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Electric Power Transmission: Background and Policy Issues

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Summary

This report provides background information on electric power transmission and related policy issues. Proposals for changing federal transmission policy before the 111th Congress include S. 539, the Clean Renewable Energy and Economic Development Act, introduced on March 5, 2009; and the March 9, 2009, majority staff transmission siting draft of the Senate Energy and Natural Resources Committee. The policy issues identified and discussed in this report include:

***Federal Transmission Planning*:** several current proposals call for the federal government to sponsor and supervise large scale, on-going transmission planning programs. Issues for Congress to consider are the objectives of the planning process (e.g., a focus on supporting the development of renewable power or on a broader set of transmission goals), determining how much authority new interconnection-wide planning entities should be granted, the degree to which transmission planning needs to consider non-transmission solutions to power market needs, what resources the executive agencies will need to oversee the planning process, and whether the benefits for projects included in the transmission plans (e.g., a federal permitting option) will motivate developers to add unnecessary features and costs to qualify proposals for the plan.

***Permitting of Transmission Lines*:** a contentious issue is whether the federal government should assume from the states the primary role in permitting new transmission lines. Related issues include whether Congress should view management and expansion of the grid as primarily a state or national issue, whether national authority over grid reliability (which Congress established in the Energy Policy Act of 2005) can be effectively exercised without federal authority over permitting, if it is important to accelerate the construction of new transmission lines (which is one of the assumed benefits of federal permitting), and whether the executive agencies are equipped to take on the task of permitting transmission lines.

***Transmission Line Funding and Cost Allocation*:** the primary issues are whether the federal government should help pay for new transmission lines, and if Congress should establish a national standard for allocating the costs of interstate transmission lines to ratepayers.

***Transmission Modernization and the Smart Grid*:** issues include the need for Congressional oversight of existing federal smart grid research, development, demonstration, and grant programs; and oversight over whether the smart grid is actually proving to be a good investment for taxpayers and ratepayers.

***Transmission System Reliability*:** it is not clear whether Congress and the executive branch have the information needed to evaluate the reliability of the transmission system. Congress may also want to review whether the power industry is striking the right balance between modernization and new construction as a means of enhancing transmission reliability, and whether the reliability standards being developed for the transmission system are appropriate for a rapidly changing power system.

This report will be updated as warranted.

Contents

Figures

Tables

Contacts

Introduction and Organization

This report discusses electric power transmission and related policy issues. Transmission is a prominent federal issue because of a perceived need to improve reliability and reduce costs, transmission's role in meeting national energy goals (such as increased use of renewable electricity), and the potential efficiency advantages of "smart grid" modernization. Proposals before the 111th Congress for changing federal transmission law and regulations to meet these and other objectives include S. 539, the Clean Renewable Energy and Economic Development Act, introduced on March 5, 2009; and the March 9, 2009, majority staff transmission siting draft of the Senate Energy and Natural Resources Committee (the "Senate Energy Majority Draft").[1]

Transmission development and regulation are complex and sometimes contentious policy areas. In addition to an overview of the electric power system, this report reviews six major transmission policy topics:

- Transmission planning.
- Transmission permitting.
- Financing and cost allocation.
- System modernization and the smart grid.
- Transmission system reliability.

A concluding section summarizes the policy issues identified in the report.

Overview of the Electric Power System

This section discusses the physical and technical characteristics of the nation's power system, and then regulation of electric power transmission.

Physical and Technical Features of the Power System

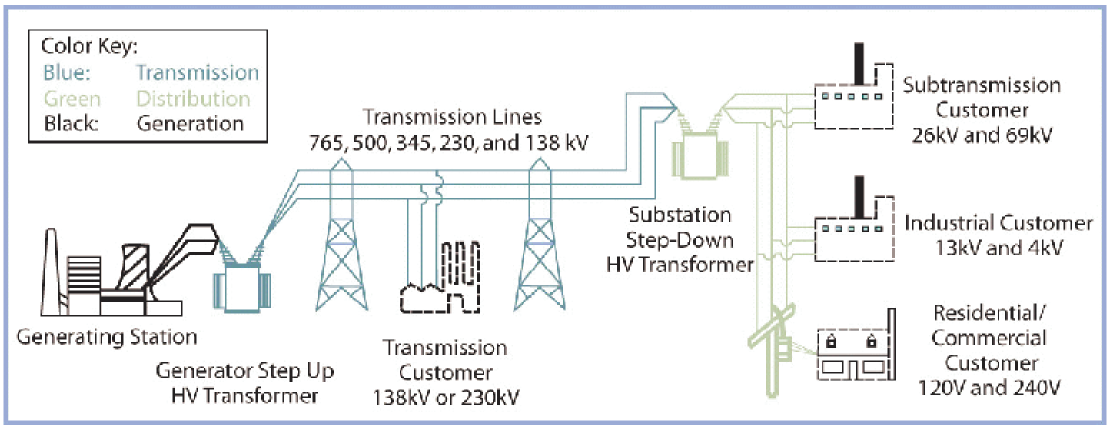
Figure 1 illustrates the major components of the electric power system. In brief:

[1] S. 539 is available at http://www.congress.gov/cgi-lis/bdquery/z?d111:S.539: (in the Legislative Information System). The Senate Energy Majority Draft is at http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.View&IssueItem_ID=6a7e4b50-e86d-452b-b0eb-630b2c7c10d1. Other transmission-related proposals as of March 2009 include the WIRES Group proposal (http://www.wiresgroup.com/); the American Electric Power /Mesa Power legislation draft (hard copy only; for related information see http://www.aep.com/about/transmission/); Energy Future Coalition proposal (http://www.energyfuturecoalition.org/editorsblog/EFC-Announces-Vision-Clean-Energy-Smart-Grid); the American Wind Energy and Solar Energy Industry Associations joint proposal (http://www.awea.org/GreenPowerSuperhighways.pdf); the Center for American Progress proposal (http://www.americanprogress.org/issues/2009/04/wired_for_progress2.0.html); the Manhattan Institute report, *The Million-Volt Answer to Oil* (http://www.manhattan-institute.org/html/cepe_10-14-08.htm); and the Institute for 21st Century Energy of the U.S. Chamber of Commerce study, *Blueprint for Securing America's Energy Future*, (http://energyxxi.org/pages/reports.aspx).

- Generating plants produce electricity, using either combustible fuels such as coal, natural gas, and biomass; or non-combustible energy sources such as wind, solar energy, and nuclear fuel.
- Transmission lines carry electricity from the power plant to demand centers. The higher the voltage of a transmission line the more power it can carry. Current policy discussions focus on the high voltage network (230 kilovolts (kV) rating and greater) used to move large amounts of power long distances.[2]
- Near customers a step-down transformer reduces voltage so the power can use distribution lines for final delivery.[3]

Figure 1. Elements of the Electric Power System

Simplified Schematic



Source: U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, p. 5, https://reports.energy.gov/BlackoutFinal-Web.pdf.

The vast majority of the transmission system in the United States is an alternating current (AC) system. This is largely because the voltage of AC power can be stepped up and down with relative ease. A small portion of the system runs on high voltage direct current (DC) lines. This technology is very efficient but requires expensive converter stations to connect with the AC system.

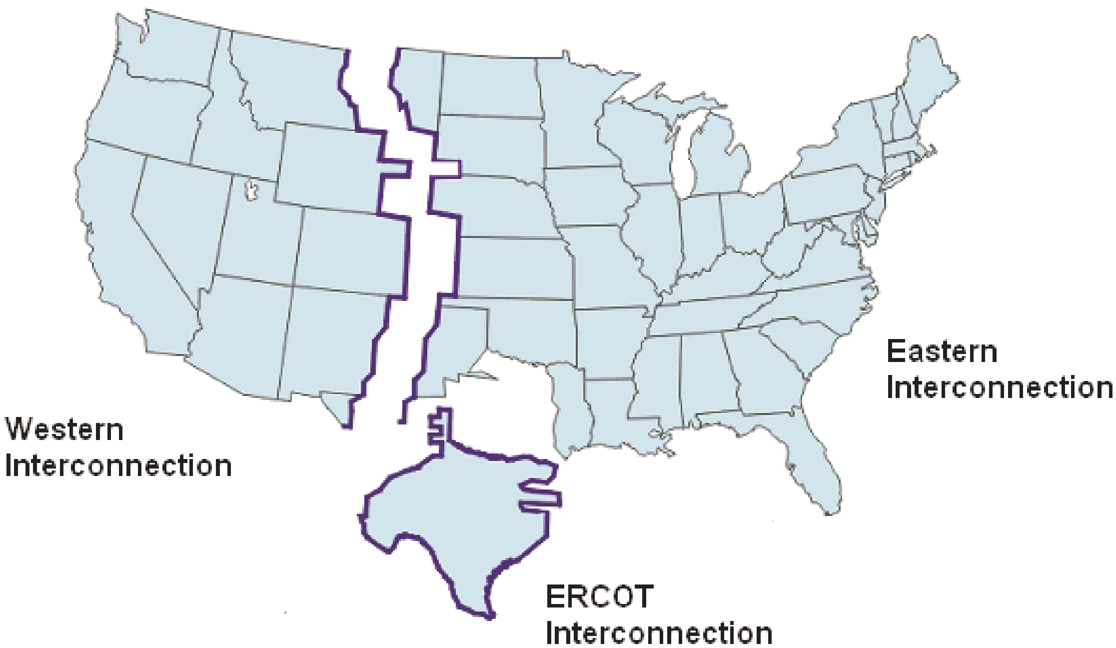
The transmission grid was not built in conformance with a plan like the interstate highway system. The grid is a patchwork of systems originally built by individual utilities as isolated transmission islands to meet local needs. These small networks were unsystematically linked when utilities decided to jointly own power plants or to connect to neighboring companies to

[2] Lines rated at 345 kilovolts (kV) or 500 kV are referred to as extra high voltage (EHV) lines. Lines rated at 765 kV are referred to as ultra high voltage (UHV) lines.

[3] In addition to the 167,000 miles of high voltage transmission lines, the transmission system includes about another 300,000 miles of lower voltage transmission lines. Note that the division between the transmission and distribution systems is not clear-cut. Depending on the application, a 69kV line might be considered a transmission or distribution line. For more information see Douglas R. Hale, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, Energy Information Administration (EIA), DOE/EIA-0639, Washington, DC, December 2004, p. 16, http://www.eia.doe.gov/cneaf/electricity/page/transmission/DOE_EIA_0639.htm.

facilitate power sales.[4] The grid eventually evolved into three major "interconnections," Eastern, Western, and the Electric Reliability Council of Texas (ERCOT, which covers most but not all of the state) (**Figure 2**). Within each interconnection the AC grid must be precisely synchronized so that all generators rotate at 60 cycles per second (synchronization failure can cause damage to utility and consumer equipment, and cause blackouts). There are only eight low capacity links (called "DC ties") between the Eastern, Western, and ERCOT Interconnections.[5] In effect, the 48 contiguous states have three separate grids with limited connections.

Figure 2. United States Power System Interconnections



Source: adapted from a map located on the Energy Information Administration website at http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/transmission.html.

Notes: ERCOT = Electric Reliability Council of Texas. For the extensions of the interconnections into Canada and Mexico see **Figure 3**. Neither figure shows the Quebec Interconnection.

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[4] As recently as 1962 the systems that now constitute the Eastern Interconnection were not fully connected (**Figure 2**). Securities and Exchange Commission, Prepared Direct Testimony of Paul B. Johnson on Behalf of the American Electric Power System, *In the Matter of American Electric Power Company, Inc*.: File No. 3-11616, December 7, 2004, pp. 9 and 11, http://www.sec.gov/divisions/investment/opur/filing/3-11616-120704aepex2.pdf.

[5] The direct current DC ties permit limited power transfers between the interconnections without synchronizing the systems. For example, a synchronization problem in the Eastern Interconnection cannot propagate across a DC tie into the Western Interconnection. ERCOT has two ties with the Eastern Interconnection and there are six ties between the Eastern and Western Interconnections. See http://www.wapa.gov/about/faqtrans.htm and Bill Bojorquez and Dejan J. Sobajic, "AC-DC Ties @ ERCOT," The 8th Electric Power Control Centers Workshop, Les Diablerets, Switzerland, June 6, 2005, http://www.epccworkshop.net/archive/2005/paper/pdf_monday/PanelSession/Sobajic_ERCOT.pdf. The typical capacity of these ties appears to be about 200 megawatts. Total generating capacity in the United States is about one million megawatts.

Within the three interconnections, the grid is operated by a total of about 130 balancing authorities.[6] These are usually the utilities that own transmission systems, but in some cases (such as ERCOT) a single authority supervises an entire regional grid. The balancing authorities operate control centers which monitor the grid and take actions to prevent failures like blackouts.

The transmission grid is owned by several hundred private and public entities. **Table 1** shows the miles of high voltage transmission line in the 48 contiguous states by region and type of owner. The table also shows the data expressed as ownership percentages (values in brackets).

Table 1. High Voltage Transmission by Owner and Region

Data in Miles [and Regional %] for the 48 Contiguous States for Transmission Lines of 230 kV and Higher

Owner Type	Northeast /Midwest	Southeast	Southwest	Upper Plains	West	U.S. Total
Federal	21 [0%]	2,768 [7%]	0 [0%]	2,541 [17%]	18,214 [27%]	23,544 [14%]
Other Public Power	964 [3%]	2,079 [5%]	731 [5%]	1,798 [12%]	5,525 [8%]	11,098 [7%]
Cooperative	0 [0%]	2,993 [8%]	387 [2%]	2,908 [20%]	4,496 [7%]	10,784 [6%]
Subtotal – All Public Power and Cooperatives	986 [3%]	7,840 [20%]	1,118 [7%]	7,247 [49%]	28,235 [42%]	45,426 [27%]
Independent Transmission Companies	4,640 [15%]	0 [0%]	351 [2%]	1,045 [7%]	0 [0%]	6,036 [4%]
Investor Owned Utilities	24,968 [81%]	31,412 [79%]	12,408 [80%]	5,402 [36%]	37,034 [56%]	111,223 [66%]
N/A	260 [1%]	264 [1%]	1,686 [11%]	1,148 [8%]	1,250 [2%]	4,609 [3%]
Total	30,853 [100%]	39,516 [100%]	15,563 [100%]	14,843 [100%]	66,519 [100%]	167,294 [100%]

Source: Data downloaded from Platts POWERmap, information on entity ownership type provided by the Energy Information Administration, and CRS estimates.

Notes: The Northeast/Midwest region is the combination of the RFC and NPCC NERC regions; the Southeast is the combination of SERC and FRCC; the Southwest is the combination of ERCOT and SPP; the Upper Plains is the MRO region; and the West is the WECC region. For a NERC regional map, see **Figure 3**. N/A signifies that ownership information is not available. Other Public Power includes municipal and state systems. kV = kilovolt. Detail may not add to totals due to independent rounding.

The table illustrates how ownership patterns vary greatly across the country. In the West and Upper Plains regions, public power owns more than 40% of the high voltage grid. In the other regions about 80% of the grid is owned by investor owned utilities.

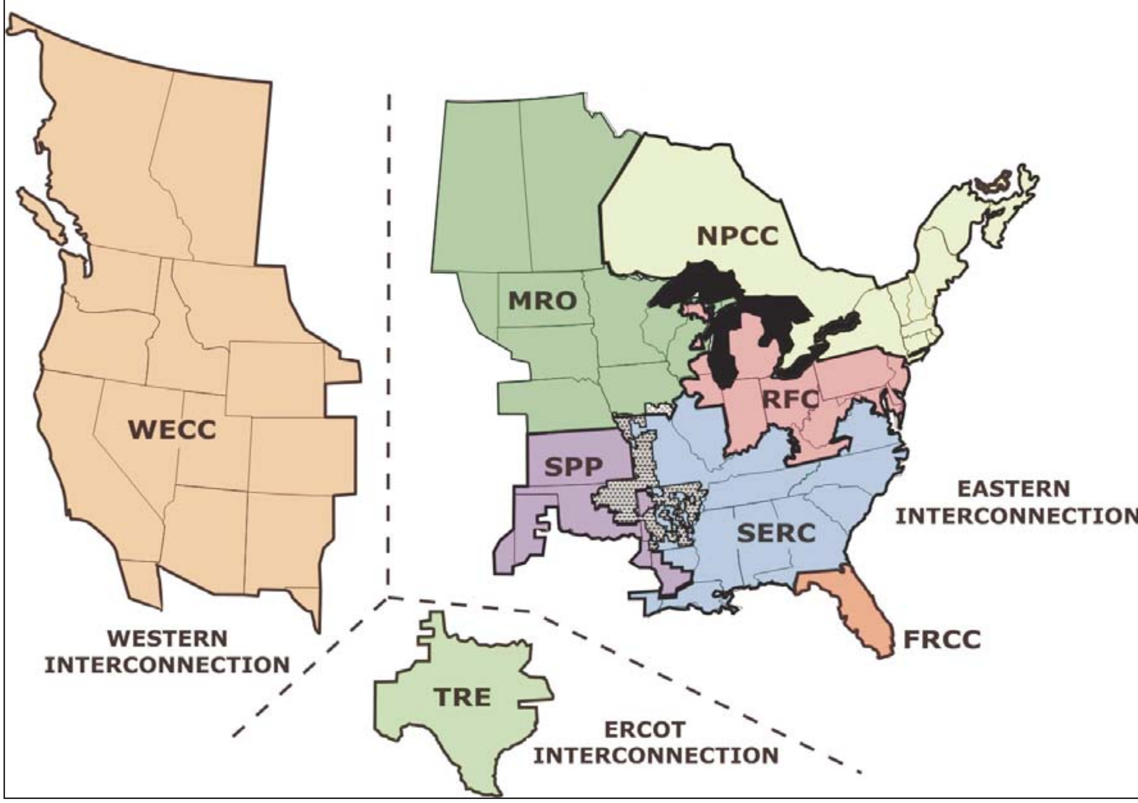
Figure 3 (below) shows the eight North American Electric Reliability Corp. (NERC) regions. As discussed later in the report, NERC and its regions play important roles in maintaining the

[6] U.S. Department of Energy, *20% Wind Energy by 2030*, Washington, D.C., July 2008, p. 91, http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf. For a map that displays balancing authorities see the NERC website at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Regions_BA.jpg.

reliability of the power system. Like the interconnections, some of these NERC regions extend into Canada or Mexico. However, this report is concerned only with the U.S. transmission grid.

Figure 3. NERC Reliability Regions

(North American Grid Interconnections Outside of Quebec Also Shown)



Source: North American Electric Reliability Corp. website at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_color.jpg.

Notes: NERC = North American Electric Reliability Corp. The NERC regional entities are ERCOT (Electric Reliability Council of Texas); FRCC (Florida Reliability Coordinating Council); MRO (Midwest Reliability Organization); NPCC (Northeast Power Coordinating Council); RFC (Reliability*First* Corp.); SERC (SERC Reliability Corp.); SPP (Southwest Power Pool); TRE (Texas Regional Entity, an independent division of ERCOT); and WECC (Western Electricity Coordinating Council). Quebec Interconnection is not shown.

Regulatory Framework

Electric power regulation is divided among federal, state, and regional authorities. The scope of federal authority is different for rates and reliability. The following discussion reviews:

- State regulation and self-governing public power.
- Federal regulation of the transmission system and the reliability of the bulk power system.

State Regulation and Self-Governing Public Power

State regulation of the electric power industry is usually centered in a public utility commission (PUC). The authority of the commissions is often limited to investor-owned utilities (IOU; i.e., private corporations, usually with publicly traded stock). The PUCs set retail rates, review utility operations, and, most importantly for the purposes of this report, issue siting approvals (permits) for new transmission lines.

Publicly-owned utilities (POUs) are owned by municipal, state, and federal governments. The term is also sometimes applied to customer-owned rural electric cooperatives. POUs are typically small and operate only distribution systems, but some have large transmission and generation systems, such as the Tennessee Valley Authority. POUs are self-regulated by their governing boards, are generally not subject to state or federal economic regulation, and make their own decisions on adding new generating capacity and building transmission lines.[7]

Federal Regulation of Electric Power Transmission and Power System Reliability

This part of the report first discusses federal regulation of transmission, and then federal regulation of the reliability of the power system.

Federal Transmission Regulation

Federal regulation of the power industry is exercised by the Federal Energy Regulatory Commission (FERC), an independent agency administratively housed within the Department of Energy. FERC regulates wholesale electricity rates,[8] approves transmission line projects, and sets transmission rates. However, FERC's authority is limited in important respects:

- For the most part FERC's rate-making and transmission authorization authority is limited to IOUs in the 48 contiguous states outside of ERCOT.[9]
- While FERC must approve transmission projects proposed by jurisdictional utilities and establishes rates, a project also needs a siting permit from every state the line will traverse.

[7] Rural cooperatives as a group are somewhat more subject to state and federal regulation than government-owned utilities. Close to half the state PUC's have authority over cooperatives, and a small number of cooperatives are also subject to FERC rate regulation.

[8] Wholesale electricity sales are transactions between a generator and a reseller of power, or between two resellers. An example is when one utility sells power to another. This is also referred to as sales for resale. A retail transaction is a sale to the final end user, as when a utility sells electricity to a homeowner.

[9] The entities which eventually formed ERCOT severed non-emergency connections with outside grids in August 1935. Their objective was to avoid falling under the ratemaking jurisdiction of the Federal Power Commission (FERC's predecessor) by maintaining a purely intrastate system. DC ties between ERCOT and the Eastern Interconnection were constructed in the 1980s, but these do not put ERCOT under FERC rate jurisdiction due to a specific exemption in the law (16 U.S.C. § 824k(k)). For additional information, see Richard D. Cudahy, "The Second Battle of the Alamo: The Midnight Connection," *Natural Resources and Environment*, Summer 1995; *West Texas Utilities Co. and Central Power and Light Co. v. Texas Electric Service Co. and Houston Lighting and Power Co.*, U.S. District Court of the Northern District of Texas, Dallas Division, Memorandum Opinion, January 30, 1979 (470 F. Supp. 798).

Critics have argued that multi-state permitting of transmission lines has delayed the construction of needed transmission lines. In the Energy Policy Act of 2005 (EPACT05), Congress gave FERC "backstop" siting authority.[10] This authority operates as follows:

- The Department of Energy (DOE) is to conduct a triennial study of transmission system congestion. Based on this study, DOE may designate as National Interest Electric Transmission Corridors (NIETC) areas with severe transmission congestion.
- A special permitting rule applies to transmission projects proposed for a NIETC. If a state has not acted on the permit application for a NIETC project within a year, the developer can bypass the state and bring its application to FERC for approval.

DOE completed its first congestion study in 2006 and in 2007 designated two NIETCs, one in southern California–Arizona, and a second covering a large part of the Northeast.[11] As of early 2009 no use had been made by transmission developers of the backstop process. Moreover, in February 2009, the Fourth Circuit Court of Appeals ruled that FERC had overstepped its authority in implementing the backstop process. FERC had interpreted the law to mean that the backstop process could be used if a state has not acted within a year *or if the state has affirmatively decided to reject the project*. However, the court ruled that a state's decision to reject a project could not be appealed to FERC.[12] On April 2, 2009, FERC asked the Fourth Circuit to reconsider its decision.

Another aspect of FERC regulation is its efforts to encourage competition in the electric power market. In 1996, FERC mandated "open access" to the transmission system.[13] Open access requires transmission owners to make available, at cost-based or market-based fees, available transmission capacity to any generator or power buyer that is or can be connected to the system. The objective is to prevent transmission owners from using their control of the power system from stifling competition. To further facilitate open access, in 1999 a FERC order[14] encouraged the creation of regional transmission organizations (RTO; see **Figure 4**). RTOs take over operation of the transmission network in a region or large state, although utilities continue to own their systems. RTO's ensure open access to the grid, coordinate transmission planning, and establish mechanisms to pay for new transmission lines.[15]

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[10] 18 U.S.C. § 824p.

[11] The first congestion study, the NIETC designation report, maps of the current NIETCs, and information on the upcoming second congestion study are available on the website of DOE's Office of Electricity Delivery and Energy Reliability at http://www.oe.energy.gov/index.htm. The second congestion study is due in 2009 and could result in revisions to the NIETCs.

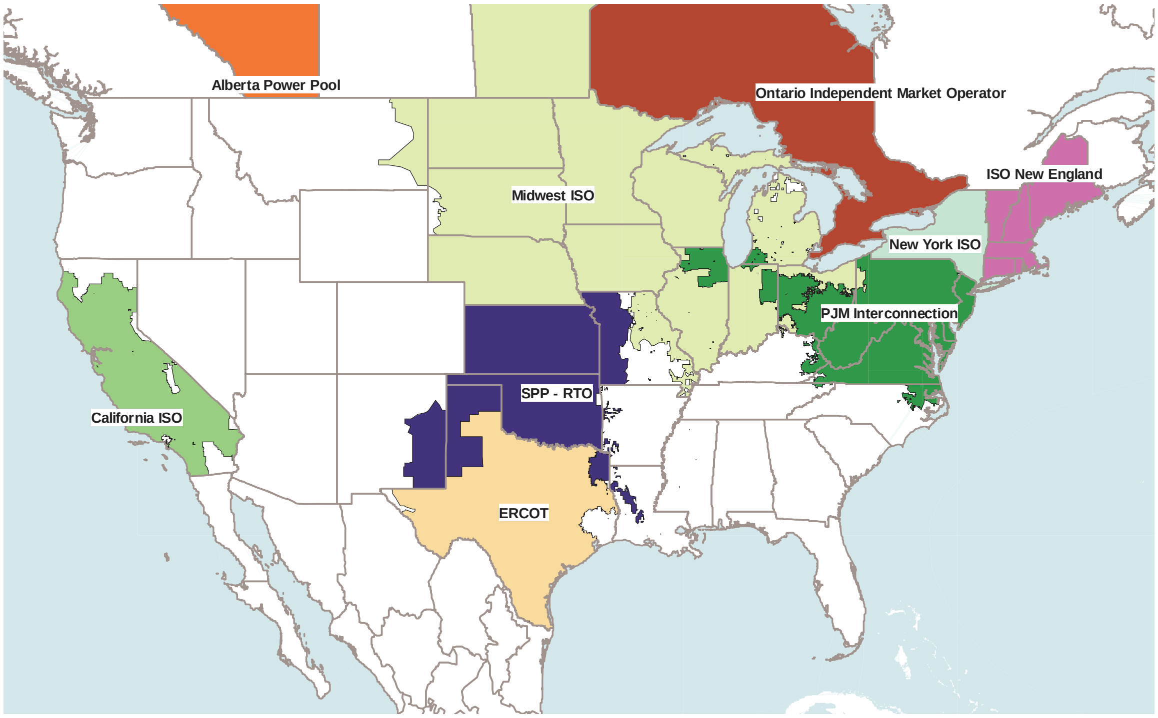
[12] *Piedmont Environmental Council v. FERC*, Case No. 07-1651 (4th Cir 2009), http://pacer.ca4.uscourts.gov/opinion.pdf/071651.P.pdf.

[13] See Orders 888 and 889 at http://www.ferc.gov/legal/maj-ord-reg.asp.

[14] See Order 2000 at http://www.ferc.gov/legal/maj-ord-reg.asp.

[15] RTOs also operate short-term markets for electricity sales and in some cases operate capacity markets which arrange for new power plants to be built. (Similar in function to RTOs are independent system operators (ISOs) and the terms are sometimes used interchangeably. However, the only ISOs to be qualified as RTOs under the terms of FERC's Order 2000 are ISO-New England, PJM, the Midwest ISO, and the SPP RTO.) As shown in **Figure 4**, RTOs and ISOs cover only part of the nation. Some regions that have been opposed to "restructuring" of the power market, such as the southeast and northwest, do not have RTOs. A full discussion of the competitive restructuring of the electric power market is beyond the scope of this report. For summaries of these developments, see The Electricity Advisory (continued...)

Figure 4. North American Transmission Organizations



Source: Created by CRS using Platts POWERMap.

Notes: ERCOT = Electric Reliability Organization of Texas; ISO = Independent System Operator; MISO = Midwest Independent System Operator; SPP = Southwest Power Pool. PJM at one time was an abbreviation for Pennsylvania – New Jersey – Maryland, but is now just part of the name of the organization. The following are regional transmission organizations under the terms of FERC's Order 2000: ISO New England, PJM, Midwest ISO, and SPP RTO.

Federal Regulation of Bulk Power System Reliability

The one sphere in which FERC's authority covers all entities in the 48 contiguous states is oversight of the reliability of the "bulk power system," including transmission.[16] Before EPACT05, transmission system reliability was subject to voluntary power industry self-regulation, exercised through the North American Electric Reliability Council (NERC).[17] As a voluntary organization NERC could not enforce reliability rules. In reaction to the northeastern

(...continued)

Committee, *Keeping the Lights on in a New World*, U.S. Department of Energy, Washington, DC, January 2009, sections 1.7 to 1.10, http://www.oe.energy.gov/eac.htm; and Federal Energy Regulatory Commission, Order No. 890, Final Rule, issued February 16, 2007, pp. 6 – 21, http://www.ferc.gov/legal/maj-ord-reg.asp.

[16] The bulk power system includes the transmission system but not distribution lines. As defined in 16 U.S.C. § 824o (added by the Energy Policy Act of 2005), "The term 'bulk-power system' means—(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy."

[17] NERC was created in 1968, in the wake of the northeastern blackout of 1965. For a summary NERC history and timeline see http://www.nerc.com/page.php?cid=1|7|11.

blackout of 2003, EPACT05 ordered FERC to designate an official Electric Reliability Organization (ERO) to design and enforce new mandatory reliability standards. In 2006, FERC designated NERC – now reorganized as the North American Electric Reliability Corporation – as the ERO, giving NERC the legal enforcement authority it had lacked. All reliability standards and enforcement actions proposed by NERC must be approved by FERC. NERC has delegated some of its reliability functions to its eight regions (**Figure 3**).[18]

Transmission Planning

Background

Many analysts have identified a need to expand the national transmission system. For example, the official report on the 2003 northeastern blackout concluded that:

> As evidenced by the absence of major transmission projects undertaken in North America over the past 10 to 15 years, utilities have found ways to increase the utilization of their existing facilities to meet increasing demands without adding significant high-voltage equipment. Without intervention, this trend is likely to continue. Pushing the system harder will undoubtedly increase reliability challenges…. Special protection schemes may be relied on more to deal with particular challenges, but the system still will be less able to withstand unexpected contingencies. A smaller transmission margin for reliability makes the preservation of system reliability a harder job than it used to be. The system is being operated closer to the edge of reliability than it was just a few years ago.[19]

Assuming more transmission capacity is needed, some of the next questions are what types of lines should be built, where should they be constructed, and on what schedule. S. 539, the Senate Energy Majority Draft," and other transmission policy proposals generally include a federally sponsored planning process, conducted at a regional or interconnection-wide scale and subject to FERC oversight, that would answer these questions. The planning process would include utilities, states, power developers, government agencies, and community representatives. The process would go far beyond current efforts by FERC to encourage transmission planning.[20]

In these proposals a primary object of the planning process is typically to identify high priority transmission projects that would be eligible for preferential permitting and financing. "High priority" is usually defined as meeting one or both of two goals:

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[18] The eight regional reliability entities are separate organizations with which NERC has entered FERC-approved delegation agreements. In somewhat different form the regions or predecessor organizations have, like NERC, existed for decades.

[19] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, p. 103, https://reports.energy.gov/BlackoutFinal-Web.pdf.

[20] FERC Order 890, issued on February 16, 2007, requires transmission providers to institute transparent transmission planning processes open to transmission customers, interconnected systems, and other interested parties. The requirement to implement this type of process only applies to FERC jurisdictional utilities. Unlike S. 539 and the Senate Energy Majority Draft, the order does not provide for federal funding of planning processes, establish regional planning entities, envision planning for major transmission network additions over a wide geographic scope, or give projects that result from the planning processes special access to federal permitting authority or possible access to federal funding. Order 890 ("Preventing Undue Discrimination and Preference in Transmission Service") is available at the FERC website at http://www.ferc.gov/legal/maj-ord-reg.asp; see pages 234 to 346 of the order, and Attachment K (sheets 162 and 163) of the pro forma open access transmission tariff attached to the order as Appendix C.

- Expanding the grid to reach areas where renewable electricity plants can be built.
- Resolving grid congestion and reliability problems.

The next two parts of the report discuss the following transmission planning issues:

- The objectives of the planning process.
- Planning authority.

Objectives of the Planning Process

This discussion looks at the objectives of federal transmission planning from three perspectives: renewable energy development; congestion relief and reliability; and alternatives to transmission.

Expansion for Renewable Energy

Currently the most important source for new renewable electricity generation is wind power,[21] but many of the best wind production areas are in thinly populated areas in the Midwest and northern plains that have limited access to transmission lines. The best region for solar development is the isolated desert southwest. Some planning process proposals, including S. 539, are explicitly focused on expanding the grid to serve these remote renewable resource areas. In the S. 539 process, the purpose of the plan is to develop transmission lines to serve "National Renewable Energy Zones," and 75% of the generating capacity connected to the lines must be renewable (e.g., wind and solar energy). Other objectives, such as congestion relief, are included in the legislation but are not the primary aims of the bill.

There are two basic concepts for expanding the transmission grid to reach remote renewable energy regions. One concept is to plan and construct a continent-spanning ultra-high voltage "overlay" system of AC or DC transmission lines that would be the electrical equivalent of the interstate highway system. This system of "transmission superhighways" would be designed to move large amounts of renewable electricity to customers across the country. No firm plans exist for such a system, but conceptual layouts have been proposed.[22] The second, less ambitious, concept relies on interconnection-wide or regional plans for identifying discrete transmission projects to connect renewable energy zones to load centers.[23]

Renewable energy-focused transmission planning could accelerate the development of renewable power. However, some critics argue that such a renewable-centric approach to transmission planning would produce costly facilities. This is because a transmission line built for peak renewable power output would be underutilized much of the time (since the output of wind and

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[21] In 2007, 5,193 net summer megawatts (MW) of new wind generating capacity was installed in the United States, compared to 89 megawatts of solar generation. The largest source of new generating capacity in 2007 was gas-fired power plants (6,673 MW). Total additions were 13,845 MW. EIA, *Electric Power Annual 2007*, Table 2.6. For more information on wind power see CRS Report RL34546, *Wind Power in the United States: Technology, Economic, and Policy Issues*, by Jeffrey Logan and Stan Mark Kaplan.

[22] For example, see U.S. Department of Energy, *20% Wind Energy by 2030*, Washington, D.C., July 2008, p. 12, http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf.

[23] Examples include the Joint Coordinated System Plan conceptual design of lines for moving wind power to the industrial Midwest and Northeast (http://www.jcspstudy.org/), and the ITC Holdings' Green Power Express, a plan for tying wind power from the Great Plains into the Midwestern grid (http://www.thegreenpowerexpress.com/).

solar power vary with the weather and time-of-day). Critics also claim that a renewable-centric planning approach might not adequately meet congestion relief and reliability objectives.[24]

Expansion for Congestion Relief and Reliability

Transmission congestion occurs when use of a power line is restricted (for example, to prevent overloading and failure of the line). Utilities and RTOs can work around transmission congestion by using alternative transmission paths or by changing power plant operations, but these steps (which often involve running expensive power plants that would otherwise be less-utilized or idle) can be costly. Studies suggest that the annual costs of transmission congestion range from the hundreds of millions to billions of dollars.[25] The solution for congestion costs is not necessarily massive transmission construction. For example, DOE found that in the Eastern Interconnection "a relatively small portion of constrained transmission capacity causes the bulk of the congestion cost that is passed through to consumers. This means that a relatively small number of selective additions to transmission capacity could lead to major economic benefits for many consumers."[26]

Transmission system reliability is defined by NERC has having two aspects: whether a transmission system has enough capacity to continuously meet customer needs, and whether the system has the resiliency to withstand major failures, such as the loss of a key transmission line.[27] As with congestion relief, the solutions to reliability problems do not necessarily involve building new transmission lines. For example, sometimes reliability can be enhanced by building new or expanded substations or by installing certain types of specialized equipment that helps maintain system voltage levels.[28]

When new transmission lines are needed for congestion relief or to improve reliability they can be expensive, multi-year projects. An example of a large transmission project for reliability is the 210 mile Trans-Allegheny Interstate Line (TrAIL) from southwestern Pennsylvania through West Virginia to Northern Virginia. This $820 million project involves construction of 210 miles of new transmission lines and substations. According to NERC, the project is needed to "relieve anticipated overloads and voltage problems in the Washington, DC area, including anticipated

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[24] According to the Large Public Power Council, "Such [renewable energy] requirements simply may not work when one considers the physics of the electric grid and the intermittent nature of renewable resources." U.S. Congress, Senate Committee on Energy and Natural Resources, *To Receive Testimony On Pending Legislation Regarding Electricity Transmission Lines*, Prepared Testimony of James A. Dickenson on Behalf of the Large Public Power Council, 111th Cong., 1st sess., March 12, 2009, p., 7, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=b9e47ea9-c62b-23fc-33ff-30fda7b3a744&Witness_ID=ed6a79eb-6664-412c-b66b-7e87e4e55435.

[25] Bernard Lesieutre and Joseph Eto, Electricity Transmission Congestion Costs: A Review of Recent Reports, Lawrence Berkeley National Laboratory, p. 2, http://certs.lbl.gov/pdf/54049.pdf, and U.S. Department of Energy, *National Transmission Grid Study*, May 2002, pp. 16–18, http://www.pi.energy.gov/documents/TransmissionGrid.pdf.

[26] U.S. DOE, *National Electric Transmission Congestion Study*, August 2008, p. 28, http://www.pi.energy.gov/documents/TransmissionGrid.pdf. Emphasis in the original not shown. DOE also found that only 20% of the constrained transmission capacity accounted for 60% of national congestion costs (p. 29).

[27] It would be uneconomic to build a transmission system capable of withstanding any conceivable failure, so systems are designed to meet "credible contingencies."

[28] The specialized equipment referred to injects "reactive power" into the grid. Reactive power supply is a relatively obscure topic that plays a critical role in power system operations. For more information see Federal Energy Regulatory Commission, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, February 4, 2005, http://www.ferc.gov/eventcalendar/files/20050310144430-02-04-05-reactive-power.pdf.

overloads expected in 2011."[29] If the project stays on schedule, it will take five years from the start of planning to operation.

Planning and Alternatives to Transmission

One perspective on renewable development, reliability, and other power system goals is that new transmission is central to meeting these objectives. This point of view is illustrated by FERC testimony to Congress in early 2009:

> We need a National policy commitment to develop the extra-high voltage (EHV) transmission infrastructure to bring renewable energy from remote areas where it is produced most efficiently into our large metropolitan areas where most of this Nation's power is consumed. Certainly, developing local renewable energy and distributed resources[30] is also important as we expand our capacity to generate clean power, but that is a separate issue from, and is not a substitute for, developing the EHV transmission infrastructure….[31]

An alternative viewpoint is that a transmission-focused planning process may, almost by definition, not give enough emphasis to non-transmission approaches to meeting energy needs. This view is illustrated by the reaction of the New York and New England RTOs to the "Joint Coordinated System Plan," which outlines massive transmission construction to bring wind power from the Dakotas to the East Coast. In the view of the northeastern RTOs, the plan was badly flawed because it did not consider other options, including eastern wind plants, demand response,[32] and building shorter transmission lines to renewable power in Canada.[33] Another example of this perspective is an "infrastructure vision" report of the National Governors' Association, which emphasizes decentralized and technological solutions to power system issues rather than big transmission projects.[34]

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[29] North American Electric Reliability Corp., *2008 Long-Term Reliability Assessment*, October 2008, p. 171, http://www.nerc.com/files/LTRA2008.pdf. This report, which is updated annually, contains information on planned transmission projects throughout the 48 contiguous states. The reliability reports are available on the NERC website at http://www.nerc.com/page.php?cid=4|61. For more information on the TrAIL project, see the project website at http://www.aptrailinfo.com/index.php.

[30] Distributed resources (also called distributed generation) refers to generation located close to load and often owned by the power customer. The term covers a wide variety of technologies, ranging from residential roof-top solar to large industrial cogeneration systems. Depending on individual circumstances the distributed generation system can be connected to the transmission or distribution system of the local utility.

[31] U.S. Congress, Senate Committee on Energy and Natural Resources, Prepared Testimony of Acting Chairman Jon Wellinghoff, Federal Energy Regulatory Commission Pending Legislation Regarding Electric Transmission Lines, 111th Cong., 1st sess., March 12, 2009, p. 2, http://www.ferc.gov/EventCalendar/Files/20090312100013-03-12-09-testimony.pdf.

[32] Demand response refers to arrangements under which electricity consumers reduce demand in real-time in response to high prices and/or short supply, thus obviating the need to construct or operate expensive peaking power plants and associated transmission lines.

[33] Letter from Gordon van Welie, President and CEO, ISO New England, Inc., and Stephen Whitley, President and CEO, New York Independent System Operator, to Joint Coordinated System Planning Initiative, February 4, 2009, http://www.nyiso.com/public/webdocs/services/planning/jcsp/2009_2_4_JCSP_Letter_FINAL.pdf.

[34] Darren Springer and Greg Dierkers, *An Infrastructure Vision for the 21st Century*, National Governors Association, Washington, DC, 2009, pp. 11-13, http://www.nga.org/Files/pdf/0902INFRASTRUCTUREVISION.PDF. The report observes (p. 13) that "electric power demand has typically been met by constructing new electricity generating plants and transmission lines with much less attention to managing demand or encouraging efficiency." The report finds that some new transmission construction will likely be needed, particularly to access new supplies of renewable energy. For further discussion of these points see U.S. Congress, Senate Committee on Energy and Natural Resources, *To*

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Another option that may require less construction of interstate transmission lines is reliance on conventional coal, nuclear, and natural gas-fired generation. Unlike location constrained resources such as wind and solar power (i.e., they must be built where the energy source is found), coal, gas, and nuclear plants can be built near load centers and existing transmission networks. Transmission upgrades may still be necessary and expensive, especially for nuclear plants which tend to be very large, but these may still be less intrusive than long-distance interstate lines for moving renewable power from remote locations to customers.[35]

This alternative perspective, which gives equal weight to non-transmission solutions to power system needs, implies that the proposed interconnection-wide transmission plans actually should be combined electricity supply and demand plans. In this case the planning process becomes much broader and possibly much more complicated than transmission planning.

Planning Authority

Many transmission planning efforts are now underway at a regional level.[36] These exercises are voluntary and generally cover at most a few states. The states are not obligated to permit any new projects that emerge from the plans.

Proposals such as S. 539 and the Senate Energy Majority Draft would mandate unprecedented Eastern and Western Interconnection-wide transmission plans. These and other proposals would also establish new, federally authorized planning authorities that would be responsible for coordinating development of the plans and submitting the plans to FERC for review and approval.[37] The proposals envision the interconnection-wide planning processes making use of the regional efforts, but it seems inevitable that the regional plans would lose influence in comparison to the federally-mandated interconnection-wide plans.

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Receive Testimony On Pending Legislation Regarding Electricity Transmission Lines, Prepared Testimony of James A. Dickenson on Behalf of the Large Public Power Council, 111th Cong., 1st sess., March 12, 2009, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=b9e47ea9-c62b-23fc-33ff-30fda7b3a744&Witness_ID=ed6a79eb-6664-412c-b66b-7e87e4e55435.

[35] For example, the estimated cost of transmission construction that would have to accompany the proposed Turkey Point 6 and 7 reactors in Florida is over $500 million. All of this work would apparently be in-state, so interstate cost allocation issues would not apply. See Pam Radtke Russell, "FPL Says Cost of New Reactors at Turkey Point Could Top $24 Billion," *Platts Nucleonics Week*, February 21, 2008, and the FPL website at http://www.fpl.com/environment/nuclear/pdf/transmissionFacts.pdf. Note that coal plants with carbon capture equipment may be built in remote locations near CO_2 disposal sites. In this case these plants would require long distance interstate transmission, much the same as renewable plants.

[36] An example of a regional planning effort is the CapX 2020 program for expanding the transmission network in the Dakotas – Minnesota – Wisconsin area (http://www.capx2020.com/).

[37] S. 539 and the Senate Energy Majority Draft both exclude ERCOT from interconnection planning, unless it chooses to opt into the process. One issue is which organizations would serve as the Eastern and Western Interconnection planning authorities. S. 539 and the Senate Energy Majority Draft each direct FERC to select the planning authorities. In the west there is an obvious candidate, the Western Electricity Coordinating Council, a NERC reliability region that covers the entire Western Interconnection (**Figure 3**). However, there is no clear candidate in the east. The Eastern Interconnection contains 11 generally non-overlapping transmission entities: six NERC regions and five RTOs/ISOs (see Figures 3 and 4). An option is to appoint more than one planning authority for the Eastern Interconnection, but that could complicate the planning process.

The proposed planning authorities and their interconnection-wide plans would differ from the regional initiatives in two critical respects:

- First is the assumption that optimal planning for new high voltage transmission lines should be based on a view of an entire interconnection, not a narrower regional focus. In essence the existing "bottom-up" and voluntary planning approach would be replaced with an arguably more "top-down," integrated, and binding approach.
- Second, new transmission projects included in the interconnection-wide plans would include preferential permitting and financing. In particular, the projects would have a federal permitting option that would bypass state regulation.

Proponents of interconnection-wide planning believe that it makes no more sense to plan the grid piecemeal than it would have been to build the interstate highway system without a national plan. However, centralized transmission planning under the aegis of FERC may be objectionable to the states, which would lose influence over power system planning.[38]

Transmission Planning: Summary of Policy Issues

In summary, transmission planning issues for Congress include:

- *What should be the objectives of the planning process*? For example, planning could be focused on renewable power development or on broader objectives, such as congestion relief and reliability enhancement.
- *What should be the scope of authority of the planning entities*? Federal transmission planning could be run by interconnection-wide centralized authorities (the top-down approach) or be conducted primarily at a regional level (the bottom-up approach), or as a hybrid.
- *What is the appropriate scope of the planning process*? Should the planning process extend beyond transmission planning narrowly defined to a include a broader array of solutions to power system issues, such as demand response, distributed power, or conventional power plant construction.
- *Could preferential treatment tied to the planning process distort transmission investment?* The planning proposals typically make available certain benefits, such as a federal permitting option, to projects included in the plan. These benefits could lead developers to add unnecessary features and costs to qualify proposals to meet plan criteria (e.g., proposing only high voltage lines if the plans have a minimum voltage threshold). Avoiding these distortions will require careful oversight or, arguably, limiting the benefits associated with the plan (for example, putting all new power lines or none, whether or not they are in the plan, under federal government permitting authority).

[38] For example, on March 10, 2009, the National Association of Regulatory Utility Commissioners (NARUC), an association of state PUCs, passed a resolution that among other things calls for the states to continue to play a primary role in transmission planning. The resolution did not, however, object to regional planning involving the states and other stakeholders. For the press release announcing the resolution, which includes a link to the document, see the NARUC website at http://www.naruc.org/News/default.cfm?pr=133.

- *Is the scheme for managing and financing the planning process realistic?* The planning process will need realistic schedules and budgets, both to develop the plans and for executive branch review. A concern is that a prolonged and contentious interconnection-wide planning process could delay transmission projects that would otherwise evolve out of smaller scale planning efforts.[39]

Transmission Permitting

Background and Discussion

As discussed above, interstate transmission projects require siting permits from every state the line will traverse. If any state disapproves a project, it will at best be delayed for rerouting or at worst canceled. A contrast is often drawn between multi-state transmission permitting and FERC's sole permitting authority for natural gas transmission lines and liquefied natural gas terminals.[40]

Some observers believe that multi-state permitting has inhibited the development of new long distance transmission lines. According to FERC, between 2000 and mid-2007 only 14 interstate high voltage transmission lines, with a total length of 668 miles, have been built.[41] This compares with current proposals to build many thousands of miles of new long-distance transmission.[42]

FERC's backstop siting authority (discussed above) was enacted to help expedite permitting. But this authority applies only in limited circumstances and areas, and in practice has never been used. Proposals for transmission reform, such as S. 539 and the Senate Energy Majority Draft, would expand FERC's siting authority. For example, S. 539 would still require a developer to initially pursue state permitting, but if a project "has failed to make reasonable progress in siting the facility based on timelines in the plan" the developer can take the project to FERC.[43] The

[39] U.S. Congress, Senate Committee on Energy and Natural Resources, *To Receive Testimony On Pending Legislation Regarding Electricity Transmission Lines*, Prepared Testimony of James A. Dickenson on Behalf of the Large Public Power Council, 111th Cong., 1st sess., March 12, 2009, p., 7, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=b9e47ea9-c62b-23fc-33ff-30fda7b3a744&Witness_ID=ed6a79eb-6664-412c-b66b-7e87e4e55435.

[40] Public power entities often can build transmission lines using their self-regulating authority. However, most public power entities are small and do not have the financial wherewithal or need to build transmission networks. As shown in **Table 1**, investor owned utilities and independent transmission companies own 70% of the transmission network and are likely to be the primary builders of new lines unless the Congress changes federal policy. For example, S. 539 envisions an expanded role for the federal utilities in building lines if private developers do not step forward.

[41] Phillip D. Moeller, FERC Commissioner, "Constructing New Transmission Lines: Implications of the Energy Policy Act," National Conference of State Legislatures 2007 Annual Meeting, Boston, MA, August 7, 2007, p. 6, http://www.docstoc.com/docs/3561261/Constructing-New-Transmission-Lines-Implications-of-the-Energy-Policy-Act.

[42] For example, a DOE wind power study concluded that 12,000 miles of new transmission lines could be cost-effectively constructed to serve new wind power plants. The same study cites a conceptual design by American Electric Power for building 19,000 miles of new 765 kV lines. U.S. Department of Energy, *20% Wind Energy by 2030*, Washington, D.C., July 2008, pp. 95 – 96, http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf.

[43] S. 539, Section 404(a)(3).

Senate Energy Majority Draft allows "National High Priority Transmission Projects" identified through a federally-sanctioned planning process to go directly to FERC for approval.

A common element in these and some other proposals is that projects eligible for FERC permitting must be included in an interconnection-wide plan. Other projects would remain under state purview. Another approach is to simply give FERC permitting authority over all transmission projects, or at least all high voltage transmission projects.[44]

An alternative view is that the current permitting process is not broken and at most needs tweaking. The National Association of Regulatory Utility Commissioners (NARUC), an association of state PUCs, passed a resolution in March 2009 urging "Congress and the White House to move cautiously, if at all, in expanding federal jurisdiction over siting and planning of new transmission infrastructure."[45] According to the NARUC president, "Siting and planning transmission is one of the most difficult yet essential jobs of a State regulator, and no federal agency will have the resources or local knowledge on its own to balance all the considerations that must be taken into account."[46]

Where FERC does have siting authority, as with natural gas pipelines and LNG terminals, it has sometimes been intensely criticized by state officials and members of Congress who believe FERC has made poor decisions.[47] However, this may simply argue for giving an agency other than FERC any new federal transmission siting authority.

Transmission Permitting: Summary of Policy Issues

In summary, in considering how much additional transmission siting authority, if any, the federal government should assume, Congress may want to consider the following policy questions:

- *Should the grid be viewed from a national perspective?* The grid began as local systems regulated by states. Now that the system has evolved into three separate synchronized interconnections, each spanning (other than ERCOT) many states, a question is whether a state-by-state view of the grid or a national perspective is most appropriate. The question is made pressing by proposals to make more use of the grid for long distance power transactions, such as for renewable energy. The issue does not necessarily have a single answer; for example, a state perspective may be appropriate for "routine" projects, while a national perspective could be applied to high priority interstate projects (however "routine" and "high-priority" are defined).
- *Can transmission system reliability be separated from authority over new transmission construction?* In EPACT05 Congress put the reliability of the grid

[44] Esther Whieldon, "FERC Needs Eminent Domain to Site Transmission Lines, Kelliher Tells Senate," *Inside F.E.R.C.*, August 4, 2008.

[45] National Association of Regulatory Utility Commissioners, "States Reiterate Vital Role in Grid Expansion, List Principles as Congress Mulls Action," press release, March 11, 2009, http://www.naruc.org/News/default.cfm?pr=133.

[46] Ibid.

[47] An example are current disputes in Oregon over the permitting of an LNG terminal and a new gas pipeline (Ted Sickinger, "State Asks Court to Toss Bradwood Site's Approval," *The (Portland) Oregonian*, January 27, 2009). Also see Jason Fordney, "Connecticut Governor Blasts Idea of Giving FERC More Authority Over Power Line Siting,: *Platts Electric Utility Week*, March 30, 2009, p. 6.

under federal jurisdiction. By extension, should the federal government have control over the permitting of transmission lines aimed at enhancing system reliability (which could mean almost any new line in an interconnected power system)? As discussed in more detail later in the report, failures at one point in a synchronized system can spread widely, and these failures (in a worst case, blackouts) do not respect state lines.

- *How important is it to accelerate the construction of new transmission lines?* One criticism of current regulation is that it takes many years to permit a project.[48] Expanding federal authority over permitting is viewed as a means of accelerating the process. The underlying assumption is that it is indeed important to build transmission lines faster. For example, if national priorities include quickly putting low carbon generating plants on line to reduce greenhouse gas emissions and to speed the introduction of electric vehicles, then a rapid permitting process may be critical. But with other assumptions about the shape of the future power market, acceleration of the permitting process may be less pressing, and therefore expanding federal permitting authority less important. (An example of such an alternative assumption would be more reliance on large nuclear or coal plants built near existing transmission networks, rather than many small wind plants in remote locations.)
- *Management of the permitting process*. Whether FERC or another agency is assigned a federal permitting role, it will need the resources to expeditiously process applications. Otherwise the whole point of giving more permitting power to the federal government would largely be obviated.

Transmission Financing and Cost Allocation

Background

Between 1977 and 1998, real dollar investment in the transmission system by investor-owned utilities generally declined, from about $4 billion annually to a trough of $2.1 billion annually by 1997 and 1998 (constant 2000 dollars; see **Figure 5**, below). Although spending picked up to $4.2 billion by 2004 (constant 2000 dollars),[49] Congress was still sufficiently concerned about

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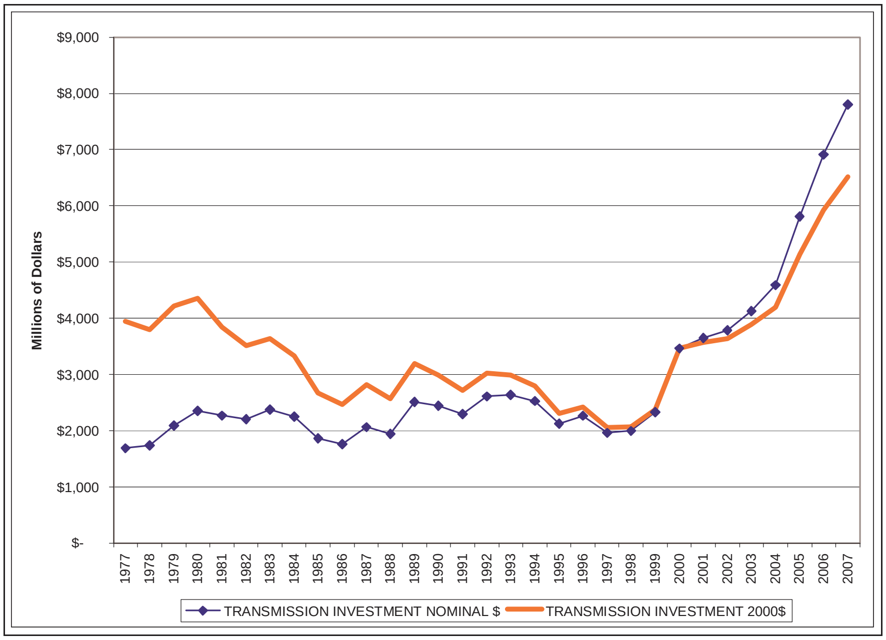
48 According to DOE's Electricity Advisory Committee, "A 'poster child' example of this problem is American Electric Power's Jacksons Ferry, Wyoming, 765 kV transmission line. It required 16 years to complete, and nearly 14 of those years and $50 million was spent on siting activities." The Electricity Advisory Committee, *Keeping the Lights on in a New World,* U.S. Department of Energy, Washington, DC, January 2009, p. 49, http://www.oe.energy.gov/eac.htm.

49 This data is only for investor owned utilities (see **Figure 5** for source notes). No source appears to capture all investment in the transmission system. For a discussion of some of the related data issues, see Energy Security Analysis, Inc., *Meeting U.S. Transmission Needs*, Edison Electric Institute, Washington, DC, July 2005, p. vi and footnote 3. The reasons for the decline in real dollar transmission investment are unclear. While insufficient return on investment is cited as one factor, another issue may have been excess capacity on the transmission system that reduced the need for transmission spending. Another factor may have been new patterns in building power plants closer to load centers. See Steve Huntoon and Alexandra Metzner, "The Myth of the Transmission Deficit," *Public Utilities Fortnightly*, November 1, 2003, p. 30. The lack of comprehensive data on the transmission system makes it difficult to sort out these issues. For a discussion of transmission system data needs see Douglas R. Hale, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, Energy Information Administration, DOE/EIA-0639, Washington, DC, December 2004, http://www.eia.doe.gov/cneaf/electricity/page/transmission/ (continued...)

transmission investment to include construction incentives in EPACT05 (in the form of more profitable rates for projects that met certain criteria).[50]

Figure 5. Transmission Investment by Investor-Owned Utilities

1977 – 2007, in Millions of Dollars



Source: nominal dollar from the Edison Electric Institute website at http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Documents/Transmission-Investment-Expenditures.pdf and http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Values were converted to constant dollars by CRS using the implicit deflator for gross domestic product.

Some critics claim that FERC has awarded incentives to projects that did not need special rates.[51] Nonetheless and for whatever reason, transmission investment has continued to grow since 2004, reaching a 30-year high of $6.5 billion (constant 2000 dollars) in 2007.

More growth in annual investment may be needed. Estimates of the cost of expanding the transmission grid to increase renewable power delivery and other goals run into the tens of billions of dollars. For example (all figures in nominal dollars):

- The estimated transmission cost of the Joint Coordinated System Plan to bring Great Plains wind power to the East Coast range from $49 to $80 billion.[52]

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DOE_EIA_0639.htm.

[50] 16 U.S.C. § 824s. The implementing rule authorizes FERC to award incentive rates to new transmission projects where the project will "either ensure reliability or reduce the cost of delivered power by reducing transmission congestion" and "there is a nexus between the incentive sought and the investment being made." Federal Energy Regulatory Commission, Order No. 697, *Promoting Transmission Investment through Pricing Reform*, Final Rule, July 20, 2006, pp. 207 – 208, http://www.ferc.gov/legal/maj-ord-reg.asp.

[51] Esther Whieldon, "FERC Grants Incentive Rates For Two Major Grid Projects Proposed In New England," *Platts Inside F.E.R.C.*, November 24, 2008; Will Harrington, "Consumer Groups Expect New FERC Will Trim Transmission Incentives," EnergyWashington.com, January 28, 2009.

- A DOE study of expanding the use of wind power estimated transmission expansion costs of $60 billion by 2030.[53]
- A study of transmission funding requirements for all purposes for the period 2010 to 2030 estimated total costs of about $300 billion.[54]

There are two major transmission financing policy issues: early financing for new projects, and how to allocate the costs of interstate projects to customers. Each issue is discussed below.

Early Financing

The early funding or "chicken and egg" problem particularly applies to renewable power. Renewable power plant developers may have difficulty getting funding because the transmission to bring their power output to market is not in place, while the transmission projects cannot get loans because the generation that would justify construction of the new lines has not been built. This early funding issue is exacerbated by the typical development pattern for many renewable energy projects. The projects are built in phases over several years.[55] However, it is not economic to build a transmission line in phases; the line must be built at once for the maximum anticipated capacity even if the full load will not be developed until years after the line is first put into operation.

The FERC, RTOs, and the states have been developing regulatory solutions for the early funding problem, but there is no standard or widely used approach.[56] The Western Governors' Association

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52 Executive summary to the Joint Coordinated System Plan 2008, p. 6, http://www.jcspstudy.org/. Note that the cost of the transmission is modest compared to the estimated cost of the generation needed to meet demand and, in one scenario, renewable energy goals ($674 billion to $1,050 billion).

53 U.S. Department of Energy, *20% Wind Energy by 2030*, Washington, D.C., July 2008, p. 98, http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf.

54 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010 - 2030*, prepared by the Brattle Group for The Edison Foundation, Washington, DC, November 2008, p. 40, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf.

55 Renewable generation is built incrementally for a number of reasons, including the nature of the technology (which lends itself to incremental development), the small size and limited financial resources of some developers, and the way in which state renewable electricity standards ratchet up goals over time. For further discussion of this and related issues see California Independent System Operator, *Petition for Declaratory Order*, before the Federal Energy Regulatory Commission, Docket EL07-33-000, January 25, 2007, http://www.caiso.com/1b71/1b71d1263dad0.pdf.

56 One approach involves changes to FERC's open transmission policies, which have required merchant transmission developers to bid-out all of the capacity of a proposed line (via an "open season" auction) before beginning construction. Developers had been precluded from making pre-auction capacity sales to a lead group of generators as a means of jump-starting the project. FERC's new ruling (involving two 500 kV DC transmission lines that would bring wind power from Montana and Wyoming to the southwest) allows large shares of a merchant project's capacity to be pre-sold to "anchor" customers. See Federal Energy Regulatory Commission, *Order Authorizing Proposals and Granting Waivers*, February 19, 2009, Docket Nos. ER09-432-000 and ER09-433-000. In this case the commission allowed the developers to pre-sell 50% of the capacity of each line prior to auctioning the balance of the capacity. At the state level, the California Independent System Operator (CAISO, the transmission authority covering most of the state) has implemented a unique financing policy for utilities developing new high voltage transmission lines that access renewable resource areas. The policy allow utilities to allocate across the utility's customer base the development costs that are not recovered from the first wave of new renewable plants that connect to the project. As more generators are connected each picks up its pro rata share of the development costs, until the full capacity of the line is subscribed and all costs are being paid by generators. Transmission projects that quality for this arrangement must have pre-sold about 25% to 35% of planned capacity in order to demonstrate commercial viability. The total cost (continued...)

has proposed that the federal government and the federal power marketing administrations[57] step in with direct funding and other incentives that will allow transmission developers to "supersize" planned lines to meet potential future generation, not just the renewable power expected to be built in the near term.[58]

Note that although the early funding issue and cost allocation issue (discussed immediately below) are currently viewed as largely problems for renewable energy development, they could also apply to new coal plants with carbon capture and sequestration (CCS) equipment. This is because one option for siting coal plants with CCS is to place them in remote locations where captured CO_2 can be stored or used for enhanced oil recovery. In this scenario, a long-term build-out of new coal capacity may face transmission funding issues similar to that of renewable development in remote areas.

Cost Allocation

Perhaps the most contentious transmission financing issue is cost allocation for new interstate transmission lines – that is, deciding which customers pay how much of the cost of building and operating a new transmission line that crosses several states. DOE's Electricity Advisory Committee concluded that "cost allocation is the single largest impediment to any transmission development."[59] The committee also noted that "cost allocation disagreements can also impact transmission siting; therefore, resolution of these two issues must be linked."[60] This is an important point, and most current transmission proposals fold the cost allocation issue into the transmission planning process. For example, S. 539 and the Senate Energy Majority Draft both require the regional planning authorities to submit cost allocation proposals along with their

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exposure of ratepayers is limited by a cap formula. FERC ruled that this proposal was just and reasonable, and not unduly discriminatory, in part because it "advances state, regional and federal initiatives to encourage the development of renewable generation" (Federal Energy Regulatory Commission, *Order Granting Petition for Declaratory Order*, Docket EL-033-000, April 19, 2007, pp. 1 – 2). This decision and related statements made by FERC commissioners can be retrieved through FERC docket search at http://elibrary.ferc.gov/idmws/docket_search.asp. CAISO's initial request for FERC approval is also available at this site or at http://www.caiso.com/1b71/1b71d1263dad0.pdf.

[57] For more information on the power marketing administrations see CRS Report RS22564, *Power Marketing Administrations: Background and Current Issues*, by Richard J. Campbell.

[58] Letter from Jon Huntsman, Jr., Chairman and Governor of Utah, and Brian Schweitzer, Vice-Chairman and Governor of Montana, Western Governors' Association, to The Honorable Nancy Pelosi, Harry Reid, John Boehner, and Mitch McConnell, January 27, 2009, http://www.westgov.org/wga/testim/transmission-for-renewables1-27-09.pdf; and "Western Governors Eye Senate Bills to Push New Transmission Policy," *EnergyWashington.com*, March 20, 2009.

[59] The Electricity Advisory Committee, *Keeping the Lights on in a New World,* U.S. Department of Energy, Washington, DC, January 2009, p.50, http://www.oe.energy.gov/eac.htm.

[60] Ibid. An example of a cost allocation dispute is arguments over a proposed 150 mile transmission line to connect wind power in Maine to other parts of New England. According to an article on the project, "States had disagreed about fair allotment of costs for the transmission project. Maine utilities pushed for all states to pitch in because they would gain economic benefits – access to Maine's renewable energy. However, Connecticut and Massachusetts disagreed and said the region should socialize costs only when transmission ensures reliability." In another instance, the Illinois utility commission characterized the PJM Interconnection's proposed allocation of regional transmission costs to a state utility as "not only unjust and unreasonable, but patently irrational." The commission has protested the allocation to FERC. See, respectively, Lisa Wood, "Maine Regulators Reject 345-MW Line to Connect Wind Power to New England," *Platts Electric Utility Week*, February 9, 2009 and Jason Fordney, "Exelon, Illinois Commission and DP&L Protest PJM Allocation of Upgrade Costs," *Platts Electric Utility Week*, February 9, 2009.

transmission plans. If cost allocation proposals are not submitted or are rejected by FERC, then FERC can order its own cost-allocation scheme.

Another suggestion is to simply allocate the costs of new projects that are part of an interconnection-wide plan to all customers in the interconnection (sometimes referred to as "socializing" costs). For example, every ratepayer in the Eastern Interconnection would help pay for a line from Maine to New Hampshire. The idea is that in a synchronized grid all ratepayers benefit to some extent from all transmission system enhancements. A related concept is that new transmission for renewable power yields environmental benefits to all ratepayers. And whether explicit or implicit, the notion is also that interconnection-wide cost sharing makes transmission projects more palatable by minimizing the rate impact on any one group of customers, and accelerates project approvals by substituting a simple cost allocation rule for lengthy rate hearings.[61]

A criticism of interconnection-wide cost allocation is that cost responsibility arguably becomes more diffuse and the incentives for cost discipline decline. Another criticism is that especially favorable funding for transmission could bias policymakers and investors away from other solutions to electric market problems, such as demand response or local renewable power.[62] Other cost allocation approaches are being explored across the country but no approach is standard or even widely used.[63]

Financing and Cost Allocation: Summary of Policy Issues

Transmission financing issues for Congress include:

- *Should the federal government help pay for new transmission lines?* Some proposals call for the federal government, possibly acting through the federal utilities, to help pay for new transmission lines, pay for expanding projects to meet future needs, or actually build new transmission. How far should the federal government go into financing the expansion of the transmission grid?

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[61] For example, the Energy Future Coalition argues that "Just as local electric ratepayers currently fund local electricity infrastructure investments, broad based groups of ratepayers should cover the costs of national grid investments which provide broad-based national benefits. This will ensure all beneficiaries of the National Clean Energy Smart Grid support the cost of its development…. Cost allocation policies should be as simple as possible (e.g., allocating designated costs proportionately to all load in the interconnection) to avoid lengthy regulatory proceedings and provide greater predictability for developers and ratepayers." Energy Future Coalition, *The National Clean Energy Smart Grid: An Economic, Environmental, and National Security Imperative*, undated, p. 4, http://www.energyfuturecoalition.org/files/webfmuploads/Smart%20Grid%20Docs/EFC%205-page%20Vision%20Statement%20-%20FINAL.pdf.

[62] U.S. Congress, Senate Committee on Energy and Natural Resources, *To Receive Testimony On Pending Legislation Regarding Electricity Transmission Lines*, Prepared Testimony of James A. Dickenson on Behalf of the Large Public Power Council, 111th Cong., 1st sess., March 12, 2009, pp., 8 – 10, http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=b9e47ea9-c62b-23fc-33ff-30fda7b3a744&Witness_ID=ed6a79eb-6664-412c-b66b-7e87e4e55435.

[63] For example, the Southwest Power Pool (SPP) RTO has adopted a policy of developing cost allocation plans for packages of transmission projects that cover all the zones in the RTO. This way, all ratepayers benefit from the package even if individual projects in the package cover a small geographical area. The SPP approach has been approved and praised by FERC, but may only be applicable to RTOs like SPP that cover a relatively small area (see **Figure 4**). Alan Kovski, "FERC Approves SPP's Plan to Handle Grid Upgrade Costs on an Economic Basis," *Platts Global Power Report*, October 23, 2008.

- *Should the Congress establish a national cost allocation rule for new transmission projects?* In order to expedite transmission development, the federal government may need to implement standard, generally applicable cost allocation methodologies. An approach included in several proposals would require all ratepayers in an interconnection to pay for new projects anywhere in the interconnection. The notion is that in an interconnected system all customers benefit to some degree from enhancements to the grid, but a preferential cost allocation mechanism for transmission may bias investment away from other alternatives.

Transmission System Modernization and the Smart Grid

Background

Distinct from proposals for expanding the grid are proposals for modernizing the transmission system. Modernization proposals are often made under the rubric of the "smart grid," a term that encompasses technologies that range from advanced meters in homes to advanced software in transmission control centers. There is no standard definition of the smart grid.[64] For the purposes of this report, the smart grid can be viewed as a suite of technologies that give the grid the characteristics of a computer network, in which information and control flows between and is shared by individual customers and utility control centers. The technologies will allow customers and the utility to better manage electricity demand, and will include self-monitoring and automatic protection schemes to improve the reliability of the system.[65] Although grid technology has not been static over the years,[66] the smart grid concept would implement capabilities well beyond any existing electric power system.

The smart grid primarily involves the development of software and small-scale technology (e.g., smart meters for homes and businesses that would interface with grid controls) rather than construction of new transmission lines. However, full implementation of the smart grid also requires new electricity rate structures, especially for residential customers, and as discussed below, this and other aspects of the smart grid may prove contentious.

The following discussion is divided into three sections:

- A more detailed description of smart grid functions.

[64] DOE's Electricity Advisory Committee noted that "there are many working definitions of a Smart Grid." Electricity Advisory Committee, *Smart Grid: Enabler of the New Economy*, U.S. Department of Energy, Washington, DC, December 2008, p. 1.

[65] Other descriptions of the smart grid emphasize its environmental benefits through reducing fossil-fueled electric generation and air pollution emissions. See the comments of FERC Commissioners Moeller and Spitzer in Federal Energy Regulatory Commission, "FERC Accelerates Smart Grid Development with Proposed Policy, Action Plan," press release, March 19, 2009, http://www.ferc.gov/news/news-releases/2009/2009-1/03-19-09.asp.

[66] Scott Gawlicki, "Demonstrating the Smart Grid," *Public Utilities Fortnightly*, June 2008, p. 51; and Kenneth Martin and James Carroll, "Phasing in the Technology: Phasor Measurement Devices and Systems for Wide-Areas Monitoring," *IEEE Power and Energy*, September/October 2008.

- A summary of current federal support for the smart grid.
- Smart grid cost and rate issues.

Smart Grid Functions

Because the smart grid involves integrated operation of the power system from the home to the power plant, this discussion will go beyond the transmission system to cover the distribution network. Within this integrated system the smart grid has two scopes. *One scope is transmission monitoring and reliability*, and includes the following capabilities:

- Real-time monitoring of grid conditions;
- Improved automated diagnosis of grid disturbances, and better aids for the operators who must respond to grid problems;
- Automated responses to grid failures that will isolate disturbed zones and prevent or limit cascading blackouts that can spread over wide areas.
- "Plug and play" ability to connect new generating plants to the grid, reducing the need for time consuming interconnection studies and physical upgrades to the grid.
- Enhanced ability to manage large amounts of wind and solar power. Some (though not all) analysts believe deployment of the smart grid is essential to the large scale use of wind and solar energy.[67]

The second scope is consumer energy management. An essential part of this scope is the installation of smart meters (also referred to as advanced metering infrastructure or AMI). These meters and other technology would implement the following capabilities:

- At a minimum, the ability to signal homeowners and businesses that power is expensive and/or in tight supply. This can be done, for instance, via special indicators or displayed through web browsers or other personal computer software. The expectation is that the customer will respond by reducing its power demand.
- The next level of implementation would allow the utility to automatically reduce the customer's electricity consumption when power is expensive or scarce. This would be managed through links between the smart meter and the customer's equipment or appliances.

[67] This issue is different from constructing new power lines to reach renewable energy production zones. Because the output of wind and solar plants varies with the weather and time of day, integrating large amounts of these variable resources into the power system is challenging. The smart grid, with its theoretical ability to monitor and balance load, generation, and power storage across the whole electricity network – from the batteries in plug-in hybrid vehicles in a homeowner's garage to the dispatch of power plants – is sometimes viewed as the solution to these integration challenges. For example, see David Talbot, "Lifeline for Renewable Power," *Technology Review*, January/February 2009, http://www.technologyreview.com/printer_friendly_article.aspx?id=21747&channel=energy&section=. The article's summary states that "Without a radically expanded and smarter electrical grid, wind and solar will remain niche power sources." However, other studies do not see the smart grid as a prerequisite to large scale introduction of renewable power. For example, see U.S. Department of Energy, *20% Wind Energy by 2030*, Washington, D.C., July 2008, http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf (the term "smart grid" does not appear in the report).

- The smart grid system would automatically detect distribution line failures, identity the specific failed equipment, and help determine the optimal plan for dispatching repair crews to restore service. The smart grid would automatically attempt to isolate failures and prevent local blackouts from spreading.
- The smart grid would make it easier to install distributed generation, such as rooftop solar panels, and to implement "net metering," a ratemaking approach that allows operators of distributed generators to sell surplus power to utilities. The smart grid would also manage the connection of millions of plug-in hybrid electric vehicles into the power system.

The transmission and customer energy management scopes described above are integrated in the full smart grid concept. For example, if the transmission system becomes overloaded, the smart grid could respond at the distribution system level by automatically reducing customer demand.

Federal Support for the Smart Grid

The Energy Independence and Security Act of 2007 (EISA) articulated a national policy to modernize the power system with smart grid technology, and authorized research and development programs, funding for demonstration projects, and matching funds for investments in smart grid technologies. [68] These and related programs received $4.5 billion in funding in the 2009 stimulus bill.[69] In addition, the Emergency Economic Stabilization Act of 2008 shortens the depreciation period for smart meters and other smart grid equipment from 20 years to 10 years (which increases each year's depreciation tax deduction for the equipment). The value of this tax change to the power industry is reportedly $915 million over 10 years.[70]

EISA assigned to the National Institute of Standards and Technology (NIST), a unit of the Department of Commerce, the lead in developing interoperability standards for smart grid equipment.[71] This is a critical role, because it is essential that the smart grid technologies installed by one utility be able to communicate with those of another and with control centers. This work has been lagging. DOE, FERC, and NIST have reportedly begun interagency efforts to accelerate development of the standards, and NIST has created and filled a new National Coordinator on Smart Grid Interoperability to push the effort forward. [72]

[68] 42 U.S.C. § 17381, et seq.

[69] For additional information see CRS Report R40412, *Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5)*, coordinated by Fred Sissine.

[70] The Electric Advisory Committee, *Smart Grid: Enabler of the New Energy Economy*, U.S. Department of Energy, December 2008, p. 16, http://www.oe.energy.gov/eac.htm.

[71] 42 U.S.C. § 17385.

[72] "Stakeholders Look To Jump-Start Stalled Smart Grid Standards," EnergyWashington.com, January 20, 2009; John Siciliano, "Administration Pursuing Major Interagency Plan to Deploy Smart Grid," EnergyWashington.com, March 25, 2009. According to this article, during March 17, 2009 testimony before the House Science and Technology Committee, Secretary of Energy Chu expressed his displeasure with the lack of progress. The NIST smart grid site is located at http://www.nist.gov/smartgrid/. For a discussion of interoperability issues, see Federal Energy Regulatory Commission, *Proposed Policy Statement and Action Plan*, Smart Grid Policy, Docket PL09-4-000, March 19, 2009, http://www.ferc.gov/whats-new/comm-meet/2009/031909/E-22.pdf.

Pursuant to EISA, once NIST's work is sufficiently advanced FERC is to establish, through a rulemaking, national smart grid interoperability standards.[73] On March 19, 2009, FERC published for comment a proposed smart grid policy statement and action plan, intended "to articulate its policies and near-term priorities to help achieve the modernization of the Nation's electric transmission system, one aspect of which is 'Smart Grid' development."[74] According to FERC, the statement focuses on "Prioritizing the development of key standards for interoperability of Smart Grid devices and systems; [and] a proposed rate policy for the interim before the standards are developed."[75] Comments are due back to FERC in May 2009.

Smart Grid Cost and Rate Issues

Advocates believe the potential benefits from the smart grid are enormous. For example, the Electric Power Research Institute, a research arm of the power industry, estimated that implementation of the smart grid and related technologies could increase annual gross domestic product by 10% annually by 2020.[76] The Galvin Institute, a proponent of grid modernization, claims that among other benefits a modernized grid would "reduce the need for massive [electric power] infrastructure investments by between $46 and $117 billion over the next 20 years."[77]

Nonetheless, because the smart grid concept and technology are still evolving and there are no operational systems to evaluate, the benefits and costs are uncertain. According to Xcel Energy, which is developing a large smart grid demonstration in Boulder, Colorado:[78]

> Everybody says they have technology that can be applied to this project. How much really exists and how much of it still needs to be developed? Right now we think 60 percent of the data architecture is already there, while the other 40 percent will probably need tweaking. Then we will determine what is or isn't scalable [to larger installations]…. As an industry we haven't really demonstrated the benefit of combining all these technologies. Until we do, there will be skepticism. That's the real value of this project.[79]

It does seem likely that costs of rolling out the smart grid will be high. Just installing the metering equipment is expensive. Pacific Gas and Electric, a large utility in California, plans to install 10.3 million smart meters by 2012 at a cost of $1.7 billion.[80] Estimates of installing smart meters

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[73] 42 U.S.C. § 17385(d)

[74] Federal Energy Regulatory Commission, *Proposed Policy Statement and Action Plan*, Smart Grid Policy, Docket PL09-4-000, March 19, 2009, p. 1, http://www.ferc.gov/whats-new/comm-meet/2009/031909/E-22.pdf.

[75] Federal Energy Regulatory Commission, "Proposed Smart Grid Policy Statement and Action Plan," fact sheet, March 19, 2009, http://www.ferc.gov/news/news-releases/2009/2009-1/03-19-09-E-22-factsheet.pdf.

[76] Electric Power Research Institute, *Electricity Sector Framework For The Future, Volume I: Achieving The 21st Century Transformation*, August 6, 2003, p. 42, Table 5-1, http://positiveenergydirections.com/ESFF_volume1.pdf. The estimated gains through an improved grid are described in the report as achievable stretch goals (p. 41).

[77] See the Galvin Institute website at http://www.galvinpower.org/resources/galvin.php?id=27.

[78] For information on the Boulder project see Xcel Energy website at http://smartgridcity.xcelenergy.com/ and Stephanie Simon, "The More You Know ... " The Wall Street Journal, February 9, 2009. For information on other demonstration projects, see Scott Gawlicki, "Demonstrating the Smart Grid," Public Utilities Fortnightly, June 2008 and Peter Slevin and Steven Mufson, "Stimulus Dollars Energize Efforts To Smarten Up the Electric Power Grid," The Washington Post, March 10, 2009. For an example of an overseas project see Todd Woody, "IBM to Build World's First National Smart Utility Grid [in Malta]," Green Wombat Blog – Fortune on CNNMoney.com, February 4, 2009, http://greenwombat.blogs.fortune.cnn.com/.

[79] Scott Gawlicki, "Demonstrating the Smart Grid," *Public Utilities Fortnightly*, June 2008, pp. 56 – 57.

[80] Lisa Weinzimer, "PG&E's Advanced Meter Upgrade Would Cost Ratepayers $900 million," *Platts Electric Utility* (continued...)

nationwide are in the $40 billion to $50 billion range.[81] Some utilities are incurring costs to replace smart meters installed just a few years ago with newer models, indicating both the rapidity with which the technology is changing and the absence of firm standards.[82]

Some consumer advocacy groups have expressed concern that utilities and regulators are pressing ahead with smart grid investments, especially the installation of smart meters, without knowing whether the benefits will justify the costs. A claim from critics is that some utilities are enthusiastic about immediate spending on smart grid technology because once the investment is reflected in the company's rate base it will result in higher profits.[83]

Another consumer advocate concern relates to the change in utility rate structures that will likely accompany implementation of the smart grid. As discussed above, one function of the smart grid is to signal consumers when electricity is expensive or in short supply. The question is whether the consumer will act on this information by reducing power usage. In typical utility rate structures, consumers pay a rate for power that reflects annual average costs. The consumer's rate does not vary from day to day or hour to hour. But if the consumer's rates do not reflect real-time power costs, then the consumer has no immediate economic incentive to respond to utility price signals. For this reason, the smart grid concept is accompanied by new rate structures, such as "dynamic" pricing in which charges to consumers reflect actual market prices (or marginal production costs) for electricity. As put by the President of NARUC, "You can't have a smart grid and dumb rates. We have been used to – for over 100 years – rates that are the same all day, every day. That's not the way electricity is produced."[84]

Dynamic rates mean that the price of power would be much higher in the afternoon of a hot summer day when demand peaks and the most expensive generating plants are on-line, than in evening of the same day or on the weekend. With dynamic rates, consumers would have an incentive to respond to utility price signals by reducing demand by turning down the air conditioner or delaying the laundry. If the capability exists, the consumer might sign-up for direct utility control of appliances.

In theory, this demand response scenario has consumer benefits in the short-term (less use of expensive fuels and inefficient peaking power plants) and long-term (less need for new power plants to meet growth in peak load and reduced air emissions). However, in the view of critics these benefits are much more nebulous than the certainty that under dynamic rates consumers will

(...continued)

Week, December 17, 2007.

[81] Ahmad Faruqui and Sanem Sergici, Household Response to Dynamic Pricing: A Survey of the Experimental Evidence, The Brattle Group, January 10, 2009, p. 6, http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf, and Katie Fehrenbacher, "Even With Stimulus, Smart Grid Could Face Rough Year," Earth2Tech, February 6, 2009, http://earth2tech.com/2009/02/06/even-with-stimulus-smart-grid-could-face-rough-year/#more-22357 (citing comments by an analyst with the Edison Electric Institute).

[82] Lisa Weinzimer, "PG&E's Advanced Meter Upgrade Would Cost Ratepayers $900 million," *Platts Electric Utility Week*, December 17, 2007, and Tom Tiernan, "Utilities Sometimes In Middle As Enthusiasm, Wariness Circle Each Other In Smart Grid Push ," *Platts Electric Utility Week*, November 3, 2008.

[83] Under traditional regulation, which still applies throughout the country to distribution system rates, investor-owned utilities earn a return on their invested capital. This means that if they make a PUC-approved investment in smart meters (which, as discussed above, for a large utility can exceed a billion dollars), other things being equal the company's profits will increase proportionally to the size of the investment.

[84] Frederick Butler, President of NARUC, quoted in Daniel Vock, "Smart Grid's Growth Now Depends On States," Stateline.org, March 17, 2009, http://www.stateline.org/live/details/story?contentId=384804.

face higher power costs. The critics also argue that lower income people may not have the schedule flexibility to shift cooking and laundry to less expensive hours of the day; however, there is some evidence that lower income people will actually be more responsive to price signals than higher-income households.[85] Another argument is that the elderly or ill may face the choice of paying higher power bills or risking their health by turning down the air conditioning or electric heat.[86]

It is also unclear how much smart grid technology and cost needs to be incurred to get most of the available demand response benefits. For example, a dynamic pricing pilot program in Chicago used minimal technology (e.g., price notifications by phone) but still produced substantial reductions in peak demand.[87] Some studies suggest that the more sophisticated the technology used in a demand response pilot program the greater the savings,[88] but the optimal balance between technology cost and benefits is still unclear. Industrial customers will reportedly recommend adding a cost-benefit test for smart grid investments to FERC's final policy.[89]

Modernization and Smart Grid: Summary of Policy Issues

Congress has already put in place federal programs to help develop the smart grid. Continuing policy issues for Congress include:

- *Program oversight*. The American Recovery and Reinvestment Act provided funding for previously authorized smart grid programs, including one key effort – development of interoperability standards by the National Institute for Standards and Technology – that has been lagging. Congress may want to monitor how these programs progress.
- *Smart grid cost/benefit oversight*. The balance of costs and benefits that the smart grid will produce for customers has been hotly debated. Many smart grid investment decisions will be made by state utility commissions. However, other investments and rate decisions will involve transmission systems and RTOs under FERC jurisdiction, or will relate to bulk power system reliability standards that are under federal jurisdiction throughout the 48 contiguous states. (This federal role will be even larger if an interconnection-wide planning process under federal supervision is made into law, because these plans will inevitably have to deal with grid modernization.) These responsibilities create ample room for

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85 Summit Blue Consulting, *Evaluation of the 2006 Energy-Smart Pricing Plan*, CNT Energy, Boulder, CO, November 2007, p. 9, http://www.cntenergy.org/reports.php.

86 For a discussion of smart grid consumer issues and responses, see Tom Tiernan, "Utilities Sometimes in the Middle as Enthusiasm, Wariness Circle Each Other in Smart Grid Push," *Platts Electric Utility Week*, November 3, 2008.

87 Summit Blue Consulting, *Evaluation of the 2006 Energy-Smart Pricing Plan*, CNT Energy, Boulder, CO, November 2007, pp. 4 and 11, http://www.cntenergy.org/reports.php.

88 Ahmad Faruqui and Sanem Sergici, Household Response to Dynamic Pricing: A Survey of the Experimental Evidence, The Brattle Group, January 10, 2009, pp. 43 (Table 31) and 46, http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

89 "FERC 'Single Issue Rate Cases' Smart Grid Policy Draws Consumer Fire," EnergyWashington.com, March 23, 2009. According to this article, some industrial power users are also alarmed by an element of FERC's smart grid policy proposal that would allow utilities to request rate increases to recover smart grid costs in isolation from all other transmission expenses. The critics object that other transmission expenses might have decreased, but these costs would not be examined in a "single issue" smart grid rate case at FERC.

Congressional oversight of the actual costs, benefits, and performance of smart grid investments.

Transmission System Reliability

This section of the report will discuss the reliability of the transmission system from three perspectives:

- Problems in evaluating the current reliability condition of the grid;
- Modernization and reliability;
- Reliability and changes in the energy market.

Problems in Evaluating the Current Reliability Condition of the Grid

As discussed earlier, power system reliability has two dimensions: adequate capacity to consistently meet customer demands, and the ability to withstand disturbances such as failed transmission lines or power plants. It is currently impossible to judge the reliability of the national transmission system by either criteria because the data does not exist to make an assessment. According to the Energy Information Administration, "The Government does not have the [analytical tools] and data necessary to verify that existing and planned transmission capability is adequate to keep the lights on."[90]

This is not to say that transmission risks cannot be evaluated for specific parts of the transmission grid. These studies are performed routinely.[91] What is missing is uniform, nationwide data on the frequency and causes of transmission outages that can be used to determine whether the overall performance of the system is improving or deteriorating, and what factors are driving these changes.

A contrast can be drawn between the data available on generating plant reliability and operations versus that for the transmission system. For decades NERC has managed a highly detailed collection of data on the reliability of power plants, and other relevant data are available from EIA and the Environmental Protection Agency (EPA).[92] In contrast to the wealth of information

[90] Douglas R. Hale, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, Energy Information Administration, DOE/EIA-0639, Washington, DC, December 2004, p. 4, http://www.eia.doe.gov/cneaf/electricity/page/transmission/DOE_EIA_0639.htm. Also see U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, pp. 147 – 148 (Recommendation I.F.10), https://reports.energy.gov/BlackoutFinal-Web.pdf.

[91] For example, DOE was able to conclude that transmission congestion is a "serious threat to the reliability of electricity supply" to southern California. Department of Energy, "National Electric Transmission Congestion Report," 72 *Federal Register* 57016, October 5, 2007.

[92] Information on NERC's Generating Availability Data System (GADS) is available from the NERC website at http://www.nerc.com/page.php?cid=4|43. EIA collects data on power plant monthly operations and plant characteristics, available through the agency's website at http://www.eia.doe.gov/fuelelectric.html or by calling the National Energy Information Center at 202-586-8800. EPA collects power plant data as part of its air emissions compliance programs. For more information see the EPA website at http://camddataandmaps.epa.gov/gdm/ and http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

on power plant operations, minimal data has been collected by government or industry on transmission system reliability. The most significant existing source is information on major transmission outages collected on DOE's Form OE-417, which is compiled by EIA and NERC.[93] A recent Carnegie Mellon University study of this data was able to conclude "that the frequency of large blackouts in the United States has not decreased over time," but could not determine why this is because of the lack of detailed information.[94]

This information gap leaves policy makers without a full understanding of transmission reliability risks or able to determine the best steps for improving reliability.[95] To help fill this gap, NERC has launched a new Transmission Availability Data System (TADS) to provide the data "needed to support decisions with respect to improving reliability and performance."[96] TADS reporting, which began in 2008, is mandatory for all high voltage transmission owners in the 48 contiguous states. NERC is still developing metrics to display and analyze the data in a meaningful way, and believes it may take up to five years before the data can be used to analyze trends."[97]

It may also take several years to judge whether TADS is collecting all the necessary data or if it needs to be revised or expanded.[98] Pursuant to EPACT05, NERC and FERC have been promulgating and enforcing new, mandatory, power system reliability standards.[99] Until a useful

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[93] Information on the OE-417 form is available on the DOE website at http://www.eia.doe.gov/cneaf/electricity/page/forms.html. Major power system disruptions are listed in EIA's Electric Power Monthly, Appendix B (http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html). EIA also collects transmission data on its EIA-411 form, but in the view of NERC this information is not useful for reliability analyses. Letter from David Nevius, Senior Vice President, North American Electric Reliability Corp., to OMB Desk Officer for DOE, Office of Management and Budget, "NERC Comments on EIA-411," October 24, 2007.

[94] Paul Hines, Jay Apt, and Sarosh Talukdar, "Large Blackouts in North America: Historical Trends and Policy Implications," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-09-01, March 4, 2009, p. 28, http://wpweb2.tepper.cmu.edu/ceic/PDFS/CEIC_09_01_blt.pdf.

[95] In the absence of solid reliability measures, data intended for other purposes are sometimes used as indicators of transmission system reliability. An example is counts of transmission load relief (TLR) requests on a power system. TLRs are used in parts of the Eastern Interconnection to reallocate and sometimes curtail transmission service when power lines are congested. TLR requests have been growing, which is sometimes cited as an indicator of increasing stress on the transmission grid (for example see Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects*, Edison Electric Institute and U.S. Department of Energy, Washington, DC, June 2004, pp. 7-8, http://www.oe.energy.gov/DocumentsandMedia/transmission_capacity.pdf). However, TLRs are used for economic as well as reliability reasons, and part of the increase in TLRs is an artifact of procedural changes by the Southwest Power Pool. For more information see North American Electric Reliability Corp., *2008 Long-Term Reliability Assessment*, October 2008, pp. 58 – 61, http://www.nerc.com/files/LTRA2008.pdf and Steve Huntoon and Alexandra Metzner, "The Myth of the Transmission Deficit," *Public Utilities Fortnightly*, November 1, 2003, p. 31 (text box). Another example is calls on customers who have signed up for demand response programs to reduce load when power supplies are tight or transmission lines are overloaded. NERC regions may record use of demand response as reliability problem events even if it is a routine use of demand control tools; see North American Electric Reliability Corp., *2008 Long-Term Reliability Assessment*, October 2008, p. 57, http://www.nerc.com/files/LTRA2008.pdf.

[96] Transmission Availability Data System Task Force, *Transmission Availability Data System Revised Final Report*, North American Electric Reliability Corp., September 26, 2007, p. 1, http://www.nerc.com/filez/tadstf.html. Detailed information on TADS is available at this website and a brief summary is at http://www.nerc.com/page.php?cid=4|62.

[97] Ibid., p. 13. At this time the detailed TADS data will be proprietary to NERC and not released to EIA. Personal communication with Robert Schnapp, Energy Information Administration, March 26, 2009. As noted above, NERC is working on how to report the aggregated data.

[98] EIA has already suggested that the TADS data coverage may be incomplete. E-mail from Robert Schnapp, Energy Information Administration, to David Nevius, North American Electric Reliability Corp. "Phase II TADS Request for Comments," June 16, 2008.

[99] For information on the FERC and NERC reliability activities, see the FERC website at http://www.ferc.gov/industries/electric/indus-act/reliability.asp and the NERC website generally (http://www.nerc.com/).

data collection and analysis system are in place, it will be difficult to judge whether these standards and other actions are actually improving the reliability of the transmission system.

Reliability and Grid Modernization

The transmission grid is sometimes portrayed as a decrepit victim of underinvestment; one recent press report described the grid as "frayed" like grandmother's quilt.[100] There is, in fact, no clear evidence that the transmission grid is physically deteriorating. But this does not mean that the grid is universally well managed or is as up-to-date as it should be. The grid probably needs to be modernized to improve reliability.[101] This is not necessarily the same as installing the full smart grid discussed above. The smart grid is an ambitious concept for integrated operation of the power system. The full smart grid is not needed to use a subset of "intelligent" technologies to improve the reliability of the transmission system.

The need for modernization is illustrated by the causes of the August 14, 2003 northeastern blackout. The blackout, which interrupted service to 50 million people in the United States and Canada for up to a week, started with transmission line trips (automatic shutdowns) and resulting overloads on the FirstEnergy utility system in Ohio. The blackout was not the result of insufficient transmission capacity or deteriorated equipment. As identified by the joint United States – Canada investigating task force, the blackout was caused by factors such as the following:[102]

- FirstEnergy and the NERC reliability region within which it operated did not understand the strengths and weaknesses of the FE system. FirstEnergy consequently operated its system at dangerously low voltages.[103]
- FirstEnergy's system operators lacked the "situational awareness" that would have revealed the blackout risk as lines began to trip. The operators were blinded by monitoring and computer system breakdowns, combined with training and procedural deficiencies which led to those failures going undetected until it was too late.[104]

[100] Peter Slevin and Steven Mufson, "Stimulus Dollars Energize Efforts to Smarten Up the Electric Power Grid," *The Washington Post*, March 10, 2009.

[101] Beyond the scope of this report is the issue of "cybersecurity" (i.e., steps taken to prevent malicious acts that would compromise the electronic or physical security perimeter of a critical cyber asset. In this context, a "critical cyber asset" includes the electronic elements of facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the electric power system). The importance of this issue was emphasized in April 2009 by press reports of apparently hostile penetrations of electric power industry computer systems (Siobhan Gorman, "Electricity Grid in U.S. Penetrated by Spies," *The Wall Street Journal*, April 8, 2009).

[102] The following points list some of the key factors that contributed to the collapse of the First Energy system and the consequent cascading blackout. For a full analysis of this complex event see U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, https://reports.energy.gov/BlackoutFinal-Web.pdf. Perhaps the best brief description of the causes of the blackout is the "Voltage Collapse" text box on page 81.

[103] Ibid., p. 33.

[104] "Transcripts of telephone conversations, released by the House Energy Committee, show bewilderment after the first control room computer went down. 'We have no clue,' one operator said. Another, speaking to a regional controller at MISO just before the blackout, said, 'We don't even know the status of some of the stuff around us.'" Ralph G Loretta and James E Anderson, "The Near Term Fix," *Public Utilities Fortnightly*, November 1, 2003, p. 34. (continued...)

- FirstEnergy did not adequately trim the trees under its transmission lines. As a result, three key transmission lines tripped when they sagged (as the lines are designed to do as they heat up with use) and came in contact with trees.[105]
- The Midwest Independent System Operator (MISO), the RTO that manages the grid in FirstEnergy's service area, did not have the real-time information necessary to assess the situation on FirstEnergy system and provide direction to the utility.[106]

Once the FirstEnergy system collapsed, overloads and power swings spread out across the Northeast, causing a cascading series of transmission line and power plant trips that left tens of millions of people without electricity. One reason the outage spread over such a wide area was because many power plants were equipped with unnecessarily sensitive automatic protection mechanisms that tripped the units prematurely.[107] The speed of the cascade allowed almost no time for manual intervention. The elapsed time from the start of the cascade (i.e., when failures began to radiate out from the collapsed FirstEnergy grid) to its full extent was about seven minutes.[108]

In summary, as discussed in the official blackout report and other analyses, the 2003 blackout was not caused by a utility having built too few transmission lines, or because power line towers and substations were falling apart. The blackout was apparently due to such factors as malfunctioning if not obsolete computer and monitoring systems, human errors that compounded the equipment failures, mis-calibrated automatic protection systems on power plants, and FirstEnergy's failure to adequately trim trees.

One part of a strategy for preventing repetitions of the 2003 blackout is to modernize the grid from a reliability standpoint. This will not always entail building more power lines. One analysis written shortly after the 2003 blackout concluded that "The common contributing factor to the recent blackout, based on investigations to date, is confusion-communication breakdowns both technical and human….[W]e maintain that much can be solved by updating technology and by changing procedures followed within the operating companies. This fix is cheaper and much more immediate than huge investment in new power lines."[109]

Modernization involves installing new technology into the existing system so that:

- Operators have accurate real time data on the status of the power network.

(...continued)

The blackout report notes that FirstEnergy had no automatic load-shedding schemes in place, and did not attempt to begin manual load-shedding. U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004, p. 70, https://reports.energy.gov/BlackoutFinal-Web.pdf.

105 U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, pp. 18 and 57, https://reports.energy.gov/BlackoutFinal-Web.pdf.

106 Ibid., p. 19, 46-49, and 55.

107 Ibid., p. 94.

108 The "full cascade" started at 4:05:57 pm and reached its maximum extent by 4:13 pm. Ibid., pp. 77 and 82.

109 Ralph G. Loretta and James E. Anderson, "The Near-Term Fix," *Public Utilities Fortnightly*, November 2003, p. 34.

- Operators also have advanced simulation tools to assist them in evaluating incipient problems and formulating responses.
- The grid can automatically respond to certain types of problems. This is sometimes referred to as the "self-healing" grid.

Some of these technologies are being implemented. An example is two new control centers installed by the Western Electricity Coordinating Council (WECC), the NERC reliability region covering the western states. According to WECC:

> These centers have a view of the entire Western Interconnection. They can see every tower, line, and transmission element over 100 kV. They will be able to see the entire Western bulk system, identify its status, and respond to outages…. they have the tools now to see and head off problems as they develop and they have the authority to contact grid operators and direct them to take certain actions to protect the interconnection as a whole.[110]

On the other hand, the control centers will not be able to remotely actuate equipment such as transmission line circuit breakers. As is typically the case, a crew will still need to be sent to manually reset the equipment, so the control system is still several steps away from automated, "self-healing" responses to grid problems.

In summary, depending on the case, building new transmission lines is not the only or best approach to enhancing power system reliability.[111] In some instances investments in new monitoring and control technology may be the better solution.

Reliability and Changes in the Energy Market

The transmission grid was built for a specific business and technical model: power plants would use transmission lines to move electricity to distribution networks for delivery to customers. The power plants were large "central station" facilities using fossil, nuclear, or hydroelectric energy sources, and were designed to run as-needed, when-needed. The power flow was one-way, from the power plant to the customer.

This model is already changing:

- *Variable Renewable Generation*: One factor is the introduction of large amounts of wind power onto the grid. Unlike conventional power plants, the output of wind plants varies with the weather. Power systems were not designed to handle this kind of power supply variability and uncertainty. Total wind capacity is now

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[110] Daniel Guido, "WECC's Two New Reliability Centers Replace Three Operations; Interconnection Now Is One," *Platts Electric Utility Week*, January 12, 2009, pp. 24 – 25. Another example is installation across the grid of phasor measurement units (PMU), a technology that provides system operators with real time data on wide areas of the power system. This is a new technology which will reportedly take five or more years to reach its full potential for enhancing system reliability. Saikat Chakrabarti et al., "Measurements Get Together," *IEEE Power and Energy*, January/February 2009, pp. 42-43.

[111] The Carnegie Mellon study cited earlier observes that "While transmission investment can, but is not guaranteed to, have a positive impact on cascading failure risk and reliability, transmission construction alone is a costly, and potentially ineffective, solution to reliability problems." Paul Hines, Jay Apt, and Sarosh Talukdar, "Large Blackouts in North America: Historical Trends and Policy Implications," Carnegie Mellon Electricity Industry Center, Working Paper CEIC-09-01, March 4, 2009, p. 29, http://wpweb2.tepper.cmu.edu/ceic/PDFS/CEIC_09_01_blt.pdf.

large enough in some parts of the country, such as the ERCOT Interconnection (covering most of Texas), to be an important influence on how the power system is operated.

The variable output of wind plants can be dealt with in a variety of ways, including improved wind forecasting, adding electricity storage and/or quick start natural gas-fired peaking plants to the grid, and drawing wind power from a wide geographic area to smooth out local changes in wind speed. However, these capabilities will have to be added rapidly to the grid if, as some expect, the use of wind power grows quickly.

- *Demand Response*: Another factor is the increasing use of demand response programs, in which large commercial and industrial customers agree to interruptible power service in return for lower rates. For example, in the Florida and northeastern NERC reliability regions, significant parts of peak demand (respectively, 6% and 4%) can now be met by customers reducing output rather than by operating power plants.

  Demand response reverses the conventional power system operating model: instead of changing power plant output to match demand, demand is reduced to match the available supply of electricity. An issue is how much real time information and control (also referred to as "visibility") system operators will have over industrial and commercial facilities that have signed on to demand response programs. Another issue is whether industrial and commercial loads will become less willing to participate in demand response programs if cycling of their operations becomes routine rather than a rarity. These issue are clearly not insuperable, given the success to date with these programs, but they may have to be dealt with on a much larger scale in the future.[112]

- *Distributed Generation*: A third factor is the use of distributed generation (local power generation controlled by the customer), which can vary from rooftop solar units to large industrial cogeneration[113] facilities. A distributed generation facility will sometimes take power off the grid. Other times it will have excess power to sell to the utility, reversing the normal flow of electricity. Buying power from customers is inconsistent with standard utility technology, accounting, and rates. This is especially true when the generation is hooked up to the distribution system, which was designed to make final delivery of power to customers, not receive power from the customer.

  Distributed generation poses control and visibility issues similar to demand response. Wide use of distributed generation will also pose institutional issues. One is that generation connected to the distribution system (in contrast to the transmission system) is not covered by NERC reliability standards. Second,

[112] Not all demand response is directly controllable by the utility, which makes integration more difficult. For information on the various flavors of demand response and issues with grid integration see North American Electric Reliability Corp., *2008 Long-Term Reliability Assessment*, October 2008, pp. 41-43 and 270-271, http://www.nerc.com/files/LTRA2008.pdf.

[113] Cogeneration (also referred to as combined heat and power or CHP) is an integrated process to produce electricity and process heat for industrial or commercial use, such as space heating. Because the CHP plant makes use of the waste heat lost in a stand-alone power plant or steam plant, it is much more energy efficient than those types of facilities.

realizing the full potential of distributed generation may require the states to implement net metering laws that allow owners to sell surplus power back to the grid.

As with demand response, these issues are neither new or insuperable, although the scale may increase greatly. On the other hand, plug-in hybrid electric vehicles would pose a truly unique challenge, since their batteries would be a load on the power system at times and a source of stored electricity at other times. System operators would have to be able to decide on a daily or hourly basis how much they can rely on electricity storage scattered over thousands or millions of batteries, none of which are owned by the utility.

Integrating non-traditional resources into the grid will be a reliability challenge. This is not because these resources are new. For example, distributed generation in the form of industrial cogeneration has been increasingly common since Congress passed the Public Utility Regulatory Policies Act (P.L. 95-617) in 1978. The issue is integration of *much larger amounts* of these resources into a power system primarily designed around a different model. For example, NERC has concluded that “Demand response will become a critical resource for maintaining system reliability over the next ten years.”[114] In 2008 NERC reported proposals to connect 145,000 MW of new wind capacity to the transmission grid by 2017, equivalent to about 14% of current total generating capacity in the United States.[115] Even if all of the proposed wind capacity is not built, many more wind plants will probably be connected to the grid. The most recent EIA long-term forecast, which assumes no changes to current laws, estimates that wind generation will increase by 300% by 2030.[116]

A characteristic that variable renewable generation, demand response, and distributed generation have in common is potentially less predictability (in respect to availability and level of service) than traditional resources. Improved real time monitoring, analysis, and control of the grid could help compensate for this issue. Another system-wide response may be to collapse the 130 balancing authorities that currently operate the transmission system into a smaller number that could call on a wider range of resources for managing electricity supply and demand.

Transmission Reliability: Summary of Policy Issues

In response to the 2003 northeastern blackout, Congress gave FERC authority over the reliability of the bulk power system in the 48 contiguous states. Continuing policy issues include:

- *Transmission system information gap*. There is currently no good source of data that measures the reliability of the transmission grid or allows trend analysis. NERC is developing a new process for collecting and analyzing transmission

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[114] North American Electric Reliability Corp., *2008 Long-Term Reliability Assessment*, October 2008, p. 20, http://www.nerc.com/files/LTRA2008.pdf.

[115] Ibid., p. 12. In 2007, total wind capacity in the United States was 16,515 MW. In 2000 it was 2,400 MW. Total net summer capacity of all types in 2007 was 994,888 MW. Energy Information Administration, *Electric Power Annual 2007*, Table 2.2, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html, and Energy Information Administration, *Annual Energy Review 2007*, Table 8.11a, http://www.eia.doe.gov/emeu/aer/contents.html.

[116] Energy Information Administration, *Annual Energy Outlook 2009 Early Release*, December 17, 2008, slide 16, http://www.eia.doe.gov/oiaf/aeo/aeo2009_presentation.html (select presentation with data). Related materials are at http://www.eia.doe.gov/oiaf/aeo/index.html.

reliability data. The progress of this effort may be of interest to Congress, because without good data it will be difficult to judge whether FERC's new reliability standards and other actions are actually improving the reliability of the transmission system.

- *Modernization and reliability*. The implementation of modernized technology and management may be an alternative, or necessary supplement, to building new transmission lines to improve the reliability of the grid. In considering new spending and planning approaches for the transmission system, Congress may wish to ensure that the right balance is struck between modernization and new construction.
- *Reliability and the changing power market.* The power system is changing from a model based on central station power plants to a more diverse range of resources, including variable renewable power, demand response, and distributed generation. Congress may want to exercise oversight to ensure that FERC and NERC are developing reliability standards for a changing grid. Also, certain kinds of distributed generation are not covered by federal reliability authority, a situation Congress may want to revisit in the future.

Summary of Transmission Policy Issues

This concluding section summarizes policy issues of potential interest to Congress.

Federal Transmission Planning

S. 539 and other proposals call for a much larger federal role in transmission planning, and suggest that planning should be conducted on a larger geographic scope than in the past. Policy issues include:

- *What should be the objectives of the planning process?* For example, planning could be focused on renewable power development or on broader objectives, such as congestion relief and reliability enhancement.
- *What should be the scope of authority of the planning entities.* Federal transmission planning could be run by interconnection-wide centralized authorities (the top-down approach) or be conducted primarily at a regional level (the bottom-up approach), or as a hybrid.
- *What is the appropriate scope of the planning process?* Should the planning process extend beyond transmission planning narrowly defined to a include a broader array of solutions to power system issues, such as demand response, distributed power, or conventional power plant construction.
- *Could preferential treatment tied to the planning process distort transmission investment?* The planning proposals typically make available certain benefits, such as a federal permitting option, to projects included in the plan. These benefits could lead developers to add unnecessary features and costs to qualify proposals to meet plan criteria. Avoiding these distortions will require careful oversight or, arguably, limiting the benefits associated with the plan (for example,

putting all new power lines or none, whether or not they are in the plan, under federal government permitting authority).

- *Is the scheme for managing and financing the planning process realistic?* An effective planning process will need realistic schedules and sufficient resources to timely develop and update transmission plans.

Permitting of Transmission Lines

Transmission line permitting is primarily under the control of the states. Current proposals would extend federal authority, perhaps by completing displacing the state role. Issues include:

- *Should the grid be viewed from a national perspective?* The grid evolved as local systems serving limited utility service areas. Now that the system has evolved into three separate synchronized interconnections, each spanning (other than ERCOT) many states. The question is whether a state-by-state or national view of the grid is most appropriate. The issue does not necessarily have a single answer; for example, a state perspective may be appropriate for "routine" projects, while a national perspective could be applied to "national interest" projects.
- *Can transmission system reliability be separated from authority over new transmission construction?* In EPACT05 Congress put the reliability of the grid under federal jurisdiction. By extension, should the federal government have control over the permitting of transmission lines aimed at enhancing system reliability (which could mean almost any new line in an interconnected power systems)?
- *How important is it to accelerate the construction of new transmission lines?* One criticism of the current regulatory regime is that it takes many years to move a transmission project through the permitting steps. Expanding federal authority over permitting is viewed as a means of accelerating the process. The question is how important is it to quickly build transmission lines to meet reliability, environmental, and other objectives.
- *Management of the permitting process*. If FERC or some other agency is assigned a federal permitting role, it will need the resources to expeditiously process applications. Otherwise the whole point of giving more permitting power to the federal government would largely be obviated.

Transmission Line Funding and Cost Allocation

Building new transmission lines could cost billions of dollars. Even more contentious than how to fund these projects is the question of how the costs of interstate transmission lines should be allocated to utility customers. Issues include:

- *Should the federal government help pay for new transmission lines?* Some proposals call for the federal government, possibly acting through the federal utilities, to help pay for new transmission lines, pay for expanding projects to meet future needs, or actually build new transmission. How far should the federal government go into financing the expansion of the transmission grid?

- *Should the Congress establish a national cost allocation rule for new transmission projects?* An approach included in several proposals would require all ratepayers in an interconnection to pay for new projects anywhere in the interconnection. The notion is that in a interconnected grid all customers benefit to some degree from enhancements to the system, but a preferential cost allocation mechanism for transmission may bias investment away from other alternatives.

Transmission Modernization and the Smart Grid

The smart grid is a concept for modernizing the grid with information technology and intelligent features. Congress has already established and funded programs for encouraging development of the smart grid. Policy issues include:

- *Program oversight*. The American Recovery and Reinvestment Act provided funding for previously authorized smart grid programs, including one key effort – development of interoperability standards by the National Institute for Standards and Technology – that has been lagging. Congress may want to monitor how these programs progress.
- *Smart grid cost/benefit oversight*. The balance of costs and benefits that the smart grid will produce for customers has been hotly debated. Many smart grid investment decisions will be made by state utility commissions. However, other investments and rate decisions will be under FERC jurisdiction, so there is ample room for Congressional oversight of the actual costs, benefits, and performance of smart grid investments.

Transmission System Reliability

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