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Electric Transmission: Approaches for Energizing a Sagging Industry

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Electric Transmission: Approaches for Energizing a Sagging Industry

Summary

The electric utility industry is inherently capital-intensive. At the same time, the industry must operate under a changing and sometimes unpredictable regulatory system at both the federal and state level. The transmission system was developed to fit the regulatory framework established in the 1920 Federal Power Act — utilities served local customers in a monopoly service territory. The transmission system was not designed to handle large power transfers between utilities and regions. Enactment of the Energy Policy Act of 1992 (P.L. 102-486) created tension between the regulatory environment and the existing transmission system: The competitive generation market encouraged wholesale, interstate power transfers across a system that was designed to protect local reliability, not bulk power transfers.

The blackout of 2003 in the Northeast, Midwest, and Canada highlighted the need for infrastructure improvements and greater standardization of operating rules. The Energy Policy Act of 2005 (P.L. 109-58) set in place government activities intended to relieve congestion on the transmission system. The law creates an electric reliability organization that is to enforce mandatory reliability standards for the bulk-power system. In addition, processes are established to streamline the siting of transmission facilities. Many observers predict that until the electric power industry reaches a new equilibrium with more regulatory certainty, investment in transmission infrastructure and technology will continue to be inadequate.

This report discusses factors that have contributed to the lack of new transmission capacity and some of the resulting issues, including

- background on the evolution of the regulatory structure, including the creation of an electric reliability organization (ERO);
- issues associated with operating a congested transmission system;
- security of the physical assets;
- siting of transmission lines;
- cost implications of burying power lines;
- pricing of new transmission projects; and
- funding of these projects.

In addition, this report reviews approaches being taken to address the lack of investment in transmission infrastructure and transmission congestion.

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Introduction

The electric utility industry is inherently capital-intensive. At the same time, the industry must operate under a changing and sometimes unpredictable regulatory system at both the federal and state level. Inconsistent rules and authorities can result in inefficient operation of the interstate transmission system. The electric transmission system has been affected by a combination of factors that has resulted in insufficient investment in the physical infrastructure.

This report discusses factors that have contributed to the lack of new transmission capacity and some of the resulting issues, including

- background on the evolution of the regulatory structure, including the creation of an electric reliability organization (ERO);
- issues associated with operating a congested transmission system;
- security of the physical assets;
- siting of transmission lines;
- cost implications of burying power lines;
- pricing of new transmission projects; and
- funding of these projects.

In addition, this report reviews approaches being taken to address the lack of investment in transmission infrastructure and transmission congestion.

The transmission system was developed to fit the regulatory framework established in the 1920 Federal Power Act[1] — utilities served local customers in a monopoly service territory. The transmission system was not designed to handle large power transfers between utilities and regions. Enactment of the Energy Policy Act of 1992 (EPACT92)[2] created tension between the regulatory environment and the existing transmission system. EPACT92 effectively deregulated wholesale

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[1] 16 U.S.C. 791a et seq.

[2] P.L. 102-486.

generation by creating a class of generators that were able to locate beyond a typical service territory with open access to the existing transmission system. The resulting competitive market encouraged wholesale, interstate power transfers across a system that was designed to protect local reliability, not bulk power transfers.

The blackout of August 2003 in the Northeast, Midwest, and Canada highlighted the need for infrastructure and operating improvements. However, a conflict exists between the apparent goal of increasing competition in the generation sector and assuring adequate transmission capacity and management of the system to move the power. Additions to generating capacity are occurring at a more rapid pace than transmission additions. The traditional vertically integrated utility no longer dominates the industry structure.[3] In addition, demand for electric power continues to increase. Unresolved regulatory issues that have emerged after 1992 have resulted in considerable uncertainty in the financial community. As a result of all of these factors, investment in the transmission system has not kept pace with demand for transmission capacity.

The Energy Policy Act of 2005 (EPACT05) addresses electric reliability and infrastructure investment.[4] In part, Title XII creates an electric reliability organization (ERO) that is to enforce mandatory reliability standards for the bulk-power system. These standards are necessary for reliable operation of the grid. The Federal Energy Regulatory Commission (FERC) will be reviewing the ERO's proposed reliability standards before granting its approval.[5] Under this title, the ERO could impose penalties on a user, owner, or operator of the bulk-power system that violates any FERC-approved reliability standard. FERC approved the North American Electric Reliability Corporation, a wholly owned subsidiary of the North American Electric Reliability Council (NERC), as the ERO.[6] NERC is a nonprofit corporation whose membership is composed of the eight regional reliability councils.[7]

Title XII also addresses transmission infrastructure issues. As required by EPACT05, the Department of Energy issued the first *National Electric Transmission*

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[3] Seventeen states and the District of Columbia are implementing retail choice for electricity. According to the Energy Information Administration, in 1996, 10% of generating capacity was owned by non-utility generators. By 2005, 43% of net summer generating capacity was owned by non-utility generators. See [http://www.eia.doe.gov/cneaf/electricity/epa/epat2p3.html].

[4] P.L. 109-58.

[5] FERC Docket No. RM06-22-000.

[6] *Order Certifying North American Electric Reliability Corporation As the Electric Reliability Organization in Ordering Compliance Filing*. 116 FERC, 61,062. Docket No. RR06-1-000. Issued July 20, 2006.

[7] The regional reliability councils are Electric Reliability Council of Texas, Inc. (ERCOT); Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); Southeastern Reliability Council (SERC); Southwest Power Pool, Inc. (SPP); and Western Electricity Coordinating Council (WECC).

Congestion Study in August 2006.[8] Additional studies are required every three years. The study identified two areas of critical congestion: Southern California and the eastern coastal area from metropolitan New York to Northern Virginia. This congestion study included detailed information on the transmission congestion in the western United States (**Figure 1**) but did not provide comparable detail on congestion in the eastern United States.[9] EPACT05 allows the Secretary of Energy to certify congestion on the transmission lines and issue permits to transmission owners. Permit holders will be able to petition in U.S. district court to acquire rights-of-way for the construction of transmission lines through the exercise of the right of eminent domain. On April 26, 2007, DOE issued two draft National Electric Transmission Corridor (National Corridor) designations (**Figure2**.)

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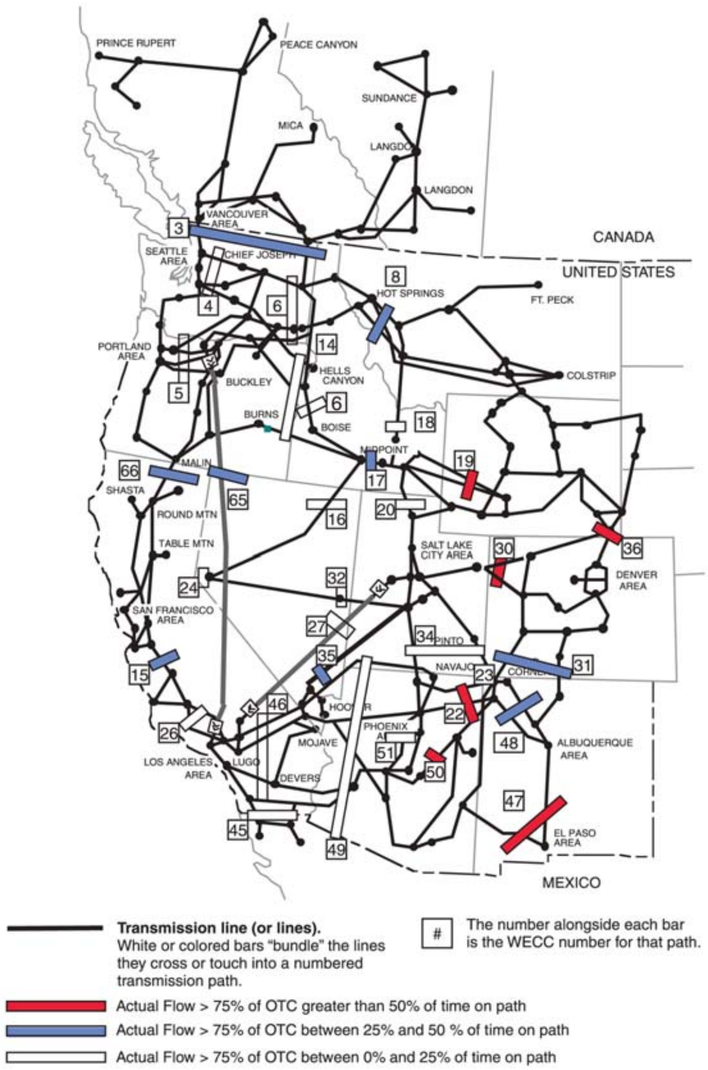
[8] U.S. Department of Energy, National Electric Transmission Congestion Study, August 2006, available at [http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf].

[9] **Figure 1** shows how many hours in a year the transmission system was loaded at or above 75% of Operating Transfer Capability (OTC) in the Western Electricity Coordinating Council (WECC) region. The most heavily loaded lines include Bridger West, which delivers power from the Bridger, Montana coal-fired plants to loads in Utah and Oregon; Southwest of Four Corners-to-Cholla-to-Pinnacle Peak in Arizona, which is designed to deliver power from baseload plants to load; western Colorado to Utah; Wyoming to Colorado; and southern New Mexico to El Paso.

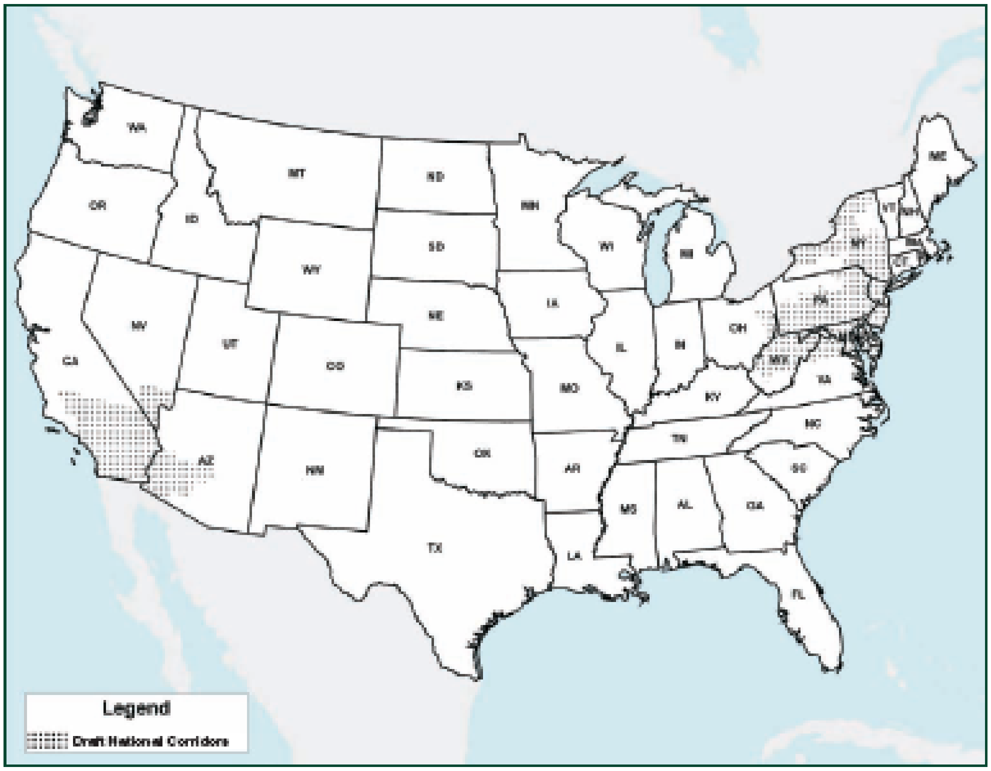
The Department of Energy will not be publishing a detailed map of eastern congestion until the release of the next progress report (late 2006) or the next congestion study (2009.) This is after it is expected that DOE will designate National Corridors in the congested eastern coastal area to relieve constraints or congestion. (E-mail communication with Agrawal Poonum, Manager, Markets and Technical Integration, Office of Electricity Delivery and Energy Reliability, Department of Energy, January 19, 2007.)

Figure 1. Western Transmission Congestion, 1999-2005



Source: U.S. Department of Energy, National Electric Transmission Congestion Study (2006), p. 33.

Figure 2. Draft Mid-Atlantic Area And Southwest Area National Corridors



Source: U.S. Department of Energy, April 2007.

Transmission pricing was also addressed in EPACT05 (§1241) to encourage investment in transmission. FERC issued Order 679 on this issue, *Promoting Transmission Investment through Pricing Reform*, on July 20, 2006.[10] The order identifies specific incentives that FERC will allow, but the burden remains on an applicant to justify the incentives.

Historical Context

There are three components to electric power delivery: generation, transmission, and distribution. Transmission, by its nature, is generally considered an interstate transaction, whereas distribution is considered intrastate. State public utility commissions regulate the siting of all transmission and distribution lines within each state's borders, as well as distribution charges and retail electric rates. In states that have not restructured, the system operates as it has since enactment of the Federal Power Act, with retail consumers paying one price that includes transmission,

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[10] Federal Energy Regulatory Commission Final Rule, Order Number 679, *Promoting Transmission Investment through Pricing Reform*, July 20, 2006, Docket Number RM06-4-000.

distribution, and generation. This is referred to as a *bundled transaction*. In states that have restructured, consumers are billed for separate transmission, distribution, and generation charges. This is referred to as *unbundled electricity service*. FERC regulates all transmission, including unbundled retail transactions.[11]

Generators of electricity need to move their power to their ultimate customers through the transmission system. The current system allows for power transfers within, but not between, three major regions of the United States: the area west of the Rockies (Western Interconnection), Texas, and the Eastern Interconnection. Transmission lines and distribution lines are categorized by their voltage rating. Transmission lines are typically rated 230 kilovolts (kV) and higher (765 kV is the highest installed). Subtransmission systems are 69 kV to 138 kV, and distribution systems are rated less than 69 kV.[12] Existing transmission infrastructure was designed to accommodate the old system of central station power plants with nearby customers. Since enactment of the Energy Policy Act of 1992, there has been an increase in interstate bulk power transfers, a purpose for which the existing system was not designed.

The Energy Policy Act of 1992 (EPACT92) created a new category of wholesale electric generators called Exempt Wholesale Generators (EWGs) that are not considered utilities.[13] EWGs, also referred to as *merchant generators*, were intended to create a competitive wholesale electric generation sector. In addition, EPACT92 provided a means for these non-utility generators to have access to the transmission system. As a result of EPACT92, FERC issued a policy statement on transmission pricing policy:

> Greater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992 (EPACT92)[footnote

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[11] On October 3, 2001, the U.S. Supreme Court heard arguments in a case (*New York et al. v. Federal Energy Regulatory Commission*) that challenged FERC's authority to regulate transmission for retail sales if a utility unbundles transmission from other retail charges. In states that have opened their generation market to competition, unbundling occurs when customers are charged separately for generation, transmission, and distribution. Nine states, led by New York, filed suit, arguing that the Federal Power Act gives FERC jurisdiction over wholesale sales and interstate transmission and leaves all retail issues up to the state utility commissions. Enron in an amicus brief argued that FERC clearly has jurisdiction over all transmission and FERC is obligated to prevent transmission owners from discriminating against those wishing to use the transmission lines. On March 4, 2002, the U.S. Supreme Court ruled in favor of FERC and held that FERC has jurisdiction over transmission, including unbundled retail transactions.

[12] Transmission lines generally carry bulk-power transfers between utilities and move power to load centers. Distribution lines move power to ultimate customers. Subtransmission is sometimes considered transmission and other times considered distribution for regulatory purposes.

[13] Exempt Wholesale Generators may sell electricity only at wholesale. EWGs may be located anywhere, including foreign countries. Before enactment of EPACT05, utility generators were limited by the Public Utility Holding Company Act of 1935 (PUHCA) to operate within one state.

> omitted]. These recent events underscore the importance of ensuring that our transmission pricing policies promote economic efficiency, fairly compensate utilities for providing transmission services, reflect a reasonable allocation of transmission costs among transmission users, and maintain the reliability of the transmission grid. The Commission also recognizes that advances in computer modeling techniques have made possible certain transmission pricing methods that once would have been impractical.[14]

In May 1994, FERC established general guidelines for comparable access to the transmission system.[15] In April 1996, FERC clarified its open-access transmission tariff policy with Orders 888 and 889, making it easier for merchant generators to gain access to the transmission grid and requiring utilities to "functionally unbundle" their operations. In practice, this means that a utility's generation and transmission operations must be conducted separately, without the sharing of resources, books, and records. Some states that have opened their retail markets to competition, including California, have required utilities to divest of either transmission and distribution or of generation. In these states, most utilities have divested generation assets and maintained their transmission and distribution business. By July 9, 1996, all utilities that own or control transmission had filed a single open-access tariff with FERC that provides transmission service to eligible wholesale customers at comparable terms to the service that the utilities provide themselves. Some merchant generators asserted that they continued to be discriminated against by incumbent transmission utilities and were denied access to the system.

Orders 888 and 889 established a pro forma open-access transmission tariff (pro forma OATT). Many argued that this pro forma OATT allowed for opportunities for the exercise of undue discrimination by transmission owners. On May 18, 2006, FERC issued a Notice of Proposed Rulemaking (NOPR), *Preventing Undue Discrimination in Preference in Transmission Service*, to remedy some of the deficiencies in the pro forma OATT.[16] According to FERC, the major reforms in the NOPR include

- greater consistency and transparency in the Available Transfer Capability (ATC) calculation;[17]
- open, coordinated, and transparent planning;
- reform of energy imbalance penalties;
- clarification of tariff ambiguities; and
- increased transparency and customer access to information.

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[14] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, policy statement, October 26, 1994, Docket No. RM 93-19-000, 18 CFR 2, 59 FR 55031.

Wheeling is defined as the movement of electricity from one system to another over transmission facilities of interconnecting systems.

[15] 67 FERC 61,168.

[16] FERC Docket Numbers RM05-25-000 and RM05-17-000.

[17] ATC is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses.

On February 16, 2007, FERC issued Order 890, *Preventing Undue Discrimination Preference in Transmission Service*.[18] The final Order reflected much of what was addressed in the NOPR, including calculations of available transfer capability, coordination of the transmission planning process, establishing a requirement for conditional firm long-term point-point service contracts, reforming energy and generator imbalance charges, and increasing the transparency of the *existing pro forma* OATT.

Current Issues

Physical Limitations

Three types of constraints limit the transfer capability within the transmission system: thermal constraints, voltage constraints, and system operating constraints. Thermal constraints limit the capability of a transmission line or transformer to carry power because the resistance created by the movement of electrons causes heat to be produced. Overheating can lead to two possible problems: The transmission line loses strength, which can reduce the expected life of the line, and the transmission line expands and sags between the supporting towers. This presents safety issues as the lines approach the ground, as well as reliability concerns. If a transmission line comes in contact with the ground, trees, or other objects, the transmission line will trip off-line and not be able to carry power.

Voltage can be likened to the pressure inside the transmission system. Constraints on the maximum voltage levels are set by the design of the transmission line. If voltage levels exceed the maximum, short-circuits, radio interference, and noise may occur. Low voltages are also a problem and can cause customers' equipment to malfunction and can damage motors.

System operating constraints refer to reliability and security. Maintaining synchronization among generators on the system and preventing the collapse of voltages are major aspects of the role for transmission operators.[19] North American Electric Reliability Council guidelines require utilities to be able to handle any single outage through redundancy in the system. When practical, NERC recommends the ability to handle multiple outages within a system. Reducing the constraints on the system through technology improvements is one way to increase the transfer capability over existing lines.[20]

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[18] FERC Order 890. Docket Numbers RM05-17-000 and RM05-25-000. *Preventing Undue Discrimination Preference in Transmission Service*. Issued February 16, 2007.

[19] Within each interconnection, all generators rotate in unison at a speed that produces a consistent frequency of 60 cycles per second.

[20] See Energy Information Administration, *Upgrading the Transmission Capacity for Wholesale Electric Power Trade*, available at [http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html].

The regulatory regime has shifted the operations of the electric utility industry, creating larger and more frequent bulk power transfers across a transmission system designed largely for local intrastate service. However, investment and infrastructure have not kept up with increases in the bulk power transfers and electricity demand. Between 1978 and 1998, electricity demand had been growing at an average rate of 2.8% per year.[21] Transmission capacity expressed in relation to electricity demand increased by 3.5% per year between 1978 and 1982 and then declined by 1.2% per year between 1982 and 1998.[22] Actual annual transmission investment had declined from nearly $5 billion in 1975 to about $2.25 billion in 1998.[23] Reversing this trend, between 1999 and 2005, transmission investment increased at a 12% annual rate.[24] However, during the same period, total circuit miles of 230 kV and above transmission lines owned and operated by investor-owned utilities increased by 0.8% annually.[25] This long period of insufficient transmission investment has led to transmission lines that are congested in several regions of United States.

Similarly, as is shown in **Figure 3**, investment in generation capacity has not kept pace with electricity demand growth. This has led to lower capacity margins for electric utilities.[26] According to NERC, available capacity margins, which include only committed resources, are projected to drop below minimum regional target levels in several regions of the United States and Canada in two to three years.[27] The ERO has proposed enforceable standards for cyber- and physical security and reliability of the electric system that are intended to ensure optimum operation of the transmission system. FERC will be reviewing NERC's proposed standards before granting approval.[28]

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[21] Energy Information Administration, Annual Energy Review, Electricity Overview, 1949-2005. Available at [http://www.eia.doe.gov/emeu/aer/elect.html].

[22] Hirst, Eric, *Expanding U.S. Transmission Capacity* (August 2000), p. 5. Available at [http://www.eei.org/industry_issues/energy_infrastructure/transmission/hirst2.pdf].

Normalized transmission capacity is calculated using megawatt-miles of transmission per megawatts of summer peak demand.

[23] Real $2003. Edison Electric Institute, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999-2008)*, Washington (May 2005), p. 3.

[24] Edison Electric Institute, *EEI Statistical Yearbook/2005 Data* (2006), p. 107.

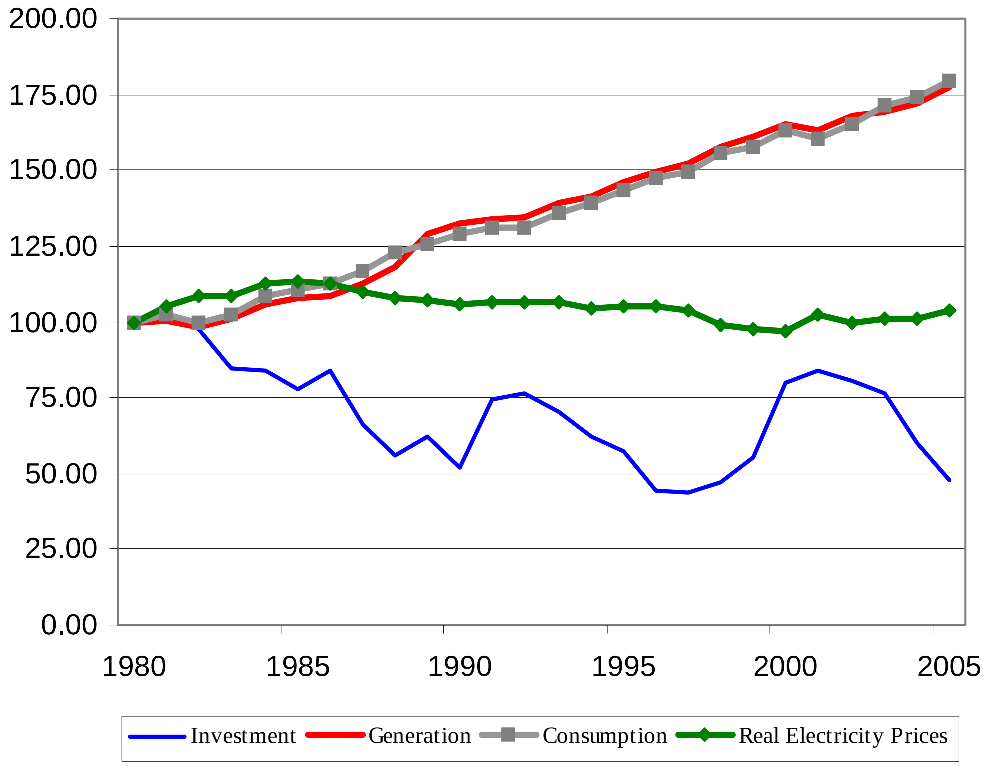
[25] NERC 2006 Long-Term Reliability Assessment and NERC Reliability Assessment 2000-2009. Available at [http://www.nerc.com/~filez/rasreports.html].

[26] *Capacity margin* is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources. This gives an indication of the ability of the system to meet demand. A narrow capacity margin indicates a risk that supply will be interrupted because of a shortage of generation. On the other hand, excessive day-ahead capacity margin could add to the cost of electricity.

[27] North American Electric Reliability Council, *2006 Long-Term Reliability Assessment*, (October 2006), p. 6.

[28] FERC Docket No. RM06-22-000.

Figure 3. Real Private Fixed Investment in Electrical Power Generation, and Electricity Consumption, Generation, and Real Prices



Source: Kliesen, Kevin L. , "Electricity: The Next Energy Jolt?" The Regional Economist, The Federal Reserve Bank of St. Louis, October 2006, p. 6.

Note: Index, 1980 = 100.

Congestion. **Figure 1** and **Figure 4** show the lines in the Eastern Interconnection and Western Interconnection that have been identified as congested. Problems with congestion on the transmission system are not new. In 1987, CRS noted that bulk power transmission lines in many parts of the country were already operating at or near capacity and the chief capacity-related barrier to bulk-power transfers (wheeling) was that the transmission system was not built for bulk-power transfers.[29] According to NERC, the number of requests to use the transmission system that were denied because of congestion (transmission line relief, TLRs) rose from 305 in 1998 to 1,494 in 2002. By 2005, there were 2,397 TLRs, dropping slightly in 2006 to 1,901 TLRs.[30] Over the next 10 years, the line-miles of high-voltage transmission are expected to increase 6%, in contrast to a 20% expected

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[29] See CRS Report 87-289, *Wheeling in the Electric Utility Industry*, by Alvin Kaufman et al. (out of print; available from the author of this report).

[30] NERC data on Transmission Loading Relief (TLR) requests are available at [http://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm].

increase in generation demand and capacity.[31] If this projection is accurate, further pressure on reliability could occur in several regions.[32]

Security. Another issue surrounding the reliability of the electric system involves security. The system operates with built-in redundancies to minimize the risk of outages resulting from myriad causes, including weather, equipment failure, and terrorist activity. In general, physical attacks could target transformers, transmission towers, substations, control centers, power plants (including nuclear reactors or dams), and fuel-delivery systems. NERC reported that in 2006, of the 57 events that resulted in a system disturbance (outage), only one (1.75%) was caused by physical attack. Between 2001 and 2006, 11.21% of the system disturbances were caused by "system protection and controls"issues, which include physical attacks and cyber-attacks.[33]

High-voltage transformers are a critical and vulnerable part of the nation's electric power network. High-voltage (HV) units make up less than 3% of transformers in U.S. power stations, but they carry 60% to 70% of the nation's electricity.[34] Power grid planners generally anticipate the possible loss of a single HV transformer substation and are prepared to reroute power flows as necessary to maintain regional electric service. Loss of multiple HV transformers simultaneously could cause extended regional outages.

Utilities generally do not maintain a stockpile of transformers to replace more than a small percentage of their operating units. Large transformers generally cost $2 million to $3 million, are custom made, require long lead times to build, and are bulky and difficult to move around.[35] NERC maintains a transformer information database, a 15-year-old program used primarily for weather-related outages of large transformers. In response to the growing need for a stockpile of large transformers, the Edison Electric Institute (EEI) has begun a FERC-approved spare transformer sharing program, which is to be used solely to deal with terrorist activity or deliberate damage to utility substations.[36] At the time of the FERC approval in September

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[31] Department of Energy, *National Transmission Grid Study*, May 2002.

[32] See CRS Report RL31469, *Electric Utility Restructuring: Maintaining Bulk Power System Reliability*, by Amy Abel, Larry Parker, and Steven Stitt.

[33] A physical attack involves human caused damage to transmission infrastructure that generally results in a major outage. Past incidents have included removing stabilizing bolts from transmission lines and shooting transformers. NERC Reported System Events available at [http://www.nerc.net/dashboard/].

[34] Loomis, William M., consulting engineer for Strategic Partners-Technical Systems, "Super-Grade Transformer and Defense: Risk of Destruction and Defense Strategies," presentation to NERC Critical Infrastructure Working Group, Lake Buena Vista, Florida, (December 10-11, 2001).

[35] Stan Johnson, NERC Manager of Situation Awareness and Infrastructure Security, as quoted in *Electric Utility Week*, "More Utilities Sign up to Share Transformers, Information As Cost- Consciousness Grows"(January 8, 2007), p. 9.

[36] FERC approved the Spare Transformer Equipment Program (STEP) on September 21,

(continued...)

2006, 43 entities had joined the EEI program, representing more than 60% of the FERC-jurisdictional bulk-power transmission system. Unlike the NERC program, which does not charge utilities to participate, EEI charges a $10,000 sign-up fee to join the transformer sharing program, as well as annual dues of about $7,500. Some utilities need to obtain state approval before joining the EEI program.

NERC also operates the Electricity Sector Information Sharing and Analysis Center (ESISAC), as required by Presidential Decision Directive (PDD) 63 on critical infrastructure protection. The ESISAC is a voluntary means for utilities to share security-related information. In turn, the EISISAC is tasked with providing "timely, reliable and actionable warnings of threats and impending attacks on our critical infrastructures."[37]

Siting

One reason additional transmission lines have not been built in recent years is the problems encountered when siting them. Siting and building transmission lines have been very difficult because of citizen opposition, as well as inconsistent siting requirements among states. Even though the transmission of electricity is considered interstate commerce, the siting of transmission lines has been the responsibility of the states. In addition, several federal agencies play various roles in the siting process, primarily with regard to environmental impacts.

Since the blackout of 2003, FERC commissioners have supported federal siting backstop authority to help transmission companies overcome some of the siting obstacles,[38] although such support has been controversial. The electric industry is in favor of giving FERC siting authority.[39] States are generally opposed to federal backstop authority.[40]

EPACT05 established that the Secretary of Energy is required to certify congestion on the transmission lines, but EPACT05 does not specifically define congestion. The first congestion study was completed in August 2006.[41] As a result of this study, the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects

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[36] (...continued)
2006. FERC Docket Nos. EC06-140-000 and EL06-86-000.

[37] The ESISAC website is available at [http://www.esisac.com].

[38] Statement of Nora Mead Brownell, *FERC Reverses Position, Will Now Take Federal Backstop Authority*, at [http://www.Energywashington.com], September 2, 2003.

[39] Edison Electric Institute, *Federal Siting Authority: Key to Expanding Electricity Infrastructure*, available at [http://www.eei.org/industry_issues/energy_infrastructure/transmission/federalsiting.pdf].

[40] Statement of National Governors Association.

[41] U.S. Department of Energy, *National Electric Transmission Congestion Study*, August 2006, available at [http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf].

consumers as a national interest electric transmission corridor." FERC may issue permits for construction of transmission lines to transmission owners within a national interest transmission corridor if FERC finds that a state does not have the authority to approve the siting of the facilities or that a state commission that has authority to approve the siting of facilities has withheld its approval for more than one year. Permit holders are able to petition in U.S. district court to acquire rights-of-way for the construction of transmission lines through the exercise of the right of eminent domain.[42]

On April 26, 2007, DOE issued two draft National Interest Electric Transmission Corridor designations (draft report), one stretching from the mid-Atlantic region through New York, and the other in Southern California.[43] EPACT05 created a new Federal Power Act §216(a)(2) which states that:

> *After considering alternatives and recommendations from interested parties (including an opportunity for comment from affected States), the Secretary shall issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.*

DOE broadly defines the term "constraints that adversely affects consumers" to include "not only constraints that cause persistent congestion, but also constraints that hinder the development or delivery of a generation source that is in the public interest ... which allows for a National Corridor designation when there is a constraint that adversely affects consumers even though there is no present congestion...."[44] DOE did not consider alternatives to new transmission, such as conservation or efficiency improvements in existing lines, in identifying National Corridors. DOE received comments from many stakeholders that argued that DOE should conduct a cost-benefit analysis on transmission versus non-transmission solutions for congestion before designating a National Corridor.[45] DOE argues that nothing in § 216 of the Federal Power Act requires that the DOE demonstrate that transmission is the best or most cost-effective solution to a congestion problem.[46]

Another controversial aspect of the National Corridor designation is their geographic boundaries. EPACT05 did not define the term "corridor," and DOE has concluded "that, while there may be circumstances where a project-based approach would be appropriate, in general the Department (DOE) will use a source-and-sink

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[42] P.L. 109-58, § 1221.

[43] DOE Draft Report available at [http://nietc.anl.gov/].

[44] *ibid.* p. 20.

[45] For examples of these comments, see those submitted by the National Association of Regulatory Utility Commissioners (NARUC), New York Public Service Commission, New Jersey Board of Public Utilities, Electric Power Supply Association, Northern Indiana Public Service Co., Old Dominion Electric Cooperative, Piedmont Environmental Council, and the Wilderness Society. Available at [http://nietc.anl.gov/].

[46] *ibid*. p. 24.

approach to define National Corridor boundaries."[47] In this process, the sink (the congested or constrained load area) and the source (an area of *potential* supply) are identified and the two areas are connected as a National Corridor. DOE does not intend to designate specific projects as National Corridors, but rather large areas with specific geographic boundaries.

In advance of DOE designating national interest electric transmission corridors, on November 16, 2006, FERC issued its Final Rule on Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities.[48] In part, EPACT05 (§ 1221) allows FERC to issue construction permits for transmission facilities within a national interest electric transmission corridor if a state has "withheld approval for more than one year." The term *withheld approval* was not unanimously interpreted by the commissioners. The final rule adopted that *withheld approval* could mean a state failing to act on the siting permit application or denying the application. Commissioner Kelly in her dissent found this interpretation to be a preemption of state rights:

> The authority to lawfully deny a permit is critically important to the states for ensuring that the interests of local communities and their citizens are protected. What the Commission does today is a significant inroad into traditional state transmission siting authority. It gives states two options: either issue a permit, or we'll do it for them. Obviously this is no choice. This is preemption.[49]

Defending the final rule before the media, Chairman Kelliher stressed that FERC must assume that the words Congress chooses to use in passing a law are "deliberate and done with care. If Congress meant only failure to act, why didn't they just say that."[50]

Several bills have been introduced in the 110th Congress that would repeal or reform § 216 of the Federal Power Act. H.R. 810 would amend § 216(e) of the Federal Power Act by repealing the section that allows a permit holder to acquire the-right-of-way for transmission facilities through the exercise of eminent domain in a federal district court and replaces it with acquisition of right-of-ways in accordance with state laws. H.R. 829 would place additional requirements before an area could be considered a National Corridor. This bill would require DOE to perform an analysis of alternatives to new transmission construction to alleviate congestion. The bill would prohibit National Corridors from including parks or historic battlefield sites that are designated as scenic, natural, cultural, or historic resources under federal or state law. H.R. 829 also amends the Federal Power Act to limit FERC's ability to issue construction permits to instances when a state's denial of transmission siting is found to have been arbitrary or capricious or the state

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[47] Draft Report. p. 34.

[48] FERC Order Number 689 (RM06-12). 117 FERC 61,202. 18 CFR Parts 50 and 380. Issued November 16, 2006.

[49] Kelly, Commissioner, *dissenting in part*. Docket No. RM06-12-000 (November 16, 2006), p. 3.

[50] Foster Electric Report, *FERC's Electric Transmission Siting Rule Sparked Strong Dissent by Kelly over Jurisdictional Concerns* (November 22, 2006), p. 2.

unreasonably withheld or delayed a siting decision beyond one year. H.R. 1945 (§ 403) would repeal § 216 of the Federal Power Act, which provides for federal siting authority for transmission lines.

Alternatives to New Rights-of-Way. Capacity of the existing transmission system can be increased without siting new lines. In addition, new generation can be sited closer to demand, reducing the need to use the transmission system. Additional transmission lines could be added to existing rights-of-way or, in some cases, existing towers could be restrung with higher capacity lines. However, in some cases, reliability levels would increase with the redundancy of new transmission lines sited on new rights-of-way; storms and other events that may cause physical damage to one area may not affect transmission lines in another part of a state or region.

Many transmission systems could increase the capacity of the transmission system with technology improvements. While many new technologies would require significant capital investment, one study by the New York Independent System Operator concluded that relatively inexpensive equipment upgrades could significantly increase the line ratings and could reduce congestion.[51] The study indicated that a significant number of transmission lines operate below their thermal limits because of equipment limitations at substations. By remediating those limitations with relatively inexpensive equipment (e.g., disconnect switches, bus connectors, relays), according to the New York study, operation at thermal capacities could be reached with little or no risk of service interruption.

Other technological improvements to increase transmission capacity and allow the transmission system to be operated more efficiently include upgrading transformers, retrofitting electromechanical devices with digital devices to allow operation of the system closer to thermal limits, and restringing existing towers with aluminum conductor composite core cable. These would require significant capital investment.

Burying Power Lines

Many reasons have been given for burying power lines, including reduced maintenance, less susceptibility to weather damage, fewer traffic accidents involving poles, improved aesthetics, and increased property values. The primary reason against burying power lines is the high cost. Design and installation of underground systems is more complex and expensive, and takes longer than for overhead systems. In addition, the cost and time involved to modify or repair an existing system is also reportedly higher.[52]

The overwhelming damage to the electricity transmission and distribution system in the wake of Hurricanes Katrina and Rita has increased interest in replacing

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[51] New York Independent System Operator, *Investigation of Potential Low Cost Transmission Upgrades Within the New York State Bulk Power System*, Interim Report (April 19, 2001).

[52] North Carolina Public Utilities Commission Staff, *The Feasibility of Placing Electric Distribution Facilities Underground* (November 2003).

overhead lines with underground cable. However, studies suggest that both overhead and underground lines have their vulnerabilities, and there are considerable cost differences in constructing and maintaining them. A review of several studies has found that overhead lines are more susceptible to storm and other damage, but the sites requiring repairs can be identified more quickly and repaired faster. Underground lines have above-ground transformers that are subject to immediate storm damage. Although underground distribution is generally more reliable during storms, corrosion from water infiltration can cause outages in the days and weeks after severe storms. The uprooting of trees can damage underground lines directly. Underground lines can be more expensive and take longer to repair. Replacing overhead lines with underground cable is also expensive. Analysis by the Florida Public Service Commission (FPSC) has found that replacing overhead *transmission lines* in Florida with underground lines over a 10-year period might require a rate increase of nearly 50% spread over all kilowatt hours. Converting overhead *distribution lines* to underground over the same period could boost rates by more than 80%.[53]

The majority of existing transmission and distribution lines are overhead, but in the 10 years between 1993 and 2002, capital expenditures for new power lines were almost equally divided between underground (49%) and overhead (51%) lines.[54] According to the Edison Electric Institute (EEI), new underground distribution costs average $1 million per mile, or $29,854 per customer, compared with $73,666 per mile, or $2,199 per customer, for existing overhead lines.[55]

Undergrounding Transmission. During storms, large steel transmission towers generally withstand high winds and rain. Because of their height, they are also less susceptible to damage from falling trees. In the United States, there are 200,000 miles of transmission lines, only 5,000 of which are underground cable. Transmission is placed underground typically to address a localized constraint, such as an airport, river crossing, or a central business district. Several factors are considered in evaluating whether burying transmission lines is feasible. As already noted, underground transmission has been found to be less susceptible to damage, but any damage is more difficult and time-consuming to locate and repair, according to an Australian study.[56] While overhead transmission lines generally take a few hours to two days to repair, EEI reports that average outage durations for underground

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[53] Florida Public Service Commission, *Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida* (March 2005), available at [http://www.psc.state.fl.us/publications/pdf/electricgas/Underground_Wiring.pdf].

[54] FERC Form 1 Data 1993-2002, as compiled by Edison Electric Institute, *Out of Sight, Out of Mind? A Study on the Costs and Benefits of Undergrounding Overhead Power Lines*, available at [http://www.eei.org/industry_issues/energy_infrastructure/distribution/UndergroundReport.pdf].

[55] Ibid.

[56] Australian Department of Communications, Information Technology and the Arts, *Putting Cables Underground* (1998).

transmission ranges from five days to nine months, depending on the technology used.[57]

There are several reasons why laying underground cable is significantly more expensive than overhead transmission. According to FPSC, an underground transmission cable needs to be about 10 times more massive than an overhead cable to transmit the same amount of power, with the cable cost being about 10 times greater than overhead cable.[58] Trenches need to have either concrete conduits or metal pipes for both safety and operational reasons. Because of the weight and thickness of underground cable, splices need to be made every 900 to 3,500 feet. At the site of each splice, an underground vault needs to be constructed for maintenance access. Above ground, a right-of-way of at least 20 to 50 feet must be completely cleared. Some studies have found that electromagnetic fields (EMFs) are stronger immediately above underground transmission than immediately below overhead transmission. However the EMF fields diminish more quickly with distance for buried transmission than for overhead transmission.[59]

FPSC completed a comprehensive analysis of burying transmission and distribution facilities and updated the analysis in 2005.[60] The study calculated a cost to remove and replace existing 138 kV overhead transmission facilities for investor-owned, municipally owned, and rural electric cooperatives. The cost calculations included

- planning and permitting,
- labor to remove existing facilities,
- new underground transmission facilities,
- labor to install the new underground facilities,
- trucks and other equipment to remove and install facilities,
- credits for existing overhead facilities that could be employed in the future, and
- disposal of facilities that could not be employed in the future.

The most recent study estimated that in 2003 dollars, the cost per mile to place transmission underground was \$3.6 million or a total of \$51.8 billion for all investor-

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[57] Average outage durations for High-pressure Fluid Filled Pipe, 8-12 days; Extruded Dielectric, 5-9 days; High-pressure Fluid Filled Pipe, 2-9 months. See [http://www.eei.org/meetings/nonav_meeting_files/nonav_2003-03-30-km/WiseSiting.ppt].

[58] Florida Public Service Commission, *Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida* (March 2005).

[59] Wise, K., *Going Underground: A Growing Reality for Transmission Line Routing?* (April 2003), presentation at Edison Electric Institute Natural Resources Workshop, Burns & McDonnell, available at [http://www.eei.org/meetings/nonav_meeting_files/nonav_2003-03-30-km/WiseSiting.ppt].

[60] Florida Public Service Commission, *Report on Cost-Effectiveness of Underground Electric Distribution Facilities*, vols. 1-4 (December 1991), and Florida Public Service Commission, *Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida* (March 2005).

owned utility transmission assets in Florida. The FPSC further calculated that converting overhead transmission facilities to underground would increase rates 49.7% for customers of investor-owned utilities (IOUs) over a 10-year period (**Table 1**).

Table 1. Revenue Requirements for IOUs To Convert Florida's Existing Transmission Facilities to Underground, and Rate Impact Over 10-Year Period

(in 2003 dollars)

Rate Impact	
Estimated cost of conversion	$51.8 billion
Estimated cost adjusted for inflation over 10 years	$57.9 billion
Levelized annual revenue requirement	$6.5 billion
Percentage rate impact (spread over all kilowatt-hours)	49.7%
Assumptions	
Weighted rate of return	12.04%
Property tax rate	1.86%
Operation and maintenance savings[a]	(0.7%)
Inflation rate	2.44%

Source: Florida Public Service Commission.

a. Federal Energy Regulatory Commission (FERC) Form 1 data do not separately identify transmission operation and maintenance (O&M) for overhead and buried transmission. FPSC used distribution O&M savings from the 2003 FERC Form 1 for its calculations.

Both the 1991 FPSC study and the 1998 Australian study included a cost savings to utilities due to fewer automobile collisions with utility poles. Both studies considered lost wages, medical expenses, insurance administration costs, property damage, and loss of life. According to FPSC, utilities would avoid approximately $117 million (2003 dollars) annually of accident-related costs.[61] Neither study considered that some communities would plant trees on old rights-of-way, and a collision with a well-established tree could cause injury and death, though in this case, a utility would not likely be liable for costs associated with the accident.

Another benefit of burying power lines is a reduction of electrocutions from sagging or downed power lines. In addition, workers would be less likely to inadvertently make contact with a buried distribution line. The FPSC study

[61] FPSC 1991. Volume II. For consistency, CRS used the same GDP deflator index ratio of 1.299 as was used in the 1995 FPSC report to index the 1990 findings to 2003 dollars.

calculated an annual avoided cost from contact accidents of $243,000 (2003 dollars) if all power lines were buried.[62]

Pricing

Some transmission-owning utilities argue that the current pricing mechanism for transmission discourages investment. FERC regulates all transmission, including unbundled retail transactions. Under the Federal Power Act (FPA), FERC is required to set "just and reasonable" rates for wholesale transactions.[63] FERC has traditionally determined rates by using an embedded cost method that includes recovery of capital costs, operating expenses, improvements, accumulated depreciation, and a rate of return. Traditionally, transmission owners have been compensated for use of their lines based on a contract path for the movement of electricity, generally the shortest path between the generator and its customer. However, electricity rarely follows a contract path and instead follows the path based on least impedance.[64] Transmission lines often carry electricity that has been contracted to move on a different path. As more bulk power transfers are occurring on the transmission system, transmission owners not belonging to RTOs (regional transmission organizations) are not always being compensated for use of their lines, because a contract path rarely follows the actual flow. This creates a disincentive for transmission owners to increase capacity.[65]

Under Order 2000,[66] FERC stated its interest in incentive ratemaking and, in particular, performance-based ratemaking. Those in favor of incentive ratemaking, including the electric utility industry, argue that incentives are needed (1) to encourage participation in regional transmission organizations (RTOs),[67] (2) to compensate for perceived increases in financial risk because of participation in a regional transmission organization, and (3) to facilitate efficient expansion of the transmission system.

FERC has used a "license plate" rate for transmission: a single rate based on customer location. As FERC is encouraging formation of large regional transmission organizations, FERC may move toward a uniform access charge, sometimes called *postage stamp rates*. With a postage stamp rate, users pay one charge for moving electricity anywhere within the regional transmission organization.

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[62] Ibid.

[63] 16 U.S.C. 824(d)(a).

[64] *Impedance* is a measure of the resistive and reactive attributes of a component in an alternating-current circuit.

[65] National Economic Research Associates, *Transmission Pricing Arrangements and Their Influence on New Investments*, World Bank Institute (July 6, 2000).

[66] 89 FERC 61,285.

[67] A *regional transmission organization* is an independent organization that does not own the transmission lines but operates a regional transmission system on a non-discriminatory basis. For additional discussion on RTOs see, CRS Report RL32728, *Electric Utility Regulatory Reform: Issues for the 109th Congress*, by Amy Abel.

Postage stamp rates eliminate so-called rate *pancaking*, or a series of accumulated transmission charges as the electricity passes through adjacent transmission systems, and increases the pool of available generation. On the other hand, by moving to postage stamp rates, customers in low-cost transmission areas may see a rate increase, and high-cost transmission providers in the same area may not recover embedded costs, because costs are determined on a regional basis.

In early 2003, FERC began to consider raising the rate of return as a way to reflect the regulatory uncertainty in the industry and encourage transmission investment.[68] The proposal would give a 1% return-on-equity-incentive for *new* transmission projects operating under an RTO. Transfer of transmission assets to an RTO would also result in an incentive return on equity of between 0.5% and 2%. This could raise return on equity to approximately 14% for some transmission projects. Increases in the return on equity would increase consumers' electric bills. However, in 2000, the cost of transmission accounted for less than 10% of the final delivered cost of electricity.[69] While the industry is in favor of increasing the return on equity as a way of providing an incentive to invest, consumer groups are opposed to such proposals because of the potential to increase consumer rates.[70]

As required by § 1241 of EPACT05, FERC issued its Final Rule on transmission pricing on July 20, 2006.[71] Although the order identifies specific incentives that FERC will allow, the burden remains on an applicant to justify the incentives by showing that the new transmission capacity will reduce the cost of delivered power by reducing transmission congestion or will ensure reliability. The applicant will also have to show that the rate is just, reasonable, and not unduly discriminatory or preferential.[72]

Although the order identifies specific incentives that FERC will allow, the burden remains on an applicant to justify the incentives. Several consumer groups argue that the Final Rule is too permissive in offering rate incentives. Under the Final Rule, FERC requires that applicants pass a "nexus test," meaning that the

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[68] Federal Energy Regulatory Commission, *Proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid,* Docket No. PL03-1-000 (January 15, 2003).

[69] Energy Information Administration, *Electric Sales and Revenue 2000*.

[70] Testimony of Gerald Norlander for the National Association of State Utility Consumer Advocates before the House Committee on Energy and Commerce, March 14, 2003, available at [http://energycommerce.house.gov/108/Hearings/03132003hearing818/hearing.htm].

[71] Federal Energy Regulatory Commission Final Rule, Order Number 679, *Promoting Transmission Investment through Pricing Reform* (July 20, 2006), Docket Number RM06-4-000.

[72] The final rule authorizes FERC to approve the following incentive-based rate treatments: a rate of return on equity sufficient to attract new investment in transmission facilities; allowance of 100% of prudently incurred Construction Work in Progress (CWIP) in the rate base; recovery of prudently incurred pre-commercial operations costs; accelerated depreciation used for rate recovery; recovery of 100% of prudently incurred costs of transmission facilities that are canceled or abandoned due to factors beyond the control of the public utility; and deferred cost recovery.

requested incentives match the demonstrable risks and challenges faced by the applicant undertaking the project. The final rule applies the "nexus test" to each incentive, rather than to the package of incentives as a whole. The American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) argue that this approach fails to protect consumers where an applicant seeks incentives that both reduce the risk of the project and offer an enhanced return on equity for increased risk. In response to comments on the Final Order, FERC issued an Order on Rehearing and determined that the nexus requirement no longer will be applied separately to each incentive but that the total package of incentives must match the demonstrable risks or challenges.[73]

In addition, the National Association of Regulatory Utility Commissioners (NARUC), APPA, NRECA, Transmission Dependent Utility Systems (TDU Systems), and the Transmission Access Policy Study Group (TAPS) argued that under the Final Rule, FERC erred in rebuttably presuming that certain review processes such as state siting approvals and regional planning processes would satisfy the requirement that a transmission project ensure reliability or reduce congestion. Under FERC's Order on Rehearing, FERC will require that each applicant explain whether any process being relied upon for a rebuttable presumption includes a determination that the project is necessary to ensure reliability or reduce congestion.[74]

Since Order 689 was issued, three projects have received transmission rate incentives: American Electric Power (AEP) Service Corp. received approval from FERC for incentive rates for a new 765 kV, 550-mile transmission line that is expected to extend from West Virginia to New Jersey; Allegheny Energy Inc. (Allegheny) was granted rate incentives on a proposed 500 kilovolt transmission line within the PJM region; and Duquesne Light Co.'s (Duquesne) petition for incentive rates was conditionally approved for several projects in Western Pennsylvania. FERC has approved incentives for the AEP and Allegheny projects that include a return on investment (ROE) "at the high end of the zone of reasonableness, with the zone of reasonableness to be determined in a future proceeding," recovery of construction work in progress (CWIP) costs, the ability to expense and recover pre-construction and pre-operating costs, and accelerated depreciation.[75] FERC conditionally granted Duquesne's ROE request of up to one and one-half percentage points above a base-level ROE, recovery of CWIP costs, recovery of prudently incurred pre-commercial operations costs, and prudently incurred costs of the project in the event the project is cancelled due to factors beyond Duquesne's control.[76]

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[73] Federal Energy Regulatory Commission Final Rule, Order on Rehearing, Order Number 679-A, *Promoting Transmission Investment through Pricing Reform*, (December 22), 2006), Docket Number RM06-4-001, p. 21.

[74] Ibid., p. 4.

[75] 116 FERC 61,059. Docket Number EL06-50-000, p. 15, available at [http://www.ferc.gov/whats-new/comm-meet/072006/E-15.pdf].

[76] FERC, Docket No. EL06-109-000, *et al*. (February 6, 2007), available at [http://www.ferc.gov/EventCalendar/Files/20070206185852-EL06-109-000.pdf].

Regulatory Uncertainty

For many years, transmission owners and investors expressed concern that the regulatory uncertainty for electric utilities is inhibiting both new investment in and construction of transmission facilities. For example, repeal of the Public Utility Holding Company Act of 1935 (PUHCA) had been debated since 1996. Without clarification on whether PUHCA would be repealed, utilities stated that they were reluctant to invest in infrastructure. It was argued that repeal of PUHCA could significantly expand the ability of utilities to diversify their investment options.[77] EPACT05 repealed PUHCA, and FERC and state regulatory bodies are given access to utility books and records. Removing this uncertainty could encourage additional investment in the transmission system.

In addition, FERC has been moving toward requiring participation in regional transmission organizations to create a more seamless transmission system. A fully operational regional transmission organization would operate the entire transmission system in a region and be able to replace multiple control centers with a single control center.[78] This type of control can increase efficiencies in the operation of the transmission system. RTO participants are required to adhere to certain operational guidelines, but these are not currently enforceable in court. Uncertainty over the form of an RTO, its operational characteristics, and the transmission rates for a specific region have apparently made utilities wary of investing in transmission. FERC has granted RTO status to several entities and conditionally approved others. If RTOs are able to operate successfully and develop a track record, some regulatory uncertainty will diminish.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) on standard market design (SMD).[79] This NOPR was highly controversial. FERC's stated goal of SMD requirements in conjunction with a standardized transmission service was to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries. The proposed rulemaking would have created a new tariff under which each transmission owner would be required to turn over operation of its transmission system to an unaffiliated independent transmission provider (ITP). The ITP, which could have been an RTO, would have provided service to all customers and would have run energy markets. Under the NOPR, congestion would have been managed with locational marginal pricing. FERC withdrew its SMD proposal shortly before passage of EPACT05.

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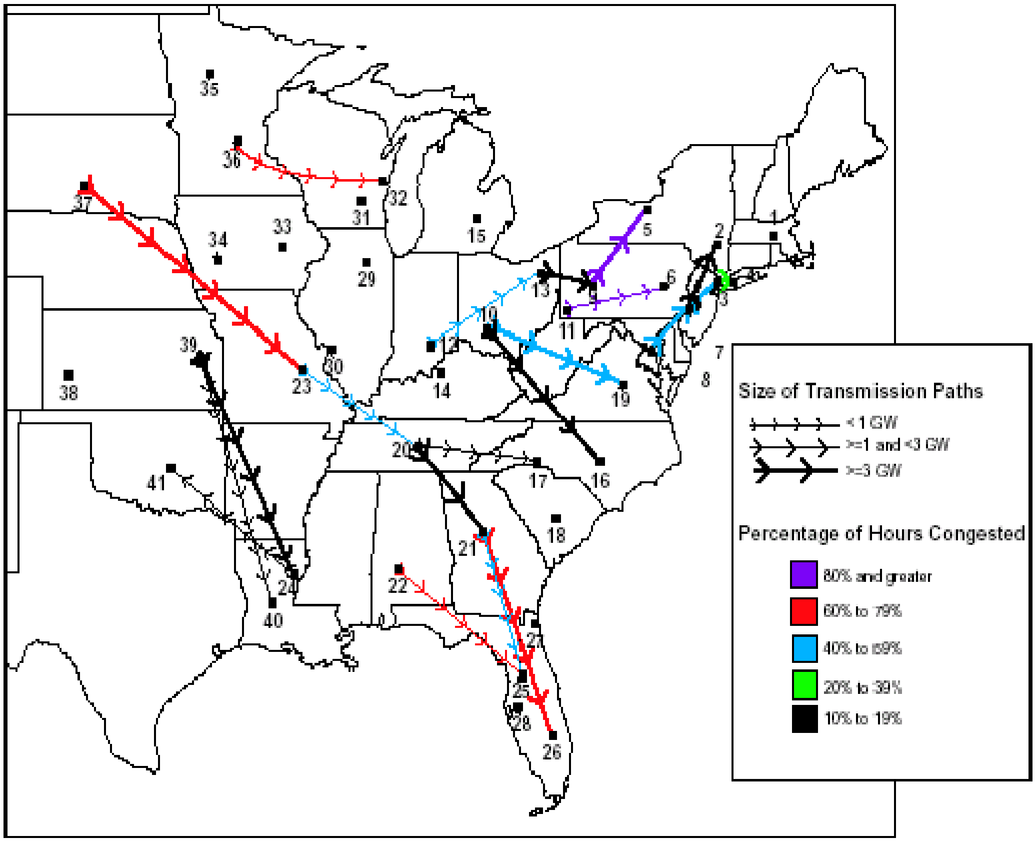
[77] For discussion of PUHCA repeal issues, see CRS Report RL32728, *Electric Utility Regulatory Reform: Issues for the 109th Congress*.

[78] PJM operates with a single control center.

[79] FERC, Docket No. RM01-12-000.

Figure 4. Congested Lines in the Eastern Interconnection



Source: U.S. Department of Energy, National Transmission Grid Study, May 2002.

Investment

Some contend that obtaining funding is the major impediment to transmission expansion.[80] Utilities have traditionally raised capital from three sources: equity investors, internal cash flow, and bondholders. Before 1978, utility stocks were seen as safe investments for investors. The Three Mile Island nuclear accident and other cost overruns of nuclear facilities made utility investment less attractive. Following enactment of the Energy Policy Act of 1992, many found investing in non-traditional utilities (Enron, Mirant, etc.) to once again be an attractive option. Following the California energy crises and the bankruptcy of several energy-related companies, investors once again withdrew from heavily investing in utility stock. Between 2000 and 2002, utility bonds had been unattractive to investors, according to Standard & Poor's.[81] Since then, many utilities have had their bond ratings reduced. In 2002, there were 182 bond rating downgrades of utility holding and operating companies and only 15 upgrades. A majority of electric utilities (62%) had a bond rating of

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[80] Roseman, E., and Paul De Martini, *In Search of Transmission Capitalists*, Public Utilities Fortnightly (April 1, 2003).

[81] Standard & Poor's, *U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue* (January15, 2003).

BBB or below while the number of those rated A- or better fell from 51% to 38% in one year. Also, according to Standard & Poor's, debt and preferred securities financing activity fell from $86 billion in 2001 to $74 billion in 2002. In addition, internal investment declined. The lack of investment options for utilities for transmission improvements had significantly slowed transmission capacity additions.

According to Standard & Poor's, the power sector had begun to experience an upward trend in bond ratings. During the first half of 2006, the U.S. power sector showed positive ratings gains, with company bond ratings being upgraded more often than downgraded. By the end of 2006, the investor-owned utility sector ratings leveled off with an equal number of upgrades and downgrades for the year.[82] This starkly contrasts with 2004 and 2005, when rating downgrades outpaced upgrades by about three to two.[83]

Conclusion

For the transmission system to operate efficiently and reliably, many observers argue that the tensions between economic, regulatory, and technology issues must be balanced. Currently, the transmission industry is widely viewed as being in a state of disequilibrium with significant regulatory and economic uncertainty. In addition, regional differences complicate regulatory solutions. A large component of regulatory uncertainty originates with a piece-meal approach to electric utility restructuring on both the federal and state level. In 1991, CRS stated that

> comprehensive regulatory reform of the electric power industry is neither desirable nor practical without a clearer vision of what form the industry should take. Too many uncertainties leave the future nature of the electric power industry such that a major overhaul of regulation would involve significant risks to the present stability of available and reliable electric power with little guarantee of improved service or lower costs.[84]

The Energy Policy Act of 1992 introduced competition to wholesale electric transactions without provisions for a comprehensive plan to address reliability issues and the development of efficient wholesale markets. In addition, many states have passed legislation or issued regulatory orders to introduce retail competition, each with its own set of rules for utilities to follow. Provisions in EPACT05 are intended to address many issues left outstanding by EPACT92. Although regulatory certainty may improve as a result of EPACT05, a clearer vision of the role of competition in the electric power industry, and additional investment in transmission infrastructure

[82] Standard & Poor's, *Pace of US Utility Raiding Activity Moderated in 2006* (January 23, 2007).

[83] Standard & Poor's, *Industry Report Card: U.S. Utility Second-Quarter Upgrade Surge Is Strongest in Years* (July 10, 2006).

[84] *Electricity: A New Regulatory Order?* Report prepared by the Congressional Research Service for the Committee on Energy and Commerce, U.S. House of Representatives, Committee Print 102-F (June 1991).

and technology, continues to be necessary to support an adequate and reliable transmission system.