3 Real Time Market Performance

3.1 Overview

2007 marked the third full year of operation under the 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 2007. 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. An analysis of uninstructed deviations under RTMA is also provided in Section 3.4. Finally, Section 3.5 provides an assessment of recent trends relating to market participants declining inter-tie bids that are pre-dispatched for the Real Time Market.

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 2006 and 2007. Monthly prices for incremental energy in 2007 were fairly stable, averaging between $54 and $89/MWh on a monthly basis, consistent with stable natural gas prices and moderate imbalance requirements. Average monthly prices for decremental energy were relatively low during the peak hydroelectric season (February through May), and averaged between $27 and $47/MWh across the entire year. In-sequence dispatch volumes were predominantly decremental in most months of 2007, albeit to a lesser degree than in 2006, especially during the spring and summer months. The preponderance of decremental dispatches can be attributed in part to high levels of forward energy scheduling which is driven by the CAISO day-ahead load scheduling requirement (Amendment 72) and Load Serving Entities (LSEs) being risk averse to volatile Real Time Market prices. The spikes in the average cost of incremental OOS dispatches in April and December are due to periods where additional local reliability support was required from less efficient resources in Northern California (please see Chapter 6 for additional details). However, incremental OOS volumes in both months were low, especially when compared to October 2007 when excessive OOS dispatch was required to manage various local reliability issues during the wild fires in Southern California.

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2006-2007)

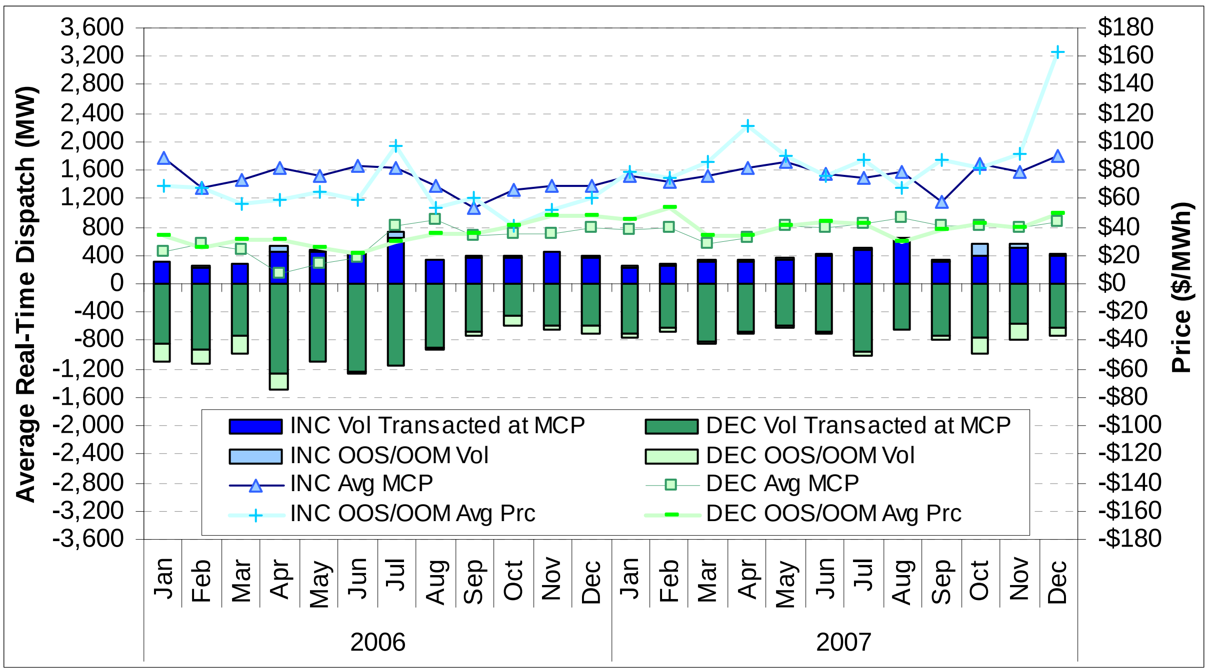


Figure 3.2 and Figure 3.3 show the same metrics presented in Figure 3.1 but separately for peak and off-peak hours, respectively. As can be seen in these figures, the average monthly market volume trends across the two years are fairly similar for peak and off-peak hours. As expected, average monthly prices were generally higher in the peak hours.

Figure 3.2 Monthly Average Dispatch Prices and Volumes in Peak Hours (2006-2007)

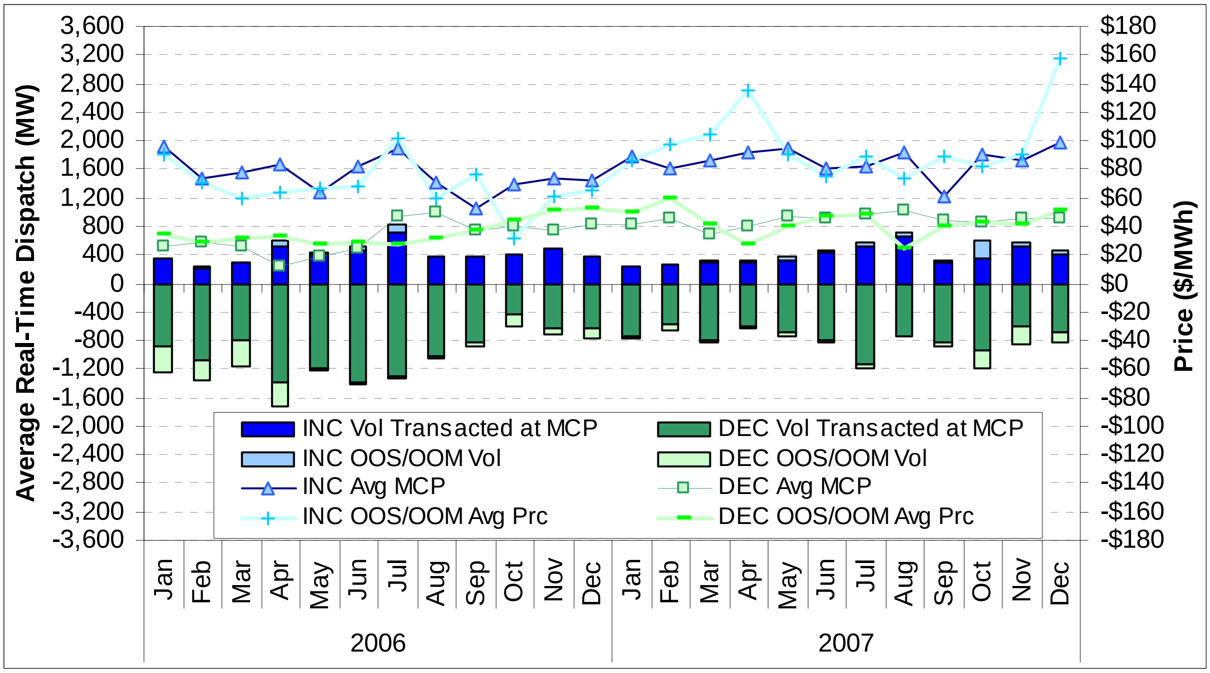


Figure 3.3 Monthly Average Dispatch Prices and Volumes in Off-peak Hours (2006-2007)

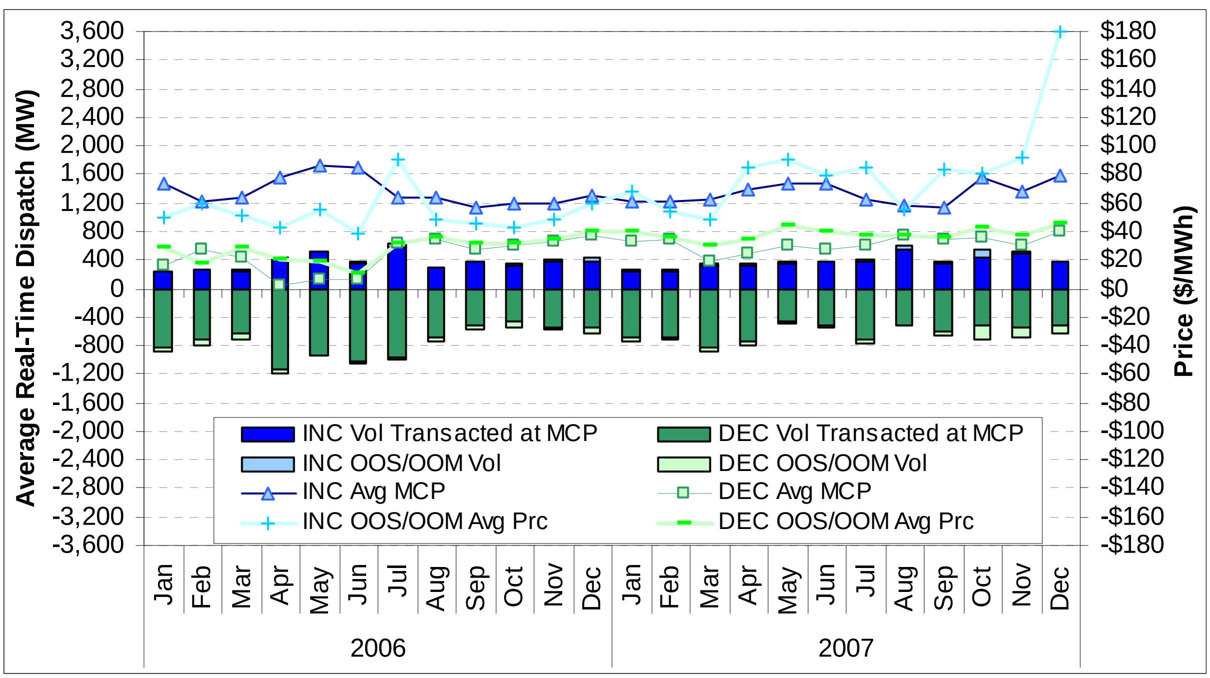
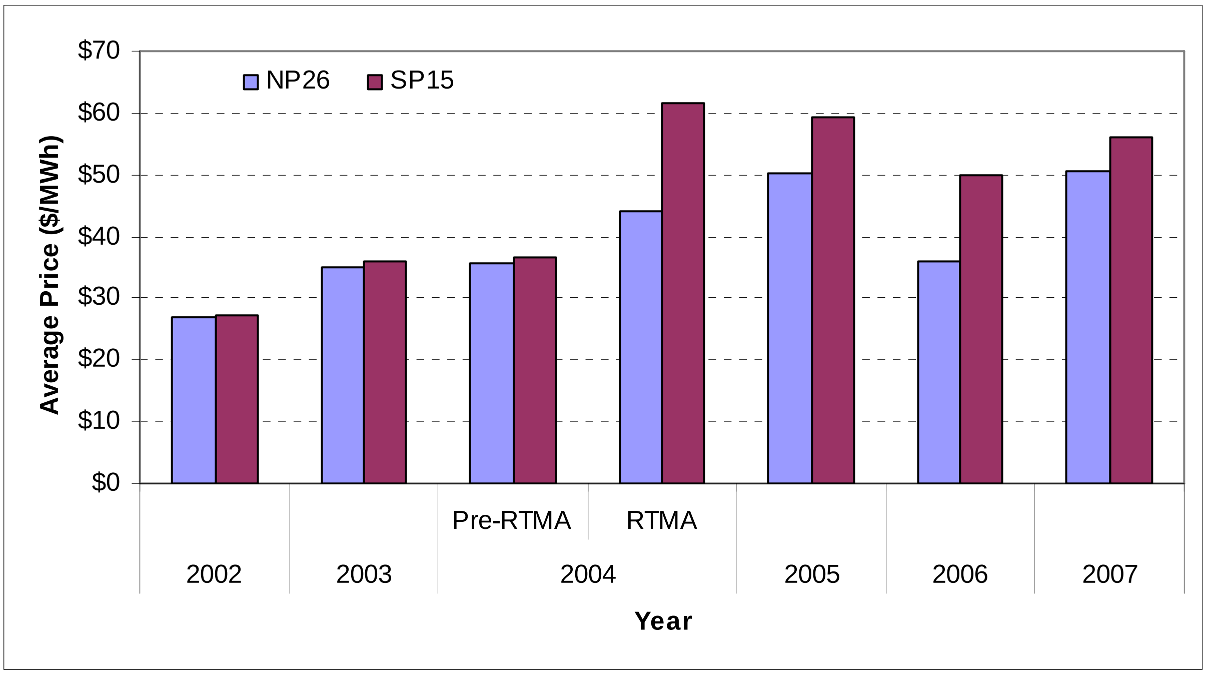


Figure 3.4 compares average annual Real Time Market prices by zone (NP26, SP15) for 2002 through 2007. Congestion on Path 26 in the north-to-south direction has resulted in consistently higher prices in SP15 than in NP26. However, this trend decreased markedly in 2007, as congestion on Path 26 was more sporadic and concentrated around a few specific grid-related events, primarily in July, as discussed below in Section 3.2.2. Historically, prices would split much more frequently than seen in 2007, such as in the spring when operators would need to manually manage flow on Path 26 to help mitigate unscheduled loop flow. The general upward trend in average prices in 2007 can be explained by the lower levels of hydroelectric production compared to 2006, resulting in higher reliance on more costly natural gas generation.

Figure 3.4 Average Annual Real-Time Prices by Zone (2002-2007)[1]



[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 shows SP15 real-time 5-minute interval price duration curves for 2003 through 2007 and indicates that real-time interval prices in 2007 were higher than in 2006 across the entire distribution, again due to the much lower level of hydro production and consequent reliance on natural gas generation. Another outcome of lower hydro production in 2007 was a decrease in the number of hours with negative prices to 0.5 percent of hours, compared to 2.5 percent of hours in 2006. Loop flow and other over-generation conditions tend to occur during strong run-of-river hydro conditions, such as occurred in 2006, and result in very low or negative prices; as the runoff from snow melt increases and reservoir levels reach their capacities, hydro facilities are typically running at or near full production regardless of load conditions. There were fewer such hours in 2007. Conversely, the higher volume of negative prices in 2006 is predominantly attributable to high levels of hydroelectric generation, which increased demand for decremental energy bids, and, under severe conditions, resulted in exhausting the supply of decremental bids.

Figure 3.5 SP15 Price Duration Curves (2003-2007)

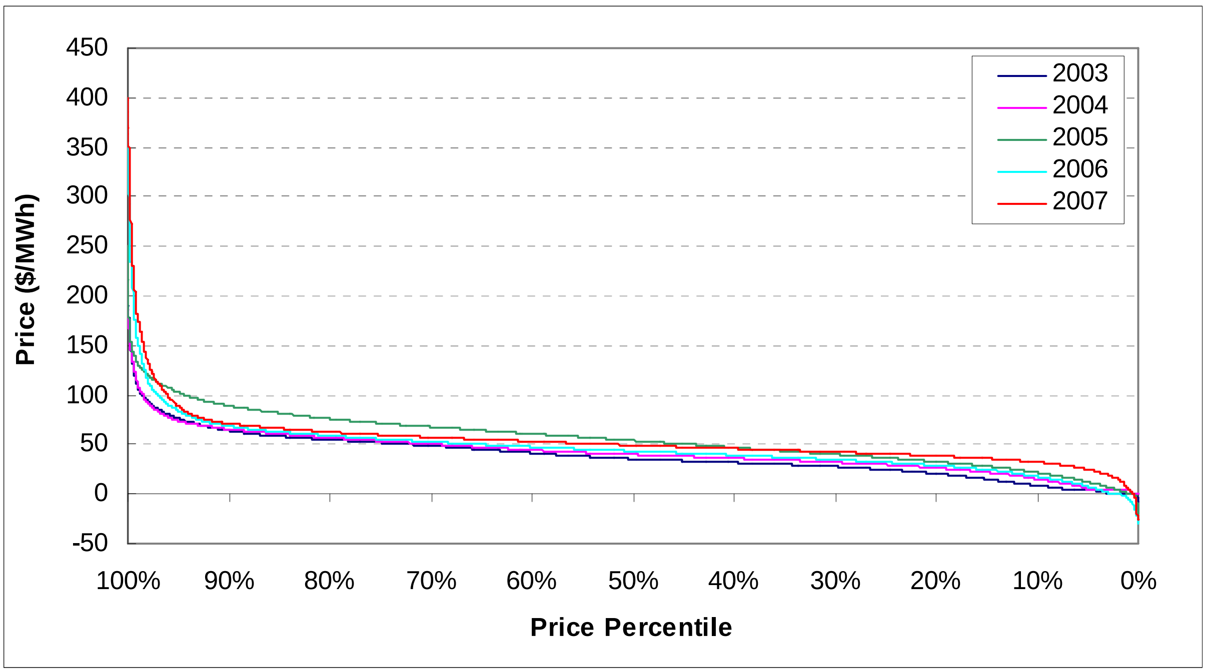
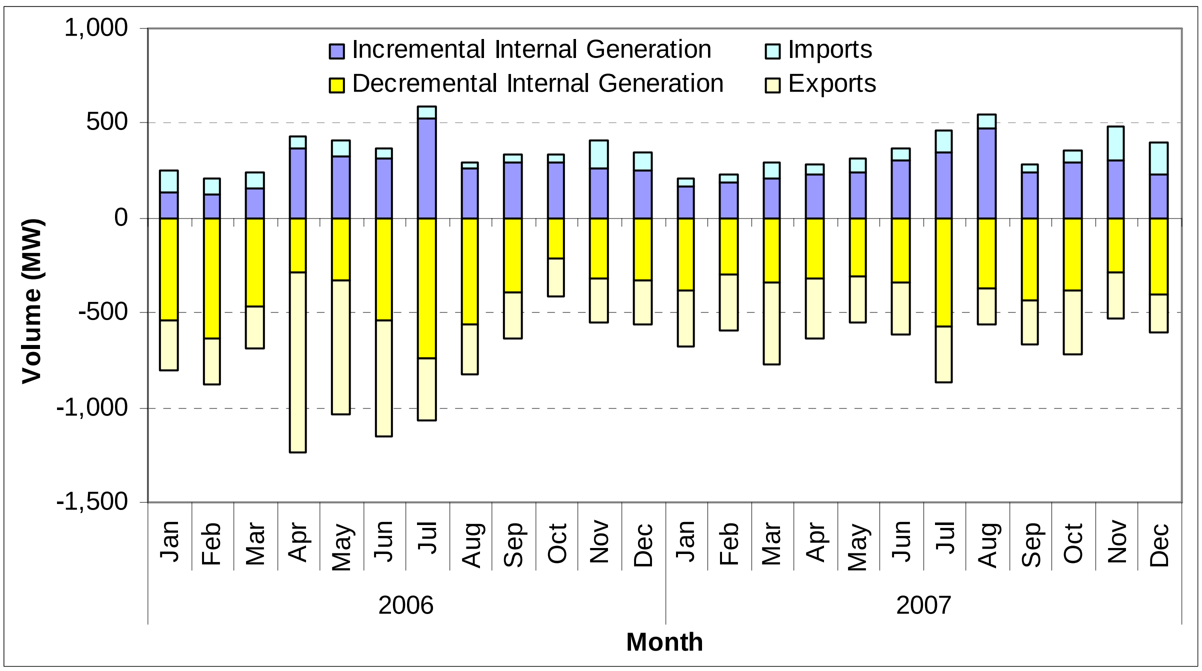


Figure 3.6 shows the monthly average dispatch volumes for internal generation, imports and exports for 2006 and 2007. Since the implementation of Amendment 72, LSEs have been conservative in meeting the 95 percent forward scheduling requirement and often have forward scheduled generation and imports in excess of the requirement. Consequently, real-time balancing in the decremental direction has typically been more prevalent than in the incremental direction. The effect of strong loop flow and over-generation, caused by hydro conditions, can be seen in the spring months of 2006, as large volumes of power were pre-dispatched to the Northwest to manage the unscheduled flow. Otherwise, internal resources constituted the bulk of RTMA dispatch volumes.

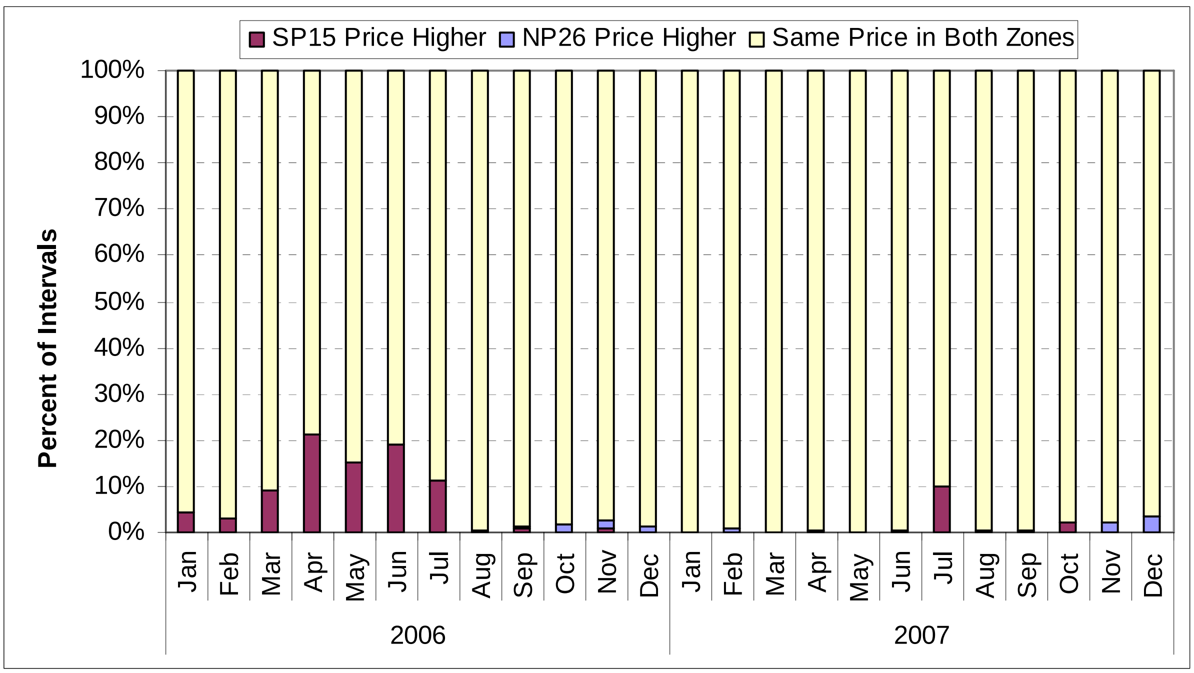
Figure 3.6 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2006-2007)



3.2.2 Real-Time Inter-Zonal Congestion

Figure 3.7 shows the monthly count of market splits in 2006 and 2007. The frequency of splits decreased markedly in 2007, following an increase in the north-to-south rating for Path 26 of 300 MW (3,700 to 4,000 MW) on June 1, 2006. Prices differed between NP26 and SP15 in approximately 1.8 percent of 5-minute intervals in 2007, compared to 7.5 percent in 2006. Of the 1,845 five-minute intervals in 2007 with price differences between NP26 and SP15, 884 were north-to-south congestion (with a higher price in SP15) within the month of July due to Path 26 congestion. On July 1 and 2, market splits occurred due to clearances for work on a transformer bank at the Vincent substation, a key component of Path 26. Another Vincent transformer bank failed on July 11, resulting in a derate of Path 26 for the remainder of July to approximately half its capacity. Work at the Los Banos Substation and a forced outage of a capacitor bank caused south-to-north congestion on Path 15 in November and December, accounting for approximately 527 five-minute intervals.

Figure 3.7 NP26-SP15 Market Price Splits (2006 - 2007)



3.2.3 Bidding Behavior

Figure 3.8 and Figure 3.9 show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for 2006 and 2007. Notable in Figure 3.8 is the significant decrease in the percentage of higher priced incremental energy bids (over $100/MWh) after early 2006, due to the stabilization of natural gas prices within the range of $5 to $8/mmBtu that has persisted throughout 2007. Also notable is the increase in incremental bid prices in the $50-$100/MWh range, in the spring and summer of 2007. This trend may be attributed to the limited supply of hydroelectric energy going in to the summer months of 2007 and more bids being made available from thermal units as more of them came on-line to meet summer loads. With respect to decremental bids, Figure 3.9 shows that the volume of decremental energy bid in at very low prices (e.g., below $0/MWh) decreased in 2007, again due to reduced over-generation caused by excess hydroelectric power. Poor hydro conditions have resulted in greater reliance on gas-fired generation to meet load. Some decline in the low-priced decremental bids can be attributed to a higher proportion of generation (gas-fired) that is willing to pay higher prices to back down their generation schedules and avoid input costs for natural gas. Also, in 2007 hydroelectric facilities were in spill conditions less frequently due to lower hydro conditions which increased their willingness to back down generation since water could be stored and not spilled, or “wasted” in terms of energy production.

Figure 3.8 SP15 Incremental Energy Bids by Bid Price Bin (2006 - 2007)

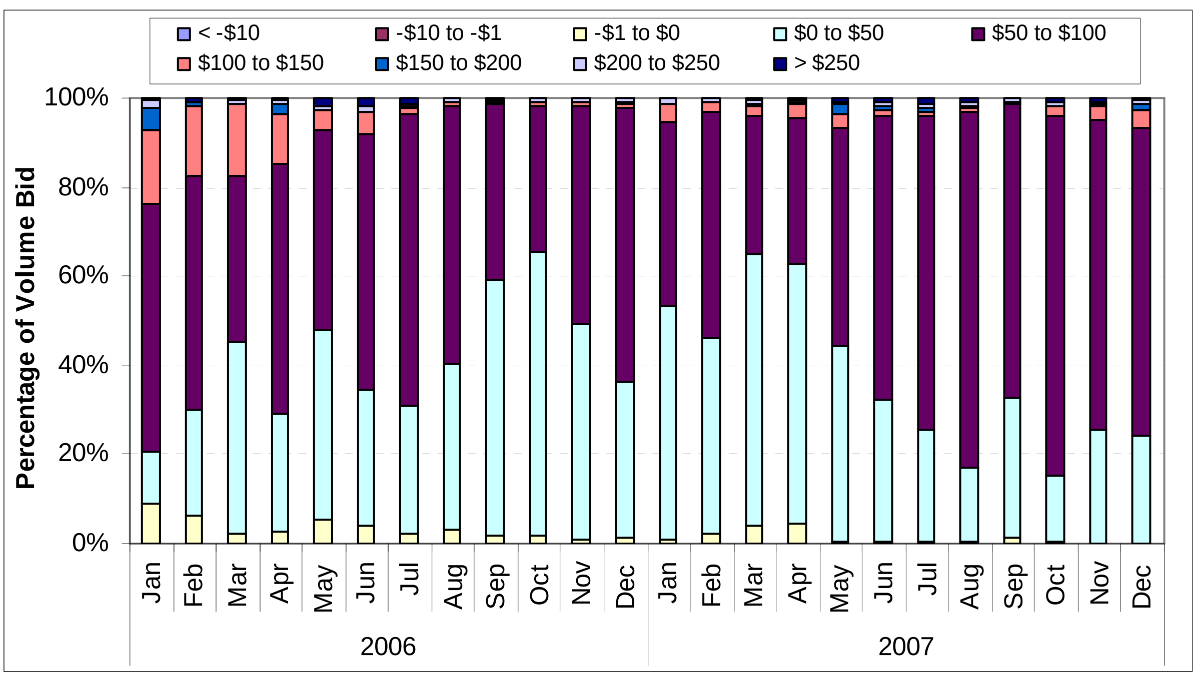
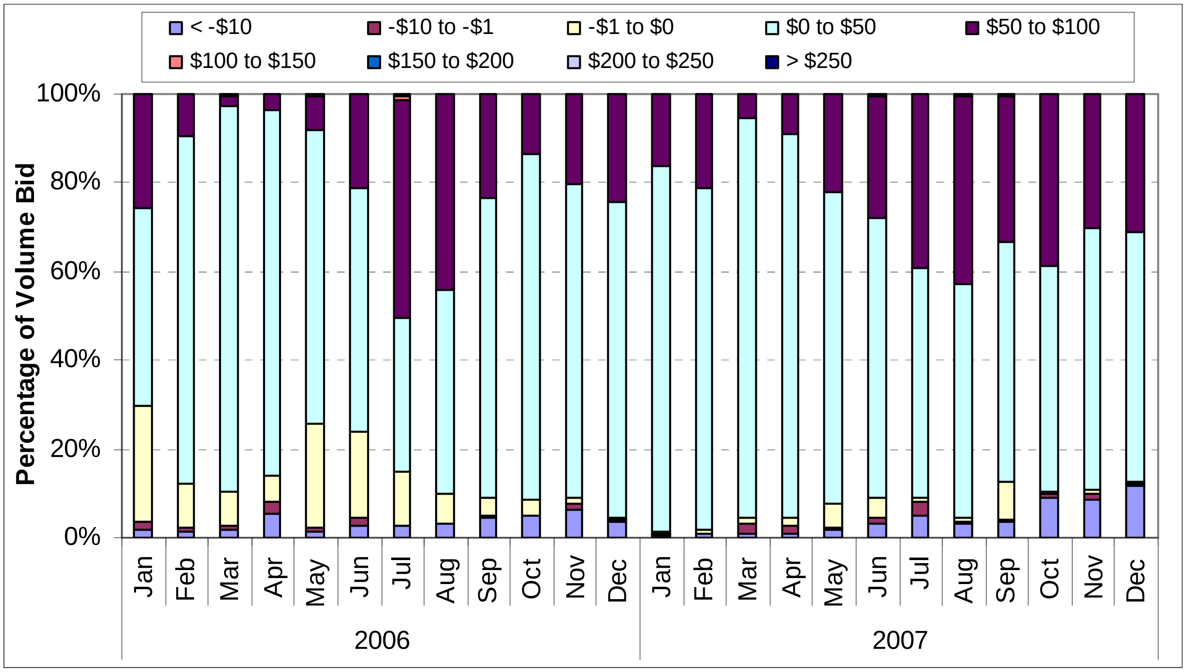


Figure 3.9 SP15 Decremental Energy Bids by Bid Price Bin (2006 - 2007)



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 2007, the level of forward scheduling was quite high, particularly during peak hours. For example, Figure 3.10 compares the average hourly values of day-ahead and hour-ahead schedules with actual load during 2007. This high level of scheduling can be attributed to a number of factors.

- In October 2005, the CAISO filed and FERC subsequently approved 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 February 2007, the CAISO filed and FERC subsequently approved, with modifications, a Tariff amendment to relax the existing minimum load scheduling requirement during off-peak hours from 95 percent to 75 percent of each Scheduling Coordinator's demand forecast, effective April 26, 2007.

- In addition, the amount of forward scheduling in 2007 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 2007 require only 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 LSEs 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 3.12. This trend suggests that factors in addition to 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 2007. One factor may simply be that LSEs are risk averse and therefore want to minimize their exposure to volatile Real Time Market prices.

Figure 3.11 shows, by month for all hours, average actual load together with day-ahead and hour-ahead under-scheduling. Even in July and August when average load peaked, the percent under-scheduled was still less than two percent of actual load. Figure 3.12 similarly depicts the percentage of under-scheduling for all hours ending 16:00 (between 3:00 and 4:00 p.m.) by month for 2007. This chart captures the fact that during the peak hours of 2007, the extent of aggregate under-scheduling was slightly less than three percent of actual load.

As discussed in Section 3.2, high levels of scheduling or over-scheduling required the CAISO to reduce or decrement additional generation in the Real Time Market during many hours in 2007. Even if energy and net import schedules submitted by SCs are approximately equal to 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 2007, 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 largely decrementing energy in real-time due to various sources of unscheduled energy. For example, Figure 3.13 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 3.13, 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 3.10 Average Actual Load Relative to Hour Ahead and Day Ahead Schedules by Operating Hour for 2007

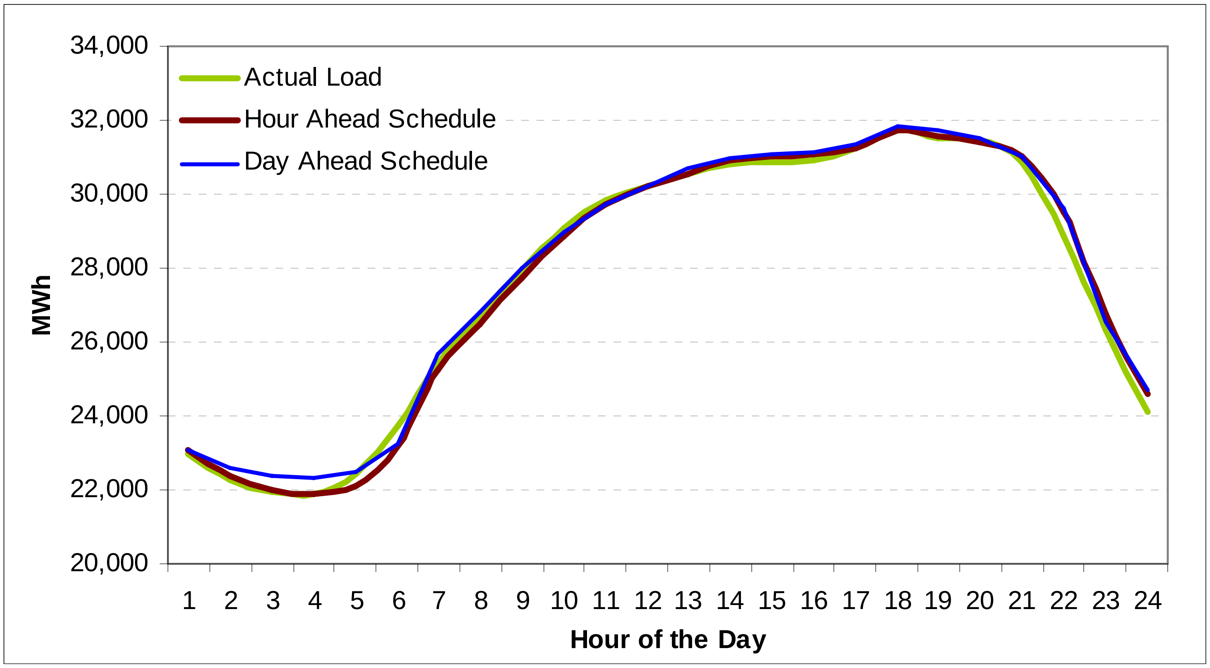


Figure 3.11 Average Hourly Actual Load Relative to Under-Scheduling for 2007 by Month for All Hours

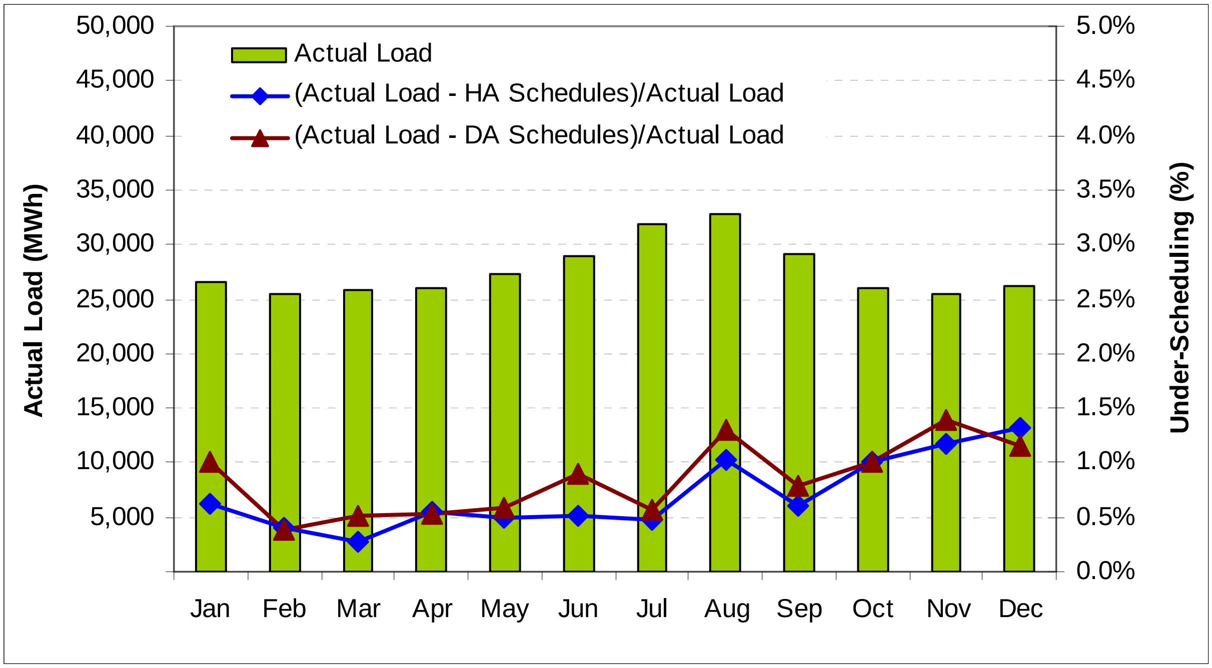


Figure 3.12 Average Hourly Actual Load Relative to Under-Scheduling for 2007 by Month for Hour Ending 16 Only

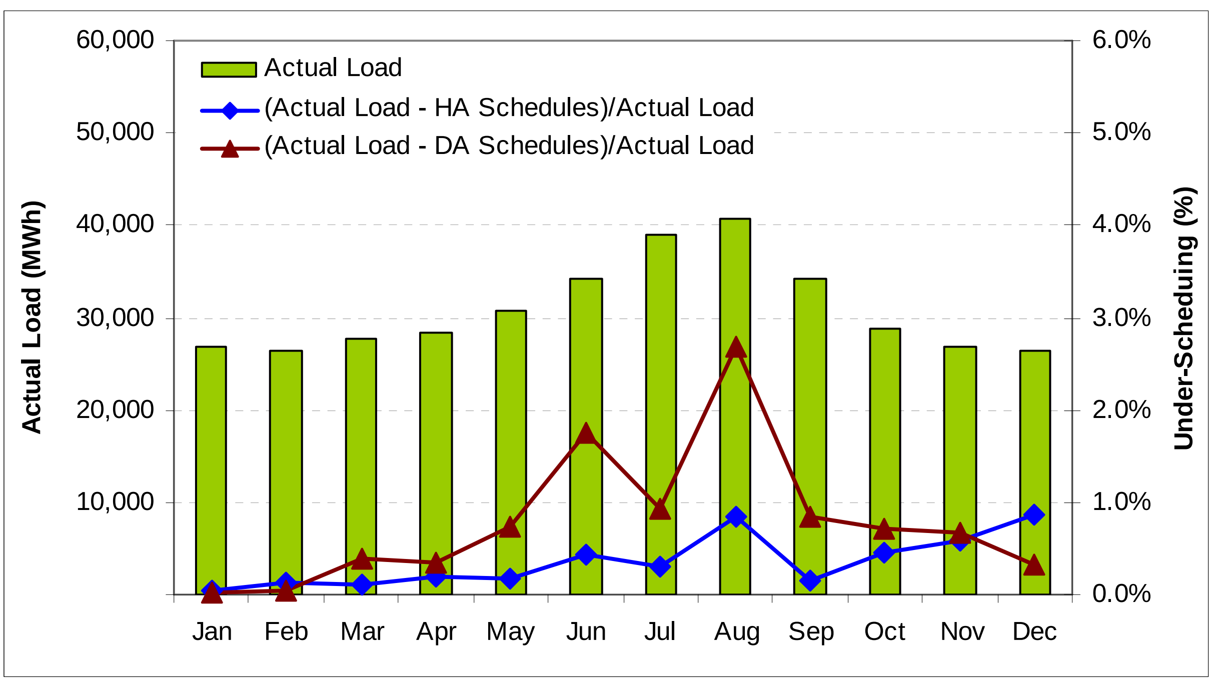
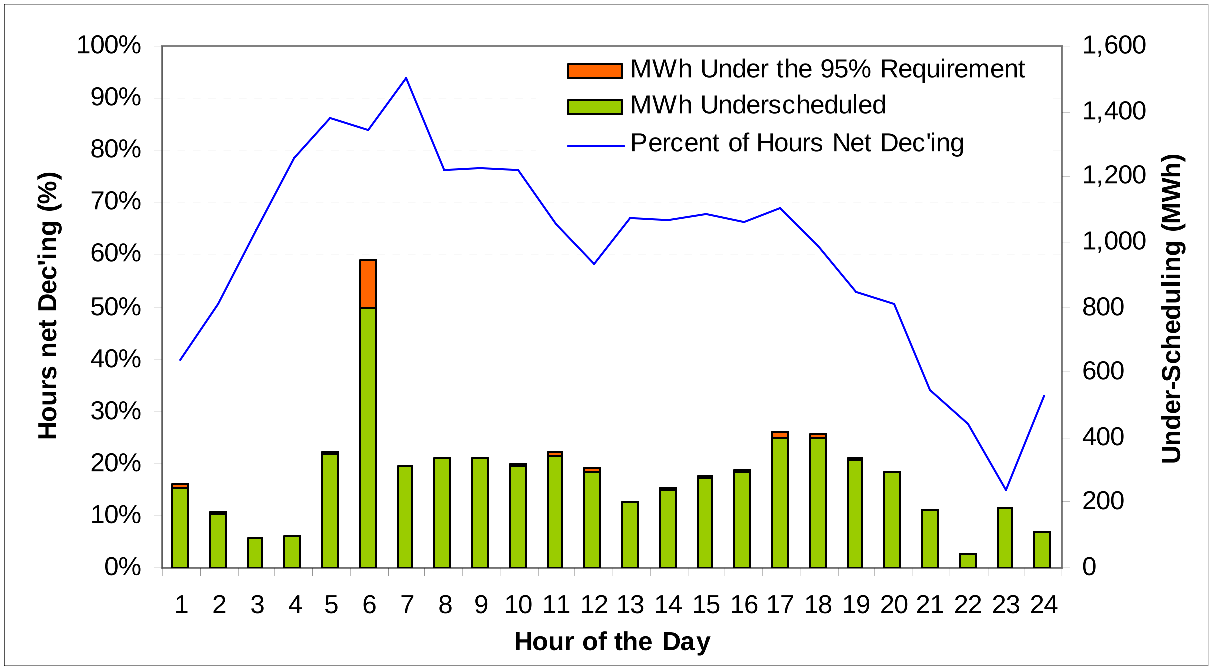


Figure 3.13 2007 Average Under-Scheduling by Hour Relative to Net Decremental Energy



3.4 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 system level generating unit uninstructed deviations in 2007 have been relatively consistent with what was observed in 2006, and appear to be within acceptable limits.

The CAISO had previously proposed the Uninstructed Deviation Penalty (UDP) as a feature of the current market design as an incentive for resources to follow their schedules and CAISO dispatch instructions. UDP has not been implemented because uninstructed deviations have remained at relatively low levels and because of past concerns that generating unit operators would not have a reasonable opportunity to avoid UDP. These concerns pertained to the manner in which RTMA dispatched generating units and the ability of the CAISO outage reporting system to facilitate market participants' reporting of generating unit limitations within a 30-minute period necessary to avoid UDP. If uninstructed deviations have a significant impact on grid or market operations under MRTU, the CAISO would likely propose to implement UDP as a feature of a future release of MRTU. Under MRTU, there would likely be less concern about a generating unit operator's ability to avoid UDP than there was in the past because of the different manner that generating units will be dispatched and because of recent improvements to the CAISO's outage reporting system.

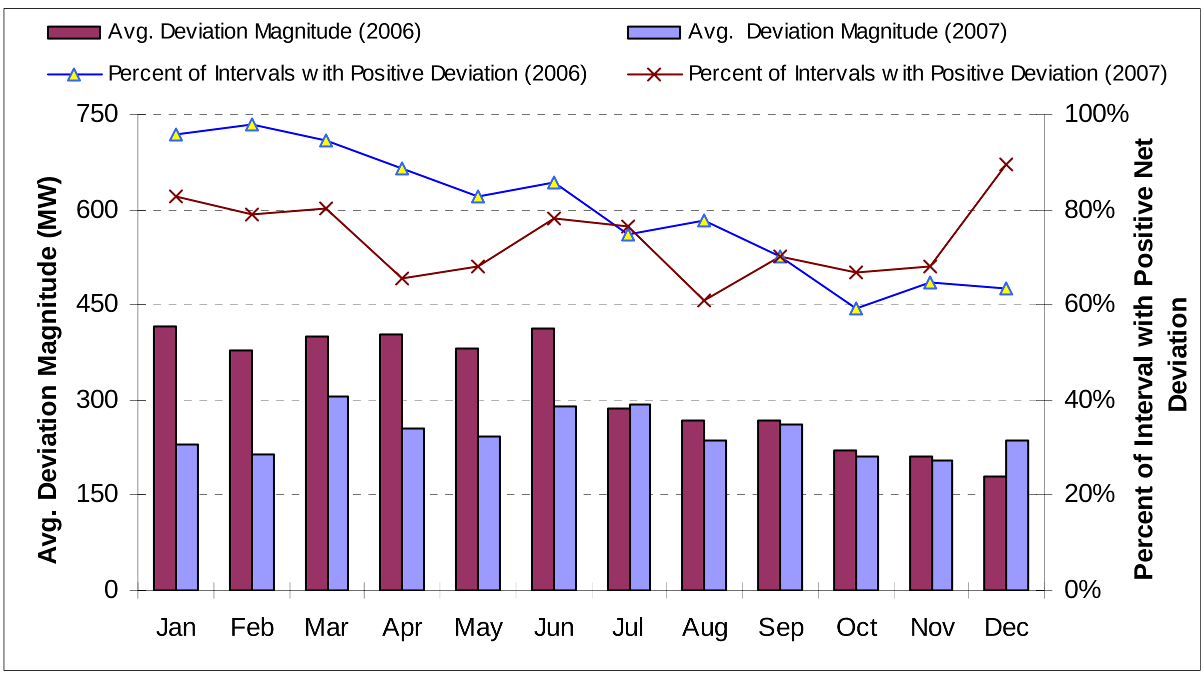
This section examines trends in uninstructed deviations based on two basic measures:

- **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 based on the approximate net deviation in each 10-minute settlement interval of all generating units in the control area.

- **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. The analysis in this section does not include deviations resulting from pre-dispatched import or export bids that are not delivered (i.e., declined bids).

Figure 3.14 compares the magnitude of generating unit uninstructed deviations during 2007 as compared to the corresponding months in 2006.[2] Figure 3.14 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.

Figure 3.14 Magnitude of Net Uninstructed Deviation



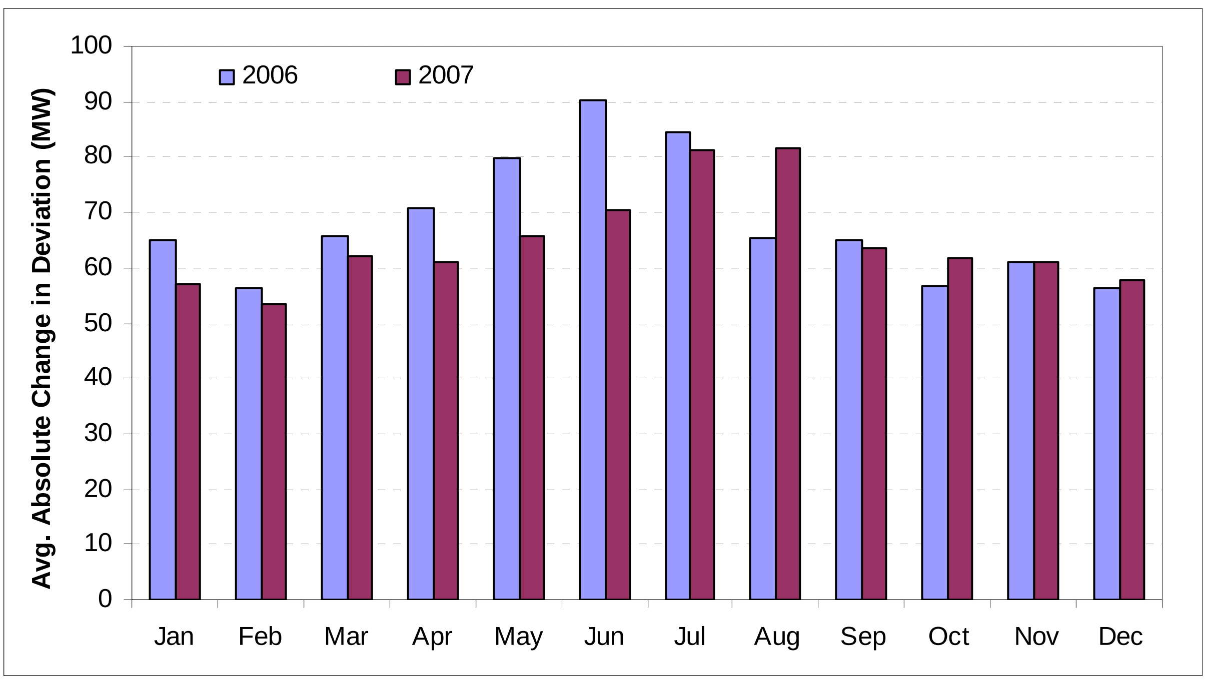
[2] The average generating unit uninstructed deviations shown in Figure 3.14 are an average of the absolute values of the total net generating unit deviations for each 10-minute settlement interval. The approximate deviation of each unit was first calculated for each interval and the net deviation on a system level of each interval was then calculated by summing up the approximate deviation of all generating units. Since the system level deviations can be either positive or negative each interval, the system level deviation in each settlement 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. These calculations exclude generating units during any settlement interval in which they were providing regulation.

As shown by Figure 3.14, uninstructed deviations in 2007 were at a slightly lower level than 2006 – uninstructed deviations averaged 249 MW in 2007 and 319 MW in 2006. This difference was primarily attributed to lower levels of deviations during the spring months of 2007 compared to the same months of the previous year. This was likely due to a smaller amount of positive deviation of hydro units during the relatively dry 2007 spring runoff period.

Figure 3.14 also shows that uninstructed deviations were predominantly positive during 2007 (i.e., generating more than schedule plus dispatch instructions), consistent with that which occurred in 2006 – the net deviation of generating units was positive in an average of 74 percent of settlement intervals throughout 2007 and in 80 percent of settlement intervals in 2006. 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 3.15 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 2007 compared to 2006.[3] As Figure 3.15 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2007 has been relatively consistent with 2006. 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 65 MW in 2007 and 68 MW in 2006.

Figure 3.15 Average Change in Net Uninstructed Deviation between Settlement Intervals by Month for 2006 and 2007



[3] 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.

3.5 Declines of Pre-Dispatched Inter-tie Bids

Under the CAISO's current market design, market participants may submit bids in the Real Time Market to provide incremental energy (as imports) or to purchase decremental energy (as exports). The CAISO "pre-dispatches" these inter-tie bids 45 minutes before each operating hour based on market software which seeks to optimize the dispatch of all incremental and decremental bids, based, in effect, on the assumption that all pre-dispatched bids will be accepted and delivered by market participants. However, upon receiving a pre-dispatch from the CAISO, market participants may fail to accept a pre-dispatched bid, without incurring any direct settlement consequence or financial disincentive.

During early 2007, increasing rates of declined pre-dispatches began to cause the potential for significant detrimental impacts on the CAISO Real Time Energy Market and system reliability. For example, high rates of declined pre-dispatched incremental energy bids could cause the CAISO to increase reliance on energy from within the CAISO that is dispatched on a 5-minute basis during the subsequent operating hour, and thereby increase prices or decrease reliability in the Real Time Market.

Based on DMM's discussions with market participants, it appears that high rates of declines typically occur when market participants submit real-time energy bids at the inter-ties as marketers or traders of energy, rather than bidding based on resources that they control. In this case, declines can occur due to differences in the timing between the CAISO energy dispatches at the inter-ties and the bilateral "real-time" market for the Western Interconnection, as described by the following scenarios:

- By the deadline for submission of real-time energy bids to the CAISO (i.e., 62 minutes prior to the operating hour in the current market design), these participants typically do not have a firm business arrangement to deliver incremental energy or receive decremental energy for each specific bid submitted. Rather, these participants indicated that they submit bids for energy that they expect to be able to deliver (or accept) based on their evaluation of bilateral market conditions conducted shortly before bids are due.

- Meanwhile, many transactions in the bilateral real-time market are being finalized at this same approximate time, and often completed by 60 minutes prior to the operating hour – or just beyond the deadline for submission of energy bids in the CAISO Real Time Market.

- Once a participant receives pre-dispatch instructions from the CAISO at 45 minutes prior to the operating hour, the potential supply (or sink) of energy may still not be available to the participant, due to commitments made in the bilateral market. Consequently, the participant may not be able to obtain a supply or sink necessary to perform on the CAISO pre-dispatch instruction and must decline it.

- In some cases, participants also indicated that, in addition to the availability of resources to take or receive energy, lack of available transmission once the CAISO issues pre-dispatch instructions at the inter-ties sometimes contributes to declines.

In the spring of 2007, DMM expressed concern to market participants about the potential market and reliability impacts of high rates of declined pre-dispatches, and recommended that the CAISO take steps to clarify or amend market rules to reduce declined pre-dispatches. Although modifications in the rule concerning declined pre-dispatches did not take effect in 2007, declined pre-dispatches did decrease significantly after DMM expressed concern about the potential market and reliability impacts of high rates of declined pre-dispatches in the spring of 2007, as shown in Figure 3.16.

While declined pre-dispatches can detrimentally affect reliability and market efficiency in a variety of ways, one of the concerns about any efforts or market design changes to decrease declined pre-dispatches is the potential effect this may have on the price and volume (or liquidity) of supply from imports and demand from exports in the Real Time Market. In analyzing this issue, DMM found that the reduced rates of declined pre-dispatches observed in 2007 were due largely to a drop in bids by smaller participants with relatively high rates of declined pre-dispatches, which accounted for a relatively high portion of declined pre-dispatches, but only accounted for a relatively small portion of total bids submitted and accepted in the CAISO market.

In March 2008, the CAISO filed a tariff amendment to establish a charge for declined pre-dispatches starting in May 2008. The level of the charge and "allowance" for declined pre-dispatches proposed in the CAISO's filing are designed to balance the need to limit the potential detrimental reliability and market effects of declined pre-dispatches with the goal of maintaining a competitive supply of real-time energy bids by not deterring suppliers from offering bids that may occasionally need to be declined due to various resource and market limitations.

Figure 3.16 Pre-Dispatched Import/Export Energy Declined (CAISO System)