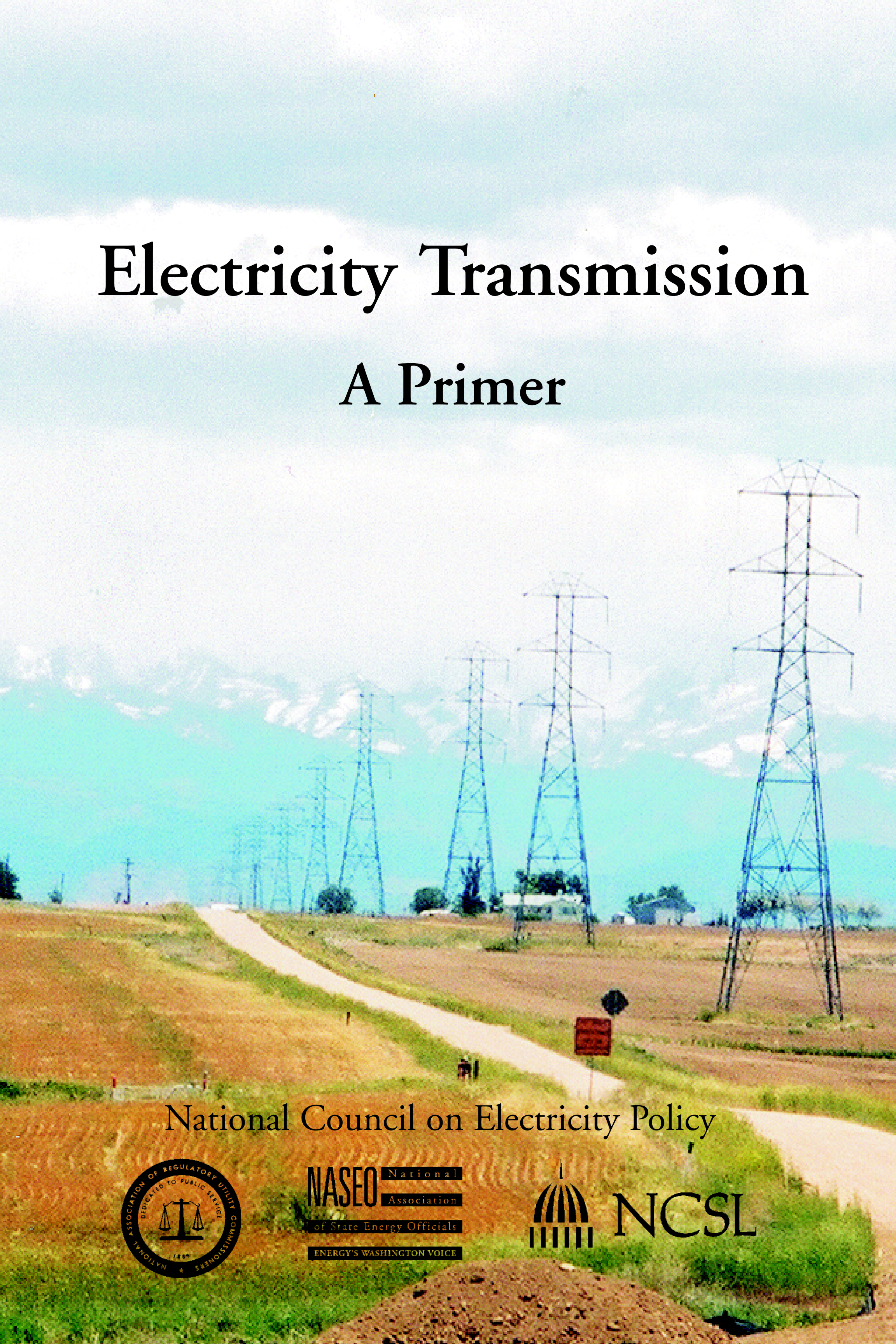

Electricity Transmission

A Primer

National Council on Electricity Policy

National Association of Regulatory Utility Commissioners
Dedicated to Public Service
1889

NASEO
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NCSL

Electricity Transmission

A Primer

By

Matthew H. Brown, National Conference of State Legislatures
Richard P. Sedano, The Regulatory Assistance Project

National Council on Electric Policy

The National Council on Electricity Policy is a joint venture among the National Conference of State Legislatures (NCSL), the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO)
www.ncouncil.org

June 2004

The National Conference of State Legislatures is the bipartisan organization that serves the legislators and staffs of the states, commonwealths and territories.

NCSL provides research, technical assistance and opportunities for policymakers to exchange ideas on the most pressing state issues and is an effective and respected advocate for the interests of the states in the American federal system. Its objectives are:

- To improve the quality and effectiveness of state legislatures.
- To promote policy innovation and communication among state legislatures.
- To ensure state legislatures a strong, cohesive voice in the federal system.

The Conference operates from offices in Denver, Colorado, and Washington, D.C.

The National Association of Regulatory Utility Commissioners (NARUC) is a nonprofit organization founded in 1889. Its members include the governmental agencies that are engaged in the regulation of utilities and carriers in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. NARUC's member agencies regulate the activities of telecommunications, energy and water utilities. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Under state law, NARUC's members have the obligation to ensure the establishment and maintenance of utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions that are just, reasonable and nondiscriminatory for all consumers.

The National Association of State Energy Officials (NASEO) is the only nonprofit organization whose membership includes the Governor-designated energy officials from each state and territory. NASEO was formed by the states and through an agreement with the National Governors Association (NGA) in 1986. The organization was created to improve the effectiveness and quality of state energy programs and policies, provide policy input and analysis where requested, share successes among the states, and to be a repository of information on issues of particular concern to the states and all their citizens.

Cover photo by Anthony Calvo.

Printed on recycled paper

ISBN 1-58024-352-5

Contents

List of Figures and Tables

Table

Figure

About the Authors

Matthew H. Brown is the director of the National Conference of State Legislatures' Energy Project. He is responsible for advising state legislators and their staff on a wide variety of energy issues. Mr. Brown has authored or co-authored numerous publications on electric industry issues. He has testified before more than 35 state legislative bodies on energy policy issues and has worked closely with many state legislatures on their own electricity policies. Mr. Brown holds an AB from Brown University and an MBA from New York University.

Richard Sedano is a director with the Regulatory Assistance Project, where he writes and presents on a variety of energy topics. Before he joined RAP in 2001, he was Commissioner of the Vermont Department of Public Service from 1991 to 2001, and was chair of the National Association of State Energy Officials from 1998-2000. In 1997-98, he served on the Electric System Reliability Task Force for the Secretary of Energy Advisory Board. He received a bachelor's degree in engineering from Brown University and master's degree in engineering management from Drexel University.

Acknowledgments

This report was prepared with the financial assistance of a grant from the U.S. Department of Energy (DOE) Office of Electric Transmission and Distribution, Jimmy Glotfelty, director. Larry Mansueti of that program provided helpful input, direction and review on the document.

The authors are grateful for the assistance of numerous others who provided information for this report and reviewed its contents. Kansas Representative Carl Holmes, Tim Kichline of the Edison Electric Institute, Maryland Delegate Carol Petzold, Terry Ross of the Center for Energy and Economic Development, Samantha Slater of the Electric Power Supply Association and Terri Walters of the National Renewable Energy Laboratory provided review and are members of the NCSL Advisory Council on Energy (ACE), an advisory board to the NCSL Energy Project.

The authors also thank Lynn Anderson and Marsha Smith of the Idaho Public Utilities Commission, Wilson Brown and Jennifer Brown of the University of Winnipeg, Jeffrey Genzer of that National Association of State Energy Officials, Chuck Gray of the National Association of Regulatory Utility Commissioners (NARUC), Cathy Iverson of the U.S. Department of Energy, Jim McCluskey and Bill Keese of the California Energy Commission, Kevin Porter of Exeter Associates and the Executive Director of the National Council on Electricity Policy, Christie Rewey of the National Conference of State Legislatures, Kansas Representative Tom Sloan, Andrew Spahn of NARUC, and Connie White of the Utah Public Service Commission.

Leann Stelzer provided the invaluable copy editing and formatting for this book. Alise Garcia gave invaluable assistance to production of this publication.

The authors are grateful to the members of the National Council on Electricity Policy Steering Committee for their support on this project.

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The National Council is funded by the U.S. Department of Energy and the U.S. Environmental Protection Agency.

The views and opinions expressed herein are strictly those of the authors and may not necessarily agree with the positions of the National Council, its steering committee members or the organizations they represent, the National Council funders, or those who commented on the paper during its drafting.

1. Introduction

Flip on the lights, and you're completing a circuit that connects your light bulb to the wires that serve your house, to the larger wires that serve your neighborhood and, ultimately, to a network of high capacity wires that deliver power over great distances. This network—the power transmission system—is complex, costly and critical to the nation's economy and way of life. Many of those who influence the electric industry, however, lack a good understanding of the transmission system.

This primer on electric transmission is intended to help policymakers understand the physics of the transmission system, the economics of transmission, and the policies that government can and does use to influence and govern the transmission system.

This book is divided into the following chapters and an appendix:

- Why has transmission become so important?
- What is the process for building a transmission line?
- Paying for transmission.
- Physical and technical characteristics of transmission.
- Action items for state officials.
- Appendix: Who plans, builds and owns transmission?

Electricity Transmission: A Primer is designed for those who are new to transmission issues. It focuses on state policy and on how state policymakers can influence transmission policy. To understand what states can do about transmission, it is important to understand a broader context of transmission technology, planning, and the interactions of state and federal policies. Thus, part of this primer provides background on these broader issues. The primer concludes with a more detailed discussion of state transmission policies. Because so many of these policies relate to permitting and siting transmission facilities, much of the policy discussion focuses on transmission siting.

A Quick History

Growth of the Transmission System

The 19th century inventors who first began to harness electricity to useful purposes did so by putting their small generators right next to the machines that used electricity. The earliest distribution system surrounded Thomas Edison's 1882 Pearl Street Station in lower Manhattan, and another that Edison built in Menlo Park, New Jersey. These, like most of the systems constructed during the next few years, distributed power over copper lines, using direct current. This method of distribution was so inefficient that most power plants had to be located within a mile of the place using the power, known as the "load." It appeared at the time that the power industry would develop into a system of many small power plants serving nearby loads. All the early power systems were what most people now refer to as distributed generation systems: generators were located close to the machines that used electricity.

By the 1890s, other inventors, many of whom were former partners or employees of Edison, further developed this system of power distribution. The most important development was high-voltage power transmission lines using alternating current (AC). Alternating current allowed power lines to transmit power over much longer distances than the direct current system that Edison preferred. In 1896, George Westinghouse built an 11,000 volt AC line to connect a hydroelectric generating station at Niagara Falls to Buffalo, 20 miles away. From then on, the voltage of typical new transmission lines grew rapidly, as table 1 illustrates.

Table 1. New Transmission Line Voltages During Electrification of the United States

Date	Typical Voltage
1896	11,000
1900	60,000
1912	150,000
1930	240,000

Source: Smithsonian Institution, 2002.

This more capable power transmission system further spurred the industry to build larger generators to serve ever-larger loads and populations. The economics of the industry began to favor larger companies instead of the multiple small power plants and local distribution systems that had been established in the 1880s to 1890s. Chicago's Samuel Insull built Commonwealth Edison by acquiring and consolidating many of these small companies; by 1907, when he formally incorporated Commonwealth Edison, he had consolidated 20 different power companies. Other cities saw the same types of consolidation and creation of the early electric monopolies, a trend that continued for the first quarter of the 20th century.

State governments reacted by extending the jurisdiction of their regulatory commissions, originally designed to regulate railroads, to electric companies. New York and Wisconsin set the trend in 1907, when their legislatures passed laws setting up a state regulatory system. By 1914, 43 states had regulatory commissions with oversight over electric utilities.

Under this structure, the electric system continued to grow at a tremendous pace. The electrical output from utility companies exploded from 5.9 million kilowatt-hours (kWh) in 1907 to 75.4 million kWh in 1927. During that same period, the real price of electricity declined by 55 percent, although many people still viewed it as a luxury; adjusted for inflation, a kilowatt hour of electricity in 1907 cost $1.56, declined to 55 cents by 1927, and continued its steady decline thereafter. The electric industry continued its path toward greater consolidation, and by 1932, eight large holding companies controlled about three-quarters of the investor-owned utility business. Because these holding companies crossed state lines, they generally were exempt from state commission jurisdiction. Many people felt federal regulation was necessary.

This first major federal regulation of the electric power industry occurred in 1935, when President Roosevelt signed the Public Utility Holding Company Act (PUHCA). PUHCA limits the geographical scope of utility holding companies and the corporate structure of the holding companies. The act of created vertically integrated utilities (owning both power plants and power lines) in monopoly service areas. The Federal Power Act gave the Federal Power Commission jurisdiction over wholesale power sales and over transmission of electric power.[1] States retain jurisdiction over siting of generation and transmission and over distribution rates. This combination of federal and state regulation of the industry remained in much the same form for close to a half century.

The growth continued in the post-World War II era. Electric utilities made technological advances by constructing larger generating plants to capture economies of scale. It cost less to generate a kilowatt-hour (kWh) of electricity from a large plant than from a small plant. In 1948, for example, only two power plants exceeding 500 megawatts (MW) existed in the United States. By 1972, 122 such plants were in existence.

Electric heat rates declined from about 16,000 British Thermal Units (BTUs) per kilowatt-hour to just over 10,000 BTUs per kilowatt-hour between 1948 and 1965, meaning that it took less energy to generate a single kilowatt-hour of electricity. Still higher voltage transmission lines also emerged, giving utilities access to ever more distant power sources. The number of miles of high-voltage transmission lines, essentially nonexistent in the 1950s, more than tripled to more than 60,000 circuit miles in the 1960s. In addition, transcontinental natural gas pipelines were built to connect consumers to gas-producing regions in the southeastern United States. This gave utilities an inexpensive boiler fuel for new generating plants.

Power System Regulation

As a result of these changes, the power system that began as fundamentally a local system evolved into an interstate system. Power used in Rhode Island might have been generated in Connecticut or elsewhere in New England. By 1927, the U.S. Supreme Court recognized that, because of this fast-developing transmission system, electricity was not an intrastate but an interstate commodity that therefore was subject to federal regulation in addition to state regulation.[2] Later Supreme Court rulings affirmed and built upon this federal jurisdiction over the transmission system. Two other major pieces of federal legislation have been important in recent years: the 1978 Public Utility Regulatory Policies Act (PURPA) and the 1992 Energy Policy Act (EPACT). Also of note are several FERC orders.

Public Utility Regulatory Policies Act

PURPA passed at a time when the nation was focused on what appeared to be a steady stream of oil price increases and a great deal of concern about energy imports from politically unstable countries. PURPA was ground-breaking because, for the first time, it required that utilities buy power from companies that were not utilities. PURPA created a new industry of nonutility power generators. It was important to transmission policy because it required that the nonutility generators be given access to the transmission system in order to deliver their power onto the grid.

Energy Policy Act

Fourteen years later, again in an era of concern about the nation's dependence on imported fuels, Congress passed the Energy Policy Act of 1992. EPACT required that the now well-established competitive generators or any utility be given access to the utilities' transmission grid on rates and terms that were comparable to those that the utility would charge itself for access to the grid. This access to the transmission grid became indispensable to the growth of wholesale power markets, whereby power generators can use the transmission system to send power to one another at fair and predictable rates and terms. Since the mid-1990s, the Federal Energy Regulatory Commission (FERC) has issued several orders to carry out the goals of EPACT.

Federal Energy Regulatory Commission Orders

Order 888 detailed how transmission owners should charge for use of their lines and the terms under which they should give others access to their lines. Order 888 also required utilities to functionally unbundle—i.e., to separate—their transmission and generation businesses and to follow a corporate code of conduct. FERC hoped that this separation would make it impossible for the transmission business to give its own power plants preferential access to the company's transmission lines.

Order 889 created an on-line system through which transmission owners could post the available capacity on their lines and the companies that wanted to use the system to ship power could observe the available capacity.

Order 2000 encouraged transmission-owning utilities to form regional transmission organizations (RTOs). FERC did not require utilities to join RTOs; instead, it asked that the RTOs meet minimum conditions, such as an independent board of directors. FERC gave these regional organizations the task of developing regional transmission plans and pricing structures that would promote competition in wholesale power markets, using the transmission system as a highway for that wholesale commerce.

In 2004, FERC issued Order 2003-A, which requires transmission owners to interconnect new generators of larger than 20 megawatts to their grid. Order 2003-A required the transmission owners to connect these large generators under a standard set of terms and conditions and to follow a standard process and timeline for interconnecting them. Sometimes new power plants add new stresses to the power grid. Transmission owners need to upgrade the transmission grid when this happens. Order 2003-A defines who pays for these upgrades.

Today's Transmission System

At the start of the 21st century, the transmission system is a truly interconnected network with more than 150,000 miles of high-voltage transmission lines. The nation's increasingly technology-dependent society depends upon the network itself as much as on the power plants that use and feed the network. Table 2 describes the size and some characteristics of today's transmission system.

Table 2.
Miles of High-Voltage Transmission Lines in the United States

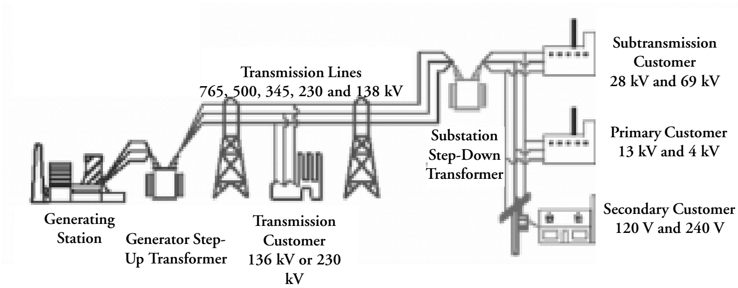
Voltage	Miles of Transmission Line
AC	
230 kV	76,762
345 kV	49,250
500 kV	26,038
765 kV	2,453
Total AC	154,503
DC	
250-300 kV	930
400 kV	852
450 kV	192
500 kV	1,333
Total DC	3,307
TOTAL AC/DC	157,810

Source: National Transmission Grid Study, U.S. DOE, May 2002.

The system developed into a sophisticated network, involving interconnected power plants and power lines that operate at many different voltages. Figure 1 illustrates today's transmission system.

The network performs well nearly all the time, although weaknesses sometimes emerge. Fast-growing counties sometimes stress the transmission system's ability to deliver power reliably, at least until the transmission owners find ways to accommodate the growth. On rare occasions, the network breaks down and causes blackouts such as the one in the northeastern and midwestern United States on August 14, 2003.

Figure 1. Key Elements of the Electric Power Grid



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

Today, electric transmission is receiving more attention than ever, not only because of recent blackouts. The goal of today's politically charged debate about transmission is to determine how to use a combination of technology and policy to shore up the weak sections of the network. The goal also includes adapting the physical network and the institutions that govern that network to the many changes that have taken place in the power industry during the past decade. The physical network may require new lines or other investments to accommodate the new patterns of power flows brought on by wholesale competition. The institutions that govern transmission will require a number of changes—some of which are necessary to support the physical changes to the grid. In the end, the power system will serve increasing demands through a combination of new wires, new generation and more energy efficiency measures.

2. Why Has Transmission Become So Important?

The speedy transformation of the power industry from a local to an interstate one occurred for four main reasons: reliability, flexibility, economics, and competition. This chapter discusses why the transmission system is critical to our way of life. Broadly, a strong transmission system 1) improves the reliability of the electric power system, 2) gives electricity customers flexibility to diversify the mix of fuels that produces their electricity by giving them access to power plants, 3) improves the cost structure of the entire industry by giving low-cost power plants access to high-cost power markets, and 4) enables competition among power plants by giving more plants access to more markets.

Reliability

Power system operators often describe two elements of electric system reliability: adequacy and security. *Adequacy* is the ability of the electric system to supply the electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of power lines and power plants. *Security* is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities such as a power plant or a power line.[1] The North American Electric Reliability Council (NERC) sets adequacy and reliability standards for utility facility owners and operators.[2]

A strong transmission system allows many different kinds of generating plants in many locations to supply power to customers. Some power plants are built to run continually; others run only at peak hours when they are most needed. Some power plants, such as the fast-growing number of wind plants or some hydroelectric units, operate intermittently, when sufficient wind blows or water flows. Hydroelectric plants also occasionally shut down because of environmental restrictions. All power plants shut down regularly for maintenance and, on occasion, due to unexpected problems. Power plants may shut down or power lines may fail unexpectedly due to technological failures or due to weather or natural disasters.

The transmission system gives power users the ability to draw from a diverse set of power plants in different locations and with different operating characteristics. If the transmission system is robust, with a certain amount of redundancy built in, it can withstand the failure of its most critical lines or other components. Analysts often refer to this as single contingency analysis, or N-1 analysis. This robustness and diversity create a network of power plants and lines that is far more reliable than one that relies on the output from a single plant or a single line. In the end, an interconnected power system needs fewer power plants to meet customers' electricity demands because all the power plants can use the transmission system to share the responsibility of meeting customers demand. The Northeast Power Coordinating Council, one of the 10 regional reliability councils, is assisting the three northeast system operators (ISO-New England, New York ISO, PJM) to develop a plan to share reserves. Participants expect to reduce both total reserve requirements and the cost of meeting reserve requirements necessary to ensure adequate reliability.[3] This is particularly important since NERC reports indicate that summer reliability margins will decline during the next decade.[4]

Flexibility

Transmission allows power systems to use diverse resources such as wind, coal or geothermal energy, even if they are located far from the people that use electricity. Wind plants need to be constructed where the wind is strongest and most consistent. Coal plants are best built near the mine's mouth, since it is far cheaper to transmit electricity than to ship coal. Biomass plants are best built near their source of fuel for the same reason. In contrast, natural gas plants can be built close to population centers, using pipes to transport the gas.[5] A strong[6] transmission system gives power companies the flexibility to consider several alternatives to meet the demand for power, including natural gas plants built close to electric load or other power plants built far from the load.

Economics

The original Edison system that delivered power over a small distribution system was adequate for the purpose it served. It tied its customers to one company and one generator. Now, with many different power plants operating across the country, some can produce power more cheaply than others. The transmission system allows the less expensive generators to deliver power in competition with other, more expensive, generators. In theory, the least expensive generators could force similar but more expensive generators to either become more efficient or to shut down.[7] For example, customers in the fast-growing markets in large cities such as Chicago and states such as Nevada and Utah would like the chance to use the transmission system to deliver the power from low-cost, mine-mouth coal power plants and wind generators in Wyoming. New and more efficient power plants should be able to use a strong transmission network to deliver power throughout their regional market, thus reducing the cost of power throughout that market.[8]

Transmission also is an insurance policy embedded within the energy system. A robust transmission system allows the lowest cost generation at that point to serve customers. As a result, the transmission system helps to insulate electricity consumers from the effects of natural gas price spikes, low hydroelectric years and catastrophic events.

Competition

The evolution of the power system from a local to interstate and regional scopes has spawned competition. Now, low-cost power plants in Illinois, Indiana and Ohio can supply power to the East Coast. The new competitive generators (nonutility companies) must be able to rely on fair and nondiscriminatory access to the transmission system to deliver their product to any connected market. As a result, low-cost, imported electricity can displace high-cost electricity from nearby power plants, as has happened in recent years as new Arizona power plants have begun to serve customers in California.

New transmission lines also can make local power markets more competitive. Analysts refer to "transmission constrained areas," which have only limited ability to import power because the transmission system feeding into the constrained area is congested or already is at or close to its capacity. Such areas can be subject to the market power of whatever the power plants inside the constrained area are able to charge for electricity, since they face little or no competition from outside the area. New transmission lines into the constrained area can force the power generators inside the constrained area to lower their prices when they have to compete with low-cost power with new access to the area. The transmission system, then, is much like a highway system that enables a new commerce in power.[9] Figure 2 represents normal power flows between significant regions of the United States. These flows can vary dramatically in the event of a major contingency such as the unexpected failure of a large power plant or power line, for example.

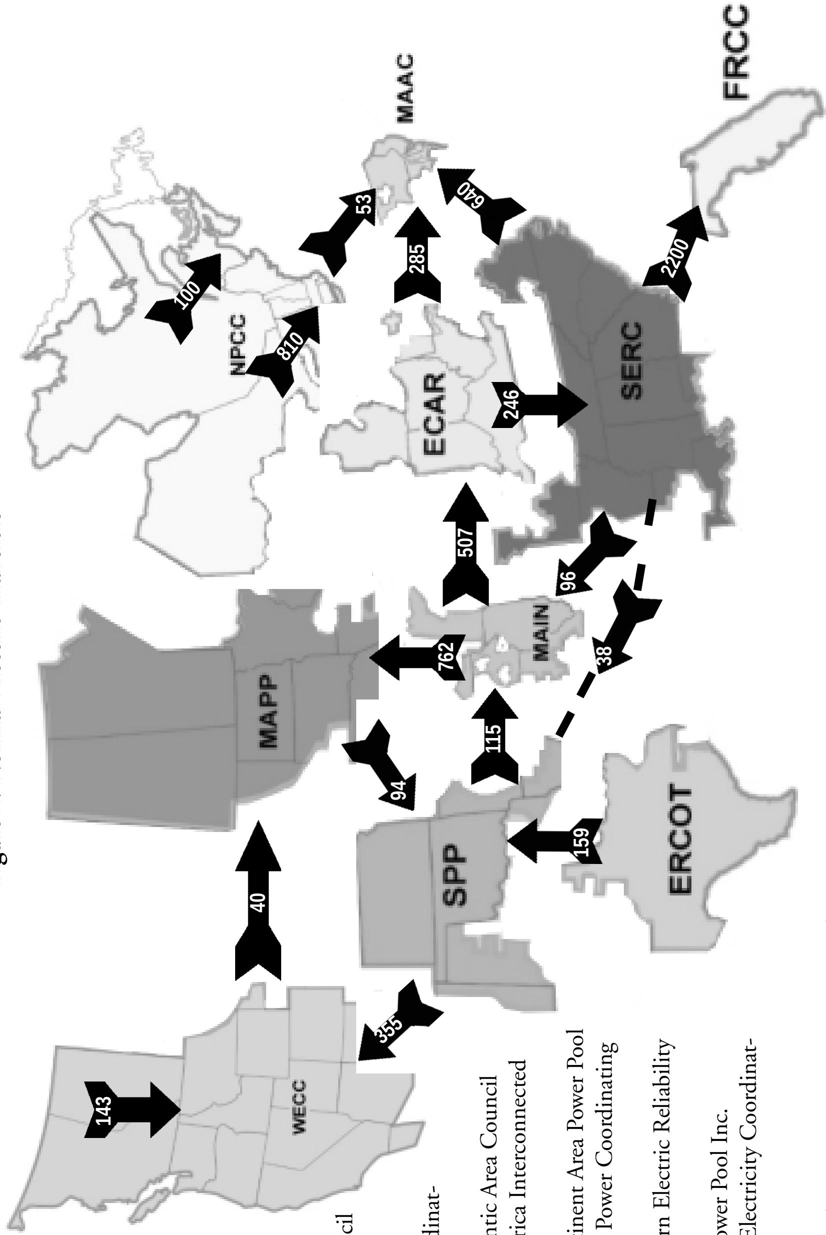
Even with these benefits, transmission is controversial. Transmission is, of course, necessary to deliver electricity to consumers; it represents approximately 10 percent of a customer's total electric bill. Opinions abound, however, as to how much transmission is needed and where to build new transmission. Most people probably would prefer that transmission companies build new transmission lines where no one can see them. Some find comfort in ensuring that ample transmission is built, while others express concern for "gold plating," a term suggesting more utility investment than is absolutely necessary to ensure reliability.

Transmission Siting Process

The transmission siting process remains one of the most difficult elements of the transmission debate. A mixture of local, state and federal government agencies hold jurisdiction over who can build what, where they can build it, when they can build it and who pays for it. In the end, transmission siting in some states is one of the most difficult yet most important elements of the transmission system.[10] The remainder of this book addresses many basic elements of transmission economics and physics in order to provide background and a context within which state policymakers can gain a better understanding of transmission siting policies. The appendix contains a more detailed discussion of who plans, builds and owns transmission.

The process to build transmission lines often is fairly long and, at times, may entail controversy. The following five steps describe a typical process for building transmission lines. The details of the process may differ, but these five generic steps are common, no matter where construction occurs.

Figure 2. Normal Electric Transfers



ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas Inc.
FRCC - Florida Reliability Coordinating Council
MAAC - Mid-Atlantic Area Council
MAIN - Mid-America Interconnected Network Inc.
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool Inc.
WECC - Western Electricity Coordinating Council

Source: NERC, *2004 Summer Assessment*, May 2004.

1. Planning;
2. The utility performs a study on costs of the new power lines;
3. The utility performs a study of possible routes for the transmission line;
4. The utility seeks permission from state agencies and federal agencies to build a power line; and
5. The builder obtains financing for the line and builds the power line.

Step 1. Planning

Power companies and power system planners always have a set of choices they can use to deliver service to customers. In short, those choices are to:

1. Send power via a transmission line.
2. Develop an aggressive program of energy efficiency,[11] distributed generation[12] and demand response[13] measures that could delay or perhaps obviate the immediate need for new transmission or generation.
3. Build power plants near the place that needs the power instead of sending power over transmission lines.
4. A combination of these choices, which could lead to smaller transmission lines or a delay in the need for the new transmission line.

Utilities and their regulators may consider each of these options and balance the costs against the benefits of each approach. No single approach to meeting new power needs works best; the answer will be specific to the needs and problems in specific locations.[14]

To assess and plan for changes, all power companies and an increasing number of regional organizations[15] analyze their network of power lines, power plants and the demand for power. Three of these changes are: 1) population growth that increases the demand for electricity; 2) new power plants; and 3) new ways to use the transmission system efficiently.

Population Growth. Sometimes planners decide the transmission system needs new investment because of population growth. In the mid-1990s, Douglas County, just south of Denver, was adding several thousand people to its population each month. As one of the fastest growing counties in the country, it requires new electricity infrastructure to serve new homes.

Eventually, growth at this pace requires new transmission lines to maintain system reliability. Planners also develop forecasts of energy use within homes and businesses.

New Power Plants. Planners also try to forecast where power plant developers will build their new power plants.[16] More than 3,600 MW of new natural gas power plants were built in New England by competitive generators between 1997 and 2001; the Pennsylvania-New Jersey-Maryland region and other regions also have seen significant construction of new power plants. The output from each of these plants travels onto and through the electric transmission system. In some cases, new generators require upgrades to the system. Some upgrades may be as basic as "on-ramps" to the grid. Others can be more significant. Competitive generators paid more than $200 million between 1998 and 2003 to perform upgrades to the transmission system of the Texas/Louisiana-based territory of Entergy.[17]

Using Transmission Efficiently. Transmission system planners also try to find ways to use new transmission lines to deliver power from a location that may have excess capacity to another area that needs the electricity. For example, North Dakota and South Dakota have some of the windiest conditions in the world, and it is an ideal area for wind turbines. The problem with building wind plants in the Dakotas is that those states are far from the population centers—often referred to as load centers—that need the electricity. The same is true for Wyoming, which has some of the best coal reserves in the country but is far from the population centers that could use the electricity. Wyoming has the somewhat expensive option of delivering its coal via rail, but more transmission capacity to the east and west would make it feasible to site power plants near the mouth of a coal mine. Coal in Wyoming, wind in the Dakotas and hydropower in Manitoba are examples of far-flung resources that need transmission lines to deliver their energy to load centers.[18]

Step 2: The utility performs a study on costs of the new power lines

One reason the debate about who will build and who will pay for new transmission lines has been so controversial is that transmission is expensive. Costs vary significantly. Table 3 gives a range of costs for various types of transmission construction.

Table 3. Typical Capital Costs for Electric Transmission Lines, by Voltage

Transmission Facility	Typical Capital Cost
New 345 kilovolt (kV) single circuit line	$915,000 per mile
New 345 kV double circuit line	$1.71 million per mile
New 138 kV single circuit line	$390,000 per mile
New 138 kV double circuit line	$540,000 per mile
New 69 kV single circuit line	$285,000 per mile
New 69 kV double circuit line	$380,000 per mile
Single circuit underground lines	Approximately four times the cost of above-ground single circuit lines.
Rebuild/Upgrade 69 kV line to 138 kV line	$400,000 per mile

Source: American Transmission Company, *10-Year Transmission Assessment*, September 2003.

The terrain over which transmission companies build transmission lines also affects costs. It is more difficult to maneuver the equipment needed to build poles and string lines through mountainous terrain that is far from roads than it is to build transmission lines across relatively flat plains with nearby roads. Other factors also affect costs, including the cost to acquire rights-of-way, the cost of upgrading substations and interconnecting with the existing grid, and the possibility of installing new grid control technologies.

The table notes address the higher transmission voltages of 500 kV and 765 kV, which are becoming more common in the United States. These are more expensive to install; costs range from $1 million per mile (or less in unusual, ideal circumstances) and higher. Sometimes these lines are unusually expensive. In a recent proposal to build 34 miles of 500 kV in California, the "per mile" cost of the project was $10 million.[19]

Step 3: The utility performs a study of possible routes for the transmission line

Transmission planners usually identify a preferred route for their transmission lines. Transmission lines are never popular with their new neighbors, however, and, as a result, planners sometimes propose alternate routes. Different routes travel over different terrain and one alternative could be longer than another, so each route entails different costs. This is the stage at which many local interest groups become involved in the transmission line process.[20]

Transmission owners often find it difficult to identify acceptable transmission routes because few property owners welcome the prospect of having new transmission lines constructed nearby. Even in areas that have a preexisting right-of-way for a transmission line, new population growth may make it difficult to install new, larger towers and lines. Space for new transmission lines may be limited, and the fact that power lines traverse federal and tribal lands also may complicate the process.

Step 4: The utility seeks permission from state agencies and federal agencies to build a power line.[21]

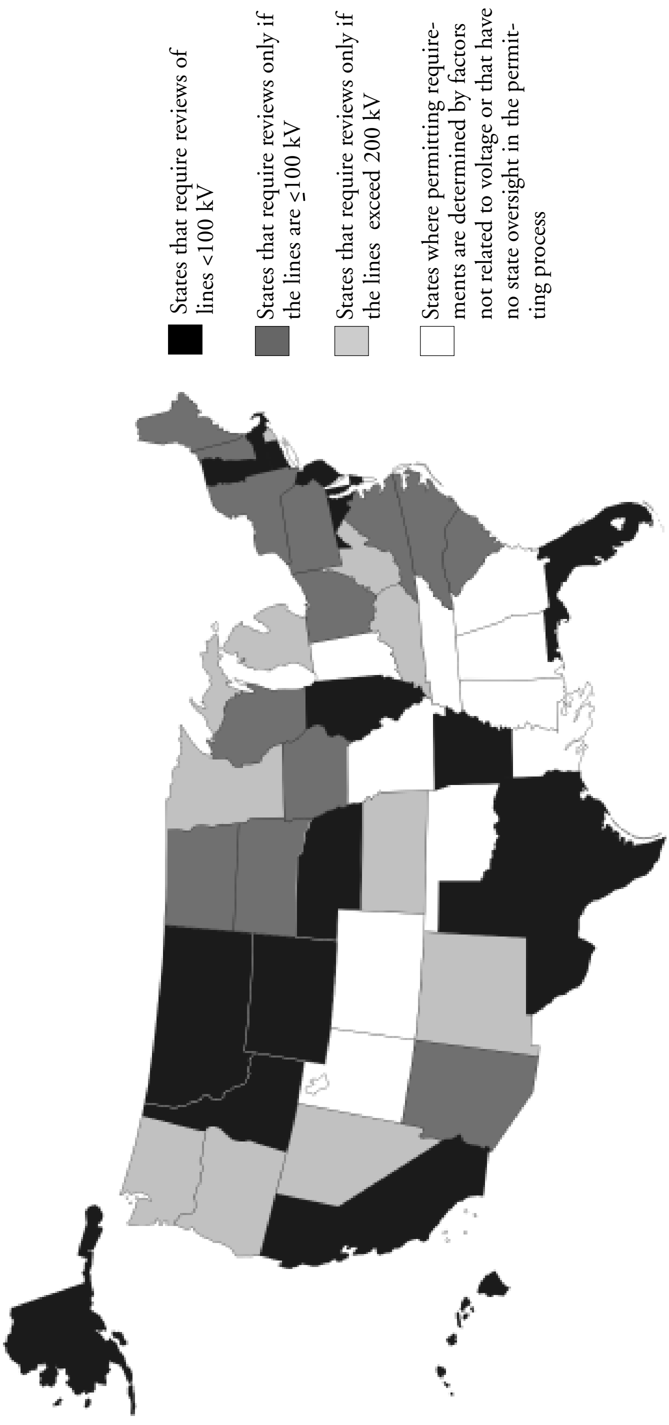
Each state has its own process for granting permission to utilities to build power lines. A small number of states do not require utilities to secure a siting certificate. Generally, the steps of the siting process are as follows.

A. Utility files an application with a state agency, a number of state agencies, or with local governments.

A siting certificate allows someone to build a transmission line and usually to use powers of eminent domain to do so. A mix of state and local government agencies wield jurisdiction over this process in different states. In Colorado, for example, local governments give or deny permission to build transmission lines within their boundaries. In Connecticut, a state siting board holds statewide authority, and some states, such as Georgia, have no centralized process for siting transmission lines. Some require only that transmission developers go through a permitting process if the power lines exceed a certain size. Siting transmission lines is a federal responsibility only when transmission lines pass through federal lands, such as Forest Service lands. Figure 3 illustrates the variety of state siting processes.

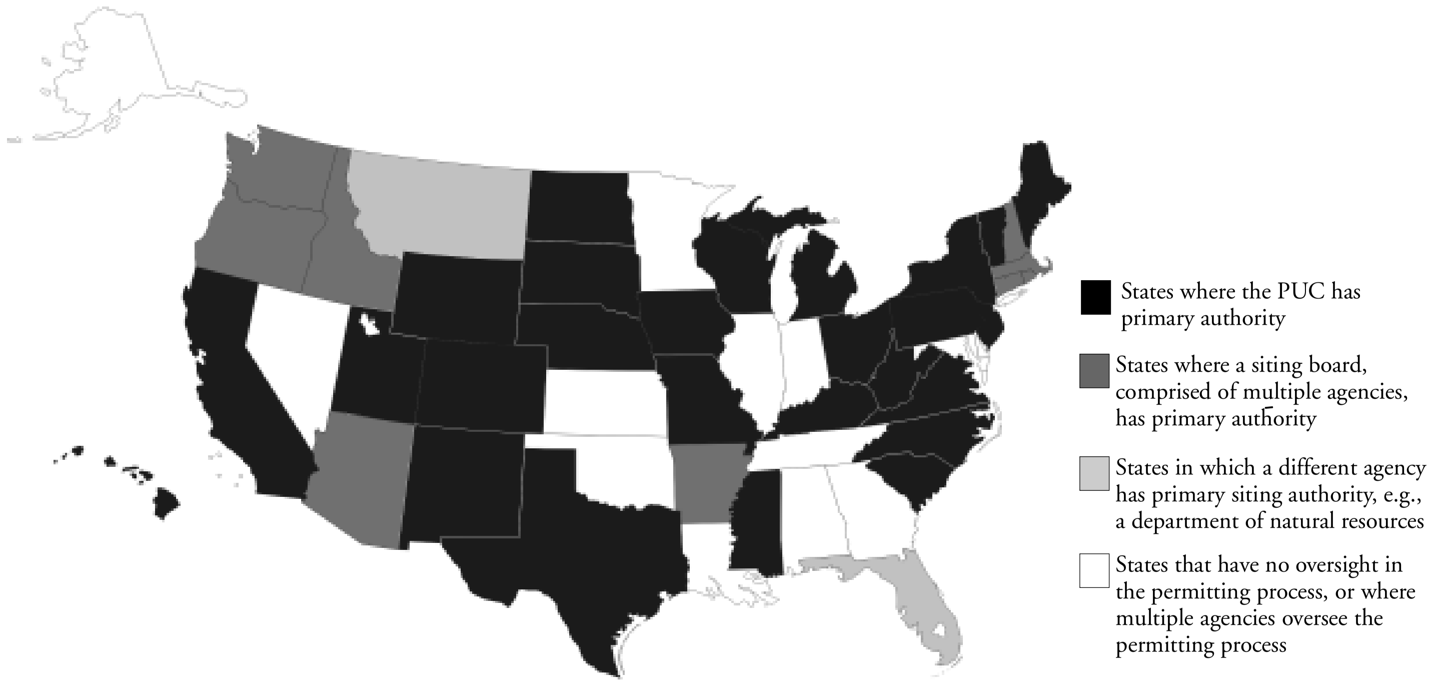
Many states have attempted to consolidate all or much of their siting authority into a single agency, such as the Public Utility Commission. Others operate their siting process through a siting board that consolidates the efforts of several agencies, including state departments of environmental protection or natural resources. Figure 4 illustrates which state government agencies issue permits for building power transmission lines.

Figure 3. States Where Permitting Needs Are Determined by Line Voltage



Source: Edison Electric Institute, *Transmission Line Siting Regulations: State-Level Directory*, 2001.

Figure 4. States with One Agency Authorization



Source: Edison Electric Institute, *Transmission Line Siting Regulations: State-Level Directory*, 2001.

Figure 5 illustrates how different states treat siting permits for transmission.

Some states allow public power governing bodies to retain jurisdiction over need for the line, although state environmental review still may be necessary.

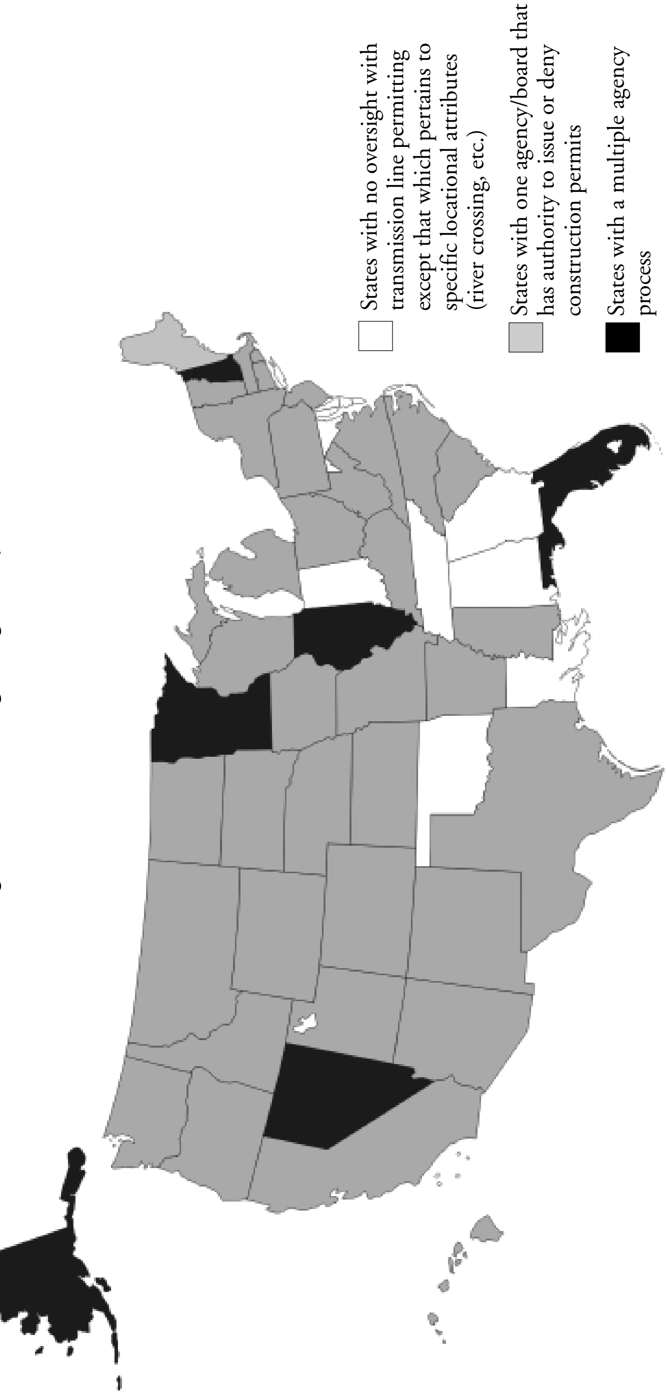
B. Once the application is deemed complete,[22] *agencies in some states are given in statute a specified period of time—ranging from three months to two years—to review and rule on the application.* Some states set aside an explicit public notice period to ensure that the public and local governments are informed about the project. In other states, the review schedule is fully under the control of the siting authority.

C. Some states require that the utility be granted a certificate of need, in which the utility commission finds that the power line is, indeed, needed. The power of eminent domain generally comes with a certificate of need, allowing the transmission company to acquire easements through condemnation, if necessary. "Need" is a complex issue. The states that make an official need determination usually rely on measurements and predictions of reliability and safety margins.

Another measure of need, related to cost rather than to reliability, is called "persistent congestion." Congestion describes a situation in which power cannot reach its market because the transmission system does not have enough capacity to carry the power. Congestion is an economic problem, not a reliability problem, if there is enough power in the high-cost area to meet demand consistent with reliability standards. Analysts refer to the area affected by congestion as "transmission constrained." Congestion can keep electricity prices artificially high if it does not allow low-cost power generators to ship power in to the constrained area.

New transmission capacity can reduce prices inside the constrained area if the new capacity allows companies to deliver sufficient low-cost power to offset the cost of the capacity. Policymakers might expect that the opportunity to create savings by relieving congestion might motivate an entrepreneur to build transmission and profit from a share of the savings.[23] Because such an entrepreneur may not have the same level of assurance of cost recovery as the utility, Wall Street also must have confidence in the plan to advance the necessary capital.

Figure 5. Permitting Categories by State



Source: Edison Electric Institute, *Transmission Line Siting Regulations: State-Level Directory*, 2001.

Some say that wholesale market rules are not yet suited to enable such projects to succeed.

In some cases, however, congestion persists, suggesting a market barrier. If, in the case of persistent congestion, the public would benefit from a new transmission facility through lower net costs, then policymakers may wish to ensure that the "need" criterion in the siting process would allow for such a project to gain approval.

D. Most states require that a certain number of hearings be held in the affected counties or towns.

E. Many states require that the utility file an application with both a preferred route and an alternative route for the power line.

F. Some states require that the utility present an analysis of alternatives to building the transmission line.

G. Most states specify a procedure to appeal the decision.

Step 5: The builder obtains financing for the line and builds the power line.

From the time permits are issued, it can take two years or more to build a power line. This includes time for the utility to secure contractors, to acquire land, to order parts and to build the line.[24]

3. Paying for Transmission

The Up-Front Investment in Transmission

The high costs of transmission, the challenges of siting, and the restructuring of industry responsibilities make it essential that government officials and industry representatives discuss who will build and pay for new transmission lines. In most situations, they have only two choices: 1) generating companies that build new power plants that must connect with the power grid or 2) the regulated utilities that currently own most of the transmission grid. Sometimes, a small number of "merchant" transmission companies finance and build transmission lines.[1]

When power developer GE Wind built a 164 MW wind farm in southern Colorado, Xcel Energy, a regulated utility, and GE Wind engaged in a detailed discussion about who should pay for what parts of the transmission system. The wind farm was about 40 miles from Xcel Energy's power grid and, as a result, someone needed to build a new power line to feed the wind power into the grid. At the same time, Xcel Energy identified several improvements to its power grid that it felt were important to perform at the time.

The debate in Colorado, as elsewhere, revolved around who should pay for what part of the upgrades to the transmission system. A pure "participant funding" process would have GE Wind pay for all the upgrades in exchange for valuable transmission rights or credits for future transmission service.[2] "Socialization" of the costs of transmission would have Xcel Energy, and by extension its ratepayers, pay for all the new lines and upgrades to the transmission system. Much of Texas' grid, Electric Reliability Council of Texas (ERCOT), which is not subject to

Who Pays for Transmission?

It is simplistic to pose the question: Who pays for transmission? Ultimately, electricity customers pay for all the investments in transmission in some way. The question is important now however, because of the new structure of the power industry. The power industry formerly consisted mainly of companies that owned and operated power plants and power lines. There was no question about who would build new power lines to connect to new power plants; the same company built and operated all the lines and the power plants within its system. The new power industry consists of many power plants, built and owned by independent companies; power lines are owned by regulated companies. Generating companies must connect their power plants to the power grid. The challenge is to allocate those costs among the generators and the regulated transmission companies. The transmission company that builds the lines bears risks associated with recovering costs in the regulatory process. That company also must raise the money to make the investment. Failure to answer the question of who pays for what investment could stop new investment in transmission in its tracks.

the jurisdiction of the Federal which Energy Regulatory Commission, "socializes" the costs of new transmission, meaning that utilities initially pay for all the upgrades to the transmission system and pass the costs on to ratepayers.[3]

The field is further complicated by the wide variation in types of utilities: government, consumer-owned and investor-owned companies. Most of the government and the consumer-owned utilities are not subject to FERC regulation, although they can submit to it at their option. If a regional system of transmission funding is to be successful, a seamless regulatory system is important.[4]

In practice, most of the country has adopted or is considering some form of participant funding that also spreads some costs to all consumers. In the southern Colorado case, GE Wind paid to build the power line to connect its wind farm to the grid, and Xcel Energy paid to upgrade some other parts of its transmission system.

Fundamentally, it is critical that both states and the federal government set clear rules about who will pay for what. Without clear rules, many transmission companies will hesitate to build new transmission capacity, and generators will hesitate to build new power plants, potentially threatening reliability.

How Can Regulated Utilities Charge for Use of Their Transmission Lines?

If a utility makes the up-front investment in transmission lines, it generally has the right to recover its investment through rates. Federal regulators approve the rates that utilities can charge others to use their transmission lines. The Federal Energy Regulatory Commission has jurisdiction because transmission is, in almost all cases, a part of interstate commerce. With a few exceptions, no single state can claim to have a transmission line that is not part of interstate commerce. Recently, FERC asked the industry players, notably transmission owners, to establish regional transmission organizations (RTOs). Where RTOs exist, the RTO and the transmission owners in the area decide which one (or both) prepares and submits transmission rates to FERC for approval.[5]

Experts describe four methods for setting transmission rates. Each method attempts to establish a means for the users of a power system to pay the owner of the transmission system for using the transmission lines.[6] The "user" of a power system usually means the company that generates electricity and wants to use the lines to ship power to its customers. That customer typically would be a utility, which then sells power to the homes and businesses in its territory.

a. Pancaked rates come into play when power under contract traverses more than one power system, and each system charges its full rate to provide transmission service. This method of pricing for a regional transmission system is expensive and tends to discourage companies from sending power over long distances and through several transmission systems, regardless of the value of the transaction to consumers.

b. Postage stamp pricing: It costs 37 cents to send a first class letter from one part of Boston to another part of Boston, and it costs 37 cents to send a first class letter from Boston to Maine or Hawaii. There are no zones that require people to compute different prices at each zone. To some degree, this pricing scheme means that the local delivery service that probably costs less than 37 cents per letter is subsidizing the long-distance letter service that probably costs more than 37 cents per letter.

Postage stamp pricing for use of transmission lines is similar. The per-unit fee to use the transmission system within a single zone is the same, whether the power is contracted to move 100 feet or 100 miles. Companies located in less densely populated areas and in higher cost areas tend to favor postage stamp pricing over an alternative known as: license plate pricing.

c. *License plate pricing*: Some parts of the transmission system—such as the system in much of North Dakota and South Dakota—are expensive to service because they have low populations and long-distance transmission lines. Other parts of the system—such as NStar, which serves the Boston area—have much less extensive transmission systems that cover only short distances and serve dense populations; therefore, their costs are lower. Older systems that have had time to gradually pay for the transmission facilities also tend to be less expensive than the new transmission systems that still are in the process of recovering their costs.

License plate pricing means that companies that use the transmission grid pay different prices based on the costs at the point at which the power is delivered to their area. The license plate metaphor applies because each company pays a fee to obtain access to the transmission system and can use any part of the system after paying that fee. In comparison, a car or truck owner who pays a license fee in Colorado can use the roads anywhere in the country. The companies based in the low-cost areas tend to favor this approach.

d. *Distance-sensitive pricing* bases the price for using the transmission system on the number of miles of the system for which users contract. Users that contract to use the transmission system for 10 miles would pay less than those that use it for 100 miles. Distance-sensitive rates may discourage unwise investments in long-distance transmission. As a result, distance-sensitive pricing may, in some markets, be a barrier to fully free-flowing wholesale power competition.

Not all transmission is subject to Federal Energy Regulatory Commission jurisdiction. Public power entities such as the New York Power Authority, Arizona's Salt River Project, North Carolina's Santee Cooper or the Los Angeles Department of Water and Power are not under FERC jurisdiction. Federal agencies also self-govern, so the Bonneville Power Administration, the Western Area Power Administration and the Tennessee Valley

Authority all fall outside FERC's authority. Finally, most of Texas and all of Hawaii and Alaska are outside FERC jurisdiction because they are not connected, or not tightly connected, to the interstate transmission grid.[7]

State vs. Federal Jurisdiction over Transmission

It seems that it should be clear who has jurisdiction over what parts of the electric industry, but it often is not.

In general, states have jurisdiction over retail rates, and the federal government has jurisdiction over wholesale rates. That means that, if a customer's total electric bill is $50, it is the state regulators who have approved that charge. Of that $50, a portion, say $10, is related to wholesale rates. State regulators do not have control over that $10 charge and are supposed to allow utilities put it into their rates. That works well except in instances where states cap their electric rates. If electric rates are capped to prevent increases to the $50 customer's bill but the wholesale portion of the rates increase from $10 to $12, a jurisdictional and financial problem may result.

In general, states also are supposed to have jurisdiction over distribution lines, usually defined as the power lines that feed into people's homes or businesses. The federal government is supposed to have jurisdiction over transmission lines. Even here, the definitions are problematic. Three approaches to the problem have been suggested:

1. That the lines should be defined by their function (any line that serves a retail customer directly, regardless of its size, is under state jurisdiction).

2. That it is the size of the line that matters (all lines over a certain size—such as 34.5 kV or 69 kV—would be transmission under this definition).

3. Finally, that all lines should be under federal jurisdiction since, by definition, the entire interconnected electric system, whether it feeds a house on the prairies or a factory outside Chicago, is ultimately connected to an interstate transmission network.

State utility commissions also can determine who pays for transmission in some situations. In Colorado, when GE Wind built a wind farm and needed to tie it into the Xcel Energy network, the issue of who would pay for the transmission line and related upgrades to the power grid was resolved by the Colorado Public Utilities Commission. FERC was not involved in this decision because the direct tie-in to the Xcel network was handled under the utility's bidding process, and the tie-in was to the utility's own "network service."

In addition to pricing transmission lines, FERC also maintains jurisdiction over the terms and conditions for using transmission lines. For instance, FERC requires that transmission-owning companies offer their customers access to the transmission system on the same terms and conditions as they would offer it to themselves. FERC also required utilities that owned both power plants and transmission to separate those activities into different businesses. FERC expected this separation to prevent the transmission portion of a utility's business from discriminating in favor of its own generators and against other companies that want access to the transmission system.

Current Issues in Financing Transmission

Those who make the significant financial investments required to build new transmission lines must justify their investment to bankers or to capital markets. Particularly in recent years, due to the major changes to electric power markets and new financial uncertainties in those markets, it has become difficult to raise capital to make any large investment, including investments in transmission. Most agree that the lack of new transmission construction is a problem. Some point to the fact that, in some parts of the country, new investments in transmission are occurring; the issue, they say, has been lack of need for new transmission.

Some people who do agree that new transmission is needed suggest that regulators should give utilities a higher return (i.e., they could charge higher rates) for transmission. This higher return would attract more capital to the industry. Others who disagree say that transmission rates are a secure, low-risk investment; if customers do not pay their bills, including transmission costs, they can be disconnected from the system.

As an alternative, some suggest that rates be structured of rates to reward companies for high-quality performance through a performance-based ratemaking plan. Through such a system, regulators would set performance goals and targets. Utilities that met those performance goals would earn a higher return.[8]

Within this broad discussion of transmission rates are some nonregulated transmission companies that have commenced operation. TransÉnergie, operating the Cross Sound Cable that connects New York and Connecticut, and the Madison, Wisconsin-based American Transmission Company are examples of this type of enterprise. Such firms can continue to be in business only if Wall Street finances them and companies use their power lines.

The problems facing utilities and transmission companies must be analyzed in the context of what has transpired in the power industry in general. The failure of Enron and the turmoil in many power markets in the past several years have made it more difficult to raise capital. Some utilities also have diversified into unregulated businesses that have been less successful than anticipated. As a result, it has become more difficult for some utilities to raise capital not only for transmission, but for any large new investment.

4. Physical and Technical Characteristics of Transmission

The transmission system operates like one very large machine with many discrete but interdependent functioning parts and hundreds of operators and control centers spread throughout America. Most of the time, this machine works well, but sometimes people expect it to do things it is not meant to do, and sometimes parts of it simply break. Policymakers will want to have a basic understanding of what the transmission system can and cannot do. This chapter offers guidance on the physical aspects of the transmission grid, using a question and answer format.

What are transmission facilities?

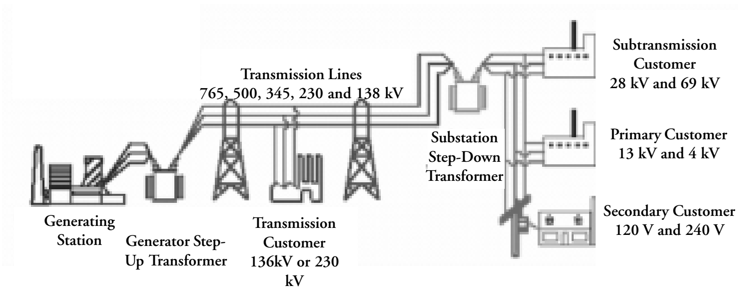
Most transmission facilities fall into two categories: lines and transformers. Transmission lines move power at high voltage from power plants to transformers. Transformers, often found in fenced enclosures in communities, connect high-voltage lines to the low-voltage distribution lines that deliver power to homes and businesses.

Does power move over a prespecified, contracted path of transmission lines from a generator to a customer?

Generally, no. Power flows over transmission lines much as water flows through a network of interconnected pipes. If one pipe, or power line, is full and running at capacity, power will seek another path. The only time one can be certain of the power's flow is when a single transmission line connects the power plant to the load.

Figure 6 illustrates not only the flow of power from generator to customer, but also the fact that transformers "step up" generation from low to high

Figure 6. Key Elements of the Electric Power Grid



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

voltages in order to transmit it over the AC power system, and then "step down" voltages as it reaches customers. These transformers are a critical part of the transmission system.

Some buyers and sellers sign bilateral contracts for a certain amount of transmission capacity to deliver specific quantities of power at specific times. The parties may make an effort to identify the transmission path and may buy rights to deliver power through a specific company's transmission lines. However, the power at any given moment will actually travel over the network's path of least resistance, perhaps onto lines that belong to a company that receives no compensation for moving the power. This type of power flow is called a "loop flow."

Fact: In the United States, the network operates using alternating current (AC). This choice was made early in the 20th century. The implications of this choice emerge later.

There is an exception. A contract path can be ensured to be the flow path for electricity if the power is shipped via a direct current (DC) line. A more in-depth discussion of DC is included later in this chapter.

What are transmission limits and congestion? What causes these limits?

The physical properties of the power lines and other safety and reliability factors may limit the capacity of individual lines and power systems.

•*Physical limits.* Colliding electrons in a high-voltage AC power line cause electrical resistance, and resistance interferes with current in a wire, producing heat. If current flows beyond engineering limits, wires can melt or start a fire. More current can flow over a wire in colder weather, since air cools the line.

•*Sag and safety limits.* As wire heats up, it softens. Since power lines are heavy, their weight makes them sag as heat builds. If trees, buildings, vehicles, water or other obstructions touch sagging wires, they may disable the wires. The National Electric Safety Code describes how to cap power flows within the physical limits of the line and how to build lines to ensure that sag does not threaten safety. Sagging lines that come into contact with trees or other vegetation have, nonetheless, caused many small and large blackouts. Measures as simple as tree-trimming can prevent many small- and large-scale blackouts.[1]

•*Contingencies.* Transmission system operators leave some unused capacity on power lines in case an unexpected event (a contingency) occurs somewhere on the system. If, for example, a large power line drops out of service, the power flows will shift to other lines at the speed of light. The power system operators' job is to ensure that none of those power lines overloads. For example, a power line from Quebec into New England is capable of carrying 2,000 MW. If it should fail, however, sudden power flows from Pennsylvania through to New York into New England would result, and could cause uncontrollable overloads. Therefore, the capacity of this line is capped at around 1,400 MW.

•*Limits on transformers.* Transformers exchange power between systems with different voltages, moving it from low to high voltages from high to low voltages. Such transfers release a great deal of heat. The amount of power a transformer can move is limited by the current-carrying capacity of the wire and the ability of internal oil coolers to keep the apparatus within operating temperature limits.

•*Congestion.* As discussed earlier, congestion is the result of physical limitation in the power system that prevents low-cost resources from reaching some markets. Congestion tends to raise costs overall, since it limits the constrained markets to nearby resources. Congestion does not always increase prices. Maine's power grid is somewhat constrained, and lower cost generators there are limited in sending power out of the state. Some policymakers feel that this constraint actually helps to lock the state's low-cost resources within the state, to Maine's advantage. Although congestion raises costs, a higher cost to eliminate the congestion means it is better for the public to live with it rather than to fix it.

Fact: Electricity flows through a network of circuits over the path of least resistance. Physics students learn this as an outcome of Kirchhoff's Law.

What special provisions are necessary if a power line is placed underground?

Underground power lines are useful in cities and in areas where views and vistas have significant social value. Air cools overhead electric lines, but engineers have had to find other ways to cool underground lines. They typically use an oil system that employs pumps to circulate the oil. Because these cooling systems are expensive and because it is costly to dig trenches for the lines, it is more expensive to bury power lines underground than to string them above ground. Although underground lines are away from weather, vegetation and vehicles, they also are more difficult to access, it is more difficult to pinpoint the location of a fault, and their cooling systems can fail.

What happens when power buyers and sellers want to send more power on a line than it can handle?

Grid operators measure the available transmission capacity on transmission lines. These operators act as referees, monitoring the activities of the parties that are vying for space on power lines. When buyers and sellers want to send more power over the lines than the system can handle and maintain reliability standards, power system operators—who generally are employees of a utility but in some cases work for regional organizations such as the Midwest Independent System Operator—activate procedures that enable them to stop the flow of—or, in some situations, even cancel—power sales contracts.

Sometimes, two parties agree to a transaction over specific transmission lines that, in theory, technically are able to handle it. Yet, different lines might overload as a result. Here, again, the difference emerges between contractual agreements and physical flows of power. Since it is very difficult in most cases to control the direction that power flows in an interconnected system of wires, the contracts that people sign have little

Reliability Standards

Reliability standards are defined, written electric system practices and protocols that have a material effect on reliability. They also tend to be measurable, enabling operators to see when a standard is compromised. Because of the importance of these standards, system operators are required to monitor them and face sanctions if they violate them.

In general, standards do not provide an unfair competitive advantage or mandate a particular investment or regulatory decision. For example, one reliability standard governs how facilities such as transmission lines are rated for power-carrying capability in order to avoid cascading outages and other problems. Another standard guides planners as to the types of system events to protect against.[3]

As important as transmission reliability standards are, they are not mandatory. The North American Electric Reliability Council (NERC) has agreements with all electric utilities that call for them to comply with the standards, and sanctions exist for violations. However, the Federal Energy Regulatory Commission (FERC), as the ultimate regulator of wholesale power markets, has no legal authority to enforce NERC's reliability standards. Proposals emerged as early as 1998 for FERC to back up NERC's administrative authority with a more compelling regulatory authority.[4]

relevance to the actual physical flows of power. Other paths over lines that other companies own may actually deliver the power, even though no one pays those companies to use their lines. Loop flow (defined earlier) may result.[2]

How do grid operators react to problems on the power grid?

The North American Electric Reliability Council (NERC) reliability standards call for grid operators to ensure that the grid can withstand the failure of any single component or a series of failures from a reasonably foreseeable single cause.

When a major power line fails or a big power plant trips off line unexpectedly, the operators (utility personnel or, in some cases, employees of a regional transmission organization) quickly reconfigure the system to ensure that it can withstand another problem. Once grid operators determine the cause of the problem, it can take only a few seconds to reconfigure the system. The August 14, 2003, blackout in the northeastern United States and Ontario, Canada, illustrated how difficult it can sometimes be to diagnose a problem before it cascades out of control. Operators might re-dispatch power plants or might start up other power plants or ask some previously selected volunteers to reduce their power use for a few hours in order to regain a secure margin of reliability.[5] The weather also matters—power generators and power lines have less capacity in warmer weather. Storms increase the probability that some other failure will occur. During severe thunderstorms, New York City's Consolidated Edison reduces its dependence on energy imported over transmission lines and increases its reliance on in-city power plants.

When several problems occur at once, some customers may lose service. If they can, the operators will try to drop customers systematically and with warning. When California customers lost power in 2000 and 2001, grid operators were able to shift the outages around the state so that many customers lost power for a few hours each (a practice known as "rolling blackouts") instead of a few customers losing power for a long time. This was made possible by isolating—or cutting off—customers and transmission lines and then "routing" the power around these locations.

What are reserves?

The North American Electric Reliability Council reliability rules require that the power system have in reserve electric generating capacity above the amount needed to meet peak electric demand. The amount needed is based on the largest contingency on the system—in other words, the failure of the plant, lines or other piece of equipment that is most critical to keeping the power grid running. In New England, the most significant risk formerly was if a large nuclear plant tripped off line or if the power line from Quebec failed. Recently, grid operators identified as a major risk the potential failure of a natural gas compressor station that feeds some power plants in New England.

Some reserve capacity must be available within 10 to 15 minutes. Other reserves might not be needed for 30 minutes. The letter category of reserves addresses secondary contingencies.

What are ancillary services?

The transmission grid is like a complex machine—much more than a series of wires and transformers that connect power plants to power users.

It needs grid operators to monitor it and to support it with a category of services known as "ancillary services." Reserves represent one category of ancillary services. Other ancillary services support specific voltage levels on the grid and keep the wires ready to receive power and to transmit power at the proper voltage levels. Generators that can restart the grid after a blackout also provide a vital ancillary service. All these services help the transmission grid meet reliability and operating standards.

Power generators provide many of the ancillary services and generally are paid to provide them. The Federal Energy Regulatory Commission has attempted to encourage a market for ancillary services.

What are VARs (or Reactive Power)?

A power plant typically produces a mixture of "active" and "reactive" power. System operators can adjust the output of either type of power at short notice to meet changing conditions. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VAR), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay and, in extreme cases, a "voltage collapse" may result.[6] The power grid needs enough reactive power to maintain reliable service.

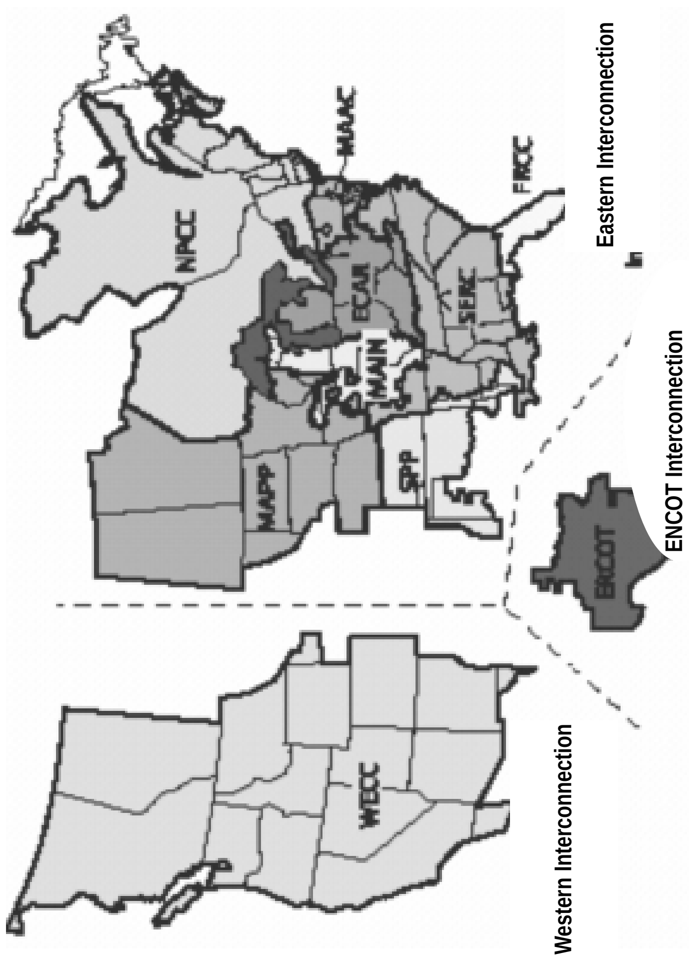
What limitations constrain power flow over long distances?

Power can flow over long distances, but with two significant limitations.

- *Line losses and voltage drop.* Power lines carry electricity over long distances, but the electrical energy gradually dissipates into the air in the form of heat. In addition, much as water flowing through a pipe gradually loses pressure, electricity gradually drops in voltage when it is transmitted over long distances. Voltage drops can be cured by devices called capacitors, but at a cost of more energy lost. The United States as a whole loses nearly 10 percent of all the power it generates to these technical limitations. So, although it is technically possible to generate power in the Dakotas with wind turbines to supply the large parts of the nation's electrical needs, it is not practicable to deliver that power over such a long distance using the existing AC transmission system.[7]

•*Constraints on the transmission system.* The North American electric power grid is divided into four major subsystems, called interconnections, and 10 reliability regions. As figure 7 illustrates, one interconnection is in the West, one is in the East, one is in Quebec and

Figure 7. Electric Interconnections and Reliability Regions in North America



Source: NERC, 2003.[9]

one covers most of Texas. The eastern interconnection is further subdivided into "reliability regions." The west is its own large reliability region. Very limited exchange of power occurs between the major interconnections. As a result, it is also very difficult to send power from Kansas (in the eastern interconnect) to Colorado (in the western interconnect), let alone from Maine to California. Other more local transmission bottlenecks, or physical constraints, also exist.[8] It is difficult to deliver power from Colorado to Utah, for example, or from Maine to the rest of New England because of these constraints.

The grid is primarily an alternating current (AC) network. Is there a greater future role for direct current (DC) lines?

Alternating current is a wave of electrons flowing back and forth through a wire. Direct current is the constant flow of electrons in a wire. DC lines connect grids and transmit power from one point to another. Since the remainder of the power system uses AC, DC systems require a converter to convert (rectify) power from AC to DC as it goes into the DC power line and to reconvert (invert) it from DC to AC as it reenters the AC system. These AC/DC converters are expensive. Examples of DC systems used to connect power grids include the DC lines that allow power to flow from the Western Interconnection to the Eastern Interconnection. (Figure 7 in the appendix shows locations of these converters in the United States.) The AC/DC/AC connection acts like an air lock between two systems that have no AC connections—power flows can be controlled precisely between the systems up to the limits of the converter station.

DC has not been used to deliver power to customers because of the cost of the AC/DC converters. A converter station costs in the range of $50 million, and a DC line requires a converter station at each end to connect to the AC grid. This is far more expensive than the transformers that step AC transmission voltages down to typical voltages that consumers use. Despite its cost, DC lines can cost-effectively connect low-cost power plants to higher cost regions of the country. In this use, a DC line might carry 1,000 MW to 3,000 MW. For example, wind and coal resources in the Great Plains could be shipped via DC lines to load centers to the east or west. DC lines now connect low-cost hydroelectric resources in northern Canada to U.S. markets. DC has long been used for underwater electric transmission. A line already is in place under Long Island Sound, and there are other proposals for San Francisco Bay and locations off the Atlantic coast from New England to New Jersey.[10]

Will new technologies affect transmission grid capabilities?

New technologies are beginning to significantly influence transmission. Devices with complex electronics can provide better control of the grid. Examples of these include Phase Angle Regulators and Flexible AC Transmission Systems (FACTS). High- temperature superconductivity (see glossary) offers potential for many applications if its costs and operating challenges can be managed. More viable storage technologies, using stored magnetic energy or flywheels to store mechanical energy, may make an enormous difference in how the grid is managed at peak hours. Improved communications and sensors can help the grid run more efficiently, with better information for market participants, enabling better use of customer resources such as generation and demand response,[11] and can react faster and more effectively to contingencies.

What special issues exist regarding transmission flows between the United States and Canada and Mexico?

Electricity flows over state and international borders with no regard for political boundaries. All matters related to interstate commerce on these lines are reserved for federal jurisdiction by the Commerce Clause of the U.S. Constitution. International crossings require action by the Canadian or Mexican government and also require a U.S. Presidential Permit, administered by the U.S. Department of Energy. International matters involve Mexican and Canadian industry and regulatory bodies as well as their U.S. counterparts, but are not fundamentally different. NERC oversees the reliability of the North American grid and offers a forum to address international grid issues.

5. Action Items for State Officials

State officials wield influence over electric transmission systems through the transmission line siting process. The laws and regulations that govern this process are critical to the development of an effective transmission grid and transmission line siting process. The following policy options for states may serve as a guide for state regulators, legislators and other energy officials who wish to improve their process for siting transmission lines.[1] These are options for consideration and may or may not be appropriate for states to adopt.

1. *Assign the responsibility for transmission siting approval to* ***one state entity****.*

2. *Establish a* ***fee structure*** *whereby applicants pay for the costs of the studies required in the siting process.*

3. *Enable state siting authorities to* ***collaborate with comparable agencies in other states*** *to review projects that cross state lines.*

4. *Set a statutory* ***limit for the time allowed*** *to consider a transmission siting application.*

5. *Establish clear and complete* ***filing requirements*** *for siting proceedings.*

6. *Ensure that the siting authority's analysis takes into account a* ***"what if" analysis, considering other options to meet a perceived need.***

7. *Consider providing* ***intervenor funding****.*

8. *Identify important **scenic, ecological, environmental and other resources.***

9. *Clarify the **definition of need.***

10. *Integrate generation and transmission **planning**; add demand resources.*

11. *Include transmission corridors in **urban growth plans.***

12. ***Define considerations** that can be evaluated and discussed in a transmission line siting case.*

13. *Integrate **the public** into consideration of siting proposals.*

14. *Impose **retail rates** that reflect actual cost differences within a service territory to promote sound siting proposals.*

15. ***Coordinate state permitting processes** with federal processes.*

16. *Examine the interactions between **rate caps and rate freezes** and investments in transmission.*

17. *Address **landowner compensation** for lands in a new or changed transmission rights-of-way.*

1. Assign the responsibility for transmission siting approval to one state entity.

In a few states, several government entities have responsibility to approve transmission siting proposals. As a result, no single entity balances all facets of the project to determine its net positive or negative contributions to the public interest. In addition, applicants must submit separate applications for permits from multiple agencies.

State policymakers may find it helpful to assign the siting authority to one agency—such as the public utility commission or environment agency—or to a siting board made up of multiple agencies.[2] In addition, consider:

- Giving the siting authority the ability to issue all permits, or if not the ability to issue all permits, then the ability to enforce timelines on the multiple agencies required to issue permits.
- Establishing a single and coordinated application, thereby streamlining the process. The siting authority will have the maximum benefit of the expertise of all these government entities.

2. Establish a fee structure whereby applicants pay for the costs of the studies required in the siting process.

Most states already operate under this type of fee structure. Some states, such as Minnesota, cap the fees. Minnesota's fees are capped at $100,000 per application.

Although this fee structure adds regulatory costs to a project, the states that operate a fee-based structure see it as an investment in a more efficient process, which could cost less in the long run because issues are resolved in a systematic way, avoiding surprises.[3]

3. Enable state siting authorities to collaborate with comparable agencies in other states to review projects that cross state lines.

Some transmission lines cross state boundaries, yet most state siting authorities can review only the part of the line located in their state. For example, Mississippi's utility commission considers only what is in the best interest of Mississippi. It is difficult for the commission to make an explicit consideration of regional reliability or economic benefits that might come from a transmission line that passes through Mississippi. The allocation of costs of the facility among consumers in different states also may be in dispute. To address cost allocation issues, the presence of a regional state committee (a forum for several states to communicate with one another on transmission issues) can serve to resolve these issues, although FERC is generally in a position, through its jurisdiction, to impose a solution. To address this issue, states may:

- Encourage state siting authorities to consult with states in their region on interstate transmission siting projects and other transmission issues and to consider the effects of a transmission line on neighboring states. Such a requirement is most effective if all the states in a region have a similar process in place. Kansas statutes allow for such regional considerations in decisions about transmission.

• Allow state siting authorities to consider regional—not just state—economic and reliability benefits of a transmission line.

Allow state siting authorities to hold joint evidentiary hearings with their peers in other states. Allowing siting authorities to work together means they all can hear the same evidence, use the same discovery process, and reduce costs to applicants for preparing for hearings. In turn, it is more likely that the individual state decisions will complement each other. Due consideration to local intervenors and their interests is important; to demonstrate this, the siting authorities may commit to have some hearings in each affected state, and they may employ technology that allows hearings to occur in multiple locations with broadband communication connections. Most state statutes restrict joint state hearings and specify where hearings must occur. It remains unclear how states would need to change their statutes and rules to accomplish these joint efforts.

• Organize a regional planning and analysis staff funded jointly by the states to provide public interest-oriented advice concerning the regional implications of a proposed project. A regional staff serving states can be an effective way for state siting authorities to receive reliable information about how a project fits into the larger regional power market. This staff may support a regional state committee of the sort already formed in the Midwest and under development in other regions.[4]

4. Set a statutory limit for the time allowed to consider a transmission siting application.

Many states impose a requirement on siting agencies, asking them to rule on transmission siting cases within a certain time frame. Arizona requires a ruling within 180 days, Kansas requires a ruling within 120 days; other states impose longer time requirements. Some states impose no time limit for a ruling, but this can create a problem. Parties can use delay as a tactic, or the applicant manages the risk of delay by filing a siting request long before the actual need in order to increase the chance that the project eventually will work its way through the state process.

If states impose a statutory limit on the duration of a siting case, the limit should allow reasonable time for discovery and hearings, and time for the petitioner to make changes to the project in response to evidence discovered during the proceeding. The limit also should provide reasonable assurance to the petitioner that, at a certain time after application, there will be a decision. Strict timetables work well when accompanied by clear and complete filing requirements.

5. Establish clear and complete filing requirements for siting proceedings.

Siting applications sometimes do not contain all the information that the siting authority needs to make a decision. A thorough set of guidelines for the type of information to be included in a siting application will speed the siting process. Oregon's siting process, for example, includes an early-stage review of the proposed project. Based on that early review, the siting authority issues a "project order" that asks for specific information to be included in the actual application.

6. Ensure that the siting authority's analysis takes into account a "what if" analysis.

Demand for electricity is volatile, despite forecasters' best efforts to predict it. Many events and policies influence demand, forecasts often are an important driver for transmission proposals. Siting proceedings may work for the best results if they allow for sensitivities from demand forecasts. The siting authority can be directed to evaluate the value of the project if key assumptions change.

Forecasted changes in electric demand, notably in load centers served by the transmission line, will be a key assumption. Yet, the economy of a region could perform differently than expected, and energy usage patterns can be affected by new products and by policies that are designed to increase or decrease energy use. Because of the size of a single transmission investment, the power line should be the right answer under the broadest range of reasonably likely outcomes. To be sure the line is superior to other alternatives, the siting authority may inquire about the possibility of reducing the demand on the transmission system through more aggressive deployment of generation near the load or of demand energy resources, such as energy efficiency, distributed generation, and demand response.

Some analysts suggest that transmission companies should use probabilistic techniques to allow clear and direct comparisons among alternatives.[5] Others, however, feel that probabilistic techniques add uncertainty to the process and are unwieldy because of the difficulty of evaluating the probabilities of events.

7. Consider providing intervenor funding.

A few states offer conditional intervenor funding, pending a finding by the siting authority that the intervenor contributes useful perspective and information to the siting process and based on cost estimates made at the outset of the case. Existing state laws generally define criteria to become an intervenor. Funding is provided by the applicant.[6]

8. Identify important scenic, ecological, environmental and other resources.

Policymakers can direct appropriate state and local agencies to identify key scenic, ecological and environmental resources. With this information, transmission companies can avoid these areas or mitigate the visual effects of their proposals if these areas cannot be avoided. Siting officials can judge whether valuable resources are damaged by the project. An important and difficult element of this task is to develop criteria to guide the process of identifying important scenic resources.

9. Clarify the definition of need.

State statutory definitions of need for transmission lines vary. Some explicitly direct a comparison with alternatives. Some states issue an official declaration that a power line is needed before ruling on the rest of the siting application. Other states rely on the market to determine the need for the line. These states assume that the applicant would not take the time and money to build a line that is not needed. It may be helpful for the public to know that a state agency has made an official determination that a line is needed. Ultimately, policymakers must balance the need for a new line against the effects of that line on the local area.

10. Integrate generation and transmission planning; add demand resources.

Because the power industry has changed so much since the early 1990s, power companies that formerly owned both power plants and power lines often have separated into separate companies. One of these companies is often an electricity production company and the other is an electricity delivery company. Where before one company planned for an integrated system of power plants and power lines, now two companies make those plans. Coordination formerly occurred within the administrative structure of a vertically integrated utility. Now, separate entities are involved in the process, introducing a different dynamic and the potential for uncoordinated planning efforts.

New generation can relieve stress on a transmission system, or it can add stress. Vertically integrated utilities historically located generation within their service territory to relieve system stress. Today, the majority of new generation is being built by competitive suppliers that do not have a native load to serve or a designated service territory. As a result, it is increasingly up to the system operator and state regulators to ensure that generation siting has no undue adverse effect on the transmission system.

A few states are considering asking their distribution utilities to reinvigorate their planning process, bringing in elements from integrated resource planning, some of which may delay or avoid the need for new power lines.[7] This planning process also would ask utilities to integrate demand resources such as energy efficiency measures equally with consideration of new transmission and generation. Regulatory changes to address lost utility income arising from lost sales are one class of actions a state can take to ensure that all resources are considered for solutions.[8] Another group of activities involves adopting minimum appliance and equipment standards and building energy codes, using the tax code for incentives; and educating students.

11. Include transmission corridors in urban growth plans.

Many states require urban growth plans, but do not in all cases require that these plans include corridors for transmission. Including transmission corridors in such plans would be helpful. In so far as siting affects property values, it also is helpful to let developers know where the corridors are before construction begins.

Some more difficult transmission siting challenges exist for upgrades to lines that were built in open land. If settlement growth has surrounded the transmission corridor, conflict may result if the corridor needs to be larger.

12. Define considerations that can be evaluated and discussed in a transmission line siting case.

Arizona statute defines the considerations that may be included in a discussion of transmission lines.[9] Such definitions, if carefully constructed, help to ensure that issues of public interest are addressed sufficiently.

13. Integrate the public into consideration of siting proposals.

In many siting cases, a proposal from a transmission company appears to the public to come from nowhere. As a result, the public may not understand the need for any facility or appreciate why a particular solution was chosen.

State officials have several options:

- Require transmission companies to report to customers and to the state public utility commission regularly about possible transmission system needs. Focusing outreach and education efforts on state and local leaders can be especially valuable.

- Ensure that any regional state committee works with the RTO to make regular periodic assessments of need. The results of these assessments could be publicly disseminated to prompt discussion of solutions. With a sufficient planning horizon, all possible solutions may be discussed.

- Once hearings are planned, ensure that at least some are held in locations that are accessible to communities where the transmission lines will be built.

14. Impose retail rates that reflect actual cost differences within a service territory. [10]

At any given time, some parts of the utility service area require investment to maintain reliable service; in other places, the existing facilities provide reliable service. An economist would observe that the long-term marginal costs in these areas are quite different. In the current rate structure, consumers in an area that may require an investment receive no signal in their retail rates that their growing electric use is leading to a significant cost that will be borne by all ratepayers in the franchise area.

If regulators recognize the need for some grid investment long before they are actually asked to permit a transmission line, they can design rates that send a signal to consumers. For example, they can authorize the utility to offer credits to customers who take certain actions to delay the need for the line. These actions may include participating in intensive energy efficiency programs, participating in demand response programs, or installing on-site generation. The credits, delivered under a distinct rate tariff, would be a cost of service in lieu of the carrying cost of the power line. The magnitude of these credits would be no greater—and preferably less—in aggregate than the avoided carrying costs of the line, so consumers would actually save.

On the other hand, using ratemaking and retail incentives to address system needs appears to some as undue price discrimination, and is thus a controversial topic in some parts of the country.

15. Coordinate with federal agencies.

In many cases, transmission line siting involves both federal and state agencies. Federal agencies may include land managers, the U.S. Army Corps of Engineers, the U.S. Environmental Protection Agency (EPA), or the U.S. Department of Energy (DOE). It may be helpful for the state and federal agencies to sign a formal memorandum of understanding that would define means of collaboration between the two levels of government.

16. Examine the interactions between rate caps or rate freezes and investments in transmission.

Many states imposed rate caps as part of restructuring policies and to protect consumers from higher electric rates. Some of these rate caps or rate freezes may discourage companies from investing in new transmission, since they see few prospects of recovering their investments in transmission. State policymakers will want be aware of this issue, and may want to consider refinements to rate caps or rate freezes in cases where reliability margins are narrowing.

17. Address landowner compensation for lands in a new or changed transmission right-of-way.

Land values change when land uses change. A right-of-way in a newly developed suburban area may be much more valuable in 2004 than it was in 1984 when the land was either farmland or undeveloped. State officials may want to examine the compensation policies for rights-of-way to be sure that they reflect current and up-to-date valuation of the land. In addition, regulators can encourage a cooperative siting process by encouraging value-based easement payments that give easement holders a financial stake in the success of the project. A value-based easement payment might pay the public to host a transmission line on a royalty basis, based on the throughput of the line, for instance. Wind turbine builders use this royalty payment process when they site their turbines on farmers' land in the Midwest. Utility commissions also would need to be prepared to allow utilities to seek recovery of these higher costs in their rate base. Some people also suggest that states that are located between remote generation and load centers are entitled to financial consideration.[11]

How Federal Energy Legislation Affects Transmission Siting

Federal legislation pending in the 2003-04 session of Congress at this writing would give the Federal Energy Regulatory Commission jurisdiction for transmission siting in limited instances. Although the authors of this report cannot predict the outcome for this legislation, the motivation for some to advocate for federal preemption of transmission siting is of interest here. Conditions for FERC jurisdiction presented in the legislation include:

- A finding that the line addresses a "National Interest Transmission Corridor" as identified by the U.S. Department of Energy;
- The state jurisdiction considering the line has taken more than 12 months to consider the completed application; or
- The state through which the line passes lacks jurisdiction to permit the line; or
- The state jurisdiction considering the line lacks the authority to consider regional benefits from the project; and
- The applicant requests that FERC act.
- The legislation also prescribes a public interest standard that FERC would apply to its decision on the project.

There is much speculation about how the state-level siting process might change if this federal preemption is adopted.

Appendix. Who Plans, Builds and Owns Transmission?

Imagine a transmission line that extends for miles through private property, state parks, national parks, over rivers and perhaps under a major waterway. A multitude of state and federal agencies evaluate the line to see how it fits into their individual missions. Private citizens evaluate the line to determine how it might affect their property, their community, their cultural heritage and scenic resources. Many utilities that would buy power off the line also evaluate it to see how well it meets their reliability needs and commercial objectives. Unlike power plants, which occupy a relatively small geographic area in a fairly intense way, transmission lines can affect many people.

This appendix describes the industry, state, federal and private interests that consider transmission lines and attempt to influence whether they are built.

Generators

Generators use transmission to send power to their customers. Generators' profits depend on how much they will have to pay to use the existing transmission system and how much they must pay to connect new power stations to the electric grid. A combination of federal laws and regulations address the interconnection issue with the objective of ensuring that all generators have access to the transmission grid on reasonable terms. The primary factors are the Public Utility Regulatory Policy Act of 1978 and the Federal Power Act as amended by the Energy Policy Act of 1992 and implemented by the Federal Energy Regulatory Commission (FERC).

Transmission Owners

Five kinds of companies and organizations own transmission lines.

- Many transmission owners are fully integrated, investor-owned utilities, meaning they own and operate transmission systems, power plants and a distribution system that delivers power to retail customers. The Southern Company in the southeastern United States and National Grid in the northeast are examples of integrated utilities.

- A growing number of regulated transmission owners own and operate a distribution system, but do not own any power plants. New England's National Grid Company is an example of such a company.

- A few regulated transmission owners own transmission, but do not own any power plants and do not distribute electricity to homes or businesses. The Vermont Electric Power Company is an example of this type of fairly unusual structure.

- Merchant companies also can own transmission. The Madison, Wisconsin-based American Transmission Company is an example of a company that earns a return on its investments based not on costs, but on what the market will pay to use its transmission lines.[1]

- Some consumer-owned and publicly owned electric companies own transmission. These entities usually are not regulated by state and federal commissions. Some transmission owners in this category are public authorities such as the New York Power Authority or Arizona's Salt River Project. Others are federal power administrations such as the Northwest's Bonneville Power Administration, the West's Western Area Power Administration or the Southeast's Tennessee Valley Authority. Some are owned and operated by local governments, such as the Los Angeles Department of Water and Power, and some are consumer-owned cooperatives, such as the Dixie Electric Membership Corporation in Louisiana. The last two categories tend to be small organizations that often pool their resources to create a joint action agency (in the case of public power), such as the Vermont Public Power Supply Association; or a Generation and Transmission Cooperative (in the case of cooperatives); or the Dairyland Power Cooperative, which operates primarily in Wisconsin. These jointly owned organizations build and finance transmission.

Distribution Companies

Distribution companies are regulated utilities that sell power to homeowners and businesses. Distribution companies need the transmission system to bring power from power plants to their distribution lines. Many own or control the transmission facilities they need to gain access to the power marketplace. All distribution companies attempt to predict and then plan for their consumers' electricity needs. As a result, they tend to be distinctly aware of economic and demographic trends and, in parts of the country where a regional system planner exists, are essential to regional plans. Distribution companies operate as monopolies in states that allow competition and in states that do not. Thus, even in states such as Ohio, where homeowners and businesses can choose their electricity provider, the distribution company still delivers power over its distribution lines.

Transmission-Dependent Utilities

Some distribution companies own no transmission facilities. They use their distribution system to serve retail customers, perhaps operate some generation, and depend on surrounding owners of transmission to meet the remainder of their needs. Even a hypothetical transmission-dependent utility that owns and operates enough power plants to meet all its customers' demand still would be connected to the regional grid to back up its power plants and to provide other services needed to deliver the power reliably.

Regional Planners

Regional system planners analyze the way power flows over the power grid, searching for places where the system might overload or fail. When planners discover a weakness in the grid, they propose plans to address the problem. In some parts of the United States, entities that are not connected to utilities—called Independent System Operators (ISOs), or Regional Transmission Organizations (RTOs)—are the regional planners. In these situations, other companies generally make the investments to shore up the grid.[2] Regional planners evaluate the ability of the system to serve customers' demand, and they "stress test" the system by assessing whether the system would continue to provide normal service even if key generators or power lines dropped out of service. A national standard for the transmission system states that the grid should be able to operate normally from the customer's perspective in the event of any single contingency.[3] Several types of regional planners of regional planners have distinct perspectives.

- On the largest scale, the North American Electric Reliability Council (NERC), created after the great Northeast Blackout of 1965, provides an overall system reliability assessment of transmission systems in the United States, Canada and parts of Mexico. The 10 regional reliability councils also are conducting planning within their areas.

- Some large utilities—such as American Electric Power, Entergy, or the Southern Company—plan the power system across several states, mixing concerns about reliability with concerns about cost, market risks, and implications for resource choices.

- In some parts of the country, multi-state power organizations both plan and operate the power grid and perform other functions. New England and the parts of the Mid-Atlantic states known as the PJM (Pennsylvania-New Jersey-Maryland) Interconnection operate these multi-state organizations, ISOs and RTOs. Super-regional planning is beginning in the Midwest with the Midwest Independent System Operator, MISO, an Indianapolis-based entity that plans and operates the power grid across several midwestern states. In larger states such as California, New York and Texas, a system operator manages the grid within the state, but across several utility territories.

- The Northwest Power and Conservation Council was created in 1980 to manage the connection between power, water supply and fish habitat in the river systems of that region, but it does not operate the transmission system.

- Some states have begun to experiment with a new form of regional planning and collaboration. Midwestern regulators formed the first such organization in 2003, the Organization of MISO States (OMS). One potential purpose of the OMS is to offer a coordinated regional plan with a public interest perspective from state officials on regional transmission policies.[4] Although the first steps of the OMS have been to offer comments on Federal Energy Regulatory Commission policies, it could later provide direct public policy-oriented input to the regional planner.

Grid Operators

The grid operator ensures that utilities and generators meet reliability standards within its area of responsibility, usually called a control area. Grid operators attempt to ensure that transmission lines are not overloaded and to prepare for equipment failures, extreme weather and other random events. The grid operator has the authority to direct generating units to increase or decrease their electricity output. In some cases, it can void electricity sales if the operator feels the sale could put the reliability of the power system in danger. The grid operators also monitor the market for commercial activity that restrains trade of electricity or drives up prices.

Traditionally, utilities have operated the grid with their territories. It has been the exception to have control areas covering many utilities and many states, despite the regional nature of the grid. Figure 8 shows a map of the United States with control areas.

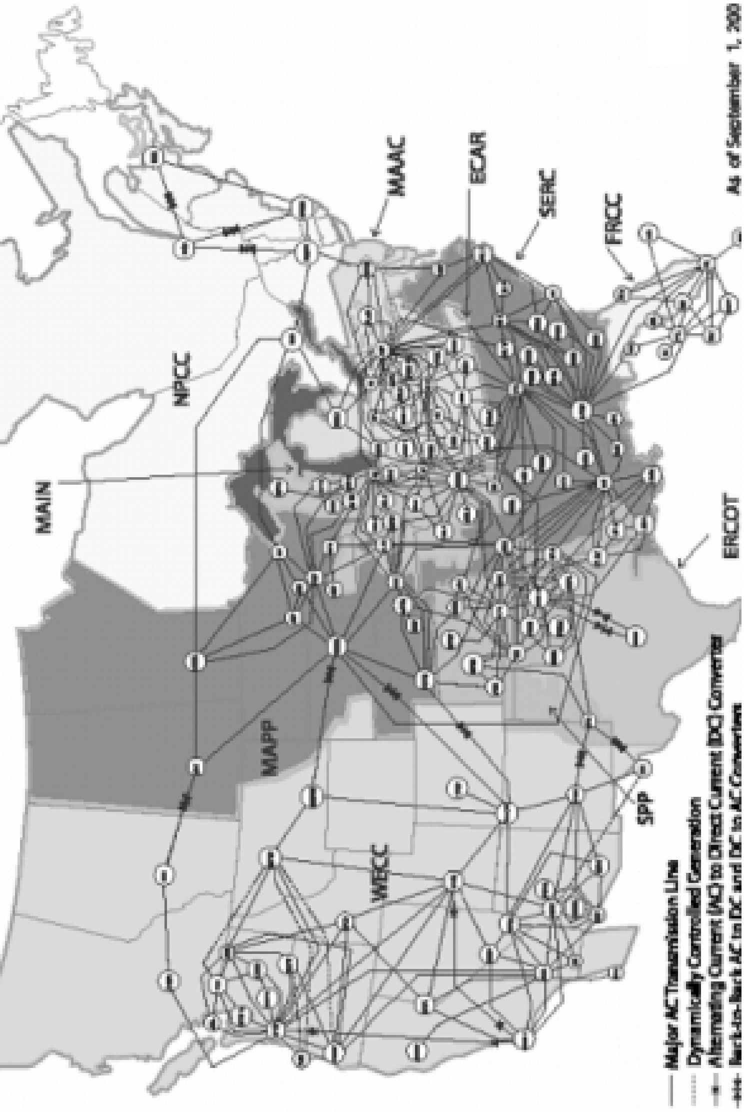
Some regulators advocate for grid operators to be independent of commercial motivations. Several independent grid operators have formed, covering the Northeast, the Midwest, California and Texas. As the 2003 blackout shows, neighboring grid operators must cooperate effectively regardless of the borders that divide them.

State Public Utility Commissions

State public utility commissions (PUC) usually take the lead state government role in transmission issues. Many commissions grant permission to build power lines along a particular land corridor, and all are involved in determining the rates that retail customers pay.[5]

State regulators determine if utilities plan appropriately and construct and operate lines properly. If regulators decide that utilities have done a poor job of planning or building power lines, they can forbid the utility from charging its customers for the costs of the line. If the transmission facilities fall under federal jurisdiction, the state commission generally must allow the utility to include its transmission costs in rates.[6] For this reason, among others, state regulators sometimes intervene in matters before the Federal Energy Regulatory Commission.

Figure 8. North American Electric Reliability Council Regions and Control Areas



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

Federal Energy Regulatory Commission

Federal law dictates that the Federal Energy Regulatory Commission oversees the rates and terms for most of the power transmission system, since transmission lines serve an interstate commercial function. Publicly owned systems are exempt from FERC regulation. FERC tariffs determine how much money transmission system owners earn from their transmission system, determine the structure of the transmission rates, and often determine who pays for upgrades to the transmission system.

Public Advocate

Forty-two states fund a public advocate office that represents the public in cases before the state utility regulators. In many states, the public advocate can hire experts and can bill those costs to the utility applicant, generally subject to review by the utility commission. Public advocates usually have people on their staff who are experts on utility regulation and participate in reviews of utility plans, with a particular focus on the rate impact of new investments. Consumer advocates also intervene in cases before the Federal Energy Regulatory Commission.

Federal and State Environmental Regulators

Transmission lines sometimes cross sensitive environmental areas, such as parks, wetlands, habitats, or streams and waterways. Often, they interfere with someone's view of the surrounding landscape. Even underground power lines may raise environmental issues, such as disturbance of wetlands and river crossings. State and federal environmental regulators may become involved in transmission siting to address these environmental issues.

State health officials may review a power line in a populated area to assess electromagnetic fields (EMF) produced by the currents in the line and their effects on people who live and work nearby. (EMF is discussed further in the next section.)

Public Interest Groups

Most state transmission siting proceedings allow others with an interest to "intervene" in order to present their point of view or question the proposal. Neighbors, communities, environmental groups and other utilities are typical intervenors in transmission siting proceedings. In most states, these groups do not have access to funding from the state or the utility applicant and must raise their own funds to pay legal and expert costs. Some states do offer intervenor funding.

Public interest groups tend to pay the most attention to new power lines or to major upgrades to power lines that require new and bigger towers or a wider right-of-way. Most states give the transmission companies an "easement," which grants permission to build towers and operate a power line and to cut vegetation along a particular corridor; changes to the terms of an existing easement or a new easement often attract attention. If homes or schools are nearby, state laws and regulations often require the transmission company to evaluate electromagnetic fields and might require the company to undertake low-cost measures to reduce the effects of the electromagnetic fields.[7]

On rare occasions, utilities or regulators organize collaborative or mediated processes designed to address the concerns of these public intervenors.

Federal Lands Managers

Transmission facilities sometimes pass through federally owned lands; if they do, federal agencies, such as the Department of Interior or the Department of Defense, become involved in the siting process. These federal agencies play a significant role in the transmission siting process because they control such massive swathes of land in the country, particularly in the western United States. Yet, their main mission has little to do with transmission lines. A state siting authority cannot preempt a federal land manager. The processes that transmission owners must undertake to site power lines on federal lands can be long and difficult because of federal requirements and because these petitions must compete for priority with the agencies' other missions. The federal government now has a process under way within the Council of Environmental Quality, an office of the White House, to examine how federal land managers can improve their responsiveness to transmission line proposals.

U.S. Department of Energy

The U.S. Department of Energy has little to do with transmission siting beyond its policy role. The DOE does have some emergency powers, however. During the August 2003 blackout on the east coast, the Department of Energy ordered that a DC power line from Connecticut to Long Island, N.Y., which passed under Long Island Sound, be energized over the objection of the state of Connecticut. In April 2004, the DOE rescinded this order since the need for preempting the state had passed.

DOE also issues "Presidential Permits" on behalf of the United States for transmission lines that cross federal boundaries.

Financial Markets

Financial markets evaluate utilities' performance. The value of utility stock and the cost of utility debt depend on the corporate risk that financial analysts and investors perceive.

Transmission lines and other grid investments can require a great deal of money. If the transmission owner cannot demonstrate that revenue from its rates will cover its costs, including its debt coverage and a reasonable return for shareholders, then capital may not be available to build transmission lines. The financial analysts also may be concerned if state and federal regulation do not offer a clear way for transmission owners to earn a reasonable return.

GLOSSARY

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

Alternating Current (AC): An electric current that reverses its direction of flow periodically, AC is wave of electrons that flow back and forth through a wire

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

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

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

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

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

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

Bulk Power System: All electric generating plants, transmission lines and equipment.

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

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

Capacitor: A device that maintains or increases voltage in power lines and improves efficiency of the system by compensating for inductive losses.
Cascading Outage: The uncontrolled, successive loss of system elements

triggered by an incident at any location. Cascading results in widespread service interruption that cannot be restrained.

Circuit: A path through which electric current can flow.

Commission: The regulatory body having jurisdiction over a utility.

Congestion: Transmission paths that are constrained, which may limit power transactions because of insufficient capacity. Congestion can be relieved by increasing generation or by reducing load.

Control Area: Electric power system in which operators match loads to resources within the system, maintain scheduled interchange between control areas, maintain frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserves.

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

Demand: The amount of power consumers require at a particular time. Demand is synonymous with load. System demand is measured in megawatts.

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

Direct Current (DC): Electricity flowing continuously in one direction, the constant flow of electrons in a wire (see Alternating Current).

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

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

Electrical Energy: The generation or use of electric power over a period, usually expressed in megawatt hours (MWh), kilowatt-hours (KWh) or gigawatt hours (GWh), as opposed to electric capacity, which is measured in kilowatts.

Federal Energy Regulatory Commission (FERC): A federal agency created in 1977 to regulate, among other things, interstate wholesale sales and transportation of gas and electricity at "just and reasonable" rates.

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

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

Forced Outage: Shutdown of a generating unit, transmission line or other facility for emergency reasons.

Forced outage reserves consist of peak generating capability available to serve loads during forced outages.

Frequency: The oscillatory rate in Hertz (Hz-cycles per second) of the alternating current: 60 Hz in the United States and 50 Hz in Europe.

Grid: Layout of the electrical transmission system; a network of transmission lines and the associated substations and other equipment required to move power.

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

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

Independent System Operator (ISO): Entity that controls and administers nondiscriminatory access to electric transmission in a region or across several systems, independent from the owners of the facilities.

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

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

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

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

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

Kilowatt (kW): A unit to measure the rate at which electric power is being consumed. One kilowatt equals 1,000 watts.

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

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

Load: The amount of power demanded by consumers. It is synonymous with demand.

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

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

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

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

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

Load Shedding: The process of deliberately removing (either manually or automatically) preselected demands from a power system, in response to an abnormal condition (such as very high load), to maintain the integrity of the system.

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

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

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

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

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

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

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

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

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

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

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

North American Electric Reliability Council (NERC): Formed in 1968 to promote the reliability of generation and transmission in the electric utility industry. Consists of 10 regional reliability councils and one affiliate encompassing all the electric systems in the United States, Canada and northern part of Baja, Mexico.

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

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

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

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

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

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

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

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

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

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

Power Pool: Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Public Utility Holding Company Act (PUHCA): Legislation enacted in 1935 to protect utility stockholders and consumers from financial and economic abuses of utility holding companies. Generally, ownership of 10 percent or more of the voting securities of a public utility subjects a company to extensive regulation under the Securities and Exchange Commission. The Comprehensive National Energy Policy Act of 1992 opened the power market by granting a class of competitive generators exemption from PUHCA regulation.

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

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

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

Real Power: Portion of the electrical flow capable of performing real work or energy transfer. Expressed in megawatts.

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

Regional Transmission Organization (RTO): An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size, established by FERC Order 2000.

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

Reliability: Term used to describe a utility's ability to deliver an uninterrupted stream of energy to its customers and how well the utility's system can handle an unexpected shock that may affect generation, transmission or distribution service.

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

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

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

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

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

Service Territory: Physical area served by a utility.

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

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

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

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

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

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

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

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

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

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

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

Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. Generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, subregion or NERC region, or a portion of any of these.

Transformer: Electrical device that changes the voltage in AC circuits.

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

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

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

Transmission: The process of transporting wholesale electric energy at high voltages from a supply source to utilities.

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

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

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

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

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

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

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

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

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

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

NOTES

Notes for Chapter 1

1. Smithsonian Institution, *Powering a Generation of Change* (Online: Smithsonian Institution, 2002) http://americanhistory.si.edu/csr/powering/ September 2002.

2. *Public Utility Commission of R. I.* vs. *Attleboro Steam & Elec. Co.*, 273 U. S. 83, 89 (1927).

3. There are boundaries within the network that limit power flows. These are reviewed in the chapter on the physical characteristics of the electric grid, notably in figure 7. The point here is that the power system covers all parts of the contiguous lower 48 states with consistently high reliability standards.

Notes for Chapter 2

1. Richard Sedano, *Dimensions of Reliability: Electric System Reliability for Elected Officials*, Electric Industry Restructuring Series (Montpelier: National Council on Electric Policy, 2001).

2. The following is excerpted from NERC's Web site at www.nerc.com. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. NERC:

- Sets standards for the reliable operation and planning of the bulk electric system.
- Monitors, assesses and enforces compliance with standards for bulk electric system reliability.
- Provides education and training resources to promote bulk electric system reliability.
- Assesses, analyzes and reports on bulk electric system adequacy and performance.

- •Coordinates with Regional Reliability Councils and other organizations.
- •Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- •Certifies reliability service organizations and personnel.
- •Coordinates critical infrastructure protection of the bulk electric system.
- •Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.
- •Administers procedures for appeals and conflict resolution for reliability standards development, certification, compliance and other matters related to bulk electric system reliability.

NERC is a not-for-profit corporation whose members are 10 Regional Reliability Councils. The members of these councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied and used in the United States, Canada and a portion of Baja California Norte, Mexico. Please see map, later.

3. Reserves protect consumers against inherent and unpredictable outages of generators and power lines, and against high demand due to extreme weather. One estimate of cost savings from reserve sharing comes from a May 2002 cost-benefit analysis of a proposed merger between ISO-NE and NYISO. The analysis estimated an annual saving from reserve sharing of $23 million, approximately 0.3 percent of wholesale costs in New York and New England.

4. North American Electric Reliability Council, *2003 Long-Term Reliability Assessment* (Princeton, N.J.: NERC, 2003), 15.

5. Natural gas facilities often can be built close to the electric loads they serve and near population centers because it can be easier to build or connect to underground gas pipelines than to build new power lines and because they do not face as much public opposition as some other types of power plants. It would be misleading to conclude, however, that siting any large power generator in an urban setting is easy.

6. A strong transmission system involves more than just transmission lines; it also includes mechanisms that lighten the load on the system and reduce the effects of a failure of any power plant, power line or other grid components. These measures include energy efficiency, demand response programs, and distributed generation, which enable a transmission system to remain strong longer.

7. This theory rests on an assumption that electricity usage is growing slowly.

8. On the other hand, citizens of states with low-cost power sources may be concerned that the inexpensive power they now rely on for low rates may be diverted to other places and that they may have to replace that power with more expensive sources. The same concerns also exist on an international scale; Manitoba, Canada, ships cheap hydropower to the United States, for example.

9. Likewise, new transmission can provide access to cleaner power supplies, enabling inefficient and polluting units to be closed with no loss of reliability.

10. Another reason for interest in transmission is that state regulatory commissions determine whether transmission owners can pass their costs to all consumers in electric rates. Therefore, the financial consequences of the choices of whether a project is needed, and how it should be built fall on consumers who have no direct say in whether they want to pay those costs. State regulators and siting authorities make that choice on behalf of consumers.

11. Local, state and federal governments can encourage energy efficiency in non-regulatory ways, including building energy codes, appliance and equipment energy standards, tax incentives, and public education. Regulatory support for energy efficiency must address utility concerns for lost revenues.

12. Distributed generation refers to small-scale power plants that usually are built very close to the place that uses the electricity. A microturbine sits in the parking lot of a McDonald's restaurant outside Chicago, for instance.

13. Demand response programs often pay customers to reduce their demand for electricity at the request of the system operator through whatever means they consider practical. Such programs differ from the longstanding practice of interruptible contracts because demand response programs compensate customers based on the value of their action, such as the market price of energy during the hours of curtailment, and not through a simple rate discount. For instance, a customer might shut down an industrial process for a few hours or use a back-up power source for the duration of the reduction.

14. The applicability of these options depends upon the problems planners are trying to solve. If it is a reliability problem caused by the addition of new power plants that will overload the transmission system when they are connected to the system, then a transmission expansion project may be the only useful alternative (the generator siting authority can factor in the potential for overloading the transmission system when it considers issuing its permit). If the challenge is to help reduce electricity prices in a particular area, then a transmission line to import electricity from low-cost sources or an efficient new generator and

demand side measures located close to load may be the right choice. The choice of options must match problems. It is important to keep in mind that, in a deregulated system, neither transmission planners nor regulators, typically control where new generation facilities will locate, except for environmental factors. This makes it more difficult to use generation as a solution to system problems where vertically integrated utilities do not operate.

15. For a description of the many entities involved in planning and in the transmission siting process, see the appendix.

16. Utilities that remain integrated, meaning they continue to generate and deliver power, retain the ability to plan generation and transmission together. Even in states in which utilities remain integrated, utilities often do not plan regionally.

17. Electric Power Supply Association, "Merchant Generators and Transmission Investment" (National Association of Regulatory Utility Commissioners, 2003, photocopied handout).

18. According to Jim McCluskey of the California Energy Commission, Personal Communication, the Seams Steering Group of the Western Interconnection (SSG-WI) also is involved in transmission and resource planning within the Western Interconnection. The purpose of the group's studies is to forecast the location and economic potential of new generation and electricity resources—hydroelectric, gas, coal, and renewables—for eight and 13-year planning horizons and to identify potential transmission needs to gain access to those resources.

19. James Avery, San Diego Gas & Electric, personal communication with author, April 12, 2004

20. In another approach, sometimes seen in highway planning, analysts would study and cost out multiple alternatives before settling on the preferred choice.

21. Utilities also must work with Indian tribal governments when transmission lines might cross Indian reservations.

22. At the request of the National Council on Electric Policy, the National Association of Regulatory Utility Commissioners plans to publish guidance for the type of information that should be included in a complete application in late 2004 or early 2005.

23. Although all transmission rates are FERC-regulated, nonutility transmission owners, also called merchant transmission owners, can negotiate value-based rates for service.

24. For information about state siting regulations in the states, as of 2000, see Edison Electric Institute, *State-Level Electric Transmission Line Siting Regulations Directory* (Washington, D.C.: EEI, 2001). http://www.eei.org/industry_issues/energy_infrastructure/transmission/siting_directory.pdf .

Notes for Chapter 3

1. Merchant transmission companies do not earn a regulated return. Instead they earn money from contracts they sign with companies that ship power over their transmission lines.

2. A transmission right credit is a way to compensate the developer for the investment it has made in transmission. In this case, GE Wind would receive transmission credits equal to its upgrade investments, plus interest. FERC has consistently upheld this form of participant funding in order to avoid what it refers to as "and" transmission pricing, i.e., paying both the transmission investment costs and the transmission service costs.

3. During the last decade, generators have been required to pay all the costs of directly interconnecting their facility to the grid, as well as the cost of network upgrades for those facilities. Once the new facilities are built and operating, generators then receive a transmission service credit for the network upgrades. Other funding systems are in place in the Northeast regional markets, where consumers and utilities that serve consumers have access to regional energy, capacity and ancillary service markets operated by independent regional transmission organizations. Both approaches provide utility customers and generators with ways to address the costs associated with interconnection.

4. The authors have not included in the chapter on State Actions a policy to bring government- and consumer-owned companies under FERC regulation because this choice is up to the companies themselves.

5. Transmission owners have significant leverage in this process because they are not obligated to join an RTO.

6. The Alternating Current grid in Texas is isolated from the surrounding grid. There are Direct Current connections but, because these are not free-flowing and are controlled and can be easily closed, this arrangement shields Texas from much FERC regulation.

7. Performance-based regulation (PBR) is a different way to regulate utilities. It establishes explicit service performance objectives, which benefit

consumers, and it establishes a method of compensation for the utility that is either more stable or that is tied to success in meeting the objectives. PBR has not been applied to a transmission company to date. For a discussion of this, see Shmuel Oren, George Gross and Fernando Alvarado, *Alternative Business Models for Transmission Investment and Operation*, National Transmission Grid Study.

8. Issue Paper prepared for the U.S. DOE, (Washington, D.C: 2002). See also The Regulatory Assistance Project, *Performance Based Regulation for Distribution Companies* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 2000), 24.

Notes for Chapter 4

1. Steve R. Cieslewicz and Robert R. Novembri, *Utility Vegetation Management Final Report,* prepared for the U.S. Federal Regulatory Commission (Washington, D.C.: U.S. FERC, 2004).

2. One motivation for creating regional operating entities such as an RTO is to roll all transmission costs from all regional owners into one pricing structure. This regional price structure would not have to deal with the loop flow issue, at least for transactions within the region.

3. See http://www.nerc.net/standards/ReliabilityStandards.aspx?tabindex=0&tabid=23 for NERC reliability standards.

4. Secretary of Energy Advisory Board, *Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability* (Washington, D.C: U.S. DOE, 1998).

5. This last action is called load management, or demand response. In developing wholesale markets, the customer is compensated at a market rate for this commitment.

6. This definition is summarized from the joint U.S./Canada Power System Outage Task Force report "Causes of the August 14, 2003 Blackout." A lack of VAR support was one cause of the 2003 blackout.

7. On a line designed to operate at 115,000 volts, if the voltage falls more than 10 percent below that figure, protective equipment will isolate the line before it damages either other parts of the grid or customer equipment.

8. Many of these bottlenecks develop because of a mismatch between sources of generation and concentrations of electric load.

9. Although not shown in the map, Direct Current (DC) links isolate Quebec from its neighbors in the same way that DC links isolate Texas from its neighbors. See www.nerc.com for more information about the reliability regions.

10. Some suggest using DC for a reliability purpose by creating smaller interconnections, and connecting them with DC lines. This would effectively stop a cascading blackout at the border of the interconnection, and it would make each interconnection easier to manage. See George C. Loehr, Presentation to NARUC Staff Subcommittee on Electricity, November 16, 2003.

11. Demand response represents customers that reduce their demand on the grid in response to the system operator, due either to an emergency or to high market prices. The customer receives market-based compensation for supplying this resource.

Notes for Chapter 5

1. State policymakers include legislators who write the laws and maintain the overall statutes, utility regulators who interpret the laws, and executive branch officials who deal with the practical and political implications of the laws and regulatory outcomes. Paying for transmission has a distinct overlap between state and federal jurisdictions; thus, the state does not fully control the outcome for all these items.

2. David H. Meyer, and Richard Sedano, *Transmission Siting and Permitting*, National Transmission Grid Study Issue Paper (Washington, D.C.: U.S. DOE, May 2002).

3. FERC has considered this issue and directed the creation of such a fee structure in its order governing the interconnection of large generation sources to the grid. See FERC Order 2003. This action may or may not be all that is needed to clarify who pays how much for the costs of interconnection studies.

4. Some regions are beginning to organize themselves to cooperate in these ways. The Organization of MISO States (OMS) is considering the degree to which this cooperation would be useful. OMS has included in its charter a goal to assist states that are interested in coordinating transmission siting proceedings and decisions. The New England Governors Conference has identified these as possible areas of cooperation. Generically, these are called regional state committees, or multi-state entities. See: Ethan W. Brown, *Interstate Strategies for Transmission Planning and Expansion* (Washington, D.C.: National Governor's Association Task Force on Electricity Infrastructure, 2002); Federal Energy Regulatory Commission, *Notice of Proposed Rule Making on Standard Market Design: Docket RM01-12-000*Federal Energy Regulatory Commission. (July 31, 2002), 551-554; Federal Energy Regulatory Commission, *White Paper on Wholesale Market Reform*, (Washington, D.C.: July 7, 2003); and National

Association of Regulatory Utility Commissioners, *Resolution Regarding Interstate Transmission Planning and Expansion* (Washington, D.C.: NARUC, 2002).

5. Probabilistic techniques identify significant possible future events on the power grid, assign probabilities to these events based on current knowledge, and subject these possible events to numerous (hundreds or thousands) computer simulations. The result is a probability distribution of outcomes for reliability margins and system cost from a given set of inputs and numerous possible subsequent events. Probabilities can vary from scenario to scenario if the analyst wants to assess a range. Such techniques are superior for examining the interaction of many events and for providing a realistic assessment to decision makers of the risks attached to different options. Computing power is now sufficient to support probabilistic analysis.

6. For example, California PUC Decision 03-10-056, (October 16, 2003).

7. Integrated resource planning refers to a public planning process that many utilities conduct under supervision of their regulatory commission. The process tries to strike a balance between the utility's need for new power plants, power lines and energy efficiency. The planning process also provides a way to evaluate the contribution that different renewable or more traditional fossil resources might make to supplying power to customers.

8. See, for example, David Moskovitz, *Profits and Progress through Distributed Resources* (Gardiner, Maine: The Regulatory Assistance Project, 2000). See also, The New England Demand Response Initiative, *Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets* (n.p.: NEDRI, 2003).

9. See http://www.cc.state.az.us/utility/electric/linesiting-faqs.htm for a description of the Arizona practice.

10. Federal regulators already are moving in this direction, in an attempt to deploy pricing systems for transmission service that reflect system "congestion."

11. Under this logic, New Hampshire and Vermont utilities were given an extra ownership share of a DC electric transmission line built in the mid-1980s that brings power from Quebec into Massachusetts.

Notes for Appendix

1. Merchant transmission companies are subject to FERC regulation. FERC, however, grants such companies conditional authority to negotiate the rates they charge, leading to a market-based outcome. Jose Rotger, personal communication with author, March 12, 2004.

2. In the case of serious grid problems, the independent regional planner and system operator may take the exceptional step of soliciting resource investments to solve the problems. Generators also maintain a reserve margin to address these problems, and customers pay for this reliability reserve factor in their bills.

3. When a contingency occurs, as it inevitably does on occasion, operators are prepared to activate reserve capacity and to reconfigure the system so that, within a few minutes, the system is still protected against the next largest contingency. Power systems in North America can generally tolerate failures of several pieces of equipment within a short time. However, at peak demand conditions, power systems are expected to absorb only the failure of the largest contingency. Further large contingency failures may lead to operators dropping load in an orderly way to avoid a cascading blackout.

4. Ethan W. Brown, *Interstate Strategies for Transmission Planning and Expansion*, a report prepared at the request of National Governor's Association Task Force on Electricity Infrastructure, (Washington, D.C.: National Governors Association, 2002).

5. Some states have a separate authority that considers requests to site a power line. The PUC participates in most of these, but is joined by public officials from other agencies.

6. The line between federal and state jurisdiction is unclear at times and may be cause for controversy. Where federal jurisdiction is clear, states generally are obliged to pass on to retail rates federally jurisdictional costs that are found to be prudent by federal regulators.

7. For more information on electromagnetic fields, the National Institute of Health Web site provides useful information: http://www.nlm.nih.gov/medlineplus/electromagneticfields.html.

The National Association of Regulatory Utility Commissioners (NARUC) is a nonprofit organization founded in 1889. Its members include the governmental agencies that are engaged in the regulation of utilities and carriers in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. NARUC's member agencies regulate the activities of telecommunications, energy and water utilities. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Under state law, NARUC's members have the obligation to ensure the establishment and maintenance of utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions that are just, reasonable and nondiscriminatory for all consumers.

The National Association of State Energy Officials (NASEO) is the only nonprofit organization whose membership includes the Governor-designated energy officials from each state and territory. NASEO was formed by the states and through an agreement with the National Governors Association (NGA) in 1986. The organization was created to improve the effectiveness and quality of state energy programs and policies, provide policy input and analysis where requested, share successes among the states, and to be a repository of information on issues of particular concern to the states and all their citizens.

The National Conference of State Legislatures is the bipartisan organization that serves the legislators and staffs of the states, commonwealths and territories. NCSL provides research, technical assistance and opportunities for policymakers to exchange ideas on the most pressing state issues and is an effective and respected advocate for the interests of the states in the American federal system. Its objectives are:

- To improve the quality and effectiveness of state legislatures.
- To promote policy innovation and communication among state legislatures.
- To ensure state legislatures a strong, cohesive voice in the federal system.

ISBN 1-58024-352-5