California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

CC: ISO Officers

Date: July 27, 2006

Re: Market Monitoring Report

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

EXECUTIVE SUMMARY

In response to increasing natural gas prices and the potential effect this might have on supply adequacy in the CAISO Real Time Market, DMM and CAISO Management recommended, and the Board subsequently approved in December 2005, an increase in the Real Time Market energy bid cap to $400/MWh. The new bid cap was approved by FERC and went into effect on January 15, 2006. Since that time, DMM has periodically provided the Board with updates on the impact the higher bid cap has had in the Real Time Market. At the March 9, 2006 Board of Governors meeting, the Board requested that DMM provide, in July 2006, an updated assessment of the performance of the Real Time Market under the higher bid cap. Accordingly, an updated assessment is provided in this memo.

The abundance of hydroelectric generation during the spring and early summer of this year resulted in very moderate spot bilateral prices and moderate average CAISO real time energy prices but this same factor did increase the 5-minute price volatility in the CAISO Real Time Market. Abundant hydro generation, often running at maximum output, displaced thermal generation in meeting load during this period. With fewer thermal units online and limited Real Time Market participation by hydro resources, there was a decrease in the 5-minute dispatchable supply available in the Real Time Market. This is a typical spring phenomenon but was particularly acute this year due to the extraordinary level of hydroelectric generation. The decline in 5-minute dispatchable supply resulted in 5-minute interval price spikes above $250 as the CAISO was forced to dispatch further up a smaller offer curve to meet imbalance requirements, particularly during periods where load or schedules were ramping quickly (primarily during morning and late evening ramping periods).

In recommending a higher cap, DMM noted in its December 5, 2005 Memo to the Board of Governors that price spikes are not just a summer phenomenon but can occur in any season during periods of fast load and generation ramping. Five-minute price spikes (above $250/MWh) have occurred with some frequency since the bid cap was increased to $400/MWh and during some months (April-May) occurred almost on a daily basis but the overall frequency (when measured over all 5-minute price intervals) was very limited, occurring in less than 2% of the total 5-minute intervals in most months during the Jan 15 – June 30 period.

In late June and early July, loads increased sufficiently such that more units were online and bidding into the Real Time Market. Coincident with this increase in load, price spikes have moderated. In late June and early July (June 18 – July 17), the frequency of price spikes dropped to 0.7% of 5-minute intervals, compared with 2% for May and 3% for the first seventeen days of June.

The financial impact of prices in excess of $250 has been limited due to the low frequency of prices in excess of $250, combined with the limited volume of energy transacted at these prices. That said, it is impossible to precisely determine cost impact of the higher bid cap because a definitive assessment would require knowing what the bids and market volumes would have been had the soft-bid cap remained at $250/MWh. Given this limitation, the simplified approach used here 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. Using this approach, the estimated net-cost impact to load for the period of January 15 to June 30 is roughly $3 million, or 3.1% of the total cost of real-time Instructed Incremental Energy. To place the estimated cost impact in context, real time imbalance energy has comprised less than three percent of the total energy requirement to meet load during this period, so a three percent net cost impact on three percent of energy required to meet load is a relatively small impact on total cost to load. Furthermore, while revenue opportunities/risks in the real time imbalance market can have some impact on prices traded in the bilateral markets, there is no indication that the higher bid cap had a discernable impact on bilateral spot energy trades over the study period (January 15 – June 30). Though during the recent extraordinary heat wave period (July 17 – July 26) numerous spot bilateral transactions occurred above $250/MWh, these additional costs should be viewed in the context of the reliability benefits a higher cap may have provided during this critical period in terms of greater generation availability during the peak hours and lower Real Time Market volumes. The extremely low level of generation outages observed during the heat wave can likely be attributed in large part to the high level of forward energy procurement by LSEs, which shifts the spot market risk to the suppliers, and the higher bid cap, which increases the spot market risk to the suppliers and therefore provides a greater incentive to undertake a higher level of generation maintenance so as to avoid a forced outage during the peak part of the day. Moreover, to the extent forced outages do occur; the higher bid cap provides a greater incentive to return the unit to service as quickly as possible.

In considering the relatively low frequency of price spikes and estimated negligible cost impact against the benefits of having the higher bid cap, DMM is not recommending any changes to the bid cap level. DMM will continue to closely monitor the CAISO Real Time Market and will update the Board should future market performance under the $400 bid cap raise any concerns or issues.

In addition to monitoring the impact of the $400 soft bid cap, DMM has also been monitoring a separate issue of the price divergence between the average cost of pre-dispatched export bids and the 5-minute Real Time Market price for internal resource dispatch. Price divergence between these two dispatches can potentially create a significant revenue imbalance in the Real Time Market that is ultimately passed on to load. In the late Winter and Spring, (real time) export requirements increased and the export bids that were pre-dispatched were settled at an average cost that was well below the corresponding average Real Time Market prices for the same hour. The resultant revenue imbalance is recovered by charging this amount proportionately to load. Pre-dispatch exports increased dramatically in April and continued to be significant through June and were at an average cost that was significantly below the average Real Time Market (5-minute) prices. For the period April - June 2006, the estimated potential real time energy revenue imbalance that could be charged to load totaled roughly $52 million. It is important to note that this is a rough approximation; the actual revenue imbalance cannot be calculated for this period until settlement quality meter data is available. Since these estimates represent a significant cost that some market participants may be unaware of, DMM felt it appropriate to alert the Board and the market (via this Board Memo and the prior June Board Memo) of this potential cost. DMM will continue to monitor and report on this trend in price divergence and resulting potential imbalance charge to load.

Assessment of Real Time Market Performance

Analysis of Price Spikes

Background

In December 2005, DMM and CAISO Management recommended and the Board approved an increase in the Real Time Energy Market soft bid cap[1] to $400/MWh in response to concerns over higher gas prices and the potential impact they may have had in reducing the volume of offers into the CAISO Real Time Energy Market under the prior soft bid cap of $250/MWh. In addition to mitigating the potential impact of higher gas prices in reducing the amount of energy offered to the CAISO Real Time Market, DMM noted in the December Board Memo several other benefits a higher bid cap could provide:

- A higher bid cap would provide several reliability benefits,
    1. It would provide greater incentives for generator owners to maintain their units at a high level of availability so they mitigate the risk of experiencing a forced outage during a critical peak load hours, which would be particularly important in light of the tight supply margins forecasted for Summer 2006.
    2. It would provide greater incentives for further development of demand response programs such as real-time pricing. Such demand programs would reduce reliance on high cost, environmentally unfriendly combustion turbines during critical peak demand hours and increase supply margins during peak load periods.
    3. It would promote reliability by providing greater fixed cost recovery for generating units during high demand periods when supply margins are tight and prices are at or near the bid cap. Several generating units in California are at risk of retirement due to insufficient fixed cost recovery. Moreover, some new generating units in the CAISO Control Area do not have long-term power contracts and a higher spot price during critical peak periods will help to make these units more economically viable.
- A higher bid cap would provide greater incentives for the LSEs to continue to minimize their spot market exposure by signing additional long-term power contracts.
- Finally, increasing the cap to $400/MWh would provide a measured transition to the $500/MWh energy bid cap scheduled to be invoked with the California ISO's new market design in November 2007.

Though natural gas prices have since moderated, the National Weather Service is forecasting another active hurricane season for the Eastern and Gulf Coast regions this year, raising the potential for higher natural gas prices this winter[2].

At the March 9, 2006 Board Meeting, the Board requested that DMM provide an assessment in July of Real Time Market performance under the higher bid cap. This section provides an overview of real-time prices, focusing on prices in excess of the prior soft bid cap of $250, and an estimate of the cost impact of raising the soft bid cap to $400.

Analysis

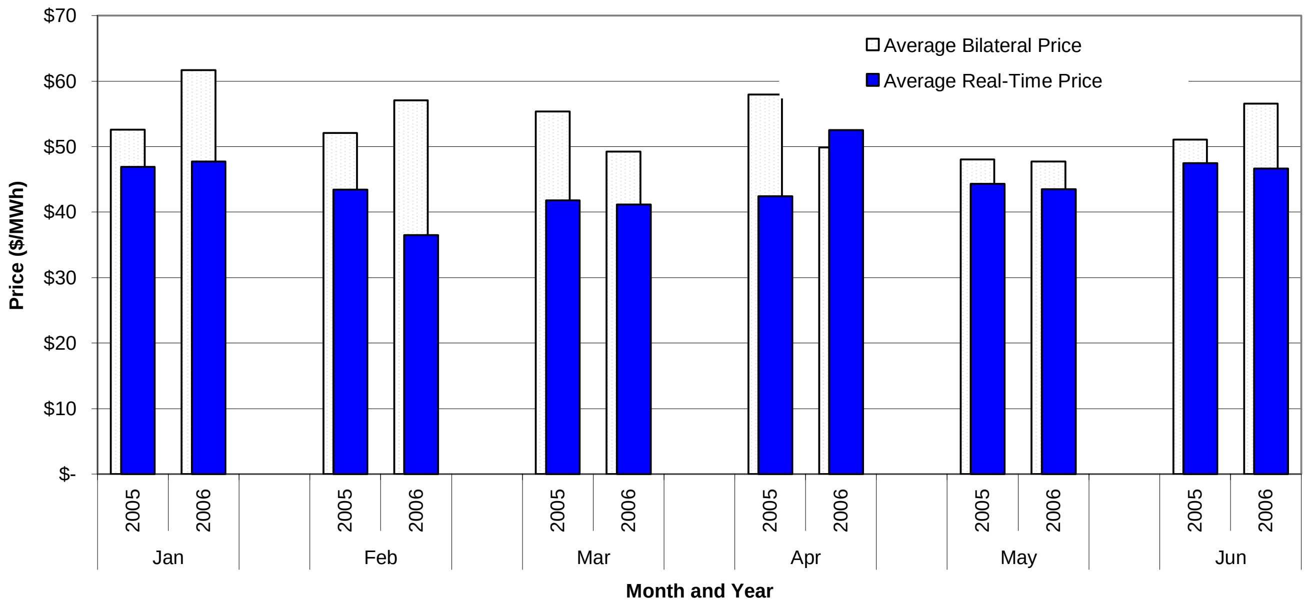
One measure of whether or not an increased bid price cap has had a pronounced effect on the market is to compare average real-time prices under the higher bid cap with real-time prices from a comparable period with the lower bid cap. Figure 1 below shows the monthly average of hourly CAISO Real Time Market clearing prices during peak hours for the months January through June of 2006 compared to the same months in 2005. The monthly average of peak hour spot hub prices is included for reference. As seen in Figure 1, prices in the CAISO Real Time Market have been lower on

[1] Under a "soft" bid cap, dispatched bids with bid prices above the cap are ineligible to set the market clearing price and are paid "as-bid" – subject to cost justification by FERC.

[2] Currently, NYMEX gas futures for December 2006 and January 2007 are trading at $9.34 and $10.10 per MMbtu, respectively

average for the first half of 2006 than they were during the same period in 2005. Though not shown in this memo, the same was true for off-peak prices as well.

Figure 1 Monthly Average of Hourly CAISO Real Time MCP and Spot Hub Price for Peak Hours in January - June of 2005 and 2006



Although this year-to-year monthly comparison is compatible with the change in bid caps (the bid cap change occurred in mid-January 2006), it is important to note that other factors that differed between the two years may have contributed to the observed differences in monthly average prices. One notable difference was the abundance of hydroelectric power in 2006 compared to 2005. Differences in natural gas prices may have also contributed to the trend in monthly average prices. For example, gas prices were $2 higher in January and February of 2006, compared to 2005, which may account for the difference in bilateral prices seen in Figure 1 for these months. Gas prices declined through January and February of 2006, leveling off in the $5.50 to $6.50 range, at the same time hydroelectric output increased substantially. The abundance of hydroelectric generation had a decreasing effect on bilateral prices for March and April compared to 2005. Average bilateral prices increased in June 2006 relative to June 2005. This increase is likely due to significantly higher loads in June 2006 compared to June 2005. In June 2006, peak period loads in the CAISO Control Area were nearly 3,500 MW higher than in June of last year. To the extent load in the southwest or northwest experienced a similar increase this June, this would have increased demand in the bilateral spot markets and contributed to the increase in the average spot bilateral price for June 2006 seen in Figure 1.

Focusing more specifically on the frequency of price spikes, Figure 2 below shows the price spike frequency for incremental and decremental dispatch intervals separately, with the monthly average hourly CAISO Real Time Market price and the monthly average spot hub price for reference. Price spikes represented in Figure 2 are defined as 5-minute interval market clearing prices over $250/MWh for positive spikes[3] and below -$1/MWh for negative spikes. Overall, average real-time prices have been moderate, but experienced increased volatility in the April – June period. The monthly frequency of positive price spikes ranged from nearly zero in February to just over two percent in May and June. Also

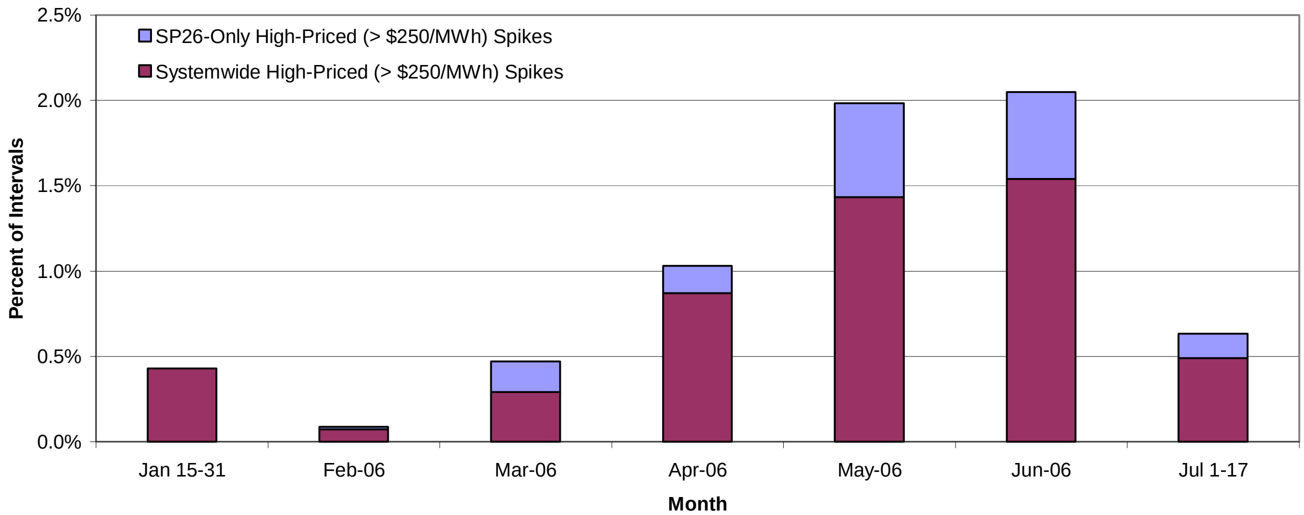
[3] The formula for calculating positive price spikes actually takes MCPs over $250.002 to avoid counting MCPs that were set by $250 bids that had a fraction of a cent added to them by the RTMA software to distinguish between multiple bids at the same bid price.

illustrated in Figure 2 is the relationship between average CAISO real time prices and the average spot hub prices. With the exception of April and May, average Real Time Market Prices have been at or below average day-ahead bilateral prices. Higher average Real Time Market prices in April and May are likely attributable to the increased frequency of real-time price spikes and the price suppressing effect that the abundance of hydroelectric generation and moderate loads were having on daily spot bilateral prices. The increase in positive price spikes in May can be largely attributed to a thinner supply in the Real Time Market compared to imbalance requirements. The thinner supply (relative to imbalance requirement) was a result of fewer internal resources online due to relatively low loads and an abundance of hydro output (resulting in less hydro resources being bid into the Real Time Market). Higher loads in the second half of June brought more internal units online, which increased supply in the Real Time Market and reduced the incidence of price spikes. In fact, 83 percent of the price spikes in June occurred prior to the 18th, after which price spikes were minimal for the remainder of the month and into July.

Figure 2 Average Hourly CAISO Real Time MCP, Spot Hub Price, and Price Spike Frequency for Incremental and Decremental Intervals: Jan 15 through Jul 17, 2006

Looking at price spikes from a zonal perspective, the majority of price spikes have been on a system-wide basis where the zones are not split and RTMA is dispatching resources to meet system-wide imbalance needs. Figure 3 shows a zonal breakout of positive price spikes indicating that even in May and June, where there was a higher incidence of positive price spikes, less than 1/3 of the intervals with positive price spikes were isolated in SP15 under dispatch conditions where the zones were split and priced separately (isolating load in NP15 from the impact of the price spike).

Figure 3 Frequency of Incremental Interval Price Spikes by Month (January - June 2006)



The CAISO managed congestion on the internal paths through the pre-dispatch of intertie bids (imports and exports) prior to the start of the operating hour as well as through splitting the zones in real-time and dispatching resources (on a 5-minute basis) in the north and south separately. The relatively low share of positive price spikes that are isolated in SP15 is, in part, the result of effective Path 26 congestion management through the pre-dispatch process, which limited the need to call on SP15 bids at or near the cap to manage any residual congestion in real-time.

Figure 4 through Figure 6 Below show price spike frequency for each of the 24 hours in a day for three distinct periods: January 15 - April 30 (winter and spring months with $400 bid price cap), May, and June.

Figure 4 Frequency of 5-Minute Interval Prices Over $250/MWh, Jan. 15 – Apr. 30 2006

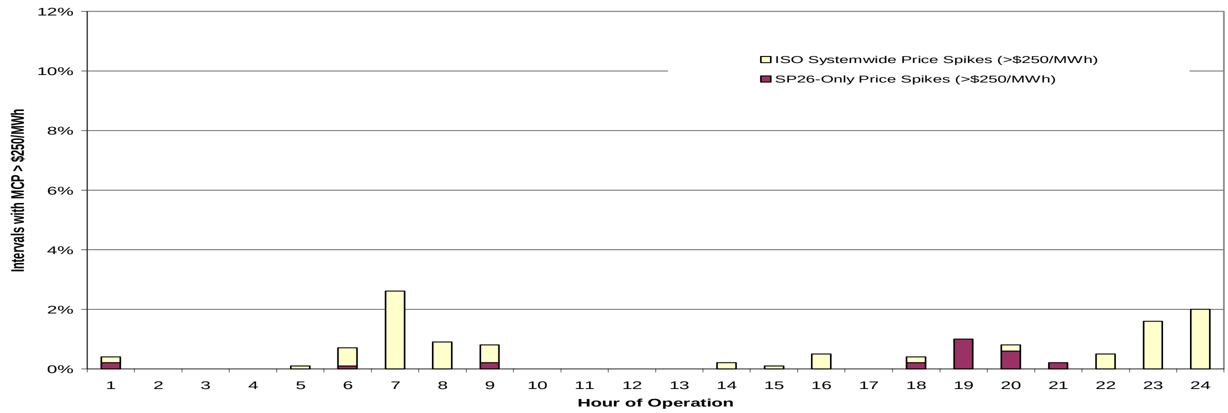


Figure 5 Frequency of 5-Minute Interval Prices Over $250/MWh, May 2006

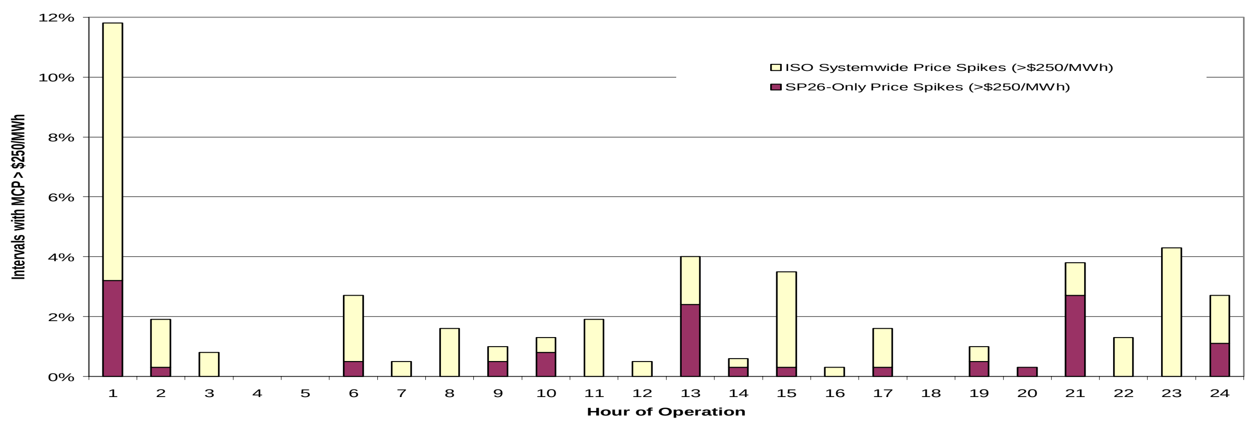
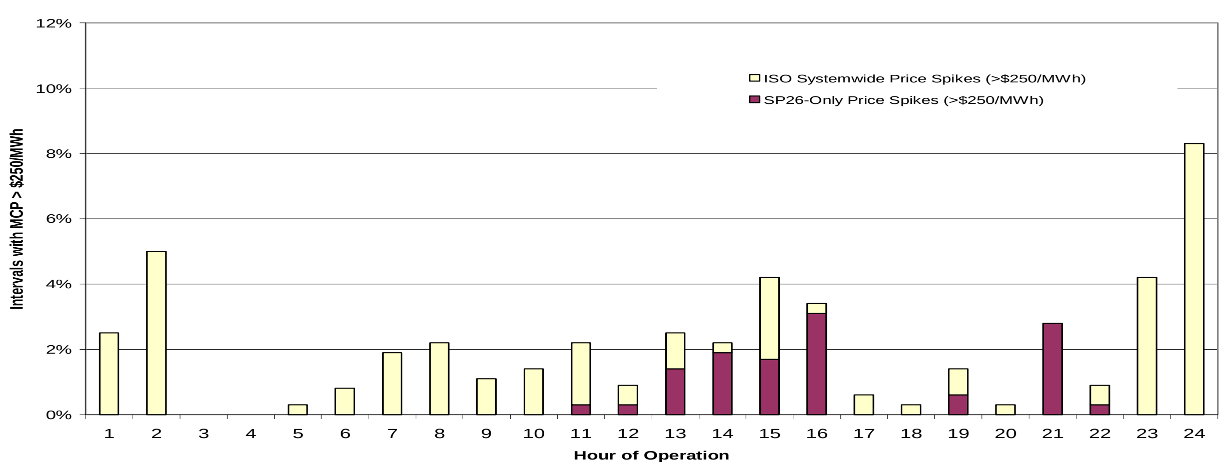


Figure 6 Frequency of 5-Minute Interval Prices Over $250/MWh, June 2006



Incremental price spikes during the period January 15 - April 30 occurred in approximately less than two percent of intervals in all hours, except for the morning ramp in HE 7 where the frequency reached approximately 2.6 percent of intervals. In May and June, the frequency of spikes increased in numerous hours, with a notable pattern of more price spikes during the peak hours than in the previous period. This is a result of increasing system wide load requiring more imbalance energy during the peak period compared to the winter and early spring coupled with less 5-minute dispatchable supply due to limited Real Time Market participation of hydro resources, which were typically running at or near maximum load, and limited participation by thermal resources that were displaced by high hydro output.

One trend worth noting is the incidence of price spikes in SP15 when the zones are split in real time. While June showed price spike frequencies at or above two percent in both the peak and off-peak periods, SP15 experienced zonal price spikes primarily during the afternoon peak and evening shoulder period. As Path 26 becomes more fully loaded when system load peaks during the day, a zonal split is often required to manage flows. Another factor in splitting the zones in real time has been the relatively high incidence of unscheduled north to south power flows through the CAISO Control Area. This unscheduled flow can increase flows from north to south on Path 26 toward the path limit. If unscheduled flows are severe enough, the path will reach its limit and RTMA will split the zones to manage real time flow on Path 26 and clear the imbalance in the zones separately.

Though there has been an increase in the frequency of incremental price spikes in the April-June period and a shift in the pattern of hourly price spike frequency to a higher frequency during afternoon peak and evening shoulder hours, these spikes are typically happening in less than two percent of all 5-minute intervals and are not having a pronounced affect on average hourly prices across the month, as seen in Figure 1.

The financial impact of prices in excess of $250 has been limited due to the low frequency of prices in excess of $250, combined with the limited volume of energy transacted at these prices. That said, it is impossible to precisely determine cost impact of the higher bid cap because a definitive assessment would require knowing what the bids and market volumes would have been had the soft-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, the simplified approach used here 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. Using this approach, Table 1 provides the estimated incremental imbalance energy cost attributable to price spikes over $250 and shows both the estimated gross cost of prices greater than $250/MWh and the net costs to LSEs, which subtracts out the revenues earned by LSE-owned or operated generation during price spike periods. Total net costs to Load Serving Entities (LSEs) resulting from market clearing prices in excess of $250 from January through June are estimated at about $3.1 million, or about 3% of total cost of Instructed Incremental Energy during this period.

Table 1 Estimated Market Impact of MCPs over $250

	Instructed Incremental Real Time Energy (IE)			Estimated Net Costs to LSEs*[4]	
	Total Costs	Cost Due to MCP > $250		Total	Percent of IE
Jan 15-Feb	$17,981,000	$382,000	+ 2.1%	$357,000	+ 2.0%
March	$12,421,00	$303,000	+ 2.2%	$49,000	+ .4%
April	$26,489,000	$1,254,000	+ 4.7%	$787,000	+ 3.0%
May	$21,227,00	$1,512,000	+ 7.1%	$694,000	+ 3.3%
June	$20,438,000	$2,000,000	+ 9.8%	$1,193,000	+ 5.9%
Total	$98,559,000	$5,451,000	+ 5.5%	$3,081,000	+ 3.1%

To place the spike frequency and cost impact in context, real time imbalance energy has comprised less than three percent of the total energy requirement to meet load during this period, so a three percent net-cost impact on three percent of energy required to meet load is a relatively small impact on total cost to meet load. Furthermore, while revenue opportunities/risks in the real time imbalance market can have some impact on prices traded in the bilateral markets, there is no indication that the higher bid cap had a discernable impact on bilateral spot energy trades over the study period (January 15 – June 30). Though during the recent extraordinary heat wave period (July 17 – July 26) numerous spot bilateral transactions occurred above $250/MWh, these additional costs should be viewed in the context of the reliability benefits a higher cap may have provided during this critical period in terms of greater generation availability during the peak hours and lower Real Time Market volumes. The extremely low level of generation outages observed during the heat wave can likely be attributed in large part to the high level of forward energy procurement by LSEs, which shifts the spot market risk to the suppliers, and the higher bid cap, which increases the spot market risk to the suppliers and therefore provides a greater incentive to undertake a higher level of generation maintenance so as to avoid a forced outage during the peak part of the day. Moreover, to the extent forced outages do occur; the higher bid cap provides a greater incentive to return the unit to service as quickly as possible.

In considering the infrequency of price spikes and the estimated minimal cost impact against the potential reliability and market benefits of a higher bid cap, DMM is not recommending any changes to the $400 soft-bid cap at this time. DMM will continue to closely monitor the CAISO Real Time Market and will update the Board should future market performance under the $400 bid cap raise any concerns or issues.

Analysis of Real Time Market Revenue Imbalance

In addition to monitoring the impact of the $400 soft bid cap, DMM has also been tracking, and reporting on, the price divergence between pre-dispatched energy across the inter-ties (import and export energy) and the 5-minute real time dispatch of internal resources. Of particular interest are periods where prices for these two dispatch periods diverge. Such divergences can potentially create a significant revenue imbalance in the Real Time Market that is ultimately passed on to

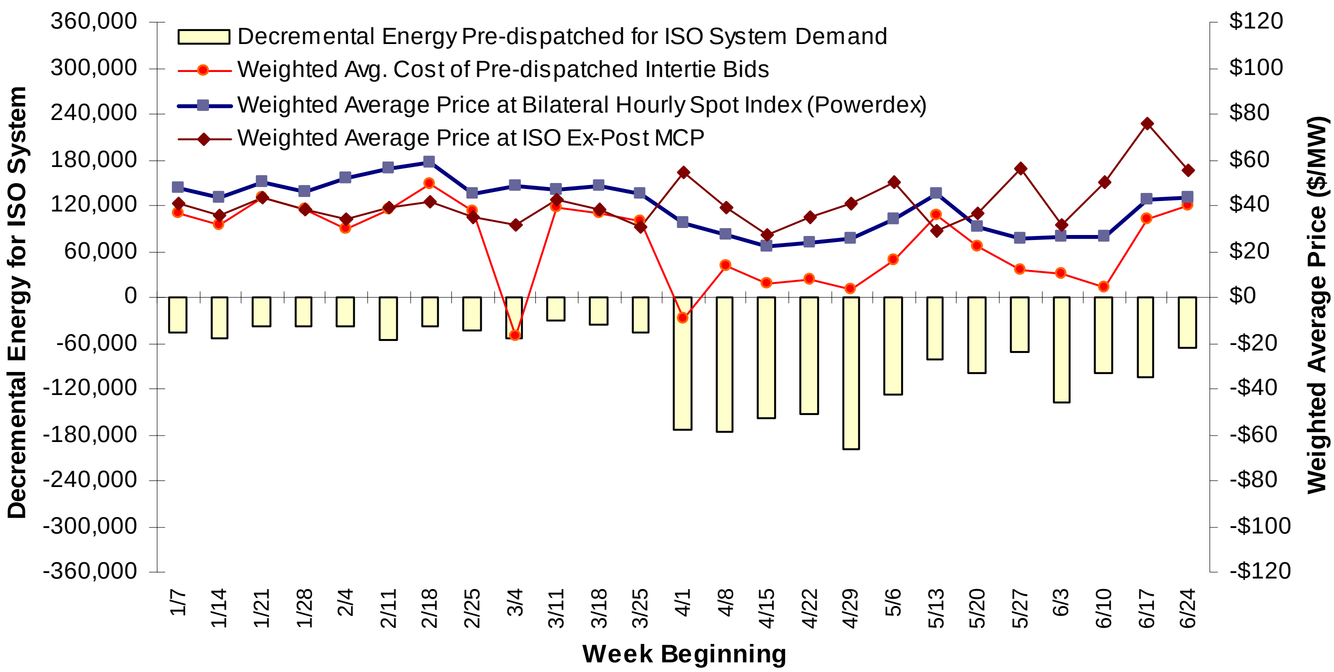
[4] Estimates in Table 1 include estimated reduction in daily uplift payments due to prices over $250 MWh. Net-costs include estimated uninstructed generation and excludes energy provided by resources owned or under contract to LSEs. Net-costs include estimated uninstructed generation and excludes energy provided by resources owned or under contract to LSEs. Estimated costs do not account for the fact that in some cases, if prices have 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 1 may overestimate the impact of the higher bid cap.

CAISO load[5]. Pre-dispatched exports continue to play a large role in the Real Time Market as a key means for mitigating persistent unscheduled loop flow through the CAISO control area and for mitigating general over-generation conditions. Pursuant to Amendment 66 to the CAISO Tariff, market participants that seek to purchase power from the CAISO Real Time Market for export do so on an hourly basis and rather than pay a single market clearing price, instead pay their offer price (i.e., as-bid) if selected in the pre-dispatch process. As export requirements have increased (again, in large part to mitigate transmission limits that have become more binding due to unscheduled flow), RTMA often pre-dispatches export bids at an average cost that is well below the corresponding average Real Time Market prices for the same hour. The resultant revenue imbalance is recovered by charging it proportionately to load as Charge Type 1401.

[5] For instance, if in expectation of over-generation, RTMA pre-dispatches 1,000 MW of export bids at an average bid price of $5/MWh and in the Real-Time Market, RTMA further mitigates over-generation by decing 400 MW of internal resources at an average price of $30/MWh, there is a potential revenue imbalance of $25,000 (1,000 MW*($30-$5)). The revenue imbalance arises in this example because the 1,400 MW of uninstructed energy that created the over-generation condition is being paid the $30/MWh real-time MCP, which results in a total payment of ($42,000 = $30*1,400), but the CAISO is only collecting $17,000 from instructed energy settlements (1,000 MW at $5/MWh and 400 MW at $30/MWh), resulting in a net revenue shortfall of $25,000 (i.e., 1,000 MW*($30 - $5)).

Figure 7 shows weekly average of three price series for the first six months of 2006, the average hourly pre-dispatch costs for pre-dispatched export quantities, the average five-minute interval price, and the average spot hub price.

Figure 7 Price Divergence Between Real Time Pre-dispatch and Five-Minute Dispatch (January – June 2006)



There was decreased price divergence in the first three months of 2006, but beginning in April prices between the pre-dispatch and real time 5-minute dispatch showed a significant divergence. The beginning of this price divergence period is marked by significantly increased pre-dispatch exports (the yellow bars in Figure 7). Pre-dispatch exports increased in April as a result of an increased need to manage unscheduled (counter-clockwise) flow through the CAISO control area and to counter the effect of significant hydro output in NP15 that limits the extent to which imports can be accommodated on PACI / COI. While there are several means for managing this flow, one method to do so is to increase counter-flow on the COI by pre-dispatching exports across that path. This increased demand / requirement for pre-dispatched exports from NP15 to the Northwest resulted in the CAISO having to dispatch export bids further into the supply stack. Since export bids are bid as a 'willingness to pay', the further into the bid stack the CAISO must go to meet requirements the lower the offer prices are. This has a decreasing effect on the average pre-dispatch price and, as seen in Figure 7, has a divergent impact on the relationship between pre-dispatch price and the real time 5-minute dispatch price.

Table 2 shows weekly average export energy volume since the first of April, the average difference between as-bid export unit costs and real-time prices, and the estimated potential exposure to load through Charge Type 1401.[6] The figures reported in Table 2 represent weekly volumes.

Table 2 Potential Real Time Energy Revenue Imbalance - April through June 2006

	Approx. Predispatched Export Energy	Price Difference (As-Bid vs. MCP)	Potential Revenue Imbalance
4/1/2006	172,872	$63.96	$11,057,094
4/8/2006	175,618	$25.19	$4,423,274
4/15/2006	158,023	$21.16	$3,344,400
4/22/2006	154,262	$26.96	$4,158,303
4/29/2006	200,312	$38.04	$7,620,613
5/6/2006	127,335	$34.66	$4,413,536
5/13/2006	80,794	($6.73)	($543,744)
5/20/2006	99,539	$14.27	$1,420,701
5/27/2006	71,477	$44.44	$3,176,674
6/3/2006	138,532	$21.21	$2,938,316
6/10/2006	99,327	$46.55	$4,623,218
6/17/2006	104,849	$41.82	$4,384,292
6/24/2006	67,425	$15.06	$1,015,707
Total	1,650,365		$52,032,383

The total potential charges attributable to the revenue imbalance created by price divergence between the pre-dispatch and real-time 5-minute dispatch total $52 million for April through June 2006. Note that the overall trend for potential revenue imbalance charges through CT 1401 have ranged from $11 million to nearly zero with a fairly high variation across the three months, reflecting the change in pre-dispatch export requirements and offer prices submitted to the CAISO. Total pre-dispatched exports were lower in May and June compared with April, resulting in a lower monthly average potential revenue imbalance charge. It should be noted that the potential cost impact may be significantly lower for Load Serving Entities since potential imbalance charges under Charge Code 1401 may be offset by payments received for positive load imbalances and/or instructed and uninstructed energy from resources owned or controlled by LSEs (e.g., hydro, wind, and minimum load energy from some thermal units).

It should be noted that the cause of this potential 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.

[6] The volumes, prices, and revenue imbalances are estimates and do not reflect actual settlement charges (CT1401). CAISO Client Relations has received a number of inquiries from market participants regarding increases in the CT1401 items on their April statements. One market participant reported an increase from roughly one-half million dollars to nearly six million dollars for CT1401 alone. This has a significant impact not only on the Market Participant's financial obligations for the billing month, but can also result in an increase in the requirement for the financial reserve account required to participate in the CAISO markets.