Memorandum

To: ISO Board of Governors

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

cc: Marcie Edwards, Interim CEO; Charlie Robinson, Vice President & General Counsel

Date: July 23, 2004

Re: ***Summary of the Market Surveillance Committee Meeting of July 16, 2004***

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

The Market Surveillance Committee (MSC) held a public meeting during the afternoon of July 16, 2004 at the ISO's Folsom headquarters. All MSC members were present. Brad Barber called the meeting to order and asked for public comments.

Public Comments

Jeff Nelson of Southern California Edison stated that he was listening to the MSC meeting through the conference call hook-up and was available to provide input to the discussion of the transitional market design issues as they relate to Southern California Edison.

Market Update

Greg Cook, Manager of Market Monitoring provided an update of market performance for the month of June 2004. The major highlights of his presentation were the significant growth in energy consumption relative to June 2003, an overall increase of 6.6 percent, despite a 4.7% reduction in monthly peak demand relative to June 2003. Real-time energy volumes in June 2004 also remained small. Consistent with much of the energy consumed in the California ISO control area being purchased far in advance of delivery, Cook presented two measures of system-wide market performance compiled by the Department of Market Analysis that indicated the real-time energy market was relatively competitive during June 2004.

Consistent with the intent of the California ISO's zonal energy market design, interzonal congestion costs were significantly larger than intrazonal costs in June 2004. Interzonal costs totaled $6.1 million, whereas intrazonal costs were $1.7 million. Intrazonal congestion costs were the lowest since the Mexicali generation units connected to the California ISO transmission network during the Summer of 2003. The reduction in intrazonal congestion costs was primarily due to a number of enhancements to the transmission infrastructure in Southern California. This fact underscores the importance of sufficient transmission infrastructure within congestion zones to the successful operation of a zonal energy market.

June 2004 also saw high prices for Regulation Reserve during off-peak hours. There were also few units available to provide this service during off-peak hours. Greg Cook noted that since the July 11, 2004 implementation of the Amendment 60 must-offer waiver denial process, where units that are issued waiver denials can keep their minimum load cost compensation (MLCC) if they subsequently win in the ancillary services market, has increased amount of available units selling Regulation Reserve and the prices of these ancillary services have fallen as well.

Greg Cook also noted that there has been substantial import growth, primarily due to new generation capacity in the Southwest. June 2004 achieved the highest monthly average imports in the history of the California ISO of approximately 9000 MW. This growing import dependence reflects the fact that a significant amount of low-cost generation has been constructed outside of California. To access all of this relatively inexpensive energy, California must have the transmission infrastructure necessary to transport it to the major coastal load centers.

FERC MD02 Decision Update

Lorenzo Kristov of the Policy Office summarized the June 17, 2004 FERC order that was issued in response to technical conferences on MD02 held in January and March of 2004 and the ISO's May 11, 2004 filing of its proposed solutions to the market design issues discussed at these technical conference. The order contained rulings on a number of points and specified further procedures on several others.

The FERC order eliminated the day-ahead must-offer requirement by stating that day-ahead market participation is voluntary unless required by a contractual obligation. However, the order did allow a flexible offer obligation (FOO) on an interim basis if resource adequacy requirements are not fully effective when MD02 starts.

The order eliminated a number of market power mitigation measures for the Residual Unit Commitment (RUC) process proposed in the ISO's May 11, 2004 filing. In particular, the bid cap on the RUC availability payment was raised to $250/MW instead of the $100/MW proposed by the ISO. The order also rejected the $250 cap on the sum of RUC Availability and Energy Payments and rejected freezing the energy bid curve associated with selected RUC capacity. The FERC order allows these energy bids to be changed in subsequent ISO energy markets. Several MSC members noted that these market rule changes ordered by FERC increase the attractiveness to suppliers of participating in the RUC process and therefore increase the likelihood that these suppliers can raise prices in the day-ahead market by bidding their higher opportunity cost of participating in the RUC process into the day-ahead energy market.

The order adopted the ISO's proposed simplified hour-ahead market, although it did reserve the right to reconsider these changes at a future date. The order also accepted the ISO's proposed purchase of 100 percent of its ancillary services requirements in the day-ahead market, while still allowing scheduling coordinators to substitute, rather than buy-back, equivalent ancillary services resources in the hour-ahead market. The order also accepted the ISO's proposed definition of constrained output generators (COGs) and ISO's proposals for compensating and allowing these entities to set the market-clearing price at their location. The order also accepted the ISO's proposals to include marginal losses in the locational marginal pricing (LMP) computation and to allocate the loss over-collections to the Congestion Revenue Right (CRR) balancing account.

The order expressed concern about the ISO's reluctance to implement virtual bidding during the initial stages of MD02. The ISO was ordered to submit tariff language to implement virtual bidding at start-up or provide a more substantial discussion for not doing so and state the date at which virtual bidding will be implemented. Several MSC members commented on this aspect of the order. Tariff language was suggested to implement virtual bidding at the start-up of the market through the use of financial collateral limits on market participants. In particular, on a daily basis, market participants could only take virtual bidding positions that were less than magnitudes specified by the ISO based on the amount of collateral they had placed with the ISO. During the initial stages of the market, the ISO could also put maximum limits on the dollar amount of virtual bids any market participant could make during a single day or hour of the day. The ISO could then allow larger amounts of virtual bidding to the extent that a scheduling coordinator posted larger collateral with the ISO to back up these financial transactions. The limits on the maximum amount of virtual bidding could be increased (subject to the scheduling coordinator meeting the collateral requirements) as the ISO operators gained more confidence in the virtual bidding process.

The order also proposed further proceedings associated with the existing transmission contracts (ETCs). Specifically, parties providing service under ETCs are required to file (with FERC) for each ETC a complete technical description of the ETC, as well as its expiration date. A technical conference for the State of California's seller's choice contracts was held on July 14, 2004, with a final administrative law judge (ALJ) report due September 15, 2004. At the July 14, 2004 meeting, parties agreed to a undertake settlement discussions to reach a satisfactory resolution by December 10, 2004. Parties must agree on how to interpret these contracts and what constitutes delivery of these contracts under the new market design. If a mutual agreement is not reached by December 10, 2004, the process will be referred to an ALJ. The final issue proposed for further proceedings is the CRR allocation mechanism. The principles underlying this process were contained in the ISO's May 11 filing. The FERC order noted that a number of details needed to be worked out before the allocation mechanism could be implemented.

Transition Market Design

Brian Theaker, Director of Regulatory Affairs, discussed a number of transitional market design issues relating to day-ahead energy schedules often creating significant levels of congestion that the ISO operators must manage in real-time. The redispatch costs associated with these actions are substantial, amounting to tens of millions of dollars for the first half of 2004. This redispatch process also requires significant operator attention. There are a number of factors contributing to this situation. The first is that the ISO's current interzonal congestion management system does not enforce intrazonal constraints in the day-ahead scheduling process. There is a significant amount of new generation capacity in Arizona. Because California is part of an integrated transmission network for the entire Western Electricity Coordinating Council (WECC), much of this energy flows to California whenever these Arizona units are operated, even if they are not serving California load. Finally, until very recently congestion charges were not considered as part of the least-cost procurement policy for the three large load-serving entities by the California Public Utilities Commission (CPUC).

The ISO's current new generation interconnection policy does not specify a zonal or system-wide deliverability criterion. New generation units must only meet "engineering" reliability standards to interconnect to the network. Zonal deliverability standards would require transmission owners to build out the network in each congestion zone so that all new generation capacity interconnected in that congestion zone could be delivered to all loads within that congestion zone under a wide range of system conditions. Because a zonal market design only prices interzonal constraints and assumes infrequent congestion within each congestion zone, this sequence of events can be maintained only if the transmission owner enhances the network within each congestion zone to limit the amount of intrazonal congestion, or equivalently, ensures that all new generation capacity is deliverable throughout the congestion zone it is interconnected to. The successful zonal market designs around the world in Australia, the United Kingdom and the Nordic countries, rely on this strategy for maintaining their transmission network to limit the magnitude of intrazonal congestion. If California were to adopt such a proactive transmission expansion policy within each congestion zone, this would limit the magnitude of intrazonal congestion that ultimate occurs in the current zonal market design.

Brian Theaker described a number of proposals for addressing this problem within in the current ISO market design. The first involves a two-pass CONG (day-ahead congestion management) run where the first round enforces all known binding intrazonal and interzonal constraints and sets generation unit operating limits and import limits. The second round relaxes the intra-zonal constraints and sets zonal prices subject to these generation unit operating and import limits. A second approach employs a post-day-ahead re-dispatch using a model that enforces all binding transmission and operating constraints.

Theaker described the results of a June 23, 2004 stakeholder call where these proposals were floated. He noted that a number of stakeholders argued that these solutions were not necessary because a number of enhancements to the California ISO transmission network had been made and were in the process of being made so that these changes were unnecessary. These stakeholders also argued that there were more pressing transition market design issues that should be addressing before this one. The ISO management has therefore decided to monitor the magnitude of this problem to determine whether further action is needed before MD02 is implemented.

One factor supporting this approach is the July 8, 2004 CPUC order that instructed the three load-serving entities to take into account deliverability in their least-cost procurement policy. However, it remains to be seen how this order will be implemented by the CPUC. One MSC member noted that if there were financial consequences borne by the three load-serving entities for procuring energy that cannot be delivered in real-time, it is very unlikely the ISO would face significant congestion management problems in real-time. It is primarily because purchases through the ISO markets, regardless of the price, have historically been deemed recoverable costs by the CPUC.

One MSC member noted that the re-dispatch costs associated with managing this congestion in real-time were, for the most part, costs that would be paid in a market that recognized all intrazonal and interzonal constraints in the day-ahead scheduling process. Therefore, the major issue is the reliability implications of managing this congestion in the real-time market. There was an extended discussion of these issues and possible solutions between Jim Detmers, Vice President of Operations, Brian Theaker and members of the MSC. Among the solutions discussed were improved software tools for system operation in real-time, future transmission upgrades, and allocating re-dispatch and must-offer costs to the load-serving entities that cause it.

The public meeting was adjourned at 3:00 pm.

Executive Session

From 3:30 pm to 6:00 the MSC had an executive session where decremental bidding practices on the Palo Verde intertie were discussed and an update on the impacts of LMP on locational energy prices in California was summarized. A number of scheduling details were also discussed.

Issues Currently Under MSC Study

The MSC continued to work on a number of market design and monitoring issues. Most of these issues relate to the MD02 process. Several MSC members continue to work with members of the Department of Market Analysis analyzing the impact of the State of California seller's choice forward contracts. This work has been concerned with quantifying the costs associated with these contracts in a LMP market. This work is also concerned with measuring the costs of several potential solutions to the seller's choice options in the current contracts. The two primary solutions under consideration are the formation of trading hubs for seller's choice contract deliveries or a physical feasibility requirement on seller's choice contract deliveries. Under the trading hubs solution, all contracts would be required to deliver at one of the three trading hubs specified by the ISO to replace the NP15, SP15 and ZP26 congestion zones in the former zonal market. Under the physical feasibility requirement approach, a supplier could not deliver more electricity at a location in the California ISO control area under a seller's choice contract than was actually scheduled at that location in the day-ahead market. For example, if 300 MW of energy was scheduled to be produced by a generation unit at a location in the transmission network in the day-ahead market, then no more than 300 MW of energy could be delivered to that location under the state contracts.

The MSC has also continues to analyze a number of aspects of the MD02 market design that are unique to the California market design versus the ISOs in the eastern U.S. On April 24, 2004, Frank Wolak, Chairman of the MSC, submitted a memo expressing market efficiency concerns with the ISO's proposed RUC process. Although the ISO's RUC proposal filed on May 11, 2004 addressed a number of these concerns, the FERC order issued on June 17, 2004 implemented market rule changes that caused a number of the market efficiency concerns raised in Frank Wolak's April 24, 2004 memo to become more relevant. The MSC therefore plans to continue to work with the DMA to address those aspects of the RUC process likely to reduce market efficiency that resulted from the June 17, 2004 FERC order.

The MSC has also been intimately involved with the CRR design and allocation process. As noted above FERC believes there are a number of issues associated with design of CRRs and the process used to allocate them that must be resolved before MD02 can be implemented. Several MSC members have been studying the CRR allocation mechanisms used in other US and international markets in order to formulate the best possible design of a CRR allocation mechanism for the California market. The MSC plans to report informally to the Department of Market Analysis on the results of this study and will ultimately prepare a formal opinion to the ISO Board on this very important issue.

The MSC has also been investigating potential alternative market designs should the California ISO Board decide not to move forward with locational marginal pricing as part of the MD02 process. A key part of this decision-making process is the extent to which the CPUC and other California parties embark on a comprehensive transmission expansion plan to support the current ISO zonal market design and enact procurement policies at all time horizons to delivery that provide strong incentives for LSEs to minimize intrazonal congestion costs.

Finally, the MSC has been closely following the state-level direct access discussions with an eye towards formulating a workable resource adequacy policy in a core/non-core retail market model. Two MSC members have made formal presentations to CPUC relating to this issue during the April 20, 2004 En Banc Hearing on this topic. Two MSC members have also made presentations in Sacramento to California policymakers and legislative staff on this issue on May 12, 2004.