Electric Gridlock: A National Solution

Jay Apt and Lester B. Lave

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The August 14th blackout was not the unique event that some journalists described. In the past 40 years, the United States and Canada have experienced six major, region-wide power failures (1965, 1977, July 1996, August 1996, 1998, and 2003) – all caused by transmission line failures[1]. In addition to these regional blackouts, there have been myriad blackouts due to ice storms, hurricanes, wildfires, and other natural hazards. For example, 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. Transmission and distribution lines are the most vulnerable part of the network, because they are easy to disrupt, and 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 USA has tripled[2], growing at a compounded annual rate of 3.5%. During this time, the transmission system has grown at half that rate[3]. Transmission, rather than generation, is generally the constraint preventing customers from getting the power they desire.

Because attention has been on generation, restructuring the electricity industry has played a large role in the failure to build more transmission, and has simultaneously 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.

Unfortunately, lack of funds for investment combined with an unsettled regulatory environment has all but prevented new investment in transmission, even though deregulation sparked an increase in generation investment. FERC ordered[4] the creation of Regional Transmission Organizations (RTO) that would own, or at least operate, the transmission network. The FERC order led to a revolt among the utilities, that mustered congressional pressure, and forced FERC to make the RTO voluntary. No investment-starved utility is going to put its scarce capital into an investment that might be turned over to the RTO and for which the rate of return is uncertain. The result has been to freeze transmission investment. Until there is clarification as to who owns transmission, how the transmission owners will be paid, and what rate of return they can expect, transmission investment is likely to remain cold.

The August blackout is a dramatic manifestation of transmission problems which 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[5]. These numbers imply that the transmission grid is bending, and sometimes breaking, under the load imposed by deregulation.

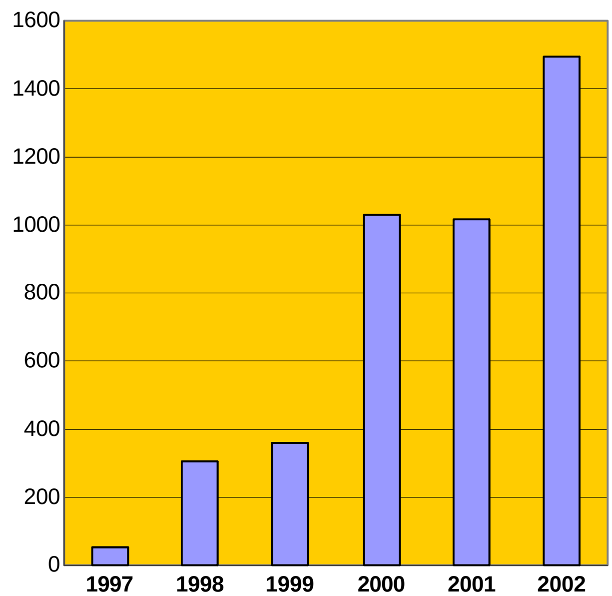

Figure 1. Annual number of transmission loading relief events. Source: NERC.

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, both requiring billions of dollars of investment. New technology, from Flexible AC Transmission System (FACTS) to improved data acquisition and control (SCADA) systems would do much to increase the operational capacity and reliability of existing lines. R&D 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. This is political rhetoric that 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. Standard reliability indices such as SAIFI (the system average interruption frequency index, or number of outages per year per customer) show that the US system is half as reliable as that in Britain[6]. 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 USA has opted for lower priced, less reliable power. Does it make sense to spend much 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 transmission grid 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 a LMP congestion charge would provide both the information and incentives to guide transmission investment. Unfortunately, LMP provide 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 needed most. Experience has shown that the line with the highest LMP may not be the tightest constraint in the transmission network, and that 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 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.

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

Where to build new lines or expand the capacity of existing lines requires a systems analysis of current and expected future locations of generators and customers. Unlike determining new investment in factories and retail stores, each part of the transmission grid interacts closely with each other part and so a systems analysis and decision are needed, as well as incorporation of stakeholder concerns.

In most places, transmission will remain a regulated monopoly. We will call that regulated monopoly a regional transmission organization (RTO), although other entities may evolve into that role. In any case, the regulators or the monopoly should have systems analysis ability, incentives to invest, and incentives to incorporate stakeholder concerns.

To provide investment incentives, we propose that the 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 1250 MWhm. Suppose that over a year the transmission system of an RTO supplied 32 billion MWhm 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 MWhm, the charge would be 5 cents per MWhm. 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 MWhm charge and the LMP. The entire LMP should go to this fund, unless the grid is so congested that the LMP exceeds the revenue that owners should receive. If there were an excess, the funds could be used for R&D or to pay down the debt of the transmission owners. More generally, the LMP will be less than the required revenue. In that case, the additional revenue will be collected from a MWhm charge. For example, suppose for the example above, that the LMP resulted in total revenue of $800 million. If so, the 32 billion MWhm would have to raise $800 million, and so the charge would be $0.025 per MWhm or $5 per MWh for a 200 million 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 who were located in congested area would have to pay a great deal for transmission at peak demand times. The LMP 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 MWhm 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 both encourage customers and generators to locate in places with low LMP, and would give investors in new transmission lines the incentive to build needed capacity.

Recommendation

We propose that FERC implement this two-part tariff composed of LMP and a transmission charge to get needed investment in the transmission network. FERC should set a rate of return that would attract sufficient investors, commensurate with the security of the expected MWhm charge. The LMP would assure 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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Jay Apt is Executive Director of the Carnegie Mellon Electricity Industry Center at Carnegie Mellon University's Graduate School of Industrial Administration and the Department of Engineering and Public Policy, where he is a Distinguished Service Professor. Lester B. Lave is a University Professor at Carnegie Mellon University; The Harry B. and James H. Higgins Professor of Economics and Finance; Professor, Engineering and Public Policy and The H. John Heinz III School of Public Policy and Management; Director, Green Design Initiative and co-Director of the Carnegie Mellon Electricity Industry Center. The Carnegie Mellon Electricity Industry Center website is www.cmu.edu/electricity.

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[6] US data from T. Short, *Reliability Indices*, presentation at T&D World Expo 2002, Indianapolis, IN, May 7-9, 2002. UK data as quoted in *Submission on Commerce Discussion Paper on Review of Asset Valuation Methodologies*, available at http://www.comcom.govt.nz/electricity/pdfnov2002/Electricity%20Networks%20Association.pdf