California Independent
System Operator

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers

Date: March 1, 2007

Re: ***Summary of the Market Surveillance Committee Meeting of February 13, 2007***

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

The Market Surveillance Committee (MSC) held a public meeting on February 13, 2007 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. He argued that there was a loophole in current MRTU market design because start-up and minimum load bids are not capped. The only market power mitigation mechanism in the current MRTU tariff is the requirement that these bids remain fixed for a six-month period. Nelson stated that under the current MRTU tariff, a supplier that knows its generation unit must be committed several times during a six-month period has unlimited ability to exercise unilateral market power with its start-up and minimum-load bids. He urged the ISO to implement additional market power mitigation measures before MRTU begins operation to address this concern. The second topic Nelson discussed is a proposal for a 95 percent scheduling requirement under MRTU. He argued against additional mechanisms to limit under-scheduling under MRTU. Nelson believes that the current market design has sufficient financial incentives that discourage under-scheduling because residual unit commitment (RUC) costs are allocated to the load-serving entities that under-schedule in the day-ahead market. Nelson wants the ISO to avoid measures that effectively force buyers to purchase out of the day-ahead market, because the MRTU design provides valuable options, such as the hour-ahead scheduling process (HASP), for load-serving entities to purchase additional energy and ancillary services following the close of the day-ahead market. The third issue raised by Nelson is the need to define ancillary services purchase regions under MRTU in order to measure the competitiveness of these local markets and determine whether additional local market power mitigation measures for ancillary services bids are needed under MTRU.

Approve Minutes from November 13, 2006 and January 18, 2007 Meetings

Following public comment, the MSC unanimously voted to approve the minutes from the November 13, 2006 and January 18, 2007 meetings.

General Session

Bid-Cap for Start-Up and Minimum Load Costs

Ming Yung Hsu, Senior Market Monitoring Analyst in the Department of Market Monitoring, addressed the question of whether the ISO should implement bid caps for start-up and minimum load costs. The existing MRTU tariff provides generation unit owners with two options for start-up and minimum load bids. The first approach computes cost-based values using publicly observable short-term market prices for the generation unit's input fuel and its operating parameters (such as start-up fuel requirement and heat rate at minimum load). The second approach allows the owner to submit bids for both start-up and minimum load subject to the restriction that these bids remain fixed for six months. The ISO is currently considering whether bid caps are needed for the second bid-based option in order to limit the exercise of local market power by certain suppliers that know their units will be required to operate at least once during a six month period because of transmission or other local grid reliability constraints.

Hsu presented three bid cap options for both start-up and minimum load bid caps and solicited MSC comment. MSC members raised questions during the discussion of these options about the extent to which generation unit owners were likely to attempt to exercise local market power using the bid-based option. Specifically, are there generation units that are sufficiently likely to be required to operate during certain times of a six-month period that their owner would choose to bid extremely high start-up and minimum-load costs that effectively eliminate the unit from the day-ahead dispatch except when it is the only one able to serve a local reliability need? Also, if California's major load-serving entities (LSEs) meet the local resource adequacy (RA) requirements specified by the California Public Utilities Commission (CPUC), will there be a need for non-RA generation units to be dispatched for local reliability reasons? To the extent that the CPUC's RA process leads California's major LSEs to procure adequate energy and ancillary services from local generation units in advance of the day-ahead market, there may be little need for bid caps on start-up and minimum load costs, because these units are typically required to submit start-up and minimum-load bids specified under the terms of their RA contract. By imposing bid caps on the start-up and minimum load bids of non-RA units, the ISO may be providing incentives for load-serving entities to avoid signing RA contracts with expensive local generation units that may be essential to system reliability during a small number of hours of the year.

Several MSC members stated that if the Department of Market Monitoring determined that the exercise of local market power with start-up and minimum load bids was sufficiently likely to impose significant costs on consumers, the ISO should set these bid caps based on publicly available information rather than on the unit owner's actual input fuel procurement decisions and reported operating characteristics of its generation unit. Publicly available input fuel prices and generation unit operating characteristics from public data sources should be used to set the level of the bid cap in order to provide strong incentives for unit owners to minimize their actual start-up and minimum load costs. Tying the level of the bid cap to actual start-up or minimum load costs incurred by the unit owner would create incentives for the unit owner to inflate these costs. Because bid caps are a regulatory intervention designed to protect consumers, publicly available data should be used to set the bid cap so that the ISO is confident the unit owner has an opportunity to recover prudently incurred start-up and minimum load costs. These bid caps should not be set to recover all possible start-up and minimum-load costs regardless of how the unit owner procures its input fuel or operates its unit.

Modification of Incremental Heat Rate Calculation

Ming Yung Hsu, Senior Market Monitoring Analyst in the Department of Market Monitoring, discussed the ISO's process of computing default energy bid (DEB) curves from the heat rate information that generation unit owners provide to the ISO. Certain technologies imply non-monotonic incremental heat rate curves for generation units.

For example, combined cycle natural gas-fired generation units can have output ranges with extremely high increment heat rates. The ISO currently ensures that the heat rate curve used to compute DEBs is monotonically increasing by requiring the incremental heat rate from each step of the heat rate curve it uses to compute DEBs to be the greater of the previous step. For units with small ranges of very high incremental heat rates at relatively low levels of output, this process can lead to monotonic heat rate curves with incremental heat rates that are far above the average heat rate for the unit or the actual incremental heat rate of the unit. These incremental heat rates can then lead to default energy bids far above the average variable cost of the generation unit.

To address these concerns, the ISO is considering modifications to the process it uses to compute the monotonic heat rate curve used to compute default energy bids. Hsu presented three options. The one favored by several MSC members is similar to Option 2 recommended by the Department of Market Monitoring. Option 2 replaces the non-monotonic segments with the average heat rate associated with the level of output at the start of the incremental heat rate segment. The modification proposed by these MSC members replaces non-monotonic segments with the highest average heat for that non-monotonic segment to ensure that at all levels of output of the generation unit, the area under the adjusted monotonic incremental heat rate curve divided by the level of output of the generation unit is always greater than or equal to the average heat rate of the unit at that level of output. The modification suggested by the MSC members ensures that the area under the DEB curve at a given level of output divided by that level of output is always greater than or equal to actual average variable cost of the generation unit if the input fuel price used to compute the DEB is the same as the actual input fuel price.

Review of Grid Management Charge

Ben Arikawa, Senior Consultant in ISO Financial Planning, provided a review of the evolution of the ISO's grid management charge (GMC) mechanism from the start of the market to the present time. This presentation was prepared at the request of **Frank Wolak** so that the MSC could gain a better understanding of how market participants are assessed charges for the use of ISO services.

Arikawa emphasized that the evolution of the GMC process at the ISO has been driven by a desire on the part of the ISO to align the costs that the ISO incurs in providing a service more closely with the charges that market participants are required to pay. From the start of the ISO until December 2000, a single charge was assessed on all load and exports. During the same time period a GMC redesign project was implemented to unbundle these charges. This led to the establishment of three separate GMC charge categories: 1) control area services, 2) congestion management, and 3) market operations. This GMC remained in place from January 2001 until December 2003, when it was replaced by a further unbundling process. The second unbundling began as a stakeholder process during the late summer of 2002 and ultimately led to the 2004 GMC settlement among the parties and the ISO. Arikawa described a number of compromises that were necessitated by the desire of the ISO to achieve a settlement between it and stakeholders from this unbundling process.

Arikawa then described changes to the GMC process that were necessitated by MRTU. He also emphasized that there are ongoing discussions with stakeholders on a number GMC issues related to the implementation of MRTU. During his presentation Arikawa answered a number of questions from MSC members about details of these unbundling processes. Several MSC members expressed an interest in having a similar presentation on the uplift charges that will exist under MRTU to ensure that these charges and GMC do not work against one another to reduce overall market efficiency.

Day-Ahead Scheduling Requirement under MRTU

Jacqueline DeRosa, Senior Market and Product Economist with the ISO Department of Market and Product Development, discussed a proposed MRTU tariff amendment to modify the current Amendment 72 day-ahead scheduling requirement. At the January 25, 2007 ISO Board of Governors meeting, the Department of Market Monitoring (DMM) proposed changes to reduce the scheduling requirement to 75 percent of the forecasted load during off-peak hours, with the 95 percent requirement only retained for hours 7 to 22. The DMM also proposed greater clarity on permissible deviations from these requirements and allowed exemptions from the scheduling requirement for one violation for each calendar month. The DMM further clarified that these scheduling requirements apply to Revised Preferred Schedules and also proposed exempting Scheduling Coordinators with peak loads less than 1 MW from the requirement.

DeRosa then discussed the Federal Energy Regulatory Commission September 21, 2006 Order which asked the ISO to address “the incentives for LSEs to under-schedule in the day-ahead market until the successful implementation of convergence bidding under MRTU.” The ISO must make a compliance filling on this issue by July of 2007. DeRosa then compared the current ISO market design with the MRTU market design to illustrate how the incentives for under-scheduling would change under MRTU.

During the ensuing discussion, several MSC members emphasized that under-scheduling is not the fault of either LSEs or generation unit owners individually. Under-scheduling is the result of a disagreement on price between sellers and buyers of electricity. If the price LSEs are willing to pay to schedule 95 percent of their load forecast is less than the price that generation unit owners want to supply this amount of energy, then there will be under-scheduling in the day-ahead market. Several MSC members also emphasized that to the extent that LSEs had fixed-price forward contracts for energy greater than or equal to 95 percent of their load forecast, those LSEs should bid as a price-taker for this amount of energy in the day-ahead market. Consequently, to the extent that LSEs have adequate fixed-price energy contracts that clear against the day-ahead price there is little need for a day-ahead scheduling requirement under MRTU without virtual bidding. Only to the extent that the level of fixed-price energy contract coverage of final demand falls below the 95 percent level does the ISO need to be at all concerned with persistent under-scheduling in the day-ahead market. Consequently, if the CPUC decides to adopt a capacity-based paradigm for resource adequacy and does ensure adequate fixed-price forward contracting for energy, the ISO may need to take action to ensure that persistent under-scheduling does not occur.

One MSC member expressed concern that in the absence of adequate fixed-price contracting for energy by LSEs, the penalties for under-scheduling implicit in the RUC process may not be sufficient to prevent under-scheduling, particularly if RA generation units are required to bid zero into the RUC process. This possibility emphasizes the need for fixed-price energy and ancillary services contracting as essential parts of the CPUC resource adequacy process. Because some MSC members are optimistic that the CPUC RA process will recognize the need for adequate fixed-price forward contracting by California’s LSEs for energy and ancillary services, they question the need for a scheduling requirement. However, all MSC members voiced support for imposing the 95 percent scheduling requirement if the ISO ever observed persistent under-scheduling under MTRU.

Granular Procurement of Ancillary Services under MRTU

Hong Zhou, Senior Market and Product Economist of Market and Product Development, discussed the September 21, 2006 FERC order on MRTU directing the ISO to procure ancillary services on a more granular basis. FERC directed the ISO to provide greater detail on how it would incorporate local constraints in the procurement and pricing of ancillary services. Zhou then presented five market design issues to be addressed with respect to more granular procurement of ancillary services.

Several MSC members expressed strong support for more granular procurement of ancillary services under MRTU. In particular, these MSC members emphasized that the use of a full network model to set locational marginal prices for energy would make building in and pricing locational ancillary services requirements straightforward. During numerous past meetings and opinions, the MSC has emphasized the need for more granular procurement of ancillary services. This issue has also come up in the past because several generation unit owners have argued that the ISO operators use the must-offer waiver denial process to ensure that there is unloaded generation capacity available at desired locations in the California ISO control area. This allows the ISO to procure ancillary services on a system-wide or zonal basis yet still have the ancillary services in the locations desired by the ISO operators. This issue continues to be a subject of debate. During the discussion of locational procurement of ancillary services **Brian Theaker** of the Williams Company raised this as an important issue to be resolved under MRTU for the generation community.

Another concern MSC members have with a more granular ancillary services procurement process is the need for local market power mitigation for ancillary services bids. On this issue, **Jeff Nelson** of Southern California Edison emphasized that the ISO should procure ancillary services with greater granularity only if the ISO's operating protocols required it. Moreover, he emphasized that greater granularity in the ancillary services procurement required revisiting the issue of whether these smaller markets for ancillary services were in fact adequately competitive. If they were not, he advocated for additional local market power mitigation mechanisms for ancillary services under MTRU. With greater granularity of ancillary services procurement and pricing the issue of more granular allocation of ancillary services costs was raised. Several MSC members supported a more granular allocation of the costs of ancillary services to accompany more granular procurement of ancillary services.

Following this discussion, Frank Wolak adjourned the public session at 3:30 pm.

Executive Session

The MSC met with ISO staff in executive session until 5:00 pm to review issues pertaining to confidential bidding behavior.