Perspective

Reliability and Markets: Two Sides of the Same Coin

Locational pricing makes the network secure, since the utilities and other market participants get 'paid' to monitor the grid.

By W. Scott Miller, III

The recent pressure on the board and stakeholders of the Midwest Independent Transmission System Operator (MISO)—to postpone the startup of energy markets and concentrate instead on "reliability"—is truly unfortunate. It allows opponents of restructuring to continue to pose a false choice: You can have markets or you can have reliability, but never both.

Such rhetoric has a nice ring, but that's about all. It's like faulting your quarterback for not being a team player because all he does is pass for touchdowns.

In reality, we've learned just the opposite—that reliability and commercial efficiency are not only compatible, but also mutually reinforcing.

Of course, ever since the blackout of Aug. 14, 2003, we've seen regulators, politicians, and company executives embrace reliability as the one issue needing attention. That is easy to understand. We should welcome it but not get sidetracked by "solutions" that hold out little promise.

For example, among the most discussed solutions today are legislation (mandatory reliability standards), investment (massive transmission upgrades), and capital redeployment (boosting distributed generation, to bring resources closer to load). Such solutions are worth examining. Some may even be desirable. Yet they do not offer the fastest, surest, and most efficient way to enhance the reliability of the North American electric grid.

What's missing in these proposals is what we've learned through actual hands-on experience: that a competitive price for power, derived honestly from bids of willing buyers and sellers, will actually enhance reliability—provided (and here's the kicker) that the price reflects the actual physical state of the grid. And how is that discovered? Through a regional dispatch constrained by the demands of network security and communicated freely to all market participants.

The concept is simple and elegant: The market in effect "pays" the utilities and traders to monitor the condition of the grid with every transaction. And what's more, this fix is already well known in our industry. It's called locational marginal pricing (LMP).

Some still persist in separating the notion of reliability from the economic incentives we offer to transmission customers. That's not smart. In truth, LMP markets go beyond economics. LMP markets actually help ensure reliability.

Standards: Not Enough Incentive

Much has been made of the lack of mandatory reliability standards and penalties in most of North America.[1] However, it is doubtful that this would be the fix for reliability that many think they will be.

For an illustration as to why this might be so, assume it is a hot day all over the Eastern Interconnect (one of several consecutive ones) and a utility that might be short is tempted to "lean" on the system rather than purchasing in the very expensive bilateral market. Under very plausible scenarios, »

the utility could save millions of dollars in a single day by using "inadvertent" energy produced by other utilities and generators in the region. By meeting its customer needs by procuring power in this manner, the utility would probably affect the region's frequency, which could endanger the entire regional transmission system.[2] Under such circumstances, it would be difficult to envision a penalty structure that would deter this sort of behavior, given the obvious economic windfall that might accrue to a utility on a high-load day. Larger, economic interests often overrun administratively set penalties. Consequently, while mandatory reliability standards might prove useful, they should not be viewed as a panacea.

Investment: Difficult to Target

As was amply demonstrated on Aug. 14, electric transmission is a regional matter, encompassing many states. Electrons do not respect state boundaries. Consequently, transmission expansion requires regional solutions, which are difficult to implement without regional structures. However, even with regional reliability structures, the industry needs a process for determining where investment of one kind or another is most badly needed. Regional market structures that provide price information that reflects system conditions on a continual basis also provide the most transparent and accurate measure for determining where upgrades are needed.

An LMP market uses real-time system condition data, as well as predictive data as provided by a state estimator to derive prices that reflect the system needs. Used over time, these prices provide the baseline necessary for those wishing to make generation investments where a plant would be most useful. This same system also provides the regional transmission organization (RTO) and state entities, which are responsible for rates and siting, with real data to justify investments involving rate allocation. In the case of private or "merchant" transmission investment, these same prices also provide the necessary transparent information to make a justification for capital.[3]

Transmission investment alone may not have stopped the August blackout. For answers as to which systems and protocols hold the promise of achieving real reliability in system operations, one needs to concentrate on transparent information that links system conditions with the very strong incentives of economics.

Prices: The Most Effective Tool

Many opponents of electric restructuring have bemoaned the functional separation of generation operation from transmission. This, some have alleged, has undermined reliability. This is clearly not the case, as even vertically integrated utility systems constitute only one part of the total system picture that can affect reliability on a regional basis.[4] In addition, there is nothing in the vertically integrated utility structure that prevents a utility from operating the transmission system and generation fleet in a manner that is beneficial to its economic interest.

For decades we have needed a way to integrate economic incentives to operate various parts of the electric grid in a manner consistent with reliability needs and in a way that yields the most efficient result. The advances in information technology over the past 15 years, combined with the development of LMP, now allow us to achieve this outcome.

LMP is a very precise way to manage congestion. However, lost in the recent discussion on markets has been the relationship this bears to reliability. LMP uses actual system inputs from a large number of points on the system[5] and integrates bid prices into an algorithm that provides real-time, transparent information. This information demonstrates to all market participants where power needs to be increased or decreased. A generator or entity serving load could ignore these price signals that reflect system need. But, since the price is available to all participants in the market every five minutes, it is unlikely that such behavior would continue for very long.

During real-time operations, operators in a system similar to PJM would monitor all transmission limitations on the system and send electronic dispatch instructions to generators to manage transmission flows within the reliability criteria. The real-time energy market is based on the same security-constrained economic dispatch analysis that vertically integrated utilities use with the difference that the market makes the information available to all market participants over a broad regional area. Therefore, the locational prices that are posted for each generator every five minutes are consistent with the dispatch instruction that is sent to ensure reliable grid operation. Since the price signal is consistent with the dispatch instructions, generators tend to respond very quickly, resulting in a much more robust and reliable operating state.

Had this system existed on Aug. 14, it is very likely that pricing information would have prompted corrective action in the initial problem areas—through a redispatch of generation driven by the transparent prices—long before the outage became a cascading regional event involving 58,000 MW of load and generation. Two authors, University of Wisconsin Professor Fernando Alvarado and Rajesh Rajaraman, both of Christensen Associates, have in fact described how that would work.

In a paper dated Aug. 18, 2003,[6] less than a week after the blackout, Alvarado and Rajaraman explained in detail how various contingencies »

provided by the North American Electric Reliability Council in its initial timeline of events would have been handled under an LMP system. They discussed how prices may have increased dramatically in certain areas for some period of time, but how this fact would have elicited action that very likely would have mitigated the problem in its initial stages (and avoided the resulting very broad economic implications).

LMP boosts reliability in other ways. As operated in PJM, the state estimator (an algorithm that evaluates the physical state of the grid) typically will anticipate 2,000 credible contingencies at more than 2,000 monitored elements in its system, resulting in 4 million potential configurations. This information is incorporated into the prices provided to market participants to ensure that operations include a level of conservative assumptions. This marriage of available technology, systems, and a transparent pricing system yields fast results in operation that benefit reliability while providing for the most efficient outcome from an economic standpoint.

In short, LMP enhances reliability in a manner that no penalty regime can achieve. The recent decision by the stakeholders of MISO to delay the adoption of an LMP market, therefore, will only delay the improvements in reliability that so many correctly want to achieve. This unfortunate decision should be reviewed and reversed as soon as possible.

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Endnotes

1. The Western Electric Coordinating Council recently has adopted mandatory standards with an associated penalty structure.
2. This situation actually occurred a few years back. According to a sampling from this incident, the inadvertent power was 1,656 MW, 1,278 MW, and 1,448 MW for the sampled hours. Power prices in the bilateral market (there was no spot market) ranged between $2,000 and $9,500 MW/hour on one day. Assume $4,000 MW/hour for only those hours and the total is $17,528,000 of unpaid energy.
3. While it cannot be said that the rules of any RTO are perfectly structured to facilitate merchant transmission investment for AC lines and systems at this time, they provide the best platform for adopting rules to achieve such investment on a regional basis.
4. Regional security coordinators are part of the North American Electric Reliability Council, but in some cases these coordinators are employed by the vertically integrated utilities in the region, and therefore their impartiality for ordering curtailments necessary in non-market areas to relieve excessive congestion has been called into question.
5. Approximately 3,500 nodes in the current PJM system.
6. *The 2003 Blackout: Did The System Operator Have Enough Power?* Fernando Alvarado (*Alvarado@engr.wis.edu*) and Rajesh Rajaraman (*rrajaraman@lrca.com*).

Benchmarks

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to about 18.6 GW by 2015. Renewable generation must increase from just over 28 Terawatt-hours (TWh) today, to 69.5 TWh by 2015.

How will this impact electric sector gas use? As illustrated in Figure 1, in the "No RPS" case, natural gas generation is expected to increase from 91 to 214 TWh. In the "Full RPS" case, natural gas generation is expected to increase only to 177 TWh by 2015, a reduction of 37 TWh, or 17 percent. Our results indicate that new renewable power generation—mostly wind—in the "Full RPS" case competes almost exclusively with natural gas generation, as coal, oil, and nuclear generation are essentially the same in both cases.

In terms of gas-fired capacity, in the "No RPS" case natural gas capacity is expected to increase from 38 to 56 GW. In the "Full RPS" case, natural gas capacity increases only to 51 GW by 2015, a reduction of 5 GW, or 9 percent. Our results indicate that new construction of baseload gas combined-cycle units is most affected as a result of RPS-driven new renewable energy capacity. The addition of peaking gas combustion turbine units is similar between the two cases.

Looking at electric sector natural gas consumption, we find that consumption drops 262 trillion Btus by 2015 when moving from the "No RPS" to the "Full RPS" case, representing a reduction of nearly 17 percent. At $4/mmBtu, this means that California will save approximately $1 billion in annual natural gas expenditures by 2015 as a result of the RPS.

What about power prices? Our modeling efforts indicate that market clearing power prices in California are likely to remain relatively unchanged when comparing the "No RPS" to the "Full RPS" case. This is primarily because our market model automatically installs capacity as needed to meet demand, thereby eliminating the possibility of unpleasant price surges (if only the real world worked in a similar manner). It bears mentioning that market clearing energy prices do not reflect the capital investment cost required to bring new resources to market. We expect total investment costs under California's proposed renewable energy capacity expansion to be substantially higher than the "business-as-usual" capacity expansion plan embodied in the "No RPS" case.

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