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California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

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

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

Date: June 7, 2006

Re: ***Summary of the Market Surveillance Committee Meeting of May 31, 2006***

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

The Market Surveillance Committee (MSC) held a public meeting on May 31, 2006 at the California ISO. All MSC members were present. Frank Wolak called the meeting to order and asked for public comment.

Public Comment

Brian Theaker of Williams Power Company submitted written comments on two topics: (1) Summer 2006 Operational Requirements and Procedures for South of Path 26 (SP26), and (2) 95% Day-Ahead Scheduling Requirement and Convergence Bidding. On the first issue, Theaker expressed his preference for the ISO to use market mechanisms to procure the necessary reserves to operate the system during the range of conditions that will occur during the summer of 2006. Theaker stated that when the Pacific DC Intertie (PDCI) is out of service, operating reserves in Northern California are less valuable than operating reserves in Southern California, and ISO's ancillary services prices should reflect this difference in value. He went on to discuss the fact that the loss of the PDCI is a 20-minute problem, whereas the ISO's current operating reserve products—spinning reserve and non-spinning reserves—are 10-minute responsive. Theaker recommended that the ISO make payments to all capacity providing operating reserves, including 20-minute responsive products. On the topic of the 95% scheduling requirement and virtual bidding, Theaker argued in favor of the implementation of virtual or convergence bidding as tool to ensure accurate day-ahead scheduling of generation units. He stated that the 95-percent scheduling requirement was a command-and-control measure, whereas convergence bidding is a market solution that provides more market efficiency benefits.

Jeff Nelson of Southern California Edison provided comments on five topics. The first concerned the ISO's analysis of difference between day-ahead bilateral prices and real-time prices. Nelson stated that there are a number of costs (implicit and explicit) that discourage purchases by load-serving entities (LSEs) from the ISO's real-time market and that this can lead to lower average prices in the real-time market. The second topic was the proposed day-ahead scheduling requirement under MRTU. Nelson did not see the need for the 95% scheduling requirement because the costs of the residual unit commitment (RUC) process would be borne by market participants that did not schedule sufficient resources through the ISO's day-ahead market. However, he did support ISO monitoring day-ahead schedules and load forecasts to determine whether each market participants was systematically under or over-scheduling. The third topic was virtual bidding. Nelson recommended that virtual bidding not be implemented until the MRTU market is working efficiently. He emphasized the need to monitor virtual bidding activity to ensure that it cannot be used to evade the ISO's local market power mitigation mechanism (LMPM). Nelson also stated that virtual bidding should not be implemented by the ISO until the CPUC allows the three major LSEs to engage in virtual bidding. The fourth topic was how the ISO plans to use Southern California Edison's I-6 tariff interruptible customers in its proposed Summer 2006 operating procedures. Nelson noted that SCE's I-6 tariff interruptible customers can be used only when the ISO declares a Stage 2 emergency. He also stated that I-6 tariff customers are, by far, the largest amount of megawatts (MWs) of interruptible load available to SCE. Nelson concluded by stating that SCE supports a centralized capacity market.

Market Performance Report

Deborah Le Vine, Director of Market Services, presented the market performance report for April and part of May. The major issue of the month was the high levels of hydroelectric production both within and outside of California. This resulted in low (relative to estimated natural gas-fired generation variable costs) bilateral energy prices in California, and a number of reliability challenges for the ISO operators. Hydroelectric generation units located in California often provide ancillary services to the ISO, but because of high water levels in the lakes, anticipated high runoff, and limited water storage capacity, most hydroelectric units in the Western Electricity Coordinating Council (WECC) are currently forced to operate. Consequently, bid insufficiency in the ancillary services market increased substantially and total ancillary services costs to load increased by 72% relative to March 2006. The total amount of generation capacity bid into the ISO's real-time decremental and incremental markets also declined relative to March 2006. The ISO continues to monitor the frequency of prices above the former $250/MWh soft bid cap. The real-time five-minute energy price exceeded the $250/MWh soft cap in 89 of the 5-minute dispatch intervals during April, or 1.09% of the total dispatch intervals during the month.

Another contributing factor to the volatility of real-time prices during April is that nearly 15,000 MW of the generation capacity in the California ISO control area was out of service at the beginning of the month. This figure declined to slightly below 10,000 MW by the end of the month. This amount of generation outages and a significant number of transmission outages contributed to Minimum Load Cost Compensation (MLCC) payments that were double the levels in March 2006. For similar reasons, both intrazonal and interzonal congestion costs were substantially higher in April relative March of 2006.

Capacity Market Design/CPUC Resource Adequacy Phase 2

David Withrow of the Department of Product and Market Development presented a summary of the California Public Utilities Commission (CPUC) Phase 1 Resource Adequacy (RA) proceedings and outlined the Phase 2 process that will begin this summer. He noted that the Capacity Market Advocate Group has formed to develop capacity market proposals and that will be submitted to the CPUC in the Phase 2 workshop discussions. Withrow then summarized the current state of capacity markets in the ISOs located in the eastern United States. Finally, Withrow posed several questions about the design and operation of a capacity market in California that the ISO would like the Market Surveillance Committee to address in a MSC opinion.

James Bushnell of the Market Surveillance Committee then gave a presentation on the factors that should go into design of the procurement process under MRTU. He contrasted the roles of reliability must-run (RMR) units and the must-offer waiver denial process in ensuring system reliability. Bushnell noted that RMR units provide reliability benefits in the sense that they can fill in gaps in the ISO's energy and ancillary services needs that the ISO's market mechanisms fail to provide. In addition, RMR contracts also play a role in mitigating the local market power of generation units needed to provide energy at certain locations in the ISO control area. Although the must-offer waiver denial process was initially designed as a market power mitigation mechanism, Bushnell expressed concern about whether it was being used by the ISO operators to provide unloaded generation capacity where the operators need it. The ISO operators have recently expressed a need for generation capacity that provides additional energy or less load with a 20-minute response time. The must-offer waiver denial process can be used by the ISO to provide this unloaded capacity. Bushnell concluded his presentation with a question of whether the must-off requirement was needed under MRTU because the ISO has the RUC process as a backstop after the close of the day-ahead market to meet its reliability constraints.

These two presentations were followed by a discussion among MSC members and the audience about the need for capacity markets in California and the design of capacity markets if California decided to adopt one. Jeff Nelson of SCE outlined the basic features of SCE's proposed 4-year forward locational capacity market with short-term penalties for non-performance by the seller of the capacity product. Joe Lawlor of Pacific Gas and Electric emphasized the need for the capacity product to address locational needs and the fact that California can be energy-constrained because of its dependence on hydroelectricity. Mary Lynch from Constellation Energy asked that the ISO and MSC study the New York ISO's approach to capacity markets.

Frank Wolak questioned the need for a long-term centralized capacity market administered by the ISO versus a centralized long-term energy market administered by the ISO. He argued that the one of the reasons so many parties are attracted to capacity markets is because the capacity product is so difficult to define and therefore rewards those parties that are best able to participate in the market design process. These market participants are able to cause the capacity product to be defined in a manner that benefits them. In contrast, energy is a well-defined product not subject to regulatory interpretation. It is straightforward to verify whether a supplier provided the energy the LSE contracted for. If it is determined that a centralized reliability forward market is required, Wolak argued in favor of a centralized market for forward contracts for energy administered by the ISO instead of a centralized capacity market. He stated that this market would provide greater reliability at lower costs to consumers and the needed revenue adequacy to suppliers to construct the new generation capacity needed to serve the load growth. Similar to the mandatory requirement that all LSEs meet certain capacity requirements in the forward market (for example, 115% of peak demand 2 years in advance); under Wolak's proposal LSEs would have energy requirements in the forward market (for example, 90% of demand 2 years in advance.)

All MSC members emphasized that if California decides to go the capacity market route, the product should be designed so that it resembles an energy option contract to the greatest extent possible. Specifically, the capacity product would have an explicit strike price in the sense that the supplier of the capacity product would be liable for non-compliance payments if it did not bid into the energy market when prices where above some level. More generally, the MSC member argued for the adoption of sizeable performance penalties for suppliers of capacity that failed to meet their contractual obligations.

The final issue discussed was the ISO's backstop role in the procurement process. Katie Kaplan of the Independent Energy Producers expressed concern that the LSEs might rely on the ISO backstop instead of procuring the necessary locational capacity or energy. Several MSC members acknowledged that this was a concern and stated that the procurement process should be designed so that reliance on the ISO backstop would be very expensive for all LSEs.

Analysis of Real-Time Prices Relative to Day-Ahead Bilateral Prices

Holly Liu of the Department of Market and Product Development presented an analysis of relationship between day-ahead bilateral prices and prices from the ISO's real-time market. Liu showed that during 2002, the day-ahead bilateral price and the real-time price showed no systematic differences for all hours of the day. However, during the first half of 2003, day-ahead bilateral prices began to be systematically higher than real-time prices for all hours of the day. This difference has averaged more than $10/MWh from June 2003 to November 2005. Liu offered a number of possible explanations for this difference. The first was risk aversion for buyers relative to seller of forward contracts. During the first half of 2003, the CPUC issued its long-term procurement order to California's three large LSEs granting them greater flexibility to enter into long-term contracts for energy. This may have led the

LSEs to purchase a substantial amount of forward contracts so that the real-time energy market became primarily a decremental market. Liu presented evidence showing that decremental energy volumes have been significantly greater since May 2003. Before that time, decremental and incremental volumes in the real-time market were roughly equal.

MSC members and several members of the audience commented that there were a number of reasons why the real-time price may not capture the full cost of purchasing energy from the real-time market. In particular, purchasers from the real-time market must pay MLCC costs, out-of-sequence costs and out-of-market costs, in addition to the real-time energy price. Although these costs have averaged approximately $3/MWh sold through the real-time energy market, there were months when these costs averaged $20/MWh. Consequently, day-ahead bilateral prices that are higher than the ISO's real-time prices appear to reflect the risk of higher total costs of purchasing from the real-time market beyond just the real-time price.

Bidding Behavior: ISO's Ancillary Services Markets

During the lunch break from noon to 1 pm, **Eric Hildebrandt** of the Department of Market Monitoring gave a presentation to the MSC on the bidding behavior in the ancillary services markets of specific market participants.

Transmission Planning Need Assessments: Methods and Issues

David Withrow of the Department of Market and Product Development discussed a challenge faced by the ISO's transmission planning process with respect to renewable resources. Because energy from a renewable resource must be produced where the resource is located, long and expensive transmission lines are typically necessary to interconnect the renewable resource to the bulk transmission network. For the most part, these upgrades cannot be classified as network upgrades or necessary for reliability or economic reasons. They are constructed to deliver the renewable resources and, under the existing ISO transmission upgrade policies, the developer of the resource is required to pay the full cost of these transmission upgrades, which can be a substantial portion of the total costs for a renewable energy project. The need for these transmission upgrades raises potential barriers for developing renewable resources and may significantly increase the cost of meeting California's renewable portfolio standard (RPS). Withrow posed the question of whether the ISO should create another type of transmission facility to address this issue.

The discussion among MSC members emphasized that if the state's RPS was a hard constraint similar to a reliability constraint, then it may be unnecessary to create a new category of transmission facilities. The constraint of meeting the RPS could be included in the transmission planning and evaluation process so that the most economical upgrades needed to meet this standard would be constructed. The goal would be to construct the least-cost transmission network for California that met the constraint of allowing sufficient renewable resources to interconnect to achieve the RPS standard.

Renewable generation unit owners constructing facilities that require transmission upgrades beyond those determined by the ISO's evaluation to meet the RPS would be treated in the same manner as existing generation interconnections. The generation owners would be required to pay for the upgrade and would be subsequently reimbursed if the upgrade were determined to be a network upgrade. Otherwise, the generation unit owner would be required to pay for the upgrade. This was thought to discourage renewable entry at locations that the ISO's transmission planning process did not identify as one of the best locations for renewable resources.

On the issue of cost allocation, MSC members felt that if the RPS exists as a state-wide requirement, then the cost of the transmission upgrades necessary to meet the RPS should be included in the system-wide transmission access charge paid by all ISO market participants. Thus, to the extent that municipal utilities use the California ISO control area transmission facilities they would pay a share of the cost of the transmission upgrades needed to meet the RPS standard. One MSC member suggested this impact could be mitigated by requiring renewable generators to pay their pro rata share of the transmission facility as they interconnect. Thus the high cost for the transmission line that is needed from renewable resource regions would be borne initially by ISO participants, but potentially the entire amount could be paid back with interest as renewable energy plants are constructed.

Day-Ahead Scheduling Requirements and Convergence Bidding

James Bushnell of the MSC gave a presentation on the proposed 95% scheduling requirement and convergence bidding based on the short paper he and Frank Wolak have written on this topic for the ISO Board of Governors. The major concern to addressed with a 95% scheduling requirement under MRTU is that 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.

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. All these factors would imply little need for a 95% scheduling requirement. .

One MSC member noted that given the high level of fixed-price forward contracting for energy in advance of the day-ahead market, a 95% scheduling requirement is more likely to degrade rather than enhance market efficiency. 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 limits the amount of energy California LSEs are allowed to purchase between the close of the day-ahead market and real-time market. This logic implies that a 95% scheduling requirement could cause California loads to forego purchasing cheaper imports available after the close of the day-ahead market.

The high level of fixed-price forward contracting by the three large California LSEs also argued in favor of implementing convergence bidding under MRTU. Day-ahead and real-time prices that closely track each other will ensure that suppliers schedule their units in the day-ahead market rather than wait until the real-time market in the hope of selling at a higher price. The potential adverse consequences of convergence bidding are unlikely to arise if the vast majority of final consumption is hedged in fixed price forward contracts. Suppliers will have little incentive to take large speculative virtual positions because they know that major counterparty to these positions is another generation unit owner. If loads are fully hedged against day-ahead price risk, they have no incentive not to schedule all of their contracted energy in the day-ahead market.

Summer 2006 Operational Requirements and Procedures for SP26

Dariush Shirmohammadi, Director of Regional Transmission--South discussed the proposed Summer 2006 operating plan to address potential operating problems, particularly those in South of Path 26 (SP26). Shirmohammadi stated that the capacity situation North of Path 26 (NP26) is forecasted not to present any significant reliability problems. However, under extreme conditions there could be reliability problems in SP26, particularly if the Pacific DC Intertie (PDCI) fails. Shirmohammadi presented the results of a study of what is required to replace the Path 26 flow within its rating after the loss of the PDCI. He then presented the ISO's proposed operating plan for capacity adequacy in SP26. During this discussion a number of issues were raised by members of the audience and members of the MSC.

Because this operating plan takes into account the amount of 20-minute responsive reserves available to the ISO, the first major question posed was how the ISO would obtain the necessary 20-minute responsive reserves given that the ISO runs operating reserves markets for 10-minute responsive products. The must-offer waiver denial process appeared to be the only way for the ISO to obtain needed 20-minute responsive reserves, although it was unclear to those in the audience precisely how this might work.

The second major issue was how interruptible demand would be used. Audience members from SCE and PG&E emphasized that the vast majority of their interruptible load could only be used if the ISO called a Stage 2 emergency. However, it appeared to several audience members that the ISO would count interruptible loads as reserves without calling a Stage 2 emergency. Further discussions between audience members and the representatives from ISO operations attempted to clarify this issue.

The third major issue was how the ISO operators could be assured of getting the necessary operating reserves in the locations that they needed. The must-offer waiver denial process appears to be the only way for this to occur. This has been an ongoing issue in ISO's ancillary services procurement process and was emphasized in Brian Theaker's written comments to the ISO Board several months ago. Theaker is concerned that the must-offer waiver denial process can allow the ISO to obtain operating reserves in the needed locations by denying waivers to generation owners located in these areas. Even if these units do not subsequently bid into the ISO's ancillary services markets or have their bid accepted in an ancillary services market, they must remain on at their minimum operating level.

The fourth major issue arose as a result of the discussion of whether slow ramping units located in SP26 that are dispatched upward following the loss of the PDCI would be allowed to set the price in the ISO's real-time market. Typically, bids from faster ramping units will be skipped to allow them to continue to provide reserves, while the slower ramping units are dispatched up. Allowing the slower ramping units to set the market price will create a circumstance where the faster ramping units that are skipped and not asked to provide additional energy with have an incentive to produce more energy in order to obtain this higher price. This logic argues in favor of paying these slower ramping units out-of-sequence and not allowing them to set the market price. However, to the extent that these slower ramping units know they will be needed and paid as bid, they will have an incentive to bid a much higher price. The general conclusion of this discussion was that the ISO should make this policy consistent with its policy to skip the energy bids of certain generation units in order preserve these generation units for a contingency.

The final issue is when and how RA units would be used versus non-RA units in determining local capacity needs. It seems reasonable for the ISO to assume that the unloaded capacity from fast (faster than 20 minutes) ramping resources can be obtained by denying waivers to slow ramping RA resources. However, the unanswered question is how the ISO will choose among non-RA units when it issues must-offer waiver denials.

There was a very lively discussion among MSC members, the ISO operators, and members of audience on these issues, which continued until 4:45 pm when the meeting was adjourned by Frank Wolak.

The MSC met in executive session until 5:30 pm to discuss administrative issues relating to future meeting dates.