California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

CC: ISO Officers

Date: August 31, 2006

Re: Market Monitoring Report

This is a status report only. No Board Action is required.

EXECUTIVE SUMMARY

The most significant market event of the summer season was the July heat wave, which resulted in record-breaking energy demand on several days and above average demands for most of July. Despite the unprecedented demands being placed on the western power grid during this period, wholesale energy markets and CAISO grid operations performed extremely well. However, the CAISO Real Time Market prices were well below prevailing bilateral prices during much of the heat wave period and this has raised concerns among several market participants. A detailed assessment of market performance during the July heat wave, including an assessment of the CAISO Real Time Market, is provided in this memo. The main observations and conclusions from this analysis are the following:

- **The level of forced outages in the CAISO Control Area was remarkably low considering the severity and duration of the heat wave.** This unusually high level of generation availability is likely attributable to several factors: 1) the concerted effort the CAISO and generator community made to prepare for the summer months, 2) a high level of forward contracting and increase in the energy bid cap to $400/MWh, which creates a strong incentive for unit owners to maintain their units so as to avoid the spot market exposure of a forced outage during critical peak periods, and 3) implementation of the CPUC Resource Adequacy program – which introduces the potential to have forced outages this year count against a generating unit's Qualifying Capacity for RA sales in future years.

- **The CAISO Real Time Market prices were generally well below prevailing day-ahead bilateral prices during much of the heat wave.** Prevailing forward bilateral energy prices during extreme system peaks often reflect scarcity and risk premiums (i.e., an aversion to not being able to cover contract positions or serve load) and therefore often depart from marginal cost pricing (i.e., prices reflect demand's willingness to buy rather than the marginal cost of supplying the energy). In contrast, prices in the CAISO Real Time Market are based on the marginal supply bid and depend largely on the demand for imbalance energy and available supply. Throughout most of the heat wave period, CAISO load serving entities typically scheduled almost all of their energy demand in the forward markets – leaving very little demand left for the imbalance market. Consequently, prices in the CAISO Real Time Market tended to be much lower than prevailing forward bilateral prices. Other factors that have historically dampened CAISO Real Time Market prices include unscheduled minimum load energy from units denied Must Offer Waivers and pre-dispatched inter-tie energy. However, these factors were not found to be significant during the heat wave period.

- **Prices in the CAISO Ancillary Service Markets generally followed prevailing day-ahead bilateral prices during much of the heat wave.** Since ancillary services are procured on a forward basis (day-ahead, hour-ahead), they reflected the opportunity costs of offering the generation capacity as reserve as opposed to selling the energy in the bilateral market.

- **The CAISO Ancillary Service Markets suffered from bid insufficiency during the most critical days of the heat wave.** Bid insufficiency in the A/S markets was particularly acute on the all-time peak day of July 24 and was a major reason for the need to declare a Stage 2 Emergency and trigger interruptible load programs. The reserve shortage conditions existed despite the fact there were unused bids in the imbalance energy stack and moderate imbalance prices primarily in the $55 to $100 range with a few intervals pricing near $400/MWh. This outcome highlights two deficiencies in the current Real Time Market design: 1) an inability to procure operating reserve in real-time and 2) a lack of a reserve shortage scarcity pricing mechanism.

The above observations and supporting analysis are covered in greater detail in the main body of this memo.

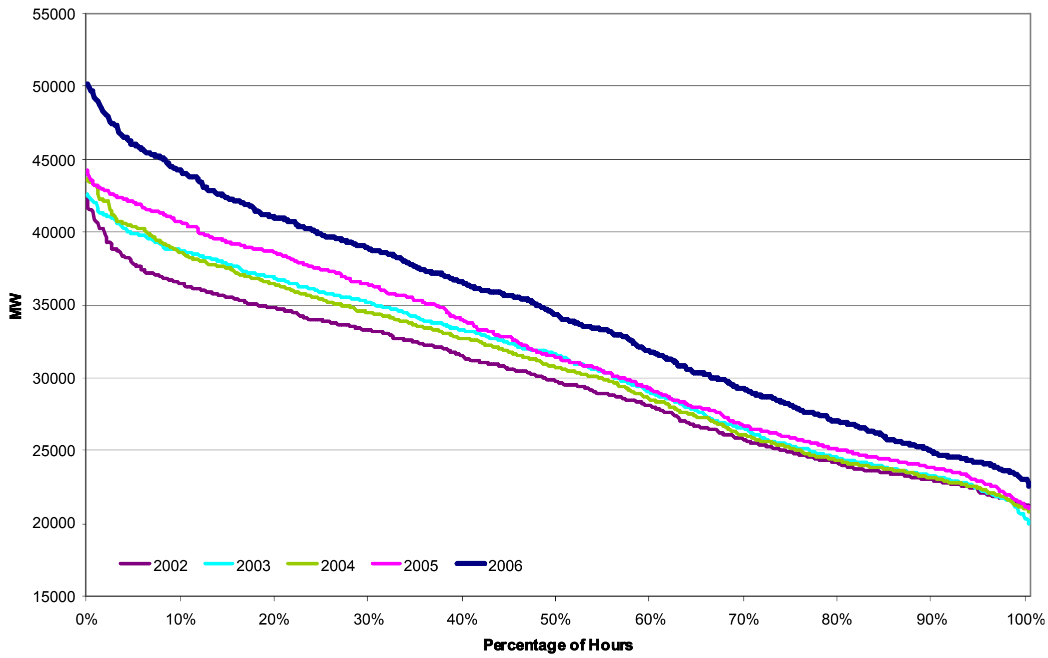
In addition to providing an analysis of the heat wave, the last section of this memo provides an update on an issue that DMM has reported on in prior Board memos. The issue concerns a revenue imbalance in the CAISO Real Time Market stemming from a divergence in the average bid prices charged to pre-dispatched exports and the prices paid to internal generation in the 5-minute Real Time Market. The update compares DMM's previously reported estimates of the potential costs of this imbalance to the actual costs based on final market settlements. This comparison indicates that DMM's estimates of the cost impact (approximately $50 million over the April – June 19 period) are fairly close to the actual settlement costs.

Finally, at the August 3 Board Meeting, a representative of Williams Power Company (Brian Theaker) posed a number of questions to the CAISO concerning various summer operational and market issues. DMM has prepared written responses to Mr. Theaker's questions as an addendum to this memo. In preparing these responses, DMM relied heavily on input from Grid Operations with respect to some of the operational questions posed by Mr. Theaker.

I. Market Performance During the July Heat wave

During the July 2006 heat wave, peak load records were set three times. On July 17, 21, and 24, load successively set record peaks at 46,545 MW, 49,014 MW, and 50,240 MW respectively. In comparison, the CAISO 2006 Summer Assessment forecasted "1-in-2" and "1-in-10" scenario peaks of 46,063 and 48,723 MW respectively. Even more extraordinary was the persistence of extreme load conditions through much of July. Figure 1 compares duration curves of July 2006 loads (loads ranked from highest to lowest) to July load duration curves for the previous four years.

Figure 1 July CAISO Load Duration Curves: 2002-2006



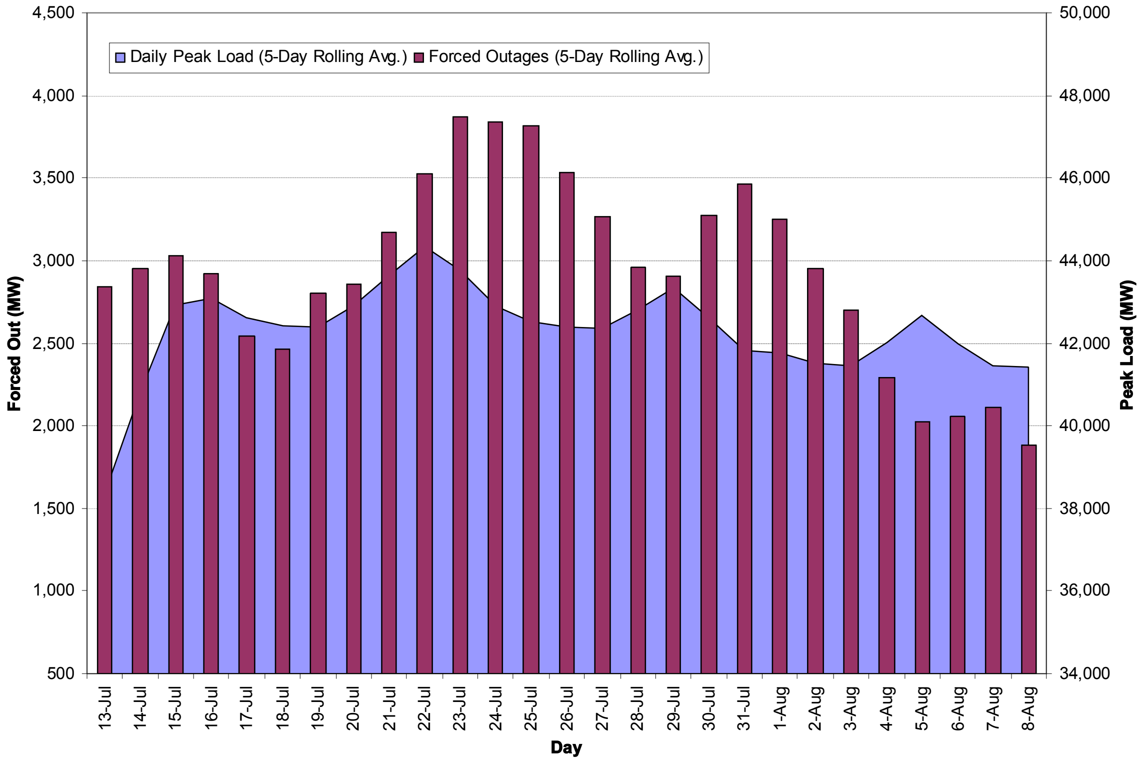
As shown in Figure 1, hourly loads in July 2006 exceeded 45,000 MW in approximately 8% of the total hours of the month and exceeded 40,000 MW in approximately 24% of the total hours of the month – compared to 0% and 12%, respectively in July 2005. The unusually high level of load levels in all hours of the month in July 2006 reflects the high level of humidity associated with this heat wave that kept temperatures up throughout the day and evening hours.

Generation Forced Outages

A prolonged heat wave, such as occurred in July, typically results in high rates of generation forced outages as the continuous operation of generation under high temperatures and high output stresses equipment – often to the point of failure. In the July heat wave, despite unprecedented load levels for an extended period, the rate of generation forced outages stayed uncharacteristically low.

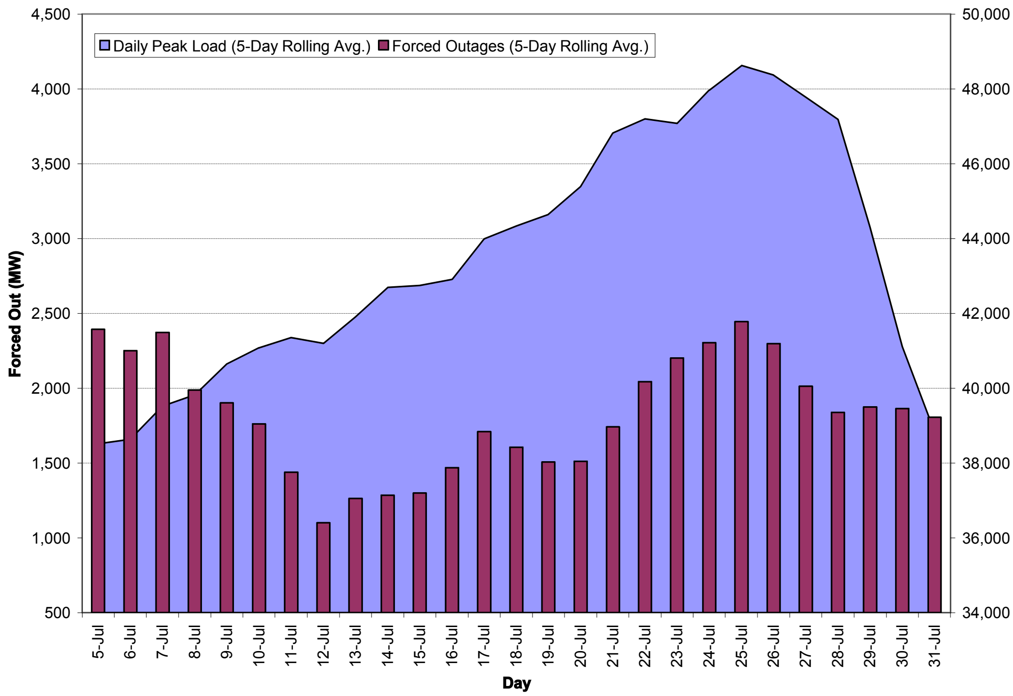
The differences between forced outage levels in the July 2006 heat wave compared to forced outage rates in prolonged heat waves in 2005 can be seen by comparing Figures 2 and 3 below. Figure 2 compares daily peak loads and forced outage levels for Summer 2005 based on a 5-day rolling average. In 2005, the five-day rolling average daily peak reached its maximum of 44,356 MW on July 22, 2005, approximately the 12th straight day of peak loads above 40,000 MW. The 2005 five-day rolling average of forced outages on this day was 3,523 MW and had increased steadily between July 20 through July 23. A similar pattern is evident for the heat wave that crested on July 29, 2005 with forced outages increasing steadily from approximately 2,900 MW on July 29 to 3,500 MW on July 31, 2005.

Figure 2 2005 Peak Load vs. Forced Outages: Five-Day Rolling Averages



In contrast, there is much less of a pattern of increasing forced outages during the July 2006 heat wave (Figure 3). The 2006 five-day rolling average of daily peak loads reached its maximum on July 25, approximately the 19th consecutive day on which peak load exceeded 40,000 MW. At this time, the 2006 five-day rolling average of forced outages only reached 2,445 MW - approximately 30 percent below the 2005 level, despite occurring later in a period of continuous high-load days.

Figure 3 2006 Peak Load vs. Forced Outages: Five-Day Rolling Averages



The unusually low level of forced outages during the July 2006 heat wave is likely attributable to several factors.

- A higher degree of summer preparedness by the generation community through coordination and planning with the CAISO.
- The increase of the West-wide price cap from $250 to $400/MWh on January 14, 2006 – coupled with high levels of forward energy contracting, which provides additional incentive for generators to be available when spot prices are likely to be high.[1]
- Generation availability incentives provided by the California Public Utility Commission's (CPUC) Resource Adequacy (RA) program, which went into effect June 1, 2006. The RA program introduces the potential to have forced outages this year count against a generating unit's Qualifying Capacity for RA sales in future years.

Bilateral and Real Time Prices

During the recent heat wave, and particularly on the peak load day of July 24, the CAISO's real-time prices remained relatively moderate, generally ranging between $50 and $100/MWh with occasional and brief excursions as high as $399/MWh. Given the record-setting load during this period and corresponding high spot bilateral prices, the relatively low range of real-time prices seems counterintuitive. However, it must be recognized that CAISO Real Time Market prices are largely driven by the amount of imbalance energy required as opposed to total system demand. Throughout most of the heat wave period, CAISO load serving entities typically scheduled almost all of their energy demand in the forward markets

[1] When the majority of load is covered by forward energy contracts, the spot market risk of high energy prices is shifted to the supply side of the market. A generator that is serving forward energy contracts has a greater incentive under a higher bid cap to avoid a forced outage, as they will bear the price risk of having to replace that energy from the spot market. Additionally, generation that is not serving forward energy contracts has a greater incentive under a higher bid cap to be available during the critical peak days in order to sell at potentially higher spot market prices.

– leaving very little demand left for the imbalance market. Consequently, prices in the CAISO Real Time Market tended to be much lower than prevailing forward bilateral prices. This trend is evident in Figure 4, which compares daily peak hour prices for the day-ahead bilateral market[2] and CAISO Real Time Market for July 2006.

Figure 4 Actual Peak Load vs. Day Ahead Bilateral and Real Time Peak-Hour Prices

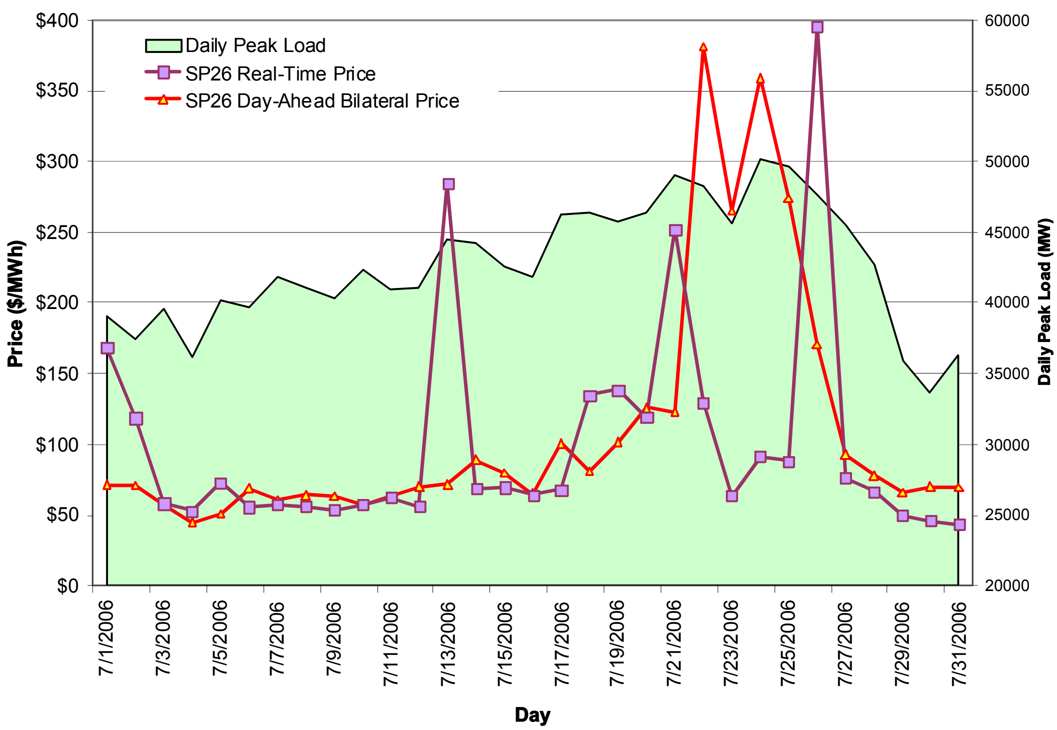


Figure 4 shows that peak day-ahead bilateral prices increased dramatically during the crest of the heat wave (July 22 – 25) when loads were at their highest – but the hourly CAISO Real Time Market prices during those same peak hours actually declined and were substantially below day-ahead bilateral prices.

In addition to a high level of forward scheduling, other historically significant factors that may have dampened CAISO Real Time Market prices include unscheduled minimum load energy from units denied Must Offer Waivers and pre-dispatched inter-tie energy. However, these factors were not that significant during the heat wave.

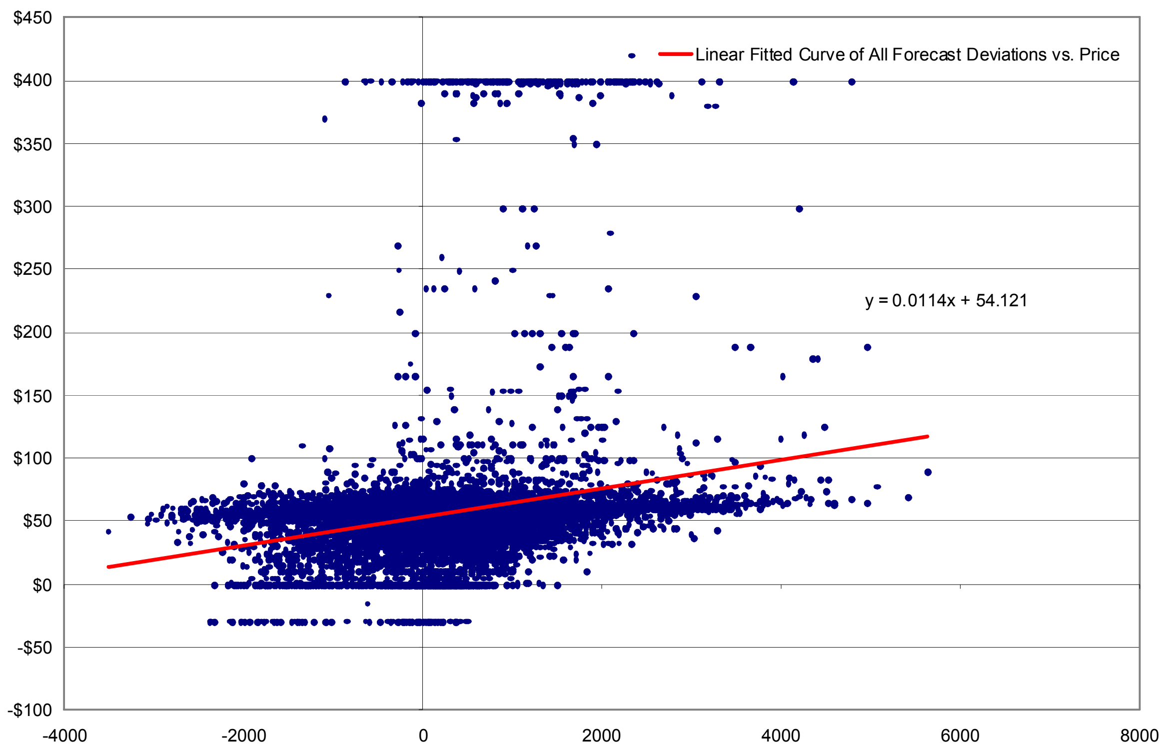
- No more than five resources were ever committed at any one time through either the FERC Must-Offer process or the Resource Adequacy process during the heat wave. All other generators were self-committed through bilaterally-negotiated transactions indicating a larger proportion of load met by scheduled energy forward of real-time.
- Pre-dispatch of inter-tie energy was moderate given the high degree of forward scheduling and limited real-time import capacity with the Northwest.

To examine the relationship between real-time prices and real-time imbalances, a linear regression model was used to estimate the effect of real-time imbalance on real-time price. Figure 5 plots net real-time imbalance (actual load less

[2] Day-ahead bilateral prices are based on price data purchased from Powerdex – an independent energy information company that surveys buyers and sellers of energy at key Western hubs and compiles hourly prices.

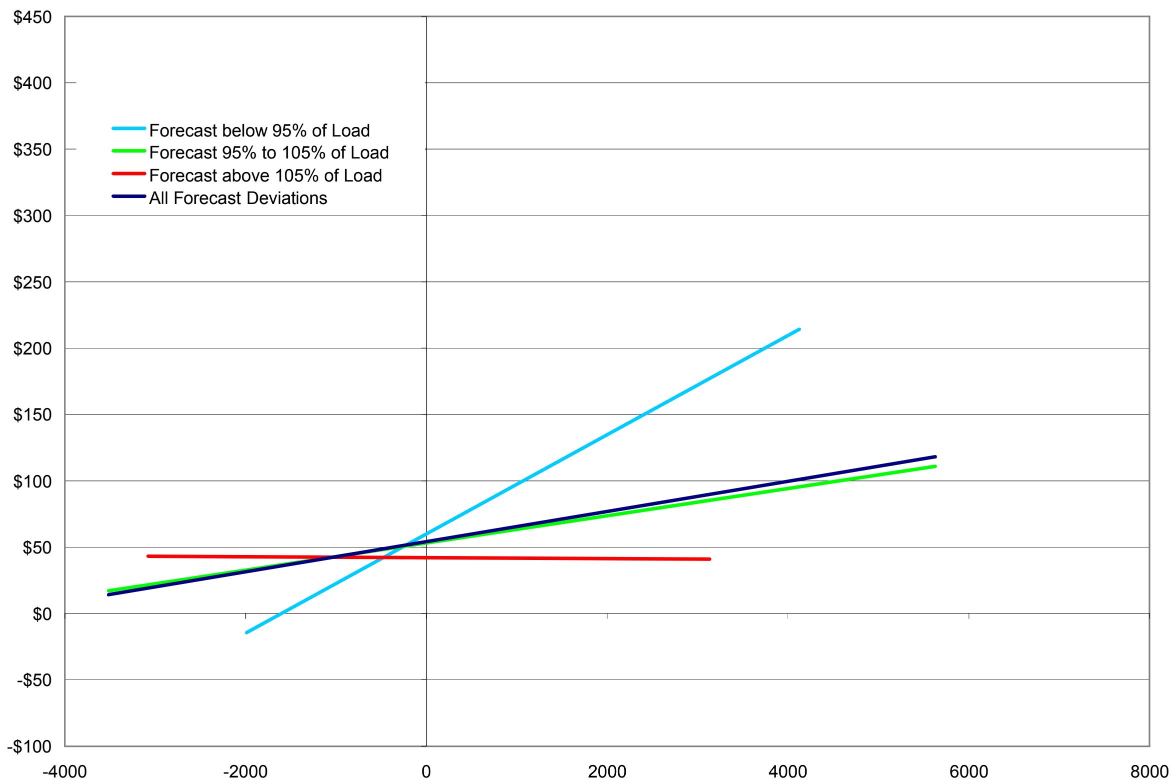
schedules and RMR dispatch) against real-time price for all 5-minute intervals on days between June 16 and August 4 that had peak loads above 40,000 MW. The scatter plot shown in Figure 5 reveals a high degree of price volatility but nonetheless, the regression shows a statistically significant positive correlation between real-time imbalances and real-time prices, which is evident in the trend line that is drawn through the scatter plot. However, the regression reveals a relatively modest price response to real-time imbalances. On average, between June 16 and August 4, 2006, the real-time price increased $1.14/MWh for every 100-megawatt increase in imbalance.

Figure 5 Plot of Imbalance vs. Real-Time Price, Days between June 16 through August 4, 2006, with Peak Load above 40,000 MW



While many factors may contribute to high real-time imbalance requirements, often periods of high imbalance occur when load forecasts are inaccurately low. Consequently, we often see higher prices when day-ahead load forecasts underestimate actual loads. This is primarily a result of the amount of capacity that is on line and offering energy into the imbalance market. The CAISO uses its day-ahead load forecast in determining unit commitments in the day-ahead must-offer waiver process. When day-ahead load forecasts are significantly below the actual load, fewer units are committed and online to offer energy in the imbalance market than would have been required if the load forecast were closer to actual. The impact of load forecast accuracy, and subsequent unit commitment, on real-time prices can be observed in the Figure 6, which divides the imbalance quantity-price pairs into categories of high, low, and accurate forecast days. The resulting data are used in a statistical estimation of the relationships between imbalance requirement and price for each category. Note in particular that the light blue line represents the relationship between imbalance requirement and price for days with inaccurately low forecasts (i.e., when the peak forecast was less than 95% of the actual peak load). For these short-forecast days, an increase in real-time imbalances has a much sharper increase in real-time prices (as evident by the light blue line). Conversely, on days where the CAISO's peak forecast is more than 105% of the actual peak (i.e., over-forecast), there is essentially no correlation on real-time imbalances and real-time prices (as evident by the red line). However, the number of days during this period in which the CAISO day-ahead load forecast was off by more than +/-5% was very low (as shown in Figure 7 below), thus the price relations indicated by the green line in Figure 6 are most typical.

Figure 6 Linear Relationship of Imbalance to Real-Time Prices for Three Categories of Forecast Deviation; June 16 through August 4, 2006[3]

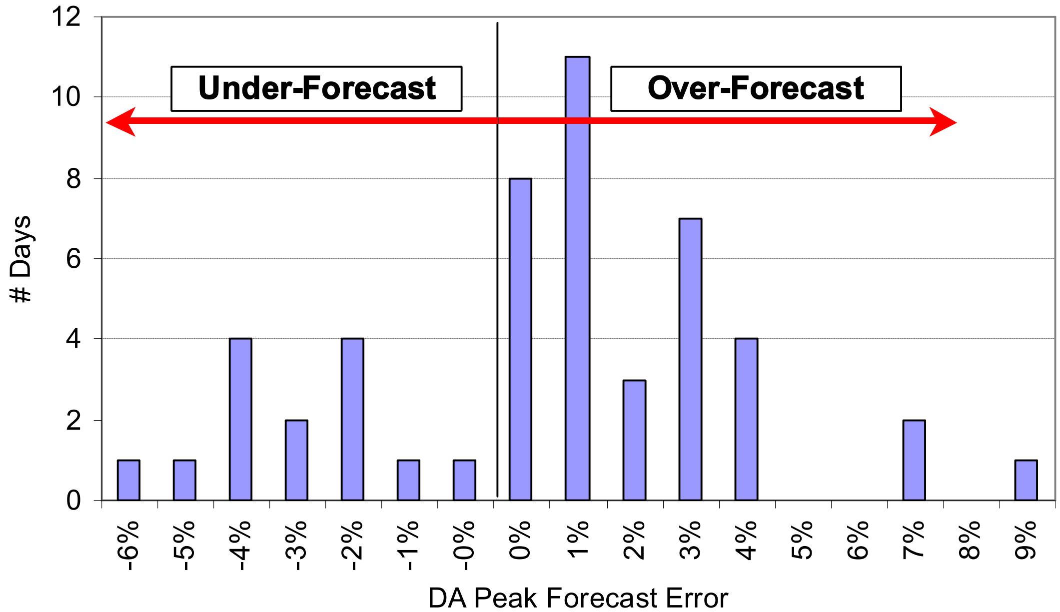


The frequency of day-ahead forecast error is shown in Figure 7 for the 50-day peak load period covering June 16 through August 4. Relating the distribution of forecast error to the price relationships in Figure 6, there were two days where the day ahead forecast was below 95% of actual load, three days where the day ahead forecast was above 105% of actual load, and the remaining 45 days where the forecast was within ±5% of actual load.[4] However, during this period there was a tendency to over-forecast load in the day ahead with 36 days of over-forecast compared to 14 days of under-forecast.

[3] Imbalance is defined as actual load less schedules and RMR dispatches.

[4] One factor of note that impacted the measurement of over-forecast error on July 24th was the dispatch of pump load and interruptible load. The day-ahead load forecast did not anticipate the decrease in actual load from these eventual dispatches. In this circumstance, the positive load forecast error reflects both the inherent error found in forecasting as well as actions taken by the CAISO in or near real-time that decreased actual load.

Figure 7 Distribution of Day Ahead Load Forecast Error for the Period June 16 - August 4, 2006[5]



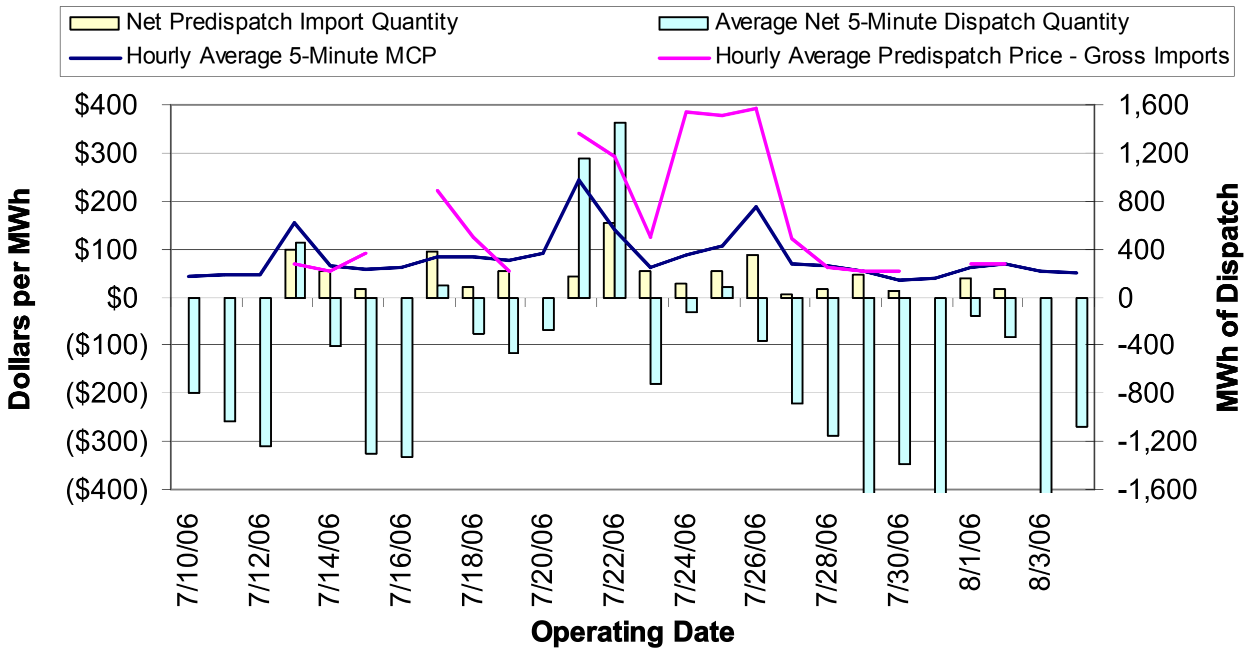
Pre-dispatch and 5-Minute Prices

Another potential driver of 5-minute real-time prices is the level of imports that are pre-dispatched prior to the start of the operating hour. These imports contribute to meeting the imbalance requirement (as do 5-minute dispatches of internal resources) but are not eligible to set the 5-minute real-time price. Pre-dispatched bids across the inter-ties are paid "as-bid" and may have an average settlement price that diverges from the 5-minute interval price. During the high load days from July 21 through July 26, the average pre-dispatch import price did diverge from the average 5-minute price paid to internal resources dispatched in real-time, as seen in Figure 8 below. During the period of greatest price divergence, July 24 - 26, the average net import quantity cleared through the pre-dispatch was relatively small, averaging under 400 MW, and this price divergence effectively evaporated toward the tail end of the heat wave. While the average pre-dispatch import price during the period July 24 - 26 does not appear to be strongly correlated with average 5-minute imbalance prices, it is strongly correlated with day-ahead spot bilateral prices.

While this divergence may create revenue imbalance charges (note there were average 5-minute decremental dispatches on some days with a significant price divergence), the greater concern lies with the potential incentives a persistent divergence like this may have on participation in the 5-minute real-time market. If this price divergence were persistent, it would create incentives for internal generating resources with available capacity to export energy outside the CAISO control area rather than offer it in the 5-minute real-time market – leaving the CAISO with less available 5-minute dispatchable supply and having to rely more heavily on pre-dispatched inter-ties and regulation to manage real-time imbalances. This risk is most significant if the price divergence shown in Figure 8 is persistent within a multi-day peak load period or predictable across peak load periods.

[5] The categories of forecast error shown in Figure 6 are such that "0%" covers 0% to .99%, "1%" covers 1% to 1.99%, etc.

Figure 8 Average Hourly Prices and Quantities for Pre-dispatch Imports and 5-Minute Real Time Dispatch - Hours 12 - 18 for July 10 through August 4, 2006



Finally, it is important to recognize that there are additional costs to purchasing energy in the CAISO Real Time Market that are not reflected in the real-time market prices and these costs can be both significant and volatile. As an example, Table 1 provides a summary of what some of these additional costs were for July-August 2005 – based on actual settlement data[6].

Table 1 Summary of Real Time Market Charges (July – August 2005)

Real Time Charge Type	2005 Charge ($/MWh NNUD) July	August
CT 721 - PIRP Intermittent Resource Net Deviation Allocation Charge	$0.39	$0.13
CT 1697 - MLCC for System (including the 'non-incremental' portion of Local)	$22.24	$10.32
CT 4487 - Excess Cost for IE + Pre-dispatch Bid Cost Recovery	$8.38	$7.16
Total	**$31.01**	**$17.61**

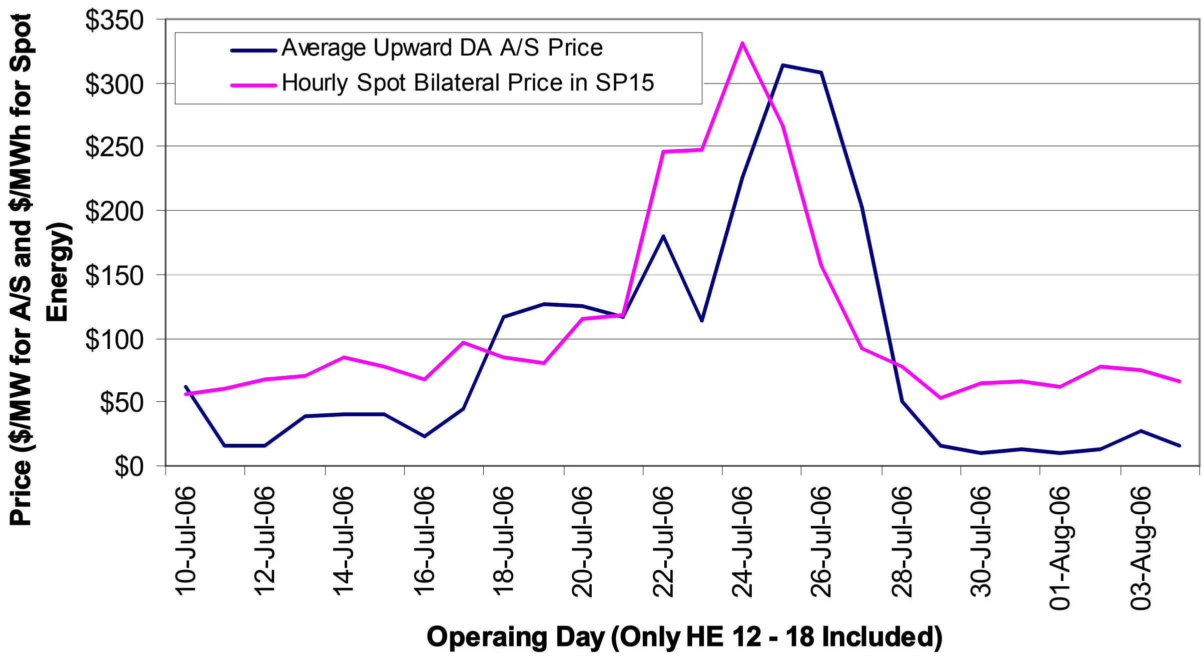
As evident from Table 1, the average cost of these additional real-time charges ranged from approximately $18/MWh in August 2005 to $31/MWh in July 2005. The most significant component is CT 1697, which includes the minimum load cost compensation of units committed under must-offer to meet system needs. Given the magnitude and volatility of these charges, a load serving entity may opt to procure energy bilaterally at a price higher than the expected CAISO Real Time Market price in order to avoid the risk of incurring these additional charges.

6 Actual settlement data are not yet available for Summer 2006.

Ancillary Service Markets

Though the CAISO Real Time Market prices are not well correlated with daily bilateral prices during extreme peak periods, the CAISO Ancillary Service Market prices are (Figure 9).

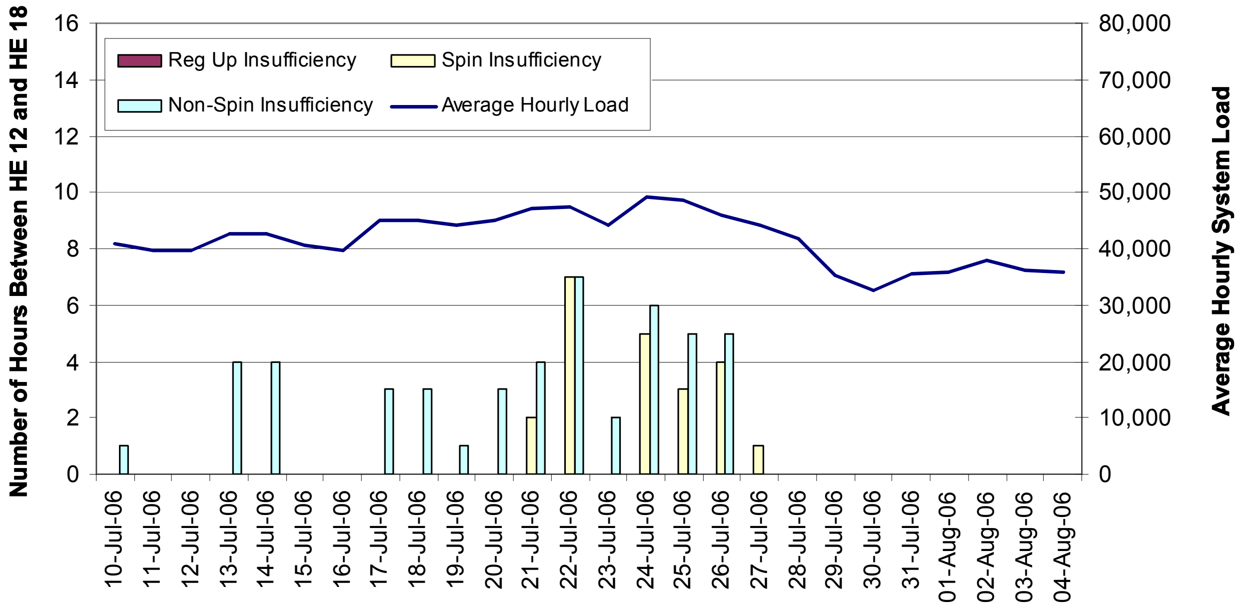
Figure 9 Day Ahead Upward Ancillary Service Average Price and Hourly Spot Bilateral Price for June 20 - 26, 2006



The average price of upward Ancillary Services (Regulation-Up, Spinning Reserve, and Non-Spinning Reserve) purchased in the day ahead market clearly reflect (a) the opportunity cost of offering the generation capacity as reserve as opposed to selling the energy in the bilateral market or (b) the expectation of being held down as reserve through the operating hour when real-time prices are reflective of day-ahead bilateral prices (i.e., the opportunity cost of foregoing real-time market prices).

Despite the higher prices for upward Ancillary Services, the CAISO did experience significant procurement shortages across the peak load days from July 21 - 26, as seen in Figure 10. Both Spinning Reserve and Non-spinning Reserve experienced high levels of procurement shortages across the super-peak hours of HE 12 - 18.

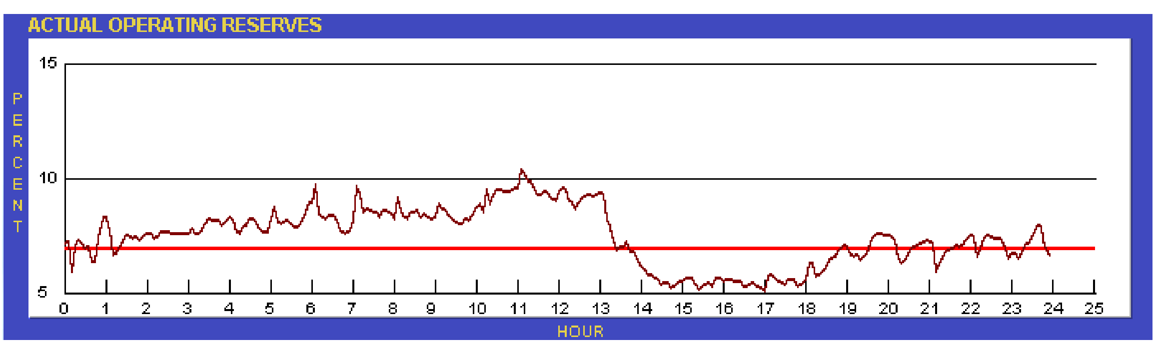
Figure 10 Hours Where Procurement < Requirement During HE 12 - 18 by Upward Service



The Hour Ahead and Day Ahead Markets are the only two markets in which the CAISO can procure operating reserves. Under extreme conditions, RMR units can also be committed to provide reserves. On July 24, the CAISO was deficient in Spinning Reserve during six hours across the super-peak and deficient in Non-spinning Reserve during five hours across the super-peak with no additional opportunity after the close of the Hour Ahead Market to procure additional operating reserves.

As load ramped up toward the super-peak period of the day on July 24, the CAISO had less operating reserve due to bid and procurement insufficiency and operating reserves dipped below the 7% level during HE 14. The CAISO declared a Stage 2 Emergency at the beginning of HE 14 when actual operating reserves began a steep decline towards the 5% level, as seen in Figure 11.

Figure 11 Actual Operating Reserve Levels for July 24, 2006 (taken from OASIS)



During the Stage 2 Emergency, the actual imbalance requirements were minimal and there were additional un-dispatched energy bids in the imbalance stack. However, there is no mechanism in the current market design to take those un-dispatched energy bids and convert them to operating reserve to be held in the event of a contingency. After declaring a

Stage 2 Emergency and observing actual operating reserves drop to near 5%, the CAISO called on 855 MW of interruptible load at 14:37 to reduce load levels and keep reserves from declining below 5%.

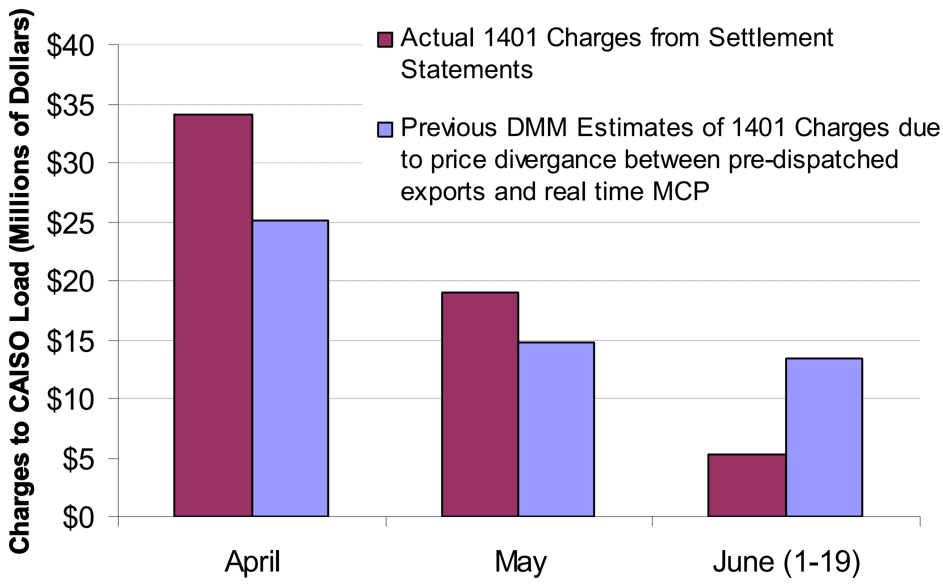
As a result of Ancillary Service bid insufficiency and a market that does not accommodate obtaining additional operating reserve in real time, the CAISO was in a Stage 2 Emergency and calling for interruptible load curtailment while there were unused bids in the imbalance energy stack and moderate imbalance prices primarily in the $55 to $100 range with a few intervals pricing near $400/MWh. This situation reflects two deficiencies in the current Real Time Market design: 1) an inability to procure operating reserve in real-time and 2) a lack of a reserve shortage scarcity pricing mechanism. If the CAISO had a real-time market for operating reserve and a reserve shortage scarcity pricing mechanism, the price of real-time operating reserve could better reflect the value of reserve (given the shortage situation) and energy prices would as well – provided the energy dispatch is co-optimized with operating reserve procurement. In which case, real-time prices (energy and reserves) would be likely at or near the $400 bid cap. Some eastern ISOs (e.g., NY ISO) have successfully incorporated these kinds of mechanisms into their real-time market design. The current release of MRTU (Release 1) will include a real-time market for operating reserves but it will not include a reserve shortage scarcity pricing mechanism thus MRTU would partially solve the design deficiency by being able to procure reserves in real-time but this in itself will not guarantee that reserve prices properly reflect scarcity conditions. A scarcity pricing mechanism is being considered as one of the design elements currently being considered for MRTU Release 1A and should be given strong consideration.

II. Analysis of Real Time Market Revenue Imbalance

As noted in DMM's previous memos to the Board, since spring the CAISO has often been decrementing significant amounts of energy through pre-dispatched export bids, with prices received for this pre-dispatched decremental energy often being significantly lower than the 10-minute real time prices paid for positive instructed and uninstructed energy provided by internal sources within the CAISO. Such divergences have created a significant revenue imbalance in the Real Time Market that is ultimately passed on to CAISO load through the 1401 Charge code. This trend has lessened during the summer months, but has continued to exist at times under moderate summer load conditions.

In previous Board memos, DMM provided estimates of the potential magnitude of costs due to these trends that may be recovered from CAISO load under the 1401 Charge Code, prior to the availability of actual settlement data. Figure 12 compares actual charges recovered under the 1401 Charge Code to these previous DMM estimates (adjusted to correspond to calendar months used to sum up actual settlement data). It should be noted that actual 1401 Charge Code includes a variety of additional sources of revenue imbalances (or surpluses), including real time price differentials within the CAISO due to inter-zonal congestion, Unaccounted for Energy settlement, unscheduled flows across interchanges, and import deviations vs. transmission loss calculations. However, as shown in Figure 12, this comparison confirms that the divergence between prices for pre-dispatched decremental energy and prices for real time instructed and uninstructed incremental energy – combined with the large volume of pre-dispatched decremental energy – appears to be the major contributor to overall 1401 charges assessed to load.

Figure 12 Actual 1401 Charges vs. DMM Estimates of Revenue Imbalance due to Divergence between Prices for Pre-Dispatched Exports and Real Time Incremental Energy



As DMM noted in its previous Board memo, the cause of this revenue balance is not attributable to a market design flaw per se rather it is the result of having real-time transactions settled through a two-settlement system (as-bid settlement for pre-dispatched inter-tie bids and MCP settlement for 5-minute dispatched transactions). It is the two settlement system – coupled with the fact that dispatches under each are based on two different sets of information concerning imbalance demands which creates the potential for price divergence, particularly if operators are dealing with challenging real-time conditions that may cause them to err on the side of caution in biasing RTMA during the pre-dispatch process. This revenue imbalance would not occur (absent real-time congestion) if all real-time transactions were settled at a single 5-minute price but such a design is not practical given the limitations of inter-ties to participate in a 5-minute market.

III. Response to Williams Power Company

See Attachment A.