California Independent
System Operator

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers

Date: October 12, 2006

Re: ***Summary of the Market Surveillance Committee Meeting of September 18, 2006***

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

The Market Surveillance Committee (MSC) held a public meeting on September 18, 2006 at the California ISO. All MSC members were present. Frank Wolak called the meeting to order and asked for public comment.

Public Comment

Jeff Nelson of Southern California Edison (SCE) spoke on three topics. The first was virtual or convergence bidding. Nelson emphasized that SCE does not oppose the implementation of the virtual bidding if several pre-conditions are met: (1) INC and DEC virtual bidding are allowed at the Load Aggregation Point (LAP) level and (2) a market monitoring process is in place to ensure that virtual bidding cannot be used to evade the CAISO's local market power mitigation mechanism. The second topic was the CAISO's deliverability analysis. Nelson stated that the CAISO's deliverability analysis assumed that 100% of California's wind capacity was available. He felt that this assumption could badly bias any analysis of deliverability of generation units because the analysis is performed for peak demand conditions. California's wind generation units produce at capacity utilization rates less than 10% during peak demand conditions. For example, during the July 2006 heat storm, wind facilities operated at capacity utilization rates less than 5%. The third topic was capacity markets. Nelson noted that SCE also supports a four-year-ahead capacity market with a capacity obligation that applies to all Load Serving Entities (LSEs).

David Withrow of Market and Product Development and **Eric Hildebrandt** of the Department of Market Monitoring gave a presentation on the major issues associated with implementing virtual or convergence bidding under the Market Redesign and Technology Upgrade (MRTU) reforms that have been and will continue to be discussed at stakeholder meetings. The key implementation issues under consideration are: (1) the spatial granularity of allowable virtual bids, (2) the choice of load distribution factors used to compute spatially aggregated prices in the day-ahead and real-time markets, and (3) provisions for market power monitoring and mitigation against potentially adverse market impacts of virtual bidding. Withrow's presentation focused on the first two issues and Hildebrandt's concentrated on the third one. Withrow noted that the MSC would be asked for an opinion on the implementation details of virtual bidding, but this would not be needed until early in 2007.

Following Withrow's presentation there were a number of comments by MSC members and stakeholders on the first two issues. The MSC proposes a design principle for virtual bidding that physical and virtual bids should be treated in the same fashion unless there are compelling market efficiency reasons not to do so. According to this logic, virtual INC bids would be allowed at the nodal level in the day-ahead market similar to generation units bidding at the nodal level in the day-ahead market, and virtual DEC bids would be allowed at the LAP level in the day-ahead market similar to physical demand bidding at the LAP level in the day-ahead market. This logic would also imply that day-ahead load-distribution factors would be used to compute the LAP price for virtual bids cleared in the day-ahead market and real-time load distribution factors would be used to compute the LAP price for virtual bids cleared in the real-time market, similar to the way LAP prices are computed in the day-ahead and real-time markets for physical energy. Several stakeholders argued that there should be symmetry between virtual INC and DEC bids in terms of the spatial granularity of the bids allowed. **Brian Theaker** of Williams Power Company argued that if DEC virtual bids were only allowed at the LAP level, then virtual INC bids should only be allowed at the LAP level. Equivalently, he stated that if virtual INC bids were allowed at the nodal level then virtual DEC bids should be allowed at the nodal level. In response, **Jeff Nelson** of SCE reiterated SCE's position that virtual bids should only be allowed at the LAP level.

Frank Wolak argued in favor of INC and DEC virtual bidding at the nodal level on the grounds that the major source of market efficiency benefits from virtual bidding in a locational marginal pricing (LMP) market resulted from transactions at the nodal level. Several stakeholders noted that PJM and New England currently allow virtual bidding at the nodal level and these ISOs have identified no adverse consequences from this functionality. Wolak stated that restricting virtual bids to the LAP level could render the potential benefits of virtual bidding so small that few, if any, market participants would make use of this functionality and the CAISO would end up spending significant sums of money to implement a market design change that is rarely used. Wolak gave several examples illustrating why the spatial granularity of virtual bids are the major source of market efficiency benefits from virtual bidding. With virtual bidding at the nodal level a generation unit owner can receive the real-time price of energy for all energy produced from its unit despite the fact that the unit is fully scheduled in the day-ahead market. Virtual bidding at the LAP level does not provide the generation unit owner with this functionality. The generation unit owner's INC bid at the LAP level will be distributed to the nodes comprising the LAP using the day-ahead load distribution factors. In addition, virtual bidding at the nodal level will allow a Congestion Revenue Rights (CRR) holder to earn the real-time congestion charge between two locations in the network instead of the day-ahead congestion charge between the two locations. Virtual bidding at the LAP level does not allow this transaction if the two nodes are within a LAP and allows a very imperfect form of this functionality if the two nodes are located in different LAPs.

Jeff Nelson responded that allowing virtual bidding at the nodal level would provide market participants with greater opportunities to take privately profitable actions that would harm system reliability and market efficiency. Wolak acknowledged that without appropriate safeguards, the potential for adverse market outcomes is greater with virtual bidding at the nodal level versus LAP level. He emphasized that if California LSEs maintain the current level of coverage of final demand with fixed-price forward contracts under MRTU, the risk of these adverse market outcomes is extremely small. In addition, there are market power mitigation measures that could be implemented to further reduce this risk. The CAISO could implement virtual bidding position limits, because most virtual bidding behavior that causes harm to system reliability and market efficiency involves a single market participant taking a sizeable financial or virtual position in the day-ahead market. By limiting the total MWhs that a market participant can submit in INC or DEC bids at a location and across all locations within an hour and the day, the CAISO can prevent suppliers from taking these sizeable and potentially harmful financial positions in the day-ahead market and allow the market efficiency benefits of virtual bidding at the nodal level to be realized.

Several MSC members and stakeholders also raised the question about what transactions costs virtual bidders would be subject to. Several MSC members noted that the principle of equal treatment of physical and virtual supply and demand should apply here. As a general rule, the MSC members felt that virtual sales and purchases of energy in the day-ahead market should be treated in the same way as physical sales and purchases in the day-ahead market and be subject to the transactions costs – grid management charges, operating reserves charges and Residual Unit Commitment (RUC) charges – as physical generation and loads. The MSC members noted that there may be a need for exceptions to this general rule, but they argued that a high standard, in terms of expected market efficiency benefits, should be required to justify any deviations from this general principle. They noted that deviations from this principle could create arbitrage opportunities between the physical and financial markets for energy that may detract from overall market efficiency and system reliability.

Jeff Nelson raised an extremely important point about the regulatory treatment by California Public Utilities Commission (CPUC) of profits and losses from virtual bidding by the three investor-owned utilities (IOUs). He noted that the CPUC had not issued any guidelines on how the costs and revenues from virtual transactions would be treated in the CPUC rate-making process. One MSC member responded that a necessary condition for implementing virtual bidding under MTRU should be rules from the CPUC on how these revenue and cost streams are be treated in the regulatory process. One simple mechanism that the CPUC could implement would place company-specific limitations on the total MW volume of virtual bids within an hour-of–the-day, day-of-the-week, and month-of-the year that could be submitted by each of the IOUs. Within these guidelines, the shareholders of these companies would bear the risk and receive the rewards from the IOU's virtual bidding activities.

Eric Hildebrandt described various dimensions of the market monitoring process for virtual bidding that were currently under consideration by the CAISO. The CAISO is not proposing to apply its bid price mitigation mechanisms to virtual bids. The CAISO does plan to have collateral requirements for virtual bidders. Specifically, this requirement would mandate that market participants provide collateral to the CAISO in advance of virtual bidding and the amount of collateral held by the CAISO would limit the amount of virtual bids that market participant could make. Hildebrandt noted that all of the eastern ISOs have collateral requirements. Hildebrandt emphasized the importance of understanding how virtual transactions are settled in the eastern ISOs in order to design the best possible virtual bidding protocols. **Frank Wolak** seconded Hildebrandt's concerns and asked if the Department of Market Monitoring could investigate the total cost of various sorts of virtual transactions in the eastern ISOs. One example is the total cost of a 1 MWh virtual INC or DEC bid that is accepted in the day-ahead market. How much does the market participant pay in day-ahead and real-time charges – the grid management fee, operating reserve charges, RUC availability charges and any other uplift charges – for the round-trip transaction of a 1 MWh sale (purchase) in the day-ahead market and a 1 MWh purchase (sale) in the real-time market. Having this information for all of the ISOs that currently allow virtual bidding would provide a very important input into the process of designing the virtual bidding protocols for MRTU.

Jeff Nelson raised the issue of public release of virtual bids as part of the market monitoring process. He advocated day-ahead release of all virtual bids and offers and sales without explicitly identifying the market participant. He wanted individual bids by the same market participant within the day and over time to be identified by a code instead of the market participant's name. Frank Wolak strongly supported the public release of virtual bid data on a day-ahead basis with the market participant's name associated with the bid. He further advocated for the release of bids and offers by all CAISO market participants without coding the identities of the market participants whether or not they were made by physical or virtual resources or loads. He argued that with high levels of fixed-price forward contracting for energy and ancillary services, the bids submitted by market participants convey little, if any, information about their underlying costs of production or any other company-specific confidential information. In addition, the release of bid information in a timely manner with the identity of the market participant would serve a very beneficial sunshine regulation function in enhancing overall market efficiency. Any market participant that wanted to bid in a manner that degrades system reliability and market efficiency would face the risk of having to explain this behavior to the press and general public. Wolak used the example of the California Electricity Crisis period, when the confidentiality of bids and offers submitted to the CAISO markets allowed market participants to bid to degrade market efficiency and overall system reliability with little public scrutiny.

Lorenzo Kristov of Market and Product Development gave a presentation on the CAISO's plans for offering Long-Term Transmission Rights. Kristov noted that the CAISO had determined that the Federal Energy Regulatory Commission's (FERC) final rule implementing the directive in the 2005 Energy Policy Act requiring organized wholesale electricity markets to provide long-term transmission rights did not apply to the current California ISO market design, but did apply to the MRTU design. He noted that offering of long-term transmission rights was a high-priority market design element for the CAISO.

Kristov then discussed seven guidelines in FERC's final rule and described the current thinking at the CAISO on each. In most cases, the CAISO's current CRR allocation process and CRR products were consistent with the guidelines. The FERC guidelines state that the CRR product should specify a source, sink and quantity of MWs awarded and that the product should be purely financial in the sense that the CRR does not have any priority for scheduling energy between the source and sink of the CRR. These guidelines also state that load-serving entities (LSEs) should have priority for transmission rights on the existing transmission network, the transmission rights should follow load as it moves from one LSE to another, parties that make additional transmission rights available by expanding the network should receive these transmission rights, and the process used to allocate these transmission rights does not have to be an auction. The current MRTU CRR product and allocation process is consistent with all of these FERC guidelines.

There are two guidelines that are somewhat more challenging for the CAISO to comply with given the existing MRTU CRR product design. One guideline states that the long-term hedge provided by the long-term transmission right cannot be modified. This would seem to imply that right should be fully funded in the sense that the CRR should always have the obligation or payment equal to the difference between the price at the sink and the source of the CRR times the number of MWs of transmission rights owned between these two locations. The CRRs that will exist under the MRTU design do not have this fully funded guarantee. Under the MRTU design there are provisions to reduce the amount of payments made proportionately if the CAISO fails to collect a large enough revenue surplus (the difference between the amount paid for energy by loads and the amount paid to generation unit owners for their energy) to fully fund its CRR obligations. The second problematic guideline states that the terms of the transmission rights must be sufficient to hedge long term power supply arrangements. This guideline raises the question of how should the terms of the long-term CRRs be set. The current MRTU CRR allocation process has renewal provisions the following year for CRRs that were allocated in previous years. The entity with the renewal right also has the right to refuse to take the CRR in the following year.

Several MSC members noted that a multi-year CRR with the right to refuse to renew each year can be a far more valuable product than a multi-year CRR with the obligation to receive or pay the difference between the price at the sink and the price at the source of the CRR for the duration of the transmission right. These MSC members argued that any long-term CRR issued by the CAISO should not include the right to terminate the CRR at any point in the future. The long-term CRR should have the same payment and cost obligations as a one-year CRR, except it should be for multiple years. The right to terminate the CRR at any time in the future also makes it extremely difficult for the CAISO to do multi-year simultaneous feasibility studies. If market participants terminate long-term CRRs with negative expected values, this eliminates a source of revenues to the CAISO that can be used to fund CRRs with positive expected values.

On the question of fully funding long-term CRRs, several MSC members felt that the CAISO should not create two classes of CRRs, one that is fully funded and another that is not. Because of the FERC guideline to fund fully the long-term CRRs, these MSC members thought that all CRRs issued by the CAISO, both short-term and long-term, should be fully funded. If there is a revenue shortfall, the CAISO should fund the necessary CRR payments from the grid management charge collected by the CAISO, rather than reduce the payments made to any CRR holder. The promise to fund all CRRs fully and the need to raise the grid management charge to do it should enhance the competitiveness of the secondary market for CRRs, because all CRRs issued by the CAISO could compete in a homogenous secondary market. If some CRRs were fully funded and others were not, this is likely to reduce the competitiveness of the secondary market, because it would be very likely to bifurcate into two markets—one for fully-funded CRRs and another for partially-funded CRRs.

One MSC member urged the CAISO to keep the long-term transmission right product and allocation process as inexpensive as possible by building on the existing CRR product and allocation process as much as is feasible. He recommended creating long-term CRRs that were exactly the same as the current one-year CRRs that will be offered under MRTU, with the only difference being the length of the CRR obligation. He could see no compelling need to make the process more complicated as long as the CRR were allocated to LSEs and followed load as it moved between the various LSEs.

Greg Cook, Manager Tariff & Regulatory Policy Development, gave a presentation on the CAISO's proposed alternative treatment of transmission interconnection for renewable generation resources. The MSC wrote an opinion on this issue for the October CAISO Board meeting entitled, "Opinion on 'Alternative Treatment of New Transmission for Interconnection of Renewable Generation,'" October 3, 2006. This opinion is provided as a separate attachment.

Robert Sparks, Lead Regional Transmission Engineer, presented a summary of the CAISO's deliverability analysis. He noted that the CAISO performs these studies to serve two purposes: (1) the CAISO's generation interconnection procedures require a deliverability assessment for the new capacity that will interconnect, and (2) to determine deliverable capacity for the CPUC resource adequacy (RA) process. The deliverability methodology is based on the PJM methodology and is designed to determine the extent to which generation can be transferred throughout the CAISO control area under peak load conditions. In particular, available capacity within a sub-area of the CAISO control area must be able to be exported to other parts of the control area experiencing a resource deficiency due to a forced generation outage.

The major conclusion of the Phase IIA study is that significant new generation investment in the California ISO control area could be accommodated without the need for significant transmission network upgrades, given the transmission upgrades recently completed and currently under construction. Specifically, approximately 3,000 MW of additional capacity could be added in the San Diego Gas and Electric (SDG&E) area, approximately 5,000 MW in the Southern California Edison (SCE) area, and 7,000 MW in the Pacific Gas and Electric (PG&E) area. For certain generation pockets in Northern California transmission upgrades would be necessary to ensure deliverability of new generation units.

In response to PG&E's and SCE's concerns about wind generation assumptions in the deliverability studies, the CAISO responded that the Phase IIA study limited the wind generation output to its maximum production amount during summer peak load hours which is between 80%-95% of installed capacity, depending on the size of the wind area. However, the CAISO is currently developing a modified approach to wind generation modeling that it proposes to use in preparing revised Phase IIA study results and in future deliverability studies.

The presentation was followed by a discussion among MSC members and stakeholders about the deliverability study and the concept of deliverability in general. Several MSC members questioned the apparent priority given to existing generation units relative to new generation units in the deliverability study, despite the fact that new generation units are typically much lower cost than existing generation units and would therefore be able to under bid them and be dispatched with a higher priority than existing generation units.

Frank Wolak gave a presentation on capacity market design issues. He first described the rationales offered for capacity payment mechanisms and markets. The two most credible are: (1) low levels of bid cap on the short-term energy market and (2) lack of active demand-side participation in the wholesale market. Wolak then noted the experience with capacity markets in the United States has been extremely disappointing, which explains why a number of the eastern ISOs are considering overhauls of their capacity payment mechanisms. Wolak then turned to the question of whether capacity payment mechanisms are necessary for resource adequacy in California. In other words, is a capacity market necessary for there to be adequate generation capacity to meet demand.

Wolak stated that a number of unique features of the California market make a capacity market an inappropriate and extremely expensive approach to resource adequacy, particularly given the results of the Summer of 2006 with the state's existing resource adequacy process. California obtains roughly 20% of its energy needs from imports and it is virtually impossible to determine which generation unit located outside of California is providing the energy to California. California is also substantially more dependent on hydroelectric energy than any eastern ISO. This implies the energy shortfalls rather than capacity shortfalls are the major resource adequacy problems for California. As a consequence, fixed-price long-term energy contracts are the least-cost way to hedge this risk. In a hydro dominated system, even if there is adequate generation capacity a market meltdown can occur if there are limited amounts of water available and limited fixed-price forward contract coverage of final demand to ensure that suppliers have an incentive to supply energy rather than withhold to increase the short-term price. Wolak noted that a far less expensive strategy for obtaining a high level of reliability in California is to continue to fix the remaining problems with the existing resource adequacy process that is based on high-levels of fixed-price forward contracts for energy. He noted that California managed to survive the extremely high load level associated with the July 2006 heat storm with few price spikes in the real-time market because of the high levels of fixed-price forward contract coverage of final demand.

Wolak emphasized that fixed-price forward contract for energy coverage of virtually all final demand would be necessary even if California adopted a capacity market, because of the two unique features of the California market described above. Because adequate fixed-price forward contract coverage of final demand is a sufficient condition for workably competitive short-term market and reliability grid operation, a capacity market is an unnecessary expense if this contracting is done far enough in advance of the clearing date to allow new entrants to compete to supply these contracts. In addition, because California is adopting a LMP market under MRTU, it will be much more straightforward for LSEs to contract for the necessary energy in a physically feasible manner, which will further enhance grid reliability and market efficiency. Wolak hoped that the CPUC and other California parties would consider the costs and benefits to California of a capacity payment mechanism or market.

Wolak then discussed key design features of a capacity payment mechanism if California parties decided that it was needed. The first feature is to provide strong incentive for generation unit owners to be available to provide energy when their capacity is needed. One way to provide this incentive is to require all sellers to pay the difference between the day-ahead nodal price at their location and a strike price, if it is positive, times the number of MW of capacity that was sold from that generation unit each hour to the purchaser of the capacity for the duration of the capacity contract. This strike price should be set at a value higher than the highest variable cost unit in the California market, but significantly lower than the bid cap on the short-term energy market to provide strong incentives for the supplier to bid this capacity into the market when prices at its location are likely to be higher than the strike price. The second feature is to distinguish between system-wide and local capacity requirements. Local capacity requirements are those that can only be served by a small number of suppliers and the market prices charged are therefore likely to reflect substantial unilateral market power on the part of the supplier. Consequently, the prices for local capacity requirements typically must be set through an administrative process. In contrast, prices for system-wide capacity requirements can be set through market mechanism because there are many suppliers able to provide this product. The third feature is to continue to emphasize the need for high levels of fixed-price forward contract coverage of the final demand for energy to limit the incentives for suppliers to exercise unilateral market power in the short-term energy market. The final feature is to make the capacity market purely financial as long as there is no compelling system reliability requirement to make the product physical. This maximizes the flexibility that suppliers have in fulfilling their capacity obligations, which reduces their costs of supplying this product and the price they must charge to cover these costs.

Wolak did not see a significant distinction between a centralized versus bilateral capacity market. In the subsequent discussion, **James Bushnell** noted that this distinction is often confused with the more important issue of whether an administrative process is used to set market price and all capacity is paid that market price versus a market where all retailers have a MW obligation and capacity prices are set through bilateral negotiations and some capacity can end up receiving no capacity payment. The MSC argued for limiting the use of administrative processes for setting capacity prices to those geographic areas where there is insufficient competition to rely on market mechanisms to set prices.

There was a very lively discussion among MSC members, the CAISO operators, and members of the audience on these issues, that continued until 5:00 pm when the meeting was adjourned by Frank Wolak.