

Midwest ISO TDU Sector
October 2010 Midwest ISO Advisory Committee “Hot Topic”
Adequate Price Signals

The Municipal, Cooperative and Transmission Dependent Utilities (TDUs) welcome the opportunity to submit comments on the “Hot Topic” issue of adequate price signals. We provide here generic comments on this topic, followed by responses to the specific Hot Topic questions.

The TDU’s believe the Midwest ISO’s price signals are generally adequate. Any changes should be done carefully to avoid shifting unwarranted costs to load. The goal of further refinements should be to improve the efficiency of these price signals to lower costs to the ultimate customers.

The TDU’s strongly support the implementation of pricing mechanisms that promote low costs and a more predictable, less volatile market and incentives for resource flexibility. Although we acknowledge that price volatility can be managed by carrying additional headroom, we think that there are opportunities to gain meaningful price stability without adding extra costs.

We believe that there are a few key areas that the Midwest ISO should focus on to achieve the greatest impact toward accomplishing this goal. The following factors have a significant impact on pricing results: Insufficient “Look Ahead” capability to manage load and other system changes; Congestion Management; Unit Flexibility; Coordination between RTOs, particularly PJM and the Midwest ISO; Real-Time system uncertainty; Real-Time physical scheduling; Real-Time Revenue Sufficiency Guarantee uncertainty, and Reserve Procurement. Many of these factors were also recognized and discussed in the 2009 State of the Market Report from the Midwest ISO Independent Market Monitor (IMM).

Our comments and suggestions will focus on the following topics:

- Look Ahead Commitment and Dispatch;
- Day-Ahead and Real-Time Unit Commitment including Ramping, Load Following, and Headroom;
- Feedback on Congestion Cost impacts to Production Cost;
- Scarcity Pricing for Operating Reserves;
- Supplemental Reserves;
- FTR Funding;
- RTO Coordination;
- Flow Control Devices;
- VAR Dispatch; and
- Voluntary Capacity Auction (Summer and Non Summer).

Look Ahead Commitment and Dispatch

The IMM acknowledged that “the price volatility in the Midwest ISO is largely because it runs a true five-minute real-time market, producing new dispatch instructions and prices every five minutes. The short timeframe and limited ability of the real-time market to ‘look ahead’ causes the system to frequently become ‘ramp-constrained,’ which results in transitory sharp movements in prices up or down.” Although the Midwest ISO and New York markets both use a five-minute dispatch interval, New York has the capability to look one hour ahead. Both PJM and New England run dispatch every fifteen minutes and look out further. Pricing fluctuation is most prominent during periods of significant load changes (i.e., ramp up in the morning or ramp down in the evening).

The ability to better optimize resource commitments and manage the ramping of resources will reduce price volatility. The Midwest ISO has initiatives underway that we believe will help acquire these capabilities. The Look Ahead Commitment and Look Ahead Dispatch tools are expected to have the ability to look out up to three hours in the future with granularity down to fifteen minutes.

The TDUs strongly support the IMM’s recommendation for the Midwest ISO to “develop a ‘look-ahead’ capability in the real-time that would facilitate better management of ramp capability and commitment of peaking resources. A look-ahead capability would by far be the single most important change to the market and would produce the maximum benefit in terms of price stability. With the look ahead concept, increased “headroom” would not be needed.

Congestion Management

Generation facilities are dispatched to minimize production cost while protecting a myriad of constraints (e.g., ramp constraints, generator dispatch constraints, load constraints, etc.). Transmission limits are a constraint that can cause significant price shifts across the MISO market. The more restrictive (conservative) the transmission limit is, the more frequent and acute the congestion costs are related to managing the transmission limit. We encourage the Midwest ISO to take steps to reduce the amount of congestion realized in market operations, and suggest the following areas of improvement:

- Improve transmission and generation outage coordination both inter and intra RTO
- Improve feedback to Transmission Owners (TO’s) on transmission limit management¹
- Encourage granularity of transmission limits based on ambient conditions²
- Compare actual vs. modeled flow to identify topology inaccuracies, and follow-up as appropriate.
- Re-examine the point at which market models start binding constraints³

¹ For example: number and duration of periods that limits were exceeded, actual flow during periods of UDS binding constraints, change in market-wide production cost due to transmission limit, etc.

² Allowing transmission limits to vary with temperature may result in increased limits during cooler-than-seasonal periods in warm weather months. Transmission limits may be reduced during warmer than seasonal weather in winter months, but this result should be consistent with ensuring the reliability of the transmission system.

- Identify and implement processes that improve the accuracy of and remove conservativeness of transmission limits.

The goal should be to operate the transmission system reliably and simultaneously fully utilize the transmission system's capability.

The TDU Sector recommends that the Power Transfer Distribution Factor (PTDF) cut-off in the LMP pricing algorithms be removed or, at the very least, reduced further. Currently the pricing algorithms ignore the congestion costs on commercial pricing nodes that have less than a 1.5% contribution to a congested element. Collectively, electrically distant resources can have a large impact on an element in a heavily utilized transmission corridor. Therefore, the congestion related pricing impacts should be reflected on the energy value of all resources. If the impacts are very small, the pricing impacts will also be very small. There is no need for an artificial cutoff.

A similar impact will be realized in the allocation of Real-Time RSG under the pending Real-Time RSG redesign proposal. As currently constructed, RSG costs will not be assigned to resources that have less than a 1.5% contribution to a congested element. This arbitrary cutoff point creates an artificial pricing discontinuity which provides no benefit to the market and instead skews the pricing signals. The sector believes this forgiveness of RSG costs is inappropriate.

Modeling Improvements

We also support the expansion of incentives that encourage resources to offer maximum flexibility (higher ramp rates, wider dispatchable ranges, etc). This includes modeling improvements that allow flexibility of offers to recognize different resource configurations that more accurately represent the available capacity of units that can be released to the Midwest ISO. Modeling improvements that recognize equipment configurations (e.g., combined cycle variations, etc.) should be explored.

Day-Ahead and Real-Time Unit Commitment/Ramping/Load Following/Headroom

We support the Midwest ISO's implementation (in April 2010) of additional Day Ahead (DA) rampable capacity during hours with large load changes. This commitment of additional, flexible resources should tend to reduce volatility in the Real-Time market. Using the least cost unit commitment in the Day Ahead Security Constrained Unit Commitment (SCUC) instead of relying on the Real-Time Reliability Assessment Commitment (RAC), which is focused on ensuring adequate capacity is on-line, should reduce overall production costs.

Initiatives that compensate resources for their flexibility assist in mitigating price volatility and reduce production costs by allowing resources to be committed and dispatched to follow reasonably foreseeable changes in load and interchange (based on short-term load forecast and known scheduled interchange).

³ For example, binding constraints at 90% of a limit may prevent the limit from ever or nearly ever being exceeded. However, exceeding limits for short periods of time may be acceptable and would allow higher transmission limits and could reduce market-wide production costs and reduce price volatility.

Generation resources are appropriately guaranteed cost recovery of their production costs when committed by the Midwest ISO in the Day-Ahead or Real-Time Market. While we acknowledge that Make Whole Payments (MWPs) are necessary for market functionality, there are opportunities for the Midwest ISO to reduce the frequency and magnitude of payments. These opportunities include:

- Day Ahead commitment algorithms that attempt to replicate commitment needs in Real-Time
- Improvement of commitment algorithms in Real-Time to favor more flexible resources
- Implementation of Extended LMP
- Creation of a load following product creates another revenue stream for committed resources and replaces units currently committed for headroom

Implementing Extended LMP and a Load Following product will reduce market-wide Make Whole by increasing revenues to MWP eligible resources.

In reference to the Day Ahead market performance in 2009, the IMM stated that “our analyses indicate that price convergence in the Midwest ISO has continued to exhibit a day-ahead premium. The day-ahead premiums are consistent with the higher volatility, risk, and RSG (Revenue Sufficiency Guarantee) cost associated with buying in the real-time market. The day-ahead premiums are larger in the Midwest ISO due to higher RSG allocations.” If a certain level of headroom is deemed necessary for reliability, it would be more cost efficient to commit that headroom in the Day Ahead rather than Real-Time. This action may lessen congestion costs in the Day-Ahead market and reduce FTR underfunding.

Feedback on Congestion Cost Impacts on Production Cost

The intent of a nodal Locational Marginal Price (LMP) Market is to efficiently manage transmission congestion by setting transparent market clearing prices at each location on the network. The objective function of the market is to minimize overall production costs. In addition to publishing LMPs, the Midwest ISO should provide market driven feedback on the effects of transmission limits by publishing information on power flows (how often and under what conditions constraints occur) and their impact on congestion costs and production costs. Market participants see shadow prices associated with binding constraints but no specifics on the impacts on production cost. Market-based feedback to Market Participants and Transmission Owners on congestion and production costs could generate more frequent communication and reevaluation of current transmission limits. It would facilitate the Midwest ISO’s ability to incorporate more granular input into their models. By providing market-driven feedback to Transmission Owners on power flows, production and congestion costs, the Midwest ISO and Transmission Owners would be in a better position to work together to identify high cost modeled congestion. This feedback could also increase awareness of the production cost impact of congestion on a transmission element.

Scarcity Pricing for Operating Reserves

The market mechanisms associated with the Ancillary Services Markets in the Midwest ISO are primarily based on NERC standards for compliance. We support the IMM recommendation to improve the performance of the spinning reserve market by “improving the consistency between the reliability requirement for spinning reserves and the market requirement” and the recommendation to “evaluate the formula for the regulation penalty price to ensure that it accurately reflects the costs of committing peaking resources in the Midwest ISO.” Overall operating reserves held by the Midwest ISO equal the sum of supplemental, spinning and regulating reserves. The level of regulating reserves that the Midwest ISO holds is not based directly on a compliance requirement; there is no NERC or Regional requirement for holding regulation reserves. On the other hand, the amount of contingency reserves, which consist of spinning and supplemental reserves, is based directly on NERC reliability requirements. The existence of scarcity pricing for reserve products should be linked closely to reliability requirements. Loss of Load Expectation (LOLE) based scarcity prices should not be invoked unless the contingency reserve requirements are not being met. Accordingly, the operating reserve scarcity price should not be invoked until the available level of operating reserves falls below the contingency reserve limit. Additionally, it appears that the current methodology to calculate the scarcity price for regulation may be biased to the high side. The scarcity price for regulation should be just above the maximum allowable offer for contingency reserves (currently \$100), but no higher, in order to further reduce price volatility.

There is no current process for developing scarcity pricing for spinning reserves. The Midwest ISO is currently soliciting stakeholder feedback on a proposal for administrative pricing, initially, and a computer based methodology to set the price in the 2012 timeframe. We support setting an administrative price which is based on a demand curve derived from an appropriate regulating reserve price and calculated on a monthly basis. The administrative pricing should be evaluated after one year to determine if it provides adequate price signals or if moving toward a computer based methodology is warranted.

Contingency Reserves

According to the Energy and Operating Reserve Markets Business Practice Manual, the Midwest ISO allows five minutes to “notify Resources to deploy Contingency Reserve after the occurrence of a disturbance” that requires a Contingency Reserve Deployment Instruction to be issued. The Contingency Reserve Deployment Period is 10.0 minutes, “which is the difference between the Disturbance Recovery Period (15.0 minutes) and the notification time (5.0 minutes).”

If the Midwest ISO were to reduce the notification time to, say, 3 minutes, then the market could clear contingency reserves based on a 12 minute deployment period, which could increase the supply of contingency reserves by 20%. This would increase the supply of contingency reserves and reduce that frequency of contingency reserve scarcity.

Appropriate use of LOLE pricing

Realization of Loss of Load Expectation (LOLE) Pricing should only occur when there are reasonable risks of loss of load. At present, scarcity pricing can occur (due to ramping and other market constraints) when there are thousands of MWs of on-line, unloaded capacity remaining on the system. The scarcity price curve should be reduced by a factor that represents the actual risk of loss of load⁴.

FTR Funding

FTR funding shortfalls arise as the result of differences between transmission made available in the FTR allocation and auctions, on the one hand, and the transmission capacity actually available in the DA Market. The Midwest ISO's analysis has shown that transmission outages and constraint modeling are the primary sources of differences in the models underlying these two markets. We support development of an automated process to incorporate scheduled transmission outages into models. Outage schedules that are new or different from those loaded into the FTR annual model and Day Ahead/Real Time models have a direct affect on congestion charges received by the Midwest ISO to support FTR settlements. Also, communication and sharing of information between the Midwest ISO and Transmission Owners to validate all models (i.e., Commercial, Network, FTR) would improve the accuracy of the models. We support the Midwest ISO's efforts to better align the Day Ahead and FTR models and to improve outage-scheduling practices.

RTO Coordination

Interregional coordination is critical to ensure appropriate LMP values at the market borders. We support continued improvements in coordination to optimally use common transmission elements. RTOs should be committed to continuous improvement of coordination and to move along the continuum of a jointly managed approach to ultimately an automated approach with coordination of operation as a single entity where there are common systems and an automated process that includes redispatch with adjustments of the interchange between markets based on participant load bids and generation offers submitted into each RTO's market. We support the RTOs expanding their current levels of coordination or joint commitment, exchange of data, and more coordination in the Day-Ahead market. By establishing a feedback loop among the RTOs in the Day-Ahead market, shared transmission facilities will be better utilized. This approach supports the goal of achieving the lowest overall operating costs for both RTOs.

Flow Control Devices

In addition to the cost-effective addition of transmission lines to eliminate transmission congestion, the Midwest ISO should also consider market mechanisms to encourage the installation and utilization of flow control devices. We support the implementation of flexible AC transmission system (FACTS) devices to provide dynamic voltage support – and enable increased, efficient use of the existing Midwest ISO infrastructure by eliminating constraints or deferring the need for new transmission. These devices are particularly useful for situations where siting a transmission line may be contentious or

⁴ For example, $1 - (\text{MISO Load} / \text{Sum of Emax of all available resources})$

where new generation is not cost justified. Another alternative is the use of high voltage direct current (HVDC) facilities. The major benefit of an HVDC link derives from its ability to control the power flow and its flexibility to adapt to different AC system characteristics at both ends of the interconnection. Both FACTS and HVDC can assist with managing transmission congestion due to the ability to control power flow, maintain system stability and voltage quality. We support development of mechanisms which enable the Midwest ISO to dispatch these flow control devices for the overall benefit of the market (i.e., reduction in overall production costs). We encourage the Midwest ISO to explore methods of compensation (i.e., tariff, market instruments, etc) to reduce overall production costs and price volatility.

Voluntary Capacity Auction - Summer

The primary driver of the extremely low pricing levels of the monthly Resource Adequacy (Module E) Voluntary Capacity Auctions (VCAs) is the excess supply of generation resources above the required planning reserve margin requirements, which is expected to be a temporary situation. As load growth recovers from the recession and generation resources are retired, this excess supply will shrink and capacity prices resulting from the VCA for the summer peak are expected to increase.

Voluntary Capacity Auction – Non Summer

The structure of Module E also contributes to the low pricing levels for months outside of the summer peak period. Under the current construct, a Market Participant must secure enough Planning Resource Credits (PRCs) to cover the monthly peak load projection plus the Planning Reserve Margin Requirement for the current Planning Year. The calculated Unforced Capacity (UCAP) rating of a generator can be converted into PRCs and used to meet the monthly requirements. Because the UCAP rating of a generator is available in all 12 months of the Planning Year, the amount of available PRCs for months outside of the summer peak is substantially greater than required. As a result, the monthly clearing price outside of the summer peak will most likely continue to be extremely low even after the overall supply/demand mix becomes tighter. Given this reality, the Midwest ISO should consider moving to an annual or possibly a seasonal Resource Adequacy requirement and move away from the monthly requirement. While capacity in non-summer months may not change appreciably, the administrative cost burden imposed on the Midwest ISO and Market Participants may be eased.

The intent of Module E is to ensure that enough resources are in place to maintain the stated Loss of Load Expectation (LOLE) goal of firm load curtailments 1 day every 10 years. Because of the time required to permit and construct generating units, an argument could be made that the current rules are too focused on the near term (e.g. next month) and do not provide the appropriate focus on the longer-term planning horizon. The existing penalty provisions for not meeting the monthly requirements do provide an incentive for Market Participants to assess their needs on a longer term planning basis in order to avoid the penalty.

Turning now to the specific questions included for this “Hot Topic”, the TDUs offer the following responses:

1. Are the price signals adequate and if not, what specific areas of improvement should the Midwest ISO consider?

The Midwest ISO is working towards the implementation of Extended LMP (a.k.a. Convex Hull Pricing) and Load Following products to compensate and incent resource flexibility. Start-up and No-load cost will be included in the marginal price with the implementation of Extended LMP (ELMP). It appears these developments will be improvements to the Midwest ISO market and are supported by most of the TDUs. Some TDUs, however, are not convinced that ELMP has been developed far enough to judge that it will be an improvement and are concerned that it in fact has the potential to increase costs without compensating benefits. The Midwest ISO should ensure ELMP is fully analyzed prior to implementation to insure that it does not result in unwarranted costs being shifted to load. If implemented, metrics should be put in place to assess the effectiveness of ELMP at reducing Make Whole Payments (MWP) and other market costs.

Make Whole Payments for units in the Day-Ahead are a result of collective power flows resulting in minimum cost for the Day-Ahead market. It is inappropriate for all MWP in Day-Ahead to be assigned to load. The RSG in Day-Ahead should be assigned to all resources impacting power flows in Day-Ahead (i.e., generators, schedules, load and virtuals).

The market experiences extreme prices due to ancillary service scarcity pricing as stated above.

The current methodology for allocation of costs associated with Operating Reserves is inadequate. We have concerns that the implementation of Reserve Procurement Enhancement will reduce available transmission capacity which will have a tendency to exacerbate congestion and to increase prices. We find no need for zonal reserve requirements since deliverability should be determined through SCED (Security Constrained Economic Dispatch). Operating reserves are maintained for a secure and safe transmission system which benefits all market participants. Therefore, operating reserve cost allocation should be assigned to all resources and load, and possibly schedules.

Although the current price signals for Resource Adequacy (Module E) Voluntary Capacity Auctions are not reflective of the capital costs necessary to construct new generation capacity, they are reflective of current market conditions and should not necessarily be viewed as inadequate.

2. Are there elements of cost that are not adequately reflected in the pricing construct? If so, what are they?

Doing a good job of reflecting the relevant costs in market price signals is important for well functioning markets and should, in turn, lead to overall lower total costs for consumers. There are a few costs that could use further attention:

- Cost associated with changing equipment states (cycling coal mills, starting or stopping CTs in a combined cycle facility, moving a unit into extended ratings operating range, etc.) are not adequately reflected.
- The cost of offering unit flexibility is not adequately reflected in the pricing construct.
- One cost element that has been identified as potentially not being reflected in the current pricing construct signals for Resource Adequacy (Module E) Voluntary Capacity Auctions is the locational value of capacity resources.

3. *Is there an effort already underway at the Midwest ISO that is attempting to address a pricing issue and if not what should the Midwest ISO be doing?*

The Extended LMP (a.k.a. Convex Hull Pricing) development is underway through a stakeholder task team. This methodology may increase the degree to which prices reflect the actual cost of meeting load. In addition, the pricing methodology would allow gas turbines and emergency demand response (EDR) to set prices and ensure that shortage pricing is not applied to transient situations when shortage pricing is not appropriate.

Here are areas where the Midwest ISO should focus additional attention:

- Development of a Load Following product.
- Currently External Asynchronous Resources (EARs) can only import power into the MISO market. Additionally, EARs can only supply ancillary products when energy imports into MISO are greater than or equal to zero. Physically, there are no impediments to an EAR being a dispatchable export out of MISO in addition to being a dispatchable import into MISO. There are also no physical impediments to providing ancillary services to MISO while exporting power from MISO. This proposal was included in the whitepaper (Five Proposed Market Instruments to Reduce Supply or Increase Demand) presented at the February 2010 Market Subcommittee meeting.
- The Midwest ISO has put forward a proposal for modifying the current Resource Adequacy construct to include a 3 – 5 year forward looking period. We understand the Midwest ISO must also make a compliance filing with the FERC to address the locational value of capacity issue. Additional detail on the proposal is to be presented by the Midwest ISO on October 7th with an intended filing date of December 8, 2010 and an

implementation target of June 1, 2012. Given the current lack of detail and the relatively short period of time until the stated filing date of December 8th, we recommend that the Midwest ISO focus on making the compliance filing on December 8th and wait to make a FERC Section 205 filing changing the current Module E structure until later in 2011.

4. *Are the market rules governing this pricing providing the correct signals as they were intended in the TEMT, BPM, JOA, SEAMS agreements?*

Generally, the answer to this question is yes. For example, the existing penalty provisions for not meeting the monthly requirements for Resource Adequacy (Module E) Voluntary Capacity Auctions do provide an incentive for Market Participants to assess their needs on a longer term planning basis in order to avoid the penalty.

There are some questions regarding whether market rules are providing the correct signals. For example, with the implementation of ELMP and administrative prices, how do we ensure that we will maintain power balance? (i.e., MinGen situations where resources reduce capacity). Also, are the levels or the existence of Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM) appropriate reflections of reliability?

5. *Where else should the Midwest ISO be “looking” to improve pricing – examples could include other ISO/RTO, other domestic/international markets, etc.*

Other RTOs (NYISO in particular) have implemented programs to better manage the economic impact of transmission outages which should lead to reduced production cost and may also reduce the level of FTR underfunding.

The TDU Sector again thanks the Board for the opportunity to address this “Hot Topic” issue on adequate pricing signals.