Testimony of
The Honorable Joseph T. Kelliher
Chairman
Federal Energy Regulatory Commission
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Introduction

Mr. Chairman and members of the Committee, thank you for the opportunity to speak here today. My testimony addresses key initiatives and policies of the Federal Energy Regulatory Commission (FERC or the Commission) designed to foster a secure, robust, and reliable transmission grid, and non-discriminatory access to that grid, to support our Nation's electric supply needs. The additional authorities and directives Congress gave the Commission in the Energy Policy Act of 2005 (EPAct 2005) have been particularly important in the Commission's efforts and therefore my testimony emphasizes our implementation of the transmission-related provisions of EPAct 2005.

Any discussion of the transmission grid should start with an understanding of the nature of the U.S. transmission system. The transmission grid is the interstate highway system for wholesale power markets, and a robust grid is necessary to assure reliability and support competitive markets. The United States does not have a national grid, but a series of large regional power grids. The grid no longer consists of a multitude of local systems, as was the case in the 1930s when the principal federal electricity law, the Federal Power Act, was written. Rather, interconnections among local utilities have shaped the U.S. transmission grid into three major interconnections – the Eastern

Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas. Moreover, some of these regional grids are also international, fully interconnected with Canada and part of Mexico. In a very real sense, some of the regional grids are North American. The nature of the transmission grid has changed remarkably over time, and the Commission is increasingly confronted with transmission issues that can involve multiple states and must be considered from a multi-state, interconnection-wide, or North American perspective.

The United States has the largest transmission system in the world, extending across about 200,000 miles. At the same time, ownership of the U.S. power grid is heavily fractured. In most countries, transmission ownership is consolidated; in the U.S. it is highly disaggregated, with more than 500 owners. There is also great variety in the nature of these owners, which include investor-owned utilities, government utilities operated by federal, state, and municipal agencies, rural electric cooperatives, and transmission companies (or "transcos"). In my view, the disaggregated ownership of the grid greatly complicates grid planning, investment, and operation.

With respect to transmission policy, the Commission has three overarching goals: first, to protect the reliability of the bulk power system; second, to assure open and nondiscriminatory access to the transmission grid, the interstate highway system for wholesale power sales; and, third, to encourage development of a robust transmission grid. There is a relationship among these goals. It is not enough to have open access to the grid – the grid itself must be robust enough to assure reliability and support competitive wholesale power markets. In recognition of the national importance of a robust transmission grid, EPAct 2005 gave the Commission significant new regulatory authority to protect reliability, assure open and nondiscriminatory access, and encourage development of a stronger grid. The Commission has pursued a number of initiatives designed to achieve these overarching policy goals, relying on both new regulatory powers granted by Congress and pre-existing authority. The Commission moved quickly to implement its new authority to protect the reliability of the bulk power system and establish rules to govern use of its limited authority to site transmission facilities. In addition, the Commission crafted new rate policies to encourage greater grid investment, relying in part on new EPAct 2005 authority. The Commission also revisited interconnection cost policy to encourage the development of new generation, reformed the landmark open access transmission tariff, required regional transmission planning, and made important decisions regarding regional allocation of transmission costs.

Reliability of the Bulk Power System

EPAct 2005 gave the Commission a new responsibility to oversee mandatory, enforceable reliability standards for the bulk power system (excluding Alaska and Hawaii). This authority is in section 215 of the Federal Power Act, which authorizes the Commission to certify an Electric Reliability Organization (ERO). The ERO is responsible for proposing, for Commission review and approval, standards to help protect and improve the reliability of the bulk power system. The ERO may delegate certain responsibilities to “Regional Entities,” subject to Commission approval.

The reliability standards apply to the users, owners and operators of the bulk power system, and become mandatory only upon Commission approval. The

Commission may approve proposed reliability standards or modifications to previously-approved standards if it finds them "just, reasonable, not unduly discriminatory or preferential, and in the public interest." If the Commission disapproves a proposed standard or modification, the Commission must remand it for further consideration. The Commission, upon its own motion or upon complaint, may direct the ERO to submit a proposed standard or modification on a specific matter.

The ERO is authorized to impose, after notice and opportunity for a hearing, penalties for violations of the reliability standards, subject to Commission review and approval. The Commission also may initiate investigations on its own motion.

The Commission has implemented section 215 diligently. Within 180 days of EPAct 2005's enactment, the Commission adopted rules governing the reliability program. In the summer of 2006, it approved the North American Electric Reliability Corporation (NERC) as the ERO. In March 2007, the Commission approved the first set of mandatory, enforceable reliability standards. In April 2007, it approved eight regional delegation agreements to provide for development of new or modified standards and enforcement of approved standards by Regional Entities.

Earlier this month, the Commission acted on the first set of penalty determinations submitted by NERC to the Commission. The Commission decided that, unless an applicant sought review of the proposed determinations, the Commission would allow these 37 determinations to be affirmed by operation of law, without further Commission action. None of the applicants sought Commission review. The Commission also issued guidance to the ERO on the content of future notices of penalty submitted to the

Commission. Also this month, the Commission, for the first time, approved modifications to strengthen previously-approved reliability standards. The Commission is committed to the continued development and steady improvement of the reliability standards over time.

While section 215 is an adequate tool for protecting the bulk power system against most reliability threats, cyber security threats are different. Cyber security threats may be posed by foreign nations or others intent on undermining our Nation through its electric grid. Cyber security threats stand in stark contrast to past causes of regional blackouts and reliability failures, such as vegetation management and relay maintenance. Given the national security risk of cyber security threats, the Commission may need to act quickly to protect the bulk power system, to act in a manner that goes beyond the existing standards development process, and to protect certain information from public disclosure. Our legal authority is inadequate for such action. Accordingly, the Congress should enact new legislation on cyber security threats.

Transmission Siting

Although FERC has authority to establish the rates, terms, and conditions associated with transmission service in interstate commerce, the primary authority for siting transmission lines lies with the individual states. However, transmission siting is increasingly becoming a regional issue involving multiple states. Congress recognized this in EPAct 2005. Section 1221 of EPAct 2005 added a new section 216 to the Federal Power Act, providing for federal siting of interstate electric transmission facilities under certain circumstances. However, when Congress enacted this change it did not provide for exclusive federal transmission siting. States retain primary jurisdiction to site transmission facilities, and federal transmission siting effectively supplements a state siting regime. Section 216 requires the Secretary of the Department of Energy (DOE) to study electric transmission congestion and to designate, as a national interest electric transmission corridor, any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.

Section 216(b) authorizes the Commission, under certain circumstances, to issue permits to construct or modify electric transmission facilities within a national interest electric transmission corridor. In June 2006, the Commission proposed regulations to implement filing requirements and procedures for entities seeking to construct electric transmission facilities. In November 2006, after considering input from numerous commenters, the Commission adopted final regulations.

The Commission's regulations provide for a pre-filing process. During pre-filing, the Commission will seek maximum participation from all stakeholders, including states and affected landowners, encouraging them to present their views and recommendations on the need for and impact of the facilities in this early stage of the process.

During pre-filing, the Commission will commence the coordination of the processing of all other federal authorizations which would be needed to construct the proposed facilities, as well as state authorizations to the extent that the states choose to participate in the Commission's process. During pre-filing, the Commission also will start its environmental review of the proposed project as required by the National Environmental Policy Act. Once the Commission determines that there is sufficient information available to enable it to process an application for a proposed project, the applicant may file an application for a permit. Once the application is filed, the Commission has one year to act on the applicant's request.

In response to concerns raised by some states regarding difficulties inherent in overlapping state and Commission proceedings, the Commission decided that it would not commence pre-filing on a proposed project until the states have had one full year to consider a siting application without there being any concurrent Commission process. Once the year is complete, the applicant may seek to commence pre-filing with the Commission. Neither the commencement of pre-filing nor a formal siting application at the Commission has the effect of interrupting or terminating state siting proceedings. If a state approves a siting request after initiation of pre-filing or a formal application, the Commission may terminate its proceeding.

Section 216 authorizes the Commission to site facilities if a state withholds approval of a project for more than one year. The Commission interpreted this provision to include instances where a state has denied a proposed project. This issue is currently on appeal in the United State Court of Appeals for the Fourth Circuit.

In October 2007, DOE issued an order designating two national interest electric transmission corridors. The Mid-Atlantic Area National Corridor includes portions of Delaware, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, West Virginia, and Washington, DC. The Southwest Area National Corridor includes portions of southern California and western Arizona.

Commission staff currently is working on its first transmission siting project. Southern California Edison Company (SCE) has proposed to construct its Devers-Palo Verde No. 2 Project (DPV2) from Arizona to California within the Southwest Area National Corridor. In January 2007, the California Public Utilities Commission approved SCE's request to construct the California portion of DPV2. In May 2006, SCE filed an application to construct the Arizona portion with the Arizona State Siting Committee, which granted SCE a certificate to construct the facility. But, in June 2007, the Arizona Corporation Commission denied SCE's request for a permit to site the facility in Arizona. In May 2008, SCE asked the Commission to commence pre-filing for the Arizona portion of DPV2, and the Commission granted the request.

The developers of other electric transmission projects in the two National Corridors may seek siting authorization from the Commission. These projects are either in the planning stage (i.e., have been announced, but have not yet been filed with the relevant state siting authority) or are currently pending before the relevant state siting authorities.

Reform of the Open Access Transmission Tariff

In April 1996, the Commission adopted Order No. 888. This Order required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to offer non-discriminatory service pursuant to an Open Access Transmission Tariff. The Commission also required these public utilities to "functionally unbundle" their generation and transmission services. This meant public utilities had to take transmission service for their own new wholesale sales and purchases of electricity under their open access tariff, and separately state their rates for wholesale generation, transmission and ancillary services. Order No. 888 greatly enhanced the ability of wholesale customers (and retail customers, if allowed by state law) to reach alternative suppliers using the transmission systems of FERC-regulated public utilities.

Last year, the Commission revisited the terms and conditions of the open access tariff and, in Order No. 890, adopted several reforms. The goals of the reform were to: (1) strengthen the open access tariff to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rules for planning and use of the transmission system.

Specifically, Order No. 890 required the following changes to the open access tariff: open, coordinated and transparent planning on both a local and regional level; greater consistency and transparency in the calculation of the transmission capacity available for use by customers; adoption of a "conditional firm" component to long-term point-to-point service, expanding the service options available to customers; and less stringent penalties for imbalances created by intermittent resources, such as wind turbines and solar power. At the same time, the Commission retained core elements of Order No. 888, such as the comparability requirement, protection of native load, and state jurisdiction over bundled retail load.

The planning requirements of Order No. 890 are particularly important. Having an open and transparent planning process helps eliminate opportunities for discrimination and provides customers with information and studies that will help them decide whether potential upgrades or other investments could reduce congestion or enable integration of new resources. Order No. 890 also required that, where demand resources are capable of providing the functions assessed in a transmission planning process and can be relied upon on a long-term basis, they should be considered on a comparable basis to other resources.

Order No. 890's regional planning requirements will improve coordination of planning among utilities. Ownership of the interstate transmission grid is highly disaggregated, with more than 500 owners. Before Order No. 890, many transmission expansions were planned by individual transmission owners, as if we had 500 distinct power grids. Like the interstate highway system, however, the transmission grid is not merely a collection of local systems that can be planned on a stand-alone basis. The need for, and effect of, transmission expansions must be considered on a local, sub-regional, and regional basis. To that end, Order No. 890 required transmission providers to expand their planning processes to provide for coordination among transmission providers in the same region. Transmission providers also were directed to establish planning processes to consider not only upgrades that are necessary to maintain reliability of the transmission grid, but also additional expansions that, although not strictly needed for reliability, could enhance the economic operation of the grid. The consideration of both reliability and economic needs, on a local and regional level, is essential to ensuring the proper functioning of the interstate transmission system.

Allocating the Cost of Transmission Upgrades

With the need for more transmission, the Commission faces the issue of who will pay for the transmission upgrades. As noted above, the U.S. has regional power grids, but fractured ownership of these regional grids. That complicates cost allocation decisions. This issue arises particularly in the context of regional transmission organizations (RTOs) and independent system operators (ISOs), but also among utilities in other regions and even among the transmission customers of an individual utility. In a number of regions, the Commission has made regional cost allocation determinations. These decisions encourage investment, by avoiding project-by-project litigation.

As part of the open and transparent planning processes required in Order No. 890, the Commission directed transmission providers to work with their stakeholders to address the issue of cost allocation for new projects that do not fall under existing rate structures. In particular, the Commission suggested in Order No. 890 that new facilities eligible for cost allocation under the new rate provisions might include regional projects involving several transmission owners or economic projects that are identified independently from individual requests for service.

The Commission suggested several factors for evaluating a cost allocation methodology. First, a cost allocation proposal should fairly assign costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, the cost allocation proposal should provide adequate incentives to construct new transmission. Third, the cost allocation proposal generally should be supported by state authorities and participants across the region. The

Commission stressed that each region should address cost allocation issues up front, at least in principle, rather than triggering relitigation each time a project is proposed. In Order No. 890-A, the Commission also made clear that the details of proposed cost allocation methodologies must be clearly defined, as participants considering new transmission investment need some degree of cost certainty.

In response, transmission providers have submitted a number of proposals to address cost allocation for new projects on both a local and regional basis. The Commission has acted on several of these new filings in recent months, while others remain pending before the Commission.

In RTO and ISO regions, the cost allocation proposals have built on existing policies intended to attract investment, tailored as appropriate to the physical differences and regional needs of each RTO and ISO. For example, in April 2005, the Commission approved a cost allocation for Southwest Power Pool (SPP) in the south central United States, specifically for its "base plan facilities," i.e., reliability-related network upgrades needed to meet SPP's reliability planning criteria. Under the approved allocation, the cost of base plan facilities costing less than $100,000 is allocated to the transmission zone in which the upgrade is located. For base plan facilities costing more than $100,000, one-third of the cost is allocated across the SPP system, while the remaining two-thirds is allocated to specific zones based on a "megawatt-mile" engineering analysis.

In November 2006, the Commission accepted a methodology proposed by Midwest Independent Transmission System Operator, Inc. (MISO) to allocate 20 percent of the costs of high-voltage "baseline reliability" network upgrades on a system-wide basis and allocate the remaining 80 percent to affected transmission owners based on a load flow analysis. In March 2007, the Commission conditionally accepted MISO's proposal to allocate 20 percent of the costs of regionally beneficial projects (e.g., new economic projects) on a system-wide basis and allocate the remaining 80 percent among three sub-regions based on a "beneficiary pays" approach.

And, in April 2007, the Commission approved a cost allocation plan for PJM. Under the approved plan, the costs of existing transmission facilities within PJM are allocated to the utility that owns the facilities. For new facilities below 500 kV, the costs would be assigned on a "beneficiary pays" approach. The costs of new facilities at 500 kV or above are allocated on a system-wide basis across PJM, in recognition of the broad regional benefits of these "backbone" facilities.

Transmission Investment

The United States is just coming out of a long period of sustained underinvestment in the power grid. Investment in transmission facilities in real terms declined significantly between 1975 and 1998. While investment increased somewhat after 1998, expansion of the interstate transmission grid in terms of circuit miles in 2005 was only 0.5 percent. Transmission expansion was still lagging behind demand growth.

This lack of investment prompted the Commission to consider new pricing policies to encourage the construction of new transmission facilities. After the Commission initiated a proceeding on these policies, Congress amended the Federal Power Act, through EPAct 2005, to require the Commission, within one year of EPAct 2005's enactment, to establish incentive-based rate treatments for transmission. Congress specified that these incentives were "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."

In July 2006, pursuant to this new directive, the Commission issued Order No. 679, allowing utilities to seek rate incentives such as: (1) incentive rates of return on equity for new investment in transmission facilities; (2) full recovery of prudently incurred transmission-related construction work in progress costs in rate base; and (3) full recovery of prudently incurred pre-commercial operations costs. The Commission allows these incentives based on a case-by-case analysis of individual transmission projects. The burden is on the applicant to justify incentives. Incentive rates remain bounded by the "zone of reasonableness" governed by the Federal Power Act, thus protecting transmission customers against excessive rates.

Since adoption of these regulations, the Commission has received more than 30 applications for rate incentives for transmission projects, representing thousands of miles of high-voltage transmission facilities. These facilities will permit the interconnection of many thousands of megawatts of additional generation capacity.

The applications have included major "backbone" projects widely recognized as providing significant benefits. For example, one case involved Southern California Edison Company's "Tehachapi Project," to provide transmission for up to 4,500 megawatts of primarily wind generation into the Los Angeles area. Other cases included transmission facilities to allow substantially more imports of economic power from the

Midwest into New Jersey, eastern Pennsylvania and nearby areas. Few transmission projects of this size have been developed for many years.

Often, the amount of new investment almost equals the transmission owner's existing investment in transmission facilities. Specifically, in a number of cases, the new investment is as much as 80 percent of existing investment.

At the same time, the cost of transmission is still just a small part of consumers' cost of electricity, typically less than ten percent. Yet, investments in new transmission facilities can significantly reduce the much-larger generation component of the total cost, by allowing buyers to reach cheaper but more distant supplies. As a result, transmission expansions can reduce overall costs to consumers.

The new projects also are often designed to increase fuel diversity and deliver renewable energy. The Tehachapi Project is one example of this. Others include a proposal by Pacific Gas & Electric Company to build a thousand-mile transmission line to import up to 3,000 megawatts of new renewable power from Canada, and a billion-dollar proposal by Northern States Power to expand its transmission system to access between 300 and 700 megawatts of windpower.

Finally, major transmission expansions have been proposed in almost all regions of the country. The geographic diversity of these projects demonstrates that transmission underinvestment is a national issue, as Congress rightly recognized in EPAct 2005.

While the Commission has approved a number of applications for incentives, the Commission also has denied requests for incentives when the requests did not meet the standards in Order No. 679.

Overall, investment in transmission facilities appears to be increasing. For example, data released by the Edison Electric Institute indicates that investment by investor-owned utilities (in real terms, 2006) increased gradually from $4.6 billion to $5.3 billion in 2000-2004. Investment then jumped to $6.3 billion in 2005 and $6.9 billion in 2006. Investment is projected to increase to $10.2 billion in 2010. I believe the Commission's implementation of EPAct 2005's incentive provisions is a factor in these actual and projected increases. It is important that the Commission maintain policies to encourage greater transmission investment.

Policies for Interconnecting Generators to the Transmission Grid

In order to facilitate the interconnection of new generation facilities to the transmission grid, the Commission has adopted standard procedures and agreements for interconnecting with the transmission facilities of jurisdictional public utilities. In the past, transmission providers with their own generating facilities had the incentive and ability to deny, delay, or make expensive the interconnection of rival generating facilities. The Commission eliminated that ability of public utilities to discriminate through a series of rulemaking proceedings to standardize the generator interconnection process. The resulting procedures and agreements vary depending on the size and nature of the generation facility, providing flexibility for small facilities and non-synchronous technologies, such as wind plants. Taken together, these standardized procedures and agreements offer comparable, open access to rival generators seeking to interconnect with their local transmission provider.

Recently, the Commission has expressed concern regarding the growing backlog of generator interconnection requests. In some regions, many interconnection requests pending in study queues appear to be for speculative or unlikely projects. Because interconnection requests are studied on a first come, first served basis, the resulting backlog in study queues is causing delay for projects ready to move forward. This problem seems to be particularly significant in markets operated by RTOs and ISOs, which have attracted significant new entry to the marketplace. Earlier this year, the Commission provided guidance to RTOs and ISOs on possible reforms that could be implemented to alleviate the backlog in processing generator interconnections. In response, interconnection queue reform proposals have already been filed by the California ISO and MISO. The Commission acted on the California ISO proposal earlier this month, while the MISO proposal remains pending.

Finally, I would note the Commission's willingness to be flexible in its approach to transmission rate design. As an example, when Southern California Edison Company proposed the Tehachapi Project, traditional Commission policy would have required the first wind generators on the line to pay the line's full cost, even if they used only a small part of the line's capacity. This policy would have discouraged development of the wind resources, which were located far from existing transmission lines. Wind and other renewable resources are often location-constrained in this way, with less flexibility than other types of generation to locate near existing transmission lines. To recognize this difference among transmission customers, and reduce barriers to development of renewable resources, the Commission approved a cost allocation under which the wind generators would pay only for the capacity they used, and any remaining costs would be allocated to other customers until the line was fully used.

Conclusion

In conclusion, the Commission has three overarching transmission policy goals: protecting the reliability of the bulk power system, assuring open and nondiscriminatory access to the transmission grid, the interstate highway system for wholesale power sales, and encouraging development of a robust transmission grid. In EPAct 2005, Congress gave us new regulatory tools to achieve these goals. I believe we have carefully used these authorities in the manner Congress intended. Much progress has been made in achieving our key policy goals, but more must be done.