California Independent
System Operator Corporation

Memorandum

To: The ISO Board of Governors

From: Frank A. Wolak, Chairman, Market Surveillance Committee of ISO

cc: Yakout Mansour, President & CEO, Charlie Robinson, VP, General Counsel, & Corporate Secretary

Date: April 12, 2006

Re: ***Summary of the Market Surveillance Committee Meeting of February 27, 2006***

This is only a status report. No Board action is requested.

The Market Surveillance Committee (MSC) held a public meeting on February 27, 2006, at the California ISO. All MSC members were present. Brad Barber called the meeting to order and asked for public comment.

Public Comment

Jeff Nelson of Southern California Edison expressed concern with aspects of the Market Redesign and Technology Upgrade (MRTU) tariff relating to the treatment of non-firm imports and exports. This was followed by a brief discussion between Nelson and several MSC members on difficulty of distinguishing firm imports and exports from non-firm imports and exports in a multi-settlement market, because any import or export scheduled in the day-ahead market could be undone through the opposite transaction in the hour-ahead or real-time market. Several MSC members noted that the expertise the Department Market Monitoring (DMM) has developed in tracking import and export schedules as a result of the Enron trading strategies investigation should help to address Nelson's concerns.

Market Performance Report

Deborah Le Vine, Director of Market Services, presented the market performance report for January 2006. The major issue of the month was implementation of a $400/MWh soft cap on the ISO's real-time energy market effective January 14, 2006. The five-minute price exceeded the previous $250/MWh soft cap in 24 of the total 5184 5-minute intervals from January 14, 2006 through January 31, 2006, or 0.46% percent of the intervals. These prices typically occurred during the ramping hours, when there were rapid load changes in the California ISO control area. For example, the longest contiguous periods on 1/24/06 and 1/31/06 involved increases in real-time dispatch of over 3000 MW during the hour. Despite this higher soft cap, the average hourly price never exceeded $250/MWh during the latter half of January. Le Vine stated that the both the Department of Market Services and Department of Market Monitoring would continue to study the causes of prices above the $250/MWh soft cap.

Because of low loads, particularly during the first half of the month, the ISO's real-time market was primarily a decremental market, where load-serving entities sold energy scheduled in the day-ahead market back to the generation owner. As a result, the average in-sequence price in the real-time market was $45.77/MWh, considerably less than $75.76, the average for December 2005.

Consistent with a decremental energy market, the cost to load for ancillary services fell relative to December 2005. The average cost in December was $1.01/MWh, compared to $0.91/MWh in January. Nevertheless, the prices of RegUp and RegDn continued to be higher than they were during the late summer and autumn of 2005. Le Vine stated that water management and local congestion issues appeared to be the major factors contributing to these higher prices for RegUp and RegDn.

Out of Sequence (OOS) energy and Out of Market (OOM) energy continue to play a major role in the real-time market. The total amount of GWh dispatched for OOS and OOM needs was approximately 40% of the total GWh dispatched in sequence during the month. One MSC member noted that this reliance on OOS and OOM energy may be due to how these costs are allocated among market participants and how they are treated in the California Public Utilities (CPUC) regulatory ratemaking process. These costs are treated as a pass-through in the CPUC ratemaking process, so the major load-serving entities have a limited incentive to arrange their forward market energy purchases in a physically feasible manner and instead rely on OOS and OOM purchases.

Market Monitoring Annual Report

Jeff McDonald of the Department Market Monitoring presented a summary of the Department of Market Monitoring Annual Report on Market Performance. The general conclusion of the report was that the ISO markets were competitive and stable during 2005. Congestion costs were reduced by 50% relative to 2004, due in large part to transmission upgrades that came into service during 2005. McDonald stated that the major events in the ISO markets during 2005 were: (1) the intertie bidding and settlement under the Real-Time Market Application (RTMA), (2) the 95% load-scheduling requirement, and (3) impact of the Gulf Coast hurricanes on natural gas and electricity prices.

McDonald also discussed the question of long-term generation adequacy in California noted that real-time market revenues for 2005 may not be sufficient to cover the annualized cost of a new combined cycle natural gas unit. In response, several MSC members noted that this result was expected given the demand and supply conditions that existed in the Western Electricity Coordinating Council (WECC) and level of forward contracting by California's major load-serving entities during 2005. In fact, if there is significant forward contracting for energy by California's major load-serving entities for virtually all of their expected demand on annual basis, then short-term prices could persistently be insufficient for full annual cost recovery for a new generation unit. One MSC member noted that this outcome provides a strong incentive for suppliers to sign fixed-price forward contracts with load-serving entities. Several MSC members emphasized that low short-term energy prices should not be a cause for concern if they are accompanied by high levels of fixed-price forward contracts for energy held by the major California load-serving entities. One MSC member stated that the primary revenue source of generation unit owners should be forward market sales, with the ISO's real-time market being primarily used to settle imbalances between its forward position and actual consumption, with all load-serving entities having close to zero net purchases from the ISO's real-time market on an annual basis.

McDonald finished his presentation with a discussion of the RTMA performance during 2005. He stated that implementation of RTMA has increased the volatility of prices and dispatch instructions during the operating hour compared to the prior market software. This result was not unexpected because RTMA was designed to provide more accurate dispatch and price signals. During 2005, the ISO implemented several modifications to the RTMA software that improved its performance. One important modification was to change the demand forecast methodology used by RTMA to assume that units chronically deviating from schedule will not return to schedule in future intervals. This modification appears to have significantly improved the demand forecast accuracy. One of the hoped for benefits of implementing

RTMA was a reduction in the demand for regulation reserve. Because this reduction in the demand for regulation reserve has not yet materialized, McDonald stated that the ISO would continue to investigate this issue.

95% Scheduling Rule Under MRTU

Greg Cook, Manager of Tariff and Regulatory Policy, discussed a proposal to require that loads schedule 95% of their demand in the day-ahead market. Amendment 72 filed in September 2005 implemented a 95% scheduling requirement on load-serving entities. However, it included a provision that would end the day-ahead scheduling requirement when MRTU is implemented. Cook then summarized stakeholder concerns with eliminating the 95% scheduling requirement under MRTU Release 1 absent convergence bidding. Specifically, load-serving entities (LSEs) may submit price-responsive demand bids to lower the day-ahead market price and the Residual Unit Commitment (RUC) capacity costs may be insufficient to counter these incentives to shift load to real-time. As a consequence, some stakeholders have recommended keeping the 95% scheduling requirement under MTRU until convergence bidding is implemented.

The discussion among MSC members pointed out two major challenges associated with implementing a 95% scheduling requirement. The first concerned the difficulty with monitoring compliance with this scheduling requirement. If the ISO requires LSEs to schedule to within at least 95% of their load forecast, this creates a situation where compliance is relatively straightforward, but the scheduling requirement is effectively meaningless. The LSE can always say that its load forecast was less than or equal to its actual day-ahead schedule divided by 0.95, which would guarantee compliance with the requirement. Alternatively, the ISO could require LSEs to schedule to within 95% of the ISO's load forecast for that LSE. However, this requirement would rightly raise concerns among LSEs because they would be required to pay the real-time market costs associated with errors in the ISO's load forecast. Alternatively, the ISO could measure compliance by comparing a LSEs actual load or generation output relative to its day-ahead schedule. For generation this creates a circumstance where the generation unit owner would be reluctant to respond to a real-time dispatch instruction because this could make their actual output multiplied by 0.95 exceed their day-ahead schedule. For LSEs, validation of compliance with the 95% percent scheduling requirement using their actual consumption compared to their day-ahead schedule would provide strong incentives for LSEs to implement demand response programs. The conclusion of this discussion was that there are number of compliance issues that must be resolved if the ISO implements a 95% scheduling requirement with financial penalties rather than for informational purposes, as is currently the case under RTMA.

The second issue raised by the MSC concerns the market efficiency consequences of a 95 percent scheduling requirement. Because California is increasingly import-dependent and many of these imports only become available at the close of the day-ahead market, a 95% scheduling requirement could unnecessarily raise wholesale energy purchase costs because it limits the magnitude of purchases California LSEs are allowed to make between the close of the day-ahead market and real-time market. Nevertheless, one MSC member acknowledged that the combination of no convergence bidding, the current sequential RUC mechanism, and the expected RUC capacity costs may not provide sufficient incentives for LSEs to avoid demand-bidding to reduce day-ahead energy prices at certain locations in the California ISO control area. For this reason, the MSC has been a strong advocate of implementing convergence bidding in MRTU Release 1.

One MSC member emphasized that if the amount of fixed-price forward contracts for energy held by LSEs is close to 100% of the expected consumption of these LSEs, then the LSEs would have little incentive to demand-bid to reduce day-ahead energy prices. Moreover, if the CPUC revised its ratemaking process to charge some of the costs of managing congestion between the day-ahead market and real-time market to the major California LSEs, these LSEs would have less of an incentive to reduce day-ahead energy prices by demand-bidding. If the three large LSEs had to bear a portion of the higher real-time energy costs caused by this demand-side bidding they would be more likely to attempt to schedule as accurately as possible or reduce their real-time purchases through demand-response programs.

Long-Term FTRs

David Withrow of the Department of Market and Product Development briefed the MSC on the current Federal Energy Regulatory Commission (FERC) proceeding on long-term Financial Transmission Rights (FTRs). The Energy Policy Act of 2005 directed FERC to enable LSEs "to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements…" FERC issued a Notice of Proposed Rulemaking on this topic on February 2, 2006 and comments were due on March 13, 2006. Withrow then summarized FERC's proposed guidelines for long-term FTRs and solicited input from the MSC on the kind of design of long-term FTRs that would best suit California.

MSC members recognized that the ISO's design for FTRs within MRTU has many of the elements that FERC seems to be seeking for long-term financial rights. However, the MSC urged caution in going beyond a one-year term for CRRs because the awarding of long-term rights could entail long-term commitments that could only be met at considerable cost. One MSC member questioned the need for the ISO to issue long-term FTRs, as long as market participants are free to enter into bilateral agreements to offer the financial equivalent of long-term FTRs. This MSC member emphasized that by granting long-term FTRs, the ISO could severely limit its ability to manage the re-distributional consequences of the transition to locational marginal pricing in California. If the ISO allocated too many long-term FTRs then it would be unable to revisit the FTR allocation process to correct inequities that arise as a result of unexpected levels and frequency of congestion during the initial years of a LMP market in California. Several MSC members stressed the need for the ISO to preserve flexibility in the FTR or CRR allocation process to manage the transition to ensure that as many customers as possible share in the benefits of the LMP market.

In concluding the discussion, the MSC members expressed support for the ISO's proposal to request that FERC not require the ISO to implement long-term FTRs before the market participants have gained considerable experience with the new LMP market.

Brad Barber's Last Meeting

Brad Barber was thanked by all MSC members and the ISO staff for his excellent service as a MSC member.

The public meeting was adjourned by Brad Barber at noon. The MSC met in executive session until 4:00 pm to discuss specific market participant bidding behavior.