California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Operations Committee

From: Keith Casey, Director, Market Monitoring

cc: ISO Board of Governors, ISO Officers

Date: March 2, 2006

Re: **Market Monitoring Report**

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

1. Overview

This month's Market Monitoring Report covers two topics: 1) a summary of 2005 market performance highlights, and 2) an assessment of the impact of the recently adopted $400 soft bid cap on the CAISO real-time imbalance energy market. Though not the focus of this report, other activities that DMM has been engaged in over the past six weeks include the following:

- MRTU Readiness – DMM continues to work with the MRTU project team in refining the market monitoring requirements under MRTU to ensure an adequate database and monitoring system are in place for day one of MRTU. In early February, DMM staff visited the market monitoring units of PJM and ISO New England to review their LMP monitoring systems and discuss monitoring techniques and data requirements under an LMP market design. Staff from Market and Product Development and Market Services also participated in the trip. The meetings with these market monitors were extremely informative. Staff from DMM, MPD, and Market Services came away with a number of valuable insights on market monitoring techniques and data requirements for monitoring an LMP market and a better understanding of how the market monitoring units from these ISOs interact with their market operations and market design departments.
- MRTU Tariff Filing – DMM staff developed, edited, and finalized the MRTU Tariff provisions relating to market monitoring, market power mitigation, and Inter-SC Trades of energy. In addition, DMM provided over 100 pages of testimony on these same issues.
- MRTU Competitive Path Assessment – The cornerstone of the local market power mitigation provisions under MRTU is the pre-designation of transmission paths as "competitive" or "non-competitive." The designations are to be determined annually based on studies conducted by DMM. A study methodology for determining these designations was developed through a stakeholder process conducted last year and was incorporated into the MRTU Tariff. DMM is now in the process of applying that methodology. This effort involves developing simulation software to conduct LMP studies, benchmarking the simulation results against previous LMP studies, and incorporating the competitive path analysis methodology into the software.

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2. Summary of Market Performance Highlights for 2005

Each year the Department of Market Monitoring publishes an annual report on the performance of markets administered by the CAISO. This memo provides a brief summary of the market performance highlights for 2005. In addition, the accompanying slide presentation (Attachment A) provides various charts and figures on the performance of each of the CAISO markets with comparisons to previous years. DMM will be finalizing the 2005 annual report over the next several weeks and will provide the Board with the final report in early April.

California's spot wholesale energy markets in 2005 were generally stable and competitive, similar to the past several years (2002-2004), however, as discussed below, the slow pace of new generation investment in California, particularly over the next several years, remains a growing concern. One of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month Market Competitive Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost markups (i.e., the difference between actual energy prices and estimated "competitive" prices that are derived from cost-based simulations). DMM considers MCI values in the range of $5-$10/MWh to be reflective of a workably competitive market. The monthly MCI values estimated for 2005 were well within this range for all months of the year. The average "all-in" cost of wholesale energy in 2005 was $57.49/MWh of load compared to $55.04 in 2004. All-in costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence energy re-dispatch premium, net RMR costs, ancillary services, and ISO-related costs (transmission, reliability, and grid management charge). The increase in the all-in costs in 2005 was primarily due to higher natural gas prices, particularly in the September-December period when there was a sharp increase in natural gas prices due to the supply interruptions from the Gulf Coast hurricanes.

The CAISO Inter-Zonal Congestion Management market was also generally stable and competitive in 2005. Total inter-zonal congestion costs in 2005 were $54.6 million, slightly lower than the $55.8 million in 2004. The two most frequently congested transmission paths in 2004, the California-Oregon Intertie (COI) from the northwest and Palo Verde branch group from the southwest, remained the top two congested paths in 2005 with COI being congested in 18% of the hours in the day-ahead market (compared to 27.5% in 2004) and Palo Verde congested in 23% of the hours (compared to 22% in 2004). Of the internal paths, Path 26 was frequently congested in the north-to-south direction before its rating was increased on June 27, 2005, while Path 15 was much less congested in either direction compared to 2004 due to upgrades that became effective in December 2004. Congestion costs on Path 15 went from $9.8 million in 2004 to $2.2 million in 2005. Not surprisingly, Palo Verde had the highest congestion costs in 2005 at $19.8 million (compared to $21.7 million in 2004, which was also the highest in that year). Congestion costs on COI totaled $6.7 million (compared to $11 million in 2004). Interestingly, the path with the second highest congestion costs in 2005 was Blythe, a relatively small path (Max OTC 218 MW with a normal rating of 168 MW) that is part of the interface between SP15 and the southwest into Arizona**.** Congestion costs on Blythe totaled $8.7 million in 2005, compared to approximately $1 million in 2004. Most of the 2005 congestion on Blythe was related to Blythe area load fluctuation, which resulted in lower ratings for the Blythe branch group.

In the ancillary service markets, prices were stable but generally higher than last year, following a similar trend to energy prices. Average ancillary service prices across all services (Regulation Up, Regulation Down, Spin, Non-Spin) was $10.72/MW in 2005, compared to $8.63/MW in 2004. The average volume of each ancillary service purchased was quite similar to previous years. Bid insufficiency was down considerably from 2004 in all the ancillary service markets, both in terms of the number of hours having insufficient bids and in the total quantity (MW) of bid deficiency. The primary reason for the reduction in insufficiency in 2005 compared to 2004 is zonal procurement of reserves. A comparison of monthly insufficiency figures for both years shows that the CAISO experienced dramatically higher bid insufficiency between August and December of 2004, which is also the period of time when the CAISO would split the reserve markets and procure by zone (as opposed to system-wide) under circumstances where transmission between NP15 and SP15 was sufficiently limited and would not facilitate reserves from one zone relieving contingencies in the other zone.

One of the major success stories in 2005 is the sharp reduction in intra-zonal congestion costs. In 2005, intra-zonal congestion costs totaled $203 million, compared to $426 million in 2004, representing a 52% decrease. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied Must-Offer Waivers, 2) RMR Costs, and 3) real-time redispatch costs. The main contributors to this decrease were a decline in MLCC costs from $274 million in 2004 to $115 million in 2005 and a decline in real-time redispatch costs from $103 million in 2004 to $35 million in 2005. RMR costs for intra-zonal congestion increased slightly in 2005 ($53 million in 2005, $49 million in 2004).

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2005, low levels of new generation investment in southern California coupled with unit retirements and significant load growth has created reliability challenges for this region during the peak summer season. In the 2005 summer season, the CAISO declared two Stage 2 Emergencies in southern California (July 21 and 22) and experienced a transmission emergency on August 25th that resulted in 900 MW of firm load being curtailed in southern California. Low levels of new generation investment within southern California coupled with significant load growth has resulted in a higher reliance on imported power from the southwest, northwest, and northern California. This dependence on imports, coupled with tight reserve margins, makes southern California very vulnerable to reliability problems should there be a major transmission outage such as occurred on August 25th with the loss of the Pacific DC Intertie. Moreover, much of the existing generation within southern California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July, with loads exceeding 40,000 MW for all but two days beginning July 11 and into early August 2005. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in southern California but such investments are not likely to occur absent long-term power contracts. The California spot market alone is not going to bring about the major investments needed to maintain a reliable electricity grid.

DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2005 indicates potential spot market revenues fell significantly short of the unit's annual fixed costs. This marks the fourth straight year that DMM's analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. This result underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Unfortunately, long-term energy contracting by the state's major investor owned utilities has been very limited. In its 2005 Integrated Energy Policy Report (2005 Energy Report), the CEC reports that, "Utilities have released some Request for Offers (RFOs) for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW out of approximately 12,500 MW under recent solicitations,"[1] and notes that, "California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the power purchase agreements needed to

1 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.

secure their financing."[2] The report notes that the predominance of short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs.

"Continuing short-term procurement for local reliability prolongs reliance on aging units that could otherwise be re-powered economically under the terms of longer-term contracts and thereby provide similar grid services at a more competitive price."[3]

In its report, the CEC recommends that the CPUC require the IOUs to sign sufficient long-term contracts to meet their long-term needs and allow for the orderly retirement or re-powering of aging plants by 2012. One of the major impediments to long-term contracting by the IOUs is concern about native load departing to energy service providers, community choice aggregators, and publicly owned utilities, which could result in IOU over-procurement and stranded costs. While this is a legitimate concern, it can be addressed through regulatory policies such as exit fees for departing load and rules governing returning load (i.e., load that leaves the IOU but later wants to return).

While long-term contracting is critical for facilitating new investment it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Though the California Public Utilities Commission (CPUC) has made significant progress in 2005 in advancing its Resource Adequacy framework, this framework must be supplemented with location-specific reliability requirements to facilitate new generation development in critical areas of the grid.

3. Assessment of the $400 Soft-Bid Cap

Summary

In response to rising spot market gas prices in early December 2005 and concerns about the potential for further increases in the winter months, the CAISO filed with FERC to modify the CAISO's $250/MWh soft bid cap to a $400/MWh hard bid cap. FERC approved the CAISO's filing on January 13, 2006, but required the $400/MWh cap to be a soft cap, with any bids dispatched over $400 being ineligible to set the Market Clearing Price and being subject to cost reporting and justification before FERC. The CAISO implemented the new $400/MWh soft bid cap on January 14, 2006.

The DMM and the Market Surveillance Committee (MSC) both recommended making this modification primarily on a concern that generation unit-level variable costs could approach or exceed the previous cap level of $250/MWh due to high and volatile natural gas prices during the winter months. Under such a scenario, a higher bid cap would increase short-term system reliability by providing greater incentives for non-participating resources to bid into the CAISO real-time market and for participating generation owners to maintain their units at a high level of availability so they mitigate the risk of experiencing a forced outage during critical peak load hours. DMM also supported this modification on the grounds that raising the cap at this time will ultimately provide additional reliability benefits by increasing available supply and demand response this summer and beyond.[4]

In the first month since the soft cap was increased from $250 to $400, which covers the period from January 15th to February 15th, the MCP for instructed energy has cleared above $250 during only thirty-three (33) 5-minute intervals, or only about .37% of all 5-minute intervals over this period. Virtually all MCPs in excess of $250 have occurred in the morning and evening "ramping hours," when relatively high prices

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2 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.
3 2005 Integrated Energy Policy Report, California Energy Commission, p. 61.
4 A more detailed discussion of DMM's recommendations were provided in a memo to the Operations Committee, the Market Monitoring Report, December 9, 2005 (http://www.caiso.com/14e2/14e2cbee31030.pdf).

frequently occur during intervals when the CAISO needs to dispatch resources quickly in order to balance relatively large swings in imbalance energy demand.

The estimated additional instructed energy costs due to prices in excess of $250 have totaled only about $313,000, or about 3.6% of total costs for net incremental instructed energy over this one-month period. This additional $313,000 also represents about .03% of total estimated wholesale energy costs for load served by the CAISO system during this period. Moreover, DMM estimates that total potential net cost exposure to load serving entities (LSEs) over this period is about $246,000, after accounting for generation owned or under contract to LSEs and uninstructed energy payments to non-LSE generation. It should be noted that these estimates are based on preliminary market dispatch data, which may be subject to future corrections prior to actual settlement with market participants.

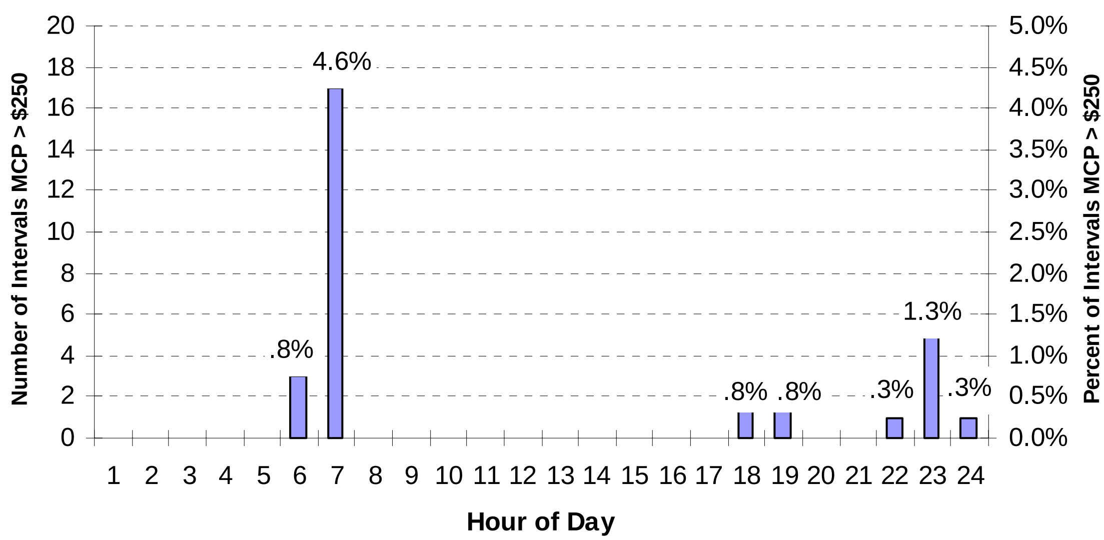
Finally, it should also be noted that additional payments for generation that is not owned or under contract to major LSEs due to prices over $250 would be further reduced due to the fact that revenues from these higher prices would reduce the daily uplift that generators receive in some cases. Generation units are eligible to receive an uplift for real time energy sales on days when their total daily market revenues from real-time energy dispatches do not cover the bid prices of the unit's bids dispatched over the course of a day. Such revenue shortfalls can occur when a unit operates in response to real-time dispatch instructions, but does not set the MCP during such intervals due to various limitations that are placed on dispatches that can set the MCP for each interval (e.g., units being ramped up to meet demand in a future interval, units ramping down from a previous dispatch instruction, and/or units continuing to run for their minimum operating time after being dispatched in a previous interval). DMM has not quantified the impact of any reduction in uplift payments in this analysis, but notes that accounting for uplift payments would further reduce the additional payments for generation that is not owned or under contract to major LSEs due to prices over $250.

Market Performance Under $400 Soft Cap

Prices over $250

In the first month since the soft cap was increased from $250 to $400, the MCP for instructed energy has cleared above $250 during up to thirty-three (33) 5-minute intervals, or only about .37% of all 5-minute intervals over this period.[5] As shown in Figure 1, almost all of these prices have occurred in the shoulder or ramping hours occurring during the transition between peak and off-peak hours. During portions of these hours, the CAISO frequently needs to dispatch resources quickly in order to balance relatively large swings in imbalance energy demand created by the combination of significant changes in load, and relatively large changes in generation and export/import schedules from one hour to the next (e.g., from Hour Ending 6 to Hour Ending 7 in the morning, and from Hour Ending 22 to Hour Ending 23 in the evening). An illustrative example of this trend is provided later in this memo.[6]

Figure 1. Real Time Market Clearing Prices Over $250
Number and Percent of 5-minute Intervals
January 15-February 15, 2006



Financial Impact

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

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5 All data and analysis in this report include eight 5-minutre intervals on January 25-26 when some energy bids at $400 were dispatched, but MCPs initially published to the market were less than $250 due to a software bug that did not allow bids priced exactly at the $400.00 soft cap to set the MCP. This problem was fixed on January 27 by setting the threshold under which bids can set the MCP to $400.01/MWh. Prices for intervals on January 25-26 when bids at $400.00 were dispatched are under review and may be corrected to $400 as part of the CAISO settlement process.

6 Additional background on these basic underlying trends was provided in a DMM report on Real Time Market Application ("RTMA") issued October 12, 2005.

(http://www.caiso.com/docs/09003a6080/37/8c/09003a6080378c2c.pdf) 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, the estimated additional instructed energy costs from January 15 to February 15 due to prices in excess of $250 have totaled only about $313,000 – about 3.6% of total costs for net incremental instructed energy, and under 2.6% of costs for gross incremental instructed energy.[7] This additional $313,000 also represents about .03% of total estimated wholesale energy costs for load served by the CAISO system during this period.[8]

DMM estimates that about two-thirds of these additional instructed energy payments will ultimately be paid for generation owned or under contract by load serving entities (LSEs), so that net instructed energy payments from prices over $250 are only $142,000. Finally, DMM estimates that an additional net payment of $104,000 due to prices over $250 may be made for uninstructed energy from resources that are not owned or under contract by LSEs, bringing additional net impacts to load from prices in excess of $250 to about $246,000 – or about .025% of total estimated wholesale energy costs for load served by the CAISO system during this period.

Figure 2 summarizes daily total costs for instructed energy since the $400 cap has been in effect, along with the portion of costs attributable to prices in excess of $250. As shown in Figure 2, the bulk of costs due to prices in excess of $250 occurred on January 23-26 and on January 31. Relatively few costs have been incurred due to prices over $250 in the first two weeks of February.

Table 1 shows a more detailed summary of DMM's calculation of additional payments due to prices in excess of $250 during the first month the $400 cap has been in effect.

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7 Gross incremental instructed energy includes all incremental generation dispatched in-sequence from both import and internal resources. Net incremental instructed energy is calculated by approximating the portion of incremental bids dispatched beyond the level needed to meet system imbalance energy needs as part of the market clearing feature of RTMA. For example, if 200 MWh of incremental bids and 50 MW of decremental bids are pre-dispatched one hour, the gross incremental energy pre-dispatched is 200 MWh while the net incremental energy pre-dispatched that hour is 150 MW (200 MW – 50 MW = 150 MW). Net instructed energy dispatched within the CAISO system within each hour is calculated separately on an interval-by-interval basis, while net energy from pre-dispatched imports/exports is calculated hourly. If the volume of decremental energy dispatched exceeds the volume of incremental energy dispatched during a time interval, the net incremental dispatch is zero.

8 Estimated based on total average CAISO system load during January 15 to February 15, 2006 (25,464 MW), and an average cost of wholesale energy of $51/MWh during the months of January-February 2005, as calculated for DMM's draft Annual Report for 2005 (not yet released).

Figure 2. Additional Instructed Energy Costs due to MCPs Over $250 Relative to Total Instructed Energy Costs January 15 - February 15, 2006

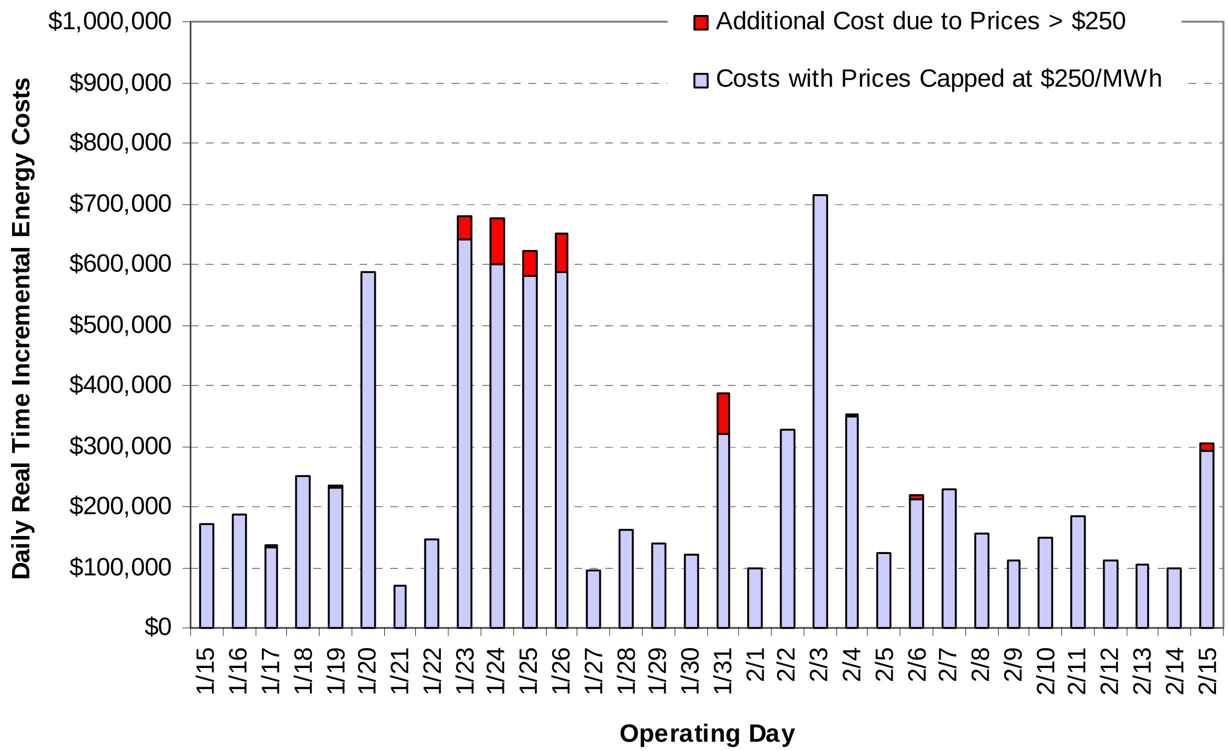


Table 1. Additional Costs due to MCPs Over $250 (January 15 - February 15, 2006)

Date	Hour	Interval	MCP	Instructed Energy (MWh)	Instructed Energy Costs Due to MCP > $250 Gross	Instructed Energy Costs Due to MCP > $250 Non-LSE [1]	Non-LSE Uninstructed Energy [2] MWh	Non-LSE Uninstructed Energy [2] Costs due to MCP >$250	Total Additional Net Cost to LSEs Due to MCP > $250 [3]
1/17/2006	22	1	$383	44	$2,726	$1,094	52	$6,922	$8,016
1/17/2006	23	1	$255	38	$154	$131	49	$246	$377
1/18/2006	6	11	$255	37	$140	$60	82	$409	$469
1/18/2006	23	1	$255	47	$198	$89	81	$406	$494
1/19/2006	23	1	$335	40	$3,128	$2,796	65	$5,518	$8,314
1/20/2006	24	1	$255	51	$197	$163	51	$257	$420
1/23/2006	18	10	$395	155	$19,253	$1,137	25	$3,630	$4,767
1/23/2006	18	12	$384	170	$19,126	$1,360	26	$3,452	$4,812
1/24/2006	7	6	$350	81	$5,410	$1,948	7	$749	$2,697
1/24/2006	7	7	$350	110	$8,202	$3,966	13	$1,339	$5,305
1/24/2006	7	8	$350	125	$9,724	$4,840	7	$720	$5,560
1/24/2006	7	9	$350	144	$11,436	$5,857	11	$1,087	$6,944
1/24/2006	7	10	$350	166	$13,309	$6,794	8	$838	$7,632
1/24/2006	7	11	$350	175	$14,542	$7,172	18	$1,820	$8,992
1/24/2006	7	12	$350	152	$12,869	$4,887	16	$1,555	$6,442
1/25/2006	7	9	$400 [4]	76	$7,682	$2,463	35	$5,233	$7,696
1/25/2006	7	10	$400 [4]	90	$9,522	$2,981	39	$5,792	$8,773
1/25/2006	7	11	$400 [4]	95	$10,743	$3,407	34	$5,027	$8,433
1/25/2006	7	12	$400 [4]	92	$11,238	$3,704	32	$4,822	$8,525
1/26/2006	6	9	$400[4]	46	$6,143	$3,429	57	$8,482	$11,911
1/26/2006	6	10	$400 [4]	68	$8,322	$4,322	52	$7,854	$12,176
1/26/2006	7	10	$350	105	$8,303	$3,063	52	$5,213	$8,276
1/26/2006	19	1	$400 [4,5]	84	$11,016	$4,713	46	$0	$4,713
1/26/2006	19	2	$400 [4,5]	103	$13,085	$5,282	41	$0	$5,282
1/26/2006	19	3	$400 [4,5]	116	$14,940	$5,787	45	$0	$5,787
1/31/2006	7	7	$400	34	$4,031	$3,272	44	$6,550	$9,821
1/31/2006	7	9	$400	87	$10,989	$8,909	41	$6,182	$15,091
1/31/2006	7	10	$400	116	$14,846	$12,162	36	$5,468	$17,630
1/31/2006	7	11	$400	137	$17,804	$14,229	34	$5,147	$19,376
1/31/2006	7	12	$400	144	$18,986	$14,420	34	$5,118	$19,538
2/4/2006	23	1	$299	79	$3,271	$1,776	43	$2,130	$3,906
2/6/2006	18	7	$400 [5]	64	$7,209	$2,757	33	$0	$2,757
2/15/2006	23	1	$349	167	$14,435	$3,032	19	$1,848	$4,881
		Totals			$312,977	$141,999		$103,816	$245,814

[1] Net instructed energy costs excluding LSE-owned generation and energy provided under RMR contract path.

[2] Net uninstructed energy costs estimated based on estimated net generation deviation for generation units only by SC, including only SC's that do not serve significant load.

[3] Total net costs of $245,814 for Jan – Feb 15 include net instructed energy costs ($141,999) plus uninstructed energy costs ($103,816).

[4] These MCPs shown here are adjusted values. The original MCPs for these intervals were below $250/MWh. However, this was due to a software glitch associated with implementation of the new $400 soft-cap that prevented accepted bids at $400/MWh from setting the MCP. This glitch was corrected as of January 27, 2006.

[5] MCP over $250 in SP15 only.

Gas and Electric Price Trends

Since mid-December 2005, daily spot market gas prices have dropped from about $14/MMBtu to about $8/MMbtu in early January. Following implementation of the $400 soft cap, gas price have gradually dropped from about $8/MMBtu to about $7/MMBtu by mid-February. Due to the drop in gas prices since implementation of the $400 soft cap, it is necessary to account for these changes in gas price when comparing real-time energy prices before and after implementation of the $400 soft cap.

Figure 3 shows comparison of daily spot gas prices with weighted average daily prices for Instructed Energy in the CAISO's real-time market over this time period.[9] For this analysis, DMM normalized average daily real time energy prices based on the average daily spot market gas price over the first two weeks of January ($8.37/MMBtu), representing the two-week period just prior to and after implementation of the $400 soft cap.[10] Results of this normalization are shown in Figure 4.

As shown in Figure 5, this analysis shows a slight increase in average prices (after normalizing for changes in daily spot market gas prices) over the first two weeks the $400 cap was in effect, followed by a significant reduction in prices over the first two weeks in February. These trends are consistent with results summarized in Figure 2, which show that the bulk of additional costs due to prices in excess of $250 occurred during the last week of January, and that minimal additional costs have been incurred in the first two weeks of February.

Overall, gas-normalized prices for instructed energy averaged about $110/MWh in the month following implementation of the $400 soft cap, compared to $119/MWh in the two week period prior to the price cap change, as shown in Figure 5.

9 Average prices represent 5-minute MCPs weighted by the amount of incremental instructed energy dispatched each interval.

10 For example, if on another day the spot market gas price was $7/MMBtu and the quantity weighted average price for Instructed Energy was $100/MWh, then the adjusted average daily real-time price would be $120 ($100 x $8.37/$7)

Figure 3. Daily Spot Market Gas Prices and Average Daily ISO Instructed Energy Prices December 1, 2005 - February 15, 2006

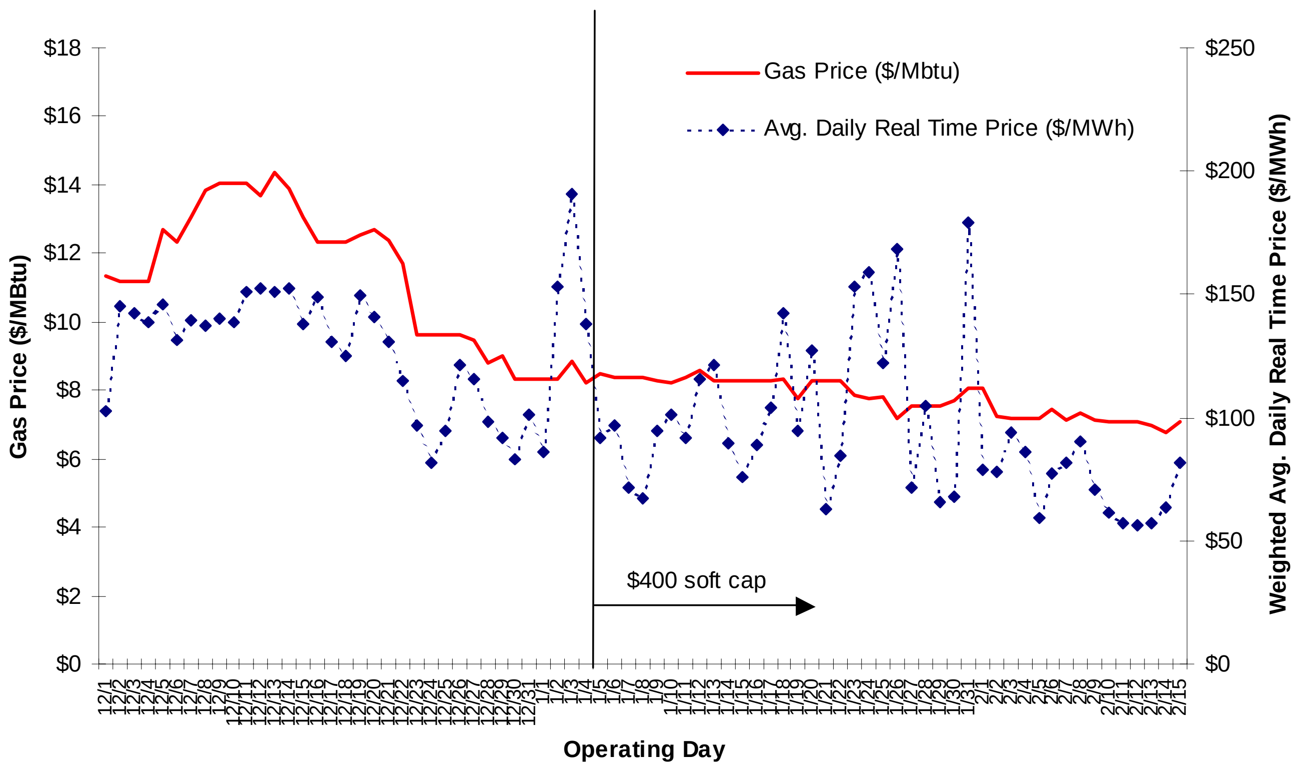


Figure 4. Average Daily ISO Instructed Energy Prices Normalized for Changes in Gas Prices December 1, 2005 - February 15, 2006

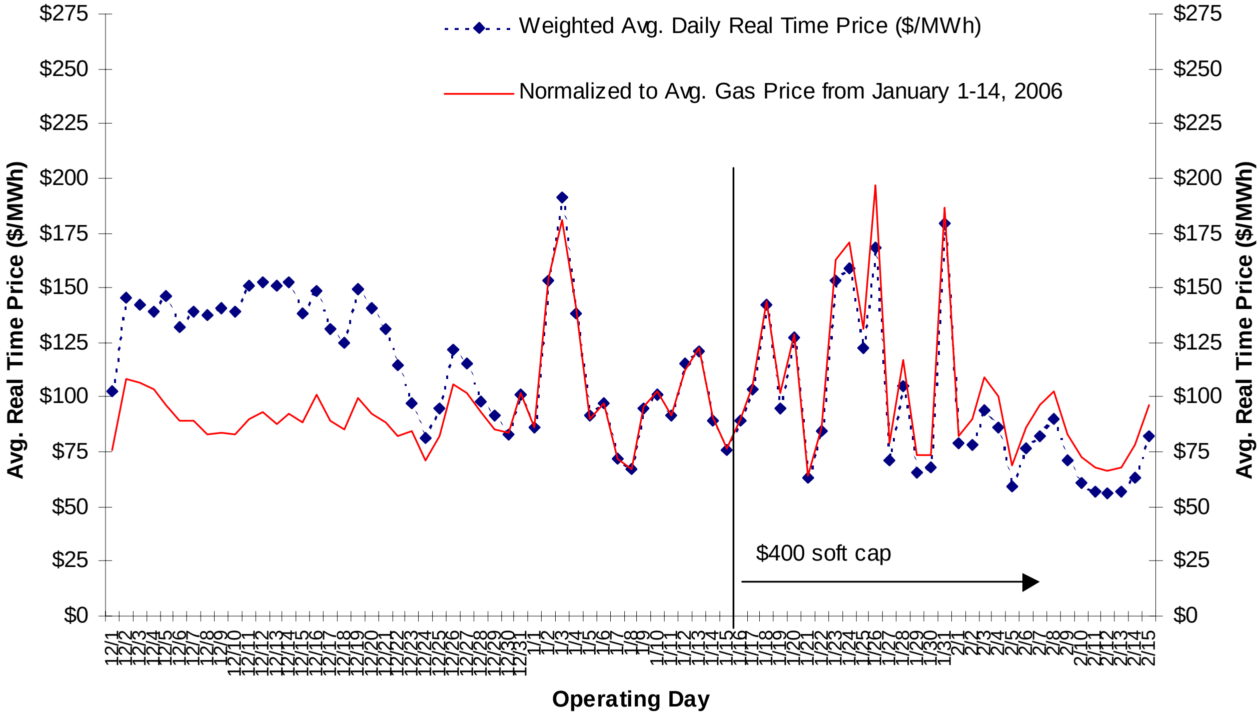
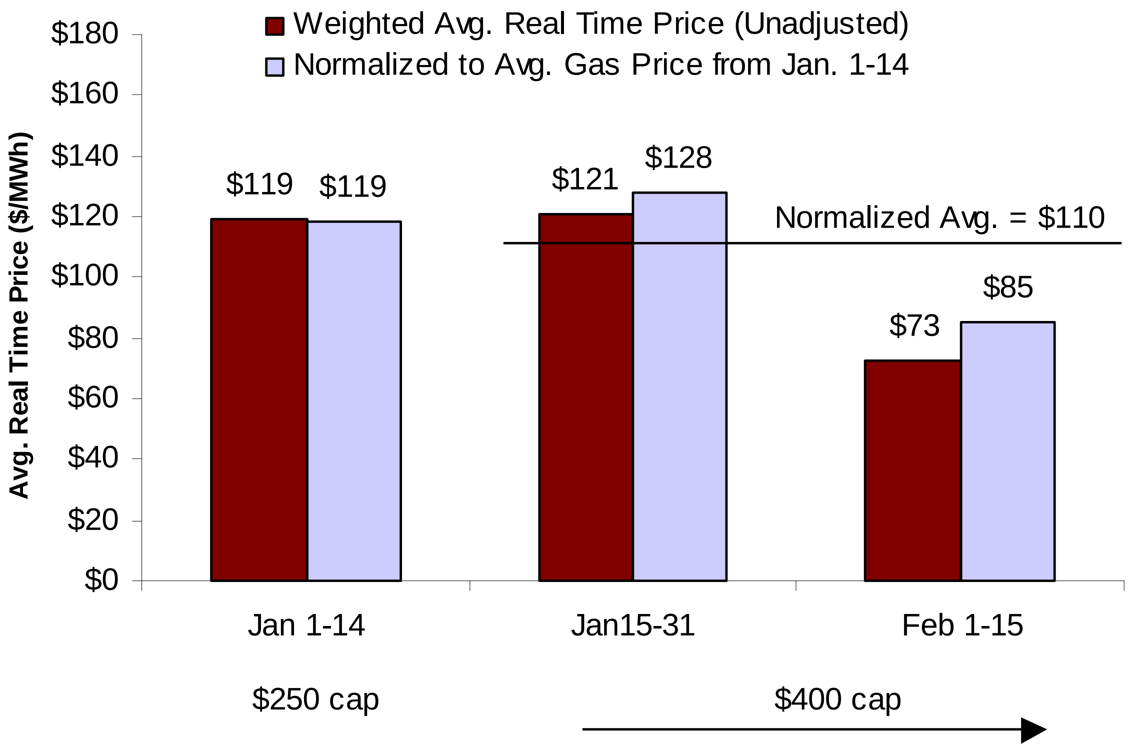


Figure 5. Average Daily ISO Instructed Energy Prices Before and After Implementation of $400 Soft Cap (With and Without Normalization for Change in Daily Gas Prices)



Illustrative Example of High Price during Morning Ramp

As previously shown in Figure 1, virtually all MCPs in excess of $250 have occurred during the morning and evening “ramping hours,” when relatively high prices frequently occur during intervals when the CAISO needs to dispatch resources quickly in order to balance relatively large swings in imbalance energy demand. Figure 6 provides a specific example of the various market conditions that combine to create this trend. This example shows real-time market dispatches and prices for the morning ramping hours on January 31, 2006, when prices hit the $400 cap for the last five (5) 5-minute intervals of Hour Ending 7.

During Hour Ending 7 of this day, system load increased from 24,039 MW to 26,710 MW – an increase of over 2,670 MW. The total hour-ahead schedule for this hour was 26,004 MW. Therefore, at the beginning of this hour the CAISO needed to decrement as much as 2,296 MW (Interval 2). For example, during this hour, 859 MW of decremental energy (exports) was pre-dispatched, while an additional 1,437 MW of dispatchable internal generation was decremented during the second 5-minute interval.

However, as load increased sharply over this hour, RTMA began incrementing internal generation by the sixth 5-mintue interval of this hour. By interval 7, RTMA had dispatched virtually all available incremental energy bids (subject to ramping limitations) so that a small volume of energy bid at the $400 cap was dispatched.

As shown in Figure 7, ramping limitations can severely reduce the supply of bids available for dispatch under such conditions. During the hour in this example, the load ramp was also exacerbated by the need to dispatch incremental generation in order to offset some out-of-sequence decremental dispatches for intra-zonal congestion.

The impact of ramping demand and ramping limitations on available supply is further illustrated in Figure 8, which compares total aggregate available supply and dispatches on a 5-minute basis for Hour Ending 7 on four consecutive days. As shown in Figure 8, over the period from January 30 to February 3, for Hour Ending 7, prices moderated after some $400 price spikes on January 31. This appears to be due in part to an increase in 5-minute dispatchable supply. DMM is conducting further analysis to assess the degree to which participants may respond to price spikes by offering additional or more flexible supply into the market. This illustrates the significant effect that even a small increase in available 5-minute supply can have on prices, and provides some evidence that additional 5-minute supply was made available on subsequent days in response to the $400 price spikes on January 31.

Figure 6. Real-time Dispatches and Market Clearing Prices January 31, 2006, Hour Ending 5-9

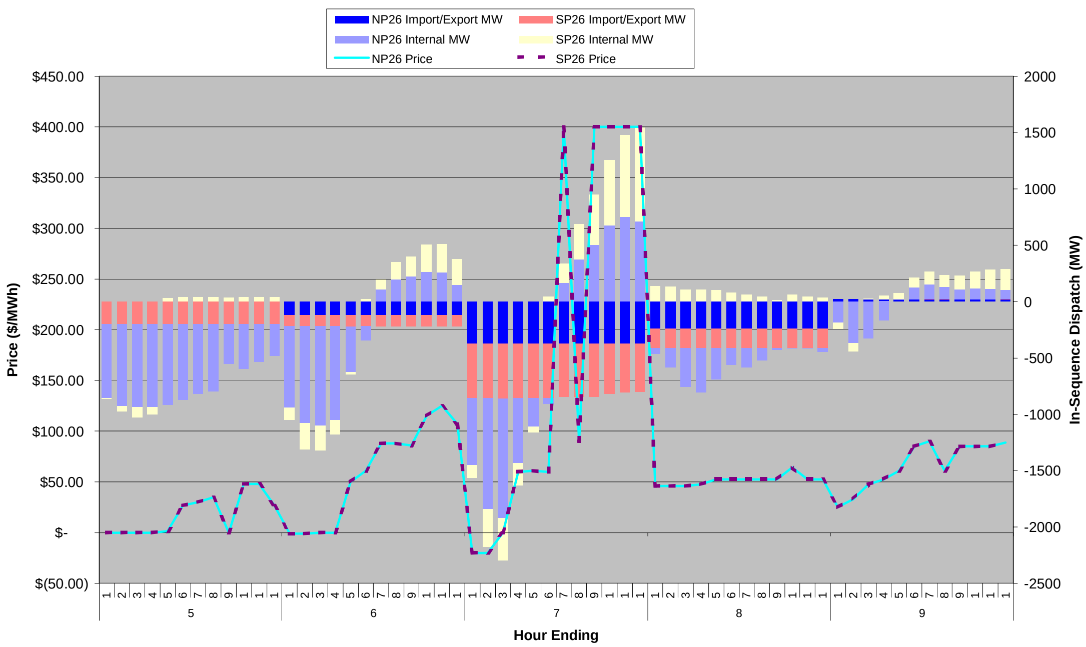


Figure 7. Constrained Incremental Bid Supply Curves for Intervals 9 and 11 January 31, 2006, Hour Ending 7

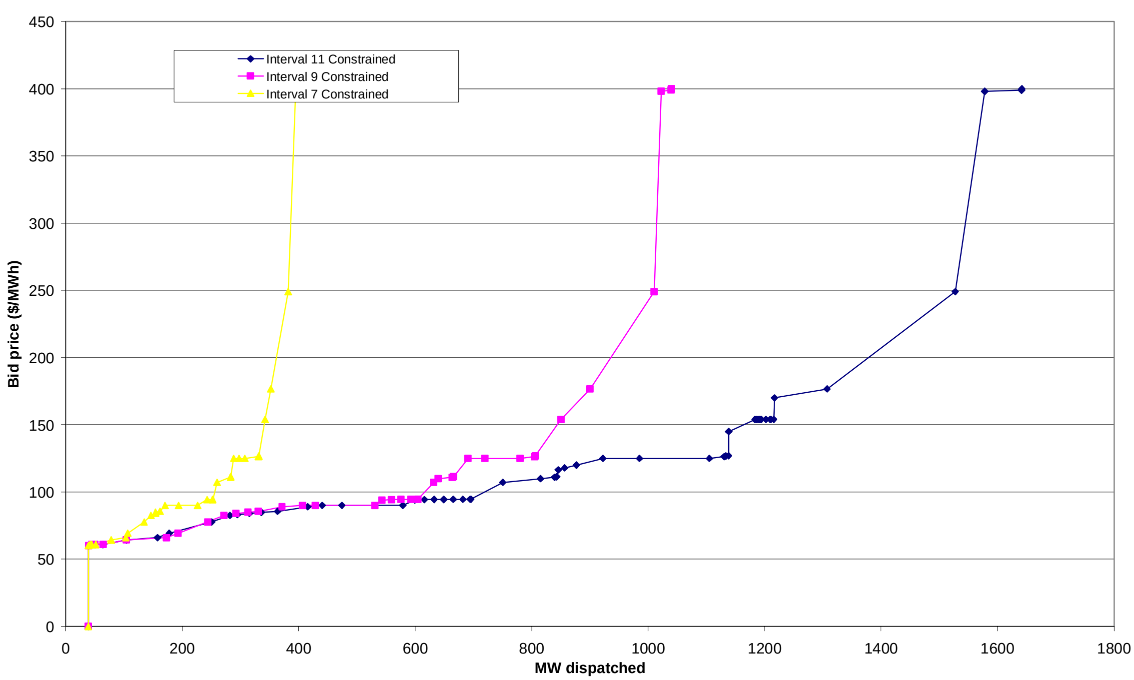
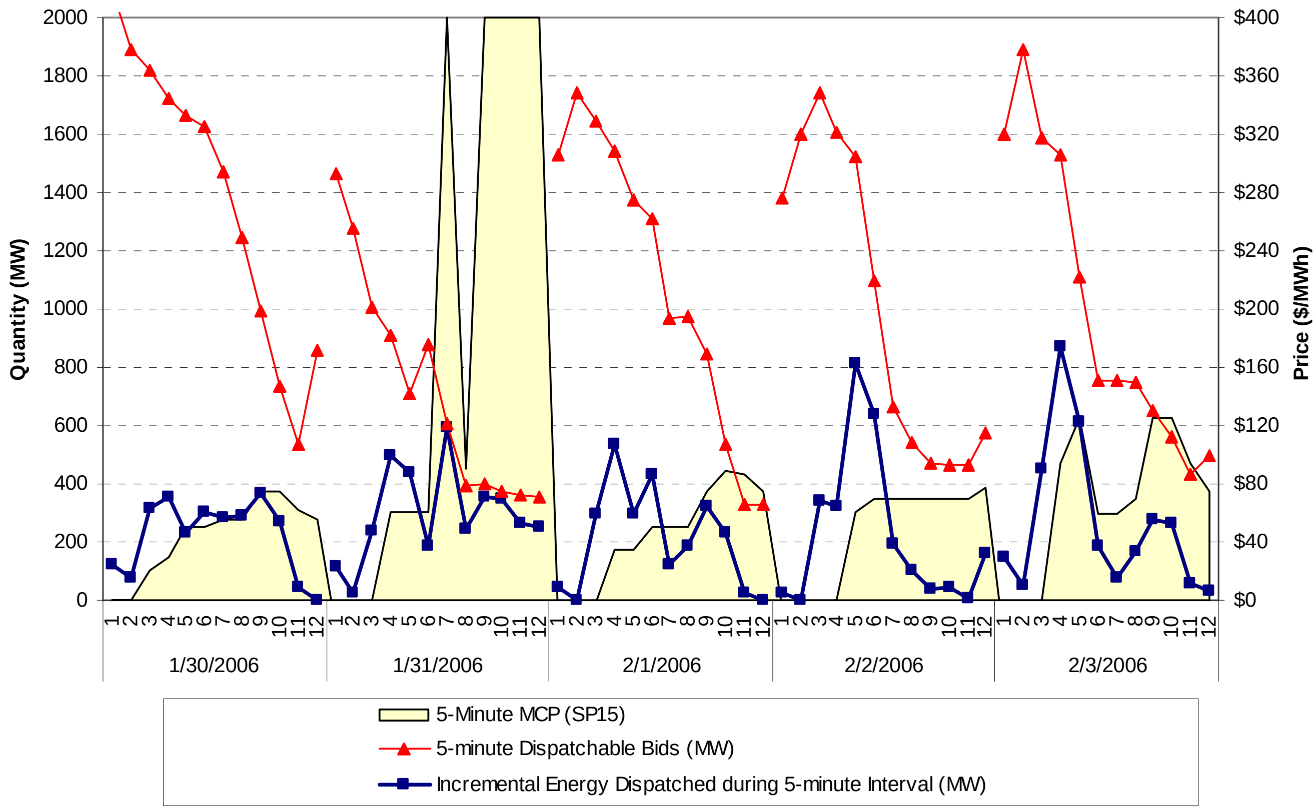


Figure 8. Ramp-limited Dispatchable Supply and Dispatches by 5-minute Interval during Hour Ending 7 (January 30 to February 3, 2006)



It should be noted that during such ramping hours, the CAISO does not dispatch fast start units (such as CTs) to meet such demand, since such demand for incremental energy only lasts a few intervals, compared to the minimum operating times of 1-2 hours for most fast start units. During ramping periods, the CAISO typically needs to incremental and then decrement generation over the course of an hour in order to balance system generation and load.

Assessment of Bids Over $250

Unit Heat Rates

DMM's recommendation for raising the bid cap to $400/MWh was based in part on a concern that if natural gas prices continued to rise, variable costs of some generation units could approach or exceed the previous cap of $250/MWh due to high natural gas prices. For example, at a gas price of $15/MMBtu, capacity with an incremental heat rate of 17,000 Btu/kWh would have a marginal cost over $250/MWh. Although the amount of capacity with heat rates in this range may be relatively small, the availability of this capacity could have a critical impact on reliability.

At the December 16, 2005 Board meeting, CAISO staff was asked how much gas-fired capacity within the CAISO system had a heat rate over 17,000 Btu/kWh. Staff indicated they did not have actual data on hand, but estimated that about 1,000 MW may have heat rates of at least 17,000 Btu/kWh. As a follow-up to this question, DMM calculated the amount of capacity with incremental heat rates of at least 17,000 Btu/kWh based on heat rate data filed by generators with the CAISO. Summary results of this are provided in Table 2.

Calculations in Table 2 are based on incremental heat rates, or the marginal amount of additional gas input needed to produce additional output of electricity from a unit.[11] Since incremental heat rates reflect the marginal fuel needed to produce additional output from unit, incremental heat rates are the measure of fuel efficiency most commonly used for economic dispatch of units in the electric utility industry.[12] Since the operating efficiency of units typically varies at different levels of output, different portions of the generating capacity of a single unit typically have different incremental heat rates. Thus, as reflected in Table 2, only a portion of an individual unit's maximum generating capacity may have an incremental heat rate over 17,000 Btu/kWh. In addition, as shown in Table 2, the amount of capacity with incremental heat rates over 17,000 Btu/kWh can also be calculated using the adjusted non-decreasing incremental heat rates used pursuant to the CAISO's tariff for purposes of calculating proxy bids and reference bid prices used in market power mitigation. A more detailed discussion of the rationale and calculation of non-decreasing incremental heat rates is provided below.

Incremental heat rates for different portions of an individual unit's output often decrease at lower levels of operation, and then increase at very high levels of output, reflecting how many units operate less efficiently at the very highest level of their maximum potential output. However, incremental heat rates can increase or decrease for different portions of a unit's output for a variety of reasons related to the specific technology of the unit. This is particularly true of combined cycle units, which have average and incremental heat rates

11 For example, if a unit has an average (or operating) heat rate of 9,000 Btu/KWh at an operating level of 100 MW, and has an average heat rate of 10,000 Btu/KWh at an operating level of 110 MW, the unit's incremental heat rate for the additional 10 MW capacity of increasing output from 100 MW to 110 MW is 20,000 Btu/kWh (110*10,000 – 100*9,000)/10).

12 A discussion of the calculation and use of heat rates is provided in *Power Generation Operation and Control*, Allen Ward and Bruce Wallenberg, p.8-17.

that can increase or decrease at different levels of output depending on the configuration under which the unit is operating.

While incremental heat rates for different portions of a unit's output may increase and decrease over the range of the unit's output, the CAISO requires that bids for different levels of incremental energy from any individual unit be monotonically non-decreasing, meaning that each additional portion of the unit's generating capacity must be bid at a price equal to or higher than bid prices for portions of the unit's generating capacity at lower operating levels. This requirement for non-decreasing bid prices from each unit is necessary so that when the CAISO real time market software dispatches incremental energy bids in economic merit order (or increasing order of price), each unit can provide the dispatched amount of energy by increasing output to the level associated with each bid. Due to the requirement that bid prices for increased output from each individual unit be monotonically non-decreasing, it may be necessary to adjust a unit's incremental heat rates to be non-decreasing (or monotonic) for purposes of calculating bid prices based on the marginal operating cost of each additional portion of a unit's generating capacity. Pursuant to the CAISO tariff, incremental heat rates are adjusted to be non-decreasing for purposes of calculating proxy bids and reference bid prices used in market power mitigation by setting the incremental heat rate for each segment of the unit's output to the higher of the segment's actual incremental heat rates, or the highest incremental heat rate for any previous segment of the unit's output.[13]

Table 2. Capacity with Incremental Heat Rates > 17,000 Btu/MWh

Type of Unit	Number of Units	Total Capacity (MW)	Portion of Capacity with Incremental Heat Rate > 17,000 Btu/kWh	Portion Capacity with Non-Decreasing Incremental Heat Rate > 17,000 Btu/kWh *
Combustion/Steam Turbine	9	428	201	335
Combined Cycle	6	2,335	43	779
Totals	15	2,763	244	1,113

As shown in Table 2, the amount of capacity with incremental heat rates over 17,000 Btu/kWh is approximately 244 MW, with over 200 MW of this representing capacity from relatively old combustion or steam turbines. Meanwhile, about 1,113 MW of capacity within the CAISO system have non-decreasing incremental heat rates of over 17,000 Btu/kWh, as calculated pursuant to the CAISO's tariff for purposes of calculating proxy bids and reference bid prices used in market power mitigation. Most of the capacity with non-decreasing incremental heat rates of over 17,000 Btu/kWh represents capacity from new combined cycle units, which have very low average heat rates when operating under ideal levels. Data are not currently available on the amount of capacity outside of the CAISO system that may have incremental heat rates in excess of 17,000 Btu/kWh.

Although a relatively small portion of generation within the CAISO system (and the WECC as whole) may have incremental heat rates in excess of 17,000 Btu/kWh, DMM notes that its recommendation to raise the

13 For example, if the incremental heat rate for increasing a 150 MW unit's output from 100 to 110 MW is 20,000 Btu/kWh, but the incremental heat rate for the rest of the unit's output is 12,000 Btu/kWh, then the monotonically non-decreasing incremental heat rate for the unit's output from 110 MW to 150 MW would be 20,000 Btu/kWh.

$250 cap did not hinge on the amount of generation that may actually have such high heat rates. As noted in the DMM's December 9, 2005, memo, DMM's recommendation was based on a range of considerations in addition to the concern that if natural gas prices continued to rise, variable costs of some generation units could approach or exceed the previous cap of $250/MWh due to high natural gas prices. In addition, DMM notes that under some conditions heat rates and daily spot gas prices can represent only a sub-set of the cost components and considerations that may actually go into whether capacity would be offered at a $250 soft cap level. For instance, generators with units that are off-line may include start-up costs and costs of continuing to operate at minimum generation level over their minimum run times when determining prices at which they are willing to offer or operate this capacity on a 5-minute dispatchable basis, as is required in the CAISO's imbalance energy market. In other cases, gas imbalance charges or other operating constraints may also increase the price at which generators are willing to offer or operate relatively high cost capacity.

Bids Over $250

Since the price cap was raised to $400, a relatively small portion of total capacity has been bid at a price in excess of $250. As shown in Figure 9, during peak weekday hours since the cap was raised to $400, an average of about 650 MW has been bid at prices in excess of $250 – representing about 14% of total incremental energy bids. In the first two weeks of January when the $250 soft cap was in effect, an average of about 430 MW was bid at prices in excess of $250. Review by DMM indicates that the decrease in total amount of incremental energy bids from resources within the CAISO system during January is not due to the increase in the price cap, and is instead due to a drop in the unloaded capacity of on-line thermal resources subject to the must-offer requirement.

Table 3 shows the total market share of incremental energy bids during hours when the MCPs in excess of $250 have occurred. As shown in Table 3, a total of about 38% of total bids during these hours are from capacity that is either owned by major LSEs, or submitted under the "contract path" option of the RMR contract. Under the RMR contract path, generation owners ultimately get paid only for variable operating costs, with any additional market revenues being credited back to the responsible Transmission Owner (e.g., PG&E, SCE or SDG&E).

As discussed in the previous section of this memo, bids in excess of $250 have been dispatched during a relatively few 5-minute intervals when the CAISO has needed to dispatch resources quickly in order to balance relatively large swings in imbalance energy demand, so that the available supply is constrained over a very short-term basis by the ramping capability of various resources.

Figure 9. Incremental Energy Bid Prices
Before and After Change in Soft Cap
Weekdays, Peak Hours 7-22

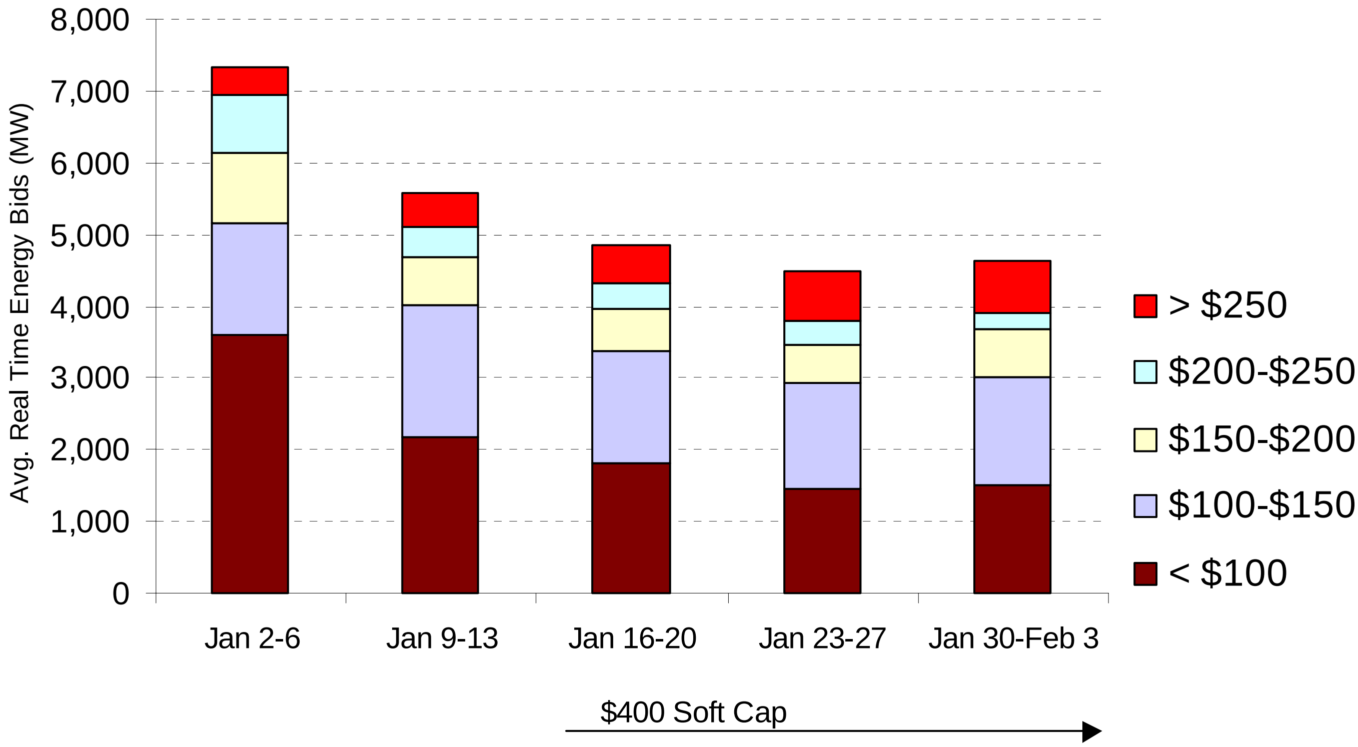


Table 3. Market Share of Incremental Energy Bids during Hours with MCPs > $250
January 15-February 15, 2006

Type	Avg. MW Bid	Share of Total
Non-LSE generators	2,798	57%
Non-LSE generation under RMR Contact Path	1,033	21%
Major LSEs (IOUs)	809	16%
Municipal Entities	220	4%
Other	73	1%
Total	4,933 MW	

Review of bidding patterns and discussion with suppliers by DMM indicates that bids in excess of $250 are often submitted for a variety of reasons other than marginal costs (as calculated based on incremental heat rates). Some of these reasons include the following:

- Resources with limited run times or limited energy (such as hydro-based or dispatchable load) may bid relatively high to avoid being dispatched and/or to ensure they only get dispatched during high priced periods.

- Combustion turbines that are off-line and would incur start-up costs in order to respond to a dispatch instruction for real-time energy from the CAISO may bid relatively high to avoid being dispatched and/or to ensure they only get dispatched during high priced periods.

- Combined cycle units can have operating constraints associated with changes in configuration (e.g., from a 1x1 to a 2x1 configuration) that are not currently modeled or captured in CAISO dispatch software and settlement rules. For example, during hours when combined cycle units are already operating at the upper range of a generating configuration, any incremental increase in output would require the unit to change to another configuration. An owner may not want to change to this configuration for a real-time dispatch that may only be issued for a relatively short period of time.

- During the morning and evening ramping hours, some units may need to ramp up or down at or near their limits in order to meet changes in their own hourly schedules. Under such conditions, unit owners may seek to avoid additional ramping in response to real-time dispatch instructions by bidding into the real-time market at relatively high prices.

Benefits of Higher Price Cap

Although extremely high spot market gas prices have not materialized so far this winter, DMM continues to believe that on balance increasing the real-time energy market cap from $250/MWh to $400/MWh will provide several significant benefits to the California energy markets. In the short term, the high cap provides continued insurance against gas price spikes or supply disruptions this winter. In addition, DMM expects that a higher bid cap will result in greater reliability given the tight supply margins forecast for next summer in a variety of ways, which include:

1. Providing 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 critical peak load hours.
2. Establishing 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. Promoting 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.
4. Ensuring that non-participating suppliers, particularly importers, are not discouraged from selling into the California real-time energy market by the regulatory uncertainty of receiving full cost recovery for accepted bids above $250/MWh.
5. Providing a greater incentive to internal suppliers with options of selling their output to external load through the western bilateral short-term energy markets to instead provide real-time energy bids to the CAISO.
6. Provide greater incentives for the LSEs to continue to minimize their spot market exposure by signing additional long-term power contracts.
7. Providing a more measured transition to the $500/MWh energy bid cap scheduled to be invoked with the California ISO's new market design in November 2007.

DMM believes that these various reliability benefits outweigh any additional costs associated with raising the cap from $250 to $400.