Perspective

Electric Gridlock: A National Solution

FERC should consider a two-part tariff to boost transmission investment.

BY JAY APT AND LESTER B. LAVE

Transmission, rather than generation, is generally the constraint preventing customers from getting the power they desire.

The August 14th blackout, which was not the unique event some journalists described, proves the point yet again. In the past 40 years, the United States and Canada have experienced six major regionwide power failures (1965, 1977, July 1996, August 1996, 1998, and 2003), all caused by transmission line failures.[1] In addition to these regional blackouts, myriad blackouts have resulted from ice storms, hurricanes, wildfires, and other natural hazards. Hurricane Andrew in 1992 cut power to 1.2 million buildings, and 300,000 were without electricity for more than a week. Half the population of Quebec was without power for up to a month in 1998 because an ice storm brought down 770 transmission towers.

The recent blackout is a dramatic manifestation of transmission problems that have been occurring with increasing frequency since the implementation of FERC Orders 888 and 889, which radically altered the use of the transmission system. The number of times the grid was unable to transmit power for which a transaction had been contracted (transmission loading relief events) is shown in Figure 1.[2] These numbers imply that the transmission grid is bending, and sometimes breaking, under the load imposed by deregulation.

Transmission and distribution lines are the most vulnerable part of the network because they are easy to disrupt and they extend for thousands of miles. Contributing to the problem is the failure to expand transmission capacity adequately: Over 40 years, the amount of electricity generated in the United States has tripled,[3] growing at a compounded annual rate of 3.5 percent. During this time, the transmission system has grown at half that rate.[4]

The increased attention to generation has increased demands on the grid. The existing transmission system was built to connect a utility's power plants to its customers, with a few ties to neighbors in case a generator went down. That system was never designed for, and is unsuited to, getting power from any generator to any customer in a competitive generation market. To be successful, a competitive generation market requires much more transmission than the old system of geographical monopolies.

Solving Transmission Problems In 2003 and Beyond

Preventing future blackouts requires increasing the capacity and reliability of the transmission grid. This can be accomplished by building more lines as well as by increasing the capacity and controllability of existing lines, which will require billions of investment dollars. New technology, from the FACTS (flexible AC transmission system) to improved SCADA (supervisory control and data acquisition) systems would do much to increase the operational capacity and reliability of existing lines. Research and development promises still larger advances in the future, such as SMES (superconducting magnetic energy storage), FCL (fault-current limiter), and HTS (high-temperature superconductor) cable.

During and immediately after the blackout, political leaders stated that the blackout was unacceptable and should never happen again, but this political rhetoric is unlikely to produce substantial government appropriations or approval of price hikes to pay for the investments.

We propose a more realistic goal: The amount of loss and inconvenience from cascading failures should be no greater, averaged over a decade or so, than the loss and inconvenience due to natural hazards such as ice storms.

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Standard reliability indexes such as SAIFI (the system average interruption frequency index, or number of outages per year per customer) show that the U.S. system is half as reliable as that in Britain.[5]

There is no mystery as to how we could make our system more reliable: Add more generation, and transmission and distribution lines to supply the load if a unit fails, as well as adding ancillary services at critical points and implementing modern automated controls.

Despite the demonstration that these measures can increase reliability, the United States has opted for lower-priced, less reliable power. Does it make sense to spend more to prevent an outage due to cascading failures than an outage due to storms?

FERC and state regulators must address the implications for the grid in light of the deregulation of generation. Peak load congestion should be managed by levying a charge when the grid is congested; locational marginal pricing (LMP) is currently in use in some areas and is adequate for signaling users to curtail transmission during congestion.

Some analysts have hoped that an LMP congestion charge would provide both the information and incentives to guide transmission investment. Unfortunately, LMP provides precisely the wrong incentives to investors. The owner of the transmission line that was paid through only LMP would never desire to expand capacity. Any capacity expansion would reduce the LMP so that the owner would receive less revenue.

Furthermore, LMP does not give a good signal as to how much money should be invested in new capacity, or even where the capacity is most needed. Experience has shown that the line with the highest LMP may not be the tightest constraint in the transmission network. Very small changes in load or generation lead to large variations in LMP.

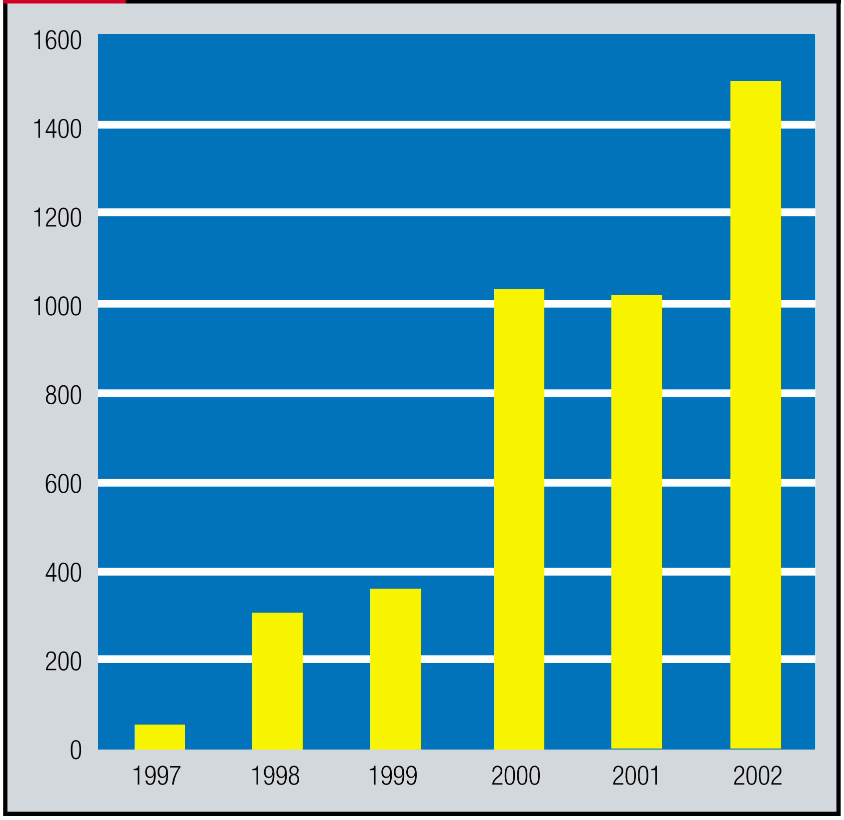
The funding to maintain the current transmission grid and encourage new transmission lines should come from a charge based on the number of megawatt-hour-miles (MW-hm) of transmission to get electricity from generator to customer. The transmission owners must be able to earn a rate of return that makes their investment attractive, given the uncertainty of the investment.

Locational marginal pricing (LMP) charges should be used to optimize flows in the existing system, since they provide the proper incentives to customers and generators not to ship power over already-congested lines. However, the LMP charges should not be paid to current owners or new investors; locational marginal prices should not guide investment, because they do not always give incentives to invest in the proper locations.

Locating new lines or expanding the capacity of existing lines requires an analysis of current and expected future locations of generators and customers. Each part of the transmission grid interacts closely with each other part, so a systems analysis and decision, as well as incorporation of stakeholder concerns, is needed.

In most places, transmission will remain a regulated monopoly, but the regulators or the monopoly should have systems analysis ability, incentives to invest, and incentives to incorporate stakeholder concerns.

FIGURE 1 ANNUAL NUMBER OF TRANSMISSION LOADING RELIEF EVENTS



Source: NERC

How To Boost Investment

To provide investment incentives, we propose that the regional transmission organization (RTO) calculate the number of megawatt-hour-miles produced by the transmission system. For example, if a customer purchased 10 megawatt-hours from a generator that is 125 miles away, that would be recorded as 1,250 MW-hm. Suppose that over a year the transmission system of an RTO supplied 32 billion MW-hm of transmission. Suppose further that cost of maintenance and repair on the lines was $200 million and that investors had to be paid $1.4 billion in interest and depreciation. Dividing the $1.6 billion in expenses by the 32 billion MW-hm, the charge would be 5 cents per MW-hm. If the average generator were 200 miles from the customer, the transmission charge would be $10 per MWh. An average charge of this nature is the economically favored solution when the marginal cost of additional service is low.

The revenue paid to transmission owners should come from this megawatt-hour-miles charge and the LMP. The entire LMP should go to this fund, unless the grid is so congested that the LMP exceeds the revenue owners should receive. If there were an excess, the funds could be used for research and development or to pay down the debt of the transmission owners. Generally, the LMP will be less than the required revenue. In that case, the additional revenue will be collected from a megawatt-hour-mile charge. For example, suppose in the example above the LMP resulted in total revenue of $800 million. If so, the 32 billion MW-hm would have to raise $800 million, and so the charge would be $0.025 per MW-hm or $5 per MWh for a 200- mile separation between generator and customer. Customers that bought power off-peak or in areas with a zero LMP would pay little for transmission, while customers located in congested areas would have to pay a great deal for transmission at peak demand times. The locational marginal price does not provide any investment signal, since the revenue paid to the RTO does not change.

If the RTO invested in new transmission lines that allowed more power to flow, the megawatt-hour-mile charge would allow them to get an adequate return on their investment. If the RTO, not the individual investor, determines when transmission lines should be built and which lines should be expanded, the RTO, rather than the investor, should bear the risk of bad decisions. Investors are taking little risk and should receive a return on their investment that reflects the risk level.

This two-part tariff would encourage customers and generators to locate in places with low LMP, and it would give investors in new transmission lines the incentive to build needed capacity.

Recommendation

FERC should implement this two-part tariff composed of LMP and a transmission charge to get needed investment in the transmission network, then set a rate of return that would attract sufficient investors, commensurate with the security of the expected megawatt-hour-mile charge. The LMP would ensure the best allocation of transmission lines at any time. The revenues from the two tariffs would be sufficient to cover expenses and give investors their desired return. If the total traffic or expenses were slightly different from the estimates, the rates would be adjusted at year-end or made up the next year. The RTO would have the responsibility of determining what investments are needed to upgrade or extend the transmission network. If the RTO wanted to make too many investments, too few investments, or put the investments in the wrong places, the generators and customers would have a strong incentive to protest (through the regulatory body supervising the RTO), since they would have to pay the LMP and transmission tariff.

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Endnotes

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