California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: May 10, 2010

Re: ***Market Monitoring Report***

This memorandum does not require Board action.

Each year the Department of Market Monitoring publishes an annual report on the performance of markets administered by the California Independent System Operator Corporation. This memo provides a brief summary of the ISO's market performance in 2009. A complete copy of the report was provided to you in late April. DMM will be presenting highlights from our 2009 annual report at the May Board meeting.

Overall market performance

The ISO's new day-ahead and real-time markets were highly efficient and competitive in 2009. During the first two months of the new market, the real-time energy market was highly volatile, with periodic extreme price spikes driving up average prices. Real-time market performance improved quickly and consistently over the rest of the year. This improved performance can be attributed to a series of adjustments and enhancements in software and operating practices implemented by the ISO to address root causes of pricing anomalies and volatility.

Wholesale costs dropped significantly due to the lower spot market prices for natural gas, which averaged about 56 percent less in 2009 than in 2008. Other factors contributing to the drop were lower loads and increased hydro availability in the summer months. The impact of congestion on costs was also low. This can be attributed to favorable load and supply conditions within the system and enhanced congestion management under the new market design.

Prices in the energy markets were approximately equal to competitive baseline prices that DMM estimates would result under highly competitive conditions. DMM calculates these competitive baseline prices by re-simulating the market using the actual day-ahead market software with default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

One of the key causes of the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets. In addition, bids for the additional supply needed to meet remaining demand in the day-ahead and real-time energy markets have been highly competitive. Most additional supply needed to meet demand has been offered at prices close to each unit's estimated actual marginal costs.

Total estimated wholesale costs for serving system load in 2009 were $8.8 billion, or about $37.50/MWh. This compares with costs of $53/MWh of load served in 2008. Using a simple normalization for changes in average natural gas spot market prices, prices increased slightly from $33/MWh to over $37/MWh.

Comparisons of costs under the new market design with previous years must consider the significant differences between the new integrated energy market and the primarily bilateral market structure previously in place.[1] Because of these differences, the decrease in 2009 costs relative to costs for previous years reported by DMM should be viewed as an indication of the general magnitude and trend of changes in wholesale costs.

Impact of new market design

The new market design resulted in increased operational and market efficiencies that also contributed significantly to the decline in costs in 2009. Analysis in our 2009 annual report provides strong indications that this design increased market efficiency and reduced costs in a variety of ways:

- ***High day-ahead scheduling* —** On average, almost 98 percent of total forecasted demand was scheduled in the day-ahead market. In the day-ahead market, the supply of resources that can be used to most meet load and manage congestion is typically much greater and more flexible than in real-time. Thus, high day-ahead scheduling allows for more efficient unit commitment, energy scheduling and congestion management. This also leaves a small volume of demand to be met by the residual unit commitment and real-time market processes.
- ***Convergence of day-ahead and real-time prices* —** In prior years, prices in day-ahead bilateral markets tended to be higher than prices in the ISO's real-time imbalance market. Under the new market, prices in the day-ahead and real-time markets have converged closely. This price convergence provides a further indication that day-ahead scheduling and dispatch patterns were accurate and efficient, and that major adjustments were not needed as part of the re-optimization that occurs in the real-time market. However, prices and dispatch patterns in the hour-ahead scheduling process used to adjust imports and exports often diverged significantly from the day-ahead and 5-minute real-time markets. This represents an area in which market efficiency can be further improved. This is discussed in more detail later in this memo.
- ***Ancillary services* —** Ancillary service markets in 2009 performed well under the new market design. Ancillary service costs declined from $.74/MWh of system load in 2008 to $.39/MWh in 2009. This represents a drop from 1.4 percent of wholesale energy costs in 2008 to only 1 percent in 2009. This also compares favorably with ancillary service costs in other ISO markets with similar designs. In these markets, ancillary service costs have ranged from just under 1 percent to over 2 percent.

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[1] Under the new market, total wholesale costs can be estimated directly from prices and quantities clearing in the day-ahead, hour-ahead and real-time markets. In prior years, more than 95 percent of total system load was met by energy schedules submitted by participants in the day-ahead and hour-ahead scheduling processes. To estimate the cost of this energy, DMM has relied upon bilateral price indices and other cost data.

- ***Bid cost recovery payments* —** Under the new market design, generating units may submit three-part offers: start-up costs, minimum load costs, and bids for energy above minimum operating levels. If a unit is started up or scheduled at minimum load during some hours through the day-ahead market, the unit is eligible for a bid cost recovery payment to ensure that it recovers the full cost of its start-up and minimum load costs, plus any energy bids that are dispatched. Three-part bidding and bid cost recovery is designed to increase the efficiency of the energy market by providing an incentive for suppliers to submit bids more closely to their marginal operating costs. Excessively high bid cost recovery payments can be indicative of inefficient unit commitment and energy dispatch. Under the new market design, bid cost recovery payments equaled about $66 million, or 1 percent of total energy costs. Equivalent uplift costs in other ISOs have also ranged from just under 1 percent to almost 3 percent of total energy costs. This provides a further indication of the efficiency of the new market design over its first nine months of operation.

Investment in new generation

The amount of generation capacity being added and retired in the ISO each year provides an indication of the effectiveness of California's overall market and regulatory structure in bringing about new generation investment to replace older inefficient plants and meet load growth. About 2,400 MW of new generation were added in 2009 and about 2,600 MW are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program and other policies designed to promote long term procurement by load serving entities have been successful at stimulating investment in new capacity.

DMM performs an annual assessment of the revenues that may be earned by a typical new generating unit from the ISO markets. This provides an indication of the extent to which the ISO's day-ahead, real-time energy and ancillary service markets may contribute to recovering the fixed costs in building new generating capacity. Annualized costs for new capacity critical for meeting reliability needs should be recoverable through a combination of bilateral contracts and spot market revenues.

Results of this analysis for 2009 show a substantial decrease in net revenues earned in the ISO markets by a typical new gas-fired combined cycle unit compared to 2008. Estimated net revenues earned by typical new gas-fired generating units from sales in the ISO markets in 2009 would fall substantially below the annualized fixed cost of new generation. The drop in net revenues for new gas combined cycle capacity is primarily attributed to the significant decrease in spot market gas prices and the associated drop in electricity prices.[2]

This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. DMM does not have information on these revenues. However, these findings underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment under the current market design.

[2] It may seem counterintuitive that lower gas prices would decrease net revenues for a new gas resource. However, since older less efficient gas units are often the marginal resources setting prices in the market, lower gas prices decrease the net revenues of new more efficient gas generation.

Short-term market improvements

DMM has provided recommendations for short-term market improvements in our quarterly reports. While the ISO has already taken steps responsive to these recommendations, follow-up on a number of these recommendations is warranted in 2010:

- ***Consistency of hour-ahead and real-time markets* —** Since the first few months of the new market, one of DMM's major recommendations has been to address the systematic divergence between dispatches and prices in the hour-ahead and real-time markets. DMM has worked with the ISO to identify several specific potential causes for this divergence. The ISO is taking steps to address these issues. The ISO has also identified a number of other modeling improvements that may address this issue and has made these initiatives a major focus in 2010.

- ***Exceptional dispatches* —** DMM has worked closely with the ISO to monitor and assess the volume and reasons for exceptional dispatches. This information was used to help identify ways to reduce the major causes of exceptional dispatch by incorporating additional constraints in the market model. The ISO has taken a number of steps to decrease exceptional dispatches. Because of this effort, the volume of day-ahead unit commitments has declined measurably. In 2010, the ISO continues to place a major emphasis on reducing the need for manual adjustments or intervention to supplement the automated market processes. DMM will continue to monitor the volumes and reasons for exceptional dispatches.

- ***Conforming transmission constraint limits based on actual flows* —** In our third quarterly report, DMM recommended that the ISO should continue to place a high priority on refining the practice of adjusting or conforming constraint limits in the market software. The ISO has taken a number of steps to reduce the need to adjust or *conform* constraint limits and provide more transparency of these adjustments to market participants. Our annual report provides a more detailed discussion of these recommendations and actions taken by the ISO in this area.

- ***Compensating injections* —** This software feature automatically adjusts market flows in the hour-ahead market to reconcile the difference between modeled flows and actual flows observed at inter-ties with other control areas. This feature was implemented in the fall of 2009, but was de-activated due to performance issues. Implementation of this feature may reduce need for manually adjusting constraint limits. However, DMM has recommended that prior to implementing this software feature, the ISO should develop metrics that can be used to monitor the impact of compensating injections on specific constraints likely to be impacted by this feature. DMM is working with the ISO to develop these metrics, and has recommended that the ISO provide participants with a technical paper and advance notice prior to re-implementing this feature.

Market power mitigation

System level market power

The new market design relies upon a high level of self-supply and forward-contracting by load serving entities as a means of mitigating system-level market power. This is consistent with CPUC policies designed to ensure that the state's major utilities are hedged for a large portion of their energy supply needs. These policies have been effective and should be continued. A higher level of forward contracting and hedging will become increasingly important as the bid cap is raised to $750/MWh and $1,000/MWh in the second and third years of the new market.

Local market power mitigation

The local market power mitigation provisions in the new market design have proven to be effective without imposing an excessive level of mitigation. These mitigation provisions should be maintained, while refinements are developed. In 2010, DMM will pursue a number of potential changes that may make these provisions more efficient and effective.

- ***Local market power mitigation procedures.*** As part of the process for developing the design for convergence bidding, DMM proposed modifications to market power mitigation procedures. These modifications would ensure that local market power provisions are not undermined by bidding of virtual demand within transmission constrained load pockets.[3] The ISO has indicated that modifications to market power mitigation procedures proposed by DMM could not be implemented in conjunction with convergence bidding in February 2011, but committed to consider these modifications for implementation in April 2012.[4] In 2010, DMM plans to further assess these proposed modifications to local market power mitigation with the ISO and stakeholders. We are recommending that the ISO and the Market Surveillance Committee perform further review of these proposed modifications, or other alternatives they may be considering in 2010. This is necessary to ensure that modifications to these procedures needed by 2012 are not hindered by the time needed for implementation.
- ***Competitive path assessment.*** DMM currently updates the assessment of whether each transmission path or constraint is *competitive* or *non-competitive* on a seasonal basis every three months. DMM is currently developing enhanced modeling tools that will allow this analysis to be performed much more quickly based on actual network and system conditions. Once such tools are in place, DMM intends to work with the ISO, stakeholders and the Market Surveillance Committee to assess potential modifications to the current competitive path assessment methodology.

Mitigation process quality improvements

In DMM's 2009 quarterly reports, we noted that there have been numerous hours in local market power mitigation procedures that were not reviewed for price impacts by the price correction team. DMM recommended that the ISO improve the process for ensuring that mitigation procedures in the hour-ahead scheduling process are thoroughly reviewed. We are continuing to work with the ISO to ensure the process for reviewing all aspects of the market power mitigation process is improved. DMM plans to make this a priority in 2010. This is important to ensure the

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[3] *Local Market Power Mitigation Options Under Convergence Bidding*, Department of Market Monitoring, October 2, 2009 (http://www.caiso.com/243b/243bebe3228c0.pdf) and *Illustrative Examples of Alternative Local Market Power Mitigation*, Department of Market Monitoring, October 6, 2009 (http://www.caiso.com/243f/243fce76bf30.pdf).

[4] The current day-ahead local market power mitigation procedures are based on the demand forecast. FERC has ordered the ISO to modify these bid mitigation procedures to be based on bid-in demand in April 2012. The approach proposed by DMM would be based on bid-in demand, and would therefore provide a way for the ISO to comply with this FERC order.

continued effectiveness of local market power mitigation procedures, and the confidence of market participants in market outcomes.

New design initiatives

DMM has provided recommendations concerning several new design initiatives developed in 2009 or that are under consideration. These include two recommendations concerning the proxy demand resource program being implemented in 2010:

- **Proxy demand resources —** DMM has offered a variety of recommendations aimed at providing a reasonable level of assurance that as the proxy demand resource product is implemented demand reductions paid for are actually occurring. The ISO has committed to develop a measurement and verification plan that addresses demand response performance, and has indicated that additional limitations may be placed on proxy demand resources in the future if necessary based on market analysis and participant behavior.[5] The ISO expects participation by proxy demand resources to start at a low level in summer 2010 (e.g. up to 25 to 50 MW). This provides the opportunity to monitor and analyze initial program participation in 2010. Results of this monitoring and analysis can then be used to develop any modifications that might be appropriate before program participation ramps up in future years. DMM is working with the ISO to ensure that effective monitoring and verification procedures are developed as part of the program implementation process.
- **Non-utility demand service providers —** California's resource adequacy program allows load-serving entities to use demand resources to meet their resource adequacy requirements. However, non-utility demand response providers are only able to earn capacity payments through utility managed retail demand response programs or through utility procurement contracts for demand response resources. This was identified as a significant potential barrier to demand response in a major report commissioned by the ISO on demand response in 2009.[6] One of the important steps to decrease this barrier to development of non-utility demand response is to define criteria or performance standards that must be met for proxy demand resources to meet resource adequacy requirement of another load-serving entity. Such criteria or standards would help make proxy demand resources a tradable product that demand service providers could sell to load serving entities in the bilateral market. Thus, we are recommending that the ISO work with the CPUC to begin to address this issue in 2010 to ensure that this does not hinder development of demand response resources by non-utility demand service providers.

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[5] Memo to ISO Board of Governors, re: Decision on Proxy Demand Resource**,** September 2, 2009, p.7. http://www.caiso.com/241e/241eb5b844d0.pdf.

[6] See *California Independent System Operator Demand Response Barriers Study (per FERC Order 719)*, April 29, 2009, prepared by Freeman, Sullivan & Co. and Energy and Environmental Economics, Inc. p. 29, http://www.caiso.com/2410/2410ca792b070.pdf.