CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: The ISO Board of Governors

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

cc: Marcie Edwards, CEO; Charlie Robinson, VP, Legal and Regulatory

Date: November 19, 2004

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

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

The Market Surveillance Committee (MSC) held a public meeting on November 16, 2004 at the California ISO. All MSC members were present. Brad Barber called the meeting to order and asked for public comment.

Public Comment

Michele Wynne of Grid Services, Inc. submitted a written statement to the MSC and made a short presentation. She asked the California ISO to work with stakeholders and regulators to develop a congestion elimination system rather than a congestion management system. She expressed a preference for an electricity delivery system in which scheduled and actual flows are identical and customers have price and delivery certainty. She recommended that the MSC work with the ISO to develop methods to identify the value and causes of congestion.

John Burnett of Los Angeles Department of Water and Power (LADWP) stated that although LADWP supports the Palo Verde-Deavers upgrade, it believes there are viable alternatives to transmission line that the ISO is considering. In particular, LADWP supports what it called the East of River 9000 Plus project, which installs phase shifters and capacitor upgrades but doesn't entail any new line construction. Anjali Sheffrin, Director of the Department of Market Analysis, responded that she believes that much of the upgrade favored by LADWP is already in progress. What is being considered by the ISO is an additional upgrade. She said that she would follow up with ISO's Department of Grid Planning to determine if this was the case.

Tony Braun of California Municipal Utility Association (CMUA) expressed his support for a significant fraction of the contents of the MSC's opinion, "Alternatives to Implementing an Locational Marginal Pricing Market." Consistent with the view expressed in the MSC opinion, CMUA believes that a satisfactory resolution of both the seller's choice contract problem and implementation of an effective Local Market Power Mitigation (LMPM) mechanism are crucial necessary conditions for California to adopt a Locational Marginal Pricing (LMP) market design. Braun also expressed a preference for the transitional market design recommended by the MSC of retaining the current zonal market supplemented by an increased amount of bilateral contracting for locational energy between load-serving entities and suppliers. He also recognized the need for cost-based Reliability Must-Run (RMR) contracts as a regulatory backstop to facilitate the bilateral contracting process when suppliers are likely to possess substantial local market power.

Jeff Nelson of Southern California Edison (SCE) also expressed SCE's support for much of the contents of the MSC's opinion, "Alternatives to Implementing an Locational Marginal Pricing Market." He supported the MSC recommendation of retaining the existing zonal market design supplemented by an increased amount of forward contracting for local reliability energy. He emphasized the need for cost-based "RMR-like" contracts as a fallback option in order for bilateral contracting to solve these local reliability problems. He emphasized the need for forwad energy schedules to be physically feasible. He also expressed a general agreement with the MSC's "Opinion on the California ISO's Proposal for Honoring Existing Transmission Contracts (ETCs) under the Market Redesign and Technology Upgrade (MRTU)." However, he reiterated SCE's concerns about the potential adverse impacts of allowing virtual bidding under the MRTU design.

Market Update

Greg Cook, Manager of Market Monitoring updated the MSC on the performance of the ISO's markets during September and October of 2004. The major highlights were: (1) the record load in the California ISO control area on September 8, 2004, (2) the unusually high level of imports of close to 10,000 MW during peak hours of the day, (3) the 60% reduction in ancillary services prices during September relative to August, and (4) continued high levels of intrazonal congestion costs.

The California ISO control area, which not excludes the Sacramento Municipal Utility District (SMUD), had a peak demand of 45,597 MW on September 8, 2004. This is close the previous system peak of 45,885 MW on July 7, 1999 when SMUD was still part of the California ISO control area. A month-to-month comparison between this year and last year yields average load growth between 2003 and 2004 in the range of 3 to 4 percent. The increased imports to the California ISO control area during September are primarily from the Southwest. These flows have contributed to the increase in intrazonal congestion costs.

On July 11, 2004, the ISO implemented the first phase of Amendment 60, where payments for Minimum Load Commitment Costs (MLCC) are no longer rescinded if a supplier issued a must-offer waiver denial subsequently sells capacity in the ancillary services markets. It was not until September 2, 2004 that the timeline for issuing must-offer waiver denials was changed so that suppliers would know their must-offer waiver denial status when they decided to bid into the ancillary services markets. Amendment 60 appears to have increased the amount of capacity bid into the ancillary services market, which moderated ancillary services prices during September. However, prices in October appear to be significantly higher, due in part to more planned generation outages.

Intrazonal congestion costs have occurred primarily at the Miguel Substation, South of Lugo interface and Sylmar interface. The vast majority of intrazonal congestion costs are MLCC payments made to generation units to keep them operating at their minimum operating level. A significantly small fraction of these payments is for out-merit-order energy in the decremental or incremental direction. One cost of Amendment 60 is a substantial increase in the total amount of MLCC payments. Total MLCC payments in July, August and September of 2004 are almost double levels in January and February 2004.

Update on the Palo Verde Devers Line Number 2 (PVD2) Economic Analysis

Anna Geevarghese, Senior Production Cost Analyst, summarized the results of the ISO's economic analysis of the Palo Verde Devers Line Number 2 (PVD2). She first described the methodology underlying the study. She emphasized that the major goal of the analysis was to quantify the economic benefits of the transmission upgrade as reflected in the increased ability to substitute high-priced local energy with low-priced distant energy. This requires modeling the details of the transmission network accounting for the ability of market participants to exploit the characteristics of the network to raise market prices. The ability of market participants to raise market prices through their unilateral actions and the need to operate certain high-cost generation units depends on a large number of factors that are not known at the time the transmission upgrade is contemplated. Consequently, it is necessary to account for the known uncertainty in variables such as the level of demand in California, the price of natural gas, the amount hydroelectric energy available, the availability of major generation units throughout the control area, the availability of transmission links throughout the control area and the extent of unilateral market power that suppliers possess. The ISO's Transmission Expansion Assessment Methodology (TEAM) accounts for these sources of uncertainty by computing the value of the transmission expansion for all potential realizations of future system conditions. These realized values of the benefit of the upgrade are multiplied by the probability assigned to the joint realization of the level of demand, the price of natural gas, hydroelectric availability, configuration of generation units and available transmission capacity, and extent of market power suppliers possess, and then added up across all the realized values of the benefit of the upgrade to yield the expected benefit of the upgrade.

Geevarghese gave a detailed description of the various scenarios for demand, gas prices, hydro conditions, and market power used to compute the expected benefit of the PVD2 transmission upgrade. She then presented a set of results for the benefits of the upgrade in 2008. This was following by a discussion of potential sources of economic benefits from the upgrade not completely captured by the modeling framework. These include the reduced capital cost of constructing generation capacity in Arizona and the Southwest instead of in California. Another source of benefits is the reduced environmental costs of NOx emissions because more efficient and clearer burning generation capacity displaces less efficient and dirtier generation located closer to Southern California load centers. Finally, Geevarghese noted that many reliability benefits of the upgrade in terms increased ease of system operation, improved system reliability, and reduction in the number of Reliability Must-Run units needed in the California ISO control area were not accounted for in the analysis.

This was followed by a discussion of how to best present the results of the application of the TEAM approach to the ISO Board, California Public Utilities Commission (CPUC) and other interested parties. The several MSC members emphasized the importance of presenting the entire distribution of realized values of the benefits of the transmission expansion rather than a single expected benefit number. Because of the substantial uncertainty associated with future system conditions—demand growth, natural gas prices, hydroelectric energy availability and extent of unilateral market power possessed by suppliers—these MSC members felt that presenting only a single expected benefit number fails to convey the insurance against extreme adverse market outcomes that transmission upgrades such at this one provide.

The discussion also emphasized the extreme asymmetry in net benefits associated with too little versus too much transmission. Specifically, inadequate transmission capacity into the Southern California load centers means, in order of severity, an increased need to run expensive and inefficient local generation units, increased risk of generation and transmission outages, and increased risk of supply shortfalls in the major load centers which would necessitate rolling blackouts. The primary cost of over-investment in transmission capacity is a higher than necessary transmission access charge to California consumers. Currently, 0.5 cents/KWh pays for the embedded cost of California's transmission network. This is a very small fraction of the current average retail price in California of more than 12 cents/KWh. Consequently, the cost of building too much transmission capacity relative to the cost of building too little transmission capacity would favor undertaking projects with positive ex post benefits under a range of future system conditions, even if the expected value of the project does not exceed the expected cost of the project

Honoring ETC Rights under MTRU

James Bushnell summarized the contents of the MSC opinion on the ISO's proposal for honoring existing transmission contracts (ETCs) under the Market Redesign and Technology Upgrade (MRTU). The MSC solicited stakeholder input in formulating its opinion at previous MSC meetings, through written comments, and in a public telephone call. The stakeholders providing comments are listed at the bottom of the first page of the document, "Opinion on the California ISO's Proposal for Honoring Existing Transmission Contracts (ETCs) under the Market Redesign and Technology Upgrade." The MSC had a draft opinion available on October 6, 2004, but as a result of stakeholder comment the ISO decided to modify its proposal for honoring ETCs under MRTU. The MSC was therefore asked to delay submitting its opinion until the ISO had finalized its proposal for honoring ETCs under MRTU. This process prevented the MSC from approving its opinion in time to make it into the binders for the November 10, 2004 ISO Board meeting.

Following the presentation by Bushnell, Brad Barber asked if there were any questions or comments from the public. The opinion was then approved by the MSC.

Transitional Alternative Pricing and Settlement (TAPAS) Market Design

Frank Wolak gave presentation on the MSC opinion, "Alternatives to Implementing a Locational Marginal Pricing Market." This opinion dealt with formulating a transitional market design that avoids the seller's choice contract liability under a Locational Marginal Pricing (LMP) market design and addresses the current reliability concerns of the ISO operators. Three alternatives were considered: (1) the ISO's proposed Transitional Alternative Pricing and Settlement (TAPAS) market design without constrained down payments (CDPs), (2) the TAPAS proposal with CDPs and (3) retaining the existing market design with enhanced bilateral contracting between load-serving entities (LSEs) and local generation owners to address the ISO operator's reliability concerns.

The MSC's preferred transitional market design is to retain the existing ISO markets with an enhanced bilateral contracting for local energy by the LSEs. If the ISO ultimately decides to adopt one of the TAPAS proposals, the MSC prefers the one without CDPs. The argument in favor of CDPs is that they provide incentives for suppliers to bid their variable cost into the day-ahead market, thus making the day-ahead dispatch process more efficient. However, this argument relies on the assumption that suppliers do not possess local market power. The MSC did not believe that during most hours of the year there would be sufficient competition among suppliers so that they would find it expected profit-maximizing to bid their minimum variable costs if they were paid CDPs. For this reason, the MSC did not believe the improvement in the efficiency of the dispatch that would result from paying CDPs was enough to compensate for the significant transfer of wealth from consumers to generation unit owners that would result from paying CDPs.

The opinion explains, in detail, the rationale for the MSC's preferred solution of increasing the magnitude of bilateral contracting between LSEs and local generation unit owners under the existing market design. The MSC felt that this solution would best facilitate the CPUC's resource adequacy process. Regardless of the market design, energy must be supplied in a physically feasible manner. CPUC procurement process must respect this reality. The MSC felt that retaining the existing market design and initiating the CPUC procurement process in a physically feasible manner was the least risky transition to an LMP market design with the CPUC procurement process. Implementing the CPUC resource adequacy process at the same time as a LMP market design could entail significant risk. A sequential strategy of first implementing a physically feasible CPUC procurement process and then implementing an LMP market design appears to be significantly less prone to costly errors.

Following Wolak's presentation, Brad Barber made some minor edits to the opinion which was subsequently approved by the MSC.

Modifications to Market Power Mitigation Mechanism

Jeff McDonald of the Department of Market Analysis briefed the MSC on the ISO's proposed modifications to its local market power mitigation mechanisms under the proposed LMP market design. The major features of the ISO's proposal are: (1) bid caps for energy and ancillary services, (2) a system-wide automatic mitigation procedure (AMP), and (3) a local market power mitigation mechanism with variable-cost-based proxy bids for mitigated generation units. System-wide AMP will apply only to internal resources.

Several MSC members continued to express general discomfort with a system-wide AMP mechanism because the associated reference prices are set as a function of accepted in-sequence bids. As has been emphasized in previous MSC opinions, this mechanism for setting AMP reference levels effectively imposes a cost on market participants for bidding low, because this can lower their AMP reference level and therefore limit their ability to raise prices during high demand periods. For this reason, AMP could be raising off-peak prices, and, because of the $250/MWh bid cap, it has little impact on peak prices, so the overall impact of AMP is to raise average prices. Several MSC members argued for the elimination of system AMP if in return the ISO could get a more stringent local market power mitigation mechanism, similar to the cost-based-bid--mitigation mechanism currently in place in the PJM market.

Several MSC members reiterated their desire for the ISO to consider eliminating its Residual Unit Commitment (RUC) process and integrating these constraints into the day-ahead energy and ancillary services market. The changes in the RUC process caused by a number of recent FERC orders have raised significant local market power concern with the RUC process. In particular, FERC has recently ordered the ISO to make the RUC capacity payment a (local) market-clearing price and not to rescind the RUC capacity payment if a unit committed in the RUC process is subsequently taken for energy. In addition, FERC has also eliminated the ISO's must-offer requirement. All of these factors enhance the ability of suppliers to exercise local market power in the provision of RUC capacity.

The MSC is currently in the process of formulating an opinion on its recommended proposal for market power mitigation under a LMP market design and will be issuing this opinion very soon.

The public meeting was adjourned by Brad Barber at 4:30 pm. The MSC met until 5:30 pm to deal with scheduling and other administrative details.