Testimony of Pat Wood, III
Chairman, Federal Energy Regulatory Commission
Before the Subcommittee on Oversight of Government Management,
the Federal Workforce, and the District of Columbia,
Committee on Governmental Affairs
United States Senate
September 10, 2003

The United States-Canada Joint Task Force, with assistance from the Federal Energy Regulatory Commission (FERC or the Commission) and others, is working to identify the cause of the blackout and the steps needed to prevent similar events in the future. Analysis of the blackout is ongoing; the cause of the blackout and the reasons for its broad cascade through eight states and parts of Canada remain the initial goal of the Task Force's efforts.

The federal role in electricity reliability is the focus of this hearing. In the electric power industry, FERC acts primarily as an economic regulator of wholesale power markets and the interstate transmission grid. In this regard, FERC is acting to promote a more reliable electricity system by: (1) promoting regional coordination and planning of the interstate grid through regional independent system operators (ISOs) and regional transmission organizations (RTOs); (2) adopting transmission pricing policies that provide price signals for the most reliable and efficient operation and expansion of the grid; and (3) providing pricing incentives at the wholesale level for investment in grid improvements and assuring recovery of costs in wholesale transmission rates.

The Commission's efforts to strengthen the interstate transmission grid could be further buttressed in the energy bill, now in conference. There are several provisions in the two electricity titles that would do so: a system of mandatory reliability rules established and enforced by a reliability organization subject to Commission oversight; Congressional support for the formation of RTOs across the nation; greater legal certainty for the Commission's efforts to adopt rate incentives for transmission or other investment to alleviate congestion on the grid, including new transmission technologies; tax incentives for transmission owners to join RTOs and to construct new transmission; and, federal backstop transmission siting authority for certain backbone transmission lines, in the event a state or local entity does not have authority to act or does not act in a timely manner.

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I. Introduction and Summary

Thank you for the opportunity to testify on the blackout experienced in the Midwest and Northeast on August 14, 2003, the current federal role in managing and regulating the generation and the transmission of electricity, and steps to ensure that we do not experience another incident of this nature.

The August 14, 2003 power blackout serves as a stark reminder of the importance of electricity to our lives, our economy and our national security. All of us have a responsibility to do what we can to prevent a repeat of such a blackout. The United States-Canada Joint Task Force (Task Force), with assistance from the Federal Energy Regulatory Commission (FERC or the Commission) and others, is working to identify the cause of the blackout and the steps needed to prevent similar events in the future. While analysis of the blackout is ongoing, it is too early to be sure what caused the blackout or why the blackout cascaded through eight states and parts of Canada.

Even at the start of this investigation, however, this much is clear: our electrical system operates regionally, without regard to political borders. Electrical problems that start in one state (or country) can profoundly affect people elsewhere. Preventing region-wide disruptions of electrical service requires regional coordination and planning, as to both the system's day-to-day operation and system upgrades.

II. Steps Taken by FERC in Response to the August 14 Blackout

FERC staff based in Washington, D.C., and at the Midwest Independent System Operator (MISO) in Carmel, Indiana, have monitored blackout-related developments from the first minutes.

Immediately after the blackout began, FERC staff members went to the U.S. Department of Energy (DOE) to coordinate our monitoring with DOE's emergency response team. At about the same time, FERC staff in the MISO control room began monitoring and communicating the events around the clock until most of the power was restored.

During this time, FERC staff was involved in nearly 20 North American Electric Reliability Council (NERC) telephone conference calls with the reliability coordinators, assessing the situation. These calls also involved close coordination with our Canadian counterparts. Also, the on-site staff monitored other calls between MISO, its control areas, transmission-owning members, and other ISOs and RTOs in their joint efforts to manage the grid during restoration.

In Washington, D.C., FERC staff immediately mobilized to provide relevant information to the Commissioners and to others, including DOE. These communications included, for example, data on output by generating facilities and markets adjacent to the blackout area. FERC also gathered information from ISO and RTO market monitors for each of the ISOs or RTOs in the affected regions. Our staff closely tracked the markets to make sure that no one took advantage of the situation to manipulate the energy markets. Working with the market monitor for the New York Independent System Operator (NYISO), we tracked the New York market especially closely during the period when that market was coming back on line and during the first unusually hot days later in the week of August 18.

Currently, members of the Commission's staff are assisting the Task Force on its investigation of the blackout. The Commission will contribute resources to this effort as needed to ensure a thorough and timely investigation. If any issues arising from the investigation merit specific Commission action, we will undertake such action independently in accordance with our statutory mandate.

III. Background

A. The Current State of the Electricity Transmission Grid

The Nation's transmission grid is an extremely complex machine. In its entirety, it includes over 150,000 miles of lines, crossing the boundaries of utilities and states, and connecting to regions outside our national borders. The total national grid delivers power from more than 850,000 megawatts of generation facilities. The grid is operated by utility staff at some 130 round-the-clock control centers. The large number of these centers – some relatively small -- has been the focus of much attention in post-Blackout analysis and discussion.

When a generating facility or transmission line fails, the effects are not just local. Instead, the problem often has widespread effects and must be addressed by multiple control centers. The utility staff at these centers must quickly share information and coordinate their efforts to isolate or end the problem. Given the speed at which a problem can spread across the grid, coordinating an appropriate and timely response can be extremely difficult without modern technology.

Transmission capital investments and maintenance expenditures have steadily declined in recent years. In the decade spanning 1988 to 1997, transmission investment declined by 0.8 percent annually and maintenance expenditures decreased by 3.3 percent annually. (Maintenance activities include such items as tree-trimming, substation equipment repairs, and cable replacements, all of which affect reliability). During this same period, demand increased 2.4 percent annually.

Transmission is a relatively small part of the overall electric power cost structure, accounting for only 7 percent of a typical end-user's bill. Generation, by contrast, accounts for over two-thirds of the customer's bill. An integrated company, owning both generation and transmission assets, could seek recovery of new transmission investment in its rates. But given that transmission is such a small part of the overall rate, a typical utility is unlikely to file to recover for just new transmission investment, particularly those expansions that may benefit *another* utility's customers.

Even more important than adding transmission capacity is improving the tools available to control center staff for operating the grid. One example is installing state-of-the-art digital switches, which would allow operators to monitor and control electricity flows more precisely than the mechanical switches used in some areas. Installing additional monitoring and metering equipment can help operators better monitor the grid, detect problems and take quicker remedial action. Improved communication equipment can help control centers coordinate efforts more quickly. The level of investment in these technologies has been varied.

B. Today's Regulatory Framework

Currently, there is no direct federal authority or responsibility for the reliability of the transmission grid. The Federal Power Act (FPA) contains only limited authorities on reliability.

For example, under FPA section 202(c), whenever the U.S. Department of Energy (DOE) determines that an "emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," it has authority to order "temporary connections of facilities and such generation, delivery, interchange or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." Secretary Abraham used this authority immediately after the Blackout to energize the Cross-Sound Cable between Long Island and Connecticut.

Under FPA sections 205 and 206, the Commission must ensure that all rates, terms and conditions of jurisdictional service (including "practices" affecting such services) are just, reasonable and not unduly discriminatory or preferential. These sections generally have been construed as governing the commercial aspects of service, instead of reliability aspects. However, there is no bright line between "commercial practices" and "reliability practices."

The explicit authorities granted to the Commission in the area of reliability are very limited. For example, under FPA section 207, if the Commission finds, upon complaint by a State commission, that "any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate or sufficient service to be furnished," and fix the same by order, rule or regulation. The Commission cannot exercise this authority except upon complaint by a State commission.

The Public Utility Regulatory Policies Act of 1978 (PURPA) also provides limited authority on reliability. Under PURPA section 209(b), DOE, in consultation with the Commission, may ask the reliability councils or other persons (including federal agencies) to examine and report on reliability issues. Under PURPA section 209(c), DOE, in consultation with the Commission, and after public comment may recommend reliability standards to the electric utility industry, including standards with respect to equipment, operating procedures and training of personnel.

Since the electric industry began, reliability has been primarily the responsibility of the customer's local utility. Most utilities have been accountable to state utility commissions or other local regulators for reliable service. Typically, the utility keeps statistics on distribution system interruptions in various neighborhoods, inspects the transmission system rights-of-way for unsafe tree growth near power lines, and follows industry requirements for “reserve” generation capability to cover unexpected demand growth and unplanned outages of power plants. Many state and local regulators exercise the authority of eminent domain and have siting authority for new generation, transmission, and distribution facilities.

In 1965, President Johnson directed FERC’s predecessor, the Federal Power Commission (FPC), to investigate and report on the Northeast power failure. In its report, the FPC stated:

> When the Federal Power Act was passed in 1935, no specific provision was made for jurisdiction over reliability of service for bulk power supply from interstate grids, the focus of the Act being rather on accounting and rate regulation. Presumably the reason was that service reliability was regarded as a problem for the states. Insofar as service by distribution systems is concerned this is still valid, but the enormous development of interstate power networks in the last thirty years requires a reevaluation of the governmental responsibility for continuity of the service supplied by them, since it is impossible for a single state effectively to regulate the service from an interstate pool or grid.

Northeast Power Failure, A Report to the President by the Federal Power Commission, p. 45 (Dec. 6, 1965).

In response to the 1965 power failure, the industry formed the North American Electric Reliability Council (NERC). NERC is a voluntary membership organization that sets rules primarily for transmission security in the lower 48 states, almost all of southern Canada, and the northern part of the Baja peninsula in Mexico. More detailed rules are prescribed by ten regional reliability councils, which are affiliated with NERC. However, neither NERC nor the ten regional reliability councils have the ability to enforce these rules.

IV. Current Commission Activities

The reliability of the grid can be bolstered through regional planning and operation of the transmission system, such as regional planning of new facilities; greater investment in infrastructure; and better methods of monitoring and managing transmission flow in order to relieve congestion. The Commission has underway several initiatives to address these issues, including: (1) promoting the formation of independent regional organizations with clear wholesale market rules to promote an efficient, reliable wholesale marketplace; (2) authorizing incentive rates for new infrastructure, including innovative technologies; and (3) identifying problems in the transmission infrastructure.

First, with respect to operating the interstate transmission grid, in Order No. 2000, the Commission identified the benefits of large, independent regional entities to operate the grid, and strongly encouraged, but did not require, utilities to join together to form such entities. The Commission noted that such entities would improve reliability because they have a broader, more regional perspective on electrical operations than a stand-alone utility. In addition, some 130 control area operators currently manage the operation of the transmission grid, whereas a smaller number of regional organizations could more effectively manage the grid. Further, unlike utilities that own both generation and transmission, RTOs are independent of market participants and, therefore, lack a financial incentive to use the transmission grid to benefit one market participant.

In Order No. 2000, the Commission recognized that regional organizations also have unique advantages to assist in regional planning for transmission infrastructure. The Commission required that RTOs have a regional planning process to identify and arrange for necessary transmission additions and upgrades. Second, almost half of the electric load in the country is being served by utilities which are part of an independent system operator or RTO. (The major distinction is the size of the entity: an ISO can be smaller than an RTO).

In a July 2002 Notice of Proposed Rulemaking (the Standard Market Design Rule), the Commission proposed to complete the nation-wide transition to independent grid operators, building upon numerous public hearings on best practices in power markets around the world, and also upon lessons learned from market failures in California in 2000. In response to over 1000 filed comments to the rulemaking, the Commission issued a White Paper in April 2003, streamlining the rulemaking effort by identifying the key elements of market design platform for improving the efficiency of wholesale markets. Such a platform would, among other things: (1) promote investment in transmission infrastructure, including new technology and in institutional infrastructure such as regional organization with good market rules and customer protection; (2) provide greater regulatory certainty to make it safe to invest in new transmission infrastructure including new technology; (3) require reliable and efficient management of the use of transmission within the region and between neighboring regions, through day-ahead markets, facilitation of demand response, and the use of price signals.

Second, the Commission has proposed the use of incentive rates to encourage the efficient expansion of the transmission grid. For example, Order No. 2000 recognized that transmission incentives were appropriate for public utilities that joined an RTO and offered various incentives.

In January 2003, the Commission sought to give additional guidance on these transmission incentives by issuing a proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid. The proposed incentives would help encourage needed investment in transmission infrastructure and improve grid performance through: an incentive adder for all public utilities equal to an additional 50 basis points on its return on equity for transfer of operational control of transmission assets to an RTO; an additional 150 basis points for sale of transmission assets to an entity independent of any market participant; and an additional 100 basis points for investments in new transmission facilities. The Commission also sought comment on whether incentives for new transmission investment should be structured to encourage the use of new technologies that can be installed relatively quickly (i.e., do not require a long siting process for procurement of new right-of-way, accommodate modular and portable application, and may be environmentally benign). Such technologies appear to offer significant promise of expanding grid capacity, reducing congestion, improving reliability, and enhancing wholesale competition without great cost or delay. The Commission is currently considering comments on the proposed policy statement.

The Commission has also acted in individual cases to provide incentives for development of transmission infrastructure. For example, in June 2002, the Commission approved a proposal to construct transmission facilities to ease the constraints on Path 15 within California. The Commission authorized a premium on return on equity (13.5 percent) and accelerated depreciation for this project as an incentive for construction.

Also, in Southwest Connecticut, an area experiencing significant transmission congestion, the Commission has authorized New England-wide rolled-in rate treatment of certain transmission upgrades and additions that were completed within a specified time period in order to provide incentives for the timely construction of these facilities.

Finally, the Commission has adopted various procedures for identifying areas that need additional investment in transmission facilities. The Commission has conducted a series of regional public conferences to discuss the state of the energy infrastructure within each region, i.e., the West, Midwest, Northeast, and South. We intend to hold public conferences in these regions every year. State officials actively participate in these conferences. These conferences provide a forum for discussing the adequacy of the electric transmission infrastructure within the region, the level of transmission congestion, and potential benefits of increasing transmission infrastructure.

V. What Congress Can Do To Help

Currently, the Congress has before it, in conference, energy legislation which could address a number of issues that have arisen in the debate in the last few weeks over reliability in our wholesale power markets.

First, both the House and Senate bills going to conference provide for mandatory reliability rules established and enforced by a reliability organization subject to Commission oversight. Many observers, including NERC and most of the industry itself, have concluded that a system of mandatory reliability rules is needed to maintain the security of our Nation's transmission system. I agree.

That leads to the question of what entity will be in charge, on a day-to-day basis, of administering the mandatory reliability rules that are developed by the independent reliability authority. In Order No. 2000, the Commission identified the benefits of large, independent regional entities, or RTOs, in operating the grid. (See Appendix for excerpts from FERC Order No. 2000 on reliability benefits of RTOs). Such entities would improve reliability because they have a broader perspective on electrical operations than individual utilities. Further, unlike utilities that own both generation and transmission, RTOs are independent of market participants and, therefore, lack a financial incentive to use the transmission grid to benefit their own wholesale sales.

In the seven years since the Commission ordered open access transmission in Order No. 888, the electricity industry has made some progress toward the establishment of RTOs, entities that combine roles relating to reliability, infrastructure planning, commercial open access and maintenance of long-term supply/demand. The House bill endorses this effort in a "Sense of the Congress" provision. Congress can direct this effort to be completed.

While coordinated regional planning and dispatch are sensible steps to take, we still need to attract capital to transmission investment. I understand that there is significant interest in investing in this industry already; however, to the extent the Commission needs to adopt rate incentives for transmission or other investment to alleviate congestion on the grid, including new transmission technologies, we should do so. While the Commission has recently taken steps in this direction, action by Congress providing more legal certainty on this issue, and in repealing the Public Utility Holding Company Act, can provide greater certainty to investors and thus encourage quicker, appropriate investments in grid improvements.

In addition to ratemaking incentives from the Commission, Congress can also provide economic incentives for transmission development. Changing the accelerated depreciation from 20 years to 15 years for new electric transmission assets is an appropriate way to provide such an incentive. Similarly, Congress can provide tax neutrality for utilities wishing to transfer transmission assets to RTOs.

To the extent that lack of assured cost recovery is the impediment to grid improvements, regional tariffs administered by RTOs are an appropriate and well-understood vehicle to recover these costs. The Commission has accepted different regional approaches to pricing for transmission upgrades, but the important step is to have a well-defined pricing policy in place.

Getting infrastructure planned and paid for are two of the three key steps for transmission expansion. The third step is permitting. States have an exclusive role in granting eminent domain and right-of-way to utilities on non-federal lands. Under current law, a transmission expansion that crosses state lines generally must be approved by each state through which it passes. Regardless of the rate incentives for investment in new interstate transmission, little progress will be made until there is a rational and timely method for builders of necessary transmission lines to receive siting approvals. Providing FERC (or another appropriate entity) with backstop transmission siting authority for certain backbone transmission lines, in the event a state or local entity does not have authority to act or does not act in a timely manner, may address this important concern.

VI. Conclusion

Both FERC and the Congress can take steps to bolster the reliability of our Nation's interstate transmission grid. Taking the steps outlined above can help avoid future disruptions in our electric supply. Thank you.

APPENDIX

Excerpts from Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 **&** 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 **&** 31,092 (2000), affirmed sub nom. Public Utility District No. 1 Snohomish County Washington, et al., v. FERC, 272 F.3d 607 (D.C. Cir. 2002).

Order No. 2000, 65 Fed. Reg. at 862:

Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.

Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.

. . .

Improving Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.

Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient if planned and coordinated over a larger region.

Order No. 2000, 65 Fed. Reg. at 863:

For example, we understand that there have been instances where transmission system reliability was jeopardized due to the lack of adequate real-time communications between separate transmission operators in times of system emergencies. To the extent possible, RTO boundaries should encompass areas for which real-time communication is critical, and unified operation is preferred.

Order No. 2000, 65 Fed. Reg. at 867-68:

The fourth proposed characteristic of an RTO is that it must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. In the NOPR we identified four basic short-term reliability responsibilities of an RTO: (1) the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules; (2) the RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities; (3) when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if the RTO operates under reliability standards established by another entity (e.g., a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service.