NATIONAL ELECTRIC POWER TRANSMISSION OVERVIEW

Prepared by
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LOUISIANA DEPARTMENT OF NATURAL RESOURCES

SCOTT A. ANGELLE
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This issue (2006) of Electric Power Transmission Overview is funded 100% with Petroleum Violation Escrow Funds as part of the State Energy Conservation Program as approved by the U. S. Department of Energy and the Department of Natural Resources.

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Introduction

Electricity is not a commodity that can be stored easily. The transmission system acts as an interstate highway that takes electricity to market. The result of a problem on the transmission grid is the loss of the commodity, not just a delay in its delivery.

Our economy relies on electricity and that reliance grows as we become more and more information based. The transmission lines are owned and operated by the larger utilities, but the move toward deregulating the generation sector has opened the transmission lines to greater use. The existing transmission system was not designed to meet today's growing demand for electricity. The reliability of the system is no longer a certainty.

The transmission system was built by vertically integrated utilities that owned the generation and transmission infrastructure. The utilities produced electricity at large generation stations and used the transmission infrastructure to move the electricity to customers. The 1920s were a period of consolidation for the electric utility industry as larger and more efficient steam turbines were developed. Electric utility ownership consolidated into large utility holding companies. The 16 largest holding companies controlled 75 percent of the generation capacity. The growth of the industry beyond city limits brought with it state regulation. The states expanded the roles of the railroad commissions to include electricity. However, the growth continued beyond state lines and Federal regulation soon followed as the electricity industry was recognized as a natural monopoly in interstate commerce.

Assuming there is a local interest in local utilities, the Public Utilities Holding Company Act of 1935 (PUHCA) limits the size of utility holding companies by limiting their geographic region. PUHCA requires utility parent companies to incorporate in the same state as the utility it owns. This would place it under state regulation. A company that owns utilities in more than one state is subject to federal regulation by the Securities and Exchange Commission (SEC). The SEC requires the utility holding companies to divest their holdings leaving them with only those businesses consistent with being a single integrated utility.
In 1978, in response to the Arab oil-producing nations ban on oil exports to the United States the Public Utility Regulatory Polices Act (PURPA) was adopted. PURPA requires electric utilities to allow a qualifying facility (QF) to connect to the transmission system and to purchase whatever capacity they produce at the utility's avoided cost (what it would have cost the utility to generate the power). The qualifying facilities are co-generators and the small power producers that use renewable resources. Most QFs are exempt from regulation by the SEC under PUHCA.

The Energy Policy Act of 1992 reformed PUHCA by creating a new category of non-utility generators called exempt wholesale generators (EWG) that were exempt form PUHCA requirements. FERC was given the mandate to open the transmission grid for wholesale power transactions on a case-by-case basis. This meant that FERC could order the utility that owned the transmission infrastructure to provide transmission service at a rate that FERC determined was reasonable.

The grid is an alternating current network that is divided into major interconnections – the eastern interconnect (the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces), the western interconnect (the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico) and the ERCOT (Electric Reliability Council of Texas) interconnect that covers most of Texas. Very little power exchange occurs between the major interconnections. The problem of moving power between the interconnections is usually some combination of physical constraints and electrical bottlenecks.

FERC, as the regulator of the wholesale electric power markets, had no authority to enforce the North American Electric Reliability Council (NERC) transmission reliability standards. NERC is a not-for-profit company formed by the electric utility industry to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one affiliate whose members are from all segments of the electricity supply industry. NERC is a voluntary organization that relies on a voluntary system of compliance with reliability standards.

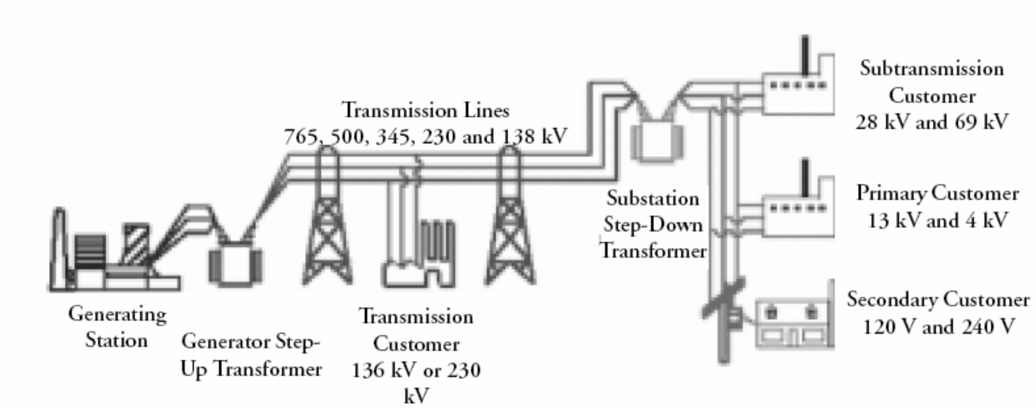
This is not adequate for the needs of the current transmission system. One of the recommendations from the August 24, 2003 Blackout task force is to "make reliability standards mandatory and enforceable with penalties for noncompliance."

The Energy Policy Act of 2005 (EPACT-2005) is the first major energy legislation in 13 years. EPACT-2005 repeals PUHCA to encourage investment in the grid and establishes mandatory reliability rules for the transmission system. EPACT-2005 also requires DOE to issue a national transmission congestion study for comment by August 2006 and every three years thereafter. Based on the study and public comments, DOE may designate selected geographic areas as "National Interest Electric Transmission Corridors" (NIETCs). If the Secretary of the Department of Energy designates an area experiencing congestion as an NIETC, FERC is authorized to issue permits for the construction and modification of electric transmission in the NIETC.

Historical Background

The electric power transmission facilities are generally the transformers that "step up" the generated power from low to higher voltage, the lines that the power is transmitted over and the transformers that "step down" voltages as it reaches the customers. The transmission lines are owned and operated by the larger utilities. But the move toward deregulating the generation sector has opened the transmission lines to greater use. The bulk power market, purchases and sales of high-voltage power, has grown substantially in part because of the regional imbalances between production and demand and because of price differences among fuels. "Transactions may be for energy (power produced by another) or capacity (ownership interest in a plant) and may be firm (interruptible only in emergencies) or interruptible, with varying contract durations. Also included in bulk market transactions is the transmission of power by one utility for another, called wheeling."[1] The existing transmission system was not designed to meet today's growing demand for electricity. The reliability of the system is no longer a certainty.

Figure 1. Key Elements of the Electric Power Grid



Source: U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations*, April 2004.

Thomas Edison located his generators close to the loads they served. The earliest electric power distribution system used direct current (DC) over copper lines. Most of the power plants were located within a mile of the equipment they served. The early power industry looked like today's concept of distributed generation; generators located close to the loads they serve. Then high

[1] Robert J. Michaels, "*Electric Utility Regulation*," The Concise Encyclopedia of Economics (http://www.econlib.org/library/Enc/ElectricUtilityRegulation.html), May 10, 2006.

voltage transmission using alternating current (AC) was developed. This development allowed the transmission of power over long distances. George Westinghouse built a transmission line to connect Buffalo, N.Y. to a hydroelectric plant at Niagra Falls, 20 miles away.[2]

The economies of scale favored larger power companies and the industry consolidated. The 1920's were a period of consolidation for the electric utility industry. Larger and more efficient steam turbines were developed. Electric utility ownership consolidated into large utility holding companies. The 16 largest holding companies controlled 75 percent of the generation capacity. The growth of the industry beyond city limits brought with it state regulation. The states expanded the roles of the railroad commissions to include regulating the siting of generation and transmission as well as electricity rates.[3] Utilities constructed larger generating plants and the miles of transmission lines continued to grow. Transcontinental natural gas pipelines connected utilities to a low cost fuel for their generating plants. The power system had evolved into an interstate system. "By 1927, the U.S. Supreme Court recognized that, because of this fast-developing transmission system, electricity was not an intrastate but an interstate commodity that was subject to federal regulation in addition to state regulation."[4]

In 1935 the Public Utility Holding Company Act (PUHCA) became the first major federal regulation of the electric power industry. "The act created vertically integrated utilities (owning both power plants and power lines) in monopoly service areas."[5] Under PUHCA, the Securities and Exchange Commission was charged with regulating the utility holding companies. "One of the most important features of the Act was that the SEC was given the power to break up the massive interstate holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. Another feature of the law permitted holding companies to engage only in business that was essential and appropriate for the operation of a single integrated utility. This later restriction practically eliminated the participation of non-utilities in wholesale electric power sales."[6]

The Public Utility Regulatory Policies Act of 1978 (PURPA) was passed in response to the OPEC ban on oil exports to the United States in 1973. PURPA requires utilities to interconnect with and buy power from qualifying facilities (generally cogenerators and small power producers using renewable resources).[7] The Energy Policy Act of 1992 (EPACT 1992) led to a nationwide open-access transmission grid for wholesale transactions. EPACT 1992 reformed PUHCA by creating a new category of power producer, exempt wholesale generators (EWG), that were exempt from the corporate and

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[2] National Council on Electricity Policy, "*Electricity Transmission A Primer*", June 2004, p. 2.
[3] National Council on Electricity Policy, p. 3.

[4] National Council on Electricity Policy, p. 4.
[5] National Council on Electricity Policy, p. 3.

[6] Energy Information Administration, "*The Changing Structure of the Electric Power Industry 2000:An Update*," p.29.
[7] Energy Information Administration, "*The Changing Structure of the Electric Power Industry 2000:An Update*," p.32

geographic restrictions imposed by PUHCA and further authorized FERC to open up the national electricity grid to wholesale suppliers.[8]

Technological improvements in gas turbines have been a factor in the restructuring of the electric power industry. "No longer is it necessary to build a 1,000 megawatt generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-driven gas turbines can be efficient at scales as small as 10 megawatts."[9]

Table 1. Federal Legislation Prior to EPACT 2005

Public Utility Holding Company Act of 1935 (PUHCA) PUHCA was enacted to break up the large and powerful trusts that controlled the Nation's electric and gas distribution networks. PUHCA gave the Securities and Exchange Commission the authority to break up the trusts and to regulate the reorganized industry in order to prevent their return. **Federal Power Act of 1935** (Title II of PUHCA) This Act was passed to provide for a Federal mechanism, as required by the Commerce Clause of the Constitution, for interstate electricity regulation.
Public Utility Regulatory Policies Act of 1978 PURPA was passed in response to the unstable energy climate of the late 1970s. PURPA sought to promote conservation of electric energy. Additionally, PURPA created a new class of nonutility generators, small power producers, from which, along with qualified cogenerators, utilities are required to buy power.
Energy Policy Act of 1992 (EPACT) This Act created a new category of electricity producer, the exempt wholesale generator, which narrowed PUHCA's restrictions on the development of nonutility electricity generation. The law also mandated that FERC open up the national electricity transmission system to wholesale suppliers on a case-by-case basis.

SOURCE: EIA (http://tonto.eia.doe.gov/FTPROOT/electricity/056296.pdf) April 4,2006.

The electric utility industry produces, transmits and distributes electricity in the United States and includes investor-owned, publicly owned, cooperative, and Federal electric utilities. Investor-owned electric utilities are privately owned and have the objective of producing a return for their investors. They are regulated and granted service monopolies in certain geographic area and are obligated to serve all customers. The majority of investor-owned utilities provide generation, transmission and distribution of electricity.

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[8] Energy Information Administration, "*The Changing Structure of the Electric Power Industry 2000:An Update*," p.33.
[9] Energy Information Administration, "*The Changing Structure of the Electric Power Industry 2000:An Update*," p.44-45.

Publicly owned electric utilities are nonprofit local agencies that include municipals, public power districts, State authorities, irrigation districts, and other State organizations. Some large publicly owned electric utilities produce, transmit and distribute electricity but most simply distribute power. Cooperative electric utilities are owned by their members and operate in rural areas. Cooperatives are incorporated under State laws and have an elected board of directors. The Federal electric utilities are part of several agencies in the U.S. Government. Most of the Federal electric utilities' power plants were hydroelectric projects originally designed for flood control and irrigation.[10]

Table 2. PURPA Qualifying Facilities

PURPA was designed to encourage the efficient use of fossil fuels in electric power production through cogenerators and the use of renewable resources through small power producers. Because of amendments to PURPA in 1990, the term "small power producer" is now a misnomer. The amendments eliminated the original size criterion for all energy sources except hydroelectric, while maintaining the criterion for the type of energy used. (Under PURPA provisions, both cogenerators and small power producers cannot have more than 50 percent of their equity interest held by an electric utility.)	
Cogenerators	**Renewables**
Cogenerators are generators that sequentially or simultaneously produce electric energy and another form of energy (such as heat or steam) using the same fuel source. Cogeneration technologies are classified as "topping-cycle" and "bottoming-cycle" systems. In a typical topping-cycle system, high-temperature, high-pressure steam from a boiler is used to drive a turbine to generate electricity. The waste heat or steam exhausted from the turbine is then used as a source of heat for an industrial or commercial process. In a typical bottoming-cycle system, high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces, and heat is then extracted from the hot exhaust stream of the primary application and used to drive a turbine. Bottoming-cycle systems are generally used in industrial processes that require very high-temperature heat. For a nonutility to be classified as a cogenerator qualified under PURPA, it must meet certain ownership, operating, and efficiency criteria established by FERC. The operating requirements stipulate the proportion (applicable to oil-fired facilities) of output energy that must be thermal energy, and the efficiency requirements stipulate the maximum ratio of input energy to output energy.	A renewable resource is an energy source that is regenerative or virtually inexhaustible. Renewable energy includes solar, wind, biomass, waste, geothermal, and water (hydroelectric). Solar thermal technology converts solar energy through high concentration and heat absorption into electricity or process energy. Wind generators produce mechanical energy directly through shaft power. Biomass energy is derived from hundreds of plant species, various agricultural and industrial residues, and processing wastes. Industrial wood and wood waste are the most prevalent form of biomass energy used by nonutilities. Geothermal technologies convert heat naturally present in the earth into heat energy and electricity. Hydroelectric power is derived by converting the potential energy of water to electrical energy using a hydraulic turbine connected to a generator. For a nonutility to be classified as a small power producer under PURPA, it also must meet certain ownership and operating criteria established by FERC. In addition, renewable resources must provide at least 75 percent of the total energy input. PURPA provisions enabled nonutility renewable electricity production to grow significantly, and the industry responded by improving technologies, decreasing costs, and increasing efficiency and reliability.

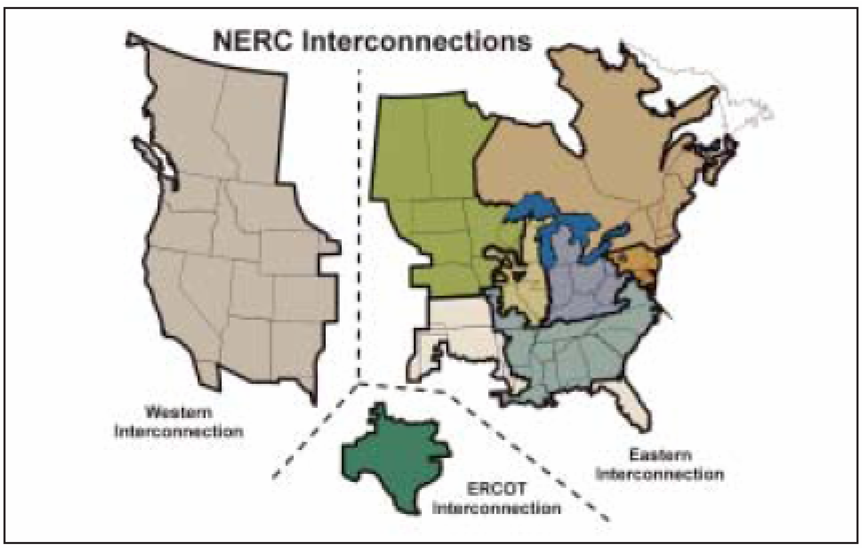
SOURCE: EIA (http://tonto.eia.doe.gov/FTPROOT/electricity/056296.pdf) accessed April 4,2006.

[10] Energy Information Administration, Electric Power Industry Overview, (http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html), May 15, 2006.

> The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion (U.S.) in asset value, more than 200,000 miles—or 320,000 kilometers (km) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.[11]

The grid is an alternating current (AC) network that is divided into major interconnections – the eastern interconnect (the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces), the western interconnect (the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico) and the ERCOT (Electric Reliability Council of Texas) interconnect that covers most of Texas. Very little power exchange occurs between the major interconnections. The problem of moving power between the interconnections is usually some combination of physical constraints and electrical bottlenecks.

Figure 2. North American Electricity Transmission Systems

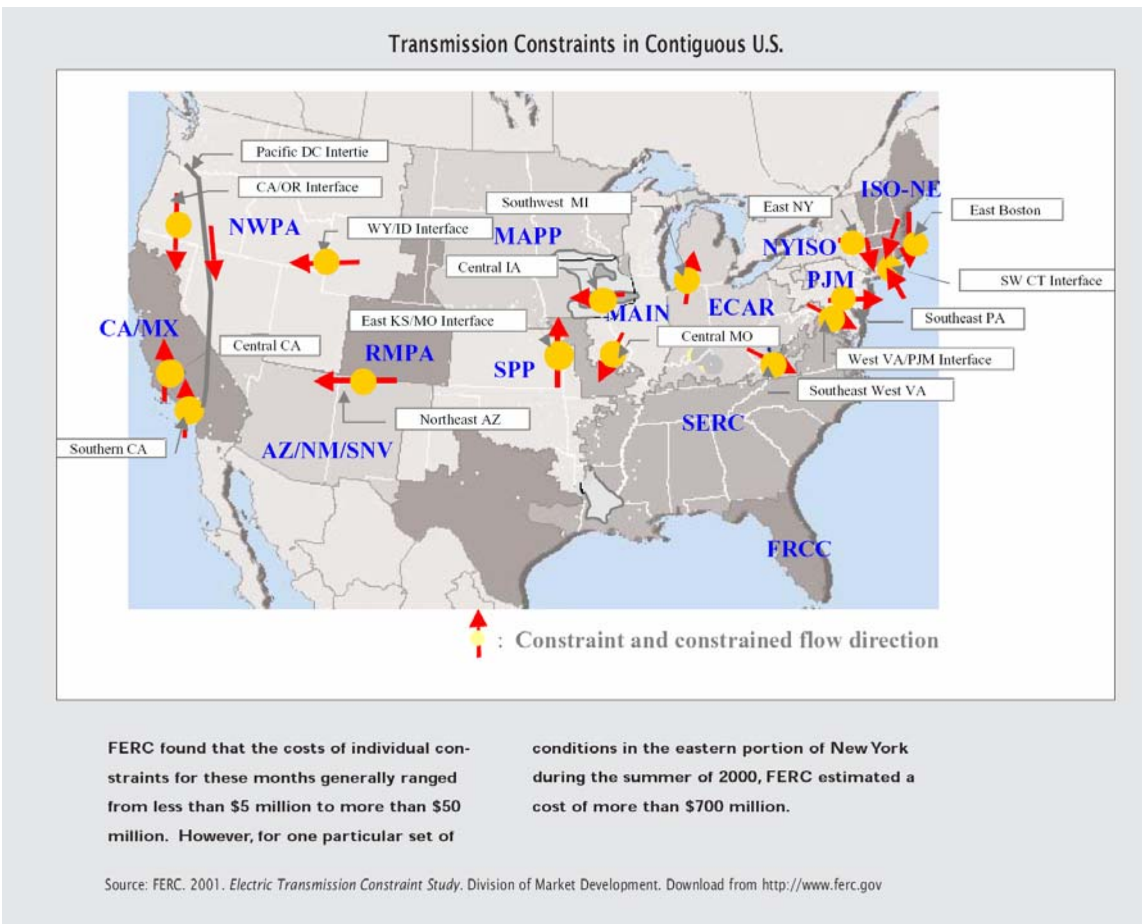


SOURCE: NERC (http://www.pi.energy.gov/pdf/library/TransmissionGrid.pdf) May 1, 2006

[11] The U.S.-Canada Power System Outage Task Force had this to say about the electrical infrastructure;

The transmission system acts as an interstate highway for wholesale electricity commerce. Electricity is not a commodity that can be stored easily. The result of a problem on the transmission grid is the loss of the commodity, not just a delay in its delivery. There is growing evidence that that the transmission system is in need of modernization. "The system has become congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities."[12] Transmission constraints or "bottlenecks increase electricity costs and increase the risk of blackouts. In 2001 DOE conducted an analysis of transmission bottlenecks and measures to address them (see Figure 3). The study only addresses major regional bottlenecks; other bottlenecks may exist within regions.

Figure 3. Transmission Constraints



[12] U.S. Department of Energy, "*National Transmission Grid Study*," May 2002, p.xi.

> "On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars)."[13]

Maintaining reliability of a transmission grid requires trained operators, sophisticated communications and planning. The North American Electric Reliability Council (NERC) developed standards for ensuring the reliability of the transmission grid based on the following concepts:

1. Balance power generation and demand continuously.
2. Balance reactive power supply and demand to maintain scheduled voltages.
3. Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.
4. Keep the system in a stable condition.
5. Operate the system so that it remains in a reliable condition even if a contingency occurs such as the loss of a key generator or transmission facility.
6. Plan, design, and maintain the system to operate reliably.
7. Prepare for emergencies.[14]

The dynamic interaction between generators and loads means that power flow is always changing on transmission and distribution lines. All lines are heated by the flow of electricity through them. Heating also causes overhead power lines to stretch and sag. The lines can sag into obstructions below and cause a short circuit.[15]

"NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. The organization was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and

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[13] U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004.

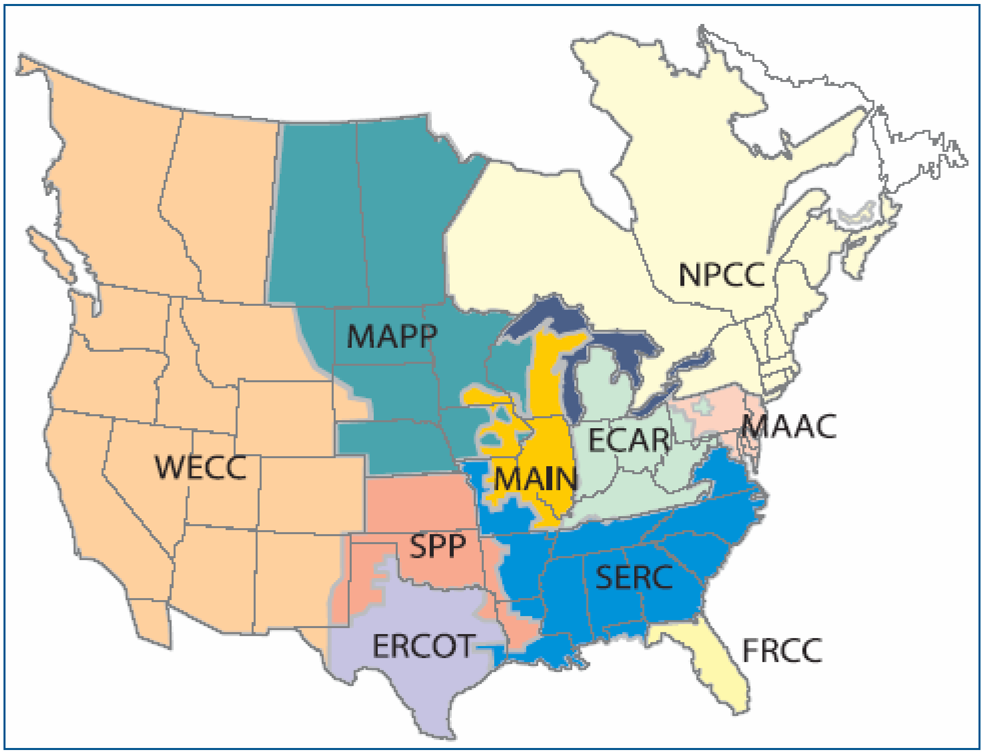
[14] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"pp.6-7.*

[15] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"pp.7-8.*

the mutual self interest of all those involved to ensure compliance with reliability requirements."[16]

NERC's members are ten regional reliability councils shown on the figure below. The councils jointly fund NERC and adapt NERC standards. "Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico."

Figure 4. NERC Regions



SOURCE: U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004.

"'Control areas' are the primary operational entities that are subject to NERC and regional council standards for reliability. A control area is a geographic area within which a single entity, Independent System Operator (ISO), or Regional Transmission Organization (RTO) balances generation and loads in real time to maintain reliable operation. Control areas are linked with each other through transmission interconnection tie lines."[17]

The restructuring of the utility industry led to an unbundling of generation, transmission and distribution activities. The unbundling separated the ownership and operation of the

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[16] *"Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 10.*

[17] *"Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 11.*

assets either functionally or through the formation of independent entities – Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs). Control areas were defined by utility service area boundaries but the restructuring of the industry has resulted in the consolidation of control areas into regional operating entities. "The primary functions of ISOs and RTOs are to manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets within their footprint."[18]

On August 14, 2003 a series of small problems cascaded into a blackout that left 50 million people without power. Summarized in Table 4 are the causes of the blackout as published in U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,*" April 2004.

Some blackouts start with short circuits (faults) on several transmission lines in quick succession. Sometimes lightning or wind or inadequate tree trimming causes the fault. The fault causes a high current and low voltage on the line containing the fault. A protective relay detects the high current and low voltage and trips the circuit breakers to isolate that line from the rest of the power system. A cascade occurs when there is a sequential tripping of many transmission lines and generators in a widening geographic area. A cascade is a dynamic phenomenon that cannot be stopped once started. "A cascade can be triggered by just a few initiating events, as was seen on August 14, 2003. Power swings and voltage fluctuations caused by these initial events can cause other lines to detect high currents and low voltages that appear to be faults, even if faults do not actually exist on those other lines. Generators are tripped off during a cascade to protect them from severe power and voltage swings. Protective relay systems work well to protect lines and generators from damage and to isolate them from the system under normal and abnormal conditions."[19]

[18] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 11.*

[19] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 73.*

TABLE 3. Impedance Relays

The most common protective device for transmission lines is the impedance (Z) relay (also known as a distance relay). It detects changes in currents (I) and voltages (V) to determine the apparent impedance ($Z=V/I$) of the line. A relay is installed at each end of a transmission line. Each relay is actually three relays within one, with each element looking at a particular "zone" or length of the line being protected.

- The first zone looks for faults over 80% of the line next to the relay, with no time delay before the trip.
- The second zone is set to look at the entire line and slightly beyond the end of the line with a slight time delay. The slight delay on the zone 2 relay is useful when a fault occurs near one end of the line. The zone 1 relay near that end operates quickly to trip the circuit breakers on that end. However, the zone 1 relay on the other end may not be able to tell if the fault is just inside the line or just beyond the line. In this case, the zone 2 relay on the far end trips the breakers after a short delay, after the zone 1 relay near the fault opens the line on that end first.
- The third zone is slower acting and looks for line faults and faults well beyond the length of the line. It can be thought of as a remote relay or breaker backup, but should not trip the breakers under typical emergency conditions.

An impedance relay operates when the apparent impedance, as measured by the current and voltage seen by the relay, falls within any one of the operating zones for the appropriate amount of time for that zone. The relay will trip and cause circuit breakers to operate and isolate the line. All three relay zone operations protect lines from faults and may trip from apparent faults caused by large swings in voltages and currents.

SOURCE: U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004.

Table 4. Causes of the August 14, 2003 Blackout's Initiation

The Ohio phase of the August 14, 2003, blackout was caused by deficiencies in specific practices, equipment, and human decisions by various organizations that affected conditions and outcomes that afternoon—for example, insufficient reactive power was an issue in the blackout, but it was not a cause in itself. Rather, deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout, rather than the lack of reactive power. There are four groups of causes for the blackout:

Group 1: FirstEnergy (FE) and ECAR (FE's reliability council) failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria.

- A) FE failed to conduct rigorous long-term planning studies of its system, and neglected to conduct appropriate multiple contingency or extreme condition assessments.
- B) FE did not conduct sufficient voltage analyses for its Ohio control area and used operational voltage criteria that did not reflect actual voltage stability conditions and needs.
- C) ECAR (FE's reliability council) did not conduct an independent review or analysis of FE's voltage criteria and operating needs, thereby allowing FE to use inadequate practices without correction.
- D)Some of NERC's planning and operational requirements and standards were sufficiently ambiguous that FE could interpret them to include practices that were inadequate for reliable system operation.

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

- A) FE failed to ensure the security of its transmission system after significant unforeseen contingencies because it did not use an effective contingency analysis capability on a routine basis.
- B) FE lacked procedures to ensure that its operators were continually aware of the functional state of their critical monitoring tools.
- C) FE control center computer support staff and operations staff did not have effective internal communications procedures.
- D) FE lacked procedures to test effectively the functional state of its monitoring tools after repairs were made.
- E) FE did not have additional or back-up monitoring tools to understand or visualize the status of their transmission system to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems.

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way. This failure was the common cause of the outage of three FE 345-kV transmission lines and one 138-kV line.

Group 4: Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support.

- A) MISO did not have real-time data from Dayton Power and Light's Stuart-Atlanta 345-kV line incorporated into its state estimator (a system monitoring tool). This precluded MISO from becoming aware of FE's system problems earlier and providing diagnostic assistance or direction to FE.
- B) MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions.
- C) MISO lacked an effective way to identify the location and significance of transmission line breaker operations reported by their Energy Management System (EMS). Such information would have enabled MISO operators to become aware earlier of important line outages.
- D) PJM and MISO lacked joint procedures or guidelines on when and how to coordinate a security limit violation observed by one of them in the other's area due to a contingency near their common boundary.

SOURCE: U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004

Short localized outages are fairly common but large system-wide outages that affect many customers are rare but they do occur. Some of the previous major outages are:

1. Northeast blackout on November 9, 1965;
2. New York City blackout on July 13, 1977;
3. West Coast blackout on December 22, 1982
4. West Coast blackout on July 2-3, 1996;
5. West Coast blackout on August 10, 1996;
6. Ontario and U.S. North Central blackout on June 25, 1998;
7. Northeast outages and non-outage disturbances in the summer of 1999.[20]

The blackout on August 14, 2003, had these causes in common with those earlier outages:

- Inadequate vegetation management
- Failure to ensure operation within secure limits
- Failure to identify emergency conditions and communicate that status to neighboring systems
- Inadequate operator training
- Inadequate regional-scale visibility over the power system
- Inadequate coordination of relay and other protective devices or systems.

New factors which occurred in the 2003 blackout that were not present in the earlier outages include: "inadequate interregional visibility over the power system; dysfunction of a control area's SCADA/EMS (Supervisory Control and Data Acquisition/Energy Management System) system; and lack of adequate backup capability to that system."[21] Table 5 lists some of the changing conditions that are affecting system reliability.

There have been no major transmission projects in the last 10 to 15 years and the existing facilities are working harder to meet increasing electricity demands.   "With the shrinking margin in the current transmission system, it is likely to be more vulnerable to cascading outages than it was in the past, unless effective countermeasures are taken."[22]

[20] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 103.*
"*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 110.*

[21] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 110.*

[22] "*Final Report on August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,"p. 103.*

Table 5. Changing Conditions That Affect System Reliability

Previous Conditions	Emerging Conditions
Fewer, relatively large resources	Smaller, more numerous resources
Long-term, firm contracts	Contracts shorter in duration More non-firm transactions, fewer long-term firm transactions
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable
Assessment of system reliability made from stable base (narrower, more predictable range of potential operating states)	Assessment of system reliability made from variable base (wider, less predictable range of potential operating states)
Limited and knowledgable set of utility players	More players making more transactions, some with less interconnected operation experience; increasing with retail access
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition, little incentive for reducing reliability investments	Utilities less willing to make investments in transmission reliability that do not increase revenues
Market rules and reliability rules developed together	Market rules undergoing transition, reliability rules developed separately
Limited wheeling	More system throughput

SOURCE: U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004

Provisions in the Energy Policy Act of 2005 that relate to Electric Transmission

On August 8, 2005, President George W. Bush signed the National Energy Policy Act of 2005 into law. This comprehensive energy legislation contains several electricity-related provisions. Appendix B contains a summary of the Energy Policy Act of 2005 Title XII – Electricity and Title XVIII- Studies, and Related Provisions prepared by the Edison Electric Institute. Following is a list of some of the key provisions of the Energy Policy Act that have impacts on electric transmission.

• Beginning within one year and every three years thereafter, the U.S. Department of Energy (DOE) will conduct a study (in *consultation* with the states) to identify 'national interest electric transmission corridors' that should be upgraded or have added transmission for reliability or economic purposes (e.g., to relieve congestion).

• The Federal Energy Regulation Commission (FERC) is given 'backstop' authority to order the acquisition and permitting of the right-of-way for siting and development of transmission within these corridors for numerous reasons, including lack of state approval within one year of application. States also may form interstate compacts to jointly consider transmission projects.

• There will be nationwide, common standards established for system reliability to which all utilities must conform. • There will be a national authority set up to monitor and provide real-time data on the status of the grid throughout the Eastern and Western Interconnections.

• Qualified transmission facilities are afforded accelerated depreciation, with a reduction from 20 years to 15 years.

• FERC is required to assess and set rates to encourage electric power transmission, including higher returns on equity and incentives to reduce congestion.

• DOE is granted over $750 million in research and development (R&D) for new transmission technologies to enhance reliability, efficiency, and environmental performance of power systems.[23]

[23] ICF Consulting, "2005 Energy Act: The Impacts on Electric Transmission," (http://www.icfi.com/Markets/Energy/Energy-Act/electric-transmission.pdf), May 24, 2006.

The U.S. Department of Energy (DOE) issued a Federal Register notice of inquiry on February 2, 2006 (71 Fed. Reg. 5660), "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," the purpose of which was "to learn stakeholders' views concerning transmission bottlenecks, identify how designation of such bottlenecks may benefit users of the grid and electricity consumers, and recognize key bottlenecks."

In the notice of inquiry DOE stated that they would consider making an early NIETC designation if a compelling case was presented. The Louisiana Energy and Power Authority (LEPA) and the Layfayette Utilities System (LUS) requested early designation as a National Interest Electric Transmission Corridor (NIETC). The LEPA response to the notice of inquiry for NIETC designation and request for early designation is included in Appendix D.

Five considerations (as stated in the Notice of Inquiry) are considered relevant to evaluate an area for NIETC designation.

(A) The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
(B) The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy and a diversification of supply is warranted.
(C) The energy independence of the United States would be served by the designation;
(D) The designation would be in the interest of national energy policy; and
(E) The designation would enhance national defense and homeland security.

LEPA, a joint action agency created by the Louisiana Legislature in 1979, consists of eighteen cities and towns which each have their own municipal power systems. LEPA is dependent upon the transmission system operated by two regulated public utilities - Entergy and Cleco. The Lafayette Utilities System is a member of LEPA , however, it owns and operates all transmission, distribution and generation resources within Lafayette.

LEPA and LUS state that they are dependent on Entergy and Cleco for transmission assets and that those assets are not available for long term planning to minimize costs or in some cases at all. LUS has had difficulty with transmission service for its generation resources. Entergy and Cleco transmission systems apparently have little excess capacity. LEPA and LUS have been asked to pay for transmission upgrades. Those upgrades would continue to be owned by the utilities. They also note that the congested transmission service to LEPA member Morgan City serves the Louisiana Offshore Oil Port (LOOP) which handles about 15% of U.S. oil imports.

DOE deferred action on all early requests for designation of National Interest Electric Transmission Corridors until after it completed its national transmission congestion study.

The Energy Policy Act of 2005 requires DOE to issue a national transmission congestion study for comment by August 2006 and every three years thereafter. Based on the study and public comments, DOE may designate selected geographic areas as "National Interest Electric Transmission Corridors" (NIETCs). If the Secretary of the Department of Energy designates an area experiencing congestion as an NIETC FERC is authorized to issue permits for the construction and modification of electric transmission in the NIETC.

- A state commission does not have siting authority.
- A state commission does not consider interstate benefits.
- A state commission has withheld approval for more than one year after the filing of an application or one year after the designation as a national interest electric transmission corridor.
- A state commission has conditioned its approval so there will be no significant reduction of transmission congestion.[24]

The Department of Energy was seeking comments on the following questions to assist in preparing the study:

1. Should the Department distinguish between persistent congestion and dynamic congestion, and if so how?
2. Should the Department distinguish between physical congestion and contractual congestion, and if so, how?
3. Appendix A of the notice of inquiry lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?
4. What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

[24] ICF Consulting, "2005 Energy Act: The Impacts on Electric Transmission," (http://www.icfi.com/Markets/Energy/Energy-Act/electric-transmission.pdf), May 24, 2006.

Conclusion

The U.S. Department of Energy (DOE) issued the *National Electric Transmission Study*[25] (The Study) on August 8, 2006. The Study was issued with a 60-day comment period which closes on October 10, 2006. The Study analyzes electrical generation and transmission capacity across the United States and identifies areas that need attention to meet growing demand.

Congestion, for purposes of The Study, is defined as the condition that occurs when transmission capacity is not sufficient to enable safe delivery of all scheduled or desired wholesale electricity transfers simultaneously. The Study identified transmission areas that need federal attention and groups them into three classes:

> **Critical Congestion Areas:** Areas where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe.
>
> - The Atlantic coastal area from Metropolitan New York southward through northern Virginia, and
> - Southern California
>
> **Congestion Areas of Concern:** Areas where this study and other information suggests that a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission and other solutions.
>
> - New England
> - The Phoenix-Tucson area
> - The San Francisco Bay area
> - The Seattle-Portland area
>
> **Conditional Congestion Areas:** Areas where future congestion would result if large amount of new generation resources were to be developed without simultaneous development of associated transmission capacity.
>
> - Montana-Wyoming (coal and wind)
> - Dakotas-Minnesota (wind)
> - Kansas-Oklahoma (wind)
> - Illinois, Indiana and Upper Appalachia (coal)
> - The Southeast (nuclear)

DOE is considering designating NIETCs in the critical congestion areas and is inviting comments to respond to the following three questions.

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[25]The full text of the Study report can be found on the Department of Energy website (http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf)

- Would designation of one or more National Corridors in these areas be appropriate and in the public interest?
- How and where should DOE establish the geographic boundaries for a National Corridor?
- How would the costs of a proposed transmission facility be allocated?

Transmission congestion prevents delivery of electricity from a less expensive source and forces a more expensive source to be used instead resulting in a higher cost. It is not always cost effective, however, to make the investments necessary to relieve congestion because generally some combination of the following is needed.

- Build new generation
- Build or upgrade transmission capacity
- Reduce electricity demand through some combination of energy efficiency, demand response, and distributed generation

Generation and transmission are costly and take time to build and often face opposition to their proposed location. The options to reduce demand are also sometimes costly with results that are hard to control. DOE published The Study with the intention of opening a dialogue with stakeholders in areas where congestion is a problem in order focus on relieving the congestion.

Going forward the key to watch in the electricity arena will be how and where these NIETCs are designated. How far will FERC step into approval processes previously controlled by the states? Will this become a regional process or a national process? The call for nationwide monitoring of the status of the grid might give some clue as will the penalties associated with noncompliance of reliability standards.

Glossary

AC: Alternating current; current that changes periodically (sinusoidally) with time.

Access Charge: A fee levied for access to a utility's transmission or distribution system.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonalbly expected unscheduled outages of system elements.

Ampere (amp): a unit of measuring electric flow.

Ancillary Services: Services necessary to support the transmission of electric energy from resources to loads, while maintaining reliable operation of the transmission system. Examples include spinning reserve, supplemental reserve, reactive power, regulation and frequency response, and energy imbalance.

Available Transmission Capacity (ATC): A measure of the electric transfer capability remaining in the physical transmission network for sale over and above already committed uses.

Biomass: In the context of electric energy any organic material that is converted to electricity, including woods, canes, grasses, farm manure, and sewerage.

Blackout: Emergency loss of electricity due to the failure of generation, transmission or distribution.

Blackstart Capability: The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the bulk electric system.

British Thermal Unit (BTU): A unit of energy equivalent to 1055 Joules, and is also the energy required to raise 1 pound of water 1 degree Fahrenheit at 39 degrees F.

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Bulk Transmission: A functional or voltage classification relating to the higher voltage portion of the transmission system, specifically, lines at or above a voltage level of 115 kv.

Busbar Cost: The cost of producing on KWh of electricity delivered to, but not through, the transmission system.

Busbar: The point at which power is available for transmission.

Capacitor: a device that maintains or increases voltage in power lines and improves efficiency of the system by compensating for inductive losses.

Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Cascading: The uncontrolled successive loss of system elements triggered by an incident. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Circuit: a conductor or a system of conductors through which electric current flows.

Circuit Breaker: A switching device connected to the end of a transmission line capable of opening or closing the circuit in response to a command, usually from a relay.

Commission: The regulatory body having jurisdiction over a utility.

Control Area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Current (Electric): The rate of flow of electrons in an electrical conductor measured in Amperes.

Curtailment: A reduction in the scheduled capacity or energy delivery due to a transmission constraint.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Demand: The rate at which electric energy is delivered to consumers or by a system or part of a system, generally expressed or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

Demand Response (DR): Deliberate intervention by a utility in the marketplace to influence demand for electric power or shift the demand to different times to capture cost savings.

DC: Direct current; current that is steady and does not change sinusoidally with time. (see "AC").

Dispatch: The physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Distributed Generation (DG): Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

Distribution: For electricity, the function of distributing electric power using low voltage lines to retail customers.

Electrical Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

Electric Utility: Person, agency, authority, or other legal entity or instrumentality that owns or operates facilitites for the generation, transmission, distribution, or sale of electric energy primarily for use by the public, and is defined as a utility under the statutes and rules by which it is regulated. An electric utility can be investor-owned, cooperatively owned, or government-owned (by a federal agency, crown corporation, State, provincial government, municipal government, and public power district).

Energy Emergency: A condition when a system or power pool does not have adequate energy resources (including water for hydro units) to supply its customers' expected energy requirements.

Fault: A fault usually means a short circuit, but more generally it refers to some abnormal system condition. Faults are often random events.

Federal Energy Regulatory Commission (FERC): Independent Federal agency that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.

Firm Transmission Right (FTR): An FTR is a tradable entitlement to schedule 1 MW for use of a flowpath in a particular direction for a particular hour.

Firm Transmission: Transmission service that may not be interrupted for any reason except during an emergency when continued delivery of power is not possible.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Frequency: The number of complete alternations or cycles per second of an alternating current, measured in Hertz. The standard frequency in the United States is 60 HZ. In some other countries the standard is 50 HZ.

Generation (Electricity): The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator: Generally, an electromechanical device used to convert mechanical power to electrical power.

Grid: An electrical transmission and/or distribution network.

Grid Protection Scheme: Protection equipment for an electric power system, consisting of circuit breakers, certain equipment for measuring electrical quantities (e.g., current and voltage sensors) and devices called relays. Each relay is designed to protect the piece of equipment it has been assigned from damage. The basic philosophy in protection system design is than any equipment that is threatened with damage by a sustained fault is to be automatically taken out of service.

High Voltage Lines: Used to transmit power between utilities. The definition of "high" varies, but it is oppose to "low" voltage lines that deliver power to homes and businesses.

Incremental Rates: The allocation of cost for an additional service or construction project directly to those who benefit from the service instead of rolling it into overall rates. To determine the incremental unti cost, the added cost is divided by the added capacity or output (see Rolled-in Pricing).

Independent System Operator (ISO): Am organization responsible for the reliable operation of the power grid under its purview and for providing open transmission access to a market participants on a nondiscriminatory basis. An ISO is usually not-for-profit and can advise utilities within its territory on transmission expansion and maintenance but does not have the responsibility to carry out the functions.

Interchange (or Transfer): The exchange of electric power between control areas.

Interconnected System: A system consisting of two or more individual electric systems that normally operate in synchronization and have connecting tie lines.

Interconnection: A specific connection between one utility and another. NERC's definition: "When capitalized, any one of the four bulk electric system networks in North America: Eastern, Western, ERCOT and Quebec. When not capitalized, the facilities that connect two systems or control areas."

Interface: The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

Intertie: Usually refers to very high voltage lines that carry electric power long distances. A term also used to describe a circuit connecting two or more control areas or systems of an electic system ("tie-line").

Island: A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Joule (J): A unit of energy equivalent to 1 Watt of power used over 1 second.

Kilovolt (kV): Electrical potential equal to 1,000 volts.

Kilowatt-hour (kWh): The basic unit for pricing electic energy; equal to 1 kilowatt of power supplied continuously for one hour. (Ir the amount of electricity needed to light 10 100-watt light bulbs for one hour.) One-kilowatt hour equals 1,000 watt hours.

Line Losses: Power lost in the course of transmitting and distributing electricity.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers. See Demand.

Load Balancing: Meeting fluctuations in demand or matching generation to load to keep the electrical system in balance.

Load Forecast: An attempt to determine energy consumption at a future point in time.

Load Profiling: The process of examining a consumer's energy use in order to gauge the level of power being consumed and at what times during the day.

Load Serving Entity (LSE): Any entity providing service to load.

Load Shape: Variation in the magnitude of the power load over a daily, weekly or yearly period.

Load Shedding: The process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition, to maintain the integrity of the system and minimize overall customer outages.

Load Shifting: Shifting load from peak to off-peak periods, including use of storage water heating, storage space heating, cool storage, and customer load shifts.

Locational Marginal Pricing (LMP): Under LMP, the price of energy at any location in a network is equal to the marginal cost of supplying an increment of load at that location.

Lockout: A state of a transmission line following breaker operations where the condition detected by the protective relaying was not eliminated by temporarily opening and reclosing the line, possibly several times. In this state, the circuit breakers cannot generally be reclosed without resetting a lockout device.

Loop Flow: The unscheduled use of another utility's transmission, resulting from movement of electricity along multiple paths in a grid, whereby power, in taking the path of least resistance, might be physically delivered through any of a number of possible paths that are not easily controlled.

Market Clearing Price: Price determined by the convergence of buyers and sellers in a free market.

Megawatt (MW): One megawatt equals 1 million watts or 1,000 kilowatts.

Megawatt-hour (MWh): One megawatt-hour equals 1,000 kilowatt-hours.

Megawatt-mile Rate: An electric transmission rate based on distance, as opposed to postage stanmp rates, which are based on zones.

Megawatt-year and Megawatt-month: Units to measure and price transmission services. A megawatt-year is 1 megawatt of transmission capacity made available for one year. Similarly, a megawatt-month is 1 megawatt of transmission capacity made available for a month.

Network: A system of transmission or distribution lines cross-connected to permit multiple supplies to enter the system.

Network Transmission (NT): A transmission contract or service as described in a transmission provider's Open Access Transmission Tariff filed with the Federal Energy Regulatory Commission.

Nonfirm Transmission: Transmission service that may be interrupted in favor of firm transmission schedules or for other reasons.

North American Electric Reliability Council (NERC): A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate, whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-Atlantic Area Council (MAAC); Northeast Power Coordinating Council (NPCC); southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).

Ohm: A unit of electric resistance equivalent to 1 volt per ampere.

Open Transmission Access: Transmission is offered equally to all interested parties.

Operating Standards: The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. An Operating Standard may specify monitoring and surveys for compliance.

Outage: Removal of generating capacity form service, either forced or scheduled.

Pancaking: Fees that are tacked on as electricity flows through a number of transmission systems.

Parallel Path Flows: The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop flows, unscheduled power flows, and circulating power flows.

Peak Demand: The maximum (usually hourly) demand of all customer demands plus losses. Usually expressed in MW.

Performance-based Regulation: Rates designed to encourage market responsiveness. They can be automatically adjusted from an initial cost-of-service rate based on a company’s performance. Performance indicators generally reflect consumer and societal values.

Point of Delivery: The physical point on connection between the transmission provider and a utility. Power is metered her to determine the cost of the transmission service.

Point-to-Point Transmission Service: The reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery under a tariff, including any ancillary services that are provided by the transmission provider.

Postage Stamp Rates: Flat rates charged for transmission service without regard to distance.

Public Utility Holding Company Act (PUHCA): Legislation inacted in 1935 to protect utility stockholders and sonsumers from financial and economic abuses of utility holding companies.

Generally, ownership of 10 percent or more of the voting securities of a public utility subjects a company to extensive regulation under the Securities and Exchange Commission. The Comprehensive National Energy Policy Act of 1992 opened the power market by granting a class of competitive generators exemption from PUHCA regulation.

Radial: An electric transmission or distribution system that is not networked and does not provide sources of power.

Rate Base: The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return.

Reactive Power: The out-of-phase component of the total volt-amperes in an electric circuit, usually expressed in VAR (volt-ampere-reactive). It represents the power involved in the electric fields developed when transmitting alternating-current power (the alternating exchange of stored inductive and capacitive energies in a circuit). Used to control voltage on the transmission network, particularly the power flow incapable of performing real work or energy transfer.

Real Time Pricing: Time-of-day pricing in which customers receive frequent signals on the cost of consuming electricity at that moment.

Regional Transmission Operator (RTO): An organization that is independent from all generation and power marketing interests and has exclusive responsibility for electric transmission grid operations, short-term electric reliability, and transmission services within a multi-State region. To achieve those objectives, the RTO manages transmission facilities owned by different companies and encompassing one, large, contiguous geographic area.

Reliability Practices: The methods of implementing policies and standards designed to ensure the adequacy and security of the interconnected electric transmission system in accordance with applicable reliability criteria (i.e., NERC, local, regional entity criteria).

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy and Security.

Right-of-Way: Strip of land used for utility lines. Most utilities negotiate easements with property owners or use the right of eminent domain to gain access. In some cases, the land is purchased outright.

Right-of-Way (ROW) Maintenance: Activities by utilities to maintain electrical clearances along transmission or distribution lines.

Rolled-in Pricing: The allocation of cost for an additional service or construction project into overall rates, regardless of the cause or beneficiary of the cost.

Schedule: An agreed-upon transaction sixe (mega-watts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

Scheduled Outage: Scheduled outages occur when a portion of a power system is shut down intentionally, typically to allow for pre-planned activities such as maintenance.

Seams: the interface between regional entities and/or markets at which material external impacts may occur. The regional entities' actions may have reliability, market interface, and/or commercial impacts (some or all).

Service Territory: Physical area served by a utility.

Short Circuit: A low resistance connection unintentionally made between points of an electrical circuit, which may result in current flow far above normal levels.

Spinning Reserve: Electric generating units connected to the system that can automatically respond to frequency deviations and operate when needed.

Spot Market: A market characterized by short-term, typically interruptible or best efforts contracts for specified volumes. The bulk of the natural gas spot market trades on a monthly basis, while power marketers sell spot supplies on an hourly basis.

Standards of Conduct: When FERC established the requirement for companies to use OASIS systems in electric transmission (Order 889), it also established a code of conduct to ensure that transmission owners and their affiliates would not have an unfair competitive advantage in using the transmission lines to sell power.

Standby Demand: The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for the outage of the customer's primary source. Standby demand is intended to be used infrequently by any one customer.

Step-Down/Step-Up: Step-down is the process of changing electricity from a higher to a lower voltage. Step-up is the opposite. Step-up transformers usually are located at generator sites, while step-down transformers are found at the distribution side.

Substation: Equipment that switches, steps down, or regulates voltage of electricity. Also serves as a control and transfer point on a transmission system.

Superconductivity, High Temperature (HTS): A technology for transmitting electricity that uses a conductor designed to offer no resistance to electrical voltage. No resistance allows power to be transmitted without losses. Materials typically have no resistance at temperatures approaching absolute zero (-273 degrees C). High temperature, for this purpose, means a temperature high enough to maintain cost-effectively while maintaining superconductivity.

Supervisory Control and Data Acquisition (SCADA): A system of remote control and telemetry used to monitor and control the electric transmission system.

Synchronize: The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

System: An interconnected combination of generation, transmission, and distribution components comprising an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

System Operator: An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

System Reliability: A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.

Tariff: A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

Tie-line: The physical connection (e.g. transmission lines, transformers, switch gear, etc.) between two electric systems that permits the transfer of electric energy in one or both directions.

Total Transmission Capability (TTC): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner at a given time.

TRANSCO (Transmission Company): A company engaged solely in the transmission function; another kind of regional transmission organization. A TRANSCO owns and operates the regional transmission system. Also refers to the portion of an electric utility's business that involves bulk transmission of power, operated separately from any other power functions the utility might own or operate.

Transactions: Sales of bulk power via the transmission grid.

Transfer Limit: The maximum amount of power that can be transferred in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between pints of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Margin: The difference between the maximum power flow a transmission line can handle and the amount that is currently flowing on the line.

Transmission Loading Relief (TLR): Procedures developed by NERC to mitigate operating security limit violations.

Transmission Operating Agreement (TOA): An agreement between an RTO and a utility, whereby the utility assigns control over the utility's transmission system in exchange for an RTO agreement to make payment to the utility to cover the utility's transmission system costs.

Transmission Operator: NERC-certified party responsible for monitoring and assessing local reliability conditions, who operates the transmission facilities, and who executes switching orders in support of the Reliability Authority.

Transmission Overload: A state where a transmission line has exceeded either a normal or emergency rating of the electric conductor.

Transmission owner (TO) or Transmission Provider: Any utility that owns, operates, or controls facilities used for the transmission of electric energy.

Transmission Reliability Margin (TRM): Amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Vertical Integration: Refers to the traditional electric utility structure, whereby a company has direct control over its transmission, distribution and generation facilities and can offer a full range of power services.

Volt: The unit of electromotive force or electric pressure which, if steadily applied to a circuit having a resistance of 1 ohm, would produce a current of one ampere.

Voltage-Ampere-Reactive (VAR): A measure of reactive power.

Voltage: The electrical force, or "pressure," that causes current to flow in a circuit, measured in Volts.

Watt: The electrical unit of real power or rate of doing work, equivalent to 1 ampere flowing against an electrical pressure of 1 volt. One watt is equivalent to about 1/746 horsepower, or one joule per second.

Watthour (Wh): A unit of measure of electrical energy equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling: In the electric market, "wheeling" refers to the interstate sale of electricity or the transmission of power from one system to another.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, nonutility generators and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and pwer quality at the transmission level.

Wholesale Wheeling: The transmission of electricity from a wholesale supplier to another wholesale supplier by a third party.

Wires Charges: A fee that is imposed on retail power providers or their customers to use a utility's transmission and distribution system.

Sources: U.S.-Canada Power System Outage Task Force, "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*," April 2004.

National Council on Elctricity Policy, *Electricity Transmission A Primer*, June 2004.

ACRONYMS

AC	Alternating current
AEP	American Electric Power
ATC	Available Transfer Capability
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CREPC	Committee for Regional Electric Power Cooperation
DC	Direct current
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible AC transmission system
FERC	Federal Energy Regulatory Commission
HTS	High Temperature superconductivity
HVDC	High-voltage direct current
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kV	Kilovolt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEPD	National Energy Policy Development
NERC	North American Electric Reliability Council
NGC	National Grid Company
NYISO	New York Independent System Operator
PBR	Performance-based regulation
PCR	Price-cap regulation
PJM	Pennsylvania, New Jersey, Maryland Interconnection
PMA	Power Marketing Administration
POEMS	Policy Office Electricity Modeling System
PUC	Public Utility Commission
R&D	Research and development
RTO	Regional Transmission Organization
SWPA	Southwestern Power Administration
TLR	Transmission Loading Relief
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
WAPA	Western Area Power Administration
WGA	Western Governor's Association
WSCC	Western Systems Coordinating Council

Source: National Transmission Grid Study

Appendix A

Full Text of the Notice of Inquiry for National Interest Electric Transmission Corridors (NIETCs)

DOH Publication 320–031, 2004, *Final Environmental Impact Statement—Commercial Low-Level Radioactive Waste Disposal Site, Richland, Washington,* Washington State Department of Health, Olympia, Washington, and Washington State Department of Ecology, Olympia, Washington.

U.S. Department of Energy, 2006, *Report of the Review of the Hanford Solid Waste Environmental Impact Statement (EIS) Data Quality, Control and Management Issues,* Washington, DC.

[FR Doc. E6–1404 Filed 2–1–06; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

AGENCY: Office of Electricity Delivery and Energy Reliability (''OE''), Department of Energy.

ACTION: Notice of inquiry requesting comment and providing notice of a technical conference.

SUMMARY: The Department of Energy (the ''Department'') seeks comment and information from the public concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors (''NIETCs'') in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005. Through this notice of inquiry, the Department invites comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announces a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs.

DATES: Written comments may be filed electronically in MS Word and PDF formats by e-mailing to: *EPACT1221@hq.doe.gov* no later than 5 p.m. EDT March 6, 2006. Also, comments can be filed by mail at the address listed below. The technical conference will be held in Chicago on March 29, 2006. For further information, please visit the Department's Web site at *http://www.electricity.doe.gov/1221.*

ADDRESSES: Written comments via mail should be submitted to:

Office of Electricity Delivery and Energy Reliability, OE–20, Attention: EPACT 1221 Comments, U.S. Department of Energy, Forestall Building, Room 6H–050, 1000 Independence Avenue, SW., Washington, DC 20585.

Note: U.S. Postal Service mail sent to the Department continues to be delayed by several weeks due to security screening. Electronic submission is therefore encouraged. Copies of written comments received and other relevant documents and information may be reviewed at *http://www.electricity.doe.gov/1221.*

FOR FURTHER INFORMATION CONTACT: Ms. Poonum Agrawal, Office of Electricity Delivery and Energy Reliability, OE–20, U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586–1411, *poonum.agrawal@hq.doe.gov,* or Lot Cooke, Office of the General Counsel, GC–76, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586–0503, *lot.cooke@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. Overview

The Nation's electric system includes over 150,000 miles of interconnected high-voltage transmission lines that link generators to load centers.[1] The electric system has been built by electric utilities over a period of 100 years, primarily to serve local customers and support reliability; the system generally was not constructed with a primary emphasis on moving large amounts of power across multi-state regions.[2] Due to a doubling of electricity demand and generation over the past three decades and the advent of wholesale electricity markets, transfers of large amounts of electricity across the grid have increased significantly in recent years. The increase in regional electricity transfers saves electricity consumers billions of dollars,[3] but significantly increases transmission facility loading.

Investment in new transmission facilities has not kept pace with the increasing economic and operational importance of transmission service.[4] Today, congestion in the transmission system impedes economically efficient electricity transactions and in some cases threatens the system's safe and reliable operation.[5] The Department has estimated that this congestion costs consumers several billion dollars per year by forcing wholesale electricity purchasers to buy from higher-cost suppliers.[6] That estimate did not include the reliability costs associated with such bottlenecks.

The National Energy Policy (May 2001),[7] the Department's National Transmission Grid Study (May 2002),[8] and the Secretary of Energy's Electricity Advisory Board's Transmission Grid Solutions Report (September 2002),[9] recommended that the Department address regulatory obstacles in the planning and construction of electric transmission and distribution lines. In response to these recommendations, the Department held a ''Workshop on Designation of National Interest Electric Transmission Bottlenecks'' on July 14, 2004, in Salt Lake City, Utah. The Department also issued a **Federal Register** notice of inquiry on July 22, 2004.[10] The purpose of the workshop and the notice of inquiry was to learn stakeholders' views concerning transmission bottlenecks, identify how designation of such bottlenecks may benefit the users of the grid and electricity consumers, and recognize key bottlenecks. In its plans for implementation of subsection 1221(a), the Department notes that it has considered the comments received via the notice and the workshop.

B. Summary of Relevant Provisions From the Statute

On August 8, 2005, the President signed into law the Energy Policy Act of 2005, Public Law 109–58, (the ''Act''). Title XII of the Act, entitled ''The Electricity Modernization Act of 2005'' includes provisions relating to the siting of interstate electric transmission facilities and promoting advanced power system technologies. Subsection 1221(a) of the Act amends the Federal Power Act (''FPA'') by adding a new section 216 which requires the Secretary of Energy (the ''Secretary'') to conduct a nationwide study of electric transmission congestion (''congestion study''), and issue a report based on the study in which the Secretary may designate ''any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects

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[1] North American Electric Reliability Council, Electricity Supply and Demand Database (2003) available at *http://www.nerc.com/esd.*

[2] Edison Electric Institute, *Survey of Transmission Investment* at 1 (May 2005).

[3] Department of Energy, *National Transmission Grid Study,* at 19 (May 2002) available at *http://www.eh.doe.gov/ntgs/reports.html.*

[4] *Id.* at 7; *see also* Hirst, U.S. Transmission Capacity Present Status and Future Prospects, 7 (June 2004).

[5] *National Transmission Grid Study, supra note* 3, at 10–20.

[6] *Id.* at 16–18.

[7] *The National Energy Policy Development Group Report,* available at *http://www.energy.gov/engine/content.do?BT_CODE=ADAP.*

[8] *National Transmission Grid Study, supra* note 3.

[9] Department of Energy Electricity Advisory Board, *Transmission Grid Solutions,* available at *http://www.eab.energy.gov/index.cfm?fuseaction=home.publications.*

[10] Designation of National Interest Electric Transmission Bottlenecks, 69 FR 43833 (July 22, 2004) also available at *http://www.electricity.doe.gov/bottlenecks.*

consumers as a national interest electric transmission corridor.'' [11]

Subsection (a) of new FPA section 216 requires the Secretary to conduct a study of ''electric transmission congestion'' within ''[one] year after the date of enactment of [the Act] and every three years thereafter.'' [12] Subsections 216(a)(1) and (a)(3) of the FPA require the Secretary to conduct each congestion study in consultation with affected states and any appropriate regional entity.[13] FPA subsection 216(a)(2) requires the Secretary ''[a]fter considering alternatives and recommendations from interested parties,'' to issue a report, based on the study, in which the Secretary may designate ''any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers'' as an NIETC.[14] In exercising the Secretary's authority to designate NIETCs, subsection 216(a)(4) states that the Secretary may consider, among other things, whether—

(A) The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;

(B)(i) The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and

(ii) A diversification of supply is warranted;

(C) The energy independence of the United States would be served by the designation;

(D) The designation would be in the interest of national energy policy; and

(E) The designation would enhance national defense and homeland security.[15]

If the Secretary designates an area ''experiencing electric energy transmission capacity constraints or congestion'' as an NIETC, subsection 216(b) of the FPA authorizes the Federal Energy Regulatory Commission (''FERC'') to issue permits for the ''construction and modification of electric transmission'' in the NIETC, provided that FERC finds that certain conditions have been met.[16]

C. Key Terms: Geographic Areas, Needs, and Corridors

In its initial electric transmission congestion study pursuant to FPA section 216, the Department expects to present an inventory of geographic areas of the Eastern and Western Interconnects that have important existing or projected needs related to the electricity transmission infrastructure. Such needs may include relieving existing or emerging congestion, addressing existing or emerging reliability problems, enabling larger transfers of economically beneficial electricity to load centers, or enabling delivery of electricity from new generation capacity to distant load centers. The Department recognizes that in some cases it may be possible to address such needs through functional alternatives such as distributed generation, conventional generation sited close to load, and/or enhanced demand response capacity.

The Department expects to identify corridors for potential projects as generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities. The Department believes that defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion. In their comments on the criteria set forth below, the Department invites commenters to address how broadly or narrowly the Department should consider and define corridors in its study and its NIETC designations.

III. Questions for Public Comment

A. Congestion Study

In conducting the initial electric transmission congestion study required by FPA subsection 216(a)(1), the Department intends to identify geographic areas where transmission congestion is significant, and where additions to transmission capacity (or suitable alternatives) could lessen potential adverse effects borne by consumers. The Department will compile an inventory of areas where planners believe significant transmission needs exist. This inventory, the work on which is already well underway, will be based on a review of existing transmission expansion plans and related studies by the regional coordination councils, other regional and subregional transmission planning groups, regional transmission operators, independent system operators and utilities. The inventory will also be informed by congestion modeling that the Department will conduct of the Eastern and Western Interconnects.

By August 8, 2006, the Department intends to publish its congestion study and to invite interested parties to provide comments and recommendations concerning these need assessments for each geographic area. Interested parties also will be invited to comment on or identify potential transmission corridors they think could be relevant to addressing such needs, and corridors suitable for designation as NIETCs. The Department will consider well-supported recommendations from affected States and interested parties throughout the study process regarding areas believed to merit urgent attention from the Department.

In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI. If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

After publishing the national congestion study by August 8, 2006 and considering comments received on it, the Department may revise or update its study, or the Department may proceed directly to designation of some NIETCs, based on the study and the comments, alternatives and recommendations offered by the public.

To assist the Department in conducting and preparing its electric transmission congestion study so that the study will be the most useful in helping identify areas of need and areas

[11] The Electricity Modernization Act of 2005, sec. 1221, § 216, 119 Stat. 594, 946–953 (2005) (to be codified as amended at 16 U.S.C. 824p). *Note* that section 216 of the FPA specifically excludes the area covered by the Electricity Reliability Council of Texas. *Id.* at § 216(k). Section 216 of the FPA does not mention Alaska and Hawaii; however, their electricity supply systems are not interconnected with the grids of the continental U.S., and therefore the Department does not plan to include these two states in its initial congestion study.

[12] *Id.* § 216(a)(1).

[13] *Id.* § 216(a)(1), (3).

[14] *Id.* § 216(a)(2).

[15] *Id.* § 216(a)(4)(A)–(E).

[16] *Id.* § 216(b).

potentially suitable for designation as an NIETC, the Department requests comments on the following questions:

(1) Should the Department distinguish between persistent congestion and dynamic congestion, and if so, how?

(2) Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

(3) Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

(4) What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

B. Criteria Development

While it is conducting the congestion study, the Department intends to develop criteria based on the considerations listed in subsections 216(b)(4)(A)–(E) of the FPA,[17] and any other criteria the Department considers relevant, to evaluate geographic areas identified in the congestion study as candidates for NIETCs. The Department intends to apply these evaluation criteria to the geographic areas identified in the congestion study in order to identify areas where NIETC designations would be appropriate.

The Department invites comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status. Preliminary criteria that might be used in evaluating these considerations for NIETC evaluation are listed below, along with associated metrics that could be useful in applying them. Commenters are also invited to apply any of the draft criteria to one or more specific geographic areas and demonstrate how the criterion helps to identify such areas as having national significance for NIETC designation.

Draft Criterion 1: Action is needed to maintain high reliability. Maintaining high electric reliability is essential to any area's economic health and future development. Accordingly, an area would be of interest for possible NIETC designation if there is a clear need to remedy existing or emerging reliability problems. *Metrics:* A definition of the affected area in terms of load, population, and demand growth; a description of the expected degree of improvement in reliability associated with a proposed project; if appropriate, identification existing or projected violations of NERC Planning Criteria TPL–001, –002, –003, or –004.[18]

Draft Criterion 2: Action is needed to achieve economic benefits for consumers. An area may need substantial transmission improvements to enable large economic electricity transfers that would result in significant economic savings to retail electricity consumers. *Metrics:* Estimates, based on transparent calculations and data, of the aggregate economic savings per year to consumers over the relevant geographic areas and markets. A demonstration of expected reduction in end-market concentration and how economic benefits for consumers would be affected.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources. Metrics: Areas that are dependent on ''reliability-must-run'' plants would benefit from targeted improvements, in terms of enhanced reliability, reduced costs, or both. Similarly, areas that are highly dependent on specific generation fuels could economically benefit from supply diversification. Estimate the likely magnitude of such benefits, showing calculations.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States. Metrics: Provide calculations showing how specific actions aided by designation as an NIETC would increase fuel diversity, improve domestic fuel independence, or reduce dependence on energy imports. Quantify these impacts, including possible impacts on U.S. energy markets.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts. Metrics: For this criterion, relevant metrics would be case-specific.

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies. Other things being equal, arguably the Department should be more inclined to designate NIETCs where there are existing needs instead of projected needs, particularly if those future needs rest upon relatively uncertain assumptions and contingencies. On the other hand, timely construction of transmission facilities often requires lead-times of five years or more, and all projections are based on assumptions and involve some degree of uncertainty. The challenge here is to determine what level of confidence can be reasonably imputed to specific projections. *Metrics:* What metrics would be suitable for gauging such uncertainties?

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently. Recognizing the value of transmission alternatives, the Department wishes to avoid designating NIETCs in ways that might unduly affect stakeholders' decisions about how to meet specific needs, confer advantage on transmission options as opposed to non-wires options or generation options, or favor some transmission options over others. At the same time, the Department is mindful that even taking these other factors into account transmission expansion is clearly needed in many areas, and that transmission expansion is itself a protracted process. The Department seeks comments on how it should balance these concerns.

The Department also seeks comment on two additional questions:

(1) Are there other criteria or considerations that the Department should consider in making an NIETC designation? If so, please explain, and show how your proposed criterion would be applied, if possible in the context of a specific area or areas that you consider suitable for NIETC designation. For each new criterion proposed, you should offer metrics that measure or quantify the criterion.

(2) Are certain considerations or criteria more important than others? If so, which ones, and why are they especially important?

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[17] The five considerations are:

(A) The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;

(B)(i) The economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted;

(C) The energy independence of the United States would be served by the designation;

(D) The designation would be in the interest of national energy policy; and

(E) The designation would enhance national defense and homeland security.

[18] North American Electric Reliability Council, planning criteria at *http://www.nerc.com/~filez/standards/Reliability_Standards.html#Transmission_Planning.*

IV. Public Meeting Announcement and Comments

The date of the public technical conference is listed in the DATES section at the beginning of this notice of inquiry. The chief purpose of this conference will be to allow participants to discuss key issues raised by commenters' responses concerning the criteria here proposed for the evaluation of geographic areas for designation as NIETCs. For more information about the conference and registration information, please go to *http://www.electricity.doe.gov/1221.*

To the extent possible, the Department wishes to make all submissions publicly available on one of its Web sites. However, if any person chooses to submit information that he or she considers to be privileged or confidential and exempt from public disclosure, that person should clearly identify the information that is considered to be privileged or confidential and explain why the submitter thinks the information should be exempt from disclosure, addressing as appropriate the criteria for nondisclosure in the Department's Freedom of Information Act regulations at 10 CFR 1004.11(f). The Department also requests that in such cases submitters provide one copy of their comments from which the information claimed to be exempt from disclosure has been redacted, and that protection of the information or data from disclosure be consistent with the requirements set forth in its Freedom of Information Act regulations at 10 CFR 1004.11.

Factors of interest to the Department when evaluating requests to treat submitted information as confidential include: (1) A description of the items; (2) whether and why such items are customarily treated as confidential within the industry; (3) whether the information is generally known by or available from other sources; (4) whether the information has previously been made available to others without obligation concerning confidentiality; (5) an explanation of the competitive injury to the submitting person which would result from public disclosure; (6) when such information might lose its confidential character due to the passage of time; and (7) why disclosure of the information would be contrary to the public interest.

Issued in Washington, DC on Friday, January 27, 2006.

Kevin Kolevar,

Director, Office of Electricity Delivery and Energy Reliability.

Appendix A

Appendix A lists those transmission plans and studies the Department currently has under review.

I. General Documents or Data

1. Electricity Advisory Board, Electric Resources Capitalization Subcommittee, U.S. Department of Energy, ''Competitive Wholesale Electricity Generation: A Report of the Benefits, Regulatory Uncertainty, and Remedies to Encourage Full Realization Across All Markets,'' September 2002.
2. Electric Transmission Constraint Study, FERC OMOI, December 2003.
3. Electricity Advisory Board, U.S. Department of Energy, ''Transmission Grid Solutions Report,'' September 2002.
4. Federal Energy Regulatory Commission, ''Testimony of Karl Pfirrmann, President, PJM Western Region, PJM Interconnection, L.L.C.,'' Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources—Docket No. AD05–3–000.
5. Federal Energy Regulatory Commission, ''Remarks of Audrey Zibelman, Executive Vice President, PJM Western Region, PJM Interconnection, L.L.C.,'' Transmission Independence and Investment—Docket No. AD05–5–000 and Pricing Policy for Efficient Operation and Expansion of the Transmission Grid—Docket No. PL03–1–000.
6. U.S. Department of Energy, ''National Transmission Grid Study,'' May 2002.
7. U.S. Department of Energy, ''Comments to the Designation of National Interest Electric Transmission Bottlenecks (NIETB) Notice of Inquiry,'' Appended 10/15/04.

II. Documents or Data From the Eastern Interconnection

1. NERC 2005 Long-Term Reliability Assessment.
2. NERC 2005 Summer Assessment.
3. NERC 2005/2006 Winter Assessment.
4. U.S. Department of Energy, ''National Transmission Grid Study,'' May 2002.
5. FERC Form–715s.
6. Florida-Southern Interface Study for 2005 Summer & 2005–06 Winter Bulk Electric Supply Conditions (Oct 2004).
7. ISO–NE Regional System Plan 2005 (October 2005).
8. Maryland Public Service Commission, ''Reply Comments of the Staff of the Maryland Public Service Commission in the Matter of the Inquiry Into Locational Marginal Prices in Central Maryland During the Summer of 2005''—Case No. 9047.
9. MEN 2002 Interregional Transmission System Reliability Assessment.
10. Michigan Public Service Commission, ''Final Staff Report of the Capacity Need Forum,'' January 3, 2006.
11. MISO 2003 Transmission Expansion Plan.
12. MISO Transmission Expansion Plan 2005 (June 2005).
13. NERC TLR Data.
14. NYISO 2004 Intermediate Area Transmission Review of the New York State.
15. NYISO Comprehensive Transmission Plan.
16. NYISO 2005 Load & Capacity Data.
17. NYISO Comprehensive Reliability Planning Process (CRPP) Reliability Needs Assessment (December 2005).
18. NYISO Comprehensive Reliability Planning Process Supporting Document and Appendices For The Draft Reliability Needs Assessment (December 2005).
19. NYISO Operating Study Winter 2004–05 (November 2004).
20. NYISO Transmission Performance Report (August 2005).
21. PJM Regional Transmission Expansion Plan 2005 (September 2005).
22. PJM, MISO, NYISO, and ISO–NE Real-time and Day-ahead Constraint Data
23. PJM Interconnection, L.L.C., ''Comments of PJM in Response to the MD PSC Notice of Inquiry''—Case Number 9047.
24. Project Mountaineer, Work Group Meeting, Sheraton Four Points Hotel Baltimore, MD, August 3, 2005.
25. SERC Reliability Review Subcommittee's 2005 Report to the SERC Engineering Committee (June 2005).
26. SPP RTO Expansion Plan 2005–2010 (September 2005).
27. VACAR 2004–2005 Winter Stability Study Report (Mar 2004).
28. VACAR 2005 Summer Reliability Study Report (Apr 2004).
29. VACAR 2007 Summer Reliability Study Report (Feb 2002).
30. VASTE 2005 Summer Reliability Study Report (May 2005).
31. VASTE 2005–06 Winter Study Report (Nov 2005).
32. VEM 2004 Summer Reliability Study Report (May 2004).
33. VEM 2004–2005 Winter Reliability Study Report (Nov 2004).
34. VST(E) 2011 Summer Study Report (Nov 2004).
35. VSTE 2008 Summer Study Report (Nov 2005).
36. NPCC 2004 Report of the CP–10 Working Group Under the Task Force on Coordinated Planning.

III. Documents or Data From the Western Interconnection

1. Available on the WECC Web site—*http://www.wecc.biz,* open ''Congestion Study'' under the Main Menu of the home page.

1.1. ''Framework for Expansion of the Western Interconnection Transmission System, October 2003''.

1.2. ''Western Interconnection Transmission Path Flow Study''—February 2003.

1.3. ''Northwestern Consortia to Study the Regional Wind Development Benefits of Upgrades to Nevada Transmission Systems''—May 10, 2005.

1.4. ''Conceptual Plan for Electricity Transmission in the West''—August 2001.

1.5. ''Proposed Criteria for Evaluation of Transmission and Alternative Resources''—October 2005.

2. Available on State of Wyoming Web site at *http://www.psc.state.wy.us/htdocs/*

subregional/reports.htm: ''Rocky Mountain Area Transmission Study''—September 2004.

3. Available on California Energy Commission Web site at *http://www.energy.ca.gov/2005publications /CEC–100–2005–006/CEC–100–2005–006–CTF.PDF:* ''Committee Final Strategic Transmission Investment Plan (Committee Final Strategic Plan), California Energy Commission, November 2005.''

4. Available on the Public Service Company of Colorado Web site at *http://www.rmao.com/wtpp.psco_studies.html:* ''Colorado Long Range Transmission Planning Study''—April 27, 2004.

5. Available from WECC (Phase 3 Accepted Path Rating Study Report)—Call (801) 582–0353: ''Southwest Power link and Palo Verde—Devers 500kV Series Capacitor Upgrade Project''—dated December 2, 2004.

6. Available from CAISO Web site.

6.1. CAISO testimony to the CPUC for the Palo Verde—Devers #2 Project *http://www.caiso.com/14cf/14cf82f921c90.pdf.*

6.2. Information on the Southwest Transmission Expansion Plan (STEP) *http://www.caiso.com/docs/2002/11/04/2002110417450022131.html.*

6.3. Documents on the Palo Verde—Devers #2 project *http://www.caiso.com/docs/2005/01/19/2005011914572217739.html.*

6.4. Information on the CAISO Transmission Economic Assessment Methodology (TEAM) *http://www.caiso.com/docs/2003/03/18/2003031815303519270.html.*

7. Available from Northwest Power Pool Web site (Northwest Regional Transmission Association reports).

7.1. ''Puget Sound Area Upgrade Study Report''—November 2004 *http://www.nwpp.org/ntac/pdf/PSASG%20Final%20Draft.pdf.*

7.2. ''Montana—Pacific Northwest Transmission Upgrade Study'' *http://www.nwpp.org/ntac/pdf/MT–NW%20Study%20Report%202005–Oct.zip.*

7.3. *http://www.nwpp.org/ntac/pdf/Selected%20Transmission%20Siting%20constraints.pdf.*

8. Available from the Southwest Area Transmission Sub-Regional Planning Group Web site.

8.1. ''Report of the Phase I Study of the Central Arizona Transmission System'' *http://www.azpower.org/cats/default.asp#phase1.*

8.2. ''Report of the Phase II Study of the Central Arizona Transmission System'' *http://www.azpower.org/cats/default.asp#phase2.*

8.3. ''Report of the Phase III Study of the Central Arizona Transmission System'' *http://www.azpower.org/cats/default.asp#phase3.*

[FR Doc. E6–1394 Filed 2–1–06; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8027–8]

Environmental Laboratory Advisory Board (ELAB) Meeting Dates and Agenda

AGENCY: Environmental Protection Agency.

ACTION: Notice of teleconference meetings.

SUMMARY: The Environmental Protection Agency's Environmental Laboratory Advisory Board (ELAB), as previously announced, will have teleconference meetings on January 18, 2006 at 1 p.m. E.T.; February 15, 2006 at 1 p.m. E.T.; March 15, 2006 at 1 p.m. E.T.; April 19, 2006 at 1 p.m. E.T.; and May 17, 2006 at 1 p.m. E.T. to discuss the ideas and views presented at the previous ELAB meetings, as well as new business. Items to be discussed by ELAB over these coming meetings include: (1) Expanding the number of laboratories seeking National Environmental Laboratory Accreditation Conference (NELAC) accreditation; (2) homeland security issues affecting the laboratory community; (3) ELAB support to the Agency's Forum on Environmental Measurements (FEM); (4) implementing the performance approach; (5) increasing state participation in NELAC; and (6) follow-up on some of ELAB's past recommendations and issues. In addition to these teleconferences, ELAB will be hosting their next face-to-face meeting on January 30, 2006 at the Westin Chicago River North in Chicago, Illinois from 9:30–12 C.T. and an open forum session on January 31, 2006 also at the Westin Chicago River North in Chicago, Illinois at 5:30 p.m. C.T.

Written comments on laboratory accreditation issues and/or environmental monitoring issues are encouraged and should be sent to Ms. Lara P. Autry, DFO, U.S. EPA (E243–05), 109 T. W. Alexander Drive, Research Triangle Park, NC 27709, faxed to (919) 541–4261, or e-mailed to *autry.lara@epa.gov.* Members of the public are invited to listen to the teleconference calls, and time permitting, will be allowed to comment on issues discussed during this and previous ELAB meetings. Those persons interested in attending should call Lara P. Autry at (919) 541–5544 to obtain teleconference information. The number of lines for the teleconferences, however, are limited and will be distributed on a first come, first serve basis. Preference will be given to a group wishing to attend over a request from an individual. For information on access or services for individuals with disabilities, please contact Lara P. Autry at the number above. To request accommodation of a disability, please contact Lara P. Autry, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

George M. Gray,

Assistant Administrator, Office of Research and Development.

[FR Doc. E6–1422 Filed 2–1–06; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8026–5]

Position Statement on Environmental Management Systems (EMSs)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: This notice is to inform the public that EPA has updated its Position Statement on Environmental Management Systems (EMSs). This updated statement replaces the 2002 Position Statement on EMS signed by Administrator Whitman and reflects EPA's experiences to date with the promotion of voluntary EMSs as well as our continued commitment to be a leader in this area. The Position Statement explains EPA's policy on EMSs and the Agency's intent to continue to promote the voluntary wide-spread use of EMSs across a range of organizations and settings. EPA encourages organizations to implement EMSs that result in improved environmental performance and compliance, cost-savings, pollution prevention through source reduction, and continual improvement.

FOR FURTHER INFORMATION CONTACT: Shana Harbour 202–566–2959.

SUPPLEMENTARY INFORMATION:

Background

During the past decade, public and private organizations have increasingly adopted formal Environmental Management Systems (EMSs) to address their environmental responsibilities. The most common framework an EMS uses is the plan-do-check-act process, with the goal of continual improvement. EMSs provide organizations of all types with a structured system and approach for managing environmental and regulatory responsibilities to improve overall environmental performance and stewardship, including areas not subject to regulation such as product design,

Appendix B

Energy Policy Act of 2005 Summary of Title XII – Electricity

EDISON ELECTRIC INSTITUTE

Energy Policy Act of 2005

SUMMARY OF TITLE XII – ELECTRICITY, TITLE XVIII—STUDIES, AND RELATED PROVISIONS

TITLE XII – ELECTRICITY

Subtitle A—Reliability Standards

Section 1211. Reliability.
Creates a new Federal Power Act Section 215—ELECTRIC RELIABILITY.

Section 1211(a) In General.—This section gives FERC jurisdiction within the United States over an electric reliability organization (ERO), any regional entities and all users and operators of the "bulk power system," including the entities listed in FPA Section 201(f) (i.e., government-owned utilities and certain electric cooperatives), for purposes of approving and enforcing reliability standards.

Section 215(a) Definitions.—The definition of "reliability standard" includes cybersecurity protection, but does not include a requirement to enlarge, or construct new transmission facilities or generating capacity.

Section 215(b) Jurisdiction and Applicability.—Provides that all users, owners and operators of the bulk power system are required to comply with the reliability standards that take effect under this section. FERC must issue a final rule to implement this section within 180 days of enactment.

Section 215(c) Certification.—FERC is to certify an applicant meeting the requirements, including independence and due process, as the electric reliability organization. If FERC receives more than one application, it is to select the applicant it determines best meets the requirements.

Section 215(d) Reliability Standards.—The ERO must file proposed reliability standards with FERC. FERC may approve the standard if it is just, reasonable, not unduly discriminatory, and in the public interest. FERC is to give due weight to the technical expertise of the ERO with respect to the content of a standard but is not to defer to it with respect to the effect of a proposed standard on competition. The ERO is to rebuttably presume that a proposal from a regional entity organized on an interconnection-wide basis for a reliability standard to be applicable on an interconnection-wide basis meets the standard for approval. If FERC disapproves a standard, it is to remand it to the ERO for reconsideration. FERC can also order an ERO to submit a proposed standard on a specific matter. There shall be a fair process to resolve a conflict between a reliability standard and a FERC-approved rate or tariff. Until the conflict is resolved, the rate or tariff controls.

Section 215(e) Enforcement.—The ERO may impose penalties for violations after notice and an opportunity for a hearing. Penalties do not take effect for 31 days after the ERO files notice with FERC and are subject to review by the Commission. FERC can require compliance on its motion.

Section 215(e)(4) Delegation to a Regional Entity—FERC is to establish regulations allowing the ERO to delegate authority to a regional entity for the purpose of proposing and enforcing reliability standards if the regional entity is governed by an independent, balanced stakeholder board, or a combination independent and balanced stakeholder board; it has the ability to develop and enforce reliability standards; and the agreement promotes effective and efficient administration of bulk power system reliability. FERC may modify such delegation. The ERO and FERC are to presume that a proposal for delegation to a regional entity organized on an interconnection-wide basis promotes effective and efficient administration of bulk power system reliability and should be approved.

Section 215(e)(6) Penalties.—Any penalty imposed shall bear a reasonable relation to the seriousness of the violation and consider efforts taken to remedy the violation in a timely manner.

Section 215(f) Changes in ERO Rules.—The ERO must file any proposed changes in its rules for approval by FERC.

Section 215(g) Reports.—The ERO is to conduct periodic assessments of the reliability and adequacy of the bulk power system in North America.

Section 215(h) Coordination with Canada and Mexico.—The President is urged to negotiate international agreements with Canada and Mexico to promote compliance with reliability standards and the effectiveness of the ERO.

Section 215(i) Savings Provision.—The ERO has authority to develop and enforce standards only for the bulk power system. The ERO and FERC do not have authority to order the construction of additional generation or transmission capacity or to set or enforce safety and adequacy standards. Nothing preempts state authority to ensure the safety, adequacy and reliability of electric service within the state, so long as such action is not inconsistent with any reliability standard, except that the state of New York can establish stricter rules so long as such action does not result in lesser reliability outside New York than provided by the reliability standards. FERC is to determine whether any challenged state action is inconsistent with a reliability standard and can stay the effectiveness of any state action pending its issuance of a final order.

Section 215(j) Regional Advisory Bodies.—FERC is to establish a regional advisory body (RAB) on the petition of at least two-thirds of the states within a region that have more than one-half of their electric load served within that region. RAB members are to be appointed by the governors of the participating states and may include representatives from provinces outside the U.S. A RAB may provide advice to the ERO, a regional reliability entity, or FERC regarding the regional reliability entity governance, proposed standards and proposed fees. FERC may give deference to the advice of any RAB if it is organized on an interconnection-wide basis.

Section 215(k) Alaska and Hawaii.— The reliability section does not apply in Alaska or Hawaii.

Section 1211(b) Status of ERO.—The ERO and any regional entity that is delegated enforcement authority are not departments, agencies, or instrumentalities of the U.S. government.

Section 1211(c) Access Approvals by Federal Agencies.—Federal agencies responsible for approving access to transmission and distribution facilities located in the U.S. shall expedite any federal agency approvals that are necessary to allow the owners or operators of such facilities to comply with reliability standards regarding vegetation management, electric service restoration, or resolution of situations that imminently endanger the reliability or safety of the facilities.

Subtitle B—Transmission Infrastructure Modernization

Section 1221. Siting of Interstate Electric Transmission Facilities.
Section 1221(a) creates a new Federal Power Act Section 216—SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES.

Section 216(a) Designation of National Interest Electric Transmission Corridors.—
Within one year of enactment, and every three years thereafter, DOE, in consultation with affected states, is to conduct a study of transmission congestion. After input from interested parties, appropriate regional reliability entities and comment from the states, DOE may designate "any geographic area experiencing transmission capacity constraints or congestion that adversely affects consumers" as a "national interest electric transmission corridor." In determining whether to designate a national interest transmission corridor, DOE may consider specific factors, including constraints or jeopardy to economic growth or economic vitality in the corridor or the end market, the need for diversification of supply, energy independence, enhancement of national defense and homeland security.

Section 216(b) Construction Permit [Backstop Siting Authority].—FERC is authorized, after notice and an opportunity for comment, to issue permits for the construction or modification of transmission facilities in a national interest electric transmission corridor if FERC finds that:

(1) (A) a state in which the facilities are to be constructed is without authority to approve the siting of the facilities or to consider the interstate benefits expected to be achieved by the project; (B) the applicant for a permit is a transmitting utility under the FPA but does not qualify for a permit under state law because it does not serve end-use customers; or (C) the state has siting authority but (i) has withheld approval for the later of one year after the filing of an application or one year after the designation of the relevant national interest electric transmission corridor; or (ii) conditioned approval in such a way that the proposed construction will not significantly reduce transmission congestion or is not economically feasible;

(2) the facilities covered by the permit will be used for interstate electric transmission;

(3) the proposed project is consistent with the public interest;

(4) the proposed project will significantly reduce interstate transmission congestion and protects or benefits consumers;

(5) the proposed project is consistent with sound national energy policy and will enhance energy independence; and

(6) the proposed modification will maximize, to the extent reasonable and economical, the transmission capacity of existing towers or structures.

Sections 216(c) and (d) Permit Applications and Comments.—FERC to establish rules for permit applications, including the opportunity for interested parties, including states and federal agencies, to present their views on a proposed project.

Section 216(e) Rights-of-Way.—If a permit holder cannot obtain the necessary rights-of-way for the project, the permit holder can acquire the rights-of-way through an eminent domain proceeding in the federal district court where the property is located**.** Any right-of-way acquired under the section shall be used exclusively for the construction, modification, operation or maintenance of transmission and related facilities within a reasonable period of time. The right-of-way shall terminate upon the termination of the use for which the right-of-way was acquired.

Section 216(f) Compensation.—A right of way acquired in an eminent domain proceeding is a taking of private property for which the landowner must receive just compensation, which is the fair market value (including applicable severance damages) on the date of exercise of eminent domain.

Section 216(g) State Law.—Nothing in this section precludes any person from constructing any transmission facilities under state law.

Section 216(h)(1)-(4)—Coordination of Federal Authorizations for Transmission Facilities [Lead Agency].—DOE shall act as lead agency to coordinate all federal authorizations and environmental reviews required to site a transmission facility, including coordination with state siting authorities and Indian tribes. "Federal authorizations" means permits, authorizations or other approvals needed to site a transmission facility under federal law. DOE is required to set deadlines for the review and authorization decisions. DOE is to ensure that once an application with all data considered necessary by the Secretary has been submitted, all permit decisions and environmental reviews under federal laws shall be completed within one year, or if another requirement of federal law makes this impossible, as soon thereafter as is practicable. DOE shall provide an expeditious pre-application mechanism for prospective applicants to confer with agencies involved.

Section 216(h)(5)—DOE is to prepare a single environmental review document to be used as the basis for all decisions on the proposed project under federal law. DOE and other agencies are to streamline the review and permitting of transmission and distribution facilities within corridors designated under Section 503 of the Federal Land Policy and Management Act (FLPMA), by fully taking prior analyses and decisions into account. The review document shall include consideration by the relevant agencies of any applicable criteria or other matters as required by applicable law.

Section 216(h)(6)—If any agency has denied a federal authorization required for a transmission facility, or has failed to act by the deadline established by DOE, the applicant, or any state in which the facility would be located, may file an appeal with the President. Based on the overall record and in consultation with the affected agency, the President may either issue the necessary authorization or deny the application. The President is to issue a decision within 90 days after the appeal is filed and is to comply with all applicable federal laws.

Section 216(h)(7) Implementation.—Within18 months of enactment, DOE is to issue regulations to implement this provision. Not later than one year after enactment, DOE and the heads of all relevant federal departments and agencies, interested Indian tribes, multi-state entities and state agencies shall enter into a memorandum of understanding to ensure the timely coordinated review and permitting of electricity transmission and distribution facilities.

Section 216(h)(8) Duration.—Each federal land use authorization for an electricity transmission facility must be issued for a duration commensurate with the anticipated use of the facility, as determined by the DOE Secretary, and be issued with appropriate authority to manage the right-of-way for reliability and environmental protection. When such authorizations (or any previously issued authorizations) expire, they can be reviewed for renewal, taking into account economic, health and safety impacts of reliance on the electricity infrastructure.

Section 216(h)(9) Coordination.—DOE is to consult with FERC, reliability organizations, RTOs and ISOs in exercising its responsibilities under this section.

Section 216(i) Interstate Compacts.—Three or more contiguous states may enter into an interstate compact establishing regional siting agencies to facilitate coordination among the states for purposes of siting future electric transmission facilities and to carry out state transmission siting responsibilities. DOE can provide technical assistance to any regional siting agency. FERC is precluded from exercising its construction permit/backstop siting authority in states that are participating in an interstate compact, unless the states are in disagreement and DOE makes the findings in section (b)(1)(C), i.e., that a state commission has withheld permit approval beyond 1 year of application submittal or designation as a national interest electric transmission corridor or so conditioned the permit as to make the project economically unfeasible or unlikely to significantly reduce congestion.

Section 216(j) Relationship to Other Laws.—Nothing in this section shall be construed to affect any requirement of the federal environmental laws, including NEPA. The appeals provision under the DOE lead agency authority subsection shall not apply to any unit of the National Park System, the National Wildlife Refuge System, the National Trails System, the National Wild and Scenic Rivers System, the National Wilderness Preservation System, or a National Monument. [As a result, agencies with jurisdiction over such lands are required to coordinate under DOE their authorization decisions, but their final decisions or failure to meet an established DOE deadline cannot be appealed to the President when these specified lands are involved.]

Section 216(k) ERCOT.—This section shall not apply within ERCOT.

Section 1221(b) Corridor and Right-of-Way Report.—Within 90 days of enactment, the Secretaries of Interior and Agriculture, and the Chairman of the Council on Environmental Quality, shall submit a joint report to Congress identifying: 1) all designated transmission and distribution corridors on federal land, the schedule for completing any work and any impediments; 2) the number of pending applications to locate transmission and distribution facilities on federal lands and key information relating to each project; and 3) the number of existing transmission and distribution rights-of-way on federal lands that will come up for renewal within the following 5, 10 and 15 year periods, and a description of how the Secretaries plan to manage such renewals.

Section 1222. Third Party Finance. For both existing and new facilities, DOE, acting through WAPA and SWPA, may participate with other entities in designing, developing, constructing, operating, maintaining or owning an electric power transmission facility and related facilities ("Project") needed to upgrade existing transmission facilities owned by WAPA and SWPA, if DOE determines that the proposed Project (1) is located in a national interest electric transmission corridor and will reduce transmission congestion or is necessary to accommodate an actual or projected increase in demand for transmission capacity; (2) is consistent with the transmission expansion plan of an RTO, ISO or FERC-approved regional reliability organization, and efficient and reliable operation of the grid; and (3) would be operated in conformance with prudent utility practice. For new facilities, it also adds the requirements that the Project (4) will be operated by, or in conformance with the rules of, the appropriate RTO/ISO, or if one does not exist, the regional reliability organization; and (5) will not duplicate the functions of existing transmission facilities or proposed facilities which are the subject of ongoing or approved siting and related permitting proceedings.

Funds contributed by another entity shall be available without fiscal year limitation and as if they had been appropriated specifically for the Project. Any costs of the Project not paid for by the contributions of another entity shall be collected through transmission rates charged to customers using the new transmission capability provided by the Project.

Nothing in this section affects any requirement of any federal environmental law, including NEPA, any federal or state siting law, or any existing authorizing statutes.

This section does not affect WAPA and SWPA authorities.

DOE shall not accept more than $100 million in funds from other entities under this subsection for fiscal years 2006 through 2015.

Section 1223. Advanced Transmission Technologies. FERC shall encourage advanced transmission technologies that increase the capacity, efficiency or reliability of existing or new transmission facilities. These technologies include energy storage devices, controllable load, distributed generation and mobile transformers and mobile substations.

Section 1224. Advanced Power System Technology Incentive Program. DOE is authorized to support deployment of advanced power system technology with incentive payments of 1.8 cents/KWH to eligible owners and operators of advanced power system technologies. An additional 0.7 cents/KWH shall be paid to the owner or operator of a qualifying security and assured power facility (one deemed to be in critical need of secure, reliable, rapidly available, high-quality power for critical governmental, industrial or commercial applications) for power generated at such facility. Incentive payments are limited to the first 10 million KWH produced by a qualifying facility in any fiscal year. Authorizes $10 million for each of the fiscal years 2006-2012.

Subtitle C—Transmission Operation Improvements

Section 1231. Open Non-Discriminatory Access
Creates a new Section 211A of the Federal Power Act—OPEN ACCESS BY UNREGULATED TRANSMITTING UTILITIES.

Section 211A(a). Definition.— An "unregulated transmitting utility" means an entity that owns or operates facilities used for the transmission of electric energy in interstate commerce and is an entity described in FPA Section 201(f) (a government-owned utility or electric cooperative that owns or operates facilities used for transmission of electricity in interstate commerce).

Section 211A(b) Transmission Operation Services.—Subject to Section 212(h) (which prohibits mandatory retail wheeling), FERC may, by rule or order, require an "unregulated transmitting utility" to provide transmission service at rates that are comparable to those it charges itself and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission service to itself and that are not unduly discriminatory or preferential.

Section 211A(c) Exemption.—FERC must exempt any unregulated transmitting utility that (1) sells no more than 4 million MWh of electricity per year; or (2) does not own or operate any transmission facilities that are necessary for operating an interconnected transmission system (or any portion thereof); or (3) meets other criteria that FERC determines are in the public interest.

Section 211A(d) Local Distribution Facilities.—The open access requirements do not apply to local distribution facilities.

Section 211A(e) Exemption Termination.—After a hearing and consideration of reliability standards, FERC shall revoke an exemption if it finds on a preponderance of the evidence that the exemption unreasonably impairs reliability of an interconnected transmission system.

Section 211A(f) - (g) Rates and Remand.—The rate changing procedures applicable to public utilities under FPA Section 205 (c) and (d) are applicable to an unregulated transmitting utility for purposes of this section.

FERC may remand transmission rates to an unregulated transmitting utility for review and revision where necessary to meet the requirements of this section.

Section 211A(h) Other Transmission Requests.—Unregulated transmitting utilities are still subject to a request for transmission service under FPA Section 211.

Section 211A(i) Limitation.—FERC may not require a state or municipal utility to act under this section if it would violate a private activity bond rule.

Section 211A(j) Transfer of Control.—Nothing in this section authorizes FERC to require an unregulated transmitting utility to join a Transmission Organization.

Section 1232. Federal Utility Participation in Transmission Organizations.
(a)-(c)—Federal power marketing agencies and TVA ("federal utilities") are authorized to voluntarily join a Transmission Organization. The contract, agreement or arrangement transferring control of transmission facilities to the Transmission Organization shall include performance standards for the operation and use of the transmission system that the federal utility determines necessary or appropriate, including standards that assure cost recovery, monitoring and oversight by the federal utility of the Transmission Organization's fulfillment of the terms and conditions of the agreement, and a provision that allows the federal utility to withdraw from the Transmission Organization.

(d)—Neither this section, actions taken pursuant to it, nor any other transaction of a federal utility using a Transmission Organization gives FERC jurisdiction over the federal utility's generation assets, electric capacity or energy that the federal utility is authorized by law to market or the federal utility's power sales activities.

(e)—No statutory provisions requiring or authorizing a federal utility to transmit electric power or to construct, operate or maintain its transmission system shall be construed to prohibit it from transferring control of its transmission system under this section. Federal utilities are not exempted from any provision of existing federal law relating to the use of the federal utility's transmission system, environmental protection, fish and wildlife protection, flood control, navigation, water delivery or recreation, or authorize abrogation of any contract or treaty obligation.

Section 1233. Native Load Service Obligation.
Creates new Section 217 of the Federal Power Act—NATIVE LOAD SERVICE OBLIGATION.

Section 217(a) Definitions.—For purposes of this section—

A "distribution utility" means an electric utility that has a service obligation to end-users or to a state or municipal utility or electric cooperative that, directly or indirectly, through one or more additional state utilities or cooperatives provides electric service to end-users.

The term "load-serving entity" means a distribution utility or an electric utility that has a service obligation. The term "service obligation" means a requirement under federal, state or local law or under long term contracts to provide electric service to end-users or to a distribution utility.

Section 217(b) Meeting Service Obligations.—(1) This subsection (as described in Paragraph (2) below) applies to any load-serving entity that as of the date of enactment of this section: (A) owns generation facilities, markets the output of federal generation facilities, or holds rights under one or more wholesale contracts for the purpose of meeting a service obligation; and (B) by reason of ownership of transmission facilities or one or more contracts or service agreements for firm transmission service, holds firm transmission rights for delivery of output of such generation facilities or purchased energy to meet such service obligation.

(2) Any such load-serving entity is entitled to use such firm transmission rights or equivalent tradable or financial transmission rights to deliver such output or purchased energy, or the output of other generating facilities or purchased energy to the extent deliverable using such rights, to the extent required to meet its service obligation.

(3) If all or part of a service obligation or contractual obligation is transferred to another load serving entity, the successor is entitled to use the transmission facilities or transmission rights associated with the transferred obligation.

(4) FERC is to exercise its authority in a manner that facilitates transmission planning and expansion to meet the reasonable needs of load-serving entities to satisfy their service obligations and enables load-serving entities to secure long term firm transmission rights (or equivalent tradable or financial rights) for long term power supply arrangements made or planned to meet such needs.

Section 217(c) Allocation of Transmission Rights.—The section grandfathers any existing or future methodology for the allocating or auctioning of transmission rights employed by a Transmission Organization if the Transmission Organization was authorized by FERC to allocate or auction transmission rights as of January 1, 2005, and FERC determines that any future allocation or auction is just, reasonable and not unduly discriminatory or preferential; provided, however, that if such a Transmission Organization never allocated transmission rights on its system before January 1, 2005, with respect to any application by the Transmission Organization to change its methodology, FERC shall exercise its authority consistent with the Act and shall take into account the policies expressed in (b)(1),(2), and (3) as applied to firm transmission rights held by a load-serving entity as of January 1, 2005, to the extent that the associated generation ownership or power purchase arrangements remain in effect.

Section 217(d) Certain Transmission Rights.—FERC may make transmission rights not used to meet a service obligation available to other entities.

Section 217(e) Obligation to Build.—This Act does not relieve a load-serving entity from any obligation under state or local law to build transmission or distribution facilities adequate to meet its service obligation.

Section 217(f) Contracts.—Grandfathers existing contracts or service agreements for firm transmission rights or service in effect as of the date of enactment. If an ISO in the Western Interconnection had allocated financial transmission rights prior to the date of enactment of this section but had not done so with respect to one or more load-serving entities’ firm transmission rights held under contracts or service agreements in effect as of the date of enactment (or held by reason of ownership or future ownership of transmission facilities), such load-serving entities may not be required, without their consent, to convert these firm transmission rights to tradable or financial rights, except where the load-serving entity has voluntarily joined the ISO as a participating transmission owner in accordance with the ISO tariff.

Section 217(g) Water Pumping Facilities.—FERC must ensure that any government-owned utility or cooperative that owns transmission facilities used predominantly to support its own water pumping facilities has comparable native load service protections with respect to those facilities.

Section 217(h) ERCOT.—This section does not apply in ERCOT.

Section 217(i) Jurisdiction.—This section does not authorize FERC to take any action not otherwise within its jurisdiction.

Section 217(j) TVA Area.—A load-serving entity in the TVA service area that has a wholesale power supply contract with TVA shall be considered to hold firm transmission rights for the transmission of such power. Nothing in this subsection affects the requirements of FPA section 212(j) (the TVA "fence" provision). FERC may not issue an order that is contrary to the purposes of section 212(j).

Section 217(k) Effect of Exercising Rights.—It shall not be considered engaging in undue discrimination or preference for an entity to exercise its rights under subsection (b) in order to meet its service obligation.

Section 1233(b) FERC Rulemaking on Long Term Transmission Rights in Organized Markets.—Within one year of enactment, FERC must issue a rule or order implementing subsection (b)(4) in Transmission Organizations with organized electricity markets.

Section 1234. Study on Benefits of Economic Dispatch. DOE, in coordination and consultation with the states, is to conduct a study on current economic dispatch procedures and identify possible revisions to those procedures to improve the ability of nonutility generators to be included in economic dispatch, and the potential consumer benefits of doing so. "Economic dispatch" means the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities. Within 90 days of enactment and annually thereafter, DOE is to report to Congress and the states on the results of the study, including any recommendations for suggested legislative or regulatory changes.

Section 1235. Protection of Transmission Contracts in the Pacific Northwest. Creates a new Section 218 of the Federal Power Act—PROTECTION OF TRANSMISSION CONTRACTS IN THE PACIFIC NORTHWEST.

FERC is prohibited from requiring an "electric utility or person" to convert to tradable or financial rights firm transmission rights held by contract or through ownership of transmission facilities or firm transmission rights obtained by exercising contract or tariff rights associated with these rights. For purposes of this section, an "electric utility or person" is one that, as of the date of enactment of the Energy Policy Act of 2005, holds firm transmission rights pursuant to contract or by reason of ownership of transmission facilities and is located in the Pacific Northwest or that portion of a state included in the geographic area proposed for RTO West [most of Oregon, Washington, Idaho, Montana, Wyoming, Utah, and Nevada].

Section 1236. Sense of Congress Regarding Locational Installed Capacity Mechanism. It is the sense of Congress that FERC should carefully consider the objections of the New England states that the proposal to establish a Locational Installed Capacity (LICAP) mechanism in New England does not provide adequate assurance of generation capacity or reliability and would impose high costs on consumers.

Subtitle D—Transmission Rate Reform

Section 1241. Transmission Infrastructure Investment.
Creates a new Section 219 of the Federal Power Act—TRANSMISSION INFRASTRUCTURE INVESTMENT.

Section 219(a) Rulemaking Requirement.—Requires FERC to issue a rule, within one year of enactment, providing transmission rate incentives to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

Section 219(b) Contents.—The rule shall promote economically efficient and reliable transmission and generation by promoting capital investment in the enlargement, improvement, maintenance and operation of transmission facilities regardless of ownership in the facilities, provide a rate of return that attracts investment in transmission, and reasonably reflects the risks involved, and provide for recovery of all prudent costs of complying with mandatory reliability standards and related to transmission infrastructure development under section 216 [Siting of Interstate Transmission Facilities].

Section 219(c) Incentives.—FERC shall provide for incentives for each transmitting utility or electric utility that joins a Transmission Organization. FERC shall ensure that any costs recoverable pursuant to this subsection may be recovered through the transmission rates charged by such utility or by the Transmission Organization that provides transmission service to such utility.

Section 219(d) Just and Reasonable Rates.—All rates approved under this section, including any revisions to the rules, are subject to the requirements of FPA sections 205 and 206 that the rates are just and reasonable, not unduly discriminatory or preferential.

Section 1242. Funding New Interconnection and Transmission Upgrades. FERC may approve a participant funding plan that allocates costs related to transmission upgrades or new generator interconnection whether or not the applicant is a member of a FERC-approved Transmission Organization if the proposed rates are just and reasonable, not unduly discriminatory or preferential and are otherwise consistent with FPA sections 205 and 206.

Subtitle E—Amendments to PURPA

Section 1251. Net Metering and Additional Standards. **Amends Section 111(d) of PURPA to add new subsections (11), (12), and (13).** These standards require a state regulatory authority and nonregulated electric utility, within two years of enactment, to consider whether to adopt new standards regarding net metering, fuel diversity and fossil fuel generation efficiency.

Section 111(d)(11) Net Metering.—This standard requires each electric utility to make available upon request net metering service to any electric consumer that the electric utility serves. “Net metering” means service to an electric consumer under which electric energy generated by the consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided to the consumer during the applicable billing period.

Section 111(d)(12) Fuel Sources.—This standard requires each electric utility to develop a plan to minimize dependence on one fuel source and to ensure it uses a diverse range of fuels and technologies to generate electricity.

Section 111(d)(13) Fossil Fuel Generation Efficiency.—This standard requires each electric utility to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

States and nonregulated electric utilities must make their determinations whether to adopt these standards within three years of enactment. States do not have to comply if the state has already adopted or considered a comparable provision.

<u>Section 1252. Smart Metering</u>.
Adds a new "Time-Based Metering and Communications" standard to Section 111(d)(14) of PURPA.

(a) Time Based Rate Schedules.—This standard requires each state regulatory authority and nonregulated electric utility to made a determination whether it is appropriate to require each electric utility to offer each of its customer classes and individual customers upon request a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance in the costs of generating and purchasing wholesale electricity. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

The types of time-based rate schedules that may be offered include time-of-use pricing, critical peak pricing, real-time pricing, and credits for consumers with large loads who enter into pre-established load reduction agreements that reduce a utility's planned capacity obligations. Each electric utility shall provide customers a time-based meter on request.

Customers of third-party marketers (in retail competition states) are entitled to receive the same time-based metering and communications device as a retail electric consumer of the electric utility.

Notwithstanding PURPA Section 112, each state regulatory authority shall issue a decision whether to adopt the standards on time-based rate schedules and time-based meters within 18 months of enactment.

(b) State Investigations.—In the determination whether to adopt these standards, these rates shall be considered cost-effective if the long-run benefits of these rates are likely to exceed the costs associated with the use of rates. Each state shall also consider whether it is appropriate for electric utilities to install time-based meters and communication devices.

(c)-(e) Demand Response.—DOE is to notify state regulatory authorities and electric utilities about technologies, techniques and ratemaking methods related to advanced metering and communications technologies. DOE is also responsible for educating consumers on the availability, advantages and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot programs; and working with states, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs. DOE shall provide a report to Congress within 180 days of enactment that identifies and quantifies the national benefits of demand response and provides policy recommendations as to how to achieve specific levels of such benefits by January 1, 2007. It is the policy of the U.S. to encourage states to coordinate on a regional basis state energy policies to provide reliable and affordable demand response services to the public. DOE is to provide technical assistance to states and regional organizations formed by two or more states to assist them regarding demand response programs.

Within one year of enactment. FERC must prepare an annual report, by appropriate region, that assesses demand response resources, including the usage of advanced meters and communications technologies; existing demand response and time-based rate programs; the annual resource contribution of demand resources; the potential for demand response as a quantifiable, reliable resource for regional planning purposes; steps taken to ensure that in regional transmission planning and operations, demand resources are treated equitably as a resource relative to the resource obligations of any load-serving entity, transmission provider or transmitting party; and regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

(f) Federal Encouragement of Demand Response Devices.—Expresses the policy of the U.S. that time-based pricing and other forms of demand response shall be encouraged, that deployment of devices that enable consumers to participate in these programs should be facilitated, and that unnecessary barriers to demand response be eliminated. Expresses the policy of the U.S. that the benefits of these programs that accrue to those not deploying these technologies and devices but who are part of the same regional electricity entity shall be "recognized."

(g)-(h) Time Limitations.—Provides that states must begin the required proceeding under this section within one year of enactment and complete it within two years of enactment.

(i) Prior State Actions.—A state does not have to comply if the state has already implemented or considered a comparable provision, the state regulatory authority has conducted a smart metering proceeding, or the state legislature has voted on the implementation of such a standard.

Section 1253. Cogeneration and Small Power Production Purchase and Sale Requirements.
Section 1253(a) adds—
PURPA Section 210(m)—TERMINATION OF MANDATORY PURCHASE AND SALE REQUIREMENTS.
PURPA Section 210(n)—RULEMAKING FOR NEW QUALIFYING FACILITIES.

Section 210(m)—Termination of Mandatory Purchase and Sale Requirements.
(m)(1) Obligation to Purchase.—The mandatory purchase obligation under Section 210 of PURPA is repealed prospectively if FERC finds that the qualifying facility (QF) has nondiscriminatory access to (A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy and (ii) wholesale markets for long-term sales of capacity and electric energy; or (B)(i) nondiscriminatory transmission and interconnection services provided by a FERC-approved regional transmission entity; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity (long-term and short-term sales), and electric energy (long-term, short-term and real-time) to buyers other than the utility to which the QF is interconnected; or (C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in (A) and (B).

(m)(2) New Facilities.—After the date of enactment, no electric utility is required to enter into a new contract to purchase from or sell electric energy to a facility that is not an "existing" QF, unless the facility meets the standards for new QFs that FERC is required to promulgate. An "existing" QF is one that was a QF on the date of enactment or had filed a notice of self-certification or recertification prior to the date that FERC issues the new QF criteria.

(m)(3) Commission Review.—FERC is to grant an application from an electric utility for relief from the mandatory purchase obligation on a service territory-wide basis if the utility demonstrates that the competitive conditions set forth above have been met.

(m)(4) Reinstatement of Obligation to Purchase.—FERC can reinstate the obligation to purchase upon a demonstration that the competitive conditions are no longer met.

(m)(5) Obligation to Sell.—After the date of enactment, the obligation to enter into a new contract to sell electric energy to a QF is eliminated if FERC finds that competing retail electric sellers are willing and able to sell and deliver electric energy to the QF and the electric utility is not required by state law to sell electric energy in its service territory.

(m)(6) Existing Contracts.—Rights and remedies under existing contracts in effect or pending approval before the appropriate state regulatory authority or nonregulated electric utility on the date of enactment (including the right to recover costs of purchasing electric energy or capacity) are not affected.

(m)(7) Cost Recovery.—FERC is to promulgate and enforce regulations to ensure that an electric utility recovers all prudently incurred costs associated with any legally enforceable PURPA obligation entered into or imposed under this section.

Section 210(n)—Rulemaking for New Qualifying Facilities.
(n)(1)—Within 180 days of enactment, FERC must issue a rule revising the criteria for new QFs seeking to sell electric energy pursuant to PURPA Section 210 to ensure – (i) that the thermal energy output of a new QF is used in a productive and beneficial manner; and (ii) the electrical, thermal and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility; (iii) continuing progress in the development of efficient electric generating technology. The revised criteria shall be applicable only to facilities that seek to sell electric energy pursuant to the mandatory purchase obligation of PURPA Section 210. For all other purposes, QF status shall be determined in accordance with the rules and regulations under PURPA.

(n)(2)—The criteria currently in effect will continue to apply to a facility that was a QF on the date of enactment or had filed with FERC a notice of self-certification or application for certification prior to the date on which FERC issues the final rule changing the QF criteria.

Section 1253(b)—Elimination of Ownership Limitations. Eliminates the ownership limitation in the definition of "qualifying small power production facility" in FPA Section 3(17) and in the definition of "qualifying cogeneration facility" in FPA Section 3(18).

Section 1254. Interconnection.
Adds a new PURPA section 111(d)(15) standard—INTERCONNECTION

(a) Adoption of Standard.—Requires each electric utility, upon request by any consumer it serves, to interconnect onsite generation facilities to local distribution facilities. Interconnection services shall be offered based on IEEE standards. The agreements and procedures under which the services are offered shall promote current best practices of interconnection for distributed generation, including stipulated model codes adopted by associations of regulatory agencies and shall be just and reasonable and not unduly discriminatory or preferential.

(b) Compliance and Time Limitations.—Each state regulatory authority and each non-regulated utility must begin to consider adoption of this standard within one year of enactment and must complete consideration within two years of enactment.

The new standard does not apply to an electric utility in a state that has, prior to enactment, implemented, conducted a proceeding to consider implementation of the same or comparable standard or where the state legislature has voted on implementation of the same or comparable standard.

Subtitle F—Repeal of PUHCA

Section 1261. Short Title. "Public Utility Holding Company Act of 2005"

Section 1262. Definitions. Includes a definition of "holding company," that amended during conferences which provides that the term does not include (i) financial institutions that own, control, or hold voting securities in a public utility or public utility holding company so long as the securities are held as collateral for a loan, held in the ordinary course of business as a fiduciary, or acquired solely for purposes of liquidation in connection with a loan previously held for at least two years; or (ii) a broker or dealer that holds voting securities in a public utility or public utility holding company, so long as the securities are not beneficially owned by the broker or dealer or acquired within 12 months in the ordinary course of business as a broker, dealer or underwriter with the bona fida intention of effecting distribution of the securities.

Section 1263. Repeal of the Public Utility Holding Company Act of 1935. PUHCA is repealed.

Section 1264. Federal Access to Books and Records. Gives FERC authority to require that each holding company, associate company and affiliate company make available to FERC books, accounts, memoranda, or other records that FERC determines are relevant to costs incurred by a public utility or natural gas company that is an associate of a holding company and that are necessary or appropriate to protect utility customers with respect to jurisdictional rates. FERC commissioners and staff are to keep such information confidential, except as directed by FERC or a court.

Section 1265. State Access to Books and Records. Provides that upon written request of a state commission having jurisdiction to regulate a public utility company in a holding company system, a holding company, associate company or affiliate company is to make available to the state commission books, accounts, memoranda and other and records that have been identified in reasonable detail in a proceeding before the state commission, that the state commission determines are relevant to costs incurred by such public utility and are necessary for the effective discharge of the responsibilities of the state commission with respect to such proceeding. States can obtain books and records under state law or other applicable federal law. Provides for confidentiality of trade secrets and sensitive commercial information.

Section 1266. Exemption Authority. Within 90 days after the effective date of the subtitle (i.e., 6 months and 90 days), FERC is to issue a final rule exempting from the federal books and records requirement any person that is a holding company solely with respect to a qualifying facility (QF), exempt wholesale generator, or foreign utility companies. FERC can exempt other records for any class of transactions that it finds is not relevant to jurisdictional rates.

Section 1267. Affiliate Transactions. Preserves the authority of FERC or a state commission to determine if a jurisdictional public utility company can recover in rates costs incurred through transactions with affiliates.

Section 1268. Applicability. Provides that, unless otherwise specified, PUHCA provisions do not apply to the U.S. government, any state or political subdivision, any foreign government authority not operating in the U.S., or any agency, authority or instrumentality of any of the above.

Section 1269. Effect on Other Regulations. Preserves authorities of FERC or state commissions under other applicable law to protect utility customers.

Section 1270. Enforcement. Authorizes FERC to use its enforcement authorities under FPA sections 306-317 to enforce this subtitle.

Section 1271. Savings Provisions. Permits continuation of activities authorized as of the date of enactment and preserves FERC authority under the FPA and the Natural Gas Act. Tax treatment under section 1081 of the Internal Revenue Code as a result of compliance with the PUHCA of 1935 shall not be affected in any manner due to the repeal of that act and the enactment of the PUHCA of 2005.

Section 1272. Implementation.
Directs FERC to promulgate regulations to implement this subtitle and to submit recommendations to Congress for technical and conforming amendments within 4 months of enactment.

Section 1273. Transfer of Resources. Provides that the SEC is to transfer books and records to FERC.

Section 1274. Effective Date. Provides that, except for section 1292 *(*implementation actions taken by FERC), the subtitle takes effect 6 months after the date of enactment. Action taken by a public utility company or a holding company to comply with FERC standard of conduct rules issued prior to the effective date shall not be subject to any regulatory requirement under PUHCA.

Section 1275. Service Allocation. In this section, "public utility" has the meaning in section 201(e) of the FPA. Authorizes FERC, in response to a utility or state commission request, to determine the allocation to any public utility in a holding company system of any costs of non-power goods or administrative or management services acquired by such pubic utility from an associate company. Nothing in this section affects the authority of FERC or a state commission under any other law.

Directs FERC to issue rules within 4 months (effective no earlier than the effective date of this subtitle) after enactment to exempt from the requirements of this section any company in a holding company system whose public utility operations are confined substantially to a single state and any other class of transactions that FERC finds is not relevant to the jurisdictional rates of a public utility.

Section 1276. Authorization of Appropriations. Authorizes such funds as may be necessary to carry out the PUHCA subtitle.

Section 1277. Conforming Amendments to the Federal Power Act. Repeals FPA Section 318, dealing with conflicts in jurisdiction between PUHCA and the FPA. Amends other FPA sections to update references to PUHCA.

Subtitle G—Market Transparency, Enforcement, and Consumer Protection

Section 1281. Electricity Market Transparency Rules. **Creates a new Section 220 of the Federal Power Act—ELECTRICITY MARKET TRANSPARENCY RULES.**

(a)(1) FERC is directed to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and protection of consumers.

(2) FERC may prescribe rules to carry out this section. The rules shall provide for the dissemination on a timely basis of information about the availability and prices of wholesale electricity and transmission service to FERC, state commissions, buyers and sellers of wholesale electricity, users of transmission services, and the public.

(3) FERC may obtain the information in (2) from any market participant and rely on entities other than FERC to receive and make public the information, subject to the disclosure rules in (b).

(4) In carrying out this section, FERC shall consider the price transparency provided by existing price publishers and providers of trade processing services and rely on them to the maximum extent possible. FERC can establish an electronic system if it determines that existing price publishers are not adequately providing price discovery or market transparency. Nothing in this section, however, shall affect any electronic information filing requirements in effect under the FPA as of the date of enactment of this section.

(b)(1) FERC shall exempt from disclosure information it determines would, if disclosed, be detrimental to the operation of an effective market or jeopardize system security.

(2) In determining what and when information should be made available under this section, FERC shall seek to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion that can be facilitated by untimely public disclosure of transaction-specific information.

(c)(1) Within 180 days of enactment, FERC shall conclude a Memorandum of Understanding with the Commodity Futures Trading Commission (CFTC) relating to information sharing, including provisions ensuring that information requests to markets within the respective jurisdiction of each agency are coordinated to avoid duplication, and provisions regarding the treatment of proprietary trading information.

(2) This section shall not affect the exclusive jurisdiction of the CFTC under the Commodity Exchange Act (CEA).

(d) FERC shall not require entities who have a de minimis market presence to comply with the reporting requirements of this section.

(e)(1) Except as provided in (2), the statute of limitations bars the imposition of civil penalties under this section for any violation occurring more than 3 years from the date on which the person is provided notice of the proposed penalty under FPA section 316A.

(2) The 3-year statute of limitations does not apply in any case in which FERC finds that a jurisdictional seller has engaged in fraudulent market manipulation activities materially affecting the contract in violation of FPA section 222.

(f) This section does not apply in ERCOT.

Section 1282. False Statements.
Creates a new Section 221 of the Federal Power Act— PROHIBITION ON FILING FALSE INFORMATION.

No entity (including entities described in Section 201(f)) shall willfully and knowingly report any information relating to the price of wholesale electricity or availability of transmission capacity, which information the entity knew to be false at the time of the reporting, to a federal agency with the intent to fraudulently affect the data being compiled by the agency.

Section 1283. Market Manipulation.
Creates new Section 222 to the Federal Power Act—PROHIBITION OF ENERGY MARKET MANIPULATION.

(a) It is unlawful for any entity (including an entity described in section 201(f)), directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or transmission services subject to FERC jurisdiction, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934) in contravention of FERC rules and regulations.

(b) Nothing in this section shall be construed to create a private right of action.

Section 1284. Enforcement. (a) Complaints.—Amends FPA Section 306 to add an “electric utility” to the list of entities that may file a complaint and adds “transmitting utility” to the list of entities against which a complaint may be filed.

(b) Investigations.—Amends FPA Section 307(a) to provide that a “transmitting utility” may be the subject of an investigation.

(c) Review of Commission Orders.—Amends FPA Section 313 to include "electric utility" in the list of entities that can seek review of a FERC order.

(d) Criminal Penalties.— Amends FPA Section 316 to increase criminal fines for violations of the FPA from $5,000 to $1 million and from two years imprisonment to five years. Additional fines under Section 316(b) are increased from $500 to $25,000 for each and every day during which the offense occurs. Strikes FPA Section 316(c), which makes criminal penalties inapplicable to violations of FPA Section 211-214.

(e) Civil Penalties.—Expands civil penalties under FPA Section 316A to cover violations of any provision of Part II of the FPA and increases civil penalties from $10,000 to $1 million per day for each day the violation continues.

Section 1285. Refund Effective Date.

Amends FPA Section 206(b)—

Authorizes FERC to establish the refund effective date in a proceeding as the date on which the complaint was filed. In the case of a proceeding initiated by FERC, the refund effective date is the date on which notice of FERC's intent to initiate the proceeding is published. These provisions would replace the current 60-day waiting period for the refund effective date. If FERC has not made a decision within 180 days of the initiation of a proceeding, FERC must state the reasons why it has failed to do so and state its best estimate as to when it reasonably expects to make a decision.

Section 1286. Refund Authority.

Amends FPA Section 206 by adding a new subsection (e).

(e)(1) For purposes of this subsection, the term "short term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts that are subject to renewal). An "applicable Commission rule" is one applicable to sales by public utilities that FERC determines after notice and comment should also be applicable to the section 201(f) entities under this subsection.

(2) If an entity described in section 201(f)) voluntarily makes a short-term sale of electricity through an organized market in which the rates for the sale are established by FERC-approved tariff and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of such sale, the entity shall be subject to the Commission's refund authority with respect to the violation.

(3) This section does not apply to (A) an entity (including affiliates of the entity) that does not sell more than 8 million megawatt hours of electricity per year or (B) any electric cooperative.

(4) FERC has refund authority with respect to a short term sale by BPA only if the sale is at an unjust and unreasonable rate, and in that event, may order a refund only for short term sales made by BPA at rates that are higher than the highest just and reasonable rates charged by any other entity for a short term sale in the same geographic market or most nearly comparable period as the sale by BPA. With respect to any federal power marketing agency or TVA, FERC shall not exercise any regulatory authority or powers under this subsection other than ordering refunds.

Section 1287. Consumer Privacy and Unfair Trade Practices.

The FTC may issue rules protecting consumer privacy and prohibiting slamming (changing the selection of an electric utility without the consumer's consent) and cramming (the sale of goods and services to an electric consumer without the consumer's consent). If the FTC determines that a state's regulations provide equivalent or greater protection than the provisions of this section, the state regulations shall apply in that state in lieu of the FTC regulations.

Section 1288. Authority of Court to Prohibit Persons from Serving as Officers, Directors, and Energy Traders.
Amends FPA section 314 [Enforcement] by adding a new subsection (d)—
(d) A court hearing an enforcement action brought by FERC may prohibit, conditionally or unconditionally, and permanently or for a time period set by the court, any person who has engaged in practices that violate new FPA section 221 [Filing False Information] from acting as an officer or director of an electric utility or from purchasing or selling electric energy or transmission subject to FERC's jurisdiction.

Section 1289. Merger Review and Reform.
Amends Section 203(a) of the Federal Power Act.
Section 203(a)(1) A public utility must secure FERC approval before it can:

(A) sell, lease or dispose of the whole of its facilities in excess of $10 million (increased from $50,000 under current law);

(B) merge or consolidate such facilities;

(C) purchase or acquire securities of a public utility in excess of $10 million; or

(D) purchase, lease or otherwise acquire an existing generation facility that has a value in excess of $10 million and that is used for interstate wholesale sales subject to FERC's ratemaking jurisdiction.

(2) Prior FERC approval is required before any holding company in a holding company system that includes a transmitting utility or an electric utility may purchase, acquire or take securities in excess of $10 million in value or directly or indirectly merge or consolidate with, a transmitting utility, an electric utility company or another holding company in a holding company system that includes a transmitting utility or an electric utility company with a value in excess of $10 million.

(3) Upon receipt of an application FERC shall give reasonable notice in writing to the governor and state commission of each of the sates in which physical property that is part of the transaction is located.

(4) In order to approve the proposed transaction, FERC must make a finding that it will be consistent with the public interest, and will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless FERC determines that the cross-subsidization, pledge or encumbrance will be consistent with the public interest.

(5) FERC is required to adopt a rule to expedite merger and facility disposition approval. Such rule shall identify the class of transactions or specify criteria for transactions that will normally satisfy the criteria for FERC approval. FERC shall give expedited review to such transactions. FERC must grant or deny any other application within 180 days after the application is filed, and may extend that period an additional 180 days on a finding of good cause, after which it must grant or deny the application.

(b) These amendments to FPA section 203(a) take effect six months after the date of enactment.

(c) Transition Provision—The amendments to FPA section 203(a) shall not apply to any application under section 203 that was filed on or before the date of enactment.

Section 1290. Relief for Extraordinary Violations.
(a) This section applies to any contract entered into in the Western Interconnection prior to June 20, 2001, with a seller of wholesale electricity that FERC has –

(1) found to have manipulated the electricity market resulting in unjust and unreasonable rates, and

(2) revoked the seller's market-based rate authority.

(b) In the case of such a contract, notwithstanding new FPA section 222 [market manipulation], any provision of Title 11, U.S. Code [bankruptcy], or other provisions of law, FERC has exclusive jurisdiction to determine whether a requirement to make termination payments for power not delivered by the seller, or any successor in interest, is not permitted under a rate schedule (or contract under such a schedule) or is otherwise unlawful on the grounds that the contract is unjust and unreasonable or contrary to the public interest.

(c) This section applies to any proceeding pending on the date of enactment of this section involving a seller described in (a) in which there is not a final, nonappealable order by FERC or any other jurisdiction determining the respective rights of the seller.

Subtitle H—Definitions

Section 1291. Definitions. The definitions include:

"Electric utility"—Changes the definition of "electric utility" to add federal power marketing administrations.

Revises definition of "transmitting utility" to include any entity that owns or operates transmission facilities used for transmission in interstate commerce or for the sale of electricity at wholesale. The definition removes the specific reference to "electric utility," which is based on sale of electricity and other specific references to certain entities, such as QFs. The revised definition covers PMAs, munis and coops, as under the current law definition.

"Regional Transmission Organization" or "RTO" means an entity of sufficient regional scope approved by FERC to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce and to ensure nondiscriminatory access to such facilities.

"Independent System Operator" or ("ISO") means an entity approved by FERC to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce and to ensure nondiscriminatory access to such facilities.

"Transmission Organization" means an RTO, ISO, independent transmission provider, or other FERC-approved transmission organization.

Amends FPA Section 201(f) to include electric cooperatives that have RUS financing or that sell less than 4 million MWH per year. This exempts most electric cooperatives from provisions of the FPA, unless it is specifically referenced that the provision applies.

Subtitle I—Conforming Amendments

Subtitle J—Economic Dispatch

Section 1298. Economic Dispatch. (a) Amends the Federal Power Act by adding a new section 223—JOINT BOARDS ON ECONOMIC DISPATCH.

(a) FERC is required to convene joint boards on a regional basis pursuant to FPA section 209 to study the issue of security constrained economic dispatch for the various market region. FERC is to designate the appropriate regions to be covered by each joint board.

(b) FERC is to request each state to nominate a representative for the appropriate regional joint board and is to designate a FERC commissioner to chair and participate as a member of each board.

(c) The sole authority of each joint board is to consider issues relevant to what constitutes "security constrained economic dispatch" and how this mode of operation affects or enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to FERC regarding such issues.

(d) Within one year of enactment, FERC is to submit a report to Congress regarding the recommendations of the joint boards, including any consensus recommendations for statutory or regulatory reform.

ELECTRICITY-RELATED PROVISIONS IN TITLE XVIII – STUDIES

Section 1802. Study of Energy Efficiency Standards. DOE-contracted NAS study of whether energy efficiency goals are best served by measuring site vs. source energy consumption. Due in 1 year.

Section 1804. LIHEAP Report. HHS report on how LIHEAP could be used more effectively to prevent loss of life from extreme temperatures. Due in 1 year.

Section 1812. Backup Fuel Capability Study. DOE study on the effect of having a backup fuel capability at gas-fired generating and industrial facilities, including the effect on the supply and cost of natural gas. Due in 1 year.

Section 1813. Indian Lands Rights-of-Way. DOE-DOI joint 1-year study of issues regarding energy rights-of-way on tribal land. Findings shall include: analysis of historic rates of compensation paid for energy ROW on tribal land; recommendations for appropriate standards and procedures for determining fair and appropriate compensation to tribes; an assessment of tribal self-determination and sovereignty interests; and an analysis of relevant national energy transportation policies. Due in 1 year.

Section 1815. Interagency Review of Competition in the Wholesale and Retail Markets for Electric Energy. Task force including DOJ, FERC, FTC, DOE, and RUS to analyze wholesale and retail electric competition. Due in 1 year. Must consult with states, utilities and the public and provide 60 days for comment on a draft.

Section 1816. Study of Rapid Electrical Grid Restoration. DOE study of benefits of using mobile transformers and substations to rapidly restore electrical service after equipment failure, natural disasters, acts of terrorism, or war. Due in 1 year.

Section 1817. Study of Distributed Generation. DOE, in consultation with FERC, to study potential benefits of cogeneration and small power production and rate impediments. Due in 18 months.

Section 1818. Natural Gas Supply Shortage Report. DOE report on natural gas supply and demand, and make recommendations to bring them into balance. Due in 180 days.

Section 1822. Effect of Electrical Contaminants on Reliability of Energy Production Systems. NAS study of the effect that electrical contaminants (such as tin whiskers) may have on the reliability of energy production systems, including nuclear energy. Contract due in 180 days.

Section 1824. Final Action on Refunds for Excessive Charges. Directs FERC to (1) seek to conclude its California proceedings; (2) seek to ensure that refunds owed to California are paid; and (3) issue a status report to Congress by the end of 2005.

Section 1826. Passive Solar Technologies. DOE study of issues related to the use of passive solar technologies for electricity generation. Due in 120 days.

Section 1829. Energy and Water Savings Measures in Congressional Buildings. Architect of the Capitol study; includes factors related to reliability in the event of power fluctuations, shortages, or outages. Due in 180 days.

Section 1831. Review of Energy Policy Act of 1992 Programs. DOE study and recommendations regarding alternative fueled vehicle provisions of 1992 EPAct. Due in 180 days.

Section 1832. Study on the Benefits of Economic Dispatch. DOE, working with states to study current procedures, possible changes to and potential benefits of revising dispatch procedures to improve ability of non-utility generators to offer their resources. Due 90 days and annually thereafter.

Section 1833. Renewable Energy on Federal Land. National Academy of Sciences study, commissioned by DOI, of potential wind, solar and ocean energy resources on federal land. Contract required in 90 days. Study due in 2 years.

Section 1834. Increased Hydroelectric Generation at Existing Federal Facilities. Joint DOE, DOI study in consultation with Corps of Engineers. Due in 18 months.

Section 1836. Resolution of Federal Resource Development Conflicts in the Powder River Basin. DOE study of conflicts between use of federal coal and all coalbed methane. Due in 180 days.

Section 1839. Transmission System Monitoring. DOE and FERC study of the feasibility of real-time information on functional status of transmission lines in the Eastern and Western Interconnections. Due in 6 months.

Section 1840. Report Identifying and Describing the Status of Potential Hydropower Facilities. DOI report on the status of potential hydropower facilities included in water storage studies undertaken by DOI for projects that have not been completed or authorized for construction; specifies numerous details to be included. Due in 90 days.

ELECTRICITY-RELATED PROVISIONS IN TITLE III—OIL AND GAS

Section 367. Fair Market Value Determinations for Linear Rights-of-Way Across Public Lands and National Forests. Requires that fee schedules be updated within one year, based on the value of the land and pursuant to BLM regulations issued in April 2005.

Section 368. Energy Right-of-Way on Corridors on Federal Land.
Section 368 establishes a 2-year deadline for the designation of corridors for energy facilities in 11 Western states, including completing all environmental reviews and incorporation into relevant land use plans. The Secretaries of Agriculture and Interior are also to develop expedited procedures for designating corridors in the future, as necessary, and for expediting permitting for transmission lines proposed to be sited within a designated corridor.

A 4-year deadline is established for identifying corridors in the other 39 states, including establishing a schedule for action.

Section 372. Consultation Regarding Energy Rights-of-Way on Public Land. This section requires the Secretary of Energy to work with other federal land agencies to complete a memorandum of understanding for coordinating the authorizations for utility facilities, which includes the generation, transmission and distribution of electricity.

Prepared August 3, 2005

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Appendix C

Consolidated List of Recommendations National Transmission Grid Study

Consolidated List of Recommendations

Section 2—The National Interest in Relieving Transmission Bottlenecks

Next Steps Toward Relieving Transmission Bottlenecks

- DOE, through a rulemaking, will determine how to identify and designate transmission bottlenecks that significantly impact national interests.

- DOE will further develop the analytic tools and methods needed for comprehensive analysis to determine national-interest transmission bottlenecks.

- In an open public process, DOE will assess the nation's electricity system every two years to identify national-interest transmission bottlenecks.

Section 3—Relieving Transmission Bottlenecks By Completing the Transition to Competitive Regional Wholesale Electricity Markets

Establishing Regional Transmission Organizations

- RTOs should be responsible for maintaining the reliability of the grid and ensuring that transmission bottlenecks are addressed.

- DOE, with industry, will assess current system monitoring and control technologies that support efficient, reliable, and secure operation of RTOs and coordinate development of a plan for future research and development.

- DOE will work with FERC and stakeholders to develop objective standards for evaluating the performance of RTOs and will collect the information necessary for this assessment.

- DOE will work with the Energy Information Administration (EIA), FERC, National Governors Association (NGA), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), industry, and consumer representatives to determine what economic and reliability data related to the transmission and the electricity system should be collected at the federal level and under what circumstances these data should be made publicly available.

- NGA and NARUC should identify state laws that could hinder RTO development.

- DOE will review federal laws that may prevent PMAs from full participation in RTOs, direct them to participate in the creation of RTOs, and take actions to facilitate their joining RTOs.

- DOE will work with TVA to help it address any issues that inhibit its participation in wholesale competitive markets, including full participation in an RTO.

Increasing Regulatory Certainty and Focus

- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate statebased organizations to promote innovative methods for recovering the costs of new transmissionrelated investments. These methods should consider situations where rate freezes are in effect and also examine incentive regulation approaches that reward transmission investments in proportion to the improvements they provide to the system.

- DOE will research and identify performance metrics and evaluate designs for performance-based regulation.

- The Department of Treasury should evaluate tax law changes related to electricity modernization. Treasury should review its current regulations regarding the application of private use limitations to facilities financed with tax exempt bonds in light of dynamics in the industry and proceed to update and finalize its regulations. This will give greater certainty to public power authorities providing open access to their transmission and distribution facilities.

- Entrepreneurial efforts to build merchant transmission lines that pose no financial risk to ratepayers and that provide overall system benefits should be encouraged.

- DOE and the Department of Treasury will evaluate whether tax law changes may be necessary to provide appropriate treatment for the transfer of transmission assets to independent transmission companies.

Section 4—Relieving Transmission Bottlenecks Through Better Operations

Pricing Transmission Services to Reflect True Costs

- DOE, working with FERC, will continue to research and test market-based approaches for transmission operations, including congestion management and pricing of transmission losses and other transmission services.

Increasing the Role of Voluntary Customer Load Reduction, and Targeted Energy Efficiency and Distributed Generation

- DOE will work with FERC, the states, and industry and conduct research on programs and technologies to enhance voluntary customer load reduction in response to transmission system emergencies and market price signals.

- DOE will work with states and industry to educate consumers on successful voluntary load-reduction programs. DOE will disseminate information on successful approaches and technologies.

- DOE will continue to work with NGA, regional governors' associations, and NARUC to remove regulatory barriers to voluntary customer load-reduction programs, and targeted energy-efficiency and distributed-generation programs that address transmission bottlenecks and lower costs to consumers.

- IEEE should expeditiously complete its technical interconnection standards for distributed generation.

- DOE will work with NGA and NARUC to develop and promote the adoption of standard interconnection agreements, rules, and business procedures for distributed generation.

Using Improved Real-Time Data and Analysis of Transmission System Conditions

- DOE will work with industry to demonstrate and document cost-effective uses of dynamic transmission system analysis.

Ensuring Mandatory Compliance with Reliability Rules

- Federal legislation should make compliance with reliability standards mandatory.

- Current reliability standards should be reviewed in an open forum to ensure that they are technically sound, nondiscriminatory, resource neutral, and can be enforced with federal oversight.

- Penalties for noncompliance with reliability rules should be commensurate with the costs and risks imposed on the transmission system, generators, and end users by noncompliance. Penalties collected should be used to reduce rates for consumers.

- DOE will work with industry and NARUC to promote development and sharing of best transmission and distribution system operations and management practices.

- DOE will work with FERC, state PUCs, and industry to ensure the routine collection of consistent data on the frequency, duration, extent (number of customers and amount of load affected), and costs of reliability and power quality events, to better assess the value of reliability to the nation's consumers.

Section 5—Relieving Transmission Bottlenecks Through Effective Investments

Implementing Regional Transmission Planning

- DOE will work with the electricity industry and state and federal regulators to identify the type of electricity system data that should be made available in the planning process to facilitate the development of market-based transmission solutions and devise a process for making that information available.

Accelerating the Siting and Permitting of Needed Transmission Facilities

- FERC and DOE should work with states, pertinent federal agencies, and Native American tribes to form cooperative regional transmission siting forums to develop regional siting protocols.

- Utilities and state utility commissions should develop an inventory of underutilized rights of way and space on existing transmission towers. DOE will work with PMAs and TVA to conduct a comparable evaluation.

- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate statebased organizations to develop a list of "best practices" for transmission siting.

- DOE will undertake demonstration programs to support the use of innovative approaches to transmission planning and siting (e.g., open planning processes, consideration of a wide range of alternatives, incorporation of innovative or uncommonly employed technologies, use of alternative mitigation measures, etc.).

- Federal agencies should be required to participate in regional siting forums and meet these forums' deadlines for reviews or complete reviews within 18 months, whichever occurs first.

- All federal agencies with land management responsibilities or responsibilities for oversight of non-federal lands should assist FERC-approved RTOs in the development of transmission plans.

- Congress should grant FERC limited federal siting authority that could only be used when national-interest transmission bottlenecks are in jeopardy of not being addressed and where regional bodies have determined that a transmission facility is preferred among all possible alternatives.

- The Council on Environmental Quality should continue to coordinate efforts with the Secretary of the Interior, Secretary of Energy, Secretary of Agriculture, Secretary of Defense, and Administrator of the EPA to ensure that federal permits to construct or modify facilities on federal lands are acted upon according to timelines agreed to in any FERC-approved regional protocol. The agencies should work together to re-evaluate the development of transmission corridors across federal lands and identify the current and potential future use of existing transmission corridors on federal lands.

Ensuring the Timely Introduction of Advanced Technologies

- DOE will work with NARUC to develop guidance for state regulators and utilities on evaluating the risks of investment in innovative new technologies that advance public interests. These guidelines will help determine when a technology is a reasonable performance risk and how to weigh the costs and benefits of using a new versus an established technology.

- The PMAs and TVA should maintain their leadership of demonstration efforts to evaluate advanced transmission-related technologies that enhance reliability and lower costs to consumers

- DOE will develop national transmission-technology testing facilities that encourage partnering with industry to demonstrate advanced technologies in controlled environments. Working with TVA, DOE will create an industry cost-shared transmission line testing center at DOE's Oak Ridge National Laboratory (with at least a 50% industry cost share).

- DOE will accelerate development and demonstration of its technologies, including high-temperature superconductivity, advanced conductors, energy storage, real-time system monitoring and control, voluntary load reduction technologies and programs, and interconnection and integration of distributed energy resources.

- DOE will work with industry to develop innovative programs that fund transmission-related R&D, with special attention to technologies that are critical to addressing transmission bottlenecks.

Enhancing the Physical and Cyber Security of the Transmission System

- DOE will work with industry to evaluate the feasibility of adopting modular designs and standards for substation and other transmission equipment to facilitate rapid replacement.

- DOE and the national laboratories will continue to develop cost-effective technologies that improve the security of, protect against, mitigate the impacts of, and improve the ability to recover from disruptive incidents within the energy infrastructure.

- DOE will continue to develop energy infrastructure assurance best practices through vulnerability and risk assessments.

- DOE will work with industry to evaluate the costs and benefits associated with maintaining a reserve supply of transmission equipment that is funded by transmission rates. This reserve would be a resource in case of major outages resulting from terrorism or natural disasters.

- DOE will continue to work with industry to promote education and awareness in the industry about critical transmission infrastructure issues.

- DOE will continue to work closely with industry on implementation plans that respond to attacks on our transmission infrastructure.

- DOE will continue to provide training in critical infrastructure protection matters and energy emergency operations to state government agencies and to private industry.

- DOE will study the Eastern and Western AC Interconnections to assess the costs and benefits, including impacts on national security, of a series of smaller interconnections that are electrically independent of one another with DC links between them.

- DOE will work with industry and the states to develop standardized security guidelines to help reduce the cost of facility protection and facilitate consequence management.

Section 6—DOE's Commitment and Leadership

- DOE will create an Office of Electric Transmission and Distribution.

Appendix D

LEPA Response to Notice of Inquiry For NIETC Designation and Request For Early Designation

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors	Notice of Inquiry

COMMENTS OF THE
LOUISIANA ENERGY AND POWER AUTHORITY
AND LAFAYETTE UTILITIES SYSTEM

The Louisiana Energy and Power Authority ("LEPA") and the Lafayette Utilities System ("LUS") appreciate this opportunity to respond to the Department of Energy's Notice of Inquiry, "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," which was published in the Federal Register on February 2, 2006. 71 Fed. Reg. 5660. These comments are submitted in conjunction with the Comments of the Transmission Access Policy Study Group also being submitted to the Department of Energy in this proceeding ("TAPS Comments"). LUS is a member of TAPS and supports the TAPS Comments. LEPA and LUS agree with those TAPS comments, but wish to add specific factual material to this record, as the TAPS comments have suggested will be done by TAPS members and others. The NOI as issued spells out:

> ***In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.*** If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early

> designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

I. DESCRIPTION OF THE PARTIES

A. Louisiana Energy and Power Authority

LEPA is a joint action agency created by the State Legislature in 1979. LEPA presently consists of eighteen (18) Louisiana cities and towns, each of which maintains its own independent municipal power system. The LEPA member communities are: Abbeville, Alexandria, Erath, Houma,[1] Jonesville, Kaplan, Lafayette, Minden, Morgan City, Natchitoches, New Roads, Plaquemine, Rayne, St. Martinville, Vidalia, Vinton, Welsh, and Winnfield, Louisiana. LEPA operates a NERC-certified (and SPP-certified) control area for its Pool Members, which are Houma, Morgan City, New Roads, Plaquemine, Rayne, Vidalia, Welsh and Winnfield, Louisiana. Some of these members (Houma and Morgan City) are within the congested Amite South region and others are within the congested West of the Atchafalaya Basin ("WOTAB") region. LEPA is also a member of the Southwest Power Pool ("SPP"), and participates in the SPP reserve sharing pool. LEPA has no transmission resources of its own. LEPA and several of its members are engaged in the generation, transmission and distribution of electric power and energy at wholesale, and the individual communities also distribute power and

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[1] Houma is also referred to as the Terrebonne Parish Consolidated Government.

energy at retail. The LEPA member communities are transmission dependent utilities on the transmission systems operated by Entergy Systems Inc. (“Entergy”) or Cleco Power LLC (“Cleco”) (or both, in the case of Lafayette).

LEPA’s 2006 Pool Member load is estimated to be approximately 216 MW, and the reserves required to meet SPP reserve sharing and operational obligations mean that LEPA is required to provide approximately 248 MW of capacity to meet that load.

B. Lafayette Utilities System

LUS is a 108 year old municipal utility serving the City and certain areas of the Parish of Lafayette, Louisiana. LUS serves a peak load within the City and Parish of approximately 430 MW which includes more than 55,000 retail customers. Although LUS is a member of LEPA, LUS has formed its own NERC-certified (and SPP-certified) control area. LUS constructed, operates, and maintains its entire transmission and distribution system and all generation resources within Lafayette. The LUS owned generation portfolio includes a 50% ownership in the Rodemacher Coal Unit in Boyce, Louisiana. LUS also owns a substantial amount of gas-fired generation, including the Louis “Doc” Bonin Generating Station which has a nameplate capacity of 325 Megawatts and the T. J. Labbé Power Plant which has a nameplate capacity of 100 Megawatts. LUS’s transmission system consists of 14 miles of 230 kV and 25 miles of 69 kV facilities. LUS has numerous interconnections with Cleco and Entergy, forming the single largest interconnection between the Entergy and Cleco systems.

C. Communications

LEPA and LUS request that all communications relating to this proceeding be directed to the following individuals, whose names should be included on the official service list for this proceeding:

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Mr. Stephen C. Pearson[2]
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II. COMMENTS

The experiences of LEPA and LUS provide specific factual examples that demonstrate the general points raised by TAPS. Moreover, because NIETC listing will help speed up planning and construction, and since it also appears clear that on both a

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[2] E-mail may be addressed to: robert.mcdiarmid@spiegelmcd.com, lisa.dowden@spiegelmcd.com and steve.pearson@spiegelmcd.com.

[3] E-mail may be addressed to: grandca@lepa.com.

short- and long-term basis the existing problems in Louisiana meet Draft Criteria 1 (reliability), 2 (economic benefit for consumers), 3 (action needed to ease supply limitations in corridor), 5 (action would further the national energy policy of wholesale competition), and 6 (action is needed to enhance the reliability of electric supply to critical loads and infrastructure), LEPA and LUS respectfully request that the constraints in the Entergy and Cleco grid, including the constantly constrained Webre – Wells line, which limit the ability of entities like LEPA and LUS to import power be included as a part of the NIETC listings.

A. Incumbent Transmission Owners have starved the grid of investment to forestall competition

1. Requests for transmission are not met.

As noted above, LEPA and LUS are transmission dependent utilities on the transmission systems operated by Entergy and Cleco. The transmission system maintained by Entergy and Cleco is simply inadequate to sustain competition, much less encourage new competition. Both LEPA and LUS have found that transmission is simply not available to them for purposes of long-term planning to minimize costs. Moreover, in some instances transmission is simply not available. In order for transmission to be made available, LEPA has been asked to pay for millions of dollars in upgrades that are far distant from the path transmitted power would take. Making matters worse, LEPA and LUS are not offered the opportunity to own those upgrades.

In a recent filing in Federal Energy Regulatory Commission ("FERC") Docket No. TX06-1-000, LEPA filed an emergency request asking that FERC order Entergy and

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[4] E-mail may be addressed to: fledoux@ieee.org and rwgary@ieee.org.

Cleco provide transmission service.[5] LEPA believes there is imminent danger that, due to the transmission constraints in Louisiana, LEPA will not be able to meet SPP control area reliability standards this summer if the Commission does not grant LEPA's request for transmission service.

LEPA's battles began well over a year ago. Anticipating the end of a power supply arrangement between LEPA and LUS, LEPA began negotiating with potential power suppliers and began utilizing Entergy's and Cleco's procedures to attempt to find transmission to deliver network resources to LEPA's network load. LEPA began its search for transmission with a January 5, 2005 Network Integration Transmission Service ("NITS") application for a 26 MW request from the Occidental Chemicals Taft Qualifying Facility ("Oxy Taft") (near Hahnville, Louisiana) to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy System Impact Study ("SIS"), LEPA would need to pay approximately $71.5 million for upgrades to enable this transaction. A copy of the Oxy Taft SIS is attached as Exhibit 1.

With this negative result, LEPA requested assistance from Entergy. Entergy directed LEPA to the Entergy "Scenario Analyzer" to determine whether there was available transmission service from Entergy or Cleco from any resource. LEPA tried every known generation resource that had been identified by Entergy or Cleco as competitive generation. The Entergy Scenario Analyzer reported that, for each resource, there was no available transmission to reach LEPA. When this result was brought to the attention of Entergy transmission personnel, they suggested that a formal application be

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[5] The filing is available from FERC's website, eLibrary accession no. 20060217-5054.

made, since that formal application would trigger a more sophisticated study process, and it might turn out that transmission would be available. Accordingly, LEPA made several NITS applications. In making these applications, LEPA recognized that the Entergy system experienced significant east-to-west congestion, so LEPA's applications attempted to utilize a west-to-east flow under the assumption that the counterflow would alleviate congestion. But LEPA did not achieve better results with these applications than its earlier Oxy Taft application. LEPA received the following negative reports:

- No available capacity for a small expansion (from 6 MW to 13 MW) of existing transmission service from the Southwestern Power Administration ("SWPA"). The only available capacity was the rollover of the existing 6 MW transaction. According to Entergy's SIS, LEPA would need to pay approximately $39.5 million for upgrades to enable the additional 7 MW. Exhibit 2.
- No available capacity for a 45 MW request from the Entergy system to LEPA member Morgan City, Louisiana. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $103 million for upgrades to enable this transaction. Exhibit 3.
- No available capacity for a 150 MW request from the Dynegy Calcasieu facility (near Sulphur, Louisiana) to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $64 million for upgrades to enable this transaction. Exhibit 4.

- No available capacity for a 150 MW request from the Exxon Mobil facility near Beaumont, Texas to the LEPA control area. Entergy reported that it did not have available transmission capacity. According to the Entergy SIS, LEPA would need to pay approximately $70.3 million for upgrades to enable this transaction. Exhibit 5.

In other words, Entergy has made so little investment in its transmission system that it could not even grant a 7 MW request for transmission.

LEPA also has not had success with a NITS application filed with Cleco. To serve the Morgan City load, LEPA also requires transmission from Cleco. As a result, LEPA filed a 45 MW request with Cleco that paralleled the 45 MW request to Entergy. In the ensuing SIS (Exhibit 6) and Facilities Study (Exhibit 7), Cleco reported that it did not have available transmission capacity. While Cleco does not there assert that network upgrades are necessary, Cleco reports that some voltage support and metering are necessary, and conditions its study on the grant of transmission capacity for this purpose by Entergy. Further, Cleco apparently has only planned for imports of 21 MW to Morgan City. Cleco's lack of planning is completely inconsistent with the fact that it has received annual Morgan City load forecasts – the most recent of which reported an expected peak load of 41.8 MW. Cleco also has known that existing generation in Morgan City is very near retirement, very expensive to run, and, consistent with prudent utility practice, should only be run in block mode in emergencies. Cleco's lack of planning is even more incomprehensible as one of the underlying premises of the Cleco-LEPA interconnection agreement is anticipation of load growth. Thus, LEPA's experience has been as a victim of incumbent utilities' transmission systems with little or no excess capability.

The lack of transmission to Morgan City should raise serious alarms within the Department of Energy. The same inadequate lines that serve Morgan City also serve the Louisiana Offshore Oil Port, off the shore of Fourchon, Louisiana. Since LOOP handles approximately 15% of the Nation's oil import needs, one would think that national security considerations, if nothing else, would have long since called for an upgrade of those lines.[6]

LUS also has had difficulty obtaining reliable transmission service for its power supply resources. For example, LUS has found it increasingly difficult to access power from its share of the Rodemacher coal plant despite the fact that it pays Cleco $4.5 million per year for "firm" transmission service. Because of conditions on the Entergy system, LUS has been faced with repeated and increasing demands[7] that it bring up more expensive peaking units in Lafayette in order to solve congestion problems on the Entergy system that generate calls for Transmission Loading Relief ("TLR") curtailments and that result in LUS having to back down its Rodemacher power output. When these curtailments have occurred, LUS customers must pay more to run the expensive peaking generation to serve LUS native load customers, even though it is Entergy that needs the change to reliably serve its own loads. LUS receives no compensation for these repeated redispatch demands. Although Entergy claims that it must also redispatch its generation

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[6] *See* http://www.dotd.louisiana.gov/programs_grants/loop/loop.shtml.

[7] Though the requests often come through the SPP, LUS understands that they are initiated by Entergy calls on SPP .

units during such transmission curtailments, there is no independent market monitor or grid operator who can confirm that this is the case. Moreover, Entergy is well aware that the financial impact for Lafayette to redispatch its generation units is several orders of magnitude greater than the financial impact to Entergy.

Although transmission upgrades at the Wells substation largely financed by CLECO have resolved some of the TLR issues, those upgrades were developed to resolve issues on both the CLECO and Entergy systems and to facilitate the purchases by both Entergy and CLECO from the Acadia Project.[8] Specifically, the upgrade makes it possible for CLECO to purchase 500 MW of low heat rate, combined cycled electric power from the plant and substantially relieve the loading on Entergy 138 kV circuits coming from the Richard substation.

Perhaps more disturbing to LUS than the fact that Entergy transmission is not available, Entergy and Cleco have both leaned heavily on the LUS system. There are very significant loop flows through Lafayette's transmission system because it is the strongest connection between Cleco and Entergy. In addition, in recent market based rate filings ("MBR"), Cleco has reported data that indicates that, at certain times, there is negative available transmission capacity into the LUS service territory.[9] There can be no

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[8] The Acadia Project is a Cleco/Calpine joint venture consisting of gas-fired combustion turbines interconnected at the Richard substation. LUS understands that when the Acadia Project interconnection was modeled, Entergy erroneously assumed LUS generation used only at extreme peaks would be run around the clock. Entergy never contacted LUS prior to performing its study. Instead, Entergy has simply assumed the LUS generation would run. Thus, Entergy forced LUS ratepayers to subsidize Entergy ratepayers in that the LUS ratepayers must pay for generation that is nearly four times as expensive as the Rodemacher generation on which LUS ratepayers had relied since 1979. Entergy never compensated LUS ratepayers.

[9] *See, e.g.*, Cleco Compliance Filing, Commission Docket No. ER03-1368-002, *et al.*, (June 23, 2005), Affidavit of Paul H. Raab, at 3 (eLibrary Accession No. 20050629-0265).

clearer evidence that action is needed to bolster the grid. Yet neither Cleco nor Entergy are acting to solve the transmission constraints into and around Lafayette.

Because of the lack of transmission capacity, Both LEPA and LUS have been unable to access generation that Entergy has boasted exists in the region. While Entergy proclaims that there are 17,000 MW of IPP facilities in its region,[10] LUS has built and is building its own combustion turbines internal to its own system because it cannot access transmission. To provide an extreme example of the inability to obtain reliable transmission service, LUS considered purchasing the financially distressed NRG generator located in Bayou Cove, a mere 40 miles from Lafayette. LUS's transmission studies showed that, given the lack of capacity in the Entergy system, delivery from the NRG plant would be subject to curtailments in Entergy's frequent TLRs. As a result, LUS did not pursue the acquisition.

As a final indication of the remarkable lack of capacity on the Entergy transmission system, LUS data show that it, via its agent the Energy Authority, made 2359 transmission requests of Entergy between January 2002 and January 2005.[11] Only 1209, just over half, of those requests were accepted and confirmed. The large number of requests reflects the inability of LUS to perform long-term risk management and planning caused by the lack of available transmission. Further, the lack of requests that have been granted amount to economical purchases that were not made. The bottom line is that

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[10] Response of Entergy Services Inc. to the Written and Oral Statements of Terry Huval on Behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, RM04-7-000, at 15 (March 15, 2005) (eLibrary accession no. 20050315-5044). It isn't clear whether the 17,000 MW includes Entergy's purchase at fire sale prices of distressed IPP facilities such as the Perryville Energy Partners' facility or the Attala facility – which facilities used to amount to over 1,000 MW of IPP power. The alarming bankruptcies of IPPs in Louisiana is discussed *infra*.

[11] LUS has not yet compiled these data for the 2005 calendar year.

Entergy and Cleco know that the transmission system lacks sufficient capacity but are unwilling to do what is necessary to provide a robust transmission system that will lead to healthy, competitive power supply markets that will benefit retail ratepayers other than those of Entergy and Cleco.

2. The same transmission upgrades appear in many SISs.

In reviewing the SISs Entergy provided to LEPA following LEPA's NITS applications, LEPA noticed that the same multi-million dollar upgrades appeared time and time again. Digging deeper, LEPA reviewed 167 SISs from January 2005 through January 2006 that are publicly available on the Entergy OASIS website.[12] LEPA's review demonstrated that each of the limiting elements from the SISs Entergy provided in response to LEPA NITS requests appeared in many other requests. Moreover, LEPA's review is conservative because many SISs are not available on the Entergy website. For example, the LEPA requests themselves were not available on the website. The following table shows the number of other SISs on which a limiting element on an SIS prepared for LEPA appeared as a limiting or contingency element (or both) on an SIS prepared for another entity:

[12] http://oasis.e-terrasolutions.com/documents/EES/studies1.html

Element	Instances
Belle Helene - Licar 230kV	10
Belle Helene - Woodstock 230kV	10
Bonin - Cecelia 138kV	2
Bull Shoals - Bull Shoals SPA 161kV	13
Champagne - Krotz Spring 138kV	34
China Bulk - Sabine 230kV	17
Colonial Academy - Acadia GSU 138 kV	3
Colonial Academy - Richard 138 kV	6
Conroe Bulk - Plantation 138kV	10
Fairview - Gypsy 230kV	25
Dayton Bulk - Cheek 138kV	4
Dayton Bulk - New Long John 138kV	4
Georgetown - Helbig 230kV	14
New Long John - Tarking 138kV	4
Gibson - Humphrey 115kV	37
Gibson - Ramos 138kV	23
Gibson 138/115kV transformer	5
Greenwood - Humphrey 115kV	37
Greenwood - Terrebone 115kV	38
Habetz - Richard 138kV	9
Line 642 Tap - Krotz Springs 138kV	17
Livonia - Line 642 Tap 138kV	36
Livonia - Wilbert 138kV	38
North Crowley - Richard 138kV	10
North Crowley - Scott 138kV	15
Richard - Scott 138kV	16
Terrebone 230/115kV transformer	24
Vulchlor - Woodstock 230kV	10
Webre - Wells 500kV	41

When the same transmission elements are listed as overloading in connection with that many different transmission requests, it becomes obvious that the Entergy "backbone" transmission system has become seriously deficient due to a lack of investment by Entergy dating back many years. As there is no certainty as to when these upgrades might be incorporated as part of a transmission plan, much less completed, it is clear that action is needed immediately to ease electricity supply limitations in end markets and incumbent transmission owners are unwilling or unable to take the needed action.

3. Independent Power Producers have been strangled in Louisiana

The Entergy Weekly Procurement Process ("WPP") which Entergy uses to buy power from independent producers has established all the ingredients to poison the IPP market. The WPP serves only Entergy's needs. Thus, suppliers, attracted by Entergy's far greater needs, will bid their capacity into that auction. LEPA and LUS are thus not only barred from the WPP, but those sellers who participate in WPP cannot offer the capacity elsewhere until they know the results of the WPP. And, of course, there would still be the problem of getting transmission for any individual sale to LEPA or LUS, while winning WPP bids receive transmission service to deliver to Entergy loads (Entergy backs down more expensive generation that it would otherwise be forced to utilize to provide for the WPP purchases). Entergy thus soaks up this capability on its own system, while providing no access to regional markets.

Because Entergy is the only buyer in the WPP energy market, Entergy effectively gets the value of the IPP generation (especially knowing that sellers are unlikely to be able to sell to anyone else if Entergy does not select them in the WPP) without contracting for the capacity. This structure keeps Entergy's purchased power costs low, but it also causes financial problems for the IPPs, some of whom have been unable to service their debts on the units and have entered bankruptcy or restructuring. Without adequate recovery, the units must often be sold off cheaply – and Entergy is a willing buyer for such financially distressed units.

LEPA and LUS are aware of two formerly independent power producers in their region which have been swallowed by Entergy. Entergy Mississippi recently received final approval from the Mississippi Public Service Commission to purchase the Attala County, 480 MW combined-cycle generating facility from Central Mississippi Generating Co. LLC. Central Mississippi had bought the plant in a foreclosure sale. Entergy boasted in its press release that the acquisition price of $88 million was "a price far below what it would cost to construct a similar facility."[13] LEPA notes that this entire 480 MW generator cost Entergy less than the $103 million upgrade Entergy has claimed is necessary to move 45 MW to Morgan City. Entergy has also stated that it will spend $20 million in facility upgrades for the Attala plant, presumably in substantial part on strengthening the transmission system.[14] Entergy has boasted that the total cost per kW of this acquisition, including upgrades and transaction costs, is $231 per kW.[15] By way of comparison, the transmission line upgrade costs alone for LEPA's 150 MW NITS applications were almost double that per kW cost for the Dynegy facility and more than double that amount for the Exxon Mobil facility. In addition, LEPA presumes the portion of the $20 million in facility upgrades related to transmission will be rolled into Entergy transmission rates. In contrast, the improvements Entergy claims are necessary so that LEPA has access to IPP power will not.

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[13] Press Release, Entergy Services, Inc, Entergy Mississippi Approved to Purchase Attala Generating Plant (Jan. 23, 2006).

[14] Press Release, Entergy Services, Inc, Entergy and Central Mississippi Generating Company, LLC Reach Agreement for Purchase of Attala Power Plant (March, 17, 2005).

[15] *See, e.g.,* Press Release, Entergy Services, Inc, Entergy and Central Mississippi Generating Company, LLC Reach Agreement for Purchase of Attala Power Plant (March, 17, 2005).

Another example of the unhealthy IPP market is Perryville Entergy Partners LLC.[16] Perryville operated a 562 MW combined cycle gas-fired generator and a 156 MW simple cycle gas-fired generator. Following Perryville's 2003 bankruptcy filing, Entergy Louisiana acquired the Perryville generator for $170 million.[17] Entergy's purchase price amounted to 50 cents on the dollar. After acquiring the former Perryville plant, Entergy committed to upgrade its transmission system to enable the plant to be a network resource.[18] The post-acquisition Entergy transmission upgrades strongly suggest that insufficient transmission could be obtained to operate the plant and that the lack of transmission contributed to the Perryville bankruptcy.

When LUS raised these complaints previously, Entergy did not even recognize that a problem exists. Because Entergy has created a situation where it has access to cheap power, in its view there is no problem. Entergy has stated:

> These 17,000 MW [of IPP generation] are in addition to the approximately 23,000 MW of generating resources of the Entergy Operating Companies that are available to supply the Operating Companies' approximately 22,000 MW of peak load. Although these merchant generators generally did not consult with Entergy to determine when, or whether, the generation being built would present an economic alternative to supply Entergy's native load, the resulting excess generating capacity has presented

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[16] Perryville was a subsidiary of Cleco.

[17] Press Release, Entergy Services, Inc, Entergy and Cleco Reach Agreement for Purchase of Perryville (Jan. 28, 2004).

[18] *Entergy Louisiana, Inc. and Entergy Gulf States, Inc.*, Louisiana Public Service Commission Order No. U-27836, slip op. at 9 (April 20, 2005).

> opportunities for many buyers to purchase energy that can increase savings to their customers. *In short, with the glut of generation in the Entergy region, there should be no surprise that energy prices are low.*[19]

In other words, it isn't Entergy's fault that generation lacks access to transmission, it is the victims' fault. Of course, Entergy does not explain why intelligent business people would loan and spend hundreds of millions of dollars on generation investment without assurances of the availability of transmission. But the real question is, "If there is such a glut and prices are so low, why is it that only Entergy has access to the cheap power?"

Action is needed to create a healthy transmission system with adequate capacity such that IPPs may compete for customers and so that customers have a choice in suppliers. The incumbent transmission owners have not proved up to the task. LEPA and LUS urge the Department of Energy to take action that will enable and encourage the construction of a robust transmission system in Louisiana and ongoing expansion to maintain the integrity of the transmission system.

B. End-users are denied access to lower cost power supply because of constraints

The preceding discussion demonstrates that the transmission system in Louisiana is insufficient to move power. LEPA cannot get access to economical bulk power supplies without millions of dollars of upgrade costs. LEPA cannot even get access to a small, 7 MW increase in transmission to access its entitlement to SWPA power. LUS cannot get transmission access to a power plant 40 miles away. LUS cannot even fully

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[19] Response of Entergy Services Inc. to the Written and Oral Statements of Terry Huval on Behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, RM04-7-000, at 15 (March 15, 2005) (e-Library accession no. 20050315-5044) (emphasis supplied).

utilize its own generation for which it pays for firm transmission. Action is needed to ensure that end users have access to lower cost power supplies.

C. NIETC designations should encourage entities in addition to incumbent TOs to invest

In Louisiana, one of the major barriers to entities other than the incumbent TOs investment is the lack of ownership rights. As noted above, LEPA has been told that it would be responsible for paying for substantial backbone upgrades to the grid. But Entergy has informed LEPA that it would not own those backbone upgrades. Instead, Entergy would own the upgrades. In Entergy's view, LEPA is also not generally entitled to any repayment for those backbone upgrades to the grid. Instead, LEPA "would be eligible for transmission credits only for upgrades that are for service that creates new transmission revenue."[20] In Entergy's "participant funding" view of the world, Entergy seems to believe it is LEPA's obligation to pay for the network upgrades that Entergy has neglected to perform, and that LEPA should be stalled until Entergy receives the authority it has sought based on an Independent Coordinator of Transmission ("ICT") proposal now before FERC. Action needs to be taken to change the status quo and facilitate the necessary investment to restore the grid in Louisiana to a condition that promotes competition and enables all end-users to benefit.

As additional evidence that action is needed, in the wake of the devastation of Hurricanes Katrina and Rita, LUS and others have offered assistance to Entergy to rebuild and expand the transmission system. LUS's only request is that it receive ownership rights in what it pays to build. As other entities own major transmission lines

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[20] Letter from Dennis Broussard, Entergy, to Kevin W. Bihm, LEPA, (May 20, 2005 [sic, Oct. 18, 2005]), at 2 ("Oct. 18 Entergy Letter") (attached as Exhibit 8).

in the Entergy service area (for example, Cleco owns a portion of the 500 kV Hartburg to Mount Olive transmission line), LUS's request is not unreasonable. To this date, however, LUS has only been successful at getting Entergy to the point of initial discussions without much apparent hope that anything fruitful will result.

D. Comment on Question: "Should the Department distinguish between physical congestion and contractual congestion, and if so, how?

LEPA and LUS agree with TAPS comments that both physical and contractual congestion can impose costs that could qualify an area as an NIETC. Specific to the Entergy system, it appears that contractual congestion may be one of the biggest obstacles to entities gaining access to new network resources. Entergy's own documentation states explicitly that "Entergy Transmission utilizes a 'contract path' approach in determining ATC."[21] Moreover, while the above discussed SISs prepared for LEPA were performed prior to Hurricanes Katrina and Rita and Entergy has not provided the follow-up Facilities Studies, LEPA has no reason to believe the results which Entergy would report would be any different now, even after the exodus of load from the Entergy service territory.[22] Thus, if the NIETC is to be a solution for Louisiana, it must allow for

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[21] Calculation Of TTC/ATC Within The Entergy Control Area, at 1, available for download at: http://www.entergy.com/content/Operations_Information/transmission/Calculation_of_TTC_ATC_Within_the_Entergy_Control_Area.pdf

[22] *See, e.g.*, Entergy Corporation and Subsidiaries, Quarterly Report (Form 10-Q), (Sept. 30, 2005) (estimating that 36,000 customers of Entergy Louisiana and 87,000 customers of Entergy New Orleans are unable to receive electric and gas service, noting a third quarter decrease of 160 GWh of retail sales by EGSI as compared to 2004, noting a third quarter decrease of 482 GWh of retail sales by ELI as compared to 2004, and noting third quarter decrease of 522 GWh of retail sales by Entergy New Orleans as compared to 2004); Gordon Russell, *Comeback in Progress*, TIMES-PICAYUNE (NEW ORLEANS), Jan. 1, 2006 (citing estimates by Entergy New Orleans officials that 35% of electric power customers were back on-line); Mary O'Driscoll, *Entergy Seeking Lost Revenue in Hurricane Aid Bill*, ENVIRONMENT & ENERGY DAILY (October 5, 2005) (reporting that "Entergy reports that 156,300 of its roughly 190,000 customers in and around New Orleans still cannot receive power.").

siting in areas where contractual congestion is an obstacle to end-users access to economical network resources.

III. CONCLUSION

LEPA and LUS believe that NIETC listing will help speed up planning and construction. Based on the above criteria, LEPA and LUS have shown that there are serious reliability problems in Louisiana. Not only have TLRs prevented LUS from using its own generation using its supposedly "firm" transmission service, but LEPA has just recently filed an emergency petition with FERC out of concern for its ability to meet SPP control area reliability standards this summer. Thus, Draft Criteria 1 is met. It should also be clear that the lack of transmission is preventing LEPA and LUS from accessing economical power, whether that power is IPP power or entitlements to federal SWPA power. Thus, NIETC listing will enable economic benefit for consumers. (Draft Criteria 2). As can be seen from the frequency with which the same problems appear over and over again with no plan in place to correct those problems, action is needed to ease supply limitations. (Draft Criteria 3). As IPPs are currently being strangled by the lack of transmission access and Entergy is acquiring former IPPs, it should be clear that action would further the national energy policy of wholesale competition. (Draft Criteria 5). Finally, the same inadequate lines that serve LEPA member Morgan City also serve the terminal for 15% of the nations oil imports. Action is needed to enhance the reliability of electric supply to this critical load and infrastructure. (Draft Criteria 6). For all of the foregoing reasons, LEPA and LUS respectfully requests that the constraints in the Entergy and Cleco grids which limit the ability of entities like LEPA and LUS to import power be included as a part of the NIETC listings.

Respectfully submitted,

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March 6, 2006

Appendix E

National Electric Transmission Congestion Study Executive Summary

NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

EXECUTIVE SUMMARY

AUGUST 2006

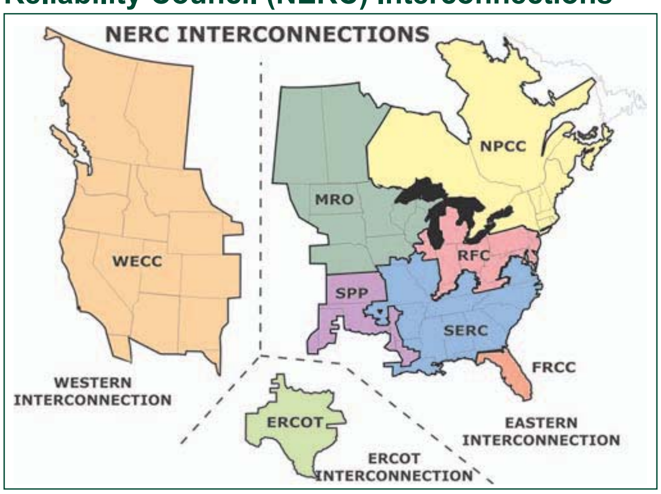
U.S. Department of Energy

Executive Summary

Section 1221(a) of the Energy Policy Act of 2005 amended the Federal Power Act (FPA) by adding a new section 216 to that Act. FPA section 216(a) directed the Secretary of Energy to conduct a nationwide study of electric transmission congestion[1] by August 8, 2006. Based upon the congestion study, comments thereon, and considerations that include economics, reliability, fuel diversity, national energy policy, and national security, the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor." The national congestion study is to be updated every three years.

This document is the Department of Energy's first congestion study in response to the law. It examines transmission congestion and constraints and identifies constrained transmission paths in many areas of the Nation, based on examination of historical studies of transmission conditions, existing studies of transmission expansion needs, and unprecedented region-wide modeling of both the Eastern and Western Interconnections. (See Figure ES-1 for a map showing these interconnections.)

Figure ES-1. Map of North American Electric Reliability Council (NERC) Interconnections



Source: NERC, 2006.

With the publication of this study, the Department of Energy (Department, or DOE) expects to open a dialogue with stakeholders in areas of the Nation where congestion is a matter of concern, focusing on ways in which congestion problems might be alleviated. Where appropriate in relation to these areas, the Department may designate national interest electric transmission corridors ("National Corridors" or "Corridors").

Transmission congestion occurs when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels—either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term "transmission constraint" may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability.

Power purchasers look for the least expensive energy available to ship across the grid to the areas where it will be used ("load centers"). When a transmission constraint limits the amount of energy that can be transferred safely to a load center from the most desirable source, the grid operator must find an alternative (and more expensive) source of generation that can be delivered safely, and re-instruct the owners of generators on how they should schedule electricity production at specific power plants. Further, if a large portion of the grid is very tightly constrained—as when demands are very high and local generation is limited—grid operators may have to curtail service to consumers in some areas to protect the reliability of the grid as a whole. All of these actions have adverse impacts on electricity consumers.

There are many ways to measure transmission congestion. This study developed congestion metrics related to the *magnitude and impact* of congestion (for example, the number of hours per year when a

[1]The law excludes the area covered by the Electric Reliability Council of Texas (ERCOT) from this requirement. In peforming the analysis reported on here, the Department also excluded Alaska and Hawaii because they are not part of the Eastern or Western Interconnections.

transmission constraint is loaded to its maximum safe operating level; and the number of hours when it is operated at or above 90% of the safe level) and the *cost of congestion* (such as the cost of the next MWh of energy if it could be sent across a facility already at its safe limit). Because no one metric captures all important aspects of congestion, the analysts identified the most constrained transmission paths according to several different congestion metrics and then identified those paths that were most constrained according to a combination of metrics.

The cost of congestion varies in real time according to changes in the levels and patterns of customers' demand (including their response to price changes), the availability of output from various generation sources, the cost of generation fuels, and the availability of transmission capacity. Transmission constraints occur in most areas of the Nation, and the cost of the congestion they cause is included to some degree in virtually every customer's electricity bill. Although congestion has costs, in many locations those costs are not large enough to justify making the investments needed to alleviate the congestion. In other locations, however, congestion costs can be very high, and eliminating one or more key constraints through some combination of new transmission construction, new generation close to a major load, and demand-side management can reduce overall electricity supply costs in the affected areas by millions of dollars per year and significantly improve grid reliability.

The Department finds that three classes of congestion areas merit further Federal attention:

- **Critical Congestion Areas.** These are areas of the country where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe. As shown in Figures ES-2 and ES-3, the Department has identified two such areas, each of which is large, densely populated, and economically vital to the Nation. They are:
  - The Atlantic coastal area from metropolitan New York southward through Northern Virginia, and
  - Southern California.
- **Congestion Areas of Concern.** These are areas where a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions. As shown in Figures ES-2 and ES-3, the Department has identified four Congestion Areas of Concern:
  - New England
  - The Phoenix – Tucson area
  - The Seattle – Portland area
  - The San Francisco Bay area.

Figure ES-2. Critical Congestion Area and Congestion Area of Concern in the Eastern Interconnection

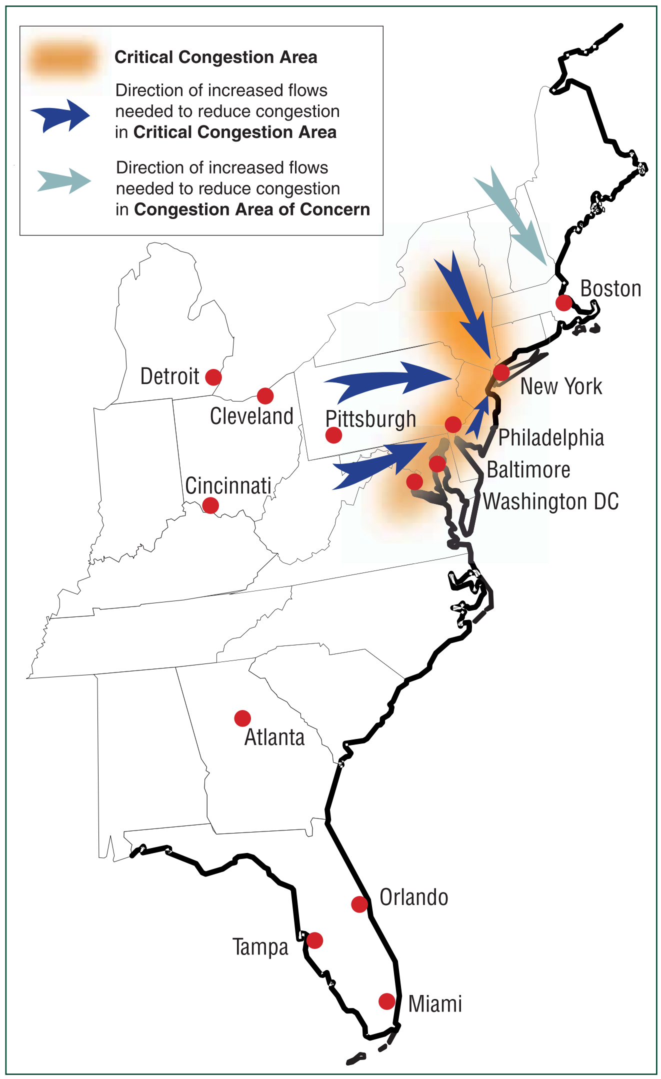
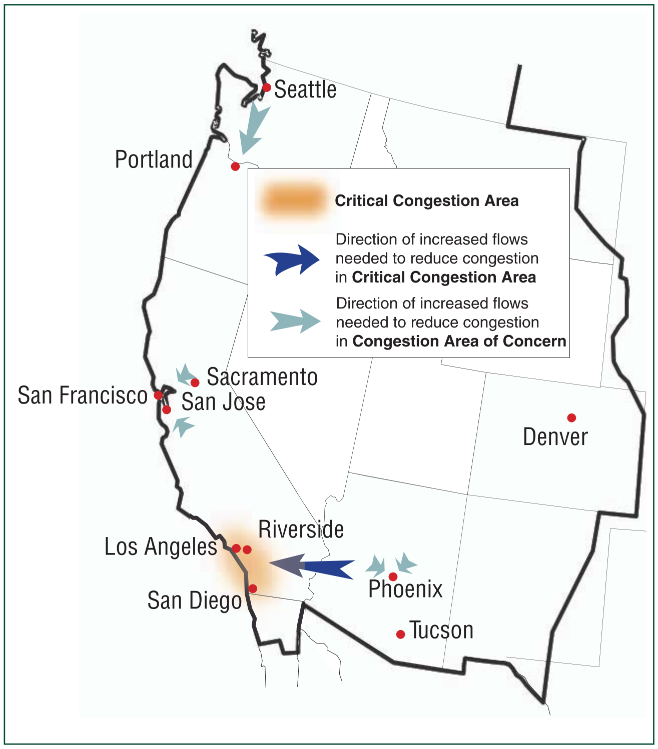


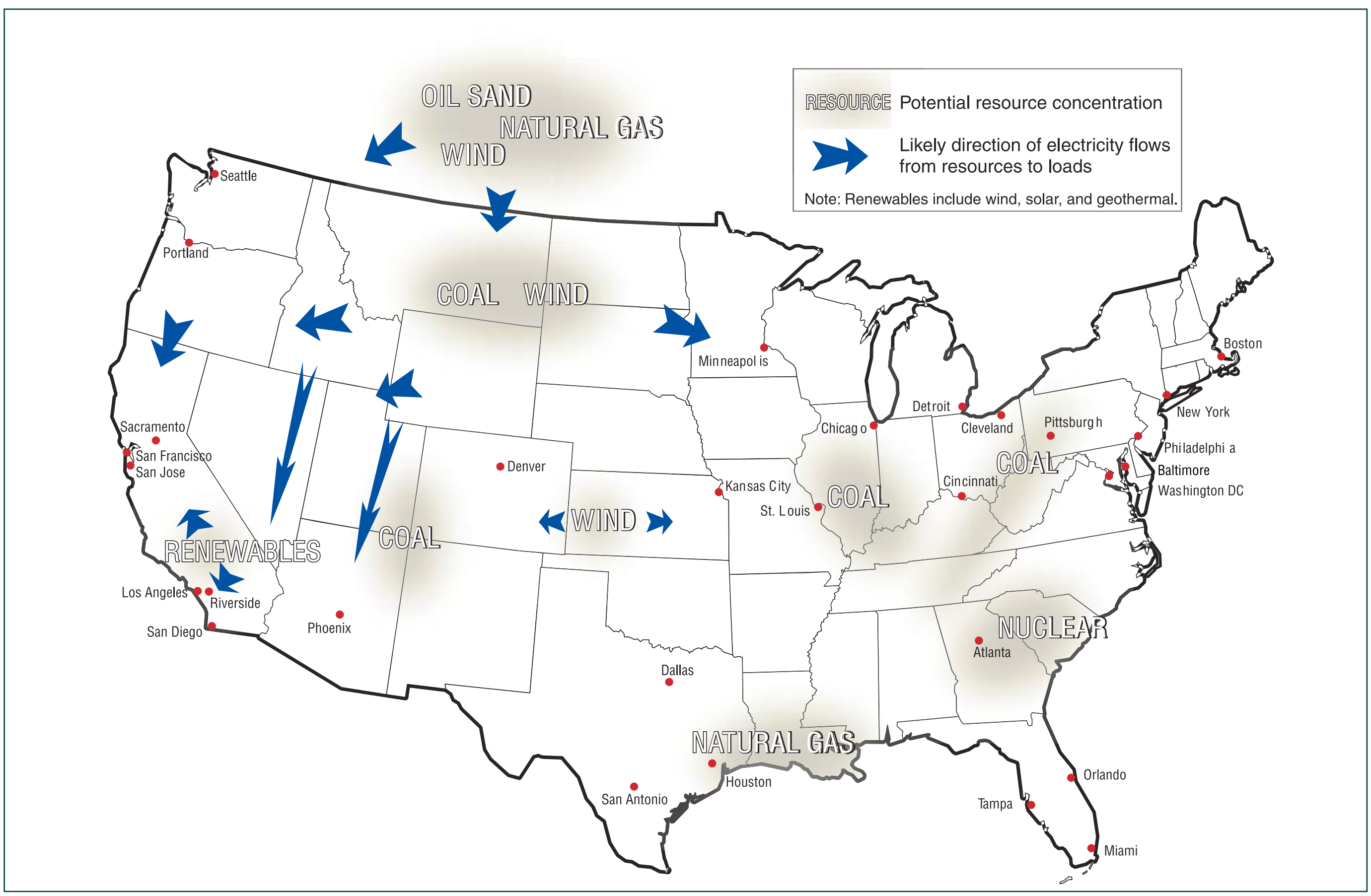
Figure ES-3. One Critical Congestion Area and Three Congestion Areas of Concern in the Western Interconnection



- **Conditional Congestion Areas.** These are areas where there is some transmission congestion at present, but significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity. As shown in Figure ES-4, these areas are potential locations for large-scale development of wind, coal and nuclear generation capacity to serve distant load centers. Some of the areas of principal interest are:
  - Montana-Wyoming (coal and wind)
  - Dakotas-Minnesota (wind)
  - Kansas-Oklahoma (wind)
  - Illinois, Indiana and Upper Appalachia (coal)
  - The Southeast (nuclear)

DOE believes that affirmative government and industry decisions will be needed in the next few years to begin development of some of these generation resources and the associated transmission facilities.

Figure ES-4. Conditional Constraint Areas



Next Steps

Notice of Intent to Consider Designation of National Corridors

For the two areas identified above as Critical Congestion Areas, the Department believes it may be appropriate to designate one or more National Corridors to facilitate relief of transmission congestion in these areas. The Department will also consider designating National Corridors to relieve constraints or congestion in Congestion Areas of Concern and Conditional Congestion Areas. The Department requests comments from stakeholders on three questions by October 10, 2006:

- Would designation of one or more National Corridors in relation to these areas be appropriate and in the public interest?
- How and where should DOE establish the geographic boundaries for a National Corridor?
- To the extent a commenter is focusing on a proposed transmission project, how would the costs of the facility be allocated? (Although the question of cost allocation for a transmission project is not directly related to the designation of a National Corridor, DOE recognizes the criticality of cost allocation issues and is interested in how they might be resolved.)

Chapter 6 provides additional discussion of these questions and information on where comments should be filed. After evaluating the comments received, the Department may proceed to designate some areas as National Corridors, seek additional information, or take other action.

Role of regional transmission planning organizations in finding solutions to congestion problems

DOE expects that regional transmission planning organizations will continue to show leadership in working with stakeholders and transmission experts to develop solutions to the congestion problems identified above in their respective areas. DOE expects these planning efforts to be inter-regional where appropriate, because many of the problems and likely solutions cross regional boundaries. In particular, the Department believes that these analyses should encompass both the congestion areas and the areas where additional generation and transmission capacity are likely to be developed. The Department will support these planning efforts, including convening meetings of working groups and working with the Federal Energy Regulatory Commission and congestion area stakeholders to facilitate agreements about cost allocation and cost recovery for transmission projects, demand-side solutions, and other subjects.

DOE anticipates that regional—and inter-regional, where appropriate—congestion solutions will be based on a thorough review of generation, transmission, distribution and demand-side options, and that such options will be evaluated against a range of scenarios concerning load growth, energy prices, and resource development patterns to ensure the robustness of the proposed solutions. Such analyses should be thorough, use sound analytical methods and publicly accessible data, and be made available to industry members, other stakeholders, and Federal and state agencies.

Annual congestion area progress reports

Each of the congestion areas identified above involves a somewhat different set of technical and policy concerns for the affected stakeholders. The Department will work with FERC, affected states, regional planning entities, companies, and others to identify specific problems, find appropriate solutions, and remove barriers to achieving those solutions.

The Department intends to monitor congestion and its impacts in these areas, and publish annual reports on progress made in finding and implementing solutions. The Department plans to issue its first progress report by approximately August 8, 2007, the second anniversary of the enactment of the Energy Policy Act of 2005.