

SPARK

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The on-line gateway for readers of Public Utilities Fortnightly magazine.



Who is right?

"Utilities that have invested in strong and highly interconnected transmission systems bring valuable assets that contribute significantly to the expansion of markets."

— J. Craig Baker, Sr. V.P.,
American Electric Power

"Locational marginal prices coupled with financial transmission rights ... these are the key economic signals ... the basic energy markets ... are the best tool for reflecting the regional value of transmission."

— Roy J. Shanker, independent
consultant

Bruce W. Radford, Publisher
radford@pur.com

Transmission Pricing

Rivals Debate the Grid's Worth

By BRUCE W. RADFORD

While the Midwest has now settled on competitive bidding for the electricity commodity, taking from PJM such tried-and-true elements as (1) locational pricing, (2) financial transmission rights, and (3) a day-ahead market with a security-constrained dispatch, the region remains divided over one final but inescapable issue: What price for transmission?

And it's no mere detail. The question goes way beyond the arcane and dusty attics of rate making. It calls for no less than a divvying up the profits and spoils of electric restructuring — and not just among companies, but among whole sectors and geographic regions.

Here's the nut. When federal regulators get done making all those ISOs and RTOs, with their protocols for bidding and markets, who gets to claim and retain all those profits created (supposedly) when the barriers fall and cheap Midwest power (from coal and nuclear) flows to high-priced eastern markets?

Will it be the power producers and merchant gens, who buy and sell, who get to keep all that margin? Or will the transmission owners, who built the grid that made all this trading possible, get to claim a piece of the pie?

In one alternative view, a grid-owning company such as American Electric Power (AEP), famous for its huge, decades-old investment in high-voltage lines, should be allowed to collect a market premium on transmission service, well-above »

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cost-based rates. Those lines prove indispensable in bringing nuclear power from Chicago to New Jersey. Why not reward the executives and stockholders of AEP for the vision to build those lines? Why not treat the grid as an asset having value that can and should be priced at a premium, according to its own intrinsic worth?

On the other hand, the PJM market has been shown to work well, and it treats transmission as a public domain. That is, the market sees nothing special in basic transmission service. It sets the price at cost, so that it exerts a largely neutral effect on the energy market. Participants in the PJM market pay a flat grid access charge based on a "license-plate" regime; the charge reflects the cost-based and regulated tariff of the owner of the particular sector in which the transaction "sinks." (The zone in which load resides.)

And so under this establishment vision, held by a majority of power market participants and regulators who have gone on record, the grid is treated as a universal network — owned by everyone, and hence no one. The transmission owners (TOs) collect a premium only for congestion. And the price of that congestion is derived solely from the difference between the locational marginal price (LMP) posted at various pairs of nodes on the grid. In short, the grid commands no independent intrinsic value. Its premium in the market, if any, is defined and derived entirely from the energy component. Generators dictate the value of the grid. Companies owning long-haul lines get cost-plus rates, but they get no real reward for the role they play in the wholesale market, and the growth they contribute to overall economic wealth.

What began simply as a move to encourage formation of RTOs has morphed into a search for the holy grail.

With the Federal Energy Regulatory Commission (FERC) having largely completed its standard market design (SMD) for wholesale power, and finished mapping the rules of the road for Regional Transmission Organizations (RTOs), this issue — grid pricing — may well mark one of the last great debates in electric restructuring.

How the Debate Got Started

Why now? Why the debate over the worth of the grid?

In truth, it was FERC that opened the door. Last month, on September 27, the FERC opened a new proceeding to investigate and implement a new long-term pricing structure intended to eliminate seams in the combined region marked by the PJM and MISO RTOs. (*See, Docket EL04-135, 108 FERC Para 61,313.*) However, that order marked only the latest in a long series of decisions, released over the past several years.

At first, FERC had sought to con-

vince Midwest utilities to join an RTO. With AEP, it had seized on its authority to approve the company's merger with Central & South West to provide the incentive. Later, however, when Commonwealth Edison and others chose to join PJM instead of MISO, FERC criticized their choices, balking at its geographic implications. And so it decided instead to force a sort of merger between the two RTOs, creating a single mega-market.

Further, to reduce "seams" within the combined RTO footprint, it required the elimination of pancaking "through-and-out" surcharges on transmission rates billed for crossing service territory boundaries, whether imposed by the RTOs (regional T&O rates, or "RTORs"), or by the individual utilities. As part of the deal to remove the T&O pancakes, FERC promised to make utilities whole over the short term by allowing a compensatory and temporary true-up charge (the SECA, or "Seams Elimination Cost Adjustment"). And to craft the SECA, FERC opened a broad settlement process, aimed at unifying the transmission price structure across the entire MISO/PJM area.

Finally, when it became clear this summer that the negotiations had ground to a halt, with two rival groups at an impasse on how to proceed, the commission acted in late September, as noted, to open the new proceeding.

So what began simply as a move to encourage formation of RTOs has morphed into a search for the holy grail — an effort to form the perfect market (a combined MISO and PJM), with a tariff providing for the perfect method of pricing for pure transmission service.

(Continued on p. 5)

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Unraveling Transmission Congestion

Searching for Answers In Regulation and Technology

BY LORI A. BURKHART

Even before the blackout of August 2003, the electric industry knew the grid needed more investment. The U.S. Department of Energy (DOE) stands ready to point the way for that investment and make the grid more efficient by identifying the worst congestion on the electric system.

September 20 marked the closing of the comment period for DOE's inquiry into identification, designation and possible mitigation of so-called National Interest Electric Transmission Bottlenecks (NIETB). It signaled the first step by DOE to publicly identify and designate NIETBs, aiming to mitigate transmission bottlenecks that constitute a significant barrier to efficient operation of regional markets, threaten safe and reliable operation of the system, and impair national security.

The 2002 DOE National Transmission Grid Study recommended that DOE designate NIETBs that significantly impact national interests. In response, DOE plans to develop analytic tools needed to determine where are such bottlenecks, and plans to then assess the nation's electricity system every two years to keep identifying them as the grid changes. DOE's Office of Electric Transmission and Distribution (OETD) leads the process.

DOE held a workshop on NIETBs on July 14, 2004 following the conclusion of the 2004 National Association

of Regulatory Utility Commissioners (NARUC) summer meeting in Salt Lake City, Utah. It wanted to find out how to design the NIETB process and obtain a better understanding of the types and availability of data needed to identify NIETBs. But according to David Meyer, senior advisor at OETD, the resulting comment period was not part of a formal rulemaking.

Bottleneck Criteria

But in the July 22, 2004 notice in the *Federal Register*, DOE pointed out it has completed some preliminary scoping studies to support DOE identification of NIETBs. That includes a survey of existing models and tools that could support bottleneck assessment by DOE and a survey of bottlenecks reported by regional transmission operators or independent system operators (the studies are available at <http://www.electricity.doe.gov/bottlenecks>).

The notice pointed to a study by the DOE's Electricity Advisory Board, which recommended that to be designated an NIETB, the bottleneck must meet one of three criteria, that it:

- Jeopardizes national security;
- Creates a risk of widespread grid reliability problems or likelihood that major customer load centers will be without adequate electricity supplies; or
- Creates the risk of significant consumer cost increases that could have serious consequences

on the economy.

DOE requested comments on whether those proposed criteria were sufficient, and if not what are the alternatives? It also wanted to know what should be the role of transmission grid operators, utilities and other market participants, such as state and federal agencies, in the designation and resolution of NIETBs.

Federal vs. State Authority

But is DOE going too far in what some view as attempting to take responsibility for planning the nation's grid? Some commentators think so. The investor-owned utilities, regional planning entities and some state commissions want DOE to back off.

National Grid USA, an investor-owned utility and managing member of Grid America, an independent transmission company within MISO, bluntly states that market participants know where are most of the electric transmission bottlenecks. And while National Grid does see a role for DOE in designating bottlenecks that merit national attention, it believes that DOE's planning for the nation's transmission system would constitute a duplication of regional and local planning efforts. It says local and regional stakeholders are better acquainted with system needs and are better suited to identify problems.

Entergy Services, Inc. echoes those comments, and in a one-page filing says it agrees with the Edison Electric Institute (EEI), and "supports the long-standing regional transmission planning process, and encourages DOE not to engage in any initiative that would duplicate these processes." Entergy wants DOE's role simply to be to contribute to facilitation of issues among parties, where a transmission provider requests DOE assistance in resolving siting and permitting issues.

The New York Public Service Commission (PSC) recognizes the need for a uniform approach in identifying »

congestion costs and benefits, so they can be compared across regions, and asks DOE to play a role in facilitating agreement among market participants as to the approach to be used in determining costs. But the PSC is joined in its thinking by the Regional Reliability Councils, and other state commissions, who argue that many factors come into play as to whether a designation as an NIETB is appropriate or not, and those are better known to state and local entities—but not to federal agencies. The PSC wants DOE to defer to designations of bottlenecks made by ISOs or RTOs that have a regional planning process in place.

Is Technology the Answer?

Perhaps the answer to solving the problem of congestion lies in technology improvements, not in more regulatory oversight. Suggested solutions from commentators to the DOE are diverse, and involve transmission corridor upgrades, alternative current (AC) to direct current (DC) conversion, and power cable changes.

Conversion of AC lines to high-voltage DC lines is getting more attention as a method to upgrade line capacity. Some of the many benefits are that it reduces line losses, and increases redundancy, voltage control and transmitted power. In favor of that transition is Lionel O. Barthold, an engineer and president of i-MOD Inc.

The Power Engineers Supporting Truth (J.A. Casazza, George Loehr and Frank Delea) also attempt to move DOE in favor of DC lines by encouraging use of a National Power Survey, modeled after the National Power Survey of 1964, which they say resulted in annual economic benefits of \$28 billion by the late 1980s from resulting inter-regional power exchanges and coordination.

They call for experienced energy engineers to make the survey, not DOE, and to ask questions such as what are the potential effects of dividing the three

Market participants know where are most of the electric transmission bottlenecks.

existing synchronous networks into eight or ten smaller networks, interconnected by DC? Also, among other questions, what changes in grid design would reduce the probability, extent and duration of blackouts, and also what are the risks and costs of new technologies such as the self-healing grid?

The Control for the Process Industry agrees that one of the simplest and most effective methods for increasing transmission line capacity is to switch from AC to DC. But the group also favors pushing more power through existing lines, which often run at just 50 percent of capacity, by upgrading transmission network control and sensing systems. Another available method is to move away from conventional cables to aluminum and carbon-glass fiber composites, which may carry twice as much power, or even super-conducting cable, which can carry five times as much power as ordinary ones.

Control for the Process Industry also points to hierarchical SCADA systems, which allows data to be shared between neighboring regions and aggregated for supervisory entities.

It is perhaps the most Internet-like aspect of technologies applied to power grid control and monitoring, according to comments by Randy Schreiber, v.p. of strategic marketing and operations at ABB. Also, Siemens uses state estimation in its hierarchical SCADA system. "Our state estimator provides a simple and cohesive view of the real-time state of the entire transmission system, including a look into the health of neighboring networks," notes Tom Garrity, v.p. of sales and business development for Siemens Power Transmission & Distribution.

Beacon Energy LLC, a consultant, teamed up with PB Power to offer a new

forecasting method, "T-insight," for identifying and predicting critical transmission congestion points, called "hot spots." It says the technique is simple, effective, transparent and cost-effective.

T-insight uses current year, projected year or daily information, all provided by major transmission utilities, to identify and predict congestion hot spots at different points in time. It models transmission line loadings and the companies say it reasonably can predict severe congestion points and areas where critical improvements are needed. It can be done within regions or in seams.

T-insight differentiates the model from other predictive techniques by noting the others usually rely on the summer and winter NERC forecasts for only the current year, do not use multiple time frames and require huge in-house utility transmission computer programs for analysis.

A benefit, according to T-insight, is that T-insight can use future demand projections to forecast future congestion zones and identify hot spots before they happen. Also, the technique is simple enough that with some degree of automation it could be applied to daily transmission and unit information to serve as a security check as a way to highlight same day or week-ahead problems. That allows regulators to secure an outside check of daily and weekly reliability problems without solely relying on utility or NERC information, which may not be available on a daily/weekly basis or in a readily usable format. ■

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Debate on Grid's Worth*(Continued from p. 2)***The Rival Plans**

Earlier this month, the MISO RTO proposed what it calls its "Unified Plan" for a single transmission pricing regime across the combined MISO/PJM footprint. In essence, that plan would employ PJM's classic license-plate pricing, using existing PJM zones, plus new zones planned for MISO. The plan carries support by a large majority of market participants in the two RTO areas, but somewhat smaller majorities of load and grid miles. The advocates include Alliant, Cinergy, FirstEnergy, Otter Tail, most of the original PJM TOs (Jersey Central, MetEd, Penelec, PPL, PEPCO, Delmarva, PSE&G, etc.), plus American Transmission (Wisconsin), International Transmission (the Detroit Edison grid spinoff), and Michigan Electric Transmission (spun off from Consumers Power).

Under the Unified Plan, MISO and PJM transmission owners would recover their grid investment through a grid access charge, reflecting the embedded-cost transmission tariffs already on file at FERC. Premiums, if any, would come from congestion pricing, driven by LMP differentials, as per PJM's current design. (*FERC Docket No. ER05-6, filed Oct. 1, 2004.*)

Meanwhile, on the same day, a smaller group of companies (led by AEP) proposed what they call the "Regional" plan. Supported by Exelon, Allegheny Power, Ameren, Illinois Power, LG&E Energy, and others, this minority group represents only 23 percent of the TO utilities in MISO and PJM, but 40 percent of the grid assets, and fully 55 percent of grid facilities rated at 345kV or above. (*See, FERC Docket Nos. EL02-111, EL03-212, EL04-135, filed Oct. 1, 2004.*)

The AEP group proposes a sort of "highway/byway" method for transmission pricing, but blended with a

"flow-based" approach. The method is extremely complicated, but becomes simple when it is understood for what it is — a method for compensating TOs for investments in the high-voltage lines that can help transport cheap power from the Midwest to the East, as envisioned under a seamless and unified MISO/PJM market.

(In a technical sense, this blended method divides transmission lines into several categories, according to voltage and usage. Higher-voltage lines are "highways." Lower-voltage lines are "byways." The byways are priced as per normal; revenue requirements for byways are set by zones and recovered through license-plate rates according to the locus of the sink. However, the revenue requirements for the higher-voltage highways and the more heavily used lines are averaged and then allocated by load through a voltage-based and a usage-based allocation across the entire MISO/PJM footprint. Thus, a retail customer who resides in a zone served by AEP, with a heavy local investment in transmission that serves long-distance needs, and with a higher than average local zonal transmission cost and charge, would see some portion of those highway costs and rates exported to other zones. Customers living in areas with less investment in high-voltage transmission would now pay higher transmission rates under the AEP plan.

The Arguments

MISO claims that its Unified Plan would provide the sort of stability needed to minimize disruptions as it does the heaving lifting to implement a bid-based, day-ahead market across the Midwest. In other words, don't rock the boat. Stick with what works in PJM, and expand it into MISO in exactly the same manner.

By contrast, AEP and the adherents of the Regional Plan focus on fairness — on identifying the haves and have-nots of electric restructuring.

AEP and its allies question why the millions (billions??) in savings from electric restructuring and wholesale market reform should flow only to consumers in high-cost areas who will see commodity prices fall, and to the merchant generators who will earn high margins from exporting cheap power to those areas. Why not reward the grid owners too? They state their case:

"Network customers of utilities that have invested in strong and highly interconnected transmission systems, which contribute significantly to the expansion of markets and the enhancement of reliability necessary for such expansion, will experience significant cost increases if a regional [our] transmission rate design is not adopted ...

"Regionalization of markets on this scale demands the creation of a regional transmission rate design."

But the proponents of the Unified Plan counter that the transmission grid forms an asset with a network character that cannot be allocated easily or fairly to one user or another. Utilities built this network over many years, the group says, funding the cost through bundled rates charged to captive customers during the era of the "regulatory compact." So it should cause no problem now to continue to bill those costs to today's native load customers, through local zone charges — especially since those charges are already on file in tariffs in the form of cost-based revenue requirements. Those tariffs have been open to challenge and thus ratified by state utility regulators and consumer advocates.

The AEP plan, by contrast, could well produce large shifts in costs and rates. Some zones could end up paying grid charges two or three times greater than they would with pure license-plate rates.

And those cost shifts are made more threatening by the fact that a grid pricing plan based in part on usage and voltage levels of various lines (a flow-based method) would force periodic »

recalculations of usage patterns and cost allocation. As the majority group explains, a recalculation would be required “each and every time a new transmission owner joined the system.

“Such a recalculation would be required, for example, with either a single postage stamp rate for the RTO footprint, a regional highway/byway design or other regional flow-based designs.”

Indeed, as the majority group explains, many of the agreements and retail rate plans that utilities and energy suppliers have offered to consumers, whether or not in states with open access, are now based on the existing transmission rate design.

“Imposing new, uncertain and volatile transmission costs on these retail suppliers which would be the case under flow-based proposals will only make their competitive position more precarious.”

The Outlook

For my money, the AEP group stands little chance of convincing FERC to stray from its tried-and-true PJM model, with its predictable zonal grid prices based on a license-plate cost allocation. Especially now, since it’s bound to be difficult to implement the PJM-style market in the Midwest, with its new regime of bidding, LMPs, and FTR allocations and auctions.

Things have gone wrong in the past, when regions have introduced new bid-based structures. Just ask New York and New England. I believe that FERC will say that the Midwest deserves a fair chance to make markets work, and that starting with a stable platform — no moving targets — is the best way to do it.

Yet, for all its confidence, the PJM model does carry with it a big logical inconsistency. And that problem is how to incentivize and price new investment in transmission.

According to their proposal, the proponents of the Unified Plan envision

that new transmission assets would fall under a separate category. Prices would be calculated not according to embedded costs, with license-plate zonal pricing, but on the basis of participant funding (the Unified plan calls it “beneficiary” pricing).

In other words, under the Unified plan, the MISO/PJM market structure attempts to value and price transmission service over newly constructed lines according to the economic benefits provided to a discreet population of beneficiaries. Yet, that is exactly the thing that the AEP group is trying to do overall, and which the majority group says is impossible to achieve!

The Unified Plan would build on the theoretical work that PJM has already conducted under its RTEP protocol. (Regional Transmission Expansion Plan). Under that process, the RTO studies the grid and regularly identifies instances of “unhedgable” grid congestion. In such cases, PJM will issue an RFP asking for grid expansion or merchant gen projects funded by private capital that would eliminate the congestion. In exchange for such investment, the private sponsors would earn FTRs or perhaps ARRs (“Auction Revenue Rights,” conferring an entitlement to an allocation of revenues from auctions of FTRs).

So the Unified Plan may appear simple, and it may have a greater chance of winning acceptance from the FERC, but in one sense, that success is entirely fortuitous. The Unified Plan banks on the fact that the nation’s electric grid is already largely built. The transmission rate cases are already finished. The Unified group can avoid all the arguments over valuation and cost allocation simply by piggybacking on top of all those completed rate cases. Such luck that it need not re-invent the wheel.

That, however, is what the AEP group is trying to do — to re-invent the way we value and price transmission, to reflect the new demands placed upon it. »

Next Month's FORTNIGHTLY

The November *Fortnightly* takes a hard look at regulation and is a special issue offered at the annual convention of the National Association of Regulatory Utility Commissioners in Nashville. Here is just some of what you will find:

- ▶ **State Regulators: Driven by Reliability**
Reliability and utility infrastructure development remain at the top of regulators’ lists of important issues. This year’s Regulators Forum spans the different regions of the country to highlight the most pressing issues facing the industry.
- ▶ **High Gas Prices: The Edge Comes Off**
Despite some expected problems this upcoming heating season, current high prices and new conservation programs will contribute to a decline in expected natural-gas demand over the next several years.
- ▶ **Transmission Upgrades: Who Pays?**
An examination of the impact of hypothetical congestion-reduction projects on generators and loads that are part of a vertically integrated utility, and generators independently owned in a deregulated environment.
- ▶ **Rate of Return on Equity: A Survey of Recent Rate Cases from State PUCs**
Our annual overview of ROE cases once again centers on interest rates, plus changes in the overall pattern of industry risk.
- ▶ **Regulatory Uncertainty: The Ratemaking Challenge Continues**
A joint survey of utility executives by Navigant Consulting and *Public Utilities Fortnightly* identifies the biggest challenge regulators face.

PLUS: The Expected Gas Price Falloff
Utilities Tap Into New Money Pipelines

Now don't get me wrong. I don't necessarily recommend the AEP model. It seems to me to be unnecessarily complicated. I believe it's simpler in the long run to rely on power commodity prices (the LMPs) to derive the value and price of transmission. Just like we use natural gas pricing hubs to

calculate the geographic basis differential and derive from that the true value of gas pipeline transport.

Yet the ugly fact remains. Sooner or later, we will want to build new transmission. And when that day comes, you can't use an old, com-

pleted rate case to set the price for that new line. You'll need a new method. I don't have the answer, but somebody must. ■

Bruce W. Radford is editor-in-chief of Public Utilities Fortnightly magazine.

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