CALIFORNIA ISO

# Memorandum

**To:** ISO Board of Governors

**From:** Keith Casey, Director, Market Monitoring

**cc:** ISO Officers

**Date:** January 17, 2006

***Re:*** **Market Monitoring Report**

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

**Natural Gas Prices, Real-Time Energy Offers, and the $400 Damage Control Bid Cap**

**Background.** Over the past few years, wholesale natural gas prices increased from approximately $3 per million British thermal units (mmBtu) in mid-2002 to well above $10/mmBtu following Hurricanes Katrina and Rita in September 2005, and peaking in mid-December at $14.28/mmBtu for delivery to Southern California. With approximately 40 percent of electric power in California produced by natural gas-fired generation, the dramatic increase and volatility in natural gas prices raised concerns that the marginal cost of certain gas-fired units could actually exceed the $250/MWh Damage Control Bid Cap (DCBC). Though the $250 DCBC was a soft-cap, the Department of Market Monitoring (DMM) and the CAISO Market Surveillance Committee (MSC) were concerned that if prevailing gas prices resulted in western wholesale power prices in excess of $250/MWh, there would be a significant risk that supplies in the California real-time market would be reduced, which could result in reliability issues. Additionally, both the MSC and DMM were concerned that if the CAISO had to take a significant amount of bids above the $250 soft-cap, this would create an incentive for suppliers to distort their bidding (inflate costs) in an effort to have accepted bids above $250 cost-justified. Such bidding behavior would lead to inefficient dispatch and potentially increase overall dispatch costs. In light of these concerns and some additional benefits that a higher bid cap could provide, CAISO Management, with the concurrence of DMM and the MSC, sought and obtained Board approval to increase the real time energy bid cap to a $400 hard cap. On December 21, 2005, the CAISO filed with the FERC a request to increase the bid price cap. The CAISO specifically requested from the FERC an expedited order on this matter so that changes could be implemented in time to deal with potentially higher natural gas prices this winter.

**Update.** As of this writing, FERC intervener comments have been submitted and the CAISO is still awaiting an order from FERC on the filing. Meanwhile, the price of natural gas decreased to $7.56/mmBtu in early January 2006, following warmer-than-predicted weather across the eastern United States. That said, the price of gas remains volatile, and risks such as weather and overall conditions in the global gas market will affect electric power supply costs in California.

The effect of natural gas prices on energy supply is evident in the CAISO real-time balancing energy market. Figures 1 and 2 below respectively plot weekly average internal and import generation bid volumes for incremental energy (on the left axis) against the Southern California weekly average gas price (on the right axis). Bid volumes are broken into the following price bin categories: Below $100/MWh, $100 to $150/MWh, $150 to $200/MWh, $200 to $250/MWh, and above $250/MWh. Note that a gas price above approximately $10.50/mmBtu causes a significant decrease in inexpensive energy bids from both internal and import suppliers, and that total import bids averaged approximately 100 MW when gas prices peaked above $12/mmBtu.

**Figure 1. Weekly Average Incremental Bid Volume by Price Bin Category v. Gas Price: Internal Generation, 8/1/05 through 12/31/05, Mondays through Saturdays**

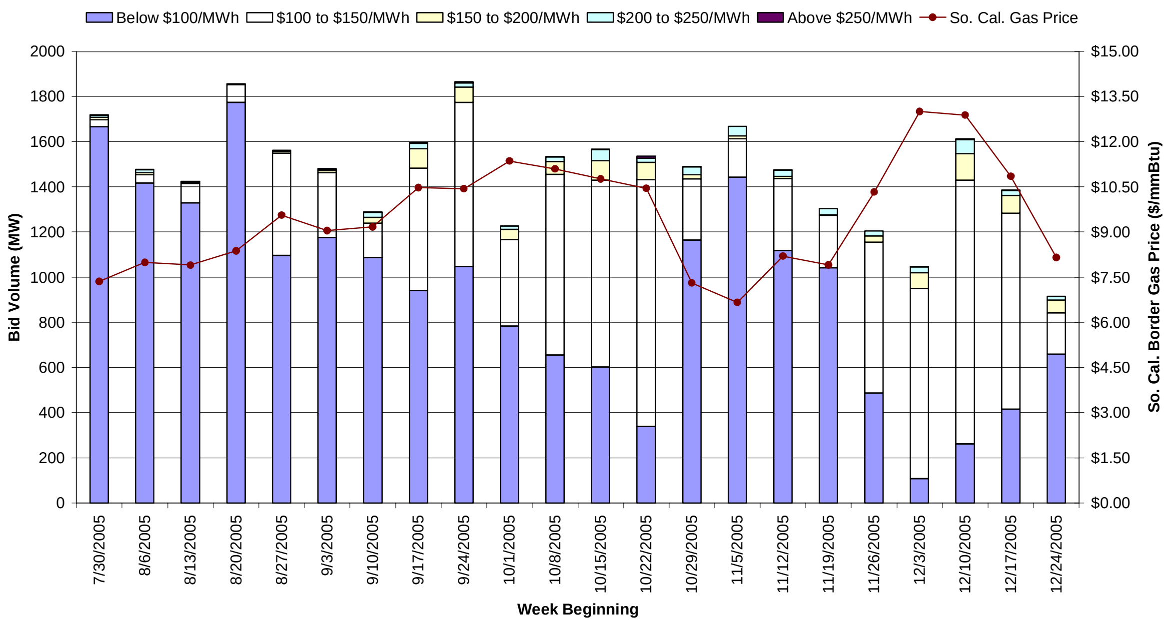
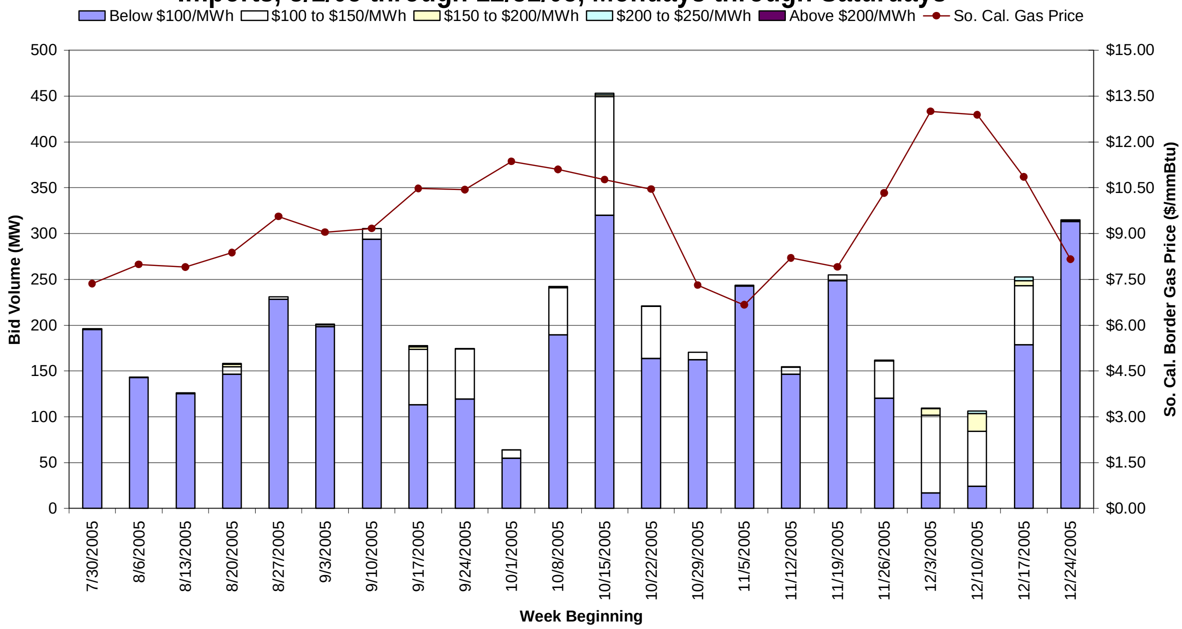


**Figure 2. Weekly Average Incremental Bid Volume by Price Bin Category v. Gas Price: Imports, 8/1/05 through 12/31/05, Mondays through Saturdays**




## Generation Forced Outages

At the December Board of Governors meeting, Governor Cazalet inquired about potential trends in forced outages of generation facilities in the CAISO control area and requested that DMM examine this issue. This request was made in response to a chart provided in a report from Operations showing higher forced outage levels for both generation and transmission in 2005 compared to 2004. The DMM monitors generation outages on a weekly basis and has observed that generation forced outage levels in 2005 were generally similar to or lower than 2004 levels, as measured by the monthly average of daily maximum generation capacity forced out.

There was one (monthly) exception to this pattern in July. A sustained heat wave from July 11 to August 12, 2005, caused peak loads to persist above 40,000 MW for all but three days, and required the entire generation fleet within the CAISO control area to be available. Consequently, generators were not shut down on weekends for maintenance, as is standard industry practice, and the rate of forced outages increased, ultimately contributing to the issuance of Stage 2 emergencies on July 21 and 22.

DMM is currently working with Operations to better understand the data underlying their analysis, which as noted above represented a combination of generation and transmission forced outages, and to reconcile their results with our findings.

## Assessment of Ancillary Service Competitiveness

**Background.** The CAISO has historically experienced intermittent bid insufficiency in the Ancillary Service (A/S) markets and disproportionate regional procurement of Ancillary Service capacity to meet reliability requirements. The DMM periodically assesses the competitiveness of the Ancillary

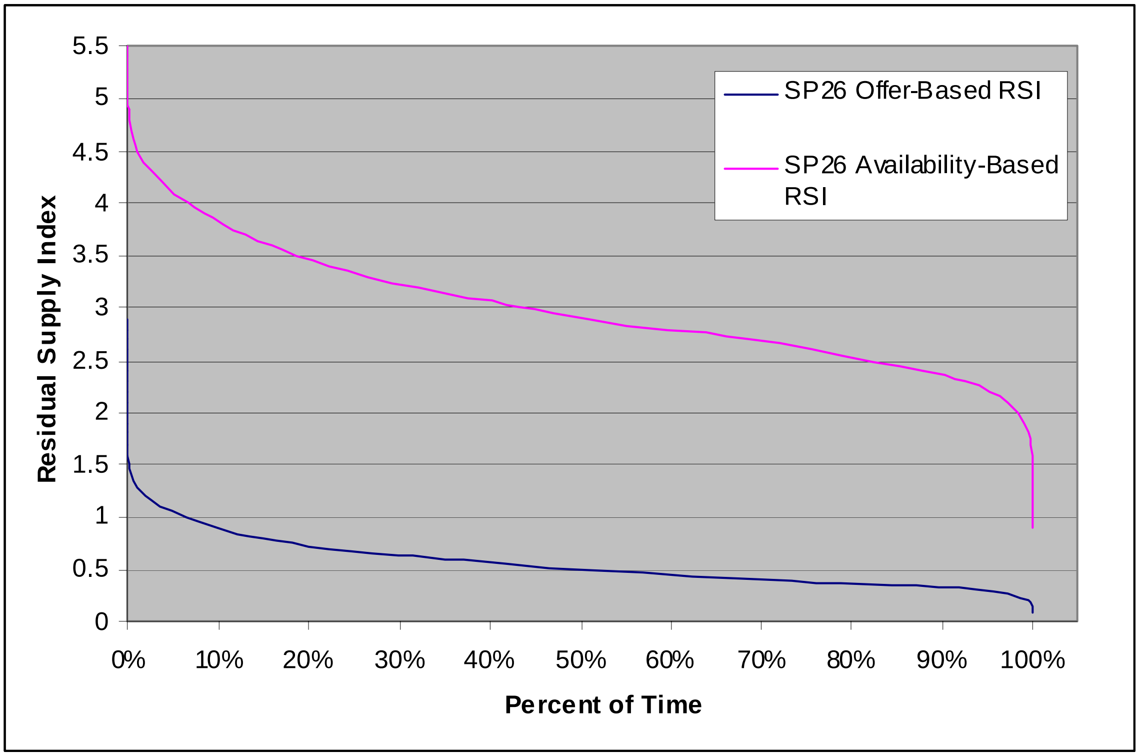
Service markets, both at the system level and at a zonal level to identify potential market power risks that might result from procuring Ancillary Services on a zonal basis to meet requirements.

**Update.** The DMM recently completed a preliminary update to the assessment of competitiveness in the Ancillary Service markets. Following the approach adopted in the prior study, levels of market power for the 2005 operating year were assessed using the Residual Supplier Index (RSI) methodology, which was applied to a standardized A/S product.

The RSI measures the extent to which supplies of A/S can meet reserve requirements after removing the largest supplier from the market. As a consequence of removing the single largest supplier, this metric measures the extent to which that supplier is pivotal in meeting demand. An RSI value below 1 indicates the largest supplier is pivotal. If the largest supplier is pivotal, that supplier has the potential to exercise market power by withholding capacity from the Ancillary Service markets resulting in a higher market clearing price.

The analysis was updated for both system-level procurement and zonal procurement of Ancillary Services. As in the prior analysis, the preliminary results for 2005 indicate that both offers and total availability at the system level are competitive. However, focusing specifically on procurement south of Path 26, we see that while availability of Ancillary Service capacity appears to be competitive, actual offers into the Ancillary Service markets were thin relative to requirements (when removing the single largest suppler) and resulted in an RSI that is below 1 for over 90% of all hours in 2005. This result indicates that, in over 90% of hours, if the single largest supplier did not bid into the market there would not be enough supply to meet requirements creating an uncompetitive market environment. In contrast, when this same analysis is done based on the A/S capacity "available" south of Path 26 (as opposed to bid-in), the results indicate that there is a significant amount of certified Ancillary Service capacity south of Path 26 that, if bid in to the Ancillary Service markets, would greatly improve the competitive environment in the south. There are two primary factors that influence the large difference between the offer-based RSI and the availability-based RSI. The first factor is that market conditions may be such that it is not economic for some units to run based entirely on spot market revenues (i.e., no contract revenues) and therefore these units do not offer into the A/S markets since they will not be in a position to provide energy if called upon. The second factor is that A/S prices may not be high enough to cover the unit's opportunity cost of providing energy and instead keeping the capacity unloaded in reserve. These results are shown graphically in Figure 3, where there are two Residual Supply Index duration curves represented.  The lower curve reflects actual offers into the A/S markets (standardized to a uniform 10-minute product) and the upper curve reflects all certified 10-minute A/S capacity in SP26.

**Figure 3. Residual Supply Index for Ancillary Services South of Path 26**



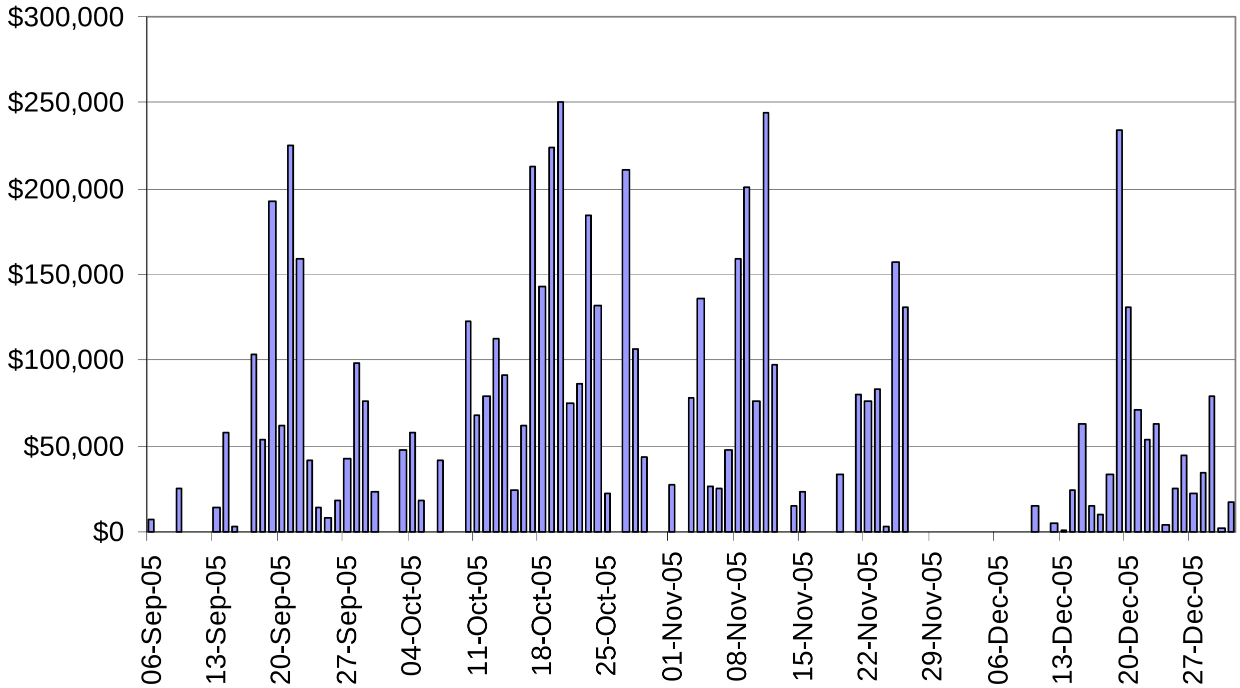

The CAISO has procured Ancillary Services system-wide to meet reliability requirements and, as noted above, at the system-level offers into the Ancillary Service markets exhibit much greater level of competition than the SP26 market when viewed in isolation. DMM is conducting additional analysis to better understand why available A/S capacity south of Path 26 is not being offered into the A/S markets and is in the process of modifying this model to provide a snapshot of the projected market competitiveness for 2006 given generation retirements and additions that are anticipated in the coming year.

## Congestion at South of Pastoria

**Background.** The December report to the Board of Governors included a section describing the congestion experienced in the South of Pastoria area and a summary of the resulting additional cost incurred as a result of real-time management of this congestion.

**Update.** Congestion at South of Pastoria has continued through December and into January requiring similar real-time congestion management measures to be taken by CAISO operators. Congestion costs associated with this transmission issue total $6.3 million to date and are expected to continue to increase as upgrades to the transmission infrastructure in that region continue. Figure 4 below shows daily real-time congestion costs incurred as a result of managing congestion at South of Pastoria.

**Figure 4. Daily Out-of-Sequence Redispatch Costs from Real-Time Mitigation of Congestion at South of Pastoria**




Given the significant and frequent congestion occurring south of Pastoria, DMM has been closely reviewing the Decremental Reference Prices used to dispatch the two units used to relieve this congestion (Pastoria and Big Creek) and working with CAISO Operations to verify that congestion mitigation procedures (M-401) are being properly followed.

**Other Issues**

***Default Price for $12 RTMA Issue:*** At the last Board of Governors Meeting, Governor Cazalet inquired about options for an appropriate default value for the interval MCP when RTMA exhausts the available energy and returns a $12/MWh default price. The current practice is to correct the $12/MWh default values within the 96-hour correction window by replacing it with the last valid interval MCP. One option suggested by Governor Cazalet is to use the bid price cap for energy as the default interval MCP in such circumstances. DMM is working with Market Services and Market and Product Development to develop and evaluate options for this pricing situation and will report findings at the next Board of Governors Meeting.

***Update of RTMA Analysis Forthcoming:*** Last October DMM submitted a report containing an assessment of RTMA performance that focused specifically on price and dispatch volatility resulting from RTMA. DMM is in the process of producing a subsequent report with updated analysis and some lessons learned from RTMA that could be applied to MRTU. DMM will be providing this report in March along with a summary of the findings and lessons learned in the Annual Report on Market Issues and Performance also in March.

***Annual Report on Market Issues and Performance:*** The DMM has begun preparation of its Annual Report on 2005 Market Issues and Performance and will present a summary of this report to the Board at the March 8th meeting. DMM will be filing this report with FERC and will be presenting the results to FERC Commissioners in April.