

**Testimony of
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Thank you for the invitation to speak to you today about the Nation's electricity infrastructure and reliability. A reliable supply of wholesale electricity at reasonable prices rests on a three-part foundation: adequate infrastructure, sound market rules, and vigilant oversight of the marketplace. FERC is working hard to address all three areas. As we saw in the last decade, weakness in any one element can hurt markets, American energy customers and, ultimately, the entire U.S. economy.

Today I will address several issues. First, I will review the recent history of our Nation's electric system, focusing on the development of wholesale competition. Second, I will describe the current state of our electric infrastructure, including the need for more infrastructure investment. Last, I will discuss the future of the electric grid, and the goals the Nation should set for enhancing the grid. I will highlight the importance of technology and innovation in improving today's infrastructure.

I. Past

Without adequate electric infrastructure, grid reliability is compromised and supply can falter. In past decades, this risk was addressed by individual utilities, with varying levels of oversight by state regulators, who have chiefly focused on the rate impact of utility decisions. Reserve margins often exceeded twenty percent, service was usually reliable, and utilities routinely made new infrastructure investments to serve their own customers.

The Federal Power Act was enacted in 1935, an age of mostly self-sufficient, vertically integrated electric utilities. Generation, transmission, and distribution facilities were owned by a single entity and power was sold as part of a bundled service (delivered electric energy). Most utilities entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to sell bundled power to wholesale customers such as municipal utilities and cooperatives. Each system covered a defined service area. This structure of separate systems arose primarily because of the cost and technological limitations on the distance over which electricity could be transmitted.

In the late 1960s and throughout the 1970s, events occurred in the electric industry that began a shift to a more competitive marketplace for wholesale power. This was a time of rapid inflation and higher nominal interest rates. Higher capital

costs increased the cost of financing infrastructure investments, and construction schedules were extended by, in part, more stringent safety and environmental requirements. Particularly hard-hit were the utilities in the midst of nuclear power plant construction. At the same time, economic conditions in some regions of the country slowed the increase in, or even reduced, demand for electricity. As a result, some utilities sought to include in rates the cost of large expensive baseload plants for which there was little or no demand.

Electricity rates began to increase. Between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation. Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation.

Also in the 1970s, the energy shortages caused by oil embargoes heightened interest in more efficient ways to generate electricity. One such technology was cogeneration, a means of generating electricity while using the byproducts such as heat and steam for industrial or commercial uses. In response, Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA), facilitating the efforts of some industrial customers to build their own cogeneration facilities and laying the groundwork for competitive wholesale power markets.

The "rate shocks" of the 1970s led customers to pressure regulators to investigate the prudence of utility decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, write-offs of nuclear power plants totaled \$22.4 billion. These write-offs significantly reduced the earnings of the affected utilities. Delays in obtaining rate increases further reduced investor returns. For the first time, there was significant risk associated with siting and constructing even coal-fired power plants due to higher environmental standards. Thus, many utilities became reluctant to commit capital to construction of large generating plants.

At the same time, technological changes, along with the low cost of natural gas, allowed some new entrants in the power markets to sell electric energy with smaller scale technology at a lower price than many utilities selling from their existing generation facilities. However, the potential customer benefits of using the power supplied by these new market entrants could be realized only if the more efficient generating plants could obtain access to the regional transmission grids. Many traditional vertically-integrated utilities did not offer open access to third parties and, even when they did, they still favored their own generation.

In an effort to increase competition in wholesale power markets, Congress enacted Title VII of the Energy Policy Act of 1992 (Energy Policy Act). This legislation exempted certain wholesale generators from the restrictions of the

Public Utility Holding Company Act of 1935 (PUHCA), and expanded FERC's authority to require transmission service on a case-by-base basis.

In April 1996, in Order No. 888, the Commission established the foundation for strong competition in bulk power markets: non-discriminatory open access transmission services by public utilities. Order No. 888 found that unduly discriminatory and anticompetitive practices existed in the electric industry, and that transmission-owning public utilities had discriminated against others seeking transmission access. Accordingly, Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to: (1) file open access non-discriminatory transmission tariffs containing, at a minimum, the non-price terms and conditions set forth in the Order; and (2) functionally unbundle their wholesale power services. In 2002, the Supreme Court affirmed Order No. 888.

II. Present

After the issuance of Order No. 888, the industry underwent sweeping restructuring activity, including the divestiture of generation plants by some traditional electric utilities, entry into the wholesale markets of many new power marketers and independent generation owners, the establishment of independent system operators (ISOs) and Regional Transmission Organizations (RTOs) as operators of large parts of the transmission system, and an effort by a number of

States to open their retail service area franchises to competition. Trade in bulk power markets increased significantly and the Nation's transmission grid began to be used more heavily and in new ways.

In 1999, in response to these changes, the Commission issued Order No. 2000, encouraging the formation of RTOs to promote efficiency in wholesale electricity markets and ensure that electricity customers receive a reliable supply of electricity at reasonable prices. Today, RTOs and ISOs benefit customers by, among other things, coordinating the operations of electrical facilities over a large region and establishing wholesale markets to set efficient and transparent prices for the region. These transparent prices allow the regional grid operator to more reliably dispatch the regional system based on lowest-cost resources.

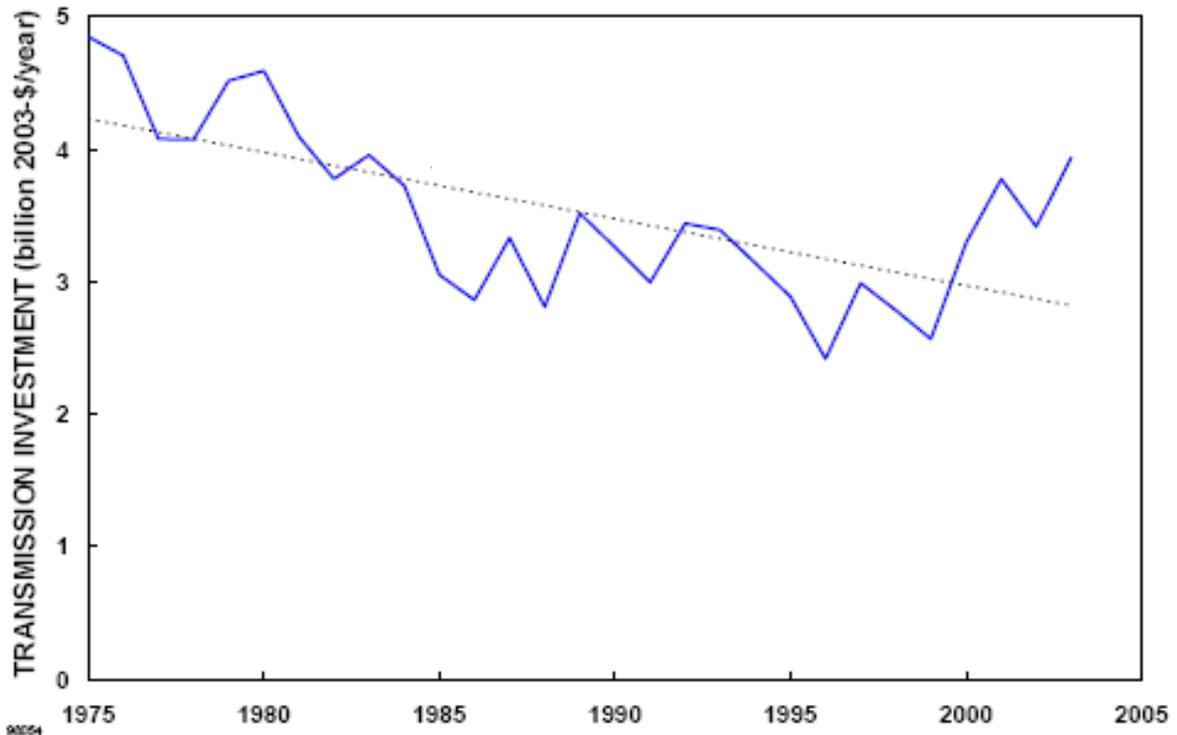
Many regions of the country have formed RTOs or ISOs to operate their electrical facilities. Currently, 69 percent of the nation's \$10 trillion economy is being served by RTO/ISOs, including New England, New York, the Mid-Atlantic region (PJM), the Midwest (MISO), the Southwest (Southwest Power Pool, or SPP), California and Texas. Although this establishment of regionally-focused, independent grid operators is a good step forward in promoting wholesale electric reliability, we have not yet reached the goal in all regions.

Transmission accounts for less than 10 percent of the final delivered cost of electricity, but it is critical to keeping our Nation's lights on. [Department of

Energy, National Transmission Grid Study at 8 (May 2002) (2002 National Grid Study).] Nonetheless, transmission investment is not keeping up with load growth. This trend has occurred in every area of the country. Construction of high voltage transmission facilities is expected to increase by only 6 percent (in line-miles) during the next 10 years, in contrast to the expected 20 percent increase in electricity demand and generation capacity (in MW).

Figure 1 shows the level of investment in transmission (in constant, inflation-adjusted 2003 dollars) over the past 30 years. Transmission investment in 1999 was less than half of what it had been 20 years earlier. Although the last few years have seen a short-term increase in transmission investment, growth in transmission capacity still appears to be lagging growth in demand.

Figure 1: Transmission System Investment over Time
Source: E. Hirst, U.S. Transmission Capacity: Present Status and Future Prospects (August 2004)



Increasing transmission congestion as evidenced by differences in locational prices and more use of transmission loading relief procedures illustrates the problem. In many regions of our country, facilities are often congested, and congestion appears to be growing. [2002 National Grid Study at 6 (data on increasing number of transmission loading relief events), 16 (calculation of the costs of congestion).] This results either in higher congestion costs being paid by customers or curtailment of otherwise economic transactions. Interregional transmission congestion costs customers hundreds of millions of dollars annually.

In addition to congestions costs, there are additional economic costs of decreased reliability. One example of the latter is the blackout of August 2003, which has been estimated to have cost U.S. and Canadian customers between \$4 and \$10 billion dollars.

The Commission recently held two public workshops on investment in transmission. At our first workshop, a witness for investor-owned utilities discussed the forecast of an unprecedented increase in transmission investment over the coming few years. [EEI Survey of Transmission Investment – Historical and Planned Capital Expenditures (1999-2008) at 5 (Edison Electric Institute, May 2005).] Other witnesses asserted, however, that much of this investment is a direct function of historic underinvestment in transmission and that U.S. investment levels are significantly below transmission investment levels in other countries.

The industry and its regulators (state and federal) must find ways to accelerate investment in transmission, if customers are to receive the many benefits achievable with competitive wholesale markets. Underdevelopment of the transmission grid impedes the achievement of the benefits of competitive markets. Significant transmission constraints limit access to competing electric resources. Since generation units cannot always be built close to load, competition in generation relies on the existence of sufficient transmission infrastructure to support such competition. This needed level of transmission infrastructure is missing in many areas of the nation. This issue becomes particularly acute as we

look more seriously at larger scale development of new coal-fired and nuclear power generation. These sources, which are almost always going to be located distant from load centers, require a more robust and stable grid than we have today.

An underdeveloped grid can cause problems even in an RTO or ISO, including the need to: mitigate potential exercises of local market power, retain otherwise uneconomic and inefficient generation for local reliability, and provide contractual support for some units needed for reliability in constrained areas.

Utilities seeking to build new transmission face a number of hurdles. Most traditional, vertically-integrated utilities with retail service obligations must go before their state commissions to seek retail rate recovery for any investment they make in new transmission. This can involve opening up all of their costs as well as their entire rate structure for reevaluation, a step few utilities desire. Often utilities are subject to retail rate moratoria, which can jeopardize their ability to recover any investment in new transmission from retail customers during the period of the retail rate freeze. Moreover, building transmission is subject to state and local siting approvals, essentially requiring utilities to negotiate not just with their state regulators and legislators, but also with a variety of other stakeholder groups prior to beginning construction of new transmission. Within a vertically-integrated utility, the need to build transmission must compete for capital with other investments such as building generation (which has been viewed by

investors as typically easier to build and having greater earnings potential) or distribution (which more directly affects and is more visible to end-use customers and the retail regulators). Finally, development of a robust inter-utility transmission grid may come into conflict with an individual utility's fiduciary responsibility to its shareholders if such a grid will allow competing generators to more economically serve the transmission-owning utility's wholesale customers.

The Commission has taken steps within our jurisdiction to ameliorate these disincentives. In the recent past we have granted rate incentives to utilities which, either through a stand-alone, transmission-only business model or through regional transmission expansion programs, have the ability to engage in beneficial expansions. As a routine matter we look at a number of factors before granting these rate incentives: why the incentive is necessary to facilitate a needed grid expansion or new form of transmission ownership, the level of independence of the applicant, and the geographic and participatory scope of the proposal.

Although the Commission is working within its current statutory authority to encourage infrastructure investment, additional measures are needed to reach the level of investment required to maintain the reliability of the Nation's bulk power system. The energy legislation currently pending before the Congress addresses certain impediments to investment in the short term, but more may be needed in the future.

III. The Future

The Administration has developed an ambitious goal for our electrical grid, a goal I fully support. In July 2003, the Department of Energy published its Grid 2030 Vision, describing the Administration's vision of the future electric system. The focus was on electric delivery – “the grid,” or the portion of the electric infrastructure that lies between the central power plant and the customer – as well as the regulatory framework that governs system planning and market operations.

The 2030 Vision builds on the existing infrastructure, but would take advantage of new technologies, tools, and techniques to increase the efficiency, quality, and security of existing systems and enable the development of a new architecture for the electric grid. As a part of Grid 2030, DOE has developed a roadmap identifying near-, mid-, and long-term actions necessary to achieve a modernized, expanded, and reliable electric system. Approval of future ratepayer-funded transmission projects should consider whether the projects support this vision.

In addition, a reliable grid will be easier to achieve through investment in a safety margin of transmission capacity. We need to have an investment and regulatory platform that is receptive to cost-efficient and energy-efficient technology. We must invest in technologies such as new overhead power conductors with double the electrical transmission capacity of conventional

conductors of the same diameter. Xcel Energy plans to install one such conductor on a 10-mile transmission line in the Minnesota Twin Cities region, for example. We must encourage the industry to continue to develop and test these new technologies so that we can move forward in achieving a more modernized and efficient grid.

One of the most critical tools missing in the current environment is demand response, but this issue raises difficult questions about federal and state jurisdiction. For example, one pending formal complaint before the Commission involves certain large commercial and industrial customers asserting that they are being blocked from participating in an RTO's demand response programs based on the local utility's claims about conflicting state law. Demand response programs can reduce energy costs and increase efficiency, but these programs are hindered because of blurred jurisdictional lines.

First, however, Congress should focus on three issues addressed in the pending energy legislation. These issues are: creating a mechanism for mandatory and enforceable reliability standards, providing federal backstop electric transmission siting authority, and the repeal of the 1935 Public Utility Holding Company Act (PUHCA).

In the wake of the August 2003 blackout, federal legislation is necessary to provide a clear, enforceable framework for reliability rules. Specifically, a system

of mandatory reliability rules, with penalties for violations of these rules, is needed to maintain the reliability of our nation's transmission system.

In addition to encouraging investment in our transmission grid, we must continue to take all appropriate measures to secure our existing infrastructure. For instance, currently there is no mandatory authority to enforce cyber security standards in the electric industry. This allows inconsistent levels of cyber security to be applied by utilities based on available resources and perceived risk. A focused cyber attack will use the least protected system as an entry point to impact a wider region. The grid is only as protected as the weakest link, that is, the least protected entity. Cyber security standards need to be mandatory, consistent, and rapidly upgraded. The House of Representatives has passed a version of the energy legislation which gives the Commission explicit authority over the interstate grid's cyber security.

It has been almost two years since the 2003 North American Blackout. Although both the House and the Senate have repeatedly passed reliability provisions, it is unconscionable that provisions obligating all users of the nation's transmission grid to comply with reliability rules have not become law. The reliability of the transmission grid is too important to let another year go by without legislation providing for nation-wide mandatory reliability rules.

The pending energy legislation would also provide the Commission with backstop interstate transmission siting authority for certain critical electric transmission corridors identified by the Secretary of Energy, in the event a state or local entity does not have authority to act or does not act in a timely manner. This authority would help facilitate the development of important transmission expansions and thus enhance the reliability of the grid, reduce the total cost to customers, or both. It is very similar to the development, a half century ago, of the interstate highway system, which elevated the principal highways of the then-existing U.S. highway system to “national interest” status and directed their expansion and improvement under a separately funded program.

Finally, the repeal of PUHCA is necessary to spur investment in the transmission infrastructure and facilitate competition. PUHCA was enacted primarily to undo the harms caused by certain holding company structures that no longer exist. In the almost 70 years since PUHCA was enacted, utility regulation has increased substantially under the FPA, federal securities law and state laws, all of which ensure that customers are protected. The existing integration requirement of PUHCA actually encourages market structures that impede competition. In particular, under PUHCA, acquisitions by registered holding companies generally must tend toward the development of an “integrated public-utility system.” To meet this requirement, the holding company’s system must be “physically interconnected or capable of physical interconnection” and “confined

in its operations to a single area or region.” This requirement tends to create greater geographic concentrations of generation ownership, which may increase market power at a time when we want a diverse and competitive generation marketplace. Further, PUHCA may impede investment in transmission companies in more than one region by subjecting any owner of ten percent or more of a public utility to becoming a holding company and possibly being required to register under PUHCA. PUHCA is a statute that has served its usefulness and now needs to be repealed.

Conclusion

Thank you again for the opportunity to address the Committee on issues involving the nation’s electric infrastructure. In order to provide for a robust bulk power system, we need to promote investment in transmission infrastructure to move us toward the Administration’s Grid 2030 vision. As President Bush stated on April 27th of this year, “[w]e have modern interstate grids for our phone lines and our highways. It’s time for America to build a modern electricity grid.” For the national public interest, we need to move forward to a more modernized, more efficient, and more reliable grid and provide a statutory framework that drives private investment toward this goal.