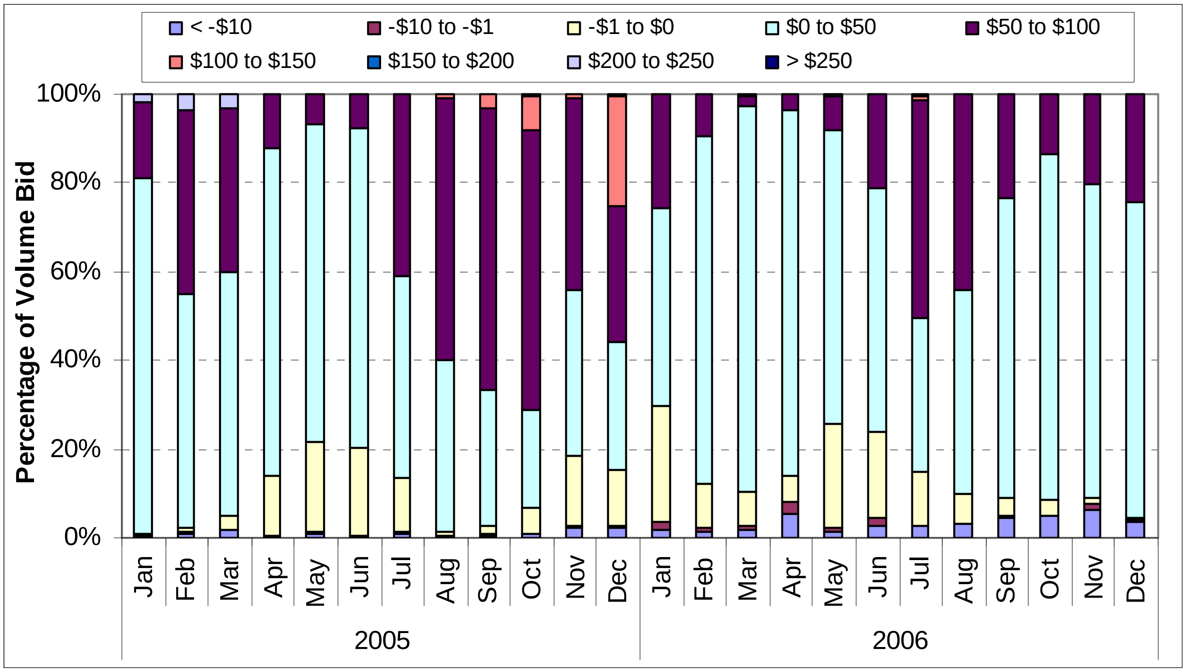


Figure 3.11 SP15 Decremental Energy Bids by Bid Price Bin (January 2005-December 2006)



Decremental bids below the price of $0/MWh were common in 2006 for a variety of reasons:

- Over-generation conditions driven by unusually high levels of hydroelectric output.
- High levels of forward energy scheduling, particularly during peak hours (See Section 3.3).
- Throughout the year, and particularly in the spring, certain hydroelectric resources faced spilling conditions due to high run-of-river water flows. In order to be decremented, resources would have had to divert water from their turbines over the spillway, effectively losing the potential energy for that volume of water.
- During off-peak hours, particularly in the lowest-load hours of 1:00 to 5:00 am, few resources are on and generating above minimum operating capacity. As a result, few units are available to be decremented in these hours. This creates instances where competition is thin among the few providers of decremental energy during these hours.

3.3 Forward Scheduling

Under the current CAISO market structure, there is no organized Day Ahead Market for energy. Instead, all day-ahead scheduling is based on bilateral contracts and supply resources directly owned or controlled by LSEs. In addition, each SC must submit balanced load and supply schedules. The amount of load and supply scheduled on a day-ahead basis can have a significant impact on CAISO operations. To the extent the amount of load and supply scheduled is insufficient to meet the CAISO's forecast of load and other system conditions, the

CAISO may commit additional supply resources on a day-ahead basis through the must-offer waiver denial process. In real time, significant under-scheduling can also require the CAISO to dispatch additional incremental energy resources through the Real Time Market.

During 2006, the level of forward scheduling was quite high, particularly during peak hours. For example, Figure 3.12 compares the average hourly values of day-ahead and hour-ahead schedules with actual load during 2006. This high level of scheduling can be attributed to a number of factors.

- In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecast demand for each hour of the next day. The 95 percent day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through MOW denials and dispatching additional energy in the real-time.

- In addition, the amount of forward scheduling in 2006 was affected by a variety of CPUC procurement guidelines which have had the effect of encouraging the state's major Investor Owned Utilities (IOUs) to forward contract for most or all of their projected energy needs.

- Finally, while Resource Adequacy requirements in effect for 2006 only require that available RA capacity be made available to the CAISO, it is likely that many RA capacity contracts are coupled with energy contracts – such as energy tolling agreements – which allow the LSE to schedule energy from RA resources on a day-ahead basis.

During peak hours (and, in particular, hour ending 16), day-ahead schedules often exceeded the 95 percent scheduling requirement established under Amendment 72, as illustrated in Figure 3.14. This trend suggests that factors other than the 95 percent scheduling requirement – such as CPUC supply procurement guidelines, and the bundling of capacity and energy contracts with RA resources – were primarily responsible for the high degree of forward scheduling seen throughout 2006.

Figure 3.13 shows, by month for all hours, average actual load together with day-ahead and hour-ahead under-scheduling. Even in July when average load peaked, the percent under-scheduled was still under two percent of actual load. Figure 3.14 similarly depicts the percentage of under-scheduling for all hours ending 16 by month for 2006. This chart captures the fact that during the peak hours of 2006, the extent of aggregate under-scheduling was slightly less than three percent of actual load.

As discussed in Section 3.2, during many hours in 2006, high levels of scheduling or over-scheduling required the CAISO to reduce or decrement additional generation in the Real Time Market. Even if energy and schedules submitted by SCs area approximately equal actual CAISO system loads, the CAISO may need to decrement significant amounts of energy due to various sources of unscheduled energy that appear in real-time under the current market design. Major sources of unscheduled energy include:

- Minimum load energy from units committed through the MOW process.

- Positive uninstructed energy from resources within the CAISO, including steam generating units operating at minimum load during off peak hours, cogeneration resources, and intermittent resources such as wind energy.

- Additional net incremental energy from real-time out-of-sequence (OOS) dispatches due to intra-zonal congestion and local reliability requirements.
- Loop flows creating net positive energy from neighboring control areas.

In 2006, the limited amount of under-scheduling that did occur did not detrimentally impact system reliability or significantly increase MOW commitment costs primarily due to the fact that the CAISO was decrementing energy in real-time due to various sources of unscheduled energy. For example, Figure 3.15 shows the percent of hours during the year in which the CAISO was decrementing energy along with the average levels of under-scheduling for each of the 24 operating hours of the day. The red portions of the bars depict the MWh by which aggregate day-ahead schedules fell below 95 percent of the CAISO day-ahead forecast. As depicted in Figure 3.15, the bulk of under-scheduling occurred during hours in which the CAISO was, on net, decrementing energy. Thus, under-scheduling did not create a need for additional incremental energy in real-time and, in fact, under conditions such as these, additional forward scheduling may have only increased the need to decrement energy in real-time.

Figure 3.12 2006 Actual Load Relative to Hour Ahead and Day Ahead Schedules

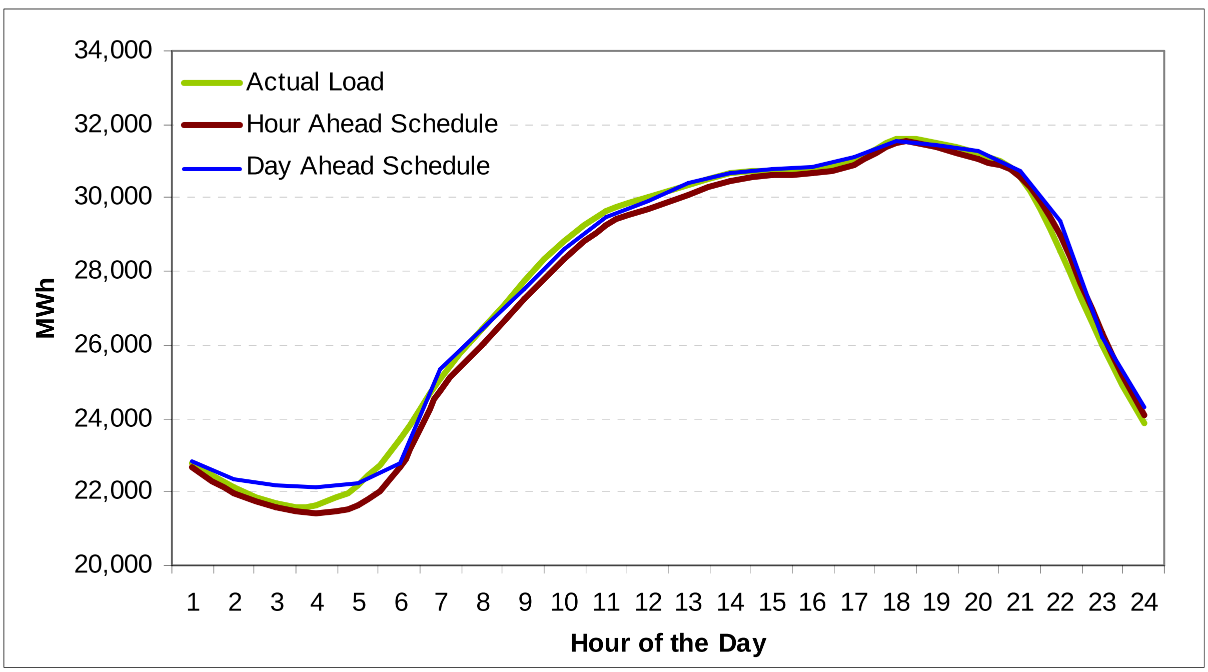


Figure 3.13 2006 Actual Load Relative to Under-Scheduling (Monthly Averages, All Hours)

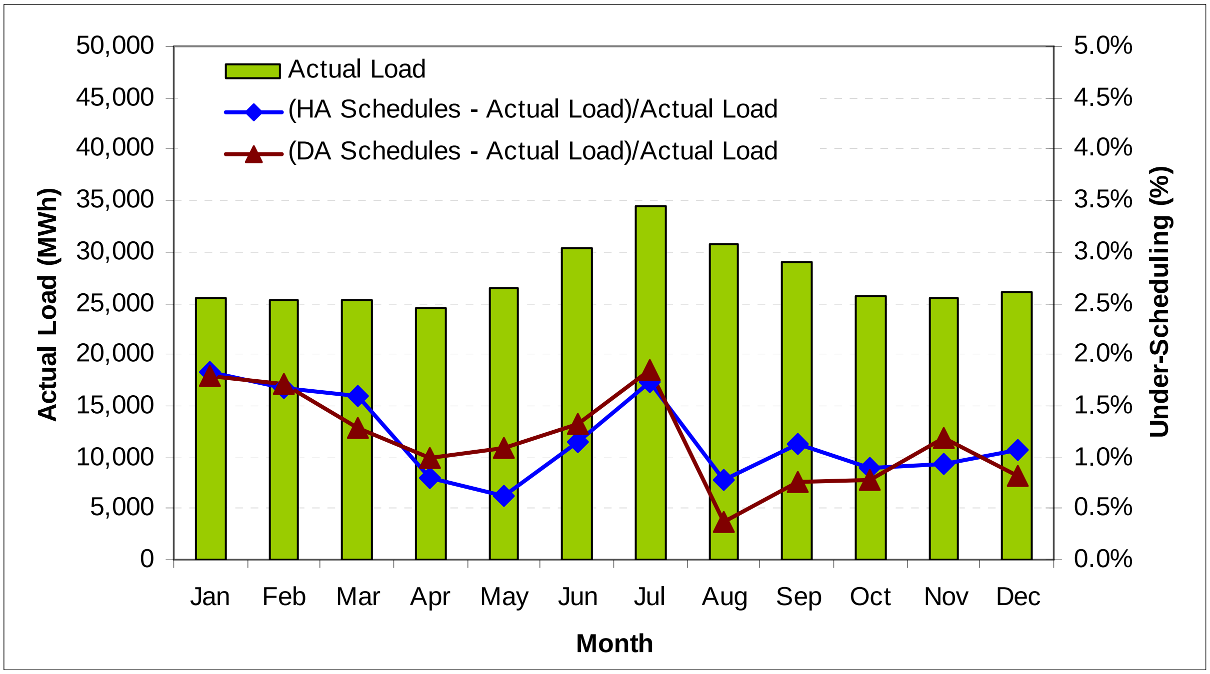


Figure 3.14 2006 Actual Load Relative to Under-Scheduling (Monthly Averages, Hour 16 Only)

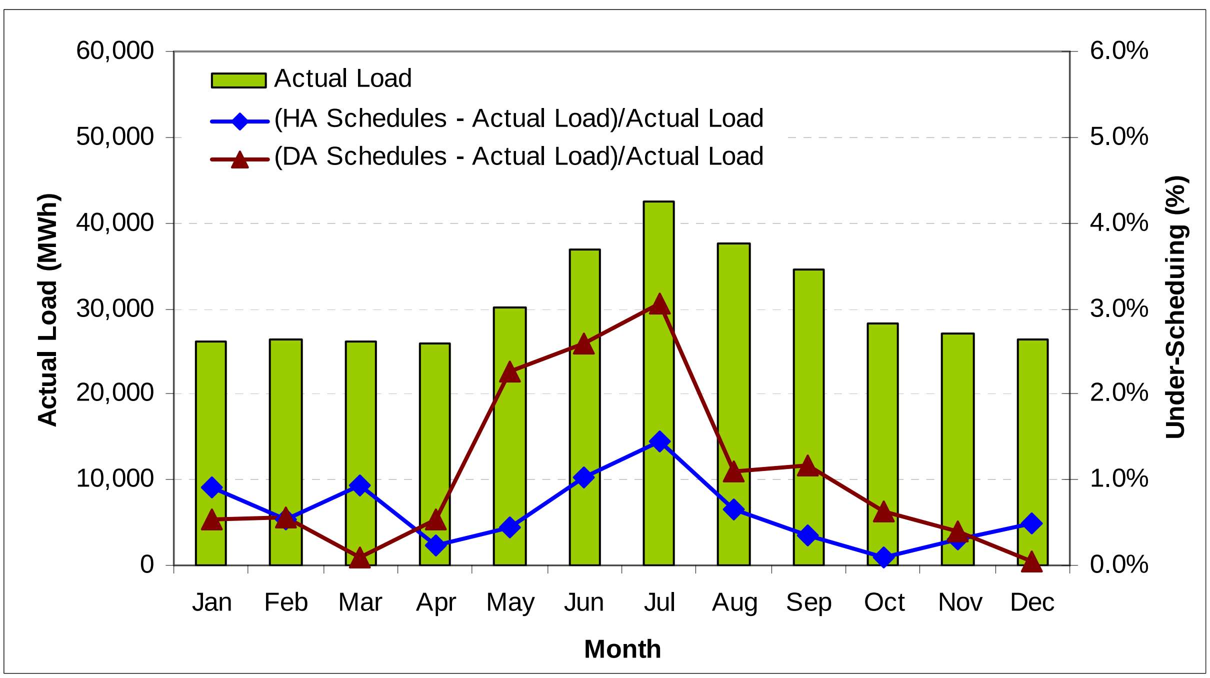
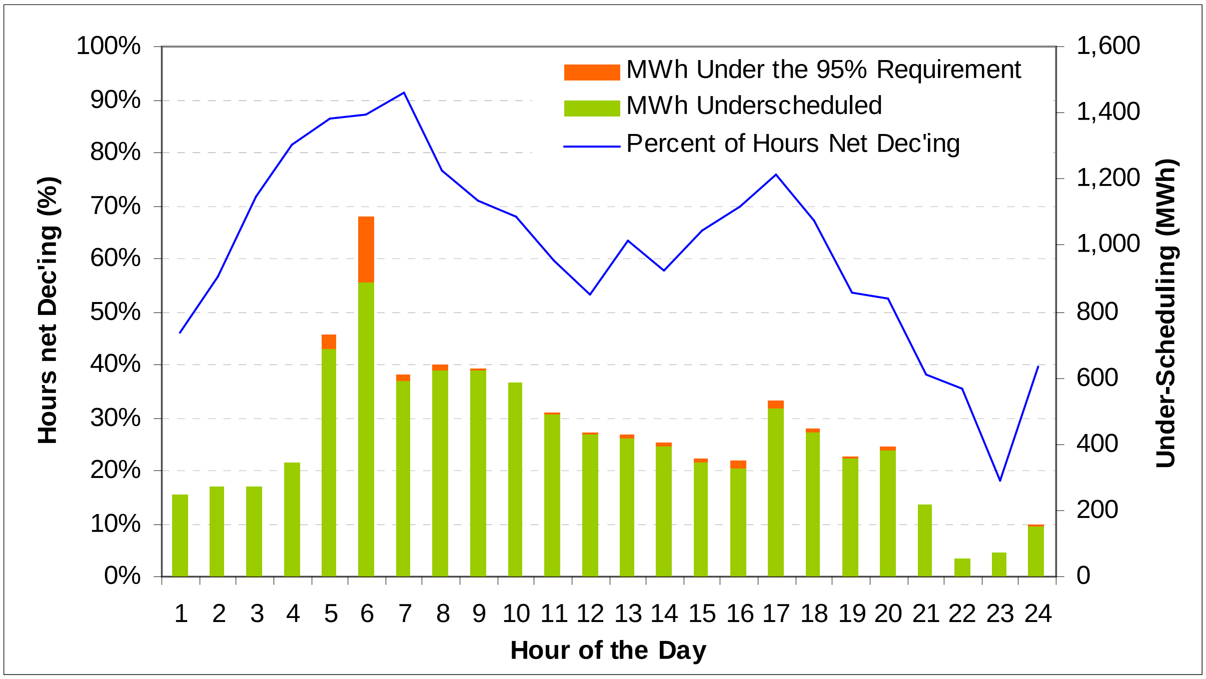


Figure 3.15 2006 Average Under-Scheduling by Hour Relative to Net Decremental Energy



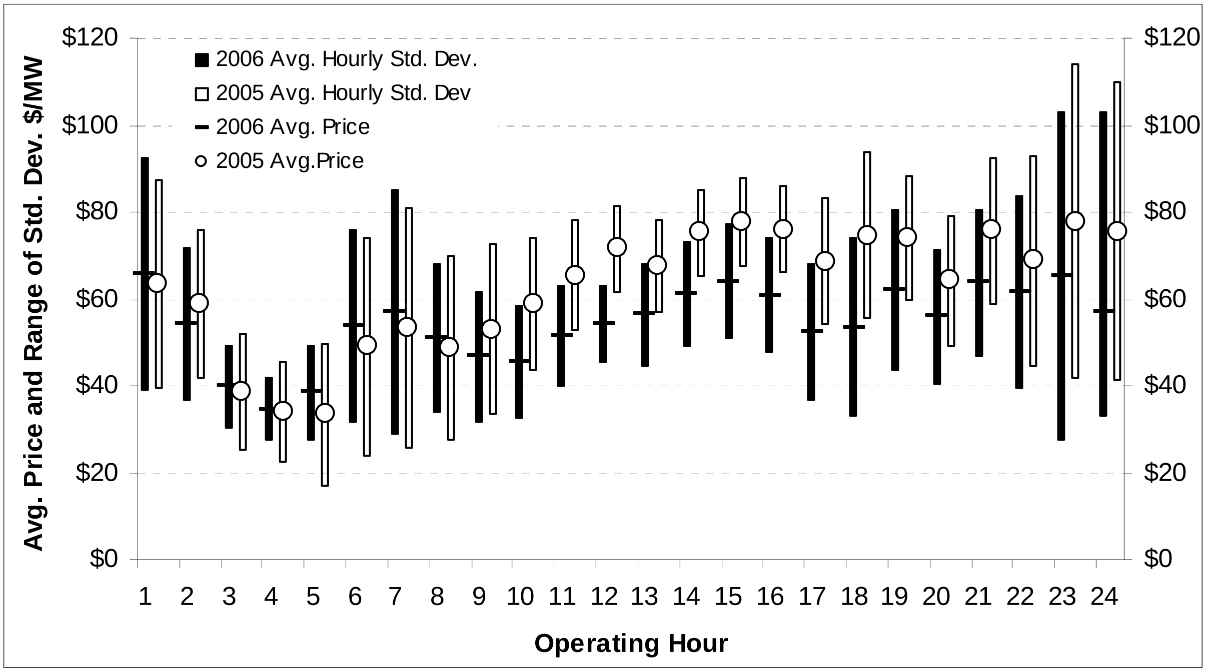
3.4 Assessment of Imbalance Market (RTMA) Performance

3.4.1 Price Volatility

RTMA was designed to address significant shortcomings in the prior real-time dispatch and pricing application (BEEP) in October 2004. One of the major concerns raised about RTMA since its implementation is a perceived high degree of price and dispatch volatility. It should be noted that a real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on a nearly instantaneous basis and the market is very thin. A high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids.

Figure 3.16 compares the average and range of RTMA interval prices for 2005 and 2006 in SP15. The range of prices for each hour shown in Figure 3.16 represents the average load-weighted interval price for that hour, plus and minus the average standard deviation of interval prices within each operating hour. As evident in Figure 3.16, the level of price volatility in 2006 is comparable to 2005 for most hours of the year – suggesting a persistent trend of price volatility.

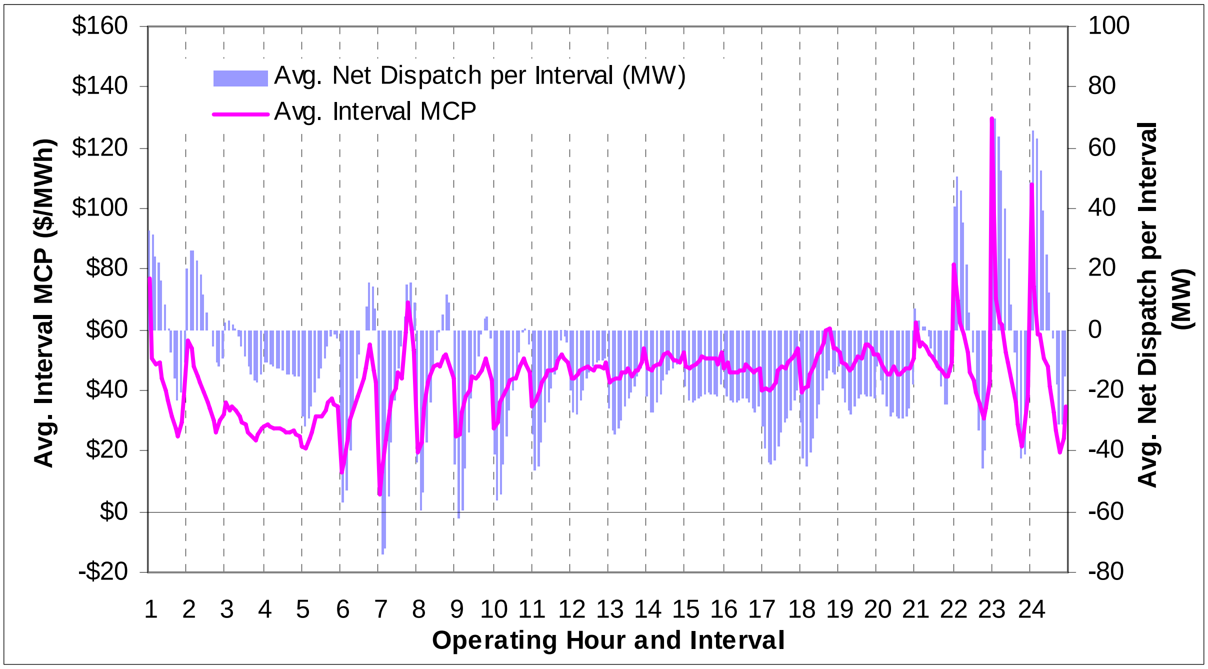
Figure 3.16 Average SP15 Hourly Prices and Standard Deviation (2005-2006)



The average of MCP and net dispatched energy for each interval during the day in 2006 is presented in Figure 3.17. The basic findings are the same as last year. Much of the intra-hour deviation of real-time prices under RTMA can be attributed to intra-hour fluctuations in demand for imbalance energy. There is a very close correlation between the intra-hour price deviations and net quantity of real-time energy dispatched each 5-minute interval since implementation of RTMA. Within each hour, prices are significantly higher when the CAISO is incrementing generation, and lower when the CAISO is decrementing generation. This pattern is especially noticeable during the morning and evening ramping hours when net dispatched energy changes directions from incrementing to decrementing or vice versa due to the rapid load increase or decrease. The volatility of prices and imbalances during those hours are also highest, as shown in more detail in Figure 3.16 and Figure 3.17, respectively.

During the morning ramp hours, prices tend to be lower during the first 15-minutes of each hour as the CAISO typically needs to decrement generation. During these intervals, the need to decrement generation stems from the fact that supply is ramping up to its new hourly schedule faster than the actual increase in loads during the first several intervals of each hour. Conversely, during late night ramp down hours, the prices tend to be significantly higher during the first 15-minutes of each hour as the CAISO typically needs to increment generation. The need to increment generation during these intervals stems from the fact that supply is ramping down to its new hourly schedule faster than the actual decrease in loads during the first portion of each hour.

Figure 3.17 Intra-Hour Price Volatility Under RTMA in 2006



3.4.2 Uninstructed Deviations

Uninstructed deviations are an important aspect of market performance to the extent that they result in a need to excessively dispatch other resources or that they interfere with RTMA's ability to effectively balance the system. As discussed in more detail below, both the volume and interval-to-interval volatility of generating unit uninstructed deviations in 2006 appears to have been relatively consistent with what was observed in 2005, and appears to be within acceptable limits.

The CAISO had previously proposed the Uninstructed Deviation Penalty (UDP) as a feature of the current market design, as well as the upcoming MRTU market design, as an incentive for resources to follow their schedules and CAISO dispatch instructions. UDP was not implemented as part of the current market design because of concerns regarding the manner in which RTMA dispatched generating units and the feasibility of reporting limitations within a 30-minute period necessary to avoid UDP. UDP is planned as a potential feature of MRTU Release 2, which is anticipated to be implemented subsequent to the initial implementation of MRTU, depending on the impact uninstructed deviations have on grid and market operations under MRTU.

This section examines trends in uninstructed deviations based on two basic measures:

- Volume of Uninstructed Deviations. The total volume or magnitude of all uninstructed deviations on a system-wide level is important since this reflects the impact of uninstructed deviations on the overall quantity of incremental or decremental energy that the CAISO must dispatch to balance system loads and resources. The magnitude of system-level uninstructed deviations was measured by calculating the approximate net deviation in each 10-minute settlement interval of all generating units (including generating units not subject to UDP). The approximate deviation of each unit was first calculated for each interval and the net deviation on a system level of each interval was then calculated by summing up the approximate deviation of all generating units. This summation and netting of individual resource deviations reflected the fact that system and market operation are affected primarily by the net system-wide deviation, rather than deviations of individual resources. Since the system level deviations can be either positive or negative each interval, the system level deviation each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net deviation over each month.

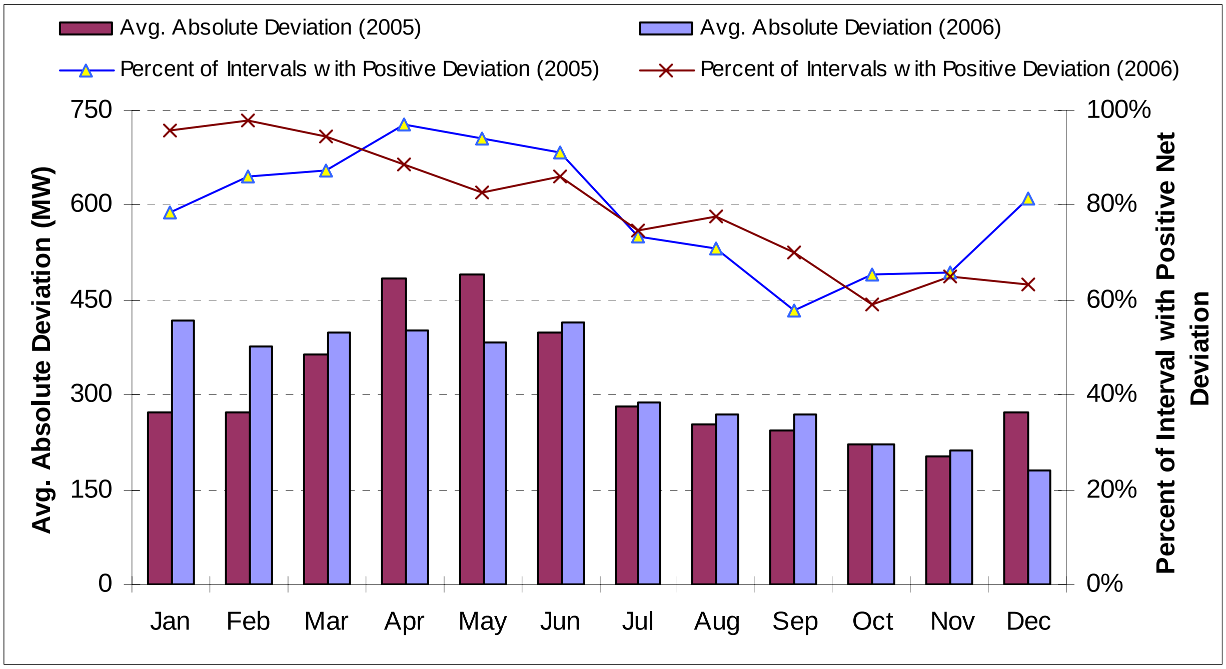
- Volatility of Uninstructed Deviations. The volatility of uninstructed deviations on a system-wide level from one interval to the next is also important since sudden and/or unpredictable changes in system level uninstructed deviations can have detrimental impacts on system and market operations. The volatility of uninstructed deviations was assessed based on the change in system level uninstructed deviations from each interval to the next. Again, since the system level deviations can be either positive or negative each interval, the change in system level deviation in each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net between settlement interval deviation over the month.

As the primary concern with uninstructed deviations under the current market design is whether generating units are responding to dispatch instructions to provide interval to interval balancing energy in real-time, the analysis presented in this section was limited to generating units within the control area and did not include deviations of import resources. The settlement interval deviation of each generating unit was based on the unit's uninstructed imbalance energy as calculated by the settlement system. Units providing regulation were excluded from the analysis during the hours they were providing regulation since this energy is provided in response to CAISO operating instructions.

Figure 3.18 compares the magnitude of generating unit uninstructed deviations during 2006 as compared to the corresponding months in 2005.[4] Figure 3.18 also shows the percentage of 10-minute settlement intervals in which the net system level deviation was positive (i.e., net generation exceeded the total amount of energy scheduled or dispatched from these units) during each of these months.

[4] The average generating unit uninstructed deviations shown in Figure 3.18 are an average of the absolute values of the total net generating unit deviations for each 10-minute settlement interval.

Figure 3.18 Average Absolute Value of Net Uninstructed Deviation

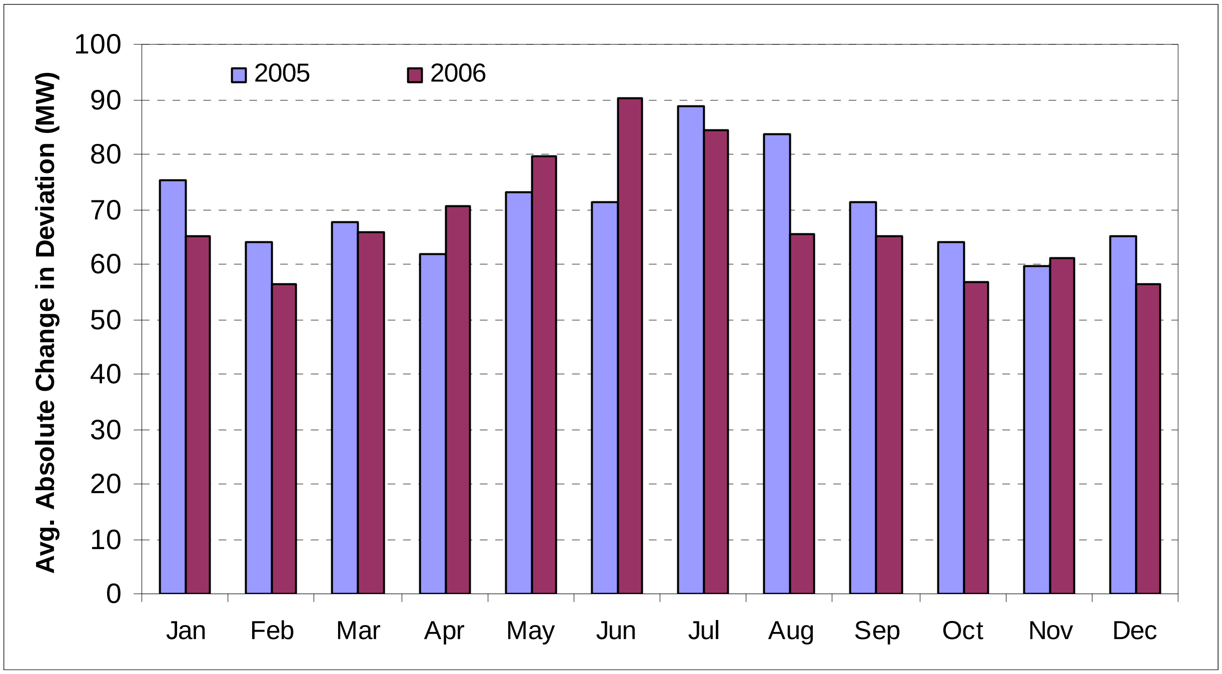


As shown by Figure 3.18, uninstructed deviations in 2006 were consistent with those that existed in 2005 – uninstructed deviations averaged 319 MW in 2006 and 313 MW in 2005. Deviations were slightly greater during January and February 2006 than during those months in 2005, while deviations were slightly less during April, May, and December 2006 than during those months in 2005. These differences were likely due to differences in the timing of runoff conditions affecting hydro units or due to a short-term non-systematic deviation of a single large unit. Both the 2006 and 2005 data appear to show the same seasonal variation, with the magnitude of deviations greater in the spring months, which is likely at least partially attributable to positive deviation of hydro units during the spring runoff period.

Figure 3.18 also shows that uninstructed deviations were predominately positive (i.e., generating more than schedule plus dispatch instructions), consistent with that which occurred in 2005 – the net deviation of generating units was positive in an average of 80 percent of settlement intervals throughout 2006 and in 79 percent of settlement intervals in 2005. The prevalence of positive uninstructed deviations are likely explained by units running uninstructed, energy produced during start-up and shutdown periods, and by units that must run at levels greater than scheduled due to environmental constraints.

Figure 3.19 examines the volatility of uninstructed deviations as represented by the monthly average absolute value of the change in net generating unit deviations between 10-minute settlement intervals for 2006 compared to 2005. As Figure 3.19 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2006 has been relatively consistent with 2005. The seasonal variation in the between-settlement interval net deviation change is similar in the two periods, as well as the average magnitude of the variation in the two periods, averaging 68 MW in 2006 and 70 MW in 2005.

Figure 3.19 Average Change in Net Uninstructed Deviation between Settlement Intervals



3.4.3 Use of Regulation and Load Bias

The RTMA software implemented in October 2004 was designed to reduce the frequency and degree of dispatcher judgment or intervention required to run the real-time imbalance market. The RTMA software continues to allow for dispatcher adjustments, but focuses dispatcher input primarily on one single input: the *load bias*, which is an optional adjustment that can be entered by the dispatcher to RTMA's internally generated projection of imbalance energy requirements over the next one to two hour period.[5] Thus, use of this load bias feature provides a key direct indicator of the degree of judgment or intervention exercised in running the real-time imbalance market.

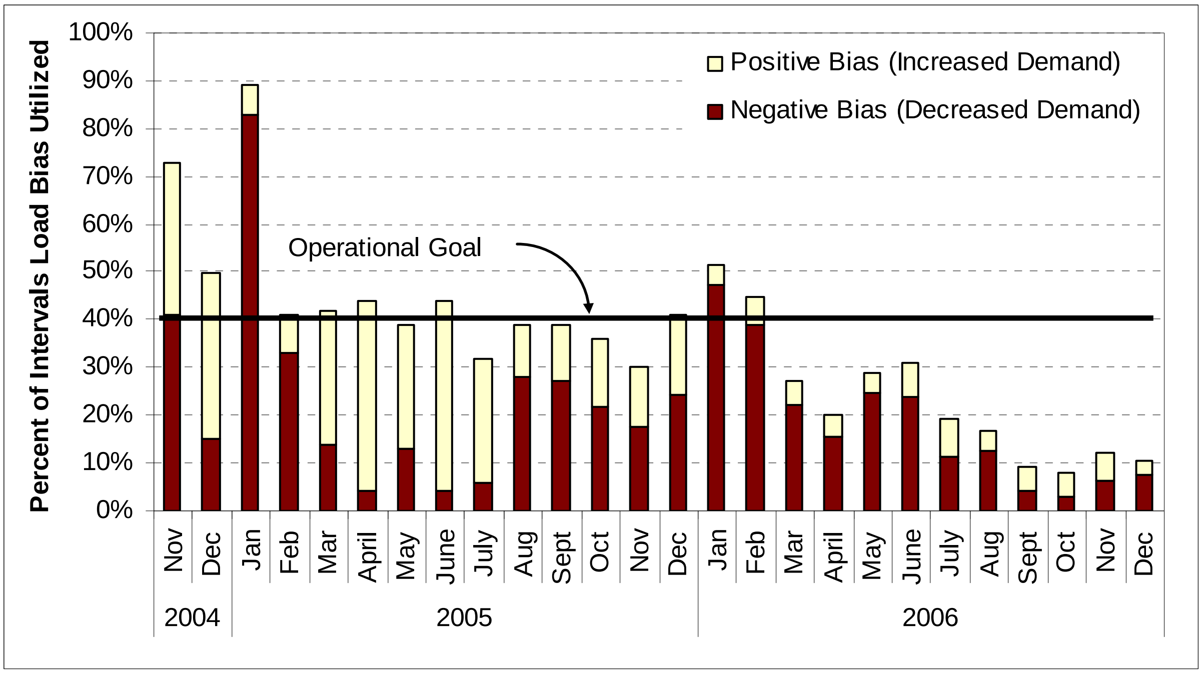
In 2005, CAISO Grid Operations had established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of all intervals. As shown in Figure 3.20, while the load bias was utilized from about 30 to 45 percent of intervals during most months of 2005, use of the load bias declined significantly in 2006. Overall, the load bias was utilized during only 23 percent of intervals in 2005 compared to 44 percent in 2006.

As shown in Figure 3.20, the decline in the frequency with which a positive load bias was utilized by Grid Operators was especially pronounced, with a positive load bias utilized during only 5 percent of intervals in 2005 compared to 22 percent in 2006. The infrequent use of a positive load bias is likely due in part to the real-time system conditions that required the CAISO to be decrementing energy throughout most of 2006.

[5] A detailed description of the RTMA software, and how dispatchers utilize the load bias function of RTMA to account for actual system conditions or anticipated conditions within the next few intervals is provided in Chapter 3 of DMM's 2005 Annual Report (see pages 3-1 to 3-2 and 3-30 to 3-31).

As described in last year's annual report, input from Grid Operations staff and analysis of load bias usage patterns by DMM indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity. In order to assess the approximate impact of load bias on regulation usage, DMM calculates, for each interval, a counterfactual regulation deviation from POP that may have occurred if load bias had not been used.[6] Figure 3.21 shows summary data for 2005. More detailed and comparative results of this analysis for 2005 and 2006 are shown in Table 3.2.

Figure 3.20 Utilization of Load Bias by Month (Percent of Intervals)



6 For example, if a 100 MW positive load bias was entered during an interval when the actual regulation deviation was +150 MW, it is assumed that in the absence of the 100 MW positive load bias, 100 MW less of instructed energy would have been dispatched and the regulation deviation would have totaled +250 MW.

Figure 3.21 Estimated Impact of Load Bias on Regulation Energy Usage (2006)

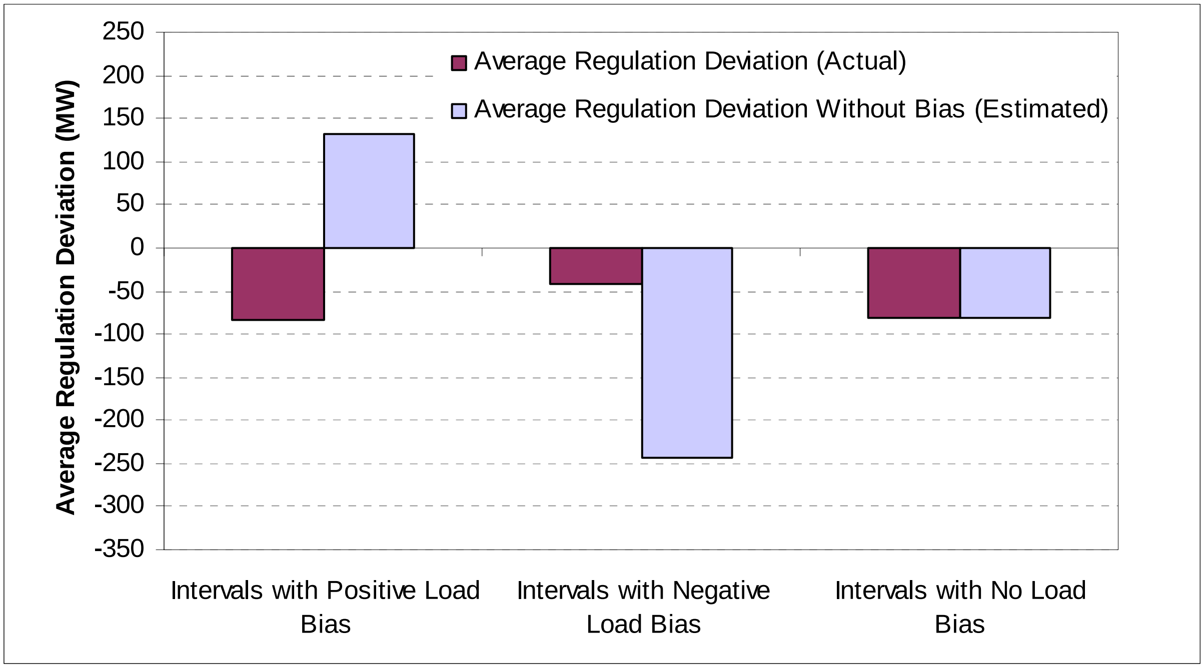


Table 3.2 Estimated Impact of Load Bias on Regulation Energy Usage and Regulation Deviation from POP (2005-2006)

	Type of Load Bias		
	Positive	**Negative**	**None**
Results for 2006			
Percent of 10-minute Intervals	5%	18%	77%
Average Load Bias (MW)	214	-202	0
Average Regulation Deviation (MW)	-83	-41	-81
Average Regulation Deviation (MW) Without Bias	131	-243	
Average Absolute Deviation (MW) from POP	158	117	121
Average Absolute Deviation (MW) from POP Without Bias	194	250	
Average Decrease in Absolute Deviation (MW) from POP due to Bias	35	133	
Results for 2005			
Percent of 10-minute Intervals	22%	20%	58%
Average Load Bias (MW)	229	-255	0
Average Regulation Deviation (MW)	-16	-51	-28
Average Regulation Deviation (MW) Without Bias	212	-306	
Average Absolute Deviation (MW) from POP	126	127	120
Average Absolute Deviation (MW) from POP Without Bias	234	316	
Average Decrease in Absolute Deviation (MW) from POP due to Bias	108	189	

As shown in Table 3.2 and Figure 3.21, the load bias appears to have been used to decrease the usage of regulation capacity relative to levels that would have occurred absent any load adjustments by operators. The actual average regulation deviation during the 23 percent of intervals when a positive or negative load bias was utilized was -83 and -41 MW, respectively, while the actual average regulation deviation during the 77 percent of intervals when no load bias was utilized was -81 MW. However, if no load bias had been utilized during the 18 percent of intervals when a negative load bias was used, the average regulation deviation may have been as high as -243 MW. Meanwhile, if no load bias had been utilized during the 5 percent of intervals when a positive load bias was used, the average regulation deviation may have been +131 MW. As summarized in Table 3.2, this equates to an average reduction in the absolute value of the system level deviation from POP of about 35 MW during interval when a positive load bias was utilized.

Another overall trend in 2006 was decreased usage of upward regulation capacity and increased usage of downward regulation capacity. These trends can be attributed largely to real-time system conditions that required the CAISO to be decrementing energy throughout most of 2006. As shown in Figure 3.22, the portion of intervals when the CAISO was utilizing upward regulation dropped from about 40 percent in 2005 to about 25 percent in 2006. During these intervals, the average amount of upward regulation energy utilized also dropped from about 39 MWh in 2005 to about 24 MWh in 2006, as shown in Figure 3.23. Meanwhile, the portion of intervals when the CAISO was utilizing downward regulation increased from about 60 percent to about 75 percent from 2005 to 2006. During these intervals, the average amount of downward regulation energy also increased from about -72 MWh in 2005 to about -96 MWh in 2006.

Figure 3.22 Regulation Capacity Usage

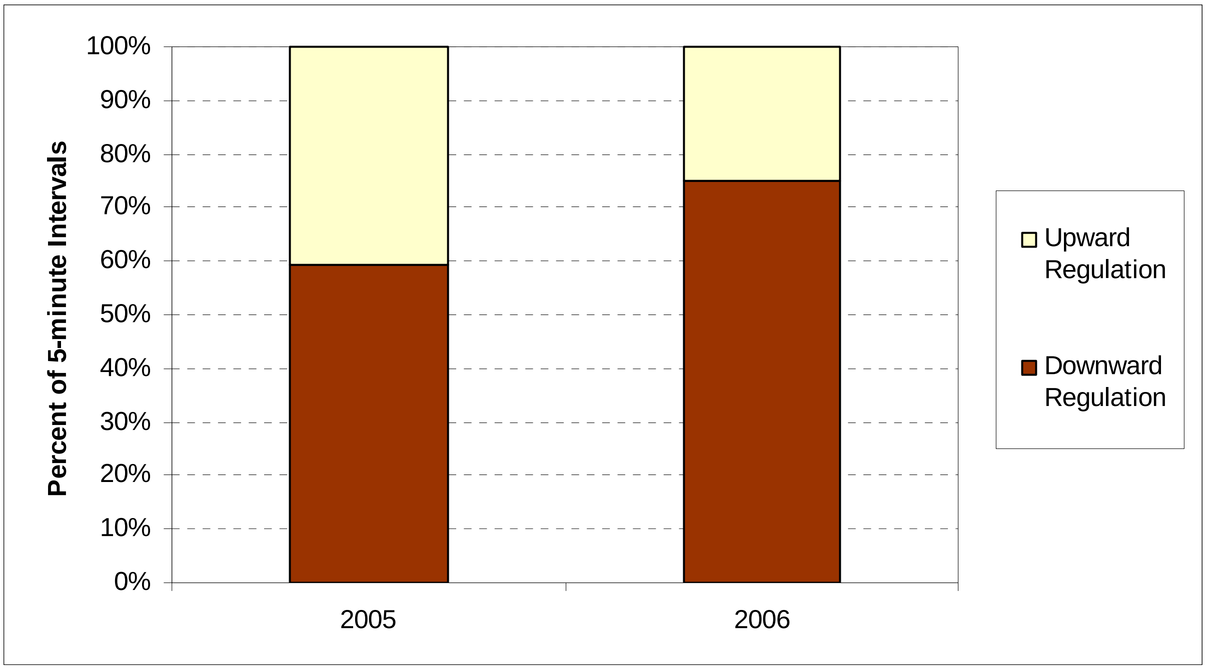
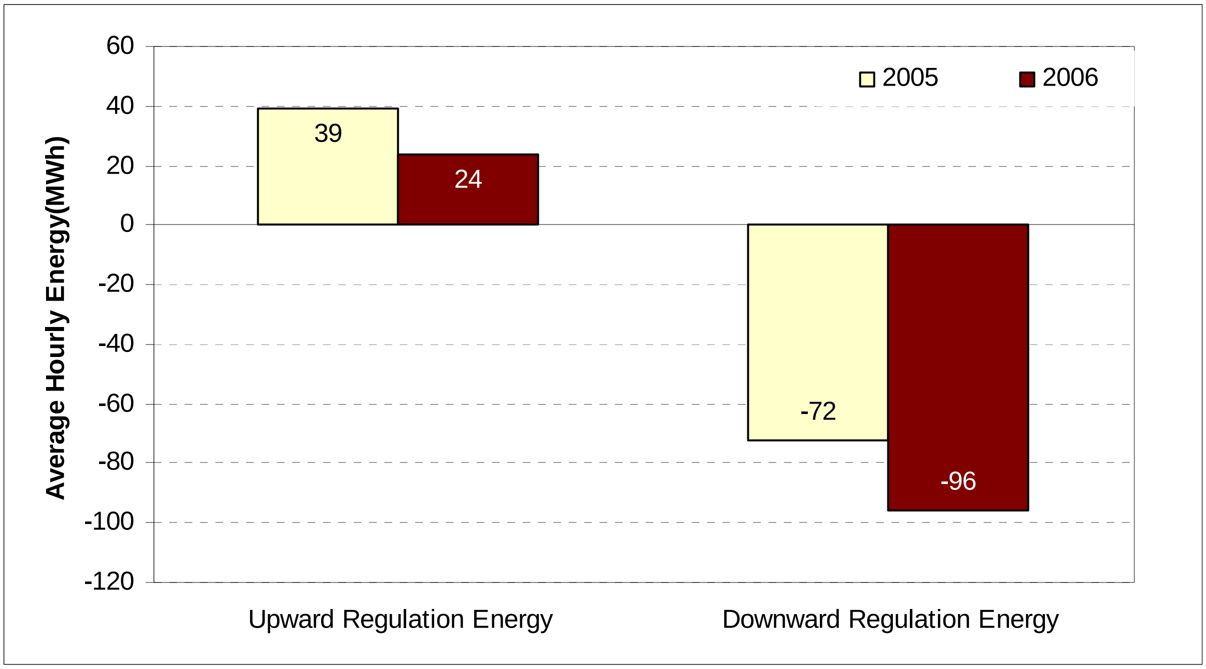


Figure 3.23 Average Hourly Regulation Usage



3.4.4 Price Convergence between Pre-dispatch Imports and Intra-hour Dispatch

Year 2006 is the first complete operating year following the implementation of Amendment 66, which specified that import/export bids from neighboring areas be paid "as-bid" (their bid prices), rather than the better of their bids and prevailing ex-post MCPs.

In the initial RTMA design, two significant modifications were included: a market clearing mechanism, under which bids for incremental energy to provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or "cleared" against each other, and a "bid or better" settlement rule for import/export bids, under which hourly import/export bids pre-dispatched by the CAISO were paid/charged the higher/lower of their bid price or the ex-post MCP subsequently set during the operating hour by resources within the CAISO system dispatched on a 5-minute basis. Although RTMA pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the "bid or better" settlement rule. In spring 2005, significant divergences were identified between the projected prices used to clear import/export bids and the actual ex-post MCPs.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the market clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the "bid or better" settlement rule for pre-dispatched import/export bids to an "as-bid" market design. Under an "as-bid" settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an "as-bid" settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

Once Amendment 66 was implemented, the volume of bids dispatched for market-clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically. Through the end of year 2006, significant improvements have been made from Amendment 66 implementation, such as price convergences for pre-dispatched energy to Real Time Market prices, dramatically reduced volume of offsetting incremental and decremental energy, and lowered the net cost for market clearing.

- **Price convergence**. Prior to implementation of Amendment 66, the prices of pre-dispatched incremental energy (including uplifts) were often significantly higher than the values of the incremental energy as reflected in the MCPs set in the CAISO real-time 5-minute imbalance market. Similarly, prior to implementation of Amendment 66, the prices of pre-dispatched decremental energy (including uplifts) tended to be systematically lower than the values of the decremental energy calculated at the ex-post MCPs set in the CAISO real-time 5-minute imbalance market. Since the implementation of Amendment 66, prices for pre-dispatched energy from import/export bids have tracked much more closely with Real Time Market prices set by resources within CAISO system subsequently dispatched within each operating hour. Figure 3.24 and Figure 3.25 show the trend in volumes and net prices of incremental and decremental energy pre-dispatched to balance CAISO system demand, respectively, and compare the net prices for pre-dispatched incremental and decremental energy with the value of this pre-dispatched energy calculated using the corresponding hourly ex-post MCP set by resources dispatched within the CAISO system. As shown in Figure 3.23, since implementation of Amendment 66, prices for pre-dispatched incremental energy generally converge with Real Time Market clearing prices. As illustrated in Figure 3.24, while prices for pre-dispatched and Real Time decremental energy often converge, prices for pre-dispatched decremental energy tends to drop below Real Time Market clearing prices when the CAISO is pre-dispatching high volumes of decremental energy. The need for the CAISO to decrement relatively large volumes in the pre-dispatch process can be caused by several reasons, including as high levels of scheduling or over-scheduling, and various sources of unscheduled energy, which include minimum load energy from units committed through the MOW process, net energy produced from intra-zonal congestion management, and uninstructed energy from resources within the CAISO.

- **Reduced volume of offsetting incremental and decremental energy**. The volume of offsetting incremental and decremental energy bids pre-dispatched by the CAISO to clear the market has also been dramatically reduced under the “as-bid” settlement rule. Since the effective date of Amendment 66 through the end of 2006, an average of only about 25 MW of off-setting incremental and decremental bids have been pre-dispatched each hour, as opposed to an average of about 600 MW per hour in the month prior to implementation of Amendment 66.

- **Lowered cost for market clearing**. Total uplift costs incurred prior to the CAISO’s March 23, 2005 filing were estimated at $33.6 million, with about $18.6 million of these uplift costs attributed to clearing of overlapping (or offsetting) incremental and decremental bids under RTMA. Costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids averaged about $400,000 per day in the month prior to Amendment 66. As shown in 0, the cost for offsetting incremental and decremental bids drops dramatically after "as-bid" settlement rule was implemented.

Figure 3.24 Average Hourly Volume of Bids Pre-Dispatched by the CAISO and Average Daily Costs to CAISO of Market Clearing

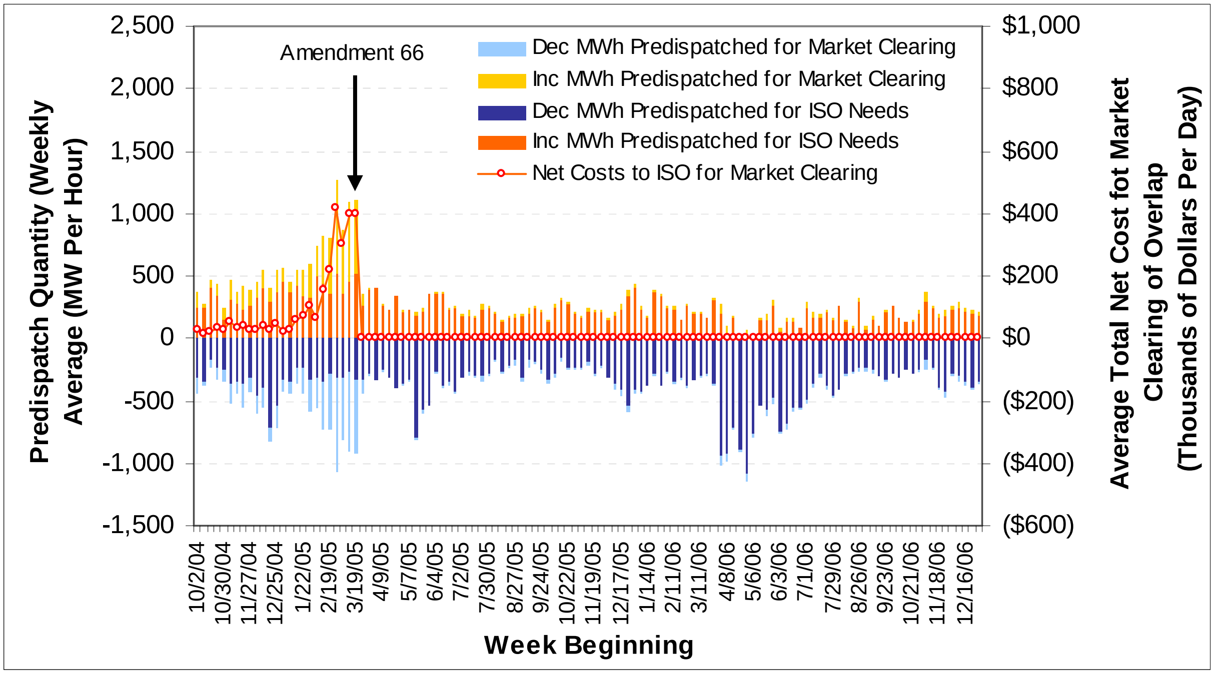


Figure 3.25 Total Net Price Paid for Incremental Energy Pre-dispatched to Balance CAISO System Demand

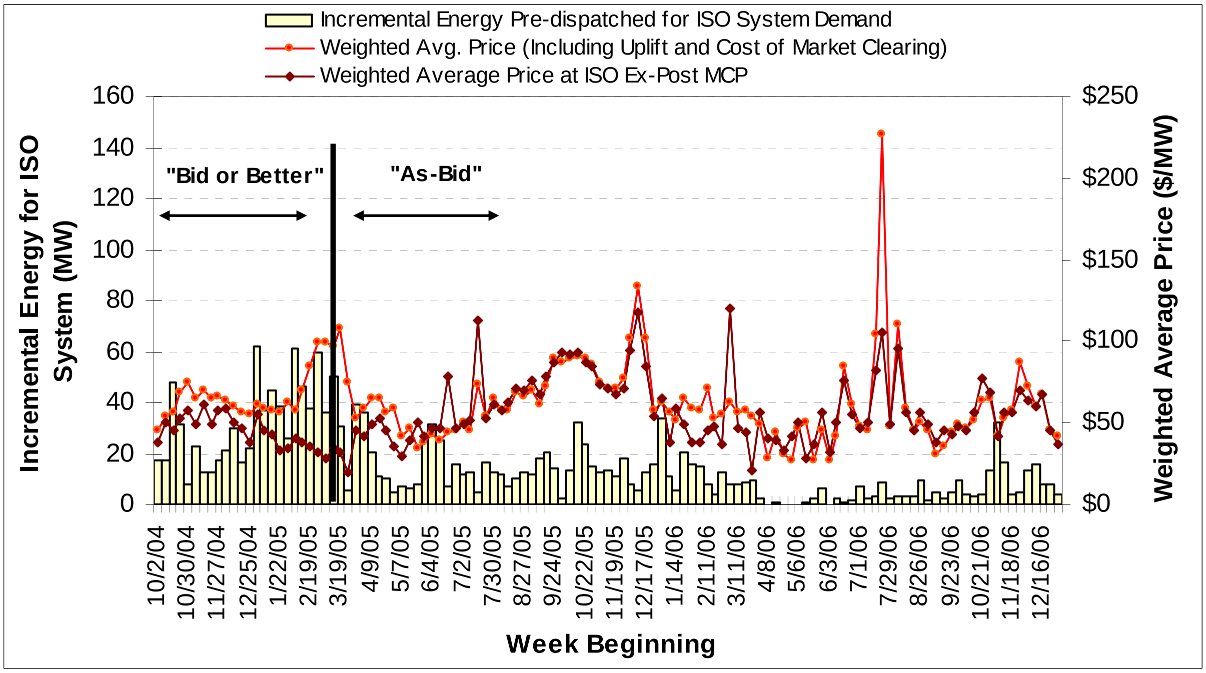
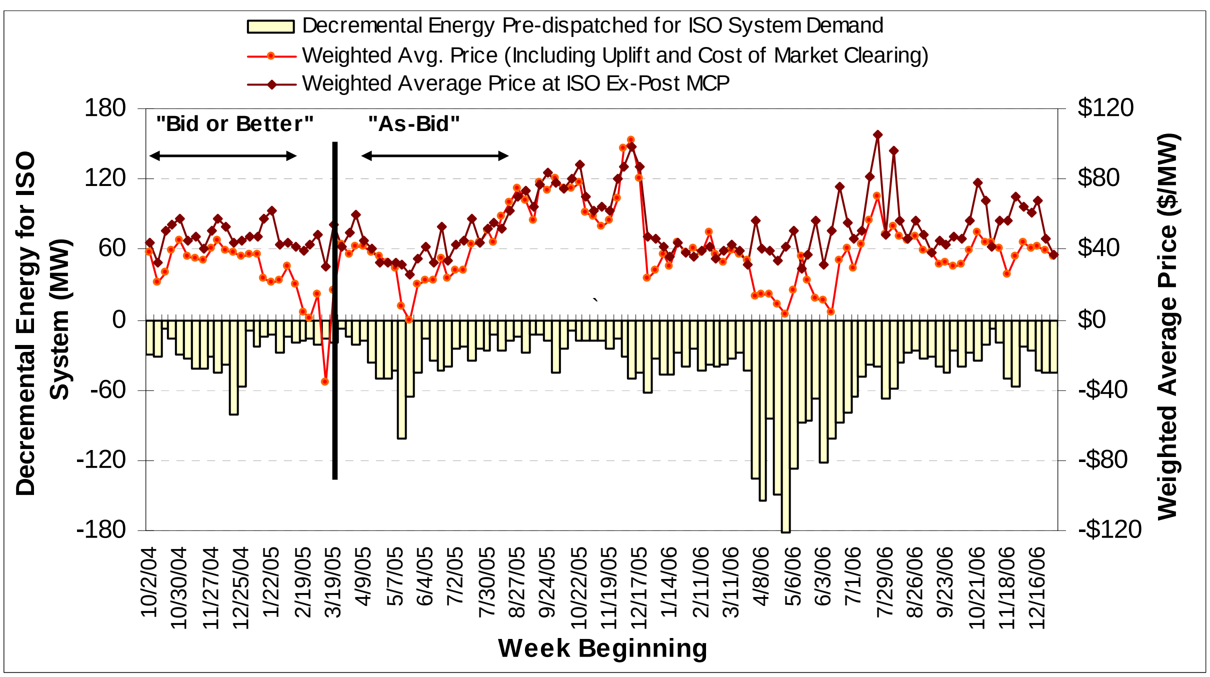


Figure 3.26 Total Net Price Received for Decremental Energy Pre-dispatched to Balance CAISO System Demand



The replacement of the "bid or better" settlement rule with an "as-bid" settlement rule for imports/export created a concern among some market participants that this change would reduce the liquidity of import/export bids submitted to the CAISO market. To date, however, the CAISO has not experienced problems in terms of bid insufficiency or liquidity of incremental energy import bids since the switch to an "as-bid" market under Amendment 66. In fact, the volume of incremental energy bids has typically been higher in 2006 than during the comparable period in 2004, and has consistently been well in excess of the quantity of bids actually pre-dispatched.

As shown in Figure 3.26, the volume of overall net imports scheduled or bid into the CAISO system remained comparable to pre-Amendment 66 levels throughout the summer months under the "as-bid" settlement rule. The volume of incremental real-time energy bids remained far in excess of amounts of imports actually pre-dispatched. Similarly, as shown in Figure 3.27, the volume of decremental real-time energy export bids submitted to the CAISO Real Time Market increased and remained far in excess of amounts of imports actually pre-dispatched for most hours.

Figure 3.27 Net Scheduled Imports, Real-Time Energy Import Bid Volumes, and Pre-Dispatched Imports - Hourly Averages by Week (Peak Hours 13-20)

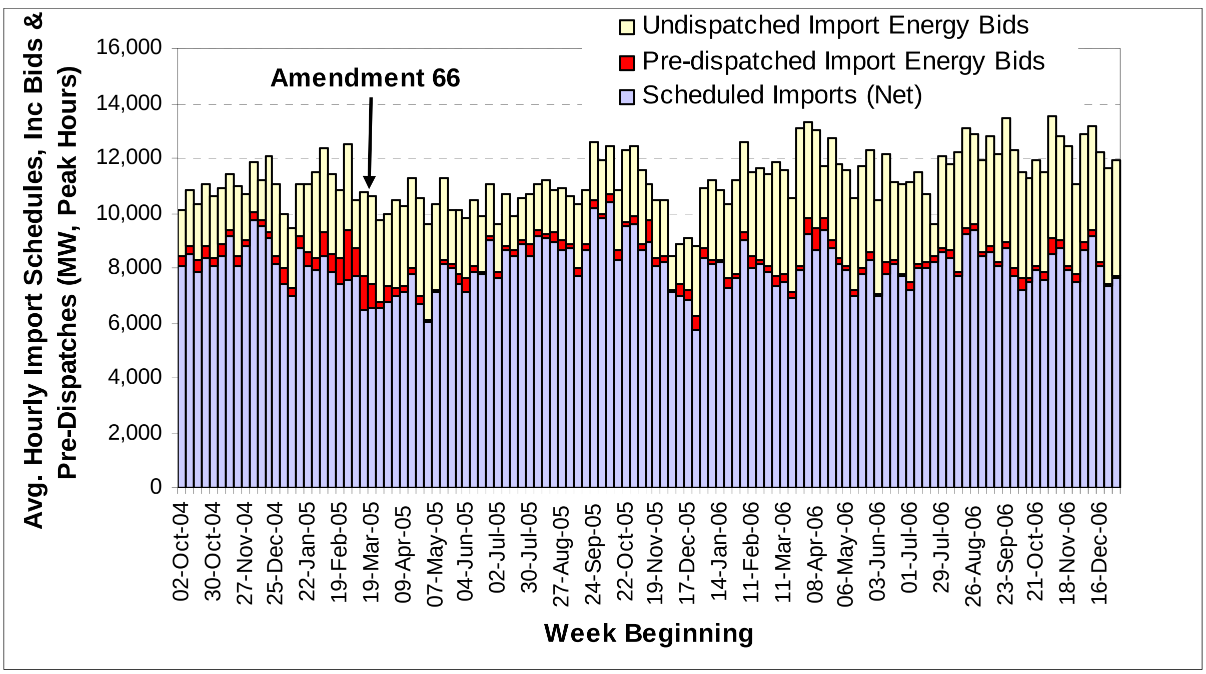


Figure 3.28 Real-Time Energy Export Bid Volumes And Pre-Dispatched Exports - Hourly Averages by Week (Off-Peak Hours 1-8)