Opinion on MD02 Single-Step Implementation and LMP Testing

by

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November 18, 2003

1. Introduction

The California ISO's proposed MD02 design originally planned to implement a multi-settlement Locational Marginal Pricing (LMP) market in two steps. First the ISO would implement a day-ahead zonal energy market, where it would commit units based on start-up costs and their energy bids using a network model that only recognized transmission constraints across the ISO's existing congestion zones. Several months later, the ISO would then implement a day-ahead LMP market with a real-time LMP balancing market. A number of factors have led the ISO to re-think this two-step implementation process and instead consider implementing the multi-settlement LMP market in a single step. As a consequence, the ISO management has asked the Market Surveillance Committee (MSC) its opinion on a single-step implementation of an LMP market. To this end, the MSC posted a notice on the ISO web site soliciting public comment on this issue. The MSC also held a public conference call on November 12, 2003, to gather more input from stakeholders about their concerns with this proposed change in the ISO's MD02 implementation process.

An important conclusion from this conference call is that the participants expressed more reservations about the speed of implementation of the LMP market, rather than about the one-step versus two-step approach to the transition. Therefore, we believe that regardless of its decision on the one-step versus two-step implementation decisions, it is extremely important that the ISO offer many opportunities for market participants to familiarize themselves with all aspects of the LMP market operation far in advance of the transition to actual LMP market operation. Our opinion provides several recommendations that address this market participant concern.

The remainder of this opinion will proceed as follows. First, we discuss the stakeholder concerns raised in written comments submitted to the MSC, comments received during our November 12, 2003, public comment conference call, and discussions with staff in the Department of Market Analysis at the ISO. We then summarize the potential costs and benefits associated with a single-step implementation of the MD02 market. The opinion concludes with our recommendations for the conditions under which the ISO should move forward with a single-step MD02 implementation.

2. Stakeholder Concerns with Single-Step MD02 Implementation

The major stakeholder concerns can be classified into four general areas. The first is the fact that a single-step implementation might limit the ability of market participants to determine how LMP would impact both the prices they receive for the output of their generation units and pay to serve their customers' loads. The second problem arises because of this lack of reliable information about LMPs. In these conditions, market participants would find it difficult to determine what Congestion Revenue Rights (CRRs) they would need to hedge their congestion charges adequately. The third issue is the impact of this proposal on the ability of the ISO to monitor and mitigate local market power. The final issue is the impact the proposal would have on the ability of market participants to perform the necessary market simulation and testing of their software systems to interact with the new market design and for the ISO to perform the necessary testing of its software systems to interact with market participants and operate the market. We now discuss these concerns in more detail.

The original two-step implementation plan envisioned the ISO computing LMPs using the bids submitted to the day-ahead zonal market for a number of months. Although these bids would be submitted by market participants to determine the dispatch and day-ahead energy and ancillary services prices based on a zonal network configuration, a number of stakeholders still felt that LMPs based on day-ahead zonal-market bids would provide useful information for predicting prices under a multi-settlement LMP market.

Discussions with stakeholders during the November 12 public conference call revealed that the ISO could also use both day-ahead energy schedules and adjustment bids and the final energy schedules and real-time energy bids to compute day-ahead and real-time LMPs. There was no clear consensus among participants about the additional information value provided by LMPs computed from a day-ahead zonal market versus those computed from day-ahead energy schedules and adjustments bids or final energy schedules and real-time energy bids from the current ISO market. However, using day-ahead energy schedules and adjustment bids and the final energy schedules and real-time energy bids to compute day-ahead and real-time LMPs would avoid incurring the additional cost of operating an interim day-ahead zonal energy market.

During the conference call, a number of stakeholders expressed concerns about participating in the allocation of CRRs without adequate information on likely congestion charges in the multi-settlement LMP market. On the other hand, none of the stakeholders wanted to participate in the LMP market without CRRs to hedge the locational price risk they faced between the source of their forward energy schedules and the location at which they withdrew this energy from the ISO network. These concerns cause the following problem for the ISO in implementing an LMP market. Fully accurate information about locational price differences under an LMP market can only be obtained if the ISO operates an LMP market that compensates and charges market participants according to these LMPs. However, all market participants want to be confident that the CRRs they have been allocated will hedge their congestion charge risk when the LMP market begins operation. One solution to this problem supported by a number of stakeholders during the conference call was to shorten the time period over which CRRs would be allocated during the initial transition to the LMP market. This would allow the ISO to correct any obvious misallocations of CRRs among LSEs that become apparent during the initial stages of operation of the LMP market.

The Department of Market Analysis at the ISO expressed concern that operating a day-ahead zonal energy market may enhance the opportunities for suppliers to exercise local market power. This would occur if suppliers bid their units in the ISO's day-ahead zonal market so that the resulting day-ahead energy schedules are ultimately infeasible in real-time. Under the original Phase II proposal, the day-ahead market would only use a zonal network model to determine the day-ahead dispatch and zonal prices. Thus, the proposed Phase II zonal day-ahead energy market could create increased opportunities for suppliers to profit by reducing their day-ahead energy schedules in real-time—what is often called the "Dec Game." A quicker implementation of an LMP market will eliminate the possibility of increased opportunities for suppliers to exercise local market power in this manner.

It is extremely important to emphasize that an LMP market will not eliminate the opportunities for suppliers to exercise local market power, and may even increase some opportunities. An LMP market only means that virtually all local market power will be exercised in an upward direction, in the sense of withholding output at a location in order to increase the LMP at that location. Only the Dec game, which involves scheduling excess production, would be largely eliminated by the implementation of LMP.

This logic increases the relevance of the concern expressed by a number of stakeholders that without an effective local market power mitigation mechanism, the ISO should not move to a LMP market. Unfortunately, the ISO has still not received clear direction from the Federal Energy Regulatory Commission (FERC) on what local market power mitigation mechanism it will receive authority to implement. Therefore, a number of stakeholders have stated that they would prefer not to move to an LMP market until this very important issue has been resolved. This is a view shared by all members of the MSC, particularly in light of FERC's unwillingness to address the potential large cost to California consumers of an LMP energy market where a number of suppliers have seller's choice delivery point forward contracts with the California Department of Water Resources (CDWR).

This seller's choice option creates a potentially large liability for California consumers in an LMP market because the supplier could fulfill its contractual obligation by delivering energy to the location in the ISO network with the lowest LMP during a given hour, even though the load-serving entity must pay for this energy at the zonal price. The LSE would then be obligated to pay and pass-on to consumers the congestion charges implicit in this price difference.

Both the Department of Market Analysis and a number of stakeholders expressed concerns that market participants should have adequate time to adapt their data systems and bidding protocols to an LMP market. During the conference call, ISO staff expressed their willingness to give market participants the time necessary to do so. The ISO staff also stated that the LMP market software would undergo significant testing, and that the ISO management would have to obtain ISO Board approval before it would move forward with a LMP market in California.

The Electricity Oversight Board's (EOB) submitted written comments related to this issue. It was generally supportive of the ISO's proposal because of the potential software savings to both the ISO and market participants, because they would only have to incur a single software change cost to move from the current market design to the LMP market, rather than incur two such costs, one for the transition to the day-ahead market and the next to the LMP market a few months later. However, the EOB felt that the LMP trials that ISO plans to operate for 4 to 5 months before the transition to LMP may not be particularly informative about LMP prices under the actual market operation because the LMP trial bids are not financially binding. The EOB recommended that the MSC and ISO staff develop a proposal to encourage suppliers to submit bids that are more representative of the ones they would submit under actual LMP market operation. We hope to work with the ISO staff to address this issue.

3. Costs and Benefits of Single-Step MD02 Implementation

The major factor in the decision to move forward with single-step MD02 implementation is the extent to which the information produced by the day-ahead zonal market is sufficient to justify the increased software development and testing costs of a two-step process and the increased opportunities for suppliers to exercise local market power in a zonal energy market. Specifically, the more quickly the ISO is able to move to an LMP market with an effective local market mitigation mechanism, the shorter is the period that participants will have an opportunity to exploit the fact that the ISO does not use the same network model in the day-ahead market that it uses to operate the system in real-time.

The fundamental criticism of all LMP testing processes is that market participants have little incentive to submit bids that are reflective of their behavior under an actual LMP market. In the case of using bids from a day-ahead zonal market or the current ISO day-ahead scheduling process or real-time operation, the logic for this criticism is that suppliers are being paid for prices determined through a zonal energy market, not through an LMP-pricing mechanism. Consequently, the resulting LMPs are the prices that would result if suppliers bid the same way as they did under a zonal day-ahead market or the current ISO day-ahead scheduling process or real-time market. The MSC has emphasized in a number of opinions that participants will respond to the financial incentives that they face. As a result, we are confident that market participant bidding and scheduling behavior should change under an LMP market, in ways that will be very difficult to predict in advance of actual market operation.

This was the logic underlying our earlier opinion of the likely value of an LMP study. In that opinion, we made the argument that there was likely to be little value in performing a study of the costs versus benefits of an LMP market because of the extreme difficulty associated with predicting market participant behavior under an LMP market.

Nevertheless, in that opinion, we did state a number of sources of potential benefits associated with the adoption of LMP that we continue to believe exist and are non-trivial. However, because it is impossible to predict in advance of actual market operation precisely how suppliers will bid and schedule their generation units and how LSEs will bid and schedule their load, there is a risk associated with adopting an LMP market. It is important to emphasize that there are also significant risks associated with maintaining the current ISO market design. We believe that, assuming satisfactory resolution to the issues involving supplier's option CDWR contracts and local market power mitigation mechanisms, the potential benefits to implementing LMP are sufficient to justify the costs.

A key issue in managing the risk to consumers associated with the transition to LMP is making sure that all LSEs have sufficient CRRs to hedge the locational price risk associated with their forward energy commitments. As noted above, because of the problem of not knowing precisely how suppliers will behave in an LMP market, it is very difficult to determine the most appropriate allocation of CRRs to market participants at the start of the operation of that market. The suggestion to limit the duration of CRR allocations during the initial stages of the LMP market may be the best way to address this problem. In particular, the ISO could allocate CRRs among market participants on a monthly basis to ensure that all LSEs are protected against the congestion charges associated with their forward energy schedules.

The fact that the MD02 market design envisions charging all LSEs and large loads the zonal average price for all energy purchased in the day-ahead market or real-time market also argues against fully allocating CRRs to all market participants, at least during the initial stages of the LMP market. The ISO could instead focus on allocating CRRs based on the locations of the source and sink of verifiable forward contracts, including actual generation facilities owned by the LSE. The remaining energy purchased by each LSE and large load would then pay the zonal average price in the day-ahead or real-time LMP market. This policy for CRR allocations during the initial stages of the LMP market would help to address the major concern of market participants that they are not adequately hedged against congestion charges associated with their forward energy schedules.

The major challenge in the initial CRR allocation process is dealing with the supplier's choice delivery point of a number of the CDWR contracts. This may require the ISO to allocate to the LSE that is assigned the CDWR contract a corresponding buyer's choice CRR contract to hedge this risk. However, it is important to note that under one interpretation of the supplier's choice contract, which we hope FERC will prohibit, the firm may be able to deliver more electricity to a location in the ISO network than is actually injected at that point in the network. Under these conditions, giving a corresponding buyer's choice CRR will result in revenue inadequacy for the resulting CRR, because there will be insufficient congestion revenues being paid to the ISO to recover its obligations to the CRR holders. Consequently, a buyer's choice CRR should be, at best, viewed as only a partial solution to the supplier's choice CDWR contracts, unless FERC rules out this interpretation of the seller's choice CDWR contracts.

The experience of the California ISO with intra-zonal congestion at the Miguel intertie near the Mexican border, as a result of the entry of a number of new suppliers, suggests that intra-zonal congestions problems will continue to arise in the California market as more new generation comes on line. For this reason, the potential costs associated with further delay in implementing a market design that prices congestion throughout the entire ISO network in the day-ahead and real-time market appears to be growing. For that reason, we favor moving to a market design that offers that opportunity to price congestion in the day-ahead and real-time market throughout the California network as rapidly as possible.

The final issue of concern to stakeholders and the ISO staff is whether there will be sufficient time for market participants and the ISO to perform all of the necessary software upgrades, and then adequately test them in time to operate the LMP market reliably. We are confident that the ISO will adequately test the LMP software and allow market participants adequate time to familiarize themselves with its operation to make the transition to an LMP market as smooth as possible. However, despite the ISO's best efforts, software glitches and unexpected inaccuracies in the network model could lead to anomalous LMPs, Depending on the local market power mitigation mechanism authority that FERC grants to the ISO, there could also be significant opportunities for suppliers to raise LMPs at certain locations in the network by exercising local market power. These are clear instances when it would be inappropriate to charge these LMPs to LSEs. However, if the high LMPs at a certain location in the network are due to the high cost of supplying energy at this location, these prices are appropriate.

4. Recommendation on Single-Step MD02 Implementation

While we agree with the view that using bids from a day-ahead zonal market or the current ISO day-ahead and real-time markets are not representative of bidding behavior in an LMP market, we believe that of the three sets of bids, those from the ISO's real-time market are probably most like those that would arise in an LMP market. For that reason, we do not believe that the benefits of operating an interim day-ahead zonal energy market are sufficient to justify its costs. Our reason for believing the ISO's real-time energy bids are more representative of supplier behavior in an LMP market is that the ISO must essentially operate an LMP market in real-time under the current market design. When it finds intra-zonal congestion in real-time, the ISO must pay the supplier that it needs to provide more energy to resolve this intra-zonal constraint as-bid regardless of the market-clearing price in the zone. Equivalently, the ISO must sell back energy to the supplier that it needs less energy from at the supplier's decremental energy bid, regardless of the market-clearing price in the zonal. Consequently, the ISO is already implementing a very inefficient form of locational marginal pricing in its current real-time market. A formal LMP mechanism would take these bids and actually solve for the least-cost mix of upward and downward movements of generation units to meet the real-time energy needs at each location in the network using the bids submitted to the real-time market. For this reason, we believe that using final energy schedules and producing LMPs from this information would provide the best possible information about

LMPs before the LMP market actually goes into operation. We should, however, immediately acknowledge that that although these may be the best estimates of actual LMPs possible, they are likely to have a considerable degree of uncertainty associated with them.

For this reason, our second recommendation is for the ISO to allocate CRRs among the LSEs for very short durations during the initial implementation of the LMP market. In particular, we believe the ISO should reserve the right to re-visit the CRR allocation process on a monthly basis during the first year of operation of the LMP market in order to ensure that no market participant experiences unnecessary harm from the congestion costs associated with the implementation of LMP.

Our final recommendation is that the ISO provide all market participants with sufficient flexibility in adapting their data, scheduling, and bidding systems to the new LMP market. In this regard, we believe that it would be very helpful for the ISO to make available a web site or downloadable software that will compute LMPs from a set of bids from all market participants. This would allow a market participant to experiment with how its bidding or scheduling behavior and those of its competitors would impact the LMPs that it would face. The ISO should also compute LMPs from the schedules and bids submitted to its real-time market for a number of months before the LMP market begins operation in order to provide an additional source of information to market participants about the likely impacts of the transition to LMP. These LMPs should be posted on the ISO's web site with as short a time lag after actual market operation as possible. The ISO should also consider using the day-ahead energy schedules and adjustments bids to compute day-ahead LMPs with the software for the day-ahead LMP market as well. These LMPs should also be posted on the ISO web site with as short a time lag as possible.

In conclusion, we believe that the transition to an LMP market should be viewed as a continuous process rather than a discrete and irreversible decision. As noted above, some form of locational pricing is necessary for reliable real-time operation of a potentially congested transmission network. To the extent that real-time system operation becomes less costly and more reliable through the adoption of a day-ahead market that accounts for all known real-time network constraints, a formal day-ahead LMP market should be adopted. To the extent that real-time system operation becomes more reliable and less costly by running this same formal LMP process in real-time, the LMP mechanism should be extended to the imbalance market. Finally, precisely how far this transition process moves forward depends crucially on the effectiveness of the local market power mitigation mechanism provided by FERC.