Energy Choice Matters

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# Monitoring Won't Make Midwest ISO Capacity Auction Mandatory, IMM Says

Regardless of the voluntary nature of the Midwest ISO's capacity market, FERC's obligations under the Federal Power Act do not allow participants with market power to voluntarily withhold resources to raise prices, MISO's Independent Market Monitor (IMM) said in a filing clarifying its market monitoring role for the Module E capacity construct (ER08-394-007).

Several capacity suppliers have raised concerns that the IMM's screens for withholding will make the voluntary capacity auction a de facto mandatory market (Matters, 12/11/08).

Such concerns are "not legitimate," the IMM countered, because the monitoring approach is only designed to identify market power abuses (not simply any unoffered capacity). For unoffered capacity to be an abuse of market power, the supplier must have the ability to raise prices, the IMM said.

The following suppliers can refuse to submit offers into the voluntary capacity market auction without being subject to referral to FERC by the IMM:

1. Suppliers that sell their capacity bilaterally before the voluntary auction;
2. Suppliers that sell their capacity bilaterally after the voluntary auction;
3. Suppliers that designate their capacity to satisfy their own capacity requirements;
4. Suppliers that export their capacity to another area at a price that is comparable to or higher than the expected Midwest ISO capacity price;
5. Suppliers whose capacity is not economic to sell in the Midwest ISO, and
6. Suppliers whose withholding would not raise prices (i.e., suppliers that do not have market power).

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# Progress, Duke Protest PJM Proposal for New External Interface Pricing

Progress Energy Carolinas and Duke Energy Carolinas protested PJM's application to institute new pricing points at the interfaces between PJM and external balancing authority areas, claiming the application would not provide accurate price signals.

As initially reported (Matters, 12/3/08), PJM's proposal would replace existing bilateral agreements with several external balancing authority areas (including Progress and Duke), and would institute three pricing options -- an aggregate option which sets a single pricing regime for a swath of control areas, a "High-Low" option for single balancing areas directly connected to PJM, and a marginal cost proxy pricing option.

Under the aggregate option, for the Southeast region, PJM would define a single pricing regime known as SOUTHIMP/SOUTHEXP, a consolidation of 12 pricing nodes stretching from near the Great Lakes in MISO, through Kentucky and Tennessee, and across the Progress and Duke territories to the Atlantic Coast.

Under the High-Low option, imports to PJM would be set at the lowest LMP at any generator bus in the entire directly connected balancing area, and exports from PJM would set at the highest LMP at any generator bus in the entire directly connected balancing area.

The marginal cost option uses the average LMP at the marginal unit or units in the directly connected balancing area to set prices, subject to a test which compares LMP and the marginal production cost of each unit that is on-line in the balancing area. However, the marginal cost option

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## Connecticut DPUC Draft Would Reject TSO Procurement Incentives

A draft Connecticut DPUC decision would find that Connecticut Light and Power and United Illuminating do not qualify for a 0.25 mill/kWh incentive available under each's prior procurement of supplies for the Transitional Standard Offer (TSO) service (03-07-01RE03, 03-07-15RE02).

Conn. Gen. Stat. § 16-244c(b)(4)(B) required the Department to establish an incentive plan for the procurement of long-term contracts for TSO service by an electric distribution company. The incentive plan was to be based upon a comparison of the actual average firm full requirements service contract price for electricity obtained by the electric distribution company compared to the regional average firm full requirements service contract price for electricity, adjusted for variables. If the actual Connecticut average price was less than the actual regional average price for the previous year, the utilities would receive a 0.25 mill/kWh incentive payment.

The draft analyzed incentive methodologies proposed by CL&P and UI, and found that the proposed methodologies do not provide a meaningful comparison of the actual average firm full requirements service contract price obtained by CL&P/UI and the regional average full requirements price. Many adjustments that would be required to arrive at a more meaningful comparison cannot be performed with the level of certainty required for the Department to approve a 0.25 mill/kWh incentive, the draft said.

When adjusting a regional proxy group used in the analysis, both CL&P and UI fail the comparison with the relevant proxy benchmark for 2004, the draft says. As such, they would not qualify for that year's bonus revenues under the incentive plan.

Adjustments were made so that any incentive awarded would be attributable to superior performance and not just favorable circumstances during procurements.

The Department noted that CL&P and UI, by statute, already received a 0.5 mill/kWh procurement fee for TSO service, above and beyond the actual costs to procure power. Over the three years of the TSO, the electric distribution companies received approximately $43 million (based on 2004 kWh sales for three years) of fixed procurement fees that were unrelated to the actual costs to procure, the DPUC said.

At issue in the instant proceeding is whether the electric distribution companies should receive an additional roughly $21.5 million over three years of TSO service.

"In light of the significant sums involved and the extraordinary nature of the fixed procurement fee already received, the Department, and ratepayers, are entitled to a high degree of certainty that any incentive awarded be attributable to superior performance," the draft said.

The draft notes the statute requires comparison between firm full requirements prices, and not the resulting retail rates, due to various factors that impact retail rates across jurisdictions (locational prices, renewables, various reconciliations of prior costs, etc.). But the results of actual underlying wholesale procurements in other jurisdictions are proprietary, and therefore unknown, the draft notes, requiring adjustments to retail rates as a proxy. The draft finds that with such adjustments, the incentive should not be awarded.

## E.ON Protests Expanded Scope, Timeframe of MISO RSG Refund

The Midwest ISO's proposal to refund Revenue Sufficiency Guarantee (RSG) charges from the period beginning with the market start-up on April 1, 2005, is inconsistent with FERC's recent RSG order which limited refunds to transactions after April 24, 2006, E.ON said in a protest at FERC (ER04-691-088).

FERC's November 7 order, which narrowly addressed the mechanics of the past RSG cost formula (unrelated to a subsequent order on RSG cost allocation), clarified that there is no mismatch between the numerator and denominator in the current calculation of the RSG charge, thus affirming that no under-recovery occurs. FERC said its earlier order erred in ruling on the formula, and thus it ordered MISO to provide refunds starting on April 25, 2006, through March 14, 2007, to the extent MISO's billing was inconsistent with FERC's ultimate interpretation. The Commission said that it had previously determined not to order refunds for the period prior to April 25, 2006, based on equitable grounds.

However, the Midwest ISO, in a compliance filing, proposed resettling the earlier period as well, citing other apparent billing determinant errors, unrelated to virtual supply offers, that the Midwest ISO has now discovered in its prior resettlement. MISO has uncovered seven other categories of determinants that it now believes should not have been included in the RSG formula for that period.

"Midwest ISO's decision on compliance, not accompanied by a reasoned explanation or proposed cost impact, will result in millions of dollars being resettled and a dramatic increase in the per unit RSG rate for certain hours. In fact, Midwest ISO has indicated that its recalculations will result in RSG rates in some hours that are nearly 300% higher than the RSG rates used in the last settlement of this period," E.ON said.

MISO's application to expand the refund time period, as well as the scope of billing corrections, bypasses needed regulatory review of the changes that would otherwise occur under a Section 205 filing, E.ON argued.

E.ON also reported that market participants have no transparent means to view the Midwest ISO's underlying data and calculations with regard to these resettlements until after the resettlement statements are distributed. FERC should remedy this problem by directing MISO to submit the necessary data and calculations underlying the proposed resettlements, E.ON said.

## *Briefly:*

**Conn. DPUC Expects IRP Order in Early January**

The Connecticut DPUC anticipates issuing a draft decision on the state's integrated resource plan (Matters, 8/4/08) by January 5, 2009. The Department asked the Connecticut Energy Advisory Board and the utilities, which will soon start working on the 2009 IRP, to not file the second annual IRP with the DPUC until they have had an opportunity to review the Department's final decision (08-07-01), so the new IRP can confirm to specific Department guidance and instructions.

**DeGraffenreidt to Step Down at WGL**

WGL Holdings CEO James DeGraffenreidt, Jr., announced he will step down from his current position effective October 1, 2009, to be replaced by current COO Terry McCallister.

## *MISO Module E ... from 1*

"Our experience with other capacity markets, however, indicates that it is extremely rare for a supplier that lacks market power to not sell its capacity in the market," the IMM noted.

The IMM conceded that if the voluntary market is thinly traded, it is possible that the market might indicate larger price effects associated with capacity that is not offered than would a well-functioning market.

Thus the IMM intends to use a quantity threshold to ensure monitoring only identifies significant market power abuses. The quantity threshold would ensure that the withholding of small quantities of unsold capacity (that should not materially affect prices) would not be deemed to be an exercise of market power.

Based on the size of the Midwest ISO market, the IMM believes that such a quantity threshold would likely be in the range of 500 MW to 2,000 MW.

Some suppliers reported that they may refuse to sell capacity as a hedge against the loss of other generating units, and the IMM affirmed that actions that are economic would not be considered withholding. Hence, if physical hedging can be demonstrated to be economic, the IMM would accept such an explanation for refusing to sell capacity in the voluntary capacity auction. But given the typical outage rates for most units, "it is unlikely that physical withholding could be economically justified for potential withholding quantities in excess of the quantity threshold," the IMM observed.

The IMM also clarified that its program does not constitute monitoring of the bilateral market, as such monitoring would be beyond the scope of the market monitoring mandated by FERC.

The voluntary capacity auction market is essentially a balancing market where undesignated supplies can be sold to satisfy residual demand for capacity, and the only way to identify withholding in the voluntary market is to know which resources are available to be sold in that market (i.e., those that have not previously been sold bilaterally).

But simply using information on whether a resource has been sold bilaterally does not constitute monitoring of the bilateral market, the IMM insisted. True monitoring of the bilateral market would require information on bilateral bids, offers, and prices, which the IMM will not be collecting or monitoring.

The IMM also outlined its program for monitoring load's behavior. Just as supply can be withheld to raise capacity prices, an LSE that chooses to be deficient rather than submitting competitive bids to buy capacity in the voluntary market may be referred to the Commission. Such conduct would tend to lower capacity prices, just as withholding supply would tend to raise prices, the IMM said.

Because a deficient LSE's next best alternative is to pay the Midwest ISO's capacity deficiency charge, in all likelihood, a competitive bid would be priced at a level close to the deficiency level, the IMM noted. Like the monitoring of the supply-side, the IMM will use a quantity threshold and evaluate the price effects of any conduct to determine whether the conduct should be referred to the Commission.

If an LSE procures capacity bilaterally after the voluntary auction occurs at a price that is not "substantially" above the clearing price in the voluntary market, the LSE will be deemed not to have engaged in conduct that warrants further investigation. Such action is comparable to supply that sells its capacity after the voluntary market, the IMM said.

A second area that will be closely monitored is the LSEs' forecasts of their load that will be used to determine their Module E obligations. If an LSE substantially under-forecasts its load in a manner that cannot be explained by weather-related uncertainties or other factors, its conduct will be further evaluated to determine its effect on the capacity market. If the quantity and price effect are substantial, and the forecasting error cannot be justified adequately, the participant will be referred to FERC for potential enforcement.

## PJM External Pricing ... *from*

would not be offered immediately (due to software development), and would only be available on a long-term basis to balancing areas executing a congestion management agreement with PJM. Otherwise, the marginal cost option would expire January 31, 2010.

PJM has proposed the changes due to concerns that the average pricing mechanism in the current bilateral external pricing agreements masks the potential adverse impacts of external transactions on the PJM system by blending lower-priced LMPs with higher-priced LMPs from the same area.

Duke and Progress objected to the High-Low pricing method since it would not reflect the locational value of generation in the Carolinas, and ignores the fact that the utilities' diverse fleet of generators spread across a wide geographic area have different LMPs.

Both the SOUTHIMP/SOUTHEXP and High-Low Pricing options do not produce accurate prices when applied to directly connected utilities such as Progress and Duke, as these options over-allocate congestion costs to sales and purchases made by Progress and Duke, the utilities claimed. For example, the SOUTHIMP/SOUTHEXP option arbitrarily assigns homogenous prices across PJM's entire southern interface, although LMPs generally are higher for interfaces in the Mid-Atlantic region than they are for interfaces located farther to the West.

"While these inaccurate price signals may benefit internal generators by forcing low-cost suppliers such as Progress and Duke out of the market, the ultimate losers are PJM energy consumers," Duke and Progress charged. "If PJM's interface pricing protocols cause neighboring entities to reduce energy interchange with the PJM market, then such an outcome would not only harm those entities but would also deprive consumers of access to low-cost resources," the utilities added.

While marginal cost pricing represents a workable alternative, PJM's proposal compels balancing areas to sign a congestion management agreement to use the superior pricing method. Such agreements will require substantial and complex negotiations, and likely would require Duke and Progress to consult with their state regulatory commissions, the utilities said.

The PJM filing does not show that a congestion management agreement is necessary in order to implement marginal cost proxy pricing, or that it would be unjust and unreasonable to permit entities to engage in marginal cost pricing without the congestion agreement, Duke and Progress said.

Tying marginal cost proxy pricing to congestion agreements will benefit PJM in such congestion management negotiations, because PJM will head into negotiations knowing that applicants must agree to PJM's congestion management terms in order to continue transacting under marginal cost proxy pricing, Progress and Duke noted.

"The quid pro quo demanded by PJM's internal stakeholders clearly unlevels the playing field for any seams negotiations," the utilities argued.

Progress and Duke urged FERC to remove the requirement to negotiate a congestion management agreement in order to utilize marginal cost proxy pricing.

Furthermore, since marginal cost proxy pricing will not be available on February 1, 2009, when PJM intends to implement the other two new options and cancel existing bilateral pricing agreements, the Commission should direct PJM to continue bilateral agreements until marginal cost pricing is implemented. PJM has the right to terminate the bilateral agreements on 90 days notice, but Duke and Progress claimed it would be unreasonable to allow the agreements to terminate before marginal cost proxy pricing is available as a suitable alternative.

## *In December 25's Issue:*