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Electric Reliability: Options for Electric Transmission Infrastructure Improvements

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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 created tension between the regulatory environment and 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.

Electricity demand has been growing at 2% to 3% per year, but additions to the transmission system have been growing by 0.7% per year. This has resulted in transmission lines that are congested in several regions of United States. Several factors have contributed to the lack of new transmission capacity. First, there is general consensus that siting new lines is difficult, needing approval of all states in which the transmission line will be located. Second, some have argued that the pricing mechanism for transmission is a deterrent for investors. Third, many contend that regulatory uncertainty has added a level of risk that investors are unwilling to assume.

The Energy Policy Act of 1992 introduced competition to wholesale electric transactions without a comprehensive plan to address reliability issues and the development of efficient wholesale markets. In addition, approximately half of the states have passed legislation or had regulatory orders to introduce retail competition, each with its own set of rules for utilities to follow. The blackout of 2003 in the Northeast, Midwest, and Canada has highlighted the need for infrastructure improvements and greater standardization of operating rules. Until the electric power industry reaches a new equilibrium with more regulatory certainty, many observers predict, investment in transmission infrastructure and technology will continue to be inadequate.

This report will be updated as events warrant.

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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.

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 (EPACT)[2] created tension between the regulatory environment and existing transmission system. EPACT effectively deregulated wholesale 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 has 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.

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

[2] P.L. 102-486.

[3] Twenty-two states and the District of Columbia have plans to allow for retail choice for electricity. According to the Energy Information Administration, in 1996, 10 percent of generating capacity was owned by non-utility generators. By 2000, 26 percent of generating capacity was owned by non-utility generators. In addition, to encourage competition, Maine and New Hampshire have required utilities to fully divest of either generation or transmission assets and California and Rhode Island have partial divestiture requirements.

Electric reliability is addressed in comprehensive energy legislation (H.R. 6) that passed the House on April 21, 2005. S. 10, introduced on June 9, 2005, also includes reliability provisions. In part, Title XII of both bills would create an electric reliability organization (ERO) that would enforce mandatory reliability standards for the bulk-power system. All ERO standards would be approved by the Federal Energy Regulatory Commission (FERC). 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. This title also addresses transmission infrastructure issues. The Secretary of Energy would be able to certify congestion on the transmission lines and issue permits to transmission owners. Permit holders would 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. For additional analysis, see CRS Report RL32936, *Omnibus Energy Legislation, 109th Congress: Assessment of H.R. 6 as passed by the House*; and CRS Issue Brief IB10143, *Energy Policy: Comprehensive Energy Legislation (H.R. 6, S. 10) in the 109th Congress*.

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 the rates for 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, 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. The Federal Energy Regulatory Commission (FERC) regulates all transmission, including unbundled retail transactions.[4]

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.

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[4] 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. Ruling available at [http://a257.g.akamaitech.net/7/257/2422/04mar20021030/www.supremecourtus.gov/opinions/01pdf/00-568.pdf].

Transmission lines and distribution lines are categorized by their voltage rating. In general, 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.[5] 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 (EPACT) created a new category of wholesale electric generators called Exempt Wholesale Generators (EWGs) that are not considered utilities.[6] EWGs, also referred to as merchant generators, were intended to create a competitive wholesale electric generation sector. In addition, EPACT provided a means for these non-utility generators to have access to the transmission system. As a result of EPACT, FERC issued a policy statement on transmission pricing policy. It stated that:

> 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 (EPACT)[footnote 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.[7]

In May 1994, FERC established general guidelines for comparable access to the transmission system.[8] 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. 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

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[5] 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.

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

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

[8] 67 FERC 61,168.

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 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.

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 go 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 as well as preventing the collapse of voltages are major aspects of the role for transmission operators.[9] North American Electric Reliability Council (NERC) 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.[10]

Current Issues

The regulatory regime has shifted the operations of the electric utility industry, creating larger and more frequent bulk power transfers across a transmission system largely designed for local intrastate service. However, investment and infrastructure has not kept up with increases in the bulk power transfers and electricity demand. Electricity demand has been growing at 2% to 3% per year, but additions to the

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

[10] 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].

transmission system have been growing by 0.7% per year. So, in addition to generation capacity shortages in certain regions of the country, transmission lines are congested in several regions of United States. As is shown in Figures 1 and 2, many lines in the Eastern Interconnection and Western Interconnection are congested. This problem is 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.[11] According to NERC, the number of requests to use the transmission system that were denied because of congestion has risen from 305 in 1998 to 1,494 in 2002.[12] Over the next 10 years, the line-miles of high-voltage transmission are expected to increase 6% in contrast to a 20% expected increase in generation demand and capacity.[13] If this projection is accurate, further pressure on reliability could occur in several regions.[14]

Siting. One reason transmission lines have not been built in recent years is the difficulty in siting lines. Even though the transmission of electricity is considered interstate commerce, the siting of transmission lines is the responsibility of the states. In addition, several federal agencies play various roles in the siting process, primarily with regard to environmental impacts. Siting and building transmission lines have been very difficult because of citizen opposition as well as inconsistent siting requirements among states. While controversial, since the blackout of 2003, FERC Commissioners are now supporting federal siting backstop authority.[15] In addition, the electric industry is in favor of giving FERC siting authority.[16] States are generally opposed to this proposal.[17]

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

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[11] CRS Report 87-289 ENR. *Wheeling in the Electric Utility* Industry. February 12, 1987 (available from the author).

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

[13] Department of Energy. *National Transmission Grid Study.* May 2002. Available at [http://www.eh.doe.gov/ntgs/reports.html#reports].

[14] See CRS Report RL31469. *Electric Utility Restructuring: Maintaining Bulk Power System Reliability.*

[15] Statement of Nora Mead Brownell. *FERC Reverses Position, Will Now Take Federal Backstop Authority*. Energywashington.com. September 2, 2003.

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

[17] Statement of National Governors Association available at [http://www.nga.org/nga/legislativeUpdate/1,1169,C_LETTER%5ED_4412,00.html].

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.[18] The study indicated that a significant number of transmission lines operate below their thermal limits due to equipment limitations at substations. By remediating the equipment limitations with relatively inexpensive equipment (e.g., disconnect switches, bus connectors, relays, etc.), 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.

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.[19] 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.[20] 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.[21]

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[18] 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.

[19] 16 U.S.C. 824(d)(a).

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

[21] See, National Economic Research Associates. *Transmission Pricing Arrangements and Their Influence on New Investments*. World Bank Institute. July 6, 2000. Available at [http://www.worldbank.org/wbi/infrafin/pdfs/samples/dc2000-weektwo/berry_trans_

Under Order 2000,[22] FERC stated its interest in incentive ratemaking and in particular performance-based ratemaking. Those in favor of incentive ratemaking argue that incentives are needed: (1) to encourage participation in regional transmission organizations (RTOs)[23]; (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 uses 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.

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 proposed to raise the rate of return as a way to reflect the regulatory uncertainty in the industry and encourage transmission investment.[24] If adopted, this policy 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 consumer's electric bills. However, in 2000, the cost of transmission accounted for less than 10% of the final delivered cost of electricity.[25] 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.[26]

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[21] (...continued)
pricing.ppt].

[22] 89FERC61,285.

[23] 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*.

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

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

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

Regulatory Uncertainty. Transmission owners and investors have expressed concern that the regulatory uncertainty for electric utilities is inhibiting new investment in and construction of transmission facilities. For example, repeal of the Public Utility Holding Company Act of 1935 (PUHCA) has been debated since 1996 without resolution. Without clarification on whether PUHCA will be repealed, utilities state that they are reluctant to invest in infrastructure. Repeal could significantly expand the ability of utilities to diversify their investment options.[27]

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.[28] This type of control can increase efficiencies in the operation of the transmission system. RTO participants are required to adhere to certain rules, 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.

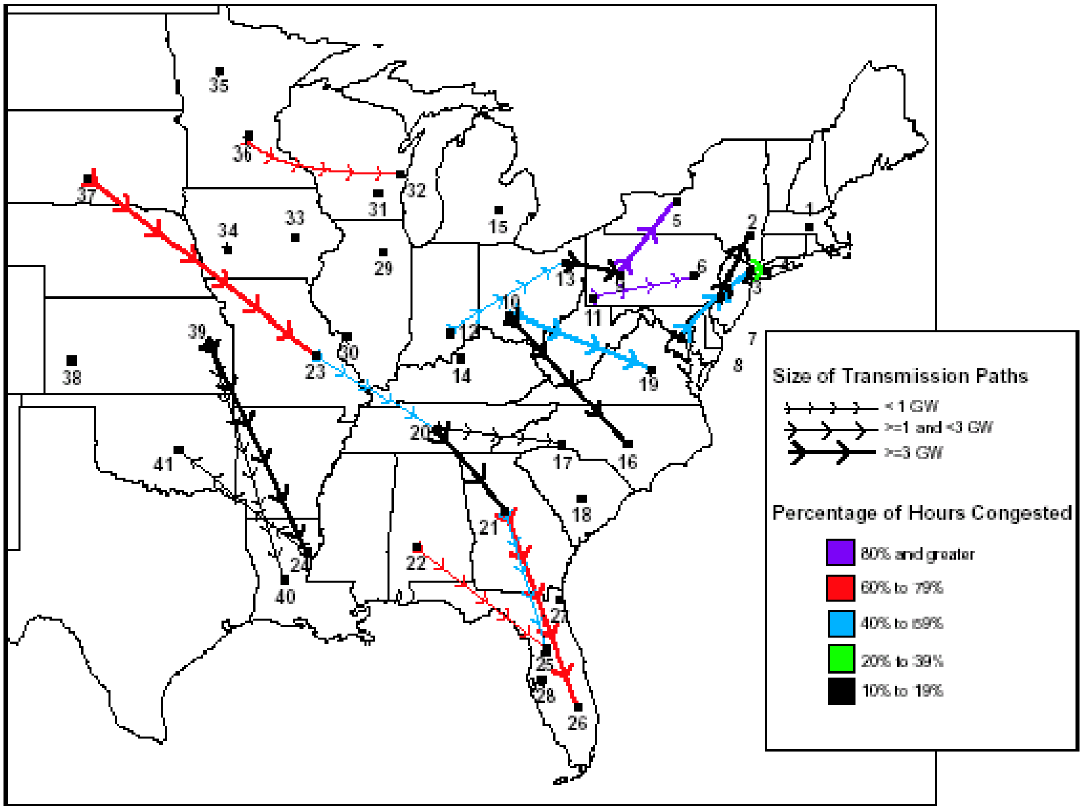
On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) on standard market design (SMD).[29] FERC's stated goal of SMD requirements in conjunction with a standardized transmission service is to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries. The proposed rulemaking would create 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 be an RTO, would provide service to all customers and run energy markets. Under the NOPR, congestion would be managed with locational marginal pricing.

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

[28] PJM operates with a single control center.

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

Figure 1. Congested Lines in the Eastern Interconnection

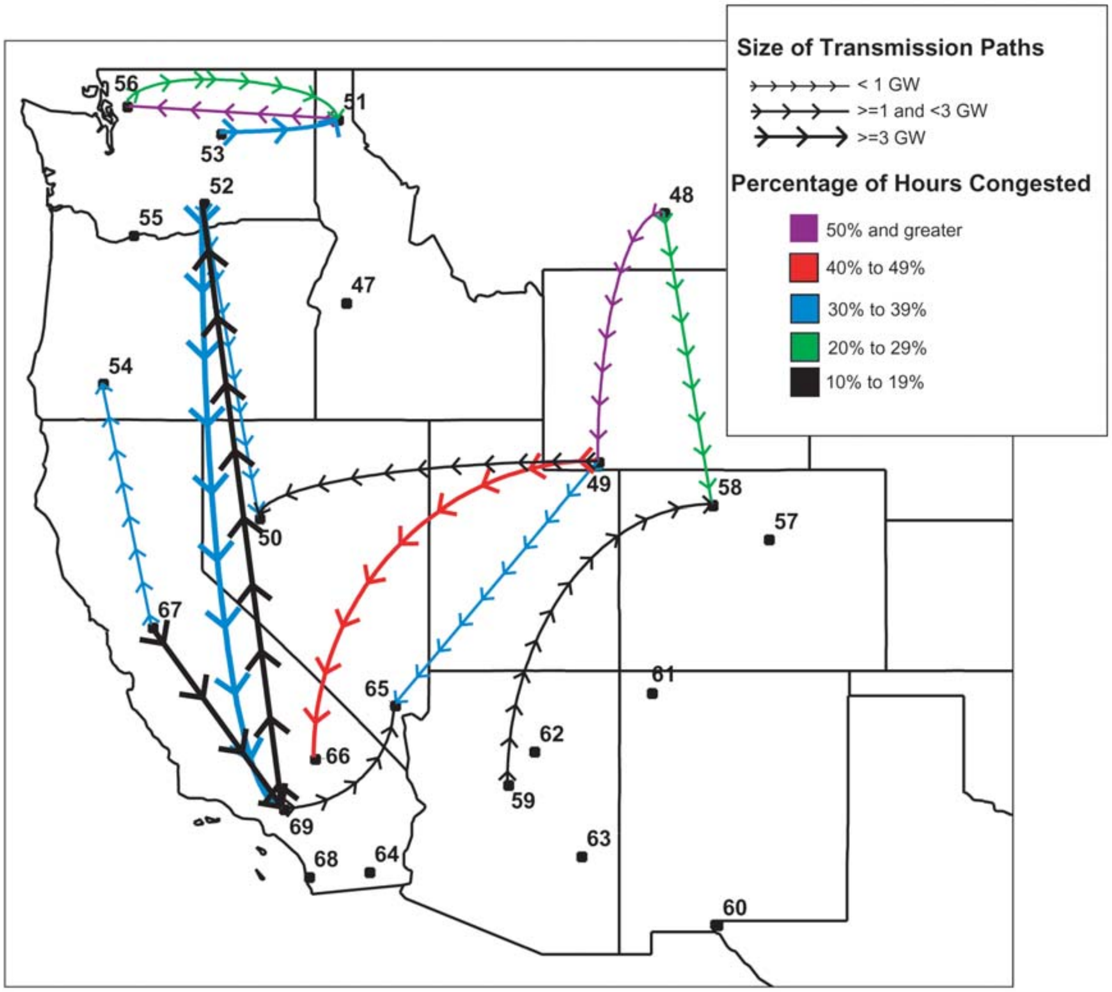


Source: U.S. Department of Energy. National Transmission Grid Study. May 2002.

On April 28, 2003, FERC staff issued *Wholesale Power Market Platform*, a White Paper that intended to clarify FERC's SMD proposal.[30] The White Paper responds to approximately 1,000 sets of formal comments submitted to FERC. In the White Paper, FERC states its intention to eliminate a proposed requirement that utilities join an Independent Transmission Provider (ITP). Instead, the final rule will require utilities to join an RTO or Independent System Operator (ISO). In the NOPR, FERC proposed to assert jurisdiction over the transmission component of bundled retail service. The White Paper reverses this position and states that the final rule will not assert new FERC jurisdiction over bundled retail sales.

[30] The FERC White Paper is available at [http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf].

Figure 2. Congested Lines in the Western Interconnection



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

Some state officials have expressed concern that the proposed rule infringes on state authority. FERC responded to this in the White Paper by clarifying that the final rule will not include a requirement for a minimum level of resource adequacy. In addition, the final rule will eliminate the NOPR's requirement that Firm Transmission Rights be auctioned. The White Paper noted that each RTO or ISO will need to have a cost recovery policy outlined in its tariff, but each region may differ on how participant funding will be used.[31] In addition, FERC stated that the final rule will allow for phased implementation to address regional differences.

This NOPR has been very controversial, with many arguing that the "one-size-fits-all" approach does not reflect regional differences. It is unlikely that FERC will

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[31] Participant Funding would additional transmission infrastructure that would be required to connect new generators to the grid to be paid for by the beneficiaries of the new transmission (ultimate consumers or new generators) rather than the traditional method of cost recovery through the entire rate-base.

issue a final SMD rule in the near future. House-passed comprehensive energy policy legislation (H.R. 6) would prohibit FERC from implementing its SMD proposal for five years. This adds to uncertainty for transmission owners who may be considering transmission additions as well as for investors.

Investment. Some contend that obtaining funding is the major impediment to transmission expansion.[32] Utilities have traditionally raised capital from three sources: equity investors, internal cash flow, and bondholders. Up through 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 have once again withdrawn from heavily investing in utility stock. According to Standard & Poor's, utility bonds are also unattractive to investors.[33] Since 2000, 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%) have a bond rating of 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. Additionally, internal investment has declined. The lack of investment options for utilities for transmission improvements has significantly slowed transmission capacity additions.

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.[34]

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[32] Roseman, Elliot and Paul De Martini. *In Search of....Transmission Capitalists*. Public Utilities Fortnightly. April 1, 2003.

[33] Standard & Poor's, *U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue*, Jan. 15, 2003.

[34] *Electricity: A New Regulatory Order?* A Report Prepared by the Congressional Research Service for the Use of the Committee on Energy and Commerce, U.S. House of

(continued...)

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, approximately half of the states have passed legislation or issued regulatory orders to introduce retail competition, each with its own set of rules for utilities to follow. Without greater regulatory certainty, and a clearer vision of the role of competition in the electric power industry, investment in transmission infrastructure and technology will likely continue to be inadequate.

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[34] (...continued)
Representatives. Committee Print 102-F. June, 1991.