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Watching the Watchers

Can RTO market monitors really be independent?

BY ROBERT J. MICHAELS

The Federal Energy Regulatory Commission (FERC) initiatives on regional transmission organizations (RTOs) and standard market design give new prominence to the market monitoring institution (MMI), a novel regulatory tool never before contemplated in legislation.[1]

FERC is requiring that all RTO applications include an MMI staffed by employees or external experts chosen by the RTO's governors. The MMI will evaluate market rules, observe regional trading, and regularly report to FERC. Commentators on the commission's proposed RTO rule had highly diverse views on the organization, functions, and sanctioning powers of MMIs. In response FERC has stated that it would be receptive to differences in MMI proposals that are justified by differences in regional markets.

MMIs already exist in all functioning RTOs and similar regional transmission entities, except in Texas, where one is being installed. Although experience is accumulating, FERC has never investigated their performance. It has yet to attempt a balanced determination of what MMIs can and should do, or whether they should exist at all. No regulatory institution has ever achieved so much centrality with so little forethought, and thus far there is little reason for optimism.

All RTOs have faced contentious and ambiguous market issues, but no MMI has ever produced a split decision. Either MMIs employ decidedly nonrandom samples of economists, or their reports are compromises that lose value because they do not make opposing opinions explicit to FERC.

Some rationales for MMIs are questionable at the outset. To get closer to a region's markets, FERC can simply post employees there. If FERC wants to standardize markets, there is little reason to let the locals specify how they will be monitored, particularly when one region might otherwise learn from others. As for independence, there are good reasons to favor distant observers rather than local ones.

It has taken only half a decade to forget some important history. MMIs were not invented by regulators but were proposed and designed by parties with economic stakes in the monitors' findings. In the case of California, MMIs met the expectations of those parties. California and other regions have further provided us with a "natural experiment" on MMI independence. Three independent system operators (ISOs) and their MMIs reached quite different decisions on the economically efficient practice of "virtual bidding." Politics trumped economics, for reasons probably inherent in the organizations themselves.

The California Experience

Ideally, an MMI would originate in a structured regulatory rulemaking where representatives of all affected interests could provide their views. In reality, it arrived in a docket, and not as a response to concerns by potential victims of monopoly. California's three large corporate utilities introduced MMIs in their 1996 application for market-based rates in the Power Exchange and ISO.[2] Their own studies showed that at times the region could not meet FERC's market power standards. (The main concern was predatory pricing that would facilitate stranded cost recovery under California's transition rules.) To save the bargain they proposed further generation divestitures, special contracts with must-run generators, and a market monitoring program whose details would come later.[3] Numerous parties testified about market power, but none independently suggested that MMIs be formed. Apparently few found it strange that regulators would rely on a watchdog institution proposed by the utilities whose market power was at issue.

The MMIs acquired structures and rules during the lengthy process that fleshed out the PX and ISO. Meetings were open to all, but only the three large utilities could vote on most matters.[4]

California got not one but four MMIs—internal and external units at the PX and the ISO. Market power concerns had separated the two institutions, but there was no obvious reason for separating and multiplying their monitors. In particular, it would be harder to detect and evaluate market power that exploited interactions between the PX and ISO. California required that its utilities obtain all of their power through the PX and ISO.[5]

In all RTOs except Texas, a day-ahead market (DAM) takes bids and determines hourly PX prices.[6] The RTO then checks security and schedules power from the DAM and bilateral contracts. A real-time market (RTM) prices the differences between planned and actual quantities. California required that those submitting day-ahead schedules commit resources equal to expected demand, fearing that over-reliance on the RTM would bring operating and pricing problems.

There were, however, reasons for buyers to behave otherwise. The supply curve slopes gently upward over normal loads but becomes steep between 35,000 and 40,000 megawatts (MW), where costly peaking capacity must operate. On a certain day, 40,000 MW would normally clear the DAM at $75 per megawatt-hour (MWh), which must be paid to all suppliers. Now assume a large buyer understates its day-ahead demand (underschedules load) by 5,000 MW, intending to make up the shortfall in the RTM. This action cuts the DAM volume to a level of 35,000 MW, where peakers are not necessary, and now it clears at $45. The remaining 5,000 MW are generated by peakers in the RTM, which clears at $75. Instead of paying $3.375 million in the hour, (45,000 X $75), buyers get the same quantity for $1.8 million (DAM) plus $0.375 million (RTM), saving $1.2 million.

Absent the buyer's action arbitrage would roughly equalize the DAM and RTM prices. Buyers that shift load can deny generators the revenue they would have earned in a competitive market. To succeed, however, they must be large enough to affect price, *i.e.* they must have market power. Buyers' gains could further increase if, as in California, the RTM had a lower price cap than the DAM. FERC's recent Western Market Report described one utility's actions:

> PG&E's strategy involved a deliberate attempt to push the Cal PX price below the capped price in the [RTM]. ... [Utilities'] underscheduling violated the California restructuring plan and the anti-gaming provisions of the Cal ISO and Cal PX tariffs. Both of these conclusions are true irrespective of the fact that the California public utilities viewed this practice as a cost minimization strategy.[7]

California's monitors understood the operational and price effects of load shifts.[8] Initially they claimed that generators rather than utilities had initiated the process for complex reasons involving "must-run" contracts. As it became clear that generators lost while utilities gained by shifting load from the loosely capped DAM to the tightly capped RTM, MMIs came to excuse the utilities' actions as "defensive."[9] The PX's external monitors even devised a strategy utilities could use to make prices still lower.[10] The MMIs were aware that a competitive energy market with little evidence of market power covered the West, but they chose to view it as an obstacle to imposing price caps in California alone.[11]

As the crisis grew the activities undertaken by MMIs changed. The ISO's internal monitors (who report to its general counsel) went beyond observing market conditions to calculating utility shortfalls in stranded cost recovery and their effects on shareholders. Its external monitor volunteered to calculate and allocate refunds due from generators, a job eventually performed by its internal monitor.[12] In 2001, state government took over most power purchases, but neither of the ISO's monitors commented on the presence of its representatives on the purchasing floor, or on available documentation that face-saving efforts by the state had led to higher prices and reliability problems. FERC finally ordered the state representatives off after a complaint from generators.[13]

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Virtual Bidding

Generators can directly counter buyers' efforts to cut the DAM price by selling into the RTM. In California, a scheduling coordinator could procure more power than required for its own load (while claiming otherwise) and sell the remainder in the RTM. Unlike California, other RTOs allow "virtual bidding" by financially eligible parties. One who expects a high RTM price can bid virtual demand into the DAM (with no expectation of delivery) and sell back to the RTM, but not without risk. One who expects the opposite can reverse those bids. Virtual bidding offers an ideal test case of independence. If considerations of economic efficiency rule, it will be a primary tool for arbitrage and risk management. If, instead, the interests of buyers loom larger, RTOs and their MMIs will be hostile to it.

Before returning to California, compare PJM and New York.[14] Prior to the opening of PJM's markets, Pennsylvania's utilities reached settlements to recover their costs of transition to retail competition. They retained generation and were free to make bilateral contracts. Most utilities outside of Pennsylvania continued under customary regulation and could pass on market prices. Virtual bidding began on June 1, 2000, the same date as the markets opened, with very minor implementation problems. PJM's MMI (an internal department) has told FERC that virtual bids have contributed importantly to the success of its markets, providing risk management and liquidity.[15]

New York's utilities faced more uncertainty than PJM's and less than California's. At the opening of the New York ISO's markets (December 1999) they did not have PJM's near-certainty of stranded cost recovery, but low rates minimized risks from retail competition. Retaining generation and free to contract, they did not face California's spot market risks and stranded cost deadlines. At the outset only utilities could shift loads between the DAM and RTM. Prices persistently differed, but New York ISO's external monitor believed that physical transactions alone could equalize them and that virtual trading could increase their divergence.[16] Studies by generators and others (not MMIs) favoring virtual bids were met by objections from utilities and resistance from the New York Public Service Commission, which saw them only as increasing rates. After a long and complex process, virtual bidding began on Nov. 1, 2001. Since then, the ISO has reported that virtual bids have fostered price convergence, particularly in transmission-constrained areas around New York City. Intervention or mitigation of virtual bids has never been required, and the ISO's external MMI has stated that their volume is large enough to thwart moderate exercises of market power.[17]

California's utilities had greater problems than New York's, having made a legislative bargain that froze retail rates, restricted purchases to spot markets, and provided little time for transition cost recovery. The comparison, however, is consistent. With little organized resistance, PJM and its monitors endorsed virtual bidding instantly. California's monitors concentrated on keeping prices low and tolerated exercise of market power by purchasers. They criticized underscheduling of loads by non-utilities and refused to consider virtual bidding. Now, however, the economics and politics have changed, and the ISO's external monitors support virtual bidding as part of a market redesign that will bring efficiency and lower prices.[18]

Rethinking Monitoring

Calling an RTO or MMI independent does not make it so. The closer to an RTO (and the farther from FERC) a monitor is, the more questionable its independence. Even California's Electricity Oversight Board has made the observation:

> Internal market monitoring units serve the interests of the organization, which cannot be expected to be aligned with the needs of regulatory agencies for

objective and comprehensive market monitoring.[19]

Minority reports by MMIs may be nonexistent because such reports will seldom serve the interest of their RTOs. In ordinary organizational life, management accepts consensus reports because it knows the range of views that went into them. MMI reports are written for FERC rather than management, and FERC cannot see the range of opinions they are considering. Unlike ordinary managements, the commission also will have a harder time understanding the balance of power that gives a report one slant rather than another.

Finding smarter experts is not a solution, since most MMIs are top-heavy with good professionals. Numerous economists whose competence and integrity are beyond question work for every sort of utility and intervenor, and they often make coherent counter-arguments to those of monitors. Why not make some of them monitors and get a mix of experts that reflects the differing professional opinions that work in the industry?

Possibly the biggest mistake is to assume that "independence" taken by itself has special value. Instead consider a stakeholder RTO board whose constituencies can each name a member of the MMI. Economists really do agree on a lot of issues, and there would be good reasons for FERC to take unanimity in a stakeholder-appointed group quite seriously. FERC also ends up better informed because where members of this MMI differ they will have good reason to put their differences in writing and argue hard for them.

Take the idea up another level. FERC is a commission of heterogeneous individuals who at times act, in effect, as monitors. Where its members agree they make the fact explicit, and when they disagree minority opinions are encouraged and accorded respect. No one likes everything the commission does, but most of us can agree that it makes coherent and intellectually respectable policy a lot more often than not. The monitors I trust are not in Folsom, Holyoke, Albany, or Valley Forge, where few can observe them or understand the local forces acting on them. They are at 888 First St. N.E. in Washington, and they need to understand that market monitoring is too important to be left to the market.

Robert J. Michaels is professor of Economics at California State University, Fullerton. He has been a consultant to generators, marketers, and utilities and provided expert testimony at state regulatory commissions and FERC. The opinions expressed here are entirely his own. Contact him at rmichaels@fullerton.edu.

Endnotes

1. Order No. 2000, Regional Transmission Organizations, FERC Stats. ¶ Regs. ¶ 31,089 (2000), 65 Fed. Reg. 809 (2000) (codified at 18 C.F.R. pt. 35); Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000 (2001).
2, Joint Application of [PG&E, SCE, and SDG&E] for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, Docket No. ER96-1663-000 (April 29, 1996) at A-1— A-5.
3. 71 FERC ¶ 61,265 (Dec. 18, 1996), Slip Op. at 25. Only a handful of public power intervenors voiced concerns about how the monitors would deal with owners of divested generation, which soon became a key issue.
4. See letter from CPUC President Daniel Fessler to the WEPEX Steering Committee, Jan. 31, 1996, quoted in Motion to Intervene of the California Municipal Utilities Association, Docket No. ER96-1663-000, at 3.
5. California utilities were required to bid contract purchases and retained generation into the PX at a price of zero.
6. The California PX ceased operating in January 2001. Elsewhere all markets are administered by the RTO. The process of day-ahead, ancillary services, and real-time bidding and scheduling is broadly similar in all of them. For details of California's former system see Nguyen T. Quan and Robert J. Michaels, "Games or Opportunities: Bidding in the California Markets," *Electricity Journal* 14 (Jan. 2001), 99-108.
7. Final Report on Price Manipulation in Western Markets, Docket No. PA02-000 (Mar. 2003) at VI-21 and VI-25. FERC ordered refunds from generators but asked nothing of buyers on the odd grounds that "there are no profits to disgorge from a price-reducing strategy." (VI-25)
8. ISO Market Surveillance Committee [MSC] [external monitor], *Report on Redesign of California Real-Time and Ancillary Services Markets*, Oct. 18, 1999 at 58.
9. MSC, *Report on Redesign of Markets for Ancillary Services and Real-Time Energy*, Mar. 25, 1999 at 17; ISO Department of Market Analysis [DMA] [internal monitor], "Price Cap Policy for Summer 2000," Mar. 2000 at 19. I provided FERC testimony on these matters for a major independent power producer.
10. PX Market Monitoring Committee, *Second Report on Market Issues in the California Power Exchange Energy Markets*, Mar. 9, 1999 at 48.
11. MSC, Analysis of Order Proposing Remedies for California Wholesale Electric Markets (Issued Nov. 1, 2000) at 55.
12. DMA, *Report on California Energy Market Issues and Performance* May-June 2000 (Aug. 10, 2000) at 20; MSC, Analysis of Order Proposing Remedies at 26.
13. Order Granting in Part and Denying in Part Complaint, Reliant Energy Power Generation Inc., et al., Docket No. 02-7, Nov. 20, 2001; "FERC Orders California ISO to End Its Preferential Treatment of DWR," *Electric Utility Week*, Nov. 26, 2001.
14. Of the other two established RTOs, Texas has no DAM. Prior to the opening of New England's new markets (which have virtual bidding), the region had physical trading mechanisms comparable to virtual bidding.
15. PJM Market Monitoring Unit, *State of the Market Report 2001* (June 2002) at 42-47.
16. NYISO's Answer to Morgan Stanley Capital Group Inc.'s Complaint, Docket No. EL00-90-000 (July 17, 2000), Attachment VI at 3.
17. NYISO, Evaluation of the Impact of Virtual Trading on the Summer 2002 New York Electricity Markets, Docket Nos. ER01-3009 et. al. (Dec. 16, 2002); Affidavit of Independent Market Advisor, Docket Nos. ER01-3155-000 et al (Mar. 19, 2002) at 35-36.
18. Market Design 2002 Comments, FERC Technical Conference (Aug. 14, 2002), unnumbered.
19. Comments of the California Electricity Oversight Board on Market Monitoring and Market Power Mitigation, Docket No. EL00-95-012 (Feb. 6, 2001) at 10.