California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Director, Market Monitoring

Date: Mach 18, 2008

Re: ***Market Monitoring Report***

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

This month's Market Monitoring Report covers two issues: 1) Summary of the 2007 Annual Report on Market Issues and Performance, and 2) Comments and recommendations on CAISO proposal for modeling Integrated Balancing Authority Areas (IBAAs).

1. 2007 Annual Report on Market Issues and Performance

Each year the Department of Market Monitoring (DMM) publishes an annual report on the performance of markets administered by the California Independent System Operator (CAISO). This memo provides a brief summary of the market performance highlights for 2007. A complete copy of the report will be provided to you in early April.

For the sixth consecutive year (2002-2007), California's wholesale energy markets remained stable and competitive in 2007. This trend is predominately due to a high level of forward energy contracting by the state's investor owned utilities, which limits their exposure to spot market price volatility, enhances competition, and facilitates new generation investment. Over the past seven years (2001-2007), approximately 14,900 MW of new generation has been added to the CAISO Control Area, enabling the retirement of 5,500 MW of older inefficient generation, resulting in a net increase of 9,400 MW of new generation. Additionally, there is another 1,800 MW of new generation projected to be operational in 2008.

While very low snowpack levels in 2007 for most of the west, including California, raised concerns about hydroelectric supply availability during the critical summer months, relatively moderate summer temperatures mitigated this concern and produced generally competitive conditions with no major reliability issues. California did experience two heat waves in 2007 – both occurring over holidays which may have tempered their effect. The first occurred over the Independence Day holiday, and the second, which set the annual peak load, occurred over Labor Day weekend. Both events were managed without any significant reliability issues. The energy markets were also generally stable and competitive during the heat waves but did experience some escalation in prices and increased volatility – particularly in the bilateral energy and ancillary service markets. Overall, the market and operational impacts of the two heat waves were moderate compared to 2006, which saw an extraordinary heat wave that lasted three weeks in July, and reached a peak well above that seen in 2007.

From a grid operations standpoint, the most notable event of the year was the California wildfires that raged through large portions of Southern California from October 21 to 25. These fires were exceptional in terms of geographical span, number of acres burned, and number of businesses and residences impacted. They burned across Southern California, threatened generation and transmission facilities, and challenged grid stability, especially in the San Diego area. Remarkably, the CAISO, in close coordination with the southern utilities and assistance from the Baja, Mexico, control area operator (Comision Federal de Electricidad (CFE)), was able to maintain reliable grid operation throughout the wildfire period. The wholesale market impacts from the wildfires were predominately local in nature as various forced limitations within Southern California required real-time Out-of-Sequence dispatches as well as day-ahead unit commitment of generation at specific locations. However, spot bilateral prices for Southern California did experience moderate and brief increases during this period. Additionally, congestion costs for some of the major inter-ties to Southern California increased as well, particularly in the hour-ahead market where significant transmission derates occurred due to shifts in the paths of the fires. Overall, the market impacts during the fires were moderate and of short duration.

In terms of the general performance of the wholesale energy markets during the entire year, one of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month Market Competitiveness Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated "competitive" prices derived from cost-based simulations). MCI values in the range of $5-$10/MWh are considered to be reflective of a workably competitive market. The monthly MCI values estimated for 2007 were well below this range for all months of the year.

The average estimated cost of wholesale energy in 2007 was $48.82/MWh of load compared to $47.55/MWh in 2006. Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The increase in the costs in 2007 was primarily due to greater reliance on fossil fueled generation – due to limited hydroelectric supplies – and to increased congestion costs on major importing paths to California.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend continued with intra-zonal congestion costs dropping from $207 million in 2006 to $101 million in 2007. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. The decline is primarily attributable to lower MLCC payments and reduced RMR dispatch costs. MLCC costs declined by $65 million in 2007 mainly due to the completion of various transmission upgrades in Southern California during 2006, which both raised the cost of MLCC payments in 2006 – due to the need to commit units while the transmission work was being completed – and lowered MLCC costs in 2007 once the upgrades were complete, which relaxed the local constraints that previously required additional unit commitments through the must-offer waiver denial process. The cost of real-time RMR dispatches declined by $54 million in 2007. However, most of this decline is due to a reduction in RMR contracts that was enabled by the introduction of Local Resource Adequacy (RA) requirements in 2007, thus the cost savings from reduced RMR contracts may have been largely offset by higher RA costs which are not accounted for in these figures. The cost savings for these two components of intra-zonal congestion costs in 2007 were partially offset by an increase in the third component, real-time redispatch cost, of $13 million. The increase in this component is largely attributed to the need to redispatch units needed in the Humboldt area that were previously under RMR contracts.

The RMR costs noted above pertain to just the cost of real-time RMR energy dispatches. The total cost of RMR units, which includes both fixed cost payments and variable cost payments for day-ahead and real-time dispatches, declined substantially from approximately $428 million in 2006 to $125 million in 2007, a reduction of approximately $303 million. This reduction is predominately due to the reduction in the amount of capacity under RMR contracts from approximately 10,000 MW in 2006 to 3,300 MW in 2007.

Another reliability management cost, which is relatively new, is the capacity payments made to generation units that are neither RMR units nor RA units. These capacity payments are made pursuant to the Reliability Capacity Services Tariff (RCST) and provide for both a daily capacity payment for non-RA units that are committed by the CAISO and potentially monthly capacity payments if a non-RA unit is designated by the CAISO as RCST. In 2007, the CAISO did not make any RCST designations but did make numerous daily capacity payments to non-RA units, amounting to approximately $26 million.

Another important market performance metric that DMM reports on each year is the extent to which spot market revenues for the entire year cover the annualized fixed cost of new generation facilities. The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2007 indicates estimated spot market revenues fell short of a new unit's annual fixed costs. The gap is significantly more pronounced given the recently released estimates from the California Energy Commission on the cost of new generation, which were adopted for this analysis. This marks the fifth straight year that the DMM's analysis found that estimated spot market revenues did not provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past four years (2004-2007) does show a positive trend of net revenues increasing for a new combined cycle unit with estimated net-market revenues in 2007 of approximately $84/kW-year and $95/kW-year for Northern and Southern California, respectively, but these estimates are well short of the estimated annualized fixed costs of $132.6/kW-year.

Despite the positive trend in spot market revenues, the fact that California's spot markets do not provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. While long-term contracting is critical for facilitating new investment, it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. The CPUC implementation of Local Resource Adequacy Requirements in January 2007, which are based on CAISO technical studies, should help in facilitating generation development in critical areas of the grid.

While six consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs, particularly for Southern California. Though approximately 8,900 MW of new generation has been added to Southern California since the energy crisis, which enabled the retirement of 4,300 MW of older inefficient generation, net generation additions for that region have only just kept pace with load growth. Consequently, reliability needs for that region continue to be met, in part, by older less efficient generation, which cannot be sustained indefinitely. Moreover, major state environmental policies such as greenhouse gas reductions, Renewable Portfolio Standards (RPS), and a potential ban on once-through cooling systems will call for even more aggressive and coordinated action on addressing infrastructure issues.

2. Integrated Balancing Authority Areas (IBAA) Proposal

In a separate memo to the Board, CAISO Management is requesting Board approval of its proposed modeling approach of Integrated Balancing Authority Areas (IBAA) under MRTU.[1] DMM recommends the Board review that memo prior to reading the comments and recommendations provided below, since the Management memo will provide a more complete overview of the IBAA proposal that will place the DMM comments in context.

The DMM has been very involved with the IBAA modeling issue since early 2007 and has worked closely with CAISO staff as they developed their proposal for modeling market interactions between the CAISO and Balancing Areas that are highly integrated with the CAISO system. Under the initial MRTU market design, this approach would only be applied to the Sacramento Municipal Utility District (SMUD) Balancing Authority Area[2] and the Turlock Irrigation District (TID) Balancing Authority Area. The SMUD and TID Balancing Authority Areas are essentially embedded within the CAISO system and are highly interconnected with the CAISO grid. Given this specific system topology, as the CAISO implements a Day Ahead and Real Time Market based on Locational Marginal Pricing (LMP), it is important for the CAISO to account for the way load and generation dispatches within the SMUD and TID areas actually affect power flows within the CAISO and on the interconnecting transmission facilities. Under MRTU, continued use of the current method for modeling inter-ties with the SMUD and TID areas (i.e., as simple radial connections) would likely cause significant and unnecessary additional real-time congestion on the CAISO system.

The primary objective of the IBAA proposal is to better model the way forward energy transactions in and out of the SMUD and TID areas impact flows and congestion on the CAISO network, in order to produce prices and schedules in the CAISO forward energy markets (Day Ahead, HASP) that are more consistent with the actual flows and prices in real-time. However, because these areas are external to the CAISO's Balancing Authority Area (or control area), the CAISO does not have real-time visibility to the specific resource schedules within these areas and therefore must make certain simplifying assumptions about the location of the supply and demand which constitute the actual source and sink for import and export schedules with the CAISO. These simplifying assumptions are reflected in the design of the various hubs, proxy resources, and distribution factors that comprise the IBAA proposal.

The proposed IBAA modeling approach is similar to the *proxy bus* approach used by ISOs in the Eastern Interconnection to model and settle transactions on inter-ties with neighboring Balancing Authorities. A *proxy bus* is the location within a neighboring dispatch area at which the ISO's dispatch and pricing models assume that generation is increased (or decreased) to support import or export schedules between the ISO and that neighboring dispatch area. With this approach, the proxy buses are modeled based on the ISO's best *ex ante* approximation of the marginal impact that changes in import or export schedules with the neighboring dispatch area will have on congestion within the ISO's own system.

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[1] See memo to CAISO Board from Chuck King, Vice President of Market Development and Program Management, March 18, 2008, re: *Approval of Integrated Balancing Authority Areas Proposal.*

[2] The SMUD Balancing Authority Area also includes the systems of the Western Area Power Administration (Western), the Modesto Irrigation District (MID), the City of Redding (Redding) and the City of Roseville (Roseville).

The approach initially proposed by the CAISO calls for the creation of six different “hubs” for the SMUD IBAA, which are analogous to the *proxy buses* used by ISOs in the Eastern Interconnection.[3] This approach reflects the fact that schedules tied to load and generation resources in each of these “hubs” have significantly different congestion effects on the CAISO system. The goal of modeling these different sub-areas of the SMUD IBAA as separate “hubs” is enhanced market efficiency and congestion management. However, if modeling and scheduling assumptions underlying this approach are inaccurate, this approach could result in inefficiencies and additional congestion management costs on the CAISO system, as well as the potential for gaming or market behaviors designed to take advantage of such problems to the further detriment of overall market efficiency, reliability and/or other participants.[4]

DMM believes that the CAISO’s approach represents a reasonable initial approach that is highly analogous to the *proxy bus* approach employed by most Eastern ISOs, but reflects an extremely high degree of integration between the CAISO and SMUD systems. The proposed approach balances the need for simplicity with other more complicated approaches that might seek to include additional modeling details which may offer the potential for better congestion management, but also increased risks of modeling inaccuracies and detrimental behavior designed to exploit modeling weaknesses. However, the DMM also notes that it will be important for the CAISO to perform analysis and monitoring of actual system conditions and scheduling patterns on an ongoing basis to validate the modeling assumptions upon which the initial SMUD IBAA is based and to modify these assumptions and enhance the modeling design if significant inaccuracies or flaws are identified that would create inefficient or inequitable market outcomes, or allow detrimental market behaviors.

The DMM believes that some aspects of this issue – such as the way the SMUD network and proxy buses are modeled – should be monitored and analyzed by the CAISO as primarily a market design and modeling issue, with the goal of establishing a feedback loop for improving specific modeling assumptions over time given actual system and market conditions. Meanwhile, DMM will monitor scheduling practices that may be designed to circumvent market design rules or exploit market design weaknesses. The DMM is working with other areas of the CAISO to ensure that all these aspects of this proposal are monitored and analyzed by the CAISO in an integrated, thorough manner as MRTU is implemented. Finally, the results and experience developed in the process of monitoring and further analyzing the initial application of the IBAA approach in the SMUD area should also provide a basis for assessing how the approach might be applied to enhance the modeling of other neighboring Balancing Authority Areas.

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[3] Within the SMUD IBAA, separate pricing hubs are proposed for the SMUD, Western, Roseville, and MID sub-areas, with another proxy hub being established for import/export schedules into the CAISO system from the SMUD IBAA that are actually sourced from the Bonneville Power Administration Balancing Authority Area (i.e., the Captain Jack inter-tie). A separate pricing hub would represent the TID area.

[4] Other ISOs have typically decided to model and settle transactions with neighboring dispatch areas based on a single proxy bus for several reasons. First, this approach is appropriate when it is difficult for an ISO to differentiate between the impact of different inter-tie schedules or flows within the ISO’s own system. In addition, allowing participants to select from different proxy buses when scheduling imports or exports creates an incentive for participants to simply schedule using a proxy bus with the most favorable settlement price, rather than the one that most accurately reflects the impacts of the inter-tie schedule on the CAISO’s system.