California Independent
System Operator Corporation

Memorandum

To: ISO Operations Committee

From: Keith Casey, Director, Market Monitoring

CC: ISO Board of Governors, ISO Officers

Date: June 7, 2006

Re: Market Monitoring Report

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

EXECUTIVE SUMMARY

This month's Market Monitoring Report provides a brief update on DMM activities over the last month and provides a detailed assessment of several key market trends and issues. Overall spot market prices during April and May have been very low in the CAISO and throughout the West due to an abundance of hydroelectric and other generation sources, combined with relatively low loads. During April, for instance, real time energy prices averaged only about $28/MWh, or 33% lower than April of last year, compared to a decrease in spot market gas prices of less than 10% relative to April of last year. Ironically, however, the same conditions that contributed to low overall spot market energy prices have also created a number of temporary reliability and market issues. For example, due to relatively low overall prices and high hydro conditions, the supply of fast ramping and regulation capacity has been very thin during ramping and off-peak hours, leading to sporadic price spikes in the real time energy and regulation markets. In addition, the abundance of surplus generation from hydro resources and minimum load energy from thermal units – combined with congestion into SP15 – has caused the CAISO to export large volumes of energy from NP15 at relatively low decremental energy bid prices through the real time pre-dispatch process. Thus, while overall spot market costs have been very low, the need to manage the reliability problems associated with overgeneration in the real time market has created some additional costs for the CAISO system.

MARKET MONITORING HIGHLIGHTS

Some of the major activities that DMM has been involved in over the past two months include the following:

- *Presentations to FERC* – In April, DMM Staff presented its 2005 Annual Report on Market Issues and Performance to FERC Staff in Washington D.C. In May, DMM Staff attended the Semi-annual Market Monitor's Meeting at FERC and participated in a panel discussion at the May 18 Commission meeting on the topic of the role of market monitors.
- *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.
- *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 and is expected to have an initial study completed for stakeholder review by September 2006.

- *Sporadic Price Spikes during Ramping and Off-Peak Hours* – While overall spot market prices have been relatively low, periodic price spikes above $250/MWh continue to occur in the real time energy market, and occurred in the regulation market for the first time during one week in April. However, these price spikes continue to be limited in duration and occur primarily in the ramping and off-peak hours when the balance of supply and demand for ramping and regulation capacity is limited. A detailed analysis of these price spikes is provided in later sections of this memo.
- *Compliance with Amendment 72* – As described in last month's Market Monitoring Report, DMM has been gradually increasing enforcement of reporting requirements established under Amendment 72, under which LSE's must provide the CAISO with Day Ahead load forecasts and weekly summary reports comparing their Day Ahead forecast to their scheduled and estimated actual load. On April 12, DMM issued another Market Notice indicating that the CAISO would begin to issue penalties for failure to submit forecast data starting with Trade Date May 16. During the first two weeks following this May 16 Market Notice, all LSEs appear to have complied with both daily and weekly reporting requirements. As indicated in the CAISO's Amendment 72 filing and subsequent communications with market participants, while the CAISO tariff does not contain any penalty provisions for SC's that do not schedule 95% of forecasted load, the CAISO provides data on load forecast and schedules to FERC's Office of Enforcement on a routine basis, and FERC may have the authority to sanction any failure to comply with the 95% scheduling requirement.
- *Summer 2006 Operating Plan for Southern California* – DMM has been providing comments on the operating plans being developed by CAISO Planning staff for Southern California this summer. DMM's major comment on the proposed plan is that procedures for addressing the single largest contingency should be closely and explicitly integrated with the Day Ahead Must-Offer Waiver (MOW) denial process. Until MRTU is implemented, the Must-Offer Waiver denial process will remain the CAISO's key mechanism for ensuring that sufficient capacity is on-line and committed for operation to meet various system and local reliability requirements. Should the total amount of capacity committed through the day-ahead preferred market be insufficient to meet various identified 20-minute reliability criteria the MOW process can and should be used to commit any additional resources needed to meet these requirements. DMM believes that whether such additional commitments should also be supplemented with zonal procurement of A/S (or 10-minute Operating Reserve) is a separate issue from the issue of whether or how the CAISO ensures that sufficient capacity is on-line to meet various other reliability requirements, such as the type of 20-minute contingencies identified in the CAISO's Summer 2006 Operating Plan for Southern California. While materials developed and released by CAISO Planning staff have helped to clarify reliability requirements and related operating practices, DMM believes additional clarity and transparency is warranted. A more detailed discussion of this issue is provided below.

Real Time Market Performance – April 2006

Price Spikes

Overall prices for spot market energy in the CAISO and throughout the west were very low in April due to moderate loads and an abundance of hydroelectric power and minimum load energy of thermal units on-line for reliability and peak load requirements. However, these same conditions also contributed to a moderate increase in periodic real time energy price spikes above $250 during the morning and evening ramping hours when the balance of supply and demand for ramping energy is extremely tight.

Figure 1 shows the number and percentage of 5-minute intervals in which 5-minute real time prices exceeded $250 since the soft bid cap was raised from $250 to $400 on January 14, 2006. As shown in Figure 1, the number of 5-minute intervals in which real time prices exceeded $250 has increased over the last two months, but equaled only about 1% of all

intervals in April. As shown in Figures 2 through 4, these price spikes continue to occur primarily in the morning and evening ramping hours when both loads and generation are increasing or decreasing sharply.

Figure 1 Number and Percentage of 5-minute Intervals with MCP over $250

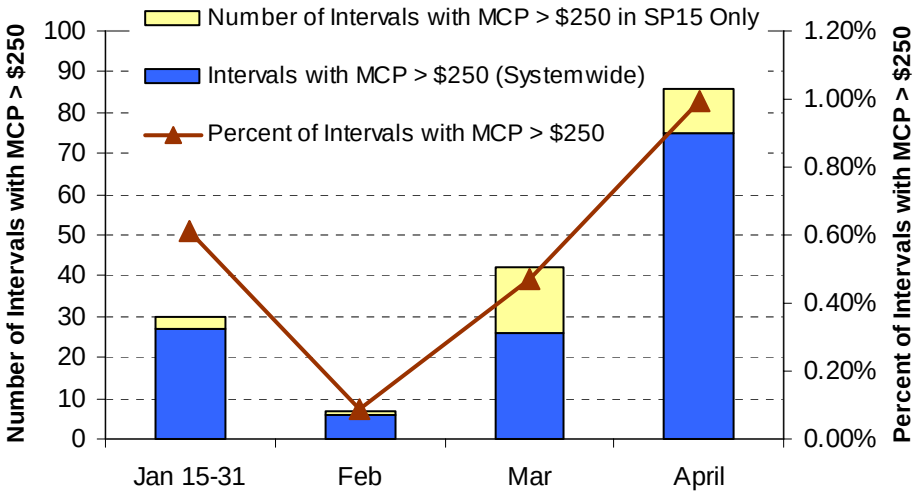


Table 1 provides the estimated market impacts of price spikes over $250 in the real time market. [1] As shown in Table 1, total net costs to Load Serving Entities (LSEs) due to MCP over $250 from January through April are estimated at about $1.3 million, or about 2.3% of total cost of Instructed Incremental Energy during this period.

Table 1. Estimated Market Impact of MCPs over $250

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

* Net-costs include estimated uninstructed generation and excludes energy provided by resources owned or under contract to LSEs. Estimated costs do not account for the fact that in some cases, if prices 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 somewhat overestimate the impact of the higher bid cap. Estimates that include impact on uplift payments will be included in the July Board report.

[1] As noted in our previous March 2 memo and Board report, it is important to note that the actual cost impact of the higher bid cap cannot be determined since this 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.

Figure 2 Number of 5-minute Intervals with MCP Over $250 (Jan. 15-Feb. 2006)

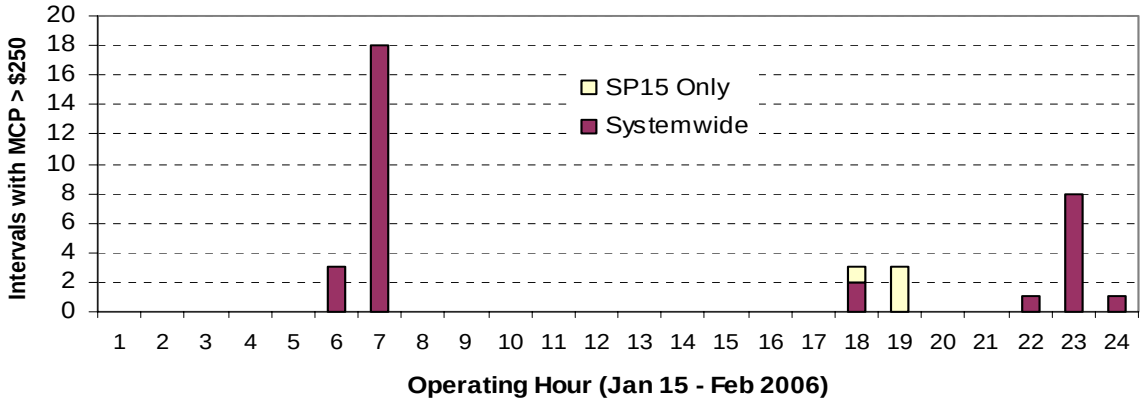


Figure 3 Number of 5-minute Intervals with MCP Over $250 (Mar. 2006)

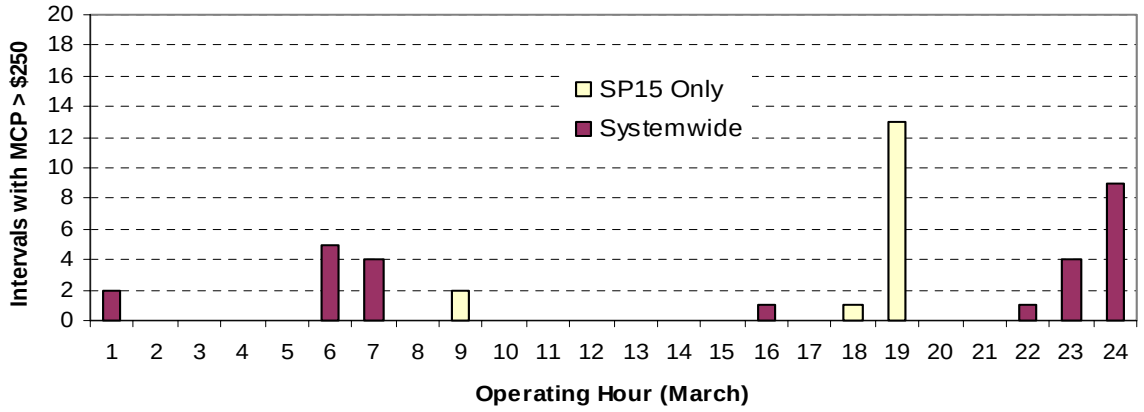
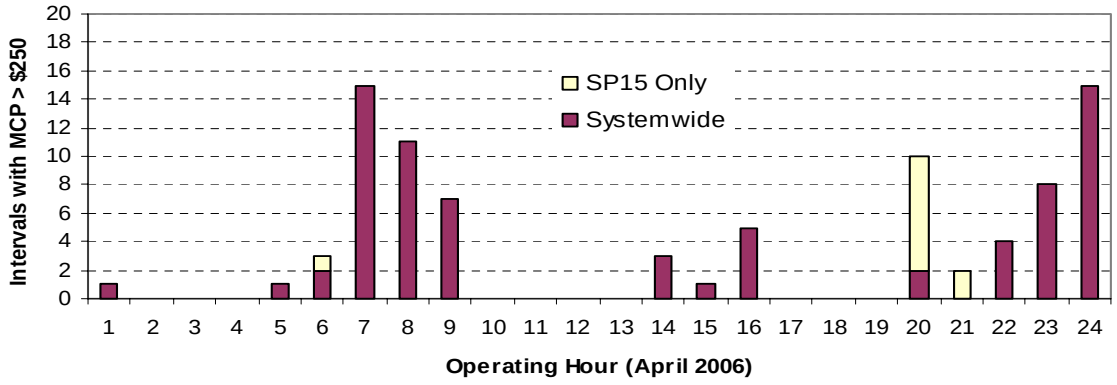
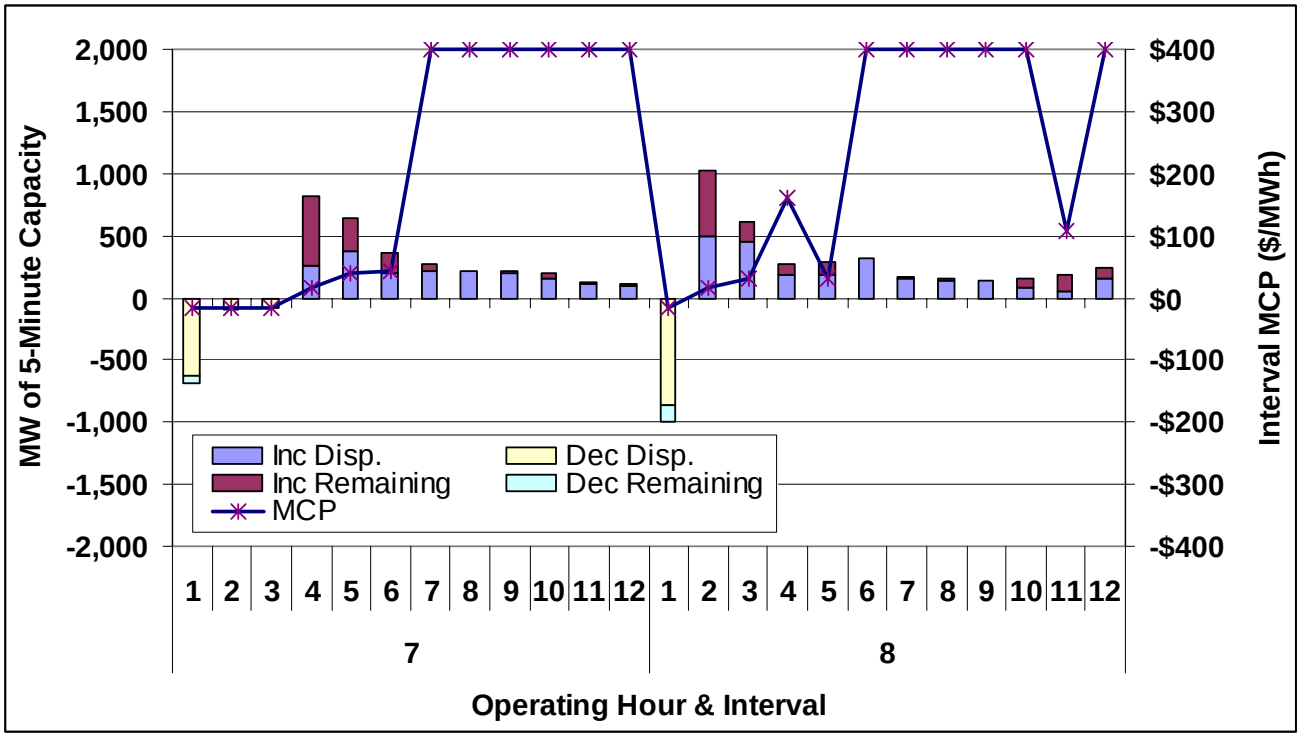


Figure 4 Number of 5-minute Intervals with MCP Over $250 (Apr. 2006)



Price spikes in the Real Time Market are most often the result of limited available 5-minute ramping energy and high bid prices during (generally) brief periods where the CAISO needs to dispatch increasing amounts of energy in real time to match or catch the load ramp. A closer look at individual 5-minute intervals for a particular day (April 24) provides a better perspective on the relationship between available 5-minute ramp-constrained capacity and interval MCPs, as seen below in Figure 5.

Figure 5 Available and Dispatched Five-minute Ramping Capacity with Interval MCP - April 24th



Two hours are depicted in Figure 5, HE 7 and HE 8, showing the relationship between available 5-minute ramp-constrained capacity and the interval MCP. These hours together illustrate (a) how price can increase dramatically when supplies of ramp-constrained capacity become tight, even when the dispatch quantity is relatively small (HE 7 Intervals 7 - 12 and HE 8 Intervals 6 - 9) and (b) how price can decrease dramatically when the CAISO shifts from incrementing internal generation to decrementing internal generation across intervals (HE 7 Interval 12 - HE 8 Interval 1).

Summary of Market Participant Comments on 5-minute Dispatch

On April 5, 2006, the CAISO issued a Market Notice requesting comments from Market Participants on RTMA's five-minute dispatch feature in response to observed bid insufficiency.

Only a few Market Participants responded, however, the comments submitted highlight issues that have been problematic with real time imbalance dispatch. Some of these comments address the dispatch of Combined Cycle units and express issues that may be somewhat exacerbated by, but are not unique to, a five-minute dispatch:

- Dispatches in and out of duct firing range pose technical problems.
- Dispatches into forbidden ranges are impossible for the resource to respond to accurately.
- Generators cannot easily bid accurate monotonically-increasing incremental cost curves that reflect cost differences between resource configurations. These units' monotonically increasing supply cost curves are fairly flat over certain ranges (especially between configurations due to the application of monotonicity), so whenever these units bid near their monotonic non-decreasing cost curve they can be dispatched across a wide output range along the flat portion of the bid curve across resource configurations. With five-minute dispatch, this can occur more than once within an hour.

An additional comment supplied specifically addresses the five-minute dispatch issue of increased dispatch volatility that results in resources being dispatched up and down more frequently within an operating hour. The argument was made that this increased dispatch volatility provides a disincentive to supply real-time energy, as it may cause thermal resources to impose additional operating restrictions on their units and/or increase bid prices (to cover increased wear and tear on resources), which would subsequently increase the cost of procuring energy in real time.

In addition to the increased dispatch volatility, another issue directly related to the five-minute dispatch timeframe is the short window for communication between the CAISO and Market Participant and dispatch action taken by the Market Participant. For resources that require some manual intervention in the execution of dispatch instructions, the time delays required for the necessary steps, (1) the CAISO ADS signal, (2) the central dispatch interpretation, (3) the phone notification to the appropriate area operator, and (4) the actual set-point adjustment and unit re-dispatch, can approach 5 minutes, and often must be repeated every 5 minutes. Operators of these resources may have responsibilities beyond the resource output management that make manually executing dispatch instructions up to twelve times an hour difficult.

Another comment was made suggesting that schedules be staggered throughout the hour (rather than all conform to the standard ramping schedule of ten minutes before to ten minutes after the hour), which would help alleviate the sharp imbalances between generally smooth load ramps and flat hourly generation contract blocks. This, in turn, would alleviate some of the insufficiency seen in the supply of five-minute ramping energy in the five-minute dispatch intervals where this difference between schedules and load is more pronounced.

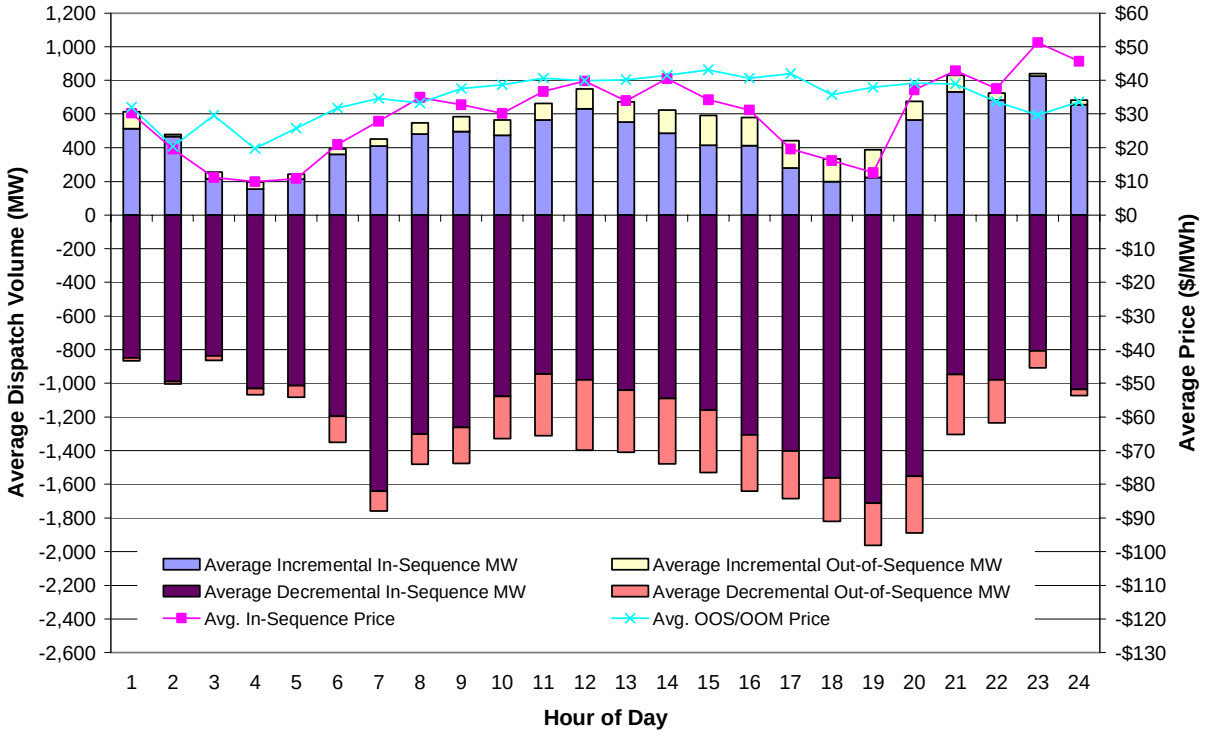
Finally, a comment was submitted suggesting that the efficiency gains from the RTMA five-minute dispatch compared to using regulation energy more heavily to meet imbalance needs may compromise reliability given the problem with insufficient supply of five-minute ramping energy and may in fact impose additional cost to load to the extent additional procurement of regulation is required to cover the insufficiency of five-minute ramping energy.

Virtually all of the comments on RTMA received from participants involve market design and software issues that would need to be considered and prioritized in the context of MRTU and other overall market design efforts. For example, MRTU software is being designed to allow more accurate modeling of the operational limits and characteristics of combined cycle units (albeit to a limited extent in that the full configuration features and limitations of combined cycle units will not be modeled) and other resources. These enhancements may reduce problems with dispatch instructions issued by the RTMA software cited by market participants. The CAISO's Market and Product Development (MPD) has indicated that other comments – such as the suggestion to stagger ramping of resources – will be taken into consideration in future market design processes.

Causes of High Decremental Energy Dispatches

Scheduling coordinators have generally scheduled generation in excess of load in the last few months, and especially in April. This over-scheduling of load – combined with positive uninstructed generation from hydro resources, QFs, wind and thermal units operating at minimum load – has caused the CAISO to dispatch generation and imports predominantly in the decremental direction. The relatively low average prices, particularly in early morning hours, reflect a strong supply condition, consisting primarily of hydroelectric energy in California and the Pacific Northwest. The low loads and strong supply often results in near-zero or even negative prices for real-time energy, indicating a lost opportunity to store potential energy until it is needed. Figure 6 provides an hourly profile of net real-time dispatch volumes, both in and out of sequence, and average prices, for the month of April.

Figure 6 Hourly Profile of ISO Average Incremental and Decremental Dispatch and Price, April 2006



The strong Pacific Northwest hydroelectric production coupled with frequent transmission congestion into Northern California has resulted in energy prices in that region that are well below those in NP15 for much of the spring. Figure 7 shows pre-dispatched export volumes in several negative price categories, compared to the difference between the COB and NP15 day-ahead bilateral prices for hourly contracts.[2]

System conditions this spring have also resulted in an unusual and high degree of loop flow mitigation. Unscheduled counter-clockwise loop flows have been congesting Path 26 this year. This is a physical phenomenon due in part to the unusually high hydroelectric production in Northern California and the Pacific Northwest this year, coupled with the fact that California's grid is primarily a 500-kV standard, while the Eastern half of the Western Interconnection is primarily a 345-kV standard.

RTMA's optimization algorithm seeks to manage the real-time imbalance using a least-cost dispatch. To this end, it has been dispatching unusually high volumes of exports from NP26 to the Pacific Northwest, which occur prior to the hour of operation since exports are not dispatchable in five-minute intervals. Because the algorithm does not model loop flow, operators must set the Path 26 limit in RTMA below the physical flow capacity of the path when they anticipate loop flow. In doing so, the additional Path 26 capacity (i.e., the difference between the imposed limit and actual flow capability) is available to accommodate loop flow. This mitigation procedure applies both during the pre-dispatch process and in real time, and can result in RTMA selecting large pre-dispatch export volumes to match its zonal load forecasts.

In addition, pre-dispatch imports into Southern California are constrained by the Southern California Import Transmission Nomogram (SCIT), a physical limit on the instantaneous importation of power into the Los Angeles basin. Because of this constraint, much of the SP15 balancing energy must be provided by internal resources, which are five-minute dispatchable. However, manual intervention is necessary to ensure that only SCIT-resolving resources are dispatched, as resources outside the Los Angeles basin cannot help to balance the system when SCIT is binding.

Because actual system conditions can and typically do vary from the anticipated conditions that the loop flow mitigation actions are based on, Path 26 often remains partially unloaded in real time. As a result, NP15 internal resources can be used for incremental real-time balancing – including addressing incremental energy needs in the South, which helps to decrease the likelihood of SP26 price spikes.

In summary, the loop flow mitigation process, which is an important and necessary reliability tool, often results in extraordinarily large decremental (export) pre-dispatches from NP15 that is followed by incremental five-minute dispatches within both NP15 and SP15. Figure 8 shows an example of this dispatch pattern, for April 6, 2006. The pattern was especially prominent in Hours Ending 11:00 to 15:00 (10:00 a.m. to 3:00 p.m.). The dark blue and coral regions are hourly blocks of pre-dispatched exports and imports, while the light purple and yellow regions are five-minute internal dispatches.

[2] Source of bilateral prices: Powerdex Hourly Indexes, www.powerdexindexes.com

Figure 7 Pre-dispatch of Inter-tie Bids by Price Bin for April 2006

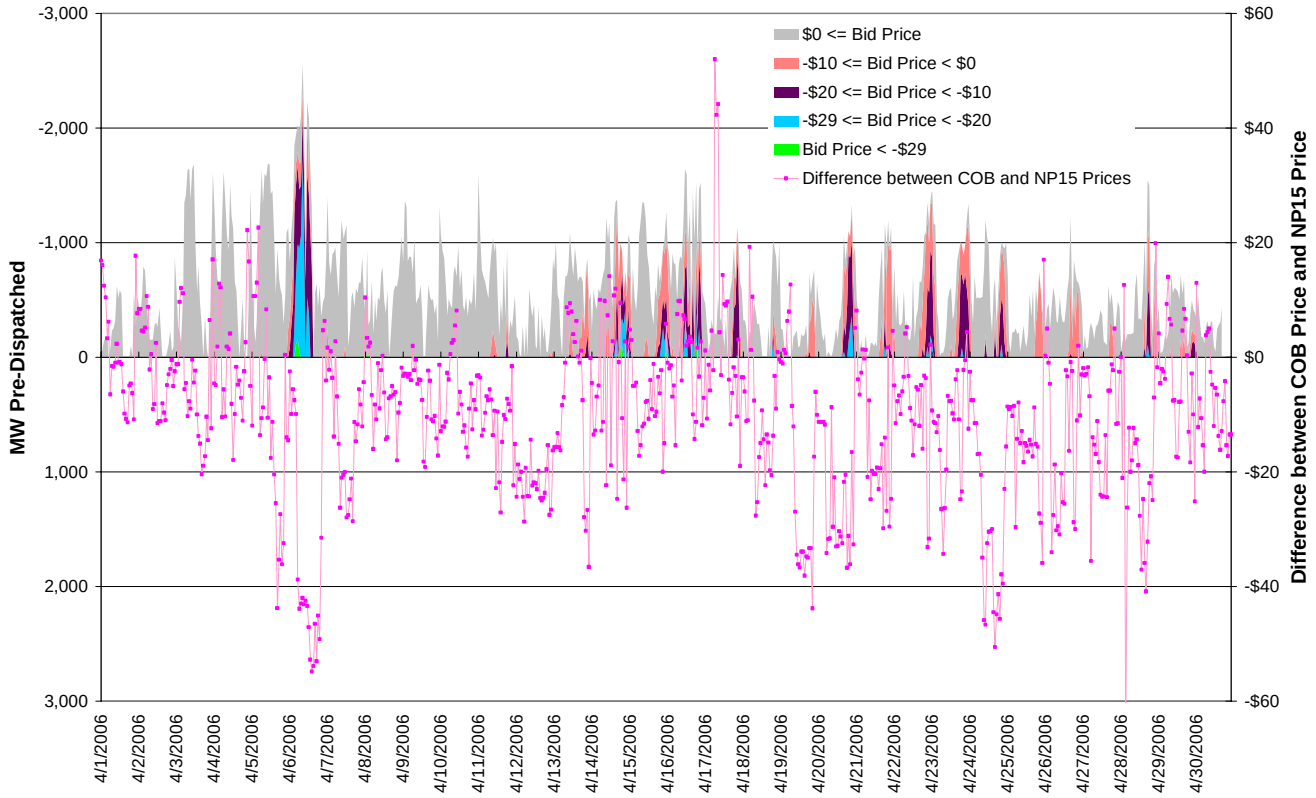
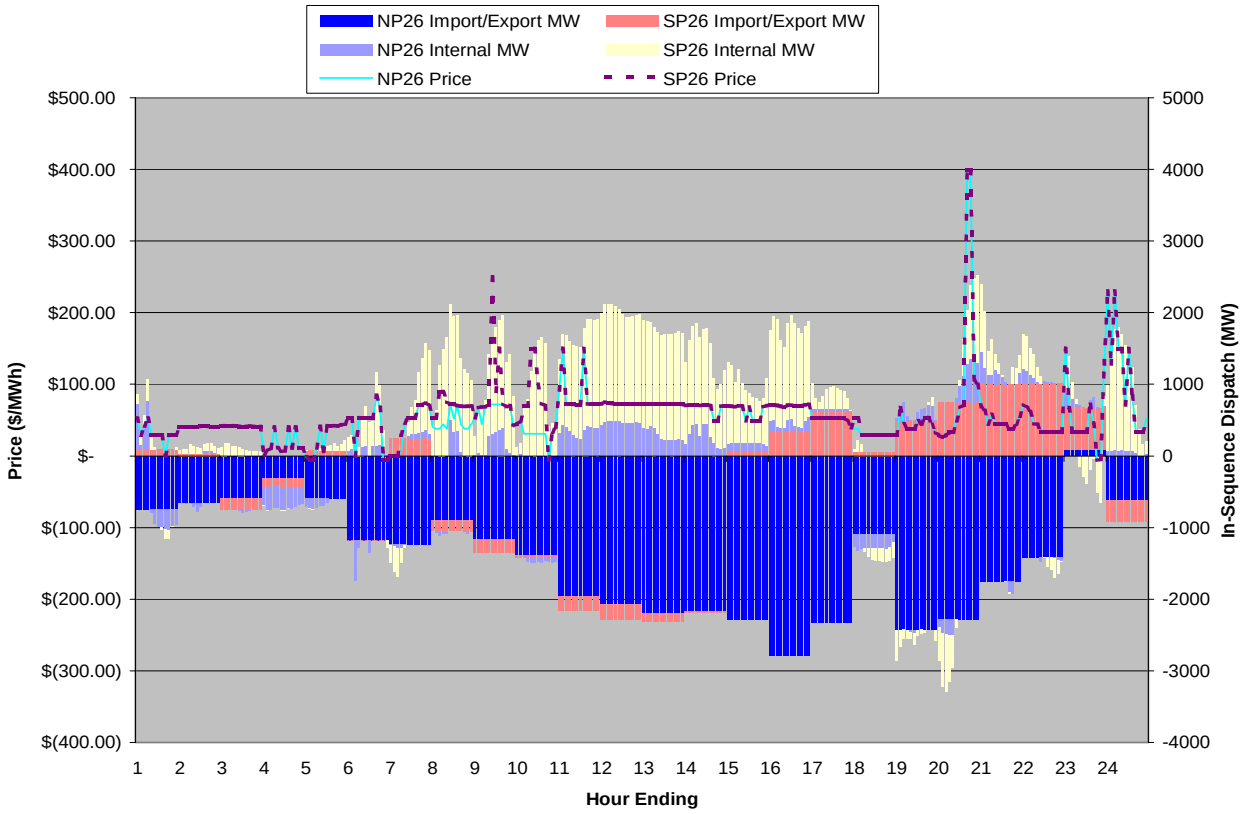


Figure 8 Time Pre-dispatch and Internal Dispatch, April 6, 2006

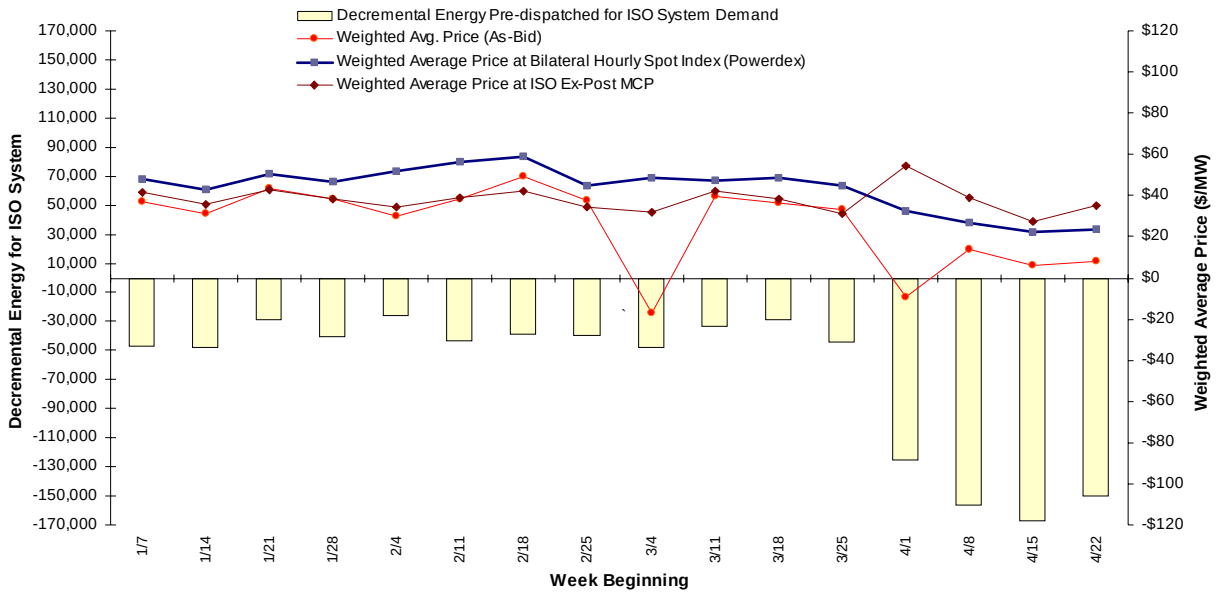


Revenue Imbalance Created by Divergence in Pre-Dispatch Bid Prices and Ex Post MCP

Volumes of pre-dispatched export bids approximately tripled in April compared to levels in recent months. In addition, prices for pre-dispatched exports have diverged well below the real-time market clearing price at which 5-minute dispatchable resources within the CAISO system are settled, as shown in Figure 9 below. Figure 9, which is based on weekly reports filed with FERC and posted on the CAISO website pursuant to Amendment 66, shows weekly total pre-dispatched export energy, the average actual cost of that energy based upon export bid prices (denoted by the red line), and the average cost had that energy been priced at the day-ahead bilateral price (denoted by the blue line) or real-time market-clearing price (denoted by the brown line).

The two trends highlighted in Figure 9 – high volumes of pre-dispatched exports at prices lower than the real time price paid for instructed and uninstructed energy within the CAISO system – create an imbalance in real time energy payments made and received by the CAISO that is ultimately allocated to LSEs based on their share of total CAISO load under the Charge Code 1401.[3] In effect, this revenue imbalance is created when pre-dispatched energy is exported at relatively low prices, but instructed and uninstructed energy within the CAISO system is paid a higher real time MCP (or bid price for OOS energy).

Figure 9 Price Divergence Between Real Time Pre-dispatch and Five-Minute Dispatch (January – April 2006)



[3] See *http://www.caiso.com/docs/2004/06/03/2004060313532329422.pdf.*

Table 2 shows the approximate magnitude of this potential revenue imbalance during April based on the volumes of pre-dispatched exports, and the difference between prices charged for pre-dispatched exports and market clearing prices paid for imbalance energy from resources within the CAISO system. As shown in Table 2, the potential magnitude of the revenue imbalance created by these trends to be recovered from participants under the 1401 Charge Code may be nearly $20 million, or over $1/MWh of total system load, in April. It should be noted that from the perspective of some LSEs, a significant portion of potential 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). DMM also notes that all information necessary to identify these potential costs is made publicly available on the CAISO website (i.e., information on hourly pre-dispatch quantities, weighted average pre-dispatch prices, and real time MCPs).

Table 2. Potential Real Time Energy Revenue Imbalance (April 2006)

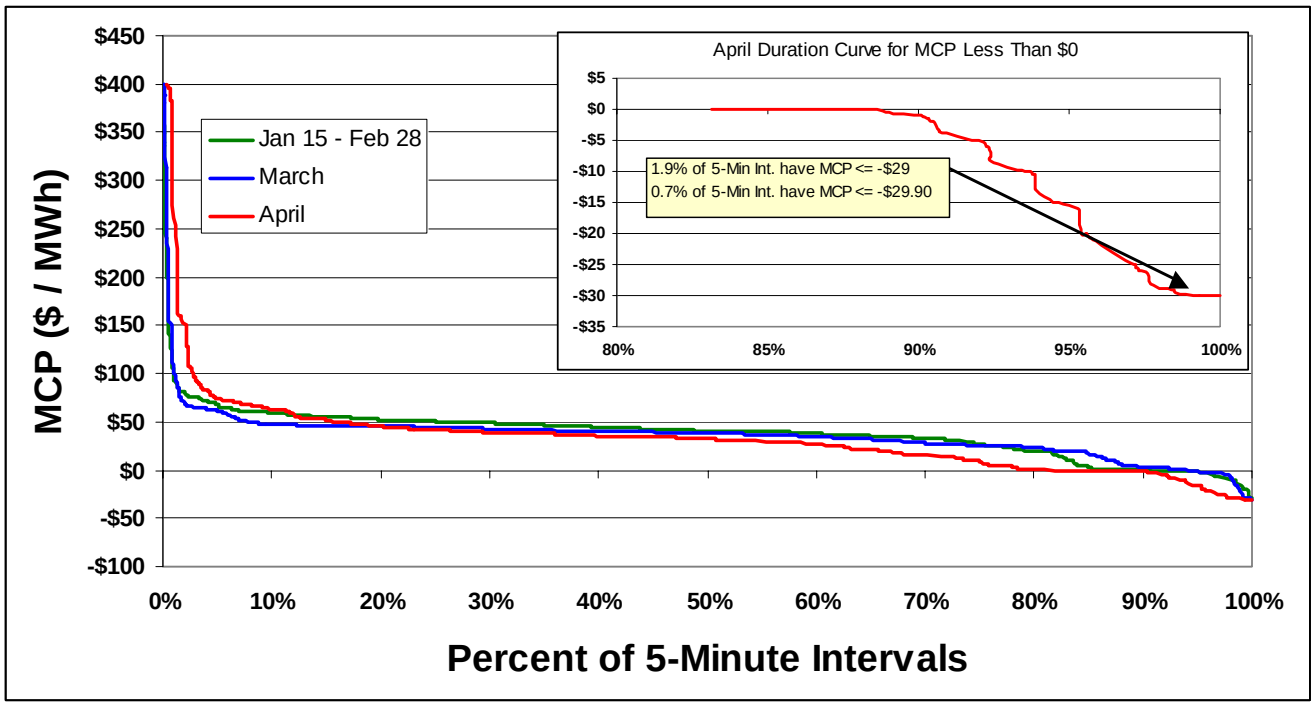
	Predispatched Export Energy	Price Difference (As-Bid vs. MCP)	Potential Revenue Imbalance
4/1/2006	125,781	$63.96	$8,045,134
4/8/2006	156,392	$25.19	$3,939,036
4/15/2006	167,156	$21.16	$3,537,681
4/22/2006	150,154	$26.96	$4,047,546
Total	599,483		$19,569,397

-$30/MWh Decremental Soft Bid Cap

Given the low real-time prices observed over the past several months, questions have been raised as to whether the current -$30/MWh soft bid cap for decremental energy bids in the CAISO Real Time Market ought to be lowered. An examination of the extent to which 5-minute interval prices have equaled or approached - $30/MWh is provided below.

In April, the NP15 real-time price, which is predominantly the lower of the two zonal prices when they are not equal, was below -$29/MWh in 1.5 percent of intervals, and below $29.90/MWh in 0.7 percent of intervals, as shown in Figure 10. In addition, the frequency of pre-dispatched export bids below -$29/MWh was also very small in April, accounting for approximately 0.6 percent of bid volume overall (Figure 10). The volume in this price range reached 9 percent of predispatch export bids on April 6. Bids for predispatch exports follow a pattern similar to actual predispatch exports, as shown in Figure 10.

Figure 10 Duration Curves for 5-Minute Interval MCPs in NP15 for Three Periods – January 15 through February 28, March, and April.



Ancillary Service Markets

Over the past several months, market clearing prices for ancillary services (A/S) have exhibited a steady increase in each market, except for Non-Spinning Reserves. In late March and April, prices for regulating reserves increased significantly from prior pricing levels, moving into the price region between the prior bid cap of $250/MW and the current bid cap of $400/MW.[4]

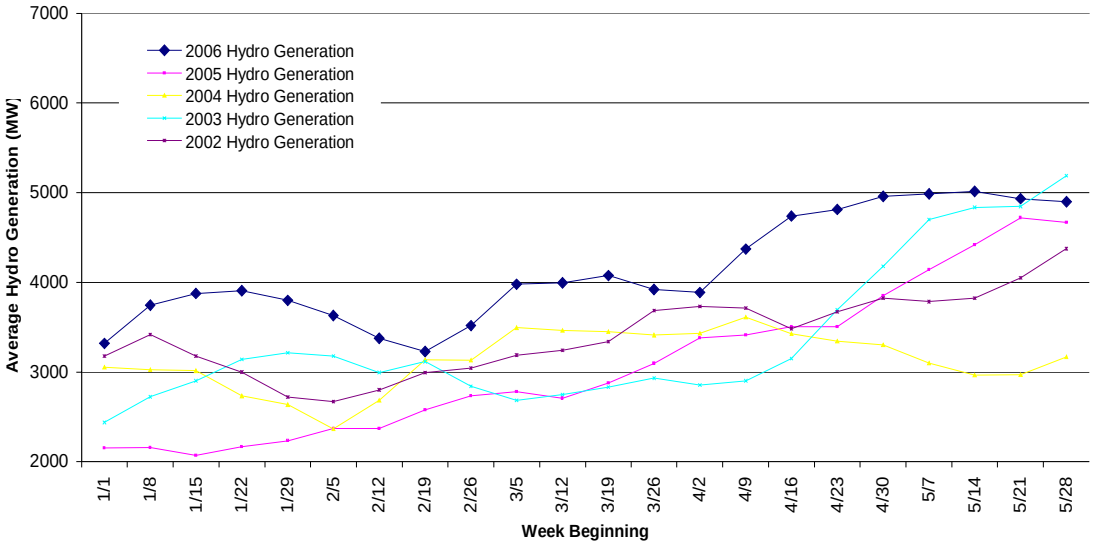
The Spinning Reserve markets have produced a few time periods with market clearing price excursions at or above $50/MW: mid-January, late February and April. There were roughly 30 hours (between the day-ahead and hour-ahead markets) where this occurred, with two-thirds of these hours occurring in the Day Ahead Market. There were just seven instances with prices over $75/MW spread across January 23, April 17, and April 28, 2006. The highest observed Spinning Reserve price for that period occurred on April 28 when the Day Ahead Market cleared at $225 in hours ending 7, 8 and 24. In contrast, Non-Spinning Reserves during this period (January 15 to April 30, 2006) posted a maximum price of $29.99.

Market clearing prices for regulating reserves exhibited a more volatile pattern. Price excursions at or above $100/MW for the Regulation Up and Regulation Down markets were nearly as frequent as those above $50/MW for Spinning Reserves. Regulation Up markets had roughly 90 such instances, with slightly less than half of those occurring in the Day Ahead Market. Regulation Down markets had roughly 100 price excursions into the $100/MW to $400/MW price range, with just a dozen occurring in the Day Ahead Market. With the exception of four instances in the Day Ahead Regulation Up Market, all of these price spikes occurred in April 2006.

The past several months of this year, and April in particular, have been relatively wet and warm, swelling river and reservoir levels. This weather pattern, and the resulting increased river flows, has driven increased generation from hydroelectric resources throughout the West. Under these conditions, hydro resources experience a “spill” state where if they did not generate they would be forced to spill water without generation output which is viewed as wasted water / electricity. These resources then often generate at full capacity, as the energy markets provide the final opportunity to capture value for the water behind the dam. If the resource has to spill water, as opposed to generating, the (electric) value of the water is lost.

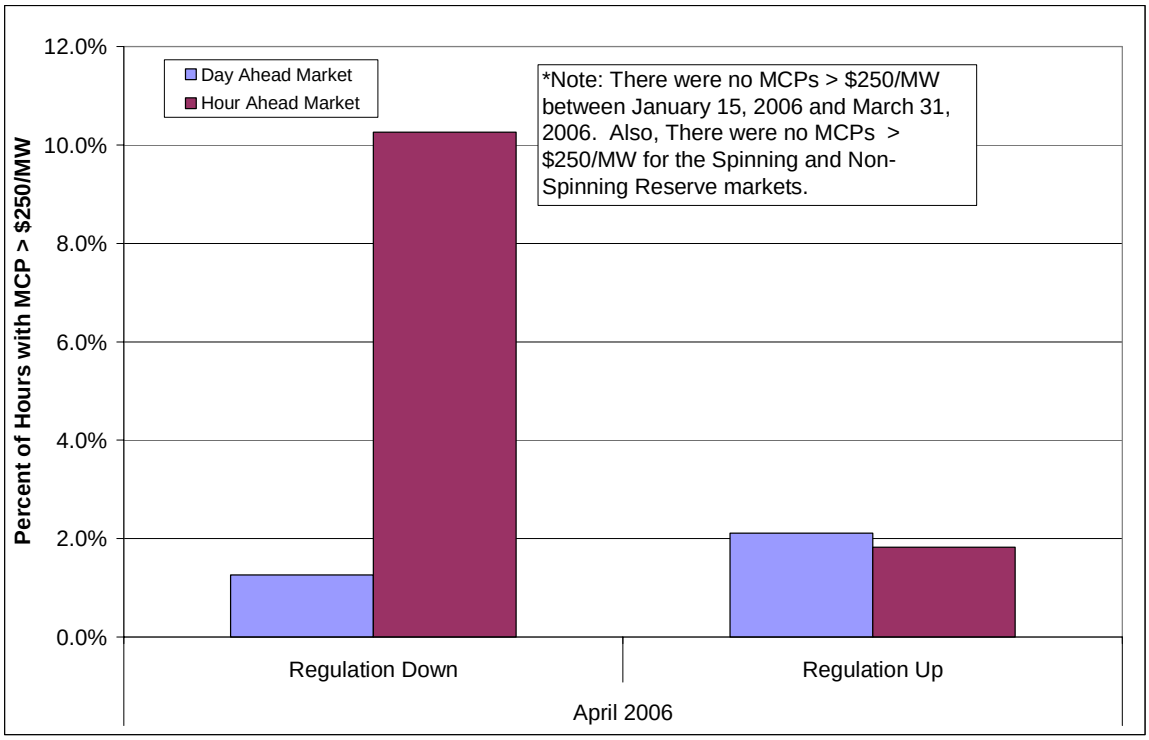
[4] In a February 13, 2006 Order, FERC directed the CAISO to increase the soft-bid cap for ancillary services to $400.

Figure 11 Approximate Hourly Average Hydro Generation within ISO Control Area (year-over-year by week for 2002 - 2006)



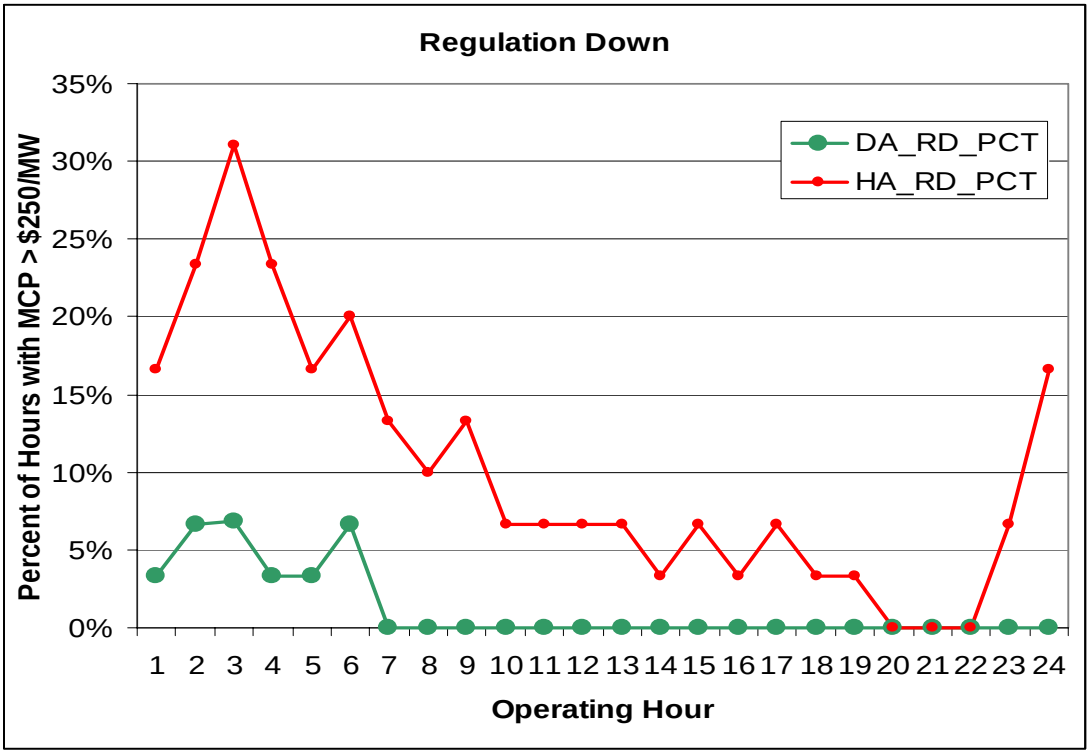
Such strong hydro-electric conditions stress A/S markets, particularly those that require on-line resources, as hydro resources can be producing near their limit, reducing the availability of Regulation Up Reserve capacity available, and are reluctant to reduce output due to the spill conditions that accompany high rain / runoff periods, reducing the availability of Regulation Down Reserve capacity available. Figure 11 above shows the high hydro output experienced in the months of January through April compared to prior years. Figure 12 depicts the frequency of price spikes over the $250/MW level in each of the Regulation Up and Regulation Down markets for the month of April. As indicated in Figure 12, the Hour Ahead Regulation Down market spiked most often, while the remaining regulation markets experienced price spikes in 2 percent or less of the hours in April.

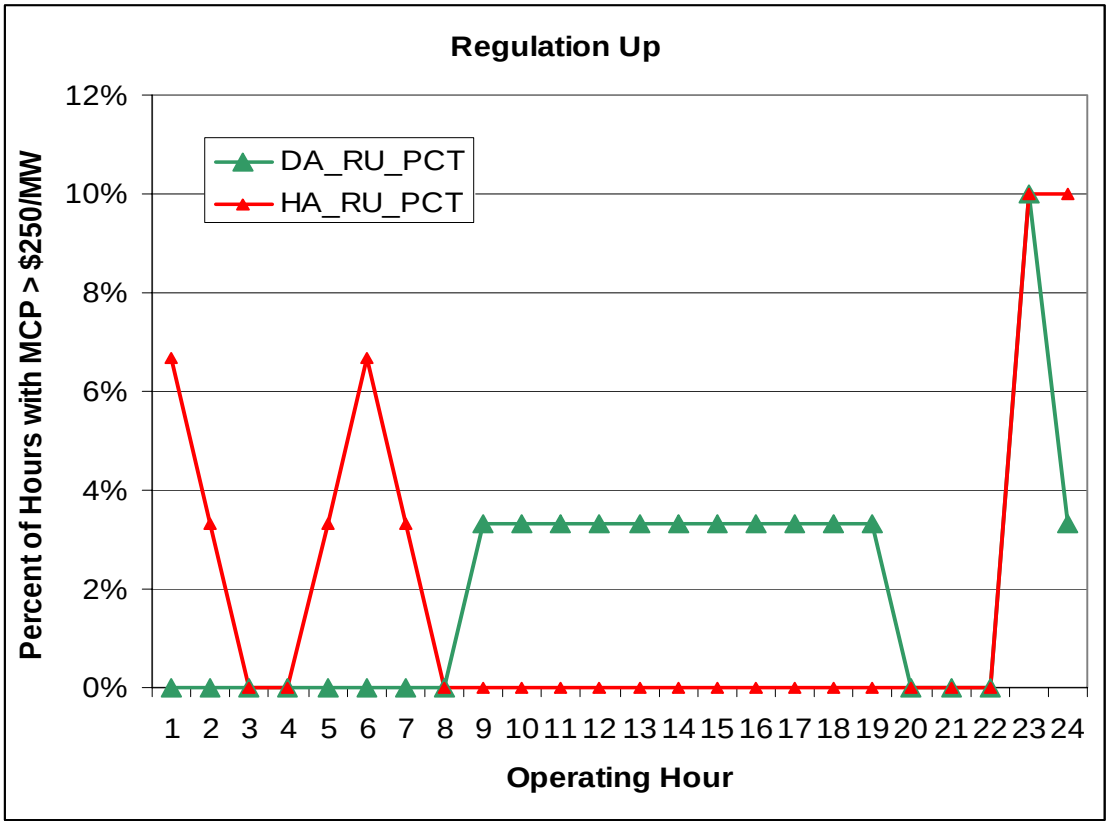
Figure 12 Frequency of Price Spikes Above $250/MW in Regulation Markets for April 2006



Load patterns also affect prices in these markets, as fewer resources are online and operating at a level where they can provide regulating reserves. Price spikes exhibit a much lower prevalence across the peak hours of the day. Figure 13 displays the price spike profiles for each of the regulation markets in the month of April. Here, the percent of time that each operating hour throughout the month of April has a price greater than $250/MW creates the plot points. As evident in Figure 13, late evening and early morning hours compound the seasonal factors and results in a higher frequency of price spikes, as generation that had been on-line to meet the daily peak ramps down or shuts off.

Figure 13 Price Spike Profiles for the Regulation Markets in April 2006





The first substantial price excursions above the $250/MW level began on April 08, 2006, the start of the second weekend in April. Weekends tend to compound driving factors of the market in ways similar to the overnight and early morning hours, as resources that were on-line to meet the week-day peaks ramp down or go off-line. However, a high level of generation outages was another contributing factor.

Figure 14 (Hour Ahead Market) and Figure 15 (Day Ahead Market) provide a visual representation of offers and prices into the market that had the greatest number of spikes, the Regulation Down market. As shown in Figure 14, there does not appear to be a noticeable supply response to consecutive price spikes in the hour-ahead time frame. However, there is a noticeable supply response in the Day Ahead Market (Figure 15). By the late hours on April 11, two days after the weekend onset of price spikes, nearly 800 MW of capacity showed up in the Day Ahead Market.

Figure 14 Offer Availability and Price Spikes in the Hour Ahead Regulation Down Market for off-peak hours in April 2006

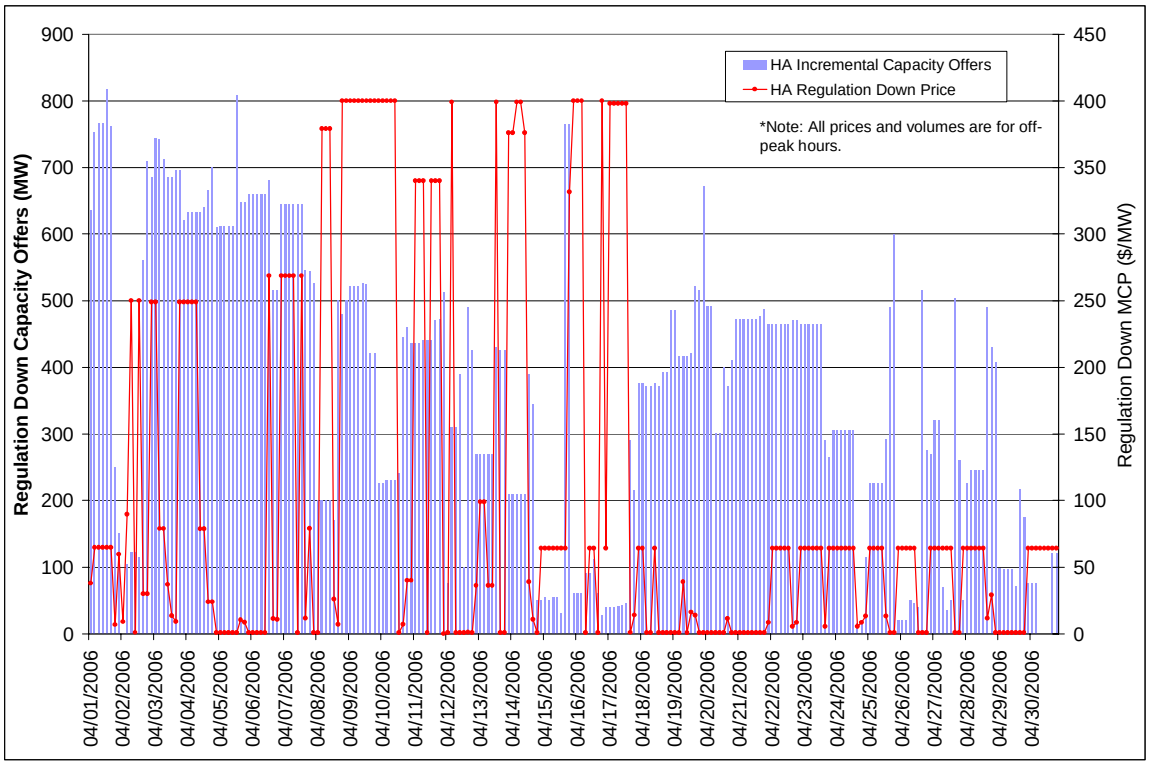
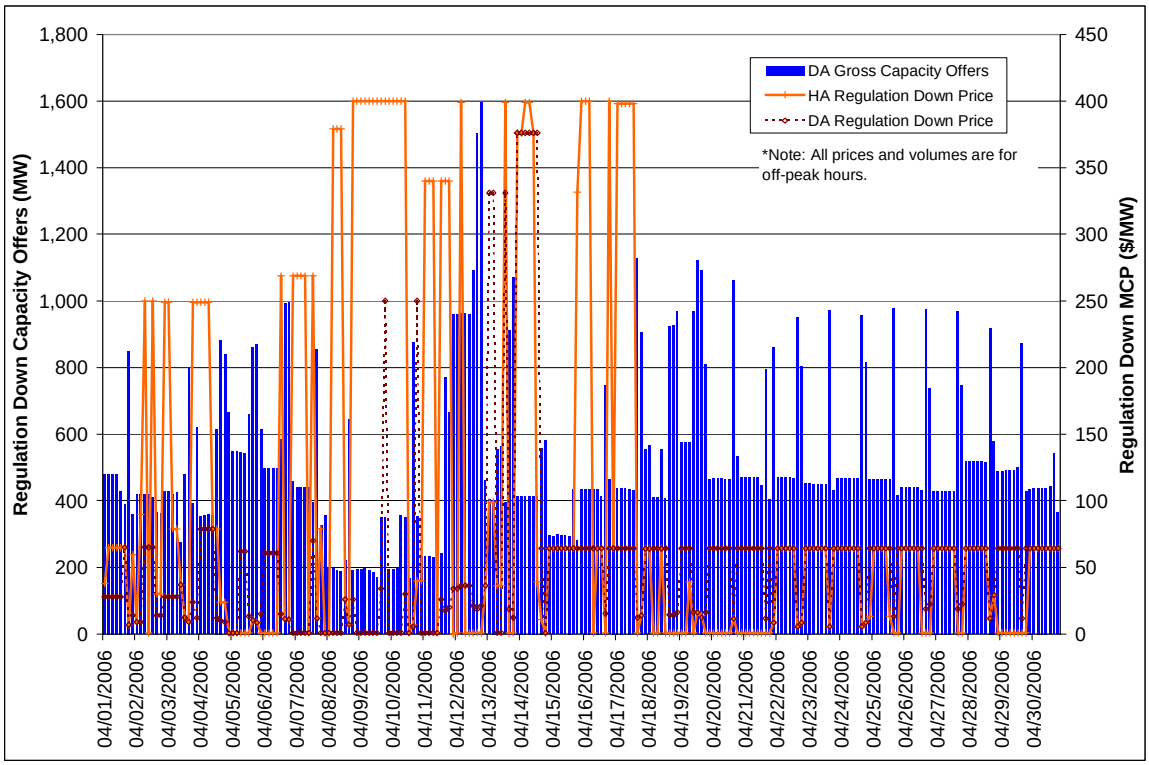
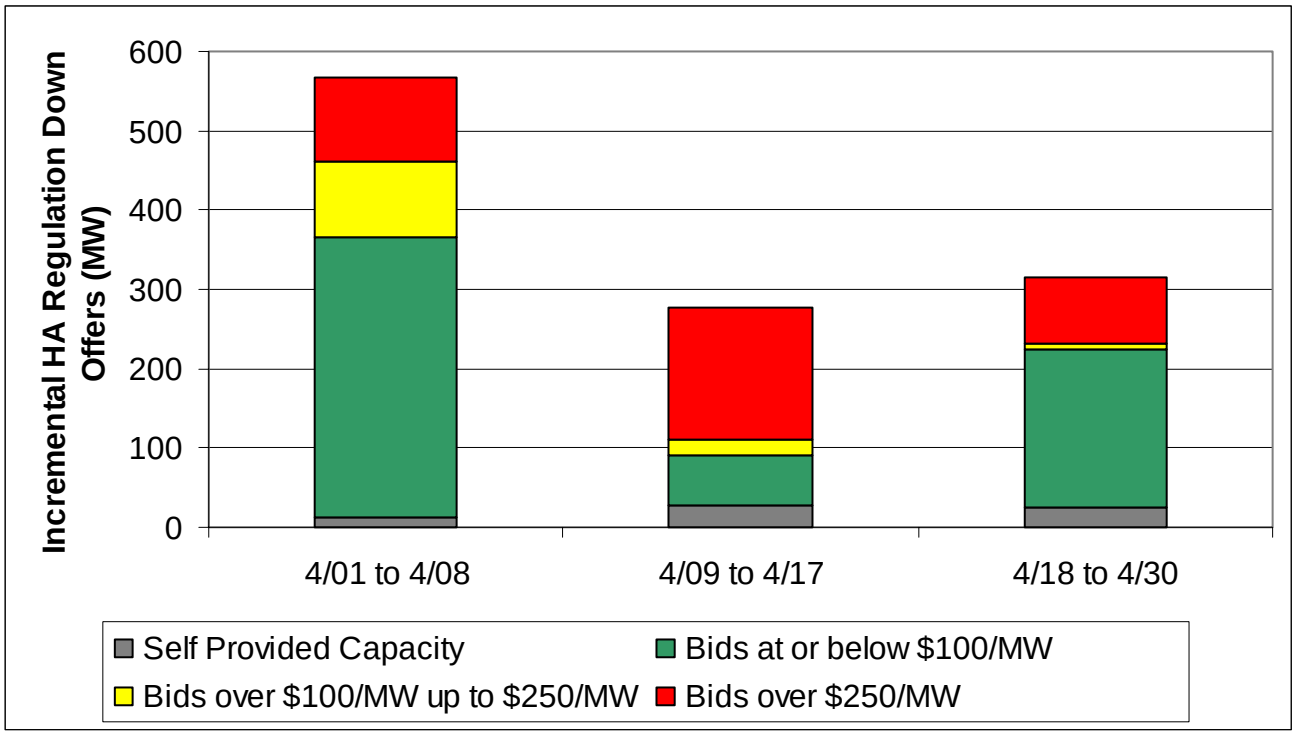


Figure 15 Supply Response to Price Spikes in the Day Ahead Regulation Down Market for off-peak hours in April 2006



The separation of April into three time periods based on pricing levels facilitates an understanding of the supply conditions. During the period with the majority of price spikes, April 9 to April 17, capacity offers at prices under $250/MW declined to average slightly more than 100 MW, as shown in Figure 16. Supply conditions improved in the last half of April as capacity offers at prices under $100/MW tripled, yet remained well shy of the volumes seen during the first week.

Figure 16 Average Hour-Ahead Incremental Regulation Down Offers at Various Price Levels for Periods in April 2006



Cost impacts due to the increases in the market clearing prices are significant, adding some 15 percent to the seasonal average monthly cost of $13 million. Figure 17 and Figure 18 provide a historic perspective of cost trends by comparing cost figures from the current operating year to those from the 2005 operating year. The incremental costs attributable to the portion of market clearing prices over the $250/MW level totaled $2.1 million, of which slightly more than 60 percent were due to the costs from Regulation Down procurement.

Figure 17 Monthly Ancillary Service Costs with Cost Attributable to Portion of MCP > $250/MW Highlighted

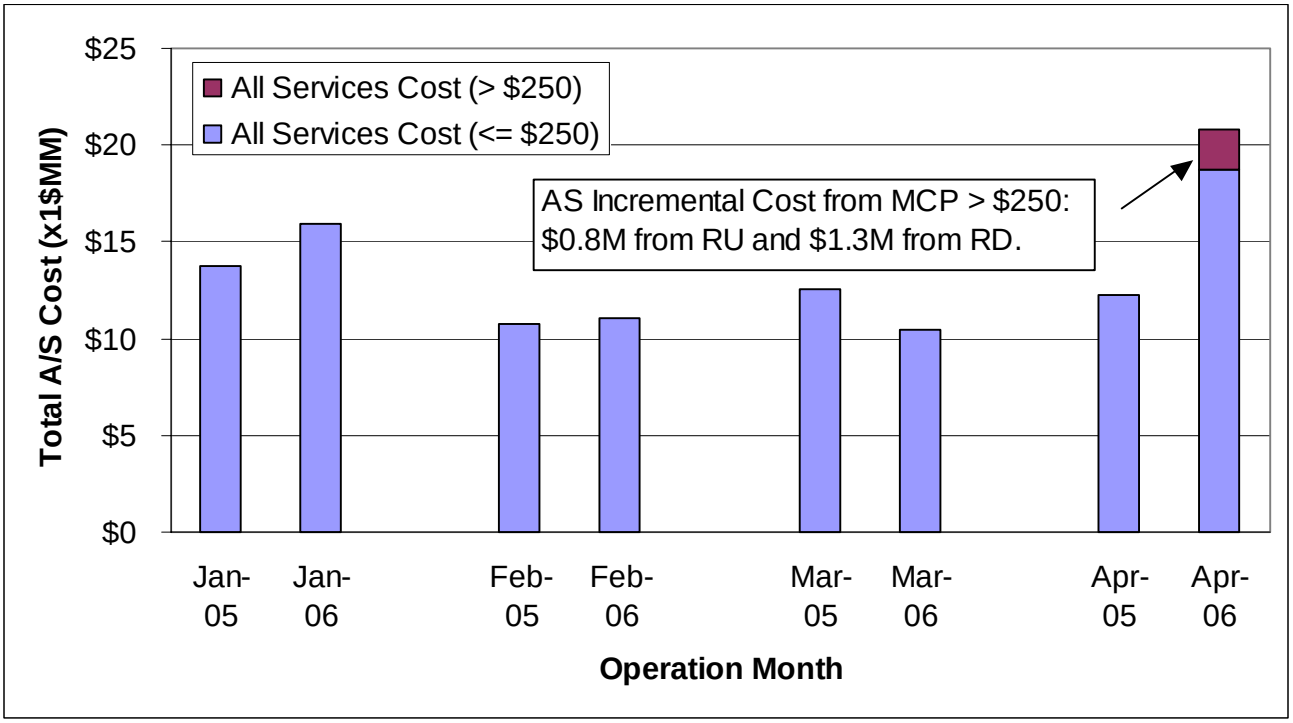
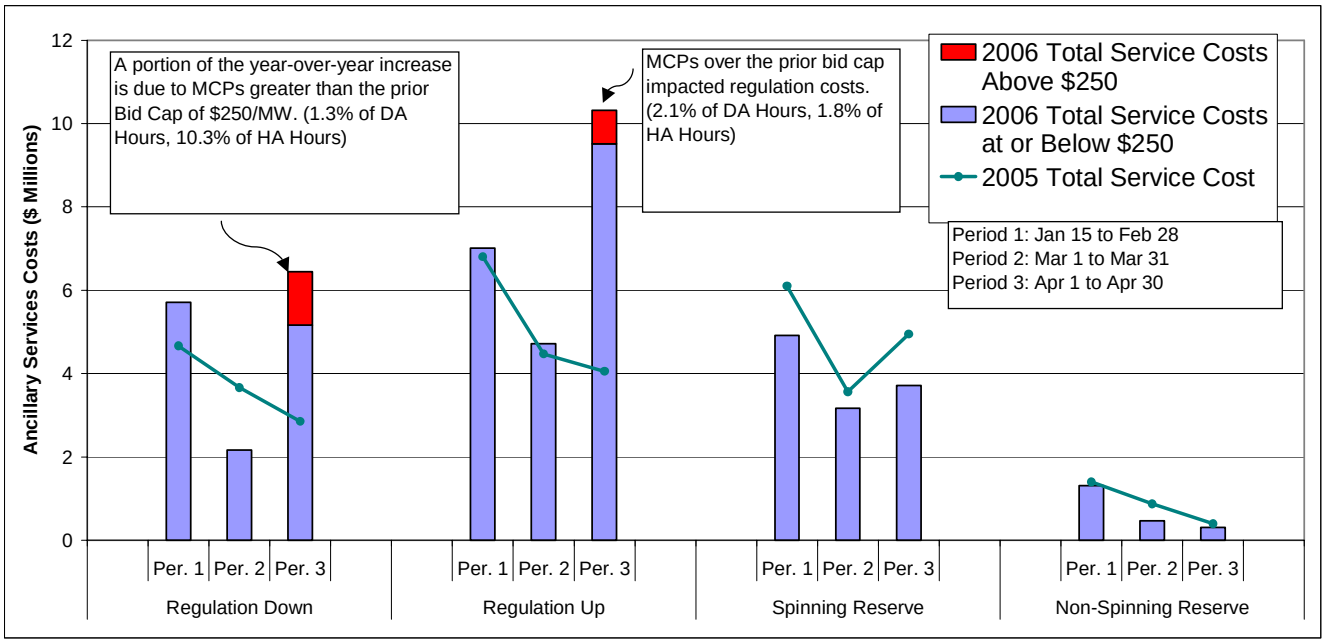


Figure 18 shows year-over-year costs for the four individual services for three periods: January 15 through February 28, March, and April, with bars representing 2006 data and lines representing 2005 data. Costs were slightly lower across the three periods in 2006 compared with 2005 for Spinning and Non-Spinning Reserve. Regulation costs, however, have been somewhat higher in 2006, and exceptionally higher in April 2006 compared to April 2005. Note in Figure 18 that costs attributable to the portion of market clearing prices over $250/MW is represented by the red portion of the bars. These total approximately $2.1 million for both regulation services and occurred only in April of 2006.

Figure 18 Ancillary Service Costs Net of Self Provision for Three Periods: January 15-February 28, March, and April



Summer 2006 Operation Plan for Southern California

In May 2006, the CAISO posted to its website a presentation describing its 2006 Operating Plan for Southern California (see **http://www.caiso.com/1802/1802d7af3acf0.pdf**). The presentation provided a description of the daily procedures the CAISO will use this summer to ensure there is adequate unloaded supply capacity available in SP26 each operating day to cover the most severe system contingency for that region (MSSC). DMM has carefully reviewed these procedures and has discussed them with CAISO Operation and Planning staff. The 2006 Operating Plan for Southern California was also discussed at the May 31 MSC meeting. Some specific concerns and areas identified as needing greater clarification are noted below. DMM and the MSC will continue to work with CAISO Operations and Planning to address these issues.

Integration with the Must Offer Waiver Denial Process. As described, the procedures for determining available capacity in SP26 count slow ramping resources and interruptible loads as "available" capacity and compare the total available capacity with the requirements to determine Must-Offer Waiver Denials for SP26. DMM believes it would be more appropriate to exclude interruptible demand and slow ramping resources from the available capacity calculation when determining Must-Offer Waiver Denials. Under some conditions, this may enable the CAISO to rely on additional fast ramping Resource Adequacy (RA) resources committed via the waiver denial process, in place of slow ramping resources or interruptible demand. DMM believes it would be preferable to rely on additional fast-ramping resources – even if these need to be committed through denial of Must-Offer Waivers – rather than slow ramping resources or interruptible demand. Since slow ramping resources or interruptible demand are not available within 20 minutes, these categories of resources would need to be dispatched prior to the operating hour if needed to protect against the possibility of a single largest contingency (which requires a response within 20 minutes) whereas capacity from fast ramping resources (available within 10 to 20 minutes) only needs to be dispatched if a contingency actually occurs. DMM believes that this key difference makes it highly preferable to maximize use of faster ramping resources – even if these need to be committed on a day-ahead basis through the Must-Offer Waiver Denials process – prior to relying on slow ramping resources or interruptible demand. DMM also recommends that procedures should also provide additional details of the criteria under which non-RA resources would be denied Must Offer Waivers under the plan. For instance, would the CAISO rely on interruptible demand or slow ramping resources as "available capacity" in lieu of denying waivers for non-RA resources?

Clarification of Advance Dispatch of Slow Ramping Resources. The procedures should clarify how slow ramping resources or interruptible load will be utilized to provide available capacity for system contingencies. Since system contingencies typically require 20 minute response capability, operators have indicated that they would pre-dispatch incremental energy bids from slow ramping capacity in SP26 to free-up north to south transmission capacity on SP26 (i.e., generation in NP26 would be dispatched down to off-set the dispatched incremental energy from slow ramping resources in SP26). The current procedures are not clear on how this pre-dispatch would occur. One option discussed was to dispatch the slow ramping resources within RTMA by introducing a load bias and "flagging out" incremental energy bids from fast ramping resources in SP26 so that only slower ramping resources would be dispatched up. This approach would tend to increase the real time market prices in SP26. An alternative would be to pre-dispatch the slow ramping resources using OOS dispatches. DMM would like to further review and discuss these two options to determine which would be most appropriate.

Potential Perverse Incentives with Advance Dispatch of Slow Ramping Resources. The proposal to pre-dispatch slow ramping resources has a perverse incentive of penalizing fast ramping resources by skipping their energy bids. This may create an incentive for fast ramping resources to lower their ramp rates in order to be dispatched up in real time. Given this potential as well as the potential cost of this practice noted above, DMM would recommend the dispatching up of slow ramping resources be an option of last resort on extreme days as opposed to a routine summer practice (i.e., Must-Offer Waiver denials of RA resources should be utilized to minimize dependence on pre-dispatching slow ramping resources).

Procurement of Additional Ancillary Services in SP15. The proposal also calls for the option of increased procurement of 10-minute Operating Reserve in SP15 through the CAISO's Ancillary Services markets as a means of potentially incenting scheduling adjustments that may increase the total amount of fast ramping resources in SP15. DMM recommends that any procurement of additional 10-minute Ancillary Services in SP15 be closely monitored and assessed in terms of whether this additional procurement resulted in increased overall supply of fast ramping resources in SP15 and the cost of this increased supply.