California Independent
System Operator

Memorandum

To: The ISO Board of Governors

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

cc: Terry Winter, CEO; Charlie Robinson, VP, Legal and Regulatory;

Date: September 16, 2003

Re: ***Summary of the Market Surveillance Committee Meeting of September 15, 2003***

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

The Market Surveillance Committee (MSC) held a public meeting on September 15, 2003 at the ISO's Folsom headquarters. All MSC members were present. Brad Barber called the meeting to order and asked for any public comment. There were no public comments.

Public Session

During the public session of the meeting the following items were discussed.

1. Market Update

Greg Cook, Manager of Market Monitoring, gave a market update of the performance of the California ISO markets for the period July and August 2003. The major issues discussed were the near-record loads system-wide and record loads in SP15. The substantial amount of forward contract coverage of these loads limited the magnitude of the price spikes that occurred in the ISO's real-time markets as a result of these load levels. Another issue was the substantial intra-zonal congestion that resulted from new Mexican generation coming on line and the Vincent Substation de-rating. A final issue was the thinness of the ISO's ancillary services markets, due in part to the increasing quantity of Reliability Must-Run (RMR) units on Condition 2, which prohibits the ISO from using these units for Ancillary Services except under system emergencies. The report also presented a new competitive benchmark pricing methodology to measure market performance that compares the market price to the variable cost of the highest cost unit operating in that hour. This index an extremely conservative measure of the magnitude of market inefficiencies in the sense that it does not account for the withholding of low cost units from the market either by the owner bidding excess of the unit's variable of cost or by simply refusing to offer the unit to the market at any price. Consequently, this index can significantly underestimate the wholesale energy cost increase due to the unilateral exercise of market power and other market imperfections in the California ISO's real-time market.

2. Generation Interconnection Update

Steve Greenleaf, Director of Policy, briefed the MSC on FERC's Large Generator Interconnection Order. Several MSC members expressed serious concern about the 5-year payback provision requirement for network upgrades. By design, this policy compensates the generation unit owner for all network upgrades that it undertakes to interconnect its units. Effectively, this policy makes suppliers indifferent to the costs to consumers of the network upgrades necessary for them to interconnect, because suppliers bear no cost associated with upgrades. Consequently, suppliers are expected to construct facilities where they find the lowest new plant construction costs or access to low-cost input fuel, with no concern for the cost to consumers of upgrading the transmission network. Several MSC members felt that this policy could result in a haphazard pattern of transmission expansion that was far more expensive than necessary. The FERC policy requires transmission expansions to react to the location decisions of generation unit owners without regard to the cost, rather than undertake only those expansions that meet an economic cost-benefit test that anticipates the capacity expansion decisions of generation unit owners. In short, FERC transmission expansion policy favors generation unit owners, at the expense of consumers. Several MSC members also expressed skepticism with FERC's distinction between an "Energy Resource" and "Network Resource," because all generation resources must compete to use the transmission network in the ISO's daily congestion management process. The only meaningful distinction that seemed to make sense is to award financial transmission right to "Network Resources" for the new network transmission capacity they built. However, this would seem to contradict the ISO's desire, that the MSC supports, to allocate transmission rights to loads. Several MSC members also expressed concern with FERC's definition of "deliverability" of the energy by the new entrant. Because new suppliers would still have to compete in the daily market for transmission capacity, this concept seemed to be essentially meaningless at stated in the order, because energy from any new generation source could delivered to all parts of the network under some system conditions. In summary, the MSC felt that a substantial amount of work was necessary to craft a workable new generation interconnection policy for the California ISO consistent with framework in the FERC order. For this reason, the MSC expressed support for the ISO delaying their compliance filing to FERC.

3. Update on Intra zonal Congestion at Miguel

Keith Casey. Manager of Market Mitigation and Market Analysis, updated the MSC on the intra-zonal congestion problems at the Miguel interconnection point. Here the major issue was the methodology used by the ISO to set reference levels for INC and DEC energy bids. Keith Casey noted that under the methodology ordered by FERC, DEC reference levels are in the range of $12/MWh to $18/MWh. Because bid reference levels are supposed to represent the avoided cost of the generators not operating, several MSC members commented that these reference levels are wildly at odds with the avoided cost of producing an additional MWh from these units, given that current natural gas prices in the range of $5/MMBTU. One MSC member commented that by comparing these reference levels to the average market-clearing prices in SP15 of $50/MWh to $60/MWh, it was understandable why there was so much intra-zonal congestion in at Miguel. Suppliers could exploit the very low DEC reference levels set by the FERC-mandated methodology to play the so-called "DEC Game" by scheduling in the day-ahead market at a price greater than or equal to the expected real-time price and then pay back $12/MWh to $18/MWh for each MWh that must be decremented because of the resulting intra-zonal congestion, and receive between $30/MWh to $40/MWh for each MWh not produced. If the DEC reference levels were set based on variable cost considerations, this strategy would be much less profitable because suppliers would have to pay back almost $40/MWh to $50/MWh for each MWh of decremental energy. The MSC recommended that the ISO immediately begin collecting information on this "DEC Game" activity by Mexican generation owners to document to FERC the problems with its methodology for setting DEC bid reference levels. The MSC also recommended that the ISO make advisory recommendations on the day-ahead energy schedules by these market participants using a least-cost dispatch criterion for units in the Miguel area to manage intra-zonal congestion until FERC revises its methodology for setting DEC bid reference levels to limit the incentive for these suppliers to play the DEC game.

4. Analysis of Must Offer

Eric Hildebrandt, Manager Market Investigations, discussed the analysis he prepared in response to the letter by Reliant Energy claiming that the ISO used its must-offer authority to increase its generation reserves without purchasing these reserves through the ancillary services market. Eric Hildebrandt computed estimates of the historical operating costs of units providing must-offer energy (minimum load and start-up costs if the unit was not currently on-line), the compensation they received (minimum load costs and start-up costs [if the unit was needed to start up] and imbalance energy for the minimum load energy), and the compensation the unit would have received from running in the market for the same period. This analysis produced two results. First, suppliers of must-off capacity were paid more than their variable costs. Second, the payments these suppliers received were more than they would have earned from selling this energy in the ISO's markets. An outstanding question for several MSC members was the extent to which units providing must-offer energy where in fact being used to provide the same product as spinning, non-spinning and replacement reserves but were not being compensated for doing so. The MSC urged the DMA to undertake further analysis of this issue. The MSC also urged the ISO operators to consider purchasing more operating reserves when they do not feel that sufficient energy has been scheduled on a day-ahead basis to meet the ISO's forecast of real-time load. One MSC member noted that this issue underscores the importance of properly designing the ISO's Residual Unit Commitment (RUC) process, which should solve this problem of insufficient capacity schedule to meet the ISO's real-time load reliably.

5. Update on the CPUC Procurement Policy and Resource Adequacy

Phil Pettingill, Manager of Policy, updated the MSC on the CPUC procurement policy and resource adequacy requirement. Several MSC members commented that the goal of the state's energy procurement policy should focus not on having generation capacity built and on-line to meet future load obligations, but on the making sure that all retailers have their spot price risk adequately hedged. In particular, if retailers have lined up sufficient forward contracts to cover a large fraction of their future load obligations, then generation owners will find it in their financial interest to build the capacity necessary to meet these forward market obligations. A clear separation between forward financial market hedging and the construction of physical generation capacity is essential to ensuring that retailers have the strongest possible incentive to hedge their future load obligations at least cost and that suppliers have the strongest possible incentive to meet their forward contract obligations at least cost. In this regard, one MSC member recommended that a core/non-core customer distinction be made between final consumers. Those customers on direct access should be required to have interval meters with interruptible switches that would turn off when the retailer supplying these customers failed to procure sufficient energy in the forward market to meet its load obligations. These are the non-core customers. The core customers could be assigned to the incumbent retailer and the CPUC would set a fixed retail price (and therefore a fixed wholesale price) for these customers for a fixed duration of at least one year. If the retailer purchases a mix of forward contracts, other hedging products and demand response programs that results in lower average wholesale energy price for the retailers, then it should be required to share portion of these benefits with consumers. On the other hand, if the retailer's average wholesale energy price is above the rate set by the CPUC, then the retailer should have to pay a portion of this shortfall in reduced returns to its shareholders. This should provide strong incentives for the retailer to hedge its spot price risk. A more high-powered incentive scheme would be to put out to bid the obligation to serve core customers at a fixed price. For example, any market participant could bid for the right to supply some portion of the core customers in California at a fixed retail price for given period of time. Specifically, all suppliers would bid a fixed wholesale price at which they would be willing sell power to core customers. The winning bidders would then essentially have a fixed-price commitment to sell energy, and would therefore have a strong incentive to hedge the wholesale price risk associated with meeting these fixed-price core customer commitments.

The public meeting was adjourned at 12:30 pm

Executive Session

During the executive session the current investigation activities of ISO were discussed. The MSC was also briefed on concerns regarding the use of and compensation paid to Condition 2 RMR units. The executive session was adjourned at 3:30 p.m.