EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Transmission Planning White Paper

January 2014

Navigant Consulting, Inc.
For EISPC and NARUC
Funded by the U.S. Department of Energy

Disclaimer

This material is based upon work supported by the U.S. Department of Energy, under Award Number DE-OE0000316.

The authors would like to thank NARUC and EISPC for their support and funding of this white paper, and the guidance and input provided by the members of the EISPC Studies and White Papers Workgroup.

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January 2014

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1 Introduction

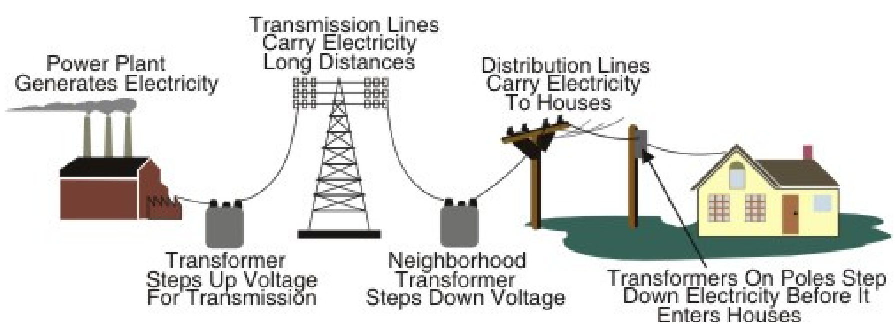
The U.S. electric transmission system is an engineering marvel critical to our economy and way of life. The details can be complex, but the basics are not—the transmission system is designed to reliably and efficiently deliver electricity from where it is generated to where it is distributed to customers. This Transmission Planning White Paper is designed to help policymakers understand the basic technology, economics, and regulations that underlie the planning of today's electric transmission system.

In the 1830s, a seemingly simple discovery was made that would profoundly change everyday life. Moving a magnet through a coil of wire generated electricity, the flow of electrons, in the wire.[1] Nearly all of today's electricity power plants use this same concept. Wind, water flowing in a river, and boiling water to create steam are some of the various means used by today's power plants to turn turbines that spin magnets within coils of wire to generate electricity. This is the **generation** of electricity. Electricity is difficult to store economically; thus, it needs to be generated when it is needed. When you turn on your light switch, a power plant must respond and increase its generation of electricity instantly.

Historically, it has been less expensive to generate electricity at large, centralized power plants, which can be hundreds of miles from where the electricity is used, than with small local generators. The electricity generated at these power plants is transmitted through the **transmission** system, a network of interconnected high-voltage lines. Transmission lines are designed to transmit a large amount of electricity while minimizing the amount of lost energy, and are interconnected with each other to make the system more reliable. The U.S. interstate highway system is analogous to the transmission system. In an interconnected network, if a line or power plant goes out of service, another pathway or power plant can take its place.

Lower-voltage lines are connected via substations to the high-voltage transmission system to distribute electricity to the exact location where it is needed, such as homes, offices, stores, and factories. These lower-voltage lines form the electric **distribution** system. Local roads and streets are analogous to the electric distribution system.

Figure 1. Electric Power Generation, Transmission, and Distribution Diagram

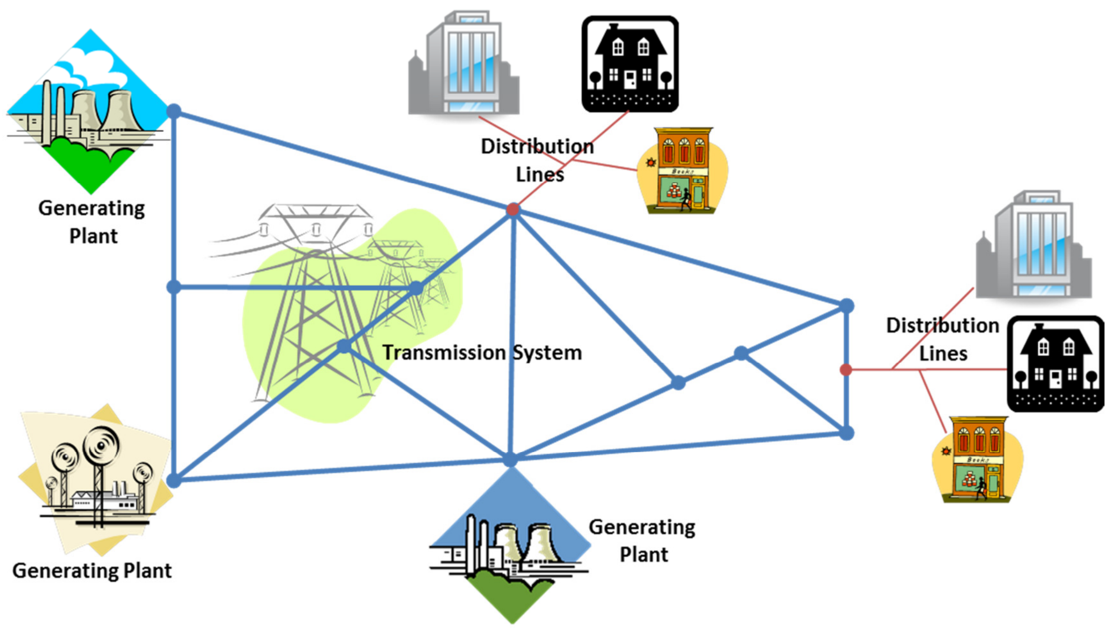


Source: U.S. Energy Information Administration

Figure 1 illustrates the basic components of the interconnected electric system. There are substations at each connection point on the system, such as between a power plant and transmission lines, from one transmission line to another, or between transmission lines and distribution lines. Substations use transformers to adjust voltage levels up or down and can disconnect or reconnect portions of the system.

While Figure 1 is useful for understanding the basic components of the electric system, it does not capture the interconnected nature of the transmission network as illustrated in Figure 2. The thick blue lines in Figure 2 represent interconnected transmission lines. These transmission lines provide multiple pathways for the electricity generated by distant power plants to flow to individual distribution systems, thus increasing reliability.

Figure 2. Simplified Representation of the Transmission System



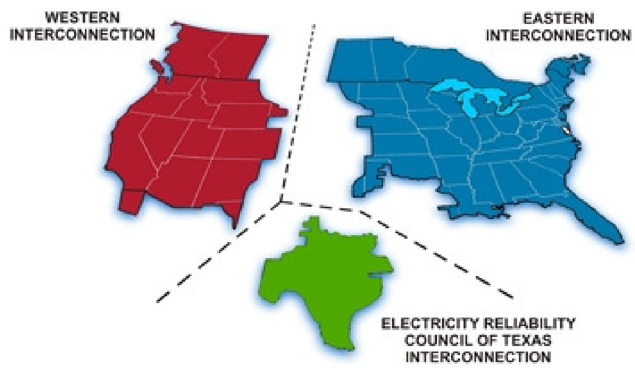
Source: Navigant

Just like traffic jams on an interstate highway, a transmission line can become congested if the power being transmitted over the line reaches the physical limit of the line. Normally, this is not a problem, as the electricity flows over other interconnected transmission lines that are not congested, or power plants located on the congested side of the line are turned down to generate less and power plants on the uncongested side are turned up to generate more. The congestion may yield additional energy losses as the electricity travels over greater distances, or additional fuel costs for generating plants as higher cost plants are turned on, but the system continues to operate reliably.

However, too much power flow can cause the protective circuitry for the line to trip the line off (like the circuit breaker in a residential home) to prevent damage to the transmission line. A transmission line that trips off will immediately result in the transfer of the power traveling on that line to other interconnected lines, possibly overloading these other lines as well, and potentially creating outages over wide areas—a cascading outage. Similarly, a power plant suddenly shutting off will require other power plants to instantly increase their output, or other plants to come on line, potentially causing a line operating near its limit to suddenly exceed this limit and trip off, creating an outage. Thus, the power flows on the interconnected transmission system must be monitored and managed carefully around the clock, and the system must be designed and planned to handle these types of contingencies.

As illustrated in Figure 3, the U.S. transmission system has evolved into three major interconnected systems (power grids or interconnections) in the 48 contiguous states: (1) the Eastern Interconnection (states east of the Rocky Mountains), (2) the Western Interconnection (from the Pacific Ocean to the Rocky Mountain states), and (3) the Texas Interconnection (also called the Electric Reliability Council of Texas [ERCOT]). These systems generally operate independently of each other, although there are limited links between them. The Eastern and Western Interconnections are fully integrated with most of Canada. The Eastern interconnection has links to the Quebec Province power grid, while parts of Mexico have limited connection to the Texas and the Western interconnections.

Figure 3. U.S. Interconnections



Source: U.S. Energy Information Administration (EIA)

Just like the siting, permitting, and building of an interstate highway is more expensive and difficult than it is for a local road, siting, permitting, and building a transmission line is more expensive and difficult than it is for a distribution line. And just as eliminating all traffic congestion by building new highways would be prohibitively expensive, eliminating all congestion on the transmission system would be prohibitively expensive. Planning a reliable, cost-effective transmission system must consider and balance numerous issues, including siting, construction costs, direction of power flows, congestion, energy losses, new power plant locations, new and changing demands for electricity, public policy considerations, and how all of the costs incurred will be recovered.

Planning for the transmission system is complicated by the fact that electricity flows instantaneously over all available pathways on the interconnected transmission system according to physical laws. As can be seen even in a simplified diagram like Figure 2, there are multiple pathways from any one point on the transmission system to another. The flow of electricity on the transmission system from a generating plant to a distribution system will be proportionally higher on those pathways with the least resistance or "impedance" (usually the most direct highest voltage lines), but electricity will flow on all available pathways.

Thus, transmitting electricity from one point to another on the transmission system will have an impact on all available pathways, not just the most direct route. This is in contrast to, for example, natural gas, in which the gas from a specific well can be traced as it travels at a relatively low speed through one specific pipe to another until it reaches its destination. As a result, an electric utility continually faces "loop flows" on its transmission system resulting from normal activity or emergency incidents on transmission systems that can be located hundreds of miles away. The fundamental nature of electricity flow on an interconnected transmission system must be incorporated into all facets of transmission operations, planning, and policy.

This Transmission Planning White Paper is written primarily for those who are new to electric transmission issues.[2] The focus is on understanding transmission technology, economics, and regulation at a basic level and how state policymakers can influence transmission planning and policy. The next chapter provides background and discusses recent events that make transmission so important to our society today.

Key policies and rules from the Federal Energy Regulatory Commission (FERC) related to transmission are discussed in the third chapter. The process for building a new or upgrading an existing transmission line is described in detail in chapter four, including the role of state authorities and other entities involved in this process. Chapter five describes the typical process undertaken to plan the future of the transmission system. A discussion of how transmission is paid for is provided in chapter six, along with a discussion of current transmission cost allocation issues and methodologies. Chapter seven provides a high-level overview of the physical characteristics of the existing transmission system, and trends for future transmission technology development. The final chapter provides specific action items for state officials involved in transmission policy decisions.

2 Why Has Transmission Become So Important?

The transmission system has always been crucial to providing reliable, low-cost electric service to customers. Today, the transmission system has become even more important in allowing access to a diverse generation supply, including renewable sources of power, and enabling competition among power plants. This chapter discusses the historical development of transmission and why transmission continues to be of critical importance today.

2.1 *Historical Development*

2.1.1 Early History

The opening of Thomas Edison's Pearl Street station in lower Manhattan in 1882 launched the modern electric utility industry. By 1887, there were 121 Edison power stations scattered across the United States delivering direct current (DC) electricity to customers. But DC had a great limitation—power plants could only send DC electricity about a mile at the low voltages being used.[3]

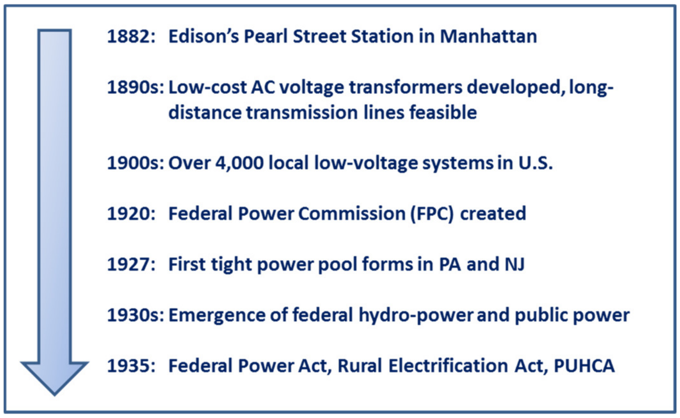
It was well known that much less energy would be lost if high-voltage transmission lines could be used. In the late 1880s, William Stanley and George Westinghouse developed cost-effective transformers to increase and decrease the voltage of alternating current (AC) electricity. Now, electricity from distant, but efficient power plants could travel with little loss of energy on high-voltage AC lines before being stepped down safely to lower voltages near consumers. AC electric systems went on to become the standard in the U.S. and throughout the world.

Around the beginning of the twentieth century, there were over 4,000 individual electric utilities in the U.S., each operating in isolation.[4] As electric generation and transmission technology dramatically improved, it encouraged growth, consolidation of the industry, and expansion into more and more cities, and across a wider geographic area. Over time, in what became known as the Regulatory Compact, these privately owned consolidated utilities were granted monopoly franchises with exclusive service territories by states, in exchange for an obligation to serve customers within that territory at rates for service based on state-regulated, cost-of-service ratemaking.[5] Among the first states to regulate electric utilities were Georgia, New York, and Wisconsin, which established state public service commissions in 1907.[6]

Despite the lure of exclusive franchises, some areas were inevitably less financially attractive than others. Under the Rural Electrification Act of 1935, service was extended to unserved, or underserved, rural areas, which also gave rise to rural electric cooperatives in many areas of the U.S. During the presidency of Franklin D. Roosevelt (1933 to 1945), funding accelerated the development of municipal electric systems, and a number of government-owned hydroelectric power facilities were built, with publicly owned utilities given priority to the output of these facilities.

In 1920, the Federal Water Power Act was passed to coordinate the initial development of these hydroelectric projects. This act created the Federal Power Commission (FPC), now FERC. Following

Figure 4. Early History



Source: Navigant

U.S. Supreme Court rulings that states could not regulate interstate transmission as it imposed a direct burden on interstate commerce,[7] in 1935 the law was renamed the Federal Power Act and the FPC's regulatory jurisdiction was expanded to include all interstate electricity transmission and sales of power for resale.

By 1907, Samuel Insull of Chicago Edison had acquired 20 other utility companies and renamed his firm Commonwealth Edison. In the 1920s, electric utilities began to exploit the use of holding companies, not to improve operating efficiency through consolidation, but as a speculative exercise. While the operating companies were subject to state regulation, the holding companies were not. By the end of the 1920s, ten utility systems controlled three-fourths of the United States' electric power business and the size and complexities of these multistate holding companies had made state regulation ineffective.[8]

In response to the collapse of several of these large, multistate electric utility holding company systems during the Great Depression, the Public Utility Holding Company Act (PUHCA) was passed in 1935, giving the Securities and Exchange Commission (SEC) responsibility for regulating utility holding companies. Among other things, PUHCA limited the geographic spread of utility holding companies, the types of business they may enter, and unnecessary corporate layers, as well as prohibiting sales of goods or services between holding company affiliates at a profit.

Thus, as shown in Figure 4, by 1935 the electric utility industry in the United States had become formally regulated at both the state and federal levels.

2.1.2 Initial Transmission Planning and the Formation of Tight Power Pools

Transmission was initially conceived and planned as a direct link between a generating plant and the distribution system serving the demand or "load." As the demand for electricity grew, particularly in the post-World War II era, electric utilities found it more efficient to interconnect their transmission systems. In this way, they could share the benefits of building larger and, often, jointly owned generators to serve their combined electricity demand at the lowest possible cost, and to avoid building duplicative power plants. By increasing access to additional power plants, interconnection also reduced the amount of extra capacity that each utility had to hold to assure reliable service.[9]

Throughout most of the twentieth century, growing demand and the accompanying need for new power plants resulted in an ever-increasing need for higher voltage interconnections to transport the additional power longer distances. In 1969, the world's first 765-kilovolt (kV) transmission line was energized between Ohio and Kentucky.[10]

Despite the expansion of the interconnected transmission system, a local utility generally would plan its transmission system as if the utility were an island or isolated from other utility systems. In effect, the presumption was that neighboring transmission would be available to provide electricity for assistance during emergency conditions, but for day-to-day operations, the generating and transmission system of the local utility needed to be robust enough to provide reliable electricity service on a stand-alone basis.

Starting in the 1920s with utilities in Pennsylvania, New Jersey and (later) Maryland (PJM), certain regions of the country began to form "tight power pools" in which the member utilities pooled their generation and transmission resources to minimize generating plant fuel costs by centrally dispatching plants over the pool footprint.[11] The savings were shared among the member utilities and transmission was collectively planned to allow for delivery of power throughout the pool. Tight power pools also eventually formed in Michigan, New England, and New York.[12] These tight pools were the precursors to the centralized energy markets in today's regional transmission organizations.

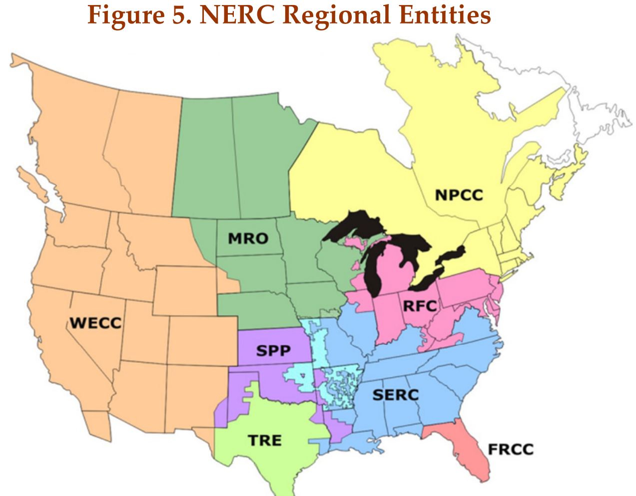
In addition to the formation of tight power pools, connections between individual utilities expanded to become the three interconnections that exist in the United States today: Eastern Interconnection (which includes parts of Canada), Western Interconnection (which includes parts of Canada and Mexico), and ERCOT. The three interconnections are shown above in Figure 3.

2.1.3 Northeast Blackouts of 1965 and 2003 and the Creation of NERC and Reliability Standards

Throughout most of the twentieth century, individual power systems developed and designed their own criteria for reliability. Following the Northeast Blackout of 1965, in which large portions of the Northeast U.S. and Ontario lost power for up to 13 hours, the North American Electric Reliability Council and regional reliability councils were voluntarily formed. These organizations later became the North American Electric Reliability Corporation (NERC) and the Regional Entities (see Figure 5).

One of NERC's roles was to establish overall reliability criteria. NERC's original planning criteria were general in nature—guidelines as to what topics the regional councils should address in creating their regional criteria. Across the nation, systems came together to establish regional reliability councils, until collectively they encompassed essentially all of the continental U.S. and Canada. The primary role of the regional reliability councils was to establish and maintain uniform reliability criteria to be applied in the planning and operation of their respective systems.

Figure 5. NERC Regional Entities



Source: NERC

Prior to 2005, compliance with NERC reliability standards was voluntary. After a blackout in the Northeast affected over 50 million people in August 2003, the Energy Policy Act of 2005 (EPAct) was enacted, eliminating the voluntary nature of the NERC reliability standards. FERC was charged with the ultimate oversight of electric reliability of the bulk power system (BPS). FERC finalized rules on the certification of an electric reliability organization (ERO) and on procedures for the establishment, approval, and enforcement of mandatory electric reliability standards, and certified NERC as the ERO in 2006.[13] NERC, along with its regional entities, develops mandatory reliability standards subject to FERC approval, monitors industry participants' compliance with these standards, trains and certifies industry personnel, and can levy penalties for noncompliance.

2.1.4 Emergence of Open Access to the Transmission System

Through the 1980s, transmission systems were owned and operated by the local utility within its franchised service territory, and interconnected with neighboring utility transmission systems. Typically, the local utility only transmitted power on its transmission system from its own power plants or contractually purchased power from neighboring utilities. The Public Utility Regulatory Policies Act of 1978 (PURPA) required utilities to purchase power from non-utility generators when economic to do so, which, for the first time, allowed non-utility generation access to the transmission system to deliver power to the local utility.

Figure 6. Time Line 1965–2011

- **1965:** East Coast Blackout, 30 million lose power
- **1968:** NERC established to create voluntary reliability standards, NERC regional councils form
- **1992:** Energy Policy Act of 1992 gives FERC authority to order utilities to provide access to their transmission systems
- **1996:** FERC Order 888 requires open-access transmission tariffs; OASIS instituted.
- **2000s:** RTOs and ISOs form in many regions of North America
- **2003:** Northeast Blackout, 50 million lose power
- **2005:** EPAct 2005 makes NERC reliability standards mandatory
- **2011:** FERC Order 1000 requires regional transmission planning

Source: Navigant

In response to ongoing concerns regarding obtaining access to utility transmission systems, the Energy Policy Act of 1992 gave FERC the explicit authority to order utilities to provide access to their transmission systems to other utilities and to non-utilities. As shown in Figure 6, in 1996 FERC issued Order No. 888, which required transmission owners to provide transmission service to other suppliers of electricity on the same terms and conditions as they provide it to themselves. FERC's objective was to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers.[14] The resulting tariffs became known as Open Access Transmission Tariffs (OATTs). Timely and accurate day-to-day information about the transmission system was also made available to all transmission users through the implementation of the Open Access Same-Time Information System (OASIS), in accordance with FERC Order No. 889.

Open access to the transmission system allowed non-utility "merchant" generating plants to deliver and sell power to wholesale customers using the utility-owned transmission system, and paved the way for the emergence of competitive generation markets.

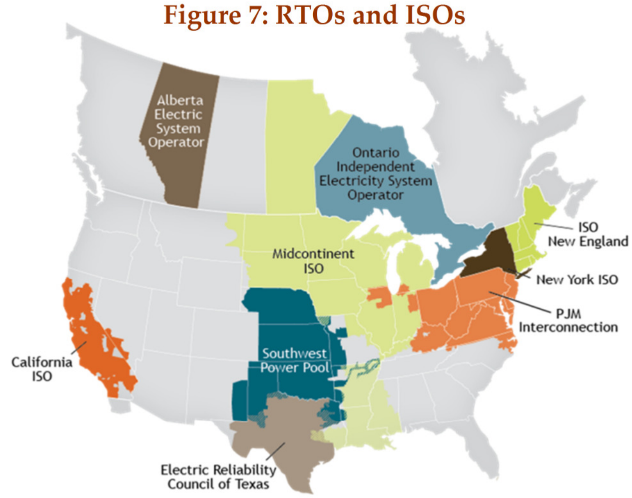
2.1.5 Formation of ISOs and then RTOs

Independent System Operators (ISOs) grew out of Orders Nos. 888/889, issued in 1996, where FERC suggested the concept of an ISO as one way for existing tight power pools to satisfy the requirement of providing nondiscriminatory access to transmission. Subsequently, in Order No. 2000, issued in 1999, FERC encouraged the voluntary formation of Regional Transmission Organizations (RTOs) to administer the transmission grid on a regional basis throughout North America (including Canada).

FERC Order No. 2000 delineated 12 characteristics and functions that an entity, such as an ISO, must satisfy in order to become a RTO, including four minimum characteristics: (1) independence from market participants; (2) appropriate scope and regional configuration; (3) possession of operational authority for all transmission facilities under the RTO's control; and (4) exclusive authority to maintain short-term reliability. Voluntary RTOs and ISOs have formed in many regions of the U.S. (see Figure 7), including California (CAISO), Southwest (Southwest Power Pool [SPP]), Midwest (MISO), Mid-Atlantic (PJM), New York (NYISO), New England (ISO-NE), and Texas (ERCOT). Similar organizations operate in the Canadian provinces of Alberta (Alberta Electric System Operator) and Ontario (Independent Electricity System Operator). For ease of reference, the term RTO is used herein to encompass RTOs and ISOs.

RTOs do not own transmission facilities. They operate the transmission system in accordance with NERC and regional reliability criteria on behalf of their member transmission owners, administer the regional OATT, ensure non-discriminatory access to the transmission system, and manage and plan for the reliability of the transmission system. Transmission owners within an RTO continue to be compensated for their transmission investment, and operation and maintenance (O&M) costs through cost-based rates approved by FERC. RTOs also perform transmission planning to ensure that transmission will be reliable as demand grows and generating plants are added or retired throughout their footprint.

Figure 7: RTOs and ISOs



Source: ISO/RTO Council (IRC)

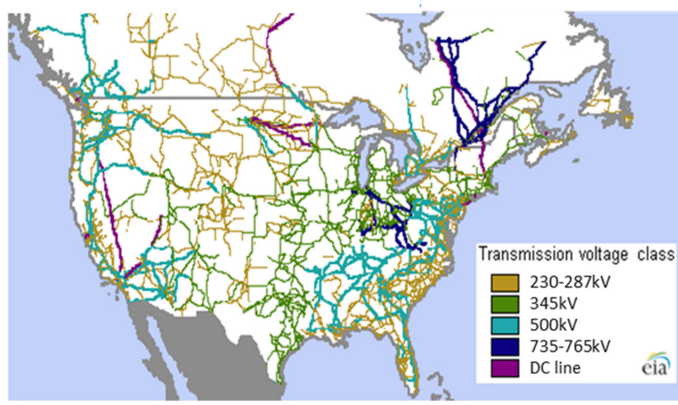
RTOs typically operate regional wholesale energy markets or power exchanges, in which generators offer to provide energy and the lowest cost offers are accepted as long as the transmission system can reliably deliver the power. In these markets, energy prices on the transmission system (locational marginal prices) will vary whenever there is congestion on the transmission system and low-cost power plants in one region cannot fully reach the demand in another. The resulting higher energy prices within congested regions provide an economic signal for new generating plants to be located in the high-priced area, or for additional transmission to be constructed to alleviate the congestion. Most RTOs also provide financial instruments, known as Financial Transmission Rights or Transmission Congestion

Contracts, which allow market participants to hedge the cost of congestion. Managing transmission congestion through these economic signals limits the need for Transmission Loading Relief procedures, in which transactions can be physically curtailed to maintain transmission system security.

2.2 Transmission System Structure and Planning Today

Today, the U.S. transmission system has over 445,000 miles of high-voltage (100 kV and above) transmission lines.[15] Figure 8 shows the transmission lines in North America that are 230 kV and above. The system today remains predominately under cost-based regulation, with transmission owned by individual utilities within defined service territories. While most transmission is owned by vertically integrated utilities that also own distribution systems and often generation, the transmission systems in some service territories are owned by independent transmission companies that hold only transmission assets.

Figure 8. North American Transmission System (230 kV and above)



Source: U.S. Energy Information Administration

Many utility-owned transmission systems are under the operational control of an RTO, while many others remain operated by the individual transmission-owning utilities. There are also merchant transmission lines, in which particular segments of the transmission system are constructed and owned by independent companies, who charge market-based rates for the use of their lines.

Whether part of an RTO or not, transmission systems are planned to reliably meet projected demand on a regional basis. FERC Order No. 1000, issued in 2011, requires each public utility transmission provider to participate in a regional transmission planning process, and coordinate with each neighboring transmission planning region to determine if there are cost-effective solutions to their mutual transmission needs. For a more detailed discussion of the transmission planning process, see Chapter 5.

While the planning of the transmission system is regional in nature, most transmission facilities will continue to be constructed and owned by the local transmission utility. However, FERC Order No. 1000 also instituted rules in which certain types of new regional transmission facilities approved in a regional plan could be constructed and owned by third parties potentially selected under competitive bidding.

2.2.1 Use of DC on the Transmission System

Direct current flows on a wire constantly in only one direction. Alternating current travels in a wave, with the flow of current changing direction back and forth about 60 times per second. Since the majority of the power system is AC, DC systems require a converter to convert power from AC to DC as it enters the DC power line and to reconvert it from DC to AC as it reenters the AC system. Despite the significant expense required for converter stations and the energy lost in the conversion, DC plays an important role in the transmission system, including inter-ties between the three U.S. interconnections and in high-voltage lines as shown in Figure 9.

DC Ties. DC ties are used today to connect the three interconnections in the U.S. The power transmitted across a DC tie can be controlled precisely, meaning that the cascading impact of outages that exist within an interconnected transmission network can be "stopped" at the DC tie between two grid interconnections. In effect, while power can flow on the DC ties, the AC waves within the two power grids remain electrically isolated and do not need to be synchronized. There are presently six "back-to-back" AC/DC/AC interconnections between the Western and Eastern Interconnections and two such interconnections between the Texas Interconnection and the Eastern Interconnection.

Figure 9. How DC Is Used Today

- **DC Ties: Inter-ties between the three U.S. Interconnections**
- **HVDC Lines: Long-distance high-voltage lines from one single point to another**

Source: Navigant

HVDC Lines. DC also can be useful for transmitting the electricity long distances from one specific point to another. At equally high voltages, a high-voltage DC (HVDC) line will have smaller power losses than a comparable AC line, which over long distances can potentially more than pay for the required costly converter stations. This is especially true for underwater and underground lines. Moreover, the ability to precisely control the amount of power on a DC line helps ensure that only those that contract and pay for a DC line can transmit power over the line. As a result, many of the recently installed and proposed HVDC lines are "merchant" transmission lines. HVDC lines are in place between the Pacific Northwest and Southern California, Utah and Southern California, North Dakota and Minnesota, and Long Island and Connecticut, among other places.

2.3 *New Expectations for Transmission*

Today, the transmission system is more important than ever, and is being called upon to address many cutting-edge issues, including:

- **Expanded access to power from a diverse portfolio of sources for improved reliability**
  Electricity is provided today by generating plants fired by coal or natural gas, nuclear, and renewables such as hydro, wind, and solar. Each generation resource faces varying risks from environmental regulations, fuel price volatility, intermittency, and maintenance outages. The geographic reach and integration of these sources of generation provided by the transmission system helps mitigate the risks from the use of any single type of power.

- **Expanded opportunities for lower cost power**
  Each of the various sources of generation has a different cost profile, and this cost profile can change over time. The wide footprints of expanded transmission systems allow the lowest cost power at any particular time to be delivered to distant points where it is consumed. The expanded transmission system also allows competitive generation markets to function across broad RTO/ISO regions.

- **Expanded access to mitigate economic ramifications of increasingly stringent environmental regulation**

Coal-fired electric plants in particular are the focus of increasingly stringent environmental regulations, and the economic costs of replacing the plants that may be retired can often be mitigated through transmission interconnections to other available sources.

- **Expanded access to foster state policies regarding renewable energy that may require long-distance transmission**
  Many of the best sources for renewable energy (e.g., wind in the Great Plains or off-shore) tend to require long-distance, extra-high-voltage transmission to deliver the power to distant load centers with limited energy losses. Meeting renewable energy standards thus requires an assessment of both renewable generation sources and the associated build-out of the transmission system.

- **Distribution generation and microgrids**
  Distributed generation, locating small generators at or near where the electricity is used, circles back to the beginning of the electric industry, and given technical advances has the potential to reduce the need for transmission and increasingly provide benefits in energy savings, avoided line losses, and improved power quality. Microgrids use advanced smart grid technologies and distributed energy resources to create localized grids that can operate autonomously if needed, typically during extreme weather events.[16] The interplay between transmission, microgrids, and distributed generation will be an important economic and policy issue facing state regulators in the upcoming years.

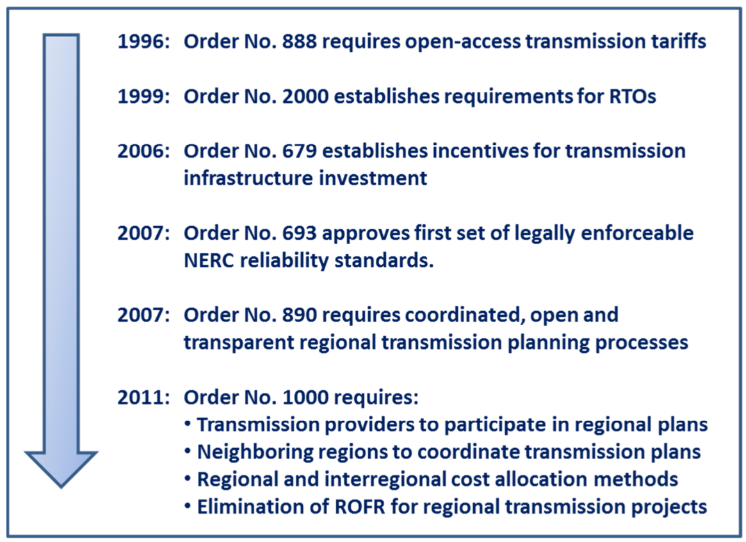
3 Federal Energy Regulatory Commission Policy and Rules

3.1 *FERC Jurisdiction and Legal Requirements*

Under the Federal Power Act, FERC regulates the transmission of electric energy and the sales of electric energy at wholesale in interstate commerce by public utilities. For FERC purposes, "public utility" is defined by the statute as "any person who owns or operates facilities subject to the jurisdiction of the Commission" which are those "facilities used for the transmission of electric energy in interstate commerce or for sales of electric energy at wholesale in interstate commerce."[17]

FERC does not regulate government-owned utilities or most cooperatives, which are often referred to as "non-jurisdictional" entities. Due to limited or nonexistent transmission connections with other states, the Texas Interconnection, along with the entire states of Alaska and Hawaii, are not subject to FERC regulation. Areas considered outside of FERC's responsibility include regulation of the provision of retail electricity to consumers and approvals for the physical construction of electric generation, transmission, or distribution facilities.

Figure 10: Key Transmission-Related FERC Orders



Source: Navigant

Under Section 205 of the Federal Power Act (FPA), the rates, terms, and conditions for interstate transmission filed at FERC must be "just and reasonable" and "not unduly discriminatory or preferential". In practice, this means that rates must be based on a regulated cost of service or the result of a competitive market, and similarly situated customers must be treated similarly. In approving rates, terms, and conditions, unlike state public utility commissions (PUCs), FERC is not required to determine the best outcomes or balance the interest of parties.

3.2 *FERC Policy to Prohibit Discriminatory Use of the Transmission System*

Key transmission-related FERC Orders over the last two decades are summarized in Figure 10. Because access to the transmission system is required for generating plants to deliver and sell power to wholesale customers, FERC is particularly concerned with discriminatory use of the transmission system. In a competitive marketplace, access to transmission has the potential to be used to limit the participation of independent generators. Since 1996, under FERC Order No. 888, transmission owners have been required by FERC to offer open access to their systems under a standardized cost-based Open-Access Transmission Tariff. Through the OATT, independent generators and their wholesale customers can reserve transmission to serve their needs on any available transmission path. Since 1996, many non-jurisdictional transmission-owning entities have voluntarily submitted OATTs under a "reciprocity" approach, in which FERC conditions the use of open-access services to those entities that offer comparable transmission services in return.

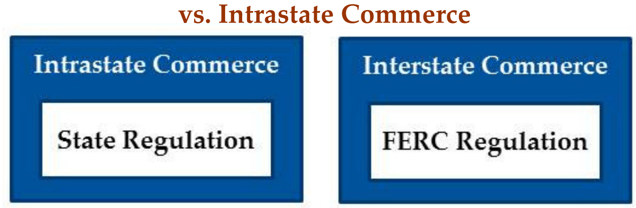
Available transfer capability (ATC) is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. ATC is a critical factor in assessing whether a specific competitive purchase or sale of energy using the provider's transmission system can be made at any given time. While determining whether a transmission path has available capacity might appear to be a straightforward examination of existing contracts, electricity on the interconnected transmission network flows according to physical laws, not contracts. Available path capacity is dependent on a number of factors, including the transmission lines in-service and where electricity is being generated and used. This makes the ATC calculations reliant on non-public information about ongoing system operations.

In response, FERC requires that transmission operations must be kept functionally separate for transmission owners that also own generation or distribution, and that any information passed out by the transmission owner must be publicly posted for all entities to see. Functional separation is designed to help prevent a transmission owner from providing preferential access to its transmission system. In Order No. 890 issued in 2007, FERC addressed and tightened a number of rules to address potential discrimination by transmission providers, including a requirement for consistent and transparent calculations of ATC, and a coordinated, open, and transparent planning process.

3.3 Regulatory Authority and the Overlap Between Wholesale and Retail Markets

The allocation of regulatory authority between the federal government and the states is distinguished by what constitutes *inter*state and *intra*state commerce (see Figure 11). State regulation extends to most areas of utility operations, rates, and end-user issues (intrastate commerce). Federal regulation generally relates to the wholesale side of the utility business, including interstate transmission and sales of electricity for resale.

Figure 11. Regulation of Interstate vs. Intrastate Commerce



Source: Navigant

Defining what is and what is not interstate commerce when considering an interconnected transmission system makes the allocation of regulatory authority between the federal government and the states complicated. In Order No. 888, FERC established a seven-factor test for identifying local distribution facilities that would not be classified as transmission. These factors include proximity to retail customers; lines that are generally radial in character; facilities in which power flows in, but rarely out; where power is not transported on to another market; and lower voltages.

Under Order No. 888, FERC regulates unbundled transmission transactions for FERC-jurisdictional public utilities. That is, if transmission service is charged to retail customers through a distinct rate separately from other services, FERC regulates the rate that is charged. In contrast, if transmission services charges to retail customers are bundled together in retail rates with other services, such as generation or distribution services, the states continue to regulate this bundled retail rate (see Chapter 6).

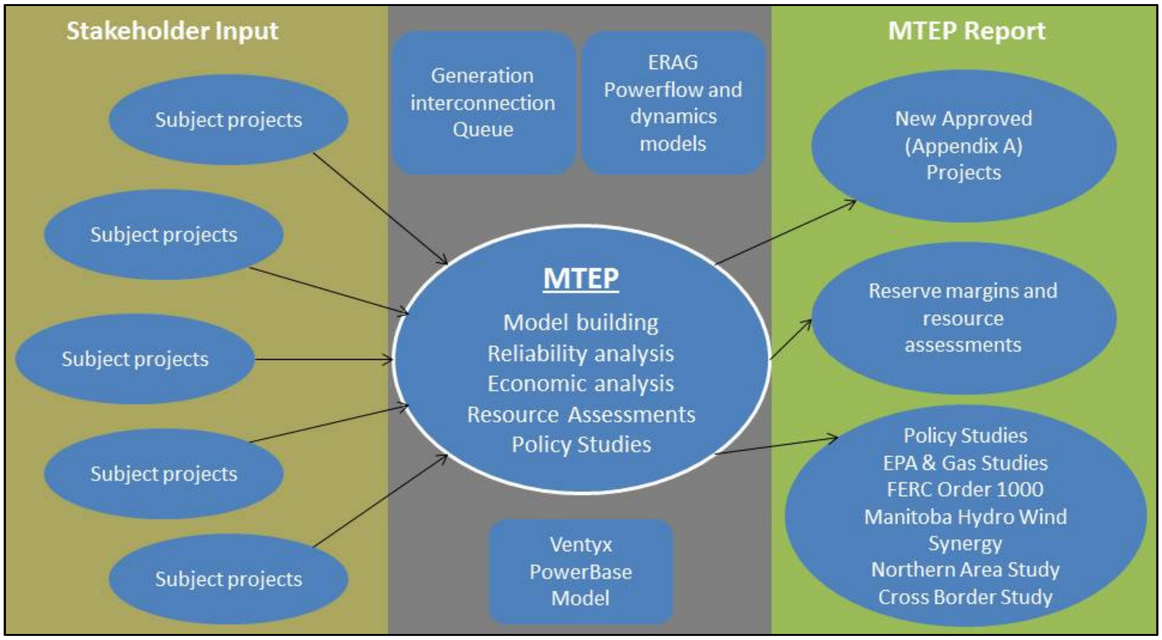
3.4 FERC Transmission Investment Incentives

The Energy Policy Act of 2005 added a new section, 219, to the Federal Power Act. FERC implemented section 219 by issuing Order No. 679, which established incentive-based rate treatments for new transmission capacity seen as particularly challenging to construct. These projects include those that apply new technologies, relieve chronic or severe grid congestion, or allow access to the wholesale market for constrained generation resources. The incentives have included higher returns on equity, rate recovery during the construction period, and other items. In the first six years of Order No. 679, FERC evaluated more than 85 incentive applications representing over $60 billion in transmission investment. These incentives have created some concerns with state regulators about the resulting rate impact of the incentives on retail customers, and ensuring that transmission is evaluated on an equal footing with generation, demand response and other options in resource planning. Over time, FERC has continued to clarify and adjust its transmission incentive policies.[18]

3.5 FERC and Broad Regional Transmission Planning

In the last decade, transmission planning has begun to encompass broader regions. In areas where RTOs have formed, transmission planning is coordinated through centralized processes administered by the RTO, including, for example, the annual Midcontinent Independent System Operator, Inc. (MISO) Transmission Expansion Plan (MTEP) and PJM's annual Regional Transmission Expansion Plan (RTEP). Transmission upgrades to mitigate identified reliability criteria violations, provide increased market efficiency, or facilitate public policy objectives such as Renewable Portfolio Standards (RPS) are examined in the RTO transmission plans for their feasibility, impact, and costs, culminating in one plan for the entire RTO footprint. The process steps used to create the MISO MTEP are illustrated in Figure 12. A more detailed discussion of transmission planning can be found in Chapter 5

Figure 12. The MISO MTEP Process



Source: MISO

FERC, in Order No. 890 issued in 2007 and Order No. 1000 issued in 2011, further advanced the regional transmission planning process. FERC Order No. 890 promoted increased, open, transparent, and coordinated transmission planning on local and regional levels. Under FERC Order No. 1000, transmission planning regions must have in place processes to coordinate planning with neighboring transmission planning regions to evaluate inter-regional solutions that may be more efficient or cost-effective than regional solutions. For projects selected in the regional processes that involve one or more regions pursuant to these inter-regional procedures, a cost allocation process between the regions must be in place. Other than the required coordination process, there is no requirement to produce a formal inter-regional transmission plan.

FERC Order No. 1000 also envisions transmission developers competing for the right to build certain types of new transmission facilities. For transmission projects subject to regional cost allocation that are not upgrades to existing facilities, FERC determined that incumbent utilities may not have a right of first refusal (ROFR) to construct these facilities.[19] The Order allows, but does not require, competitive bidding for potential solutions to an identified transmission need.

In Order No. 1000, FERC stated that the requirements of the Order do not affect state regulations regarding the construction of transmission facilities, including authority over siting or permitting. Implementation of Order 1000 is ongoing, and a number of important questions regarding the interrelationship between state authority over transmission siting, inclusion of new projects in a regional transmission plan, and the integrated resource planning of generation and transmission at the state level, will be addressed by federal and state policymakers.

For a description of key policies and orders related to the history and evolution of FERC, see Appendix G.

3.6 NERC Rules

FERC also oversees NERC as the ERO under the Federal Power Act. In turn, NERC delegates compliance monitoring and enforcement oversight to its eight regional entities (see Figure 5 in Chapter 2). The Reliability Standards are grouped into broad categories relating to the operation and planning of the NERC-defined Bulk Electric System (BES). The BES is generally comprised of transmission elements operated at a voltage of 100 kV or above, and does not include facilities used in the local distribution of electric energy. The BPS as defined in the Federal Power Act is distinct and more expansive than the BES as defined by NERC.[20]

Within the United States, other than Alaska and Hawaii, all users, owners, and operators of the BES must comply with the Reliability Standards. Currently, there are more than 100 Reliability Standards applicable and mandatory. For a description of key NERC policies and rules, as well as potential changes in these policies, see Appendix H.

3.7 Related DOE Policies

While the majority of siting authority currently lies with the states, there are instances where federal approvals are required. The Energy Policy Act of 2005 established a limited role for the U.S. Department of Energy (DOE) and FERC in transmission siting. The act directed DOE to conduct triannual congestion studies within the Eastern and Western interconnections and allowed DOE to designate “transmission corridors” in locations that had “national interest” implications. The act also granted FERC secondary authority over transmission siting in these corridors, which may not be exercised by FERC unless the state where the facility would be sited lacks the authority to issue the permit or the state has withheld approval of the permit for more than one year (see Chapter 4 for more detail). DOE also funds and promotes new transmission technologies and issues permits for international cross-border transmission lines. For a further description of key DOE policies, see Appendix I.

4 Process for Building a Transmission Line

Historically, transmission lines were planned by local utilities to serve local needs. The lines seldom crossed state borders as they were designed to deliver electricity from power plants to load centers. Over time, transmission lines were constructed to interconnect with neighboring utility systems to increase reliability and for access to lower cost electricity.

Today, with the emergence of regional transmission planning, "Planning Coordinators" integrate and evaluate transmission plans within their NERC-defined regions. New transmission lines can be developed by the local utility or an independent "merchant" transmission developer. While the process for building a transmission line has evolved, the basic steps are familiar:

1. A need for a new transmission line is identified in the transmission planning process by conducting technical and economic studies.
2. The transmission developer does the following:
    a. Performs a study of possible siting routes for the identified transmission line
    b. Seeks permission from state and federal agencies to build the line
    c. Obtains financing for the line and builds the line

Transmission planning is the process of identifying areas of the current transmission grid that are in need of expansion to maintain reliability and to accommodate new generation and/or growing load. Planning is the big picture process of assessing the robust nature and reliability of the grid, and is discussed in greater detail in Chapter 5. In contrast, transmission siting is the process of determining specifically where new transmission projects will be located. It includes considerations such as investigating environmental impacts, obtaining rights-of-way, and complying with local zoning ordinances. Siting becomes a particularly complex process when a line crosses through two or more states, across federal lands, protected ecosystems or in scenic or historic areas.

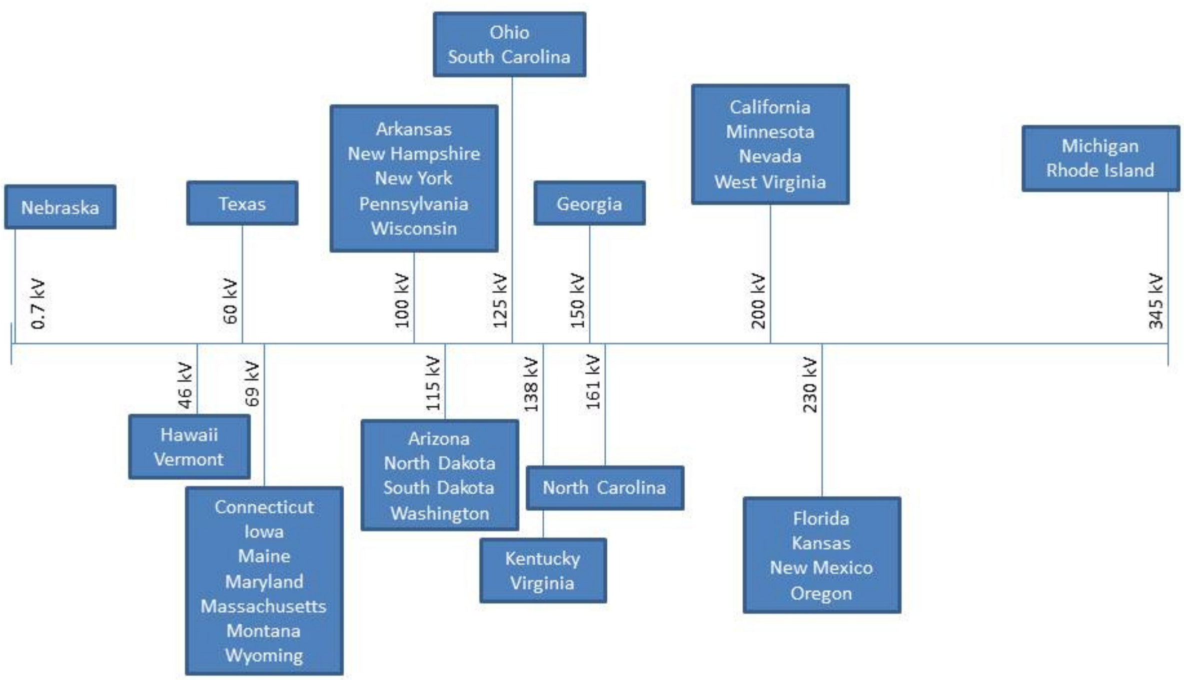
Building a transmission line requires the involvement of a number of parties, including state and federal authorities, Planning Coordinators, utilities, merchant transmission developers, and affected stakeholders. The role played by each of the parties in this process is discussed in turn below.

4.1 Role of State Authorities

The primary regulatory responsibility for the siting of transmission lines resides with the individual states. Each state has its own process for granting permission to build power lines. State siting approval allows the transmission developer to build a transmission line and if necessary to use the power of eminent domain to do so. Eminent domain is the power to take private property for public use following the payment of just compensation to the owner of the property. New transmission lines are rarely popular with nearby residents, and alternative routes are sometimes proposed that may cover more distance or cover more difficult terrain. Public utility commissions or dedicated state siting authorities must consider a number of factors, including the overall need for a new transmission line, environmental impacts, property rights, and cost.

A mix of state and local government agencies wield jurisdiction over the siting approval process in each state, and there is no universal approach to the way states approve the siting of new transmission lines. For example, a number of states consolidate siting approval under a single agency, such as a PUC. Some states, such as Connecticut and Ohio, have a dedicated energy siting authority that approves major generation and transmission facilities. In a few states, utilities are required only to give notice of intent to build a transmission line; after a specified period, if no challenges are raised, the utility may proceed with acquisition of any needed rights-of-way and construction. Other states use a voltage or size threshold such as 100 or 200 kV for siting approvals to be required, as illustrated in Figure 13. Most states require that hearings be held in the affected counties or towns. In certain states, there is a statute with a specific period of time to review and rule on the siting application.

Figure 13. Summary by State of Line Voltage Thresholds for Requiring Permitting



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

Although state siting and permitting processes vary, there are some commonalities. Transmission developers submit an application to the state that includes an analysis of the need for the new line (e.g., to ensure grid reliability or connect new generation), cost estimates, and at least one proposed route. The state approval process often begins with granting overall approval for the line and any necessary environmental permits. The commission or siting authority in the state holds hearings, usually in one or more of the impacted communities, to determine the exact route of the line, addresses landowner and community concerns, and discusses alternatives to the transmission developer's proposed route.

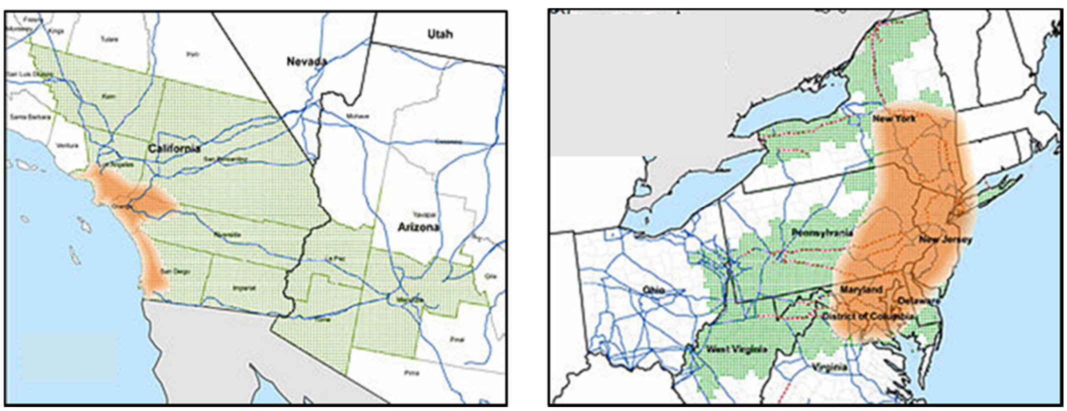
Most states combine their need and siting approvals into one decision from the PUC or siting body. For lines that cross private land, the state's siting body often has the power to grant eminent domain authority to the transmission developer, a power often assigned with the siting certificate.[21]

See Appendix B for additional information on the siting approval processes in the various states.

4.2 *Role of Federal Authorities*

National Corridors. Under the Energy Policy Act of 2005, which added section 216 to the FPA, FERC has the authority to consider a transmission line application and issue a permit to construct electric transmission facilities located in a National Interest Electric Transmission Corridor (National Corridor). DOE has identified two National Corridors, one in the Mid-Atlantic area and one covering Southern California and part of western Arizona (the green and orange shaded areas in Figure 14). In 2011, the U.S. Court of Appeals for the Ninth Circuit vacated DOE's National Corridor designations and remanded the cases to the DOE for further proceedings.[22]

Figure 14. Southwest and Mid-Atlantic National Corridors



Source: DOE

For a proposed National Corridor project, FERC has permitting authority (sometimes referred to as "FERC backstop siting authority") if a state withholds siting approval for more than one year, does not have the authority to site transmission facilities, or cannot consider interstate benefits. The backstop authority cannot be exercised if a state commission denies an application to site a transmission facility within one year after the date the application is submitted, even though the facility would be located within a national interest transmission corridor.[23] If the proposed facilities are located in a state that has authority to approve the siting of the facilities and consider its interstate benefits, the project developer must file an application with that state. The developer must be engaged in the state process for at least one year prior to initiating a filing process with FERC.

As part of the process, FERC staff conducts an environmental analysis to identify the potential environmental impacts of the proposed project and reasonable alternatives as required by the National Environmental Policy Act (NEPA). Under NEPA, FERC is required to analyze all reasonable alternatives, even if the alternative does not fall under FERC's jurisdiction. Thus, FERC can look at a wide range of non-transmission alternatives (e.g., local generation, DSM, and energy storage), in addition to transmission line route alternatives, as part of the environmental review process. In order to issue a permit, FERC must find that the proposed project does the following:

- Is located in a National Corridor designated by DOE
- Is in the public interest
- Will significantly reduce transmission congestion and protect and benefit consumers
- Is consistent with sound national energy policy and will enhance energy independence

Presidential Permits. DOE is responsible for reviewing presidential permit applications and determining whether to grant a permit for electric transmission facilities that cross the U.S. international border. A presidential permit authorizes the applicant to construct, operate, maintain, and connect the U.S. portion of the project at the international border. Applications for presidential permits are evaluated based on the impacts that a project could have on the environment pursuant to NEPA and the operating reliability of the U.S. electric system.

Federal Land. For new transmission lines that cross federal land, additional federal approvals are required. DOE coordinates a Rapid Response Team for Transmission comprised of nine federal agencies, including FERC, the U.S. Environmental Protection Agency (EPA), and the Departments of Interior, Agriculture, Commerce, and Defense, to expedite the federal approvals needed for the siting of transmission.

4.3 Role of Planning Coordinators

Historically, utility control areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional control area balanced its load with its generation, implemented interchange schedules with other control areas, and ensured transmission reliability. Balancing load with generation required that control area generation plus net interchange energy (energy imported from neighboring utilities minus energy exported) matched at all times the control area demand for electricity. In general, transmission planners for each control area ensured that: (1) reliability would be maintained during contingency conditions, and (2) no cascading outages (outages that cannot be restrained from spreading to other areas) would occur during credible multiple contingency conditions.

As utilities began to provide transmission service to other entities, the control area also began to perform the function of transmission service provider through tariffs or other arrangements. Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by control areas began to change to reflect the newly emerging industry structure. In particular, the developing power markets were requiring regional transmission reliability assessment and dispatch solutions beyond the functions that utility control areas had traditionally performed.[24]

In response, NERC formally created the role of Planning Coordinators (also known as Planning Authorities) that include RTOs, government power authorities, and electric utilities who have taken on the responsibility of coordinating, facilitating, integrating, and evaluating transmission facilities. Today, there are approximately 80 NERC Planning Coordinators, 10 of which are ISOs/RTOs.[25] Each Planning Coordinator is responsible for assessing the reliability of its assigned region, and coordinating planning with adjoining regions.

Planning Coordinators evaluate, develop, document, and report on expansion plans for each individual transmission planning area within the Planning Coordinator regional boundaries. The Planning Coordinator must also assess whether the integrated transmission plan meets reliability needs, and, if not, provide alternative solutions.

4.4 Role of Utilities

Most transmission lines continue to be developed and owned by utilities operating under cost-of-service rates. The utility is responsible for seeking permission to build the new line from the appropriate state and local authorities, and for providing a demonstration of need and the appropriateness of the proposed route. The demonstration of need for the line often comes through the analysis and recommendations included in the regional transmission plans in which the utility operates and/or through an integrated resource planning (IRP) process, which simultaneously considers all resource options available to the vertically integrated utility (see Chapter 5). Once approved, the utility must raise the funds to construct the line, generally through a combination of internal cash flow and the issuance of bonds, and engage and oversee contractors to design and build the line.

The utility generally will act as the transmission planner for its local area within a Planning Coordinator's regional boundaries. The utility will work closely with the Planning Coordinator to integrate its local transmission planning process with the regional process. Transcos that own the transmission system in some service territories under FERC-regulated cost-of-service ratemaking follow the same process as vertically integrated utilities when seeking siting approval for a new line. FERC has defined a Transco as a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.[26]

4.5 Role of Merchant Transmission Developers

Merchant transmission providers are private companies that finance and own transmission facilities independent of generation developers or customer-serving utilities. Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities are recovered through negotiated rates instead of the cost-based rates used by utilities.[27] Like utility projects, merchant transmission projects must obtain state (and federal) siting approval. Unlike utility projects, merchant transmission providers must recoup their costs through access charges paid by generators and/or load-serving utilities. Given the need to control access to the line to those that are paying for the line, merchant transmission projects have been largely comprised of long-distance or submarine HVDC lines since their inception in the last decade.

Merchant transmission developers face the same state siting approval process as utilities, although the regulatory agencies involved and filing requirements may differ somewhat. For example, Kentucky has a separate state siting board for merchant projects. Given the long-distance and/or undersea nature of many merchant transmission projects, federal siting approvals are often required as well.

4.6 Impact on Roles from FERC Order No. 1000

As discussed in Chapter 3, under FERC Order No. 1000, the potential solutions for meeting regional transmission needs may become subject to competitive bidding by utilities and merchant transmission developers, although such bidding is not required. In response, the ownership profile of the transmission system in any particular region may become increasingly comprised of multiple parties.

FERC Order No. 1000 defined several terms to help better capture these multiple roles. FERC defined an "incumbent transmission developer/providers" as an entity that develops a transmission project within its own retail distribution service territory or footprint.[28] The use of the phrase "or footprint" is meant to convey that an entity can be an incumbent transmission provider/developer without having a retail distribution service territory.[29] As such, a Transco (see definition in Section 4.4) that owns the transmission system in a specific service territory would be the incumbent transmission provider in that service territory.

FERC defined a "nonincumbent transmission developer" as an entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint.[30] Merchant transmission developers, which recover costs through negotiated rates instead of cost-based rates, are a subset of nonincumbent transmission developers.[31] Nonincumbent transmission developers also include developers who recover costs through FERC-approved cost-based rates.

5 Transmission Planning

Transmission planning is the process of identifying areas of the current transmission grid, or Bulk Electric System, that are in need of expansion to cost-effectively maintain reliability and accommodate new generation and/or growing load. The BES is generally comprised of transmission elements operated at 100 kV or above, and does not include the distribution system.[32]

As shown in Figure 15, there are two basic planning elements for maintaining the reliability of the Bulk Electric System—transmission security and resource adequacy. Transmission security ensures reliable system operation in the face of contingencies such as the loss of generation or transmission. Resource adequacy ensures that there will be adequate generation or demand-side resources to meet the aggregate electric energy demand requirements of customers at all times.[33] Each planning element is discussed in turn below.

Figure 15. Planning Elements for Maintaining System Reliability

Transmission Security: The transmission system can continue to operate normally even when there is a generating plant or transmission line outage.

Resource Adequacy: Sufficient generating and demand-side resources are available to meet the electric demand of end-use customers at all times.

Source: Navigant

Transmission Security. The transmission system is expected to maintain its integrity and continue to operate without a major disruption even when a component fails. The security of the transmission system is primarily achieved by ensuring that the outage of any single system component will not cause a cascading outage (an outage that cannot be restrained from spreading to other areas). A system that is resistant to the outage of any one component is said to be "N-1" secure.[34] Additionally, the system should remain within the applicable emergency thermal ratings and voltage limits (see Chapter 7) after an additional single contingency (N-1-1) condition.[35] N-1 security is fundamental to system operation and achieving this level of security is generally accepted to be required, regardless of cost. However, once the goal is to make the system N-2 or N-3 secure (resistant to the outage of any 2 or 3 components), cost and other similar considerations enter the picture. Operators have traditionally handled the threat of multiple contingencies adaptively. For example, operators may dispatch more generation closer to loads when storms approach and the likelihood of an outage increases.[36]

Resource Adequacy is defined as the ability of the electric system to supply the aggregate electric demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages on the system. Underlying most resource adequacy standards (for example, in setting a target margin) are criteria set by the NERC Regional Entities, typically a "1 day in 10 years Loss of Load Expectation (LOLE)".[37] LOLE means the expected number of days in the year when the peak demand exceeds the available generating and demand-side resources. The utility industry, for decades, has used a LOLE of one day in ten years as the primary means for setting target reserve margins and capacity requirements in resource adequacy analyses. Fundamentally, a LOLE reliability standard involves evaluating the trade-off between the cost to customers of installing and maintaining additional back-up resources in comparison to the cost to customers of incurring additional electricity outages.[38]

5.1 Interrelated Nature of Transmission Planning

Transmission security has historically been the primary focus of transmission planning, while resource adequacy has historically been the primary focus of resource planning—the planning of adequate supplies of generation and demand-side resources. For example, the analysis supporting a recommendation by a vertically integrated utility to build a new gas-fired generating plant to meet a forecasted increase in the demand for electricity by retail customers on the utility's system would be an example of traditional resource planning. The additional transmission facilities that might be needed to keep the transmission system stable and secure with the new gas-fired plant in service would be an example of traditional transmission planning. For this traditional type of transmission planning, the planning horizon has been typically shorter than that used for resource planning.

Over time, transmission has become planned more formally in an integrated manner with resource planning, as the least-cost, most reliable solution for meeting electricity demand can include generation, transmission, and/or demand-side resources. For example, building generation within a congested transmission area or "load pocket" may be less expensive than building new transmission facilities to mitigate the congestion. Building long-distance transmission lines to gather energy from distant renewable resources must consider both the cost of the transmission line and the cost and efficiency of the distant renewable resources in comparison to the cost and efficiency of nearby renewable resources. Building transmission to support a gas-fired power plant at a distant location may be less economical than building a gas pipeline to allow the gas-fired power plant to be located closer to the load.

In non-RTO regions, the interrelationship between generation, transmission, and demand-side resources is generally handled through an IRP process, which simultaneously considers all options available to the vertically integrated utility. In an RTO region, with multiple parties owning generation, transmission, and serving load, the RTO planning process assesses the impacts of forecasted firm loads, existing generation and transmission assets, and anticipated new generation and transmission facilities to integrate transmission options with generation and demand response projects. See, for example, the MISO MTEP process described in Section 3.5, Figure 12.

5.2 Reliability and Efficiency in Transmission Planning

The objective of transmission planning is to evaluate transmission investment options to reliably and economically deliver power from generation sources to anticipated loads. The relationship of these two key drivers of transmission planning, reliability and economic efficiency, in planning for the transmission security and resource adequacy of the Bulk Electric System, is illustrated in Table 1, and discussed in turn below.

Table 1. Planning for the Bulk Electric System

	Transmission Planning	Resource Planning
Reliability	*Transmission Security:* Contingencies Will Not Cause Cascading Outages	*Resource Adequacy:* Enough Generation and Demand-side Resources to Meet Customer Demand
Economic Efficiency	*Integrated Planning* of Transmission with Generation and Demand-side Resource Alternatives to Minimize Costs	

Source: Navigant

Reliability in Transmission Planning. Reliability analyses are conducted to help ensure the security of the transmission system in serving all existing and projected firm transmission use, including existing and projected native load growth as well as firm transmission service. These studies typically extend 10 to 15 years into the future and variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability (the ability of the system to remain stable if a disturbance such as a generating unit outage occurs), thermal line loadings, and voltage limits (see Chapter 7). Regional and local reliability criteria may also be applicable in certain areas. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact, and comparative costs, culminating in a recommended plan.

Economic Efficiency in Transmission Planning. Transmission planning for economic efficiency focuses on building new transmission lines designed primarily to achieve the economic delivery of power rather than ensuring reliability. Transmission facilities that economically relieve historical or projected transmission congestion and allow lower-cost power to flow to consumers are often candidates. In evaluating a proposed project's economic benefits, the reduction in the costs of supplying electricity and, in an RTO, the prices paid by load-serving entities are examined through production cost modeling across all hours of the year. In an RTO, a proposed transmission solution's economic savings typically must exceed its projected costs by at least 25 percent to be recommended.[39] In vertically integrated markets, integrated resource planning assesses resource options considering both the cost of generation and the transmission expansion needed to access the resource and dispatch it economically.

Reliability projects are proposed because reliability standards are projected to be violated. Economic projects are proposed not because reliability standards are violated, but because there is an economic benefit. In some regions, more comprehensive "multi-benefit" evaluation approaches are being developed to evaluate proposed transmission projects that incorporate standard reliability and economic efficiency measures, but also consider such items as avoided energy and capacity costs due to reduced physical losses and the value provided in limiting costs during times of extreme events and system contingencies.

5.3 *Risk Analysis in Transmission Planning*

Traditional transmission planning methods are typically deterministic; that is, outcomes are precisely determined through known relationships among states and events, without any consideration of random variation or uncertainty regarding key parameters. A power system model representing the transmission and generation system is developed. The model has the ability to show how the system responds to things such as increases in load, addition or removal of generation sources, and addition or removal of transmission elements. The model indicates when parts of the system are stressed beyond their safe operating limits. Certain inputs to the model, such as the initial conditions assumed for the period to be tested, are developed by transmission planners based on power system conditions and their experience.

The risk created by uncertainty is typically assessed with scenarios, such as an evaluation of a high and low demand case. Under a deterministic approach, contingencies are considered, but not the probability of occurrence. For example, the N-1 criterion requires that the system be able to tolerate the outage of any one component. Even if an outage or contingency is highly unlikely, the criterion is still generally applied because system failure when a component is lost is unacceptable.[40]

While deterministic methods serve the industry relatively well, fundamental changes in the use of transmission have led to an increased focus on evaluating risk in transmission planning. For example, the Western Electricity Coordinating Council provides an option to member systems to categorize their N-1, N-2, and N-3 contingencies based on the historical frequency of outages of the transmission facilities. These fundamental changes in the use of transmission include the increasing cost of transmission facilities, uncertainties concerning the location of new resources and retirement of older generators, increasingly stringent environmental regulations requiring changes to the resource mix, the need to integrate large amounts of variable energy resources, more dynamic electric loads, and the lead times to construct major facilities.

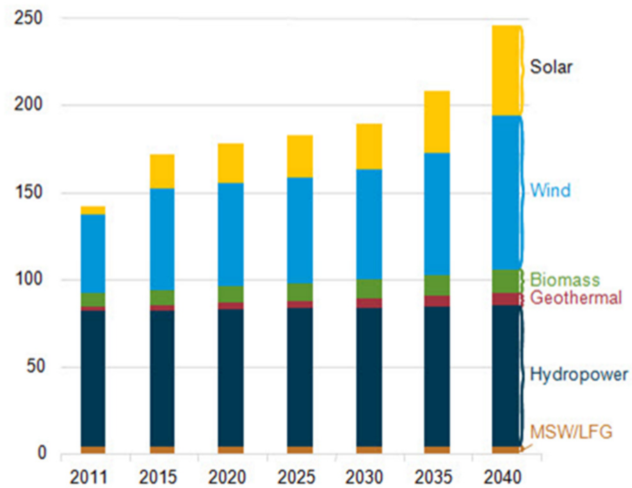
These fundamental changes have together led to significantly more complex and less predictable use of transmission facilities, thereby increasing risk. Risk-based approaches include information on the likelihood of an event occurring along with the magnitude of the event. Industry research is underway to better understand and assess risk in performing transmission planning, and risk analysis is likely to become an increasingly institutionalized part of transmission planning in the future.

5.4 Transmission Planning and Intermittent Resources

As public policies and regulations on greenhouse gas emissions and Renewable Portfolio Standards (RPS) are developed throughout North America, and as the economics of renewable resources continue to improve, the addition of renewable generation into the bulk power system is expected to grow considerably. As shown in Figure 16, the U.S. Energy Information Administration (EIA) projects that solar and wind capacity will increase by 46 and 42 gigawatts (GW), respectively, by 2040. This increasing commitment to renewable resources offers benefits such as new generation resources, fuel diversification, and greenhouse gas reductions. However, renewable commitments present significant new challenges to maintaining bulk power system reliability, as the expected significant increase in variable generation additions likely will increase the amount of uncertainty faced by a system operator.[41]

Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the bulk power system will require significant changes to traditional methods used for system planning and operation. To improve system reliability, the industry has already begun development of new planning methods and techniques that include the characteristics of variable generation assets. For example, storage technologies, if economical and properly planned and implemented, can provide the flexibility to accommodate large amounts of variable resources as an alternative to the construction of more conventional flexible generation resources or transmission.[42]

Figure 16. EIA Projection of Renewable Electric Generation Capacity by Energy Source (gigawatts)



Source: EIA Annual Energy Outlook

Large-scale integration of variable generation likely will increase the short-term variability of the supply of generation and the uncertainty of future system conditions. To ensure reliability, transmission facilities will be expected to interconnect variable energy resources, accommodate the variable generation output across a broad geographical region and resource portfolio, and allow the delivery when needed of back-up generation to equalize supply and demand.

At low variable generation penetration levels, traditional approaches toward sequential expansion of the transmission network and managing wind variability in Balancing Authorities may be satisfactory. However, at higher penetration levels, a regional and multi-objective perspective for transmission planning, including the identification of concentrated variable generation zones, may be needed.[43]

In particular, larger balancing areas or participation in wider-area balancing management may be needed to enable high levels of variable resources, thereby allowing impacts on resources facing unfavorable weather in one area to be mitigated by resources in the broader region facing normal and/or favorable weather conditions. New transmission planning models will be needed to optimize new technologies, such as storage, demand response, and the incorporation of flexible resources.

5.5 Current and Future Transmission Planning Models

Commonly used transmission models today include, among others, Power System Simulator for Engineering (PSS/E) and Positive Sequence Load Flow (PSLF) transmission planning software licensed from Siemens PTI and GE, respectively. These and other similar programs, e.g., PowerWorld, simulate, analyze, and optimize power system performance. Transmission planners use these tools to satisfy a variety of NERC and approved regional compliance requirements. Using these models, transmission planners can analyze transfer limits and simulate the transfer of large blocks of power across the transmission grid and the import or export of power to neighboring systems.

Although some of the existing transmission planning software allow probabilistic analysis, future transmission planning tools are likely to more fully incorporate probabilistic risk analysis, including capturing the impact of uncertainty associated with generating unit and transmission system performance, weather-related demand volatility, resource intermittency, economic growth, fuel prices, and public policies. Full co-optimization of resource (generation and demand response) and transmission planning within one planning model is a longer-term objective, likely requiring advancements in simulation software, credible input data for probabilities, and additional research.

A common understanding among grid operators/planners, as well as confidence in simulation tools results, is predicated on an accurate and shared database regarding key parameters and capabilities of existing and planned facilities. Further development and refinement of a shared data set with mechanisms regarding timely updates and accountability for accuracy from owners/operators will help improve the efficiency and effectiveness of grid operations and long-range planning.

6 Paying for Transmission

Transmission is ultimately paid for through the rates charged to end-use customers. For retail customers, transmission typically represents only about 10 percent of their total bill.[44] The process by which the cost of building and maintaining transmission facilities is recovered in rates is made more complex by the interconnected nature of the transmission system and the overlapping transmission rate responsibilities of federal and state authorities. Whether and how much customers located in one area should pay for the cost of interconnected transmission facilities located in another area is often subject to contention. Transmission ratemaking is further complicated by the fact that electricity travels through the transmission system according to physical laws and not on a defined "contract path" from one point directly to another.

Summarized below is a basic overview of how rates are set to recover transmission costs, followed by a review of how regional transmission project costs are allocated to end-use customers.

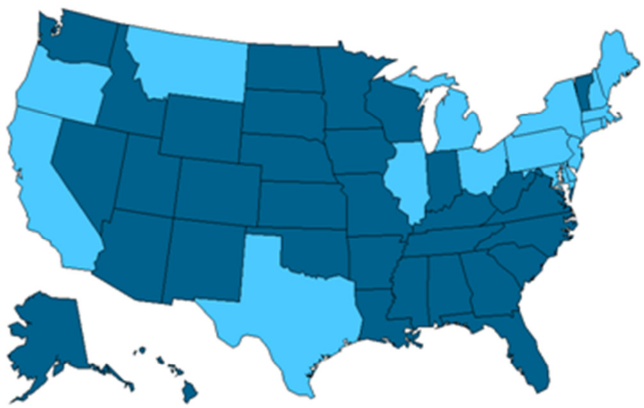
6.1 Rate Recovery

6.1.1 Retail Rates for Transmission

For vertically integrated utilities charging bundled rates (generation, transmission, and distribution costs recovered together as a bundled rate) to their retail customers, the bundled retail rates are set by the state public utility commission, as FERC has not claimed jurisdiction over the pricing of transmission within bundled retail rates.[45] Typically, along with the utility's retail customers, wholesale transmission customers also will use the utility's transmission system. A retail allocation factor will be developed (e.g., share of peak demand on the transmission system) to allocate a share of the utility's transmission assets and operating costs to retail customers in deriving bundled retail rates.

For utilities charging an unbundled transmission rate directly to retail customers, the retail rate will fully recover the charges to retail customers incurred under the utility's FERC-approved Open Access Transmission Tariff. Unbundled retail rates are typically instituted in states with retail open access, whereby retail customers are permitted to shop for electricity from retail energy suppliers other than the incumbent utility and have the incumbent utility or local distribution company deliver the electricity (see Figure 17).[46] Depending on the state, the utility's FERC-approved OATT charges may be collected from retail customers by the local utility or the alternative retail energy supplier.

Figure 17. Electricity Retail Choice States



Source: EIA, data as of 2010

Differences between unbundled retail rates for transmission and the transmission-related share of bundled retail rates will arise from a number of items, including potential differences between FERC and the state public utility commission with respect to capital structure, return on equity, and the treatment of Construction Work in Progress. Rate incentives granted by FERC under FERC Order No. 679 can also contribute to these differences (see Section 3.4).

6.1.2 FERC OATT Wholesale Rates for Transmission

A transmission-owning utility will have wholesale customers, such as municipalities, power marketers, and neighboring utilities, who pay to use the utility's transmission system using FERC-approved, cost-based rates under the utility's OATT. In the OATT, the annual transmission revenue requirement is usually divided by the peak demand on the transmission system, often "1CP" (highest single "coincident peak" in the year in megawatts [MW]), to determine rates given that a primary driver of transmission costs is reliably meeting projected peak demand.

FERC OATT rates are updated periodically, often annually, if the utility is using "formula rates". If so, the rates are updated by formula using data filed in the utility's FERC Form 1. Alternatively, if "stated rates" are being used, the current OATT rates remain in effect until a new rate filing is made and approved at FERC. There are three main types of transmission service offered under a utility's OATT:

- Network Integration Transmission Service (NITS) allows a transmission customer to integrate, plan, economically dispatch, and regulate its generating resources to serve its customers in a manner comparable to the way the transmission provider uses its transmission system to serve its own retail or "native load" customers. NITS is often used by municipalities and other transmission-dependent utilities and usually involves delivery to the network customer's distribution system at multiple delivery points.

- Firm Point-to-Point (PTP) allows delivery from one specific point of receipt (the source) to another point of delivery (the sink) on the transmission system. One use, among many, of this service is to deliver a share of the energy from a jointly owned generating plant located in a neighboring balancing area to the balancing area where the plant owner's retail customers are located. Firm transmission service is intended to be available at all times to the maximum extent practicable. Firm PTP reservations are available on a daily, weekly, monthly, annual or multi-year basis. For a request for new firm PTP transmission service to be approved by the transmission provider, transfer capability must be available to provide the service. If not available, a system impact study can be requested to identify the transmission upgrades needed to be completed for the service to be approved.

- Non-Firm Point-to-Point is reserved and scheduled on an as-available basis for periods ranging from one hour to one month and is subject to curtailment or interruption prior to NITS and Firm PTP reservations. This service is commonly used by, among others, power marketers or neighboring utilities involved in short-term economic purchases and sales of energy. Non-firm reservations are available for periods from one hour to one month. Non-firm transmission revenues are credited back to network and firm point-to-point customers in setting transmission rates.

These transmission service types are summarized in Table 2.

Table 2. Main Types of Transmission Service

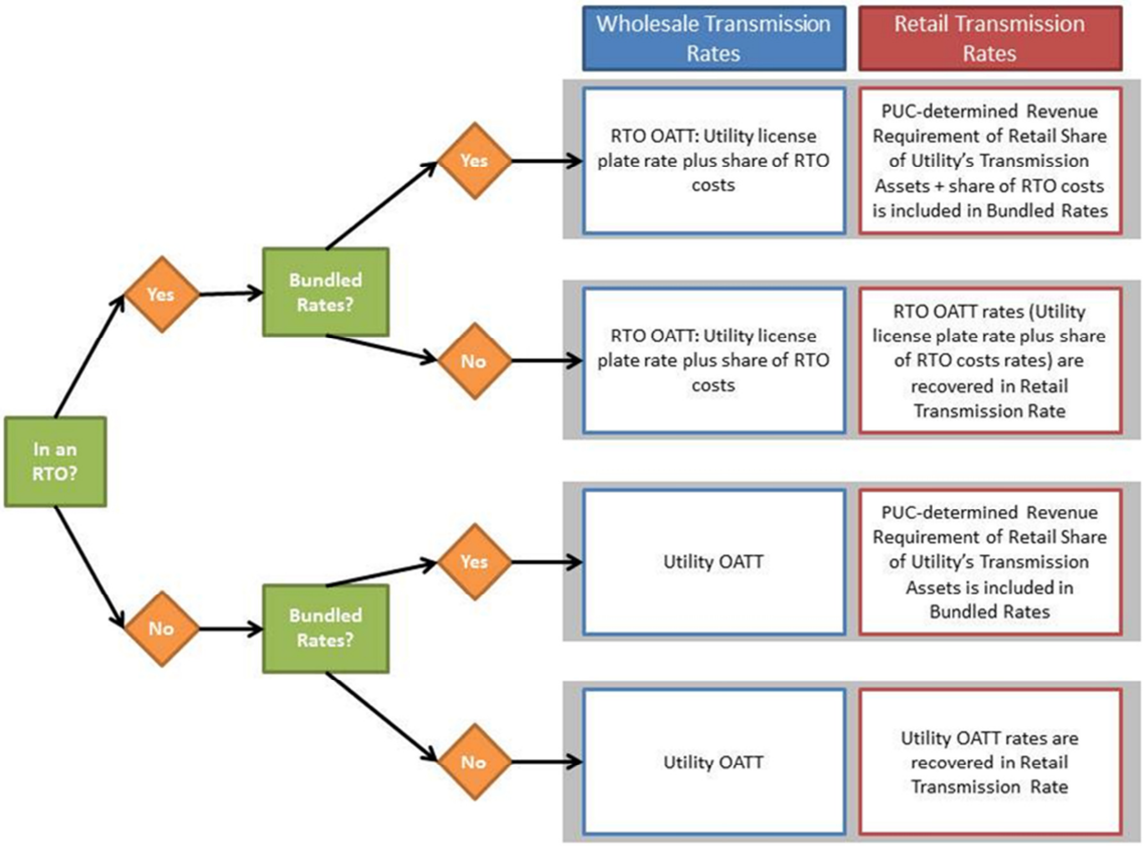
	Network Integration	Firm Point to Point	Non-Firm Point to Point
Often Used By:	Municipalities and other Transmission-Dependent Utilities	Many entities, including owners and purchasers of external capacity	Many entities, including power marketers and neighboring utilities
Defined Path?	No, allows use of provider's entire transmission system, which is planned to incorporate the customer's resources and demand.	Source to Sink	Source to Sink, scheduled on an as-available basis
How Firm?	Highest	Highest	Subject to curtailment prior to Network and Firm PTP

Source: Navigant

6.1.3 The Path from Transmission Line Costs to Rates

The process for recovery of transmission costs incurred by a FERC-jurisdictional utility in rates depends on whether its retail rates are bundled or unbundled, and whether the utility is part of an RTO. A basic overview is shown in Figure 18, and further illustrative examples are discussed below.

Figure 18. Simplified Overview of How Utility Transmission Costs Are Recovered in Rates



Source: Navigant

A utility not in an RTO builds a new transmission line in the utility's transmission system. In the utility's next OATT filing, the capital and operating costs of the line are included in the derivation of the FERC OATT revenue requirement and the corresponding rates for wholesale transmission customers.[47] Bundled retail rates are generally in effect for utilities not in an RTO, and the utility will include the retail share of the capital and operating costs of the new line in its next base rate filing at the state public utility commission. If unbundled retail transmission rates are used, the utility's OATT rates would be recovered from the utility's retail customers through the unbundled rate and collected either by the utility or an alternative retail energy supplier.

A utility in an RTO builds a new transmission line in the utility's transmission system. The capital and operating costs of the line are included in the derivation of the utility's FERC transmission revenue requirement, often through an annual formula rate update. The utility's transmission revenue requirement and peak demand are typically used to create a "license plate" transmission rate for the utility's system in the RTO's OATT. (A postage stamp transmission rate may alternatively be assessed; see next section.) A license plate rate means that the rate paid is based on the delivery point (sink). All RTO wholesale transmission customers pay the RTO OATT rates designed to recover costs incurred at the RTO level, such as losses, ancillary services, and RTO administrative costs. A utility with bundled retail rates will include the retail share of the capital and operating costs of the new line in its next base rate filing at the public utility commission. If unbundled retail transmission rates are used, the RTO OATT rates would be recovered from the utility's retail customers through the unbundled rate and collected either by the utility or an alternative retail energy supplier.

A Transco builds a new transmission line in the Transco's "incumbent" transmission system. The Transco recovers these costs through its FERC-approved OATT transmission rates assessed to the local distribution utility or to alternative retail energy suppliers. If the Transco's transmission system is part of an RTO, the OATT charges are assessed through the RTO's OATT.

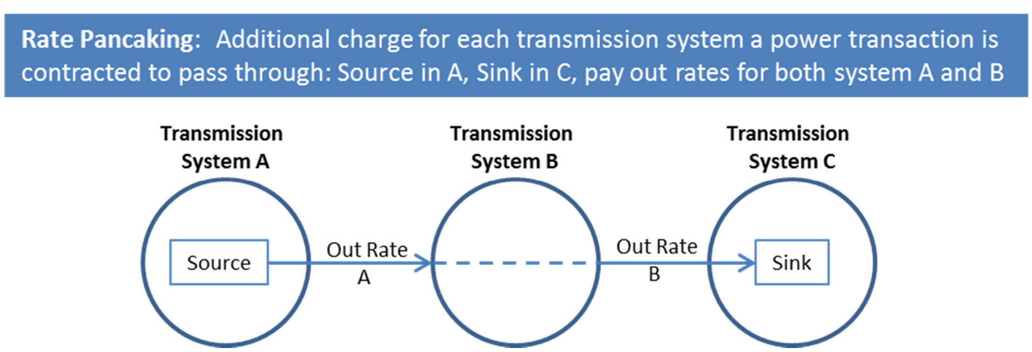
A utility contracts capacity on a merchant transmission line. The merchant line will be paid by the utility per the negotiated rates in the contract, subject to FERC approval, and the costs will be recovered in the utility's retail rates. Only those parties that enter into a contract with the merchant line would pay for the line.

6.2 Pancaked, License Plate, and Postage Stamp Rates

FERC policy in recent years has actively discouraged the pancaking of transmission rates, and encouraged a single transmission rate over broad regions.

Rate pancaking occurs when a transmission customer is charged separate access charges for each utility service territory crossed by the transmission customer's power transaction (see Figure 19). Pancaking discourages long-distance transmission transactions regardless of the value of the transaction to consumers. In response, FERC has required RTOs to eliminate rate pancaking within its borders. Within RTOs, a single transmission charge is assessed for transactions within the RTO (based on the delivery point or sink). For transactions that pass through or out of the RTO, a single regional through or out rate (RTOR) is usually assessed. The RTOR is sometimes waived between RTOs, for example, between MISO and PJM.

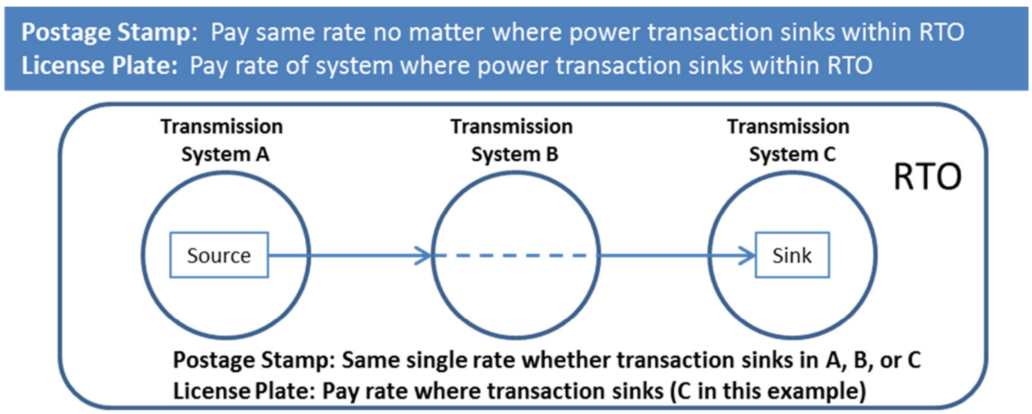
Figure 19. Rate Pancaking Example



Source: Navigant

With postage stamp rates, all transmission customers in the RTO pay a uniform rate regardless of where a transaction sources or sinks within the RTO, just as a single postage stamp is used for first-class letters whether sent to a local or distant address. FERC encourages RTOs to establish one uniform access charge for all transmission customers. However, FERC has recognized that this approach may result in cost shifting (i.e., lower-cost transmission providers would see a rate increase, and higher cost providers a rate decrease). As such, FERC allows license plate rates within the RTO in which the applicable rate is based on the revenue requirement of the utility transmission system in which the power is delivered (sinks). The name is derived from the fact that a car with a license plate from a single state has access to all of the nation's roads (see Figure 20). Concerns regarding the cost shifting inherent in postage stamp rates are similarly a concern with respect to transmission cost allocation, as discussed below.

Figure 20. RTO Postage Stamp and License Plate Rate Example



Source: Navigant

6.3 *Regional Transmission Cost Allocation*

RTOs have developed FERC-approved cost-allocation methods for allocating the costs of regional transmission projects to individual transmission systems or "zones" within the RTO. These costs are often recovered from transmission customers under a separate RTO OATT schedule, such as PJM's Schedule 12, and remitted to the transmission developer. Under FERC Order No. 1000, regional cost sharing will likely be in place for all transmission-owning utilities, whether in an RTO or not.

FERC has noted that issues of cost allocation are some of the most contentious and difficult issues that face the industry and FERC. They are contentious because the transmission costs to be allocated are usually precise, concrete, and quantifiable whereas the benefits that arise from the improved transmission grid are generally difficult to quantify with precision, involving a greater need for prediction about the future use and operation of electric systems.[48] As a general matter, FERC has required that regional cost allocation methods must meet certain principles, including that allocated costs be "roughly commensurate" with estimated benefits, and that those who do not benefit from transmission do not have to pay for it. There are a number of cost allocation methods in place within RTOs today, and they generally fall into the following four categories:

Broad Socialization. The costs of higher voltage transmission lines within an RTO are often allocated equally (i.e., socialized) to all load in the RTO based on the energy (megawatt-hours) withdrawn from the transmission system or on the peak demand (MW) on the transmission system. Support for socialization rests on broadly based benefits provided by these higher voltage facilities in helping relieve multiple transmission constraints over long distances, multiple zones, and long periods of time. As an example, the costs of MISO's Multi-Value Projects and ISO-NE's Pool Transmission Facilities are allocated using this method, along with 300-kV and above projects in SPP.[49]

Flow-Based. The costs of constructing lower voltage transmission facilities within an RTO are often allocated using a flow-based method, in which a model is used to determine: 1) the load in each zone's contribution to the flow of power that contributed to the reliability violation being solved by the new facilities, or 2) the load in each zone's contribution to the flow of power on the new facilities. This allocation method is a form of "beneficiary pays"; that is, those that benefit from the new facilities pay for them.

Economic Value. For transmission lines added for economic efficiency purposes, the economic value of the new line provided to each zone as determined in economic modeling of the system (e.g., based upon impacts to locational prices or cost savings to load) is sometimes used to allocate the cost of the line to individual transmission zones. This allocation method is another form of beneficiary pays.

Localized. The costs of projects below a specific cost threshold (for example, $5 million in PJM) or installed to solve a local reliability issue are often simply allocated to the local transmission zone in which the facilities are constructed.

As illustrated in Table 3, broad socialization and localized cost allocation methods are relatively easy to administer and are easy for stakeholders to understand. In contrast, flow-based and economic value cost allocation methods usually require complex modeling and thus are more difficult to administer and understand.[50] However, flow-based and economic value methods more directly address whether those that are benefiting from the transmission expansion are paying for it.

Table 3. Overview of Cost Allocation Methods

	Broad Socialization	Flow-Based	Economic Value	Localized
Facility-types typically allocated	High-voltage long distance lines	Lower-voltage facilities solving regional reliability issues	Lines constructed for economic efficiency reasons	Low-cost projects solving local reliability issues
Administrative ease & understandability	Easy/simple	Harder, need complex reliability modeling	Harder, need complex economic modeling	Easy/simple
Directly quantifies whether those that benefit are paying?	No, unless modeling is also performed	Yes	Yes	Not needed

Source: Navigant

In practice, each RTO uses a mix of each of these cost allocation methods, usually differentiating by the voltage of the new facilities, the cost of the new facilities, and whether the new facilities are being constructed for reliability or economic efficiency purposes.

6.3.1 Order No. 1000 Regional Transmission Cost Allocation Considerations

Under FERC Order No. 1000, each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Under FERC Order No. 1000, "non-public utility" transmission providers, that is, transmission providers not under FERC jurisdiction such as transmission owning cooperatives and municipalities, are also encouraged to participate in a regional planning process.[51]

The goal of the regional transmission plan is to identify transmission facilities that meet the region's reliability, economic, and public policy-related needs more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning processes.

Under FERC Order No. 1000, the regional cost allocation method used must satisfy six regional cost allocation principles:

1. Costs are allocated in a manner roughly commensurate with estimated benefits.
2. Costs are not involuntarily allocated to those who receive no benefits.
3. Method includes clearly defined benefit-to-cost thresholds that do not exceed 1.25 (i.e., the threshold itself cannot exceed 1.25, where 1.25 means benefits are 25% higher than costs. If the threshold is set, for example, at 1.15, then projects with benefits more than 15% above costs would be included.).
4. Costs are allocated solely within the affected transmission planning region; however, the regional planning process must identify upgrades that may be required in another region and, if the original region agrees to bear the costs associated with these upgrades, there must be provisions for allocating the costs of the upgrades among the beneficiaries in the original region.
5. The methods for determining benefits and beneficiaries are transparent with adequate documentation provided to allow a stakeholder to determine how they were applied to a proposed transmission facility.
6. Different cost allocation methods for different types of facilities are set out clearly and explained in detail.

The specific cost allocation methods developed by each transmission provider under FERC Order No. 1000 will follow these principles, and likely involve a mix of the allocation methods noted above, along with potential consideration of the costs avoided by local transmission projects that may be displaced by a more economic and cost-effective regional transmission project.

7 Physical and Technical Characteristics of Transmission

A number of individual components, including lines, cables, support structures, transformers, and substations, collectively comprise the physical transmission system. Electricity flows through this system in accordance with physical laws. The basic physical components of the transmission system and the technical operation of this system are discussed in turn below.

7.1 Physical System

7.1.1 Transmission lines

Transmission lines come in two basic varieties: overhead lines and underground (or undersea) cables.

Overhead lines represent the vast majority of transmission lines, and are considerably less expensive to construct than underground cables. The main design consideration for overhead lines is the choice of conductor type and size, which must balance the need to minimize energy losses, cost, and the weight that must be carried by support structures. While copper is a better conductor, it has been overtaken by aluminum, which is lighter and cheaper.[52] There have been continual innovations which allow the specific conductor type and size to be optimized for its intended use.

Figure 21. Overhead Lines Supports

Source: OSHA Electric Power Illustrated Glossary

There are many possible types of support structures for overhead transmission lines (see, for example, Figure 21). Typically, transmission lines are supported on structures made out of steel lattice, tubular steel, wood, and/or concrete. The main function of support structures is to keep the conductors from contacting each other or other objects such as trees, including when the conductors sag due to high temperatures caused by resistive heating and/or high ambient temperatures.[53] See Appendix D for an explanation of resistive heating, among other technical terms used in this chapter.

Underground cables are used where overhead lines are inappropriate due to environmental or land use considerations, such as in high-density urban areas or ecologically sensitive areas. Cables are insulated and are typically routed through underground conduits, and often require cooling systems to dissipate heat. Cables may use copper instead of aluminum, balancing the greater cost of copper against its superior conductivity and lower resistive heating. Undersea (submarine) cables are usually made of copper, and may be surrounded by oil or an oil-soaked medium, then encased in insulating material to protect from corrosion.[54]

7.1.2 Transformers and Substations

Transformers are used to change voltage levels in AC circuits, allowing transmission at high voltages to minimize losses, and to convert to low voltages at the customer end for safety. Transformers step up the voltage from generator to transmission system, and step it down, often in several stages, before reaching the desired end-user voltage, such as 120 volts for households.[55]

Substations. Large transformers are housed in substations, where sections of a transmission and distribution system operating at different voltages are joined. Larger substations have a manned control room, while smaller substations often operate automatically. In addition to transformers, important substation equipment includes switchgear, circuit breakers, relays, and other protective equipment, and capacitor and reactor banks used to provide reactive power support.[56]

Converter stations to convert power from AC to DC and from DC to AC are also located on the transmission system where there are HVDC lines and DC ties.

7.1.3 Communications, Monitoring, and Control Systems

System conditions must be continuously monitored and controlled, and, increasingly, these activities are automated. Supervisory control and data acquisition (SCADA) systems combine remote sensing of system conditions, such as load flow and temperature, with remote control over operations. For example, control center SCADA systems control key generators through automatic generator control (AGC), and can change the topology of the transmission and distribution network by remotely opening or closing circuit breakers. This monitoring and control is enabled by dedicated phone systems (often fiber-optic based), microwave radio, and/or power line carrier signals.[57]

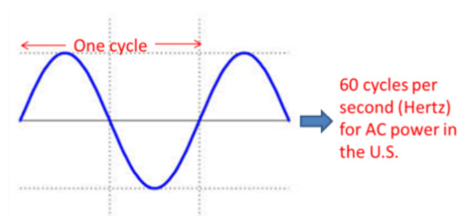
7.2 *Key Technical Aspects in Reliably Operating the Transmission System*

In operating the transmission system, there are a number of overriding concerns that are continuously monitored to allow for reliable operation. These include managing flows to stay within preestablished limits on transmission lines and maintaining voltages and frequencies on the transmission system within a desired range. See Appendix D for a basic overview of the underlying terms important to understanding electricity flows. Summarized below are some of the key aspects involved in operating the transmission system reliably.

7.2.1 Frequency, Voltage, Current, and Power

Almost all bulk electric power in the United States is generated, transported, and consumed in an alternating current network. In an AC electrical system, voltage and current pulsate (described mathematically by sine waves) at the system frequency (in North America this is 60 hertz, or 60 cycles per second) (see Figure 22).

Figure 22. Example "Sine Wave" for AC



Source: Navigant

Voltage is a measure of the potential energy in an electric charge, and current is a measure of the average rate at which electric charges are flowing. Voltage (measured in volts) is analogous to pressure in a water system, while current (measured in amperes) is analogous to the rate of water flow.[58] In the simplest case, for DC circuits, power is the algebraic product of voltage and current, as shown in Figure 23. As the formula implies, for the same amount of power, one can have a higher voltage and lower current, or a lower voltage and higher current. While the formulas for AC power are more complex (see Appendix D), this same general relationship between voltage and current still holds. Because higher current is associated with greater energy losses (e.g., from heating of the wires), higher voltages are used on the transmission system to reduce current and thereby minimize these losses.

Figure 23. Formula for DC Circuits

Power = Voltage x Current

Source: Navigant

AC systems produce and consume two kinds of power: real power (measured in watts) and reactive power (measured in volt-amperes reactive, or var). Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports the voltages that must be controlled for system reliability. By way of analogy, imagine walking to a destination on a long trampoline. The effort needed to maintain your balance while pulsating up and down is analogous to reactive power (maintain control), while the work done in moving forward (your goal, and thus the "useful" work) is analogous to real power.

7.2.2 Limits and Regulation

As electricity is generated at generating stations and flows to load over the transmission system, the system must be operated to manage a number of key items in real time.

Managing Flow Limits. The flow of electricity on the transmission system must be continually monitored to ensure that the flows through transmission facilities do not exceed preestablished limits established using reliability criteria. These limits include:

- Thermal limits. The capacity of transmission lines, transformers, and other equipment is determined by temperature limits. If these limits are exceeded, the equipment can be damaged or destroyed. For example, when a transmission line heats up, the metal expands and the line sags, potentially coming into contact with surrounding objects, causing a fault. Instead of a single thermal limit, dynamic or seasonal ratings are sometimes used. For example, transmission lines can carry more current on cold, windy days without direct sunlight.
- Stability limits. The stability limit of a transmission line is the maximum amount of flow through the line for which the transmission system will remain stable if a disturbance (e.g., a generating unit outage) occurs.

Voltage Regulation. Voltage regulation keeps voltages throughout the electric system within defined limits and is important for proper operation of electric power equipment and to maintain the ability of the system to withstand disturbances. Reactive power is critical to maintaining voltages on the AC system. Inadequate reactive power supply lowers voltage; as voltage drops, current must increase to maintain the power supplied. If current increases too much, transmission lines trip, or go offline, potentially overloading other lines and possibly causing cascading failures. If voltage drops too low, some generators will automatically disconnect to protect themselves and customer equipment may malfunction.

Reactive power may be supplied by several different sources, including transmission equipment (e.g., capacitors) and generating plants. A generating plant typically produces a mixture of real and reactive power. System operators can adjust the output of either type of power from a generating plant at short notice to meet changing conditions. Because reactive power losses become significant over longer distances, voltage-control equipment supplying reactive power must be dispersed throughout the system and located close to where the voltage support is needed.

Frequency Regulation. Controlling frequency on the interconnected electric system requires precisely matching generation to load. From hours to months in advance, the dispatch of generating units and power exchanges with other systems is matched with load demands based on factors such as historical load patterns, weather predictions, and maintenance schedules. However, at the scale of minutes to seconds, frequency is maintained by governors and AGC, which precisely controls the power output of certain generators that are able to respond rapidly to changes in load.

7.2.3 Ancillary Services

FERC has defined ancillary services as those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system.[59] The ancillary services defined by FERC in Order No. 888 are shown in Figure 24.

Figure 24. FERC-Defined Ancillary Services in Order No. 888

1. Scheduling, system control and dispatch
2. Reactive supply and voltage control
3. Regulation and frequency response service
4. Energy imbalance service
5. Operating reserve – synchronized
6. Operating reserve – supplemental

Source: Navigant

As shown, ancillary services include the voltage control (reactive power) and regulation (AGC) services discussed above. Operating reserves, first synchronized (or "spinning") and then, if needed, supplemental, are used to restore the generation and load balance in the event of a contingency such as the sudden, unexpected loss of a generator. Generators that can restart the grid after a blackout also provide a vital ancillary service.

Power generators provide many of these ancillary services and generally are paid to provide them. FERC has encouraged, and RTOs have been gradually introducing, markets for many of these ancillary services. For example, PJM currently provides regulation, energy imbalance, synchronized reserve, and supplemental operating reserve through market-based mechanisms.[60]

7.3 Power Flow and Modeling

In AC power systems, power flows do not necessarily follow a specified transmission path—for example, from seller in system A to buyer in system B—but divide themselves among various connected transmission paths according to the voltage levels and impedances of the path. In general, these phenomena are referred to as circulating power, loop flows, and parallel path flows. What is important for the reliability of an interconnected system is that operators know the sources and destinations of all transactions and where the power will physically flow, and are able to calculate the resulting reliability risks.[61]

These risks are assessed through power flow models, also called load flow models. These models are used to compute voltages and flows of real and reactive power through all branches of the system. Power flow models account for loop flows, and make it possible to understand how much power will actually flow on transmission lines under a given set of circumstances. Modelers vary the initial conditions—for instance, adding a proposed new generator to the network—and determine the impact on power flows throughout the system. [62]

Contingencies are modeled with a power flow model, and if the model results indicate a problem, planners and operators must address it, typically by adding new generation and/or transmission capacity, or by changing operational procedures. To run power flow models requires that each bus and line in the system be thoroughly described, requiring a great deal of input data. The real and reactive power consumption at each load bus, the impedance of each line and transformer, and the generating capacity of all generators must be known. [63]

Power flow models are used by NERC to calculate a transfer distribution factor (TDF) for individual power transfers—effectively, the percentage of the power that flows on each "flowgate" on the system. A flowgate is a designated point on the transmission system mathematically capturing one or more monitored transmission lines or elements. If a flowgate is overloaded, transactions with TDF values greater than 5 percent on the overloaded flowgate can be curtailed.[64]

7.4 Next Generation Transmission System

A number of technical advancements are taking place that will drive transmission development in upcoming years. These include the use of Flexible AC Transmission Systems (FACTS), further development of a smarter grid enabling advance system monitoring and control, the use of advanced materials and superconductors in transmission lines, and maintaining cyber security.

7.4.1 Advanced System Monitoring, Visualization, and Control

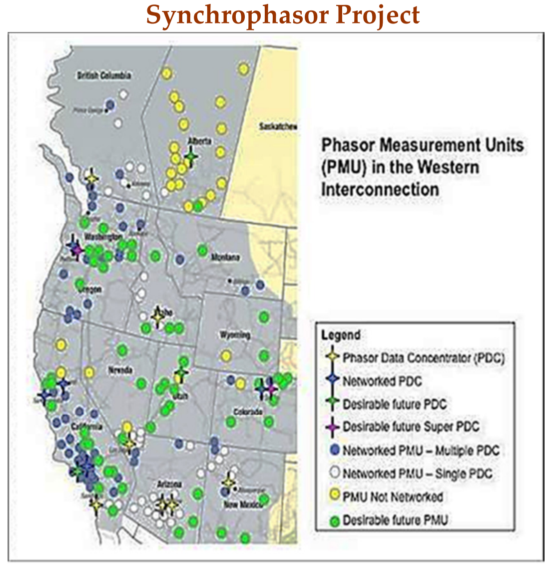
Research and development is ongoing into tools to improve advanced system monitoring, visualization, control, and operations to ease congestion and provide a greater degree of security. These systems will enable grid operators to react swiftly before a local disturbance can cascade into a larger problem, using sensors for measuring system conditions and computerized monitoring equipment that enables system operators to "see" the grid in real time and make necessary adjustments.

In particular, synchrophasor technology is expected to offer automated controls for transmission and demand response as well as great benefits for integrating renewable and intermittent resources, increasing transmission system throughput, and improving system modeling and planning. Synchrophasors are precise electrical grid measurements of values such as voltage or power that are available from monitors called phasor measurement units (PMUs). These measurements are taken at high speed (30 observations per second), and each measurement is time-stamped according to a common time reference.[65]

Time stamping allows synchrophasors from different areas to be time-aligned and combined together, providing a detailed and internally consistent operational picture of the entire interconnection. This picture can help grid operators detect disturbances that would have been impossible to see with older SCADA systems, which typically collect one measurement every 2-4 seconds.[66] The Western Interconnection Synchophasor Project is illustrated in Figure 25.

The availability of more detailed data about system conditions from devices, such as PMUs for wide area visibility and advanced meter infrastructure for dynamic pricing and demand response, can be a great benefit for electric system reliability and flexibility. However, this large volume of data poses its own set of challenges. Shifting operational data analytics from a traditionally offline environment to real-time situational awareness to measurement-based, fast control will require significant advancements in algorithms and computational approaches. DOE is coordinating research on the advanced modeling that will be required by these systems.[67]

Figure 25. Western Interconnection Synchrophasor Project



Source: BPA.gov

7.4.2 Advanced Materials and Superconductors

Additional research and testing is ongoing into improvements in throughput of electricity over existing transmission corridors by using advanced composite materials for new overhead conductors and high-temperature superconducting cables.

Superconducting cables are cooled cryogenically to remove the resistance to the flow of electricity, cutting down on the losses that typically occur during transmission. Superconducting fault current limiters (FCLs) can dissipate a surge of current on utility distribution and transmission networks. Under normal circumstances, these FCLs are invisible to the system, having nearly zero resistance to the steady-state current; however, when there is an excess of electricity, the FCL intervenes and dissipates the surge, thus protecting the other transmission equipment on the line.[68]

Research and testing is also ongoing in developing a high-strength, high-temperature overhead conductor. One example is aluminum conductor composite reinforced, which can increase the current-carrying capacity of a transmission line by 1.5 to 3 times over that of conventional conductors, without the need for tower modification or re-permitting.[69]

7.4.3 Cyber Security

Cyber security is a serious and ongoing challenge for the energy sector, and the electricity transmission and delivery system in particular. As the U.S. moves forward with the modernization of its transmission systems, it is critical that infrastructure protection be built into these decision-making processes. In 2006, NERC adopted the Critical Infrastructure Protection (CIP) standards. The standards establish the minimum requirements to ensure the security of electronic information exchange to support the reliability of the bulk power system. Since then, a number of updates have been issued, with version 5 approved by the FERC in November 2013.[70]

New technologies are continuously changing the landscape for physical access to the electricity transmission and delivery system. Smart technologies are introducing millions of new intelligent components to the system infrastructure that communicate and control energy delivery in much more advanced ways than in the past. New infrastructure components and the increased use of mobile devices in energy infrastructure environments introduce new digital vulnerabilities and additional physical access points. New applications, such as managing energy consumption, involve new stakeholders and require protection of private customer and energy market information.[71]

The U.S. electric industry has established a goal that by 2020, resilient energy delivery systems will be designed, installed, operated, and maintained to survive a cyber incident while sustaining critical functions. The strategies to achieve this vision confront the formidable technical, business, and institutional challenges that lie ahead in protecting critical systems against increasingly sophisticated and persistent cyber attacks.[72]

8 Action Items for State Officials

State officials face unique challenges when addressing transmission policy. As described throughout this white paper, electric transmission systems are interconnected and thus regional and multistate in nature. However, state officials are generally focused on the specific state which they represent. Recognizing that state statutes are difficult to change and that state officials will need to develop policy within the paradigm of existing state law, which may not be consistent with federal and regional initiatives, the following are intended as suggestions that states may wish to consider. Most importantly, effective state involvement in transmission policy will likely be contingent upon involvement in both jurisdictional utility planning processes and broad regional transmission planning.

8.1 Meaningful State Involvement in Broad Regional Transmission Planning

As this white paper makes clear, transmission planning is not a localized issue, and likely will evolve to encompass broader regions and even entire interconnections in the future. State involvement in regional transmission planning processes will be beneficial in understanding the costs and benefits of a transmission project on a regional as well as a local basis, how public policy goals of the state and surrounding states are being implemented through the transmission planning process, and how issues such as renewable power, demand-side alternatives, and smart grid are being considered in the process. Some state-level policies have been integral in shaping the economic landscape for these issues, such as RPS and net metering policies that make demand-side generation more economically attractive.

State collaboration can help foster and produce consistent and coordinated direction to regional analyses and planning. Significant state input and direction increases the probability that the outputs of transmission planning processes will be useful to state-level officials, whose decisions may determine whether proposals that arise from such analyses become actual investments. States, because of their Constitutional and legal authorities (including siting and cost recovery), arguably offer the most important perspective to ensure an appropriate weighing of all resource options of transmission in comparison to other resources, including generation, new transmission technologies such as smart grid, demand response, distributed generation, energy storage, and energy efficiency. This objective perspective should be valuable to utilities and stakeholders as they consider controversial issues.

Each RTO has a mechanism for state involvement in the process. For example, the Organization of MISO States, Inc., coordinates regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions. Given the importance that broad regional transmission planning will have on the electricity system in each individual state, each state should seek to carve out a meaningful role in the planning process at each jurisdictional utility and the regional Planning Coordinator for those utilities, including, where applicable, the RTO/ISOs operating in the state.

8.2 Encourage Continued Improvement in Jurisdictional Utility Planning Practices

States should be ideally suited to facilitate the planning of transmission (and other resources) by Planning Coordinators (RTOs/ISOs, utilities) by encouraging their jurisdictional utilities to acquire the requisite data to support state-of-the-art load forecasting and planning tools, and perform ongoing maintenance and quality control of the data. States should also encourage best practices for measurement and verification of demand response (as well as energy efficiency, distributed generation and energy storage) and encourage reporting of that information. States should also continue to encourage jurisdictional utilities to give appropriate consideration to important risk factors (such as fuel costs, load growth, economic drivers, and capital costs), and incorporate all types of resources (transmission, generation, demand response, non-utility generation, energy efficiency, and energy storage) in their planning processes.

8.3 Encourage Stakeholder Involvement in the Transmission Planning Process

States individually or collectively should encourage broad stakeholder involvement in regional planning. Stakeholder involvement will help provide long-run support and understanding for regional planning methodologies and recommendations. For example, in Illinois, Commonwealth Edison established a smart grid advisory panel to review and advise the company on smart grid investment. Similar stakeholder groups could be developed for regional transmission planning.

Regional transmission planning processes on occasion will yield recommendations for the construction of transmission facilities with broad regional benefits, but limited benefits to any individual state. Educating stakeholders in understanding the transmission planning process, and the corresponding expected benefits in terms of reliability and economics from being part of a broad regional process, likely will be helpful in considering the costs and benefits of any individual project.

8.4 Harmonization of State Siting Processes with Wholesale Markets

States should consider the possibility of harmonizing their siting process with the wholesale markets. By way of example, since RTOs/ISOs have transmission planning processes in place, it may be in the interest of a state to be an active participant in that process to better ensure the state's interests are considered. This logic may be beneficially extended to state siting authorities. Collaboration may well prove to be beneficial to both the state and the RTO/ISO.

8.5 Harmonization of Retail Rate Structures with Wholesale Markets

States should consider, to the extent practicable, harmonizing retail rate structures with the wholesale markets. Since a portion of the costs that a retail customer incurs emanate from the wholesale market, there is a rationale for having retail rate structures take advantage of the opportunities afforded by the wholesale market price structure. RTOs/ISOs have short-term pricing intervals, which could facilitate retail rates that include components based on real-time pricing that can provide price signals important to encouraging cost-effective demand response. Other wholesale market structures may offer price signals that could facilitate retail rate initiatives and similarly improve resource decisions. Such rate structuring would need to be carefully considered and instituted, as retail rates in many states reflect historical embedded costs, which will not generally align with the marginal cost pricing inherent in wholesale markets.

8.6 States and "Cooperative Federalism"

States should consider "cooperative federalism" to work with federal agencies on resource development. States have primary authority over resource development, but FERC has relatively new responsibilities for reliability and on matters of interstate transmission and interstate pipelines. As such, states should consider collaborating more with federal agencies to better ensure that states' and national policy needs are being fully considered. For example, states should consider expanding their involvement in FERC proceedings and rulemakings such as tariffs, mergers, and NERC policies such as resource adequacy.

8.7 State Coordination with and Between Gas and Electric Utilities

States may also find it beneficial to work with both gas and electric industries to ensure coordination of operations and planning and the interplay between electric transmission lines and gas pipelines. It may be, for example, that states could foster the development of natural gas infrastructure that would better enable the state to fulfill its obligations to provide both electric and natural gas service.

Appendix A Who Builds, Owns, and Operates Transmission?

As opposed to the small geographic footprint of traditional, central power generation stations, transmission lines have a much wider and more diverse geographic presence. This appendix summarizes who builds and owns transmission, and the different entities that interact with these entities. For an overview of the transmission planning process, see Chapter 5

Transmission Owners

Several different kinds of organizations own transmission facilities.

Vertically integrated utilities are those that own generation, transmission, and distribution and provide service to retail customers. These entities can be investor-owned utilities, publicly owned electric companies (i.e. municipal or federal utilities), or customer-owned electric companies (i.e. cooperatives). Vertically integrated utilities are the most traditional type of transmission owners.

There are also traditional regulated utilities that own transmission and distribution and provide service to retail customers, but do not own generation. These utilities are sometimes referred to as "T&D utilities".

Transcos. FERC has defined a Transco as a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.[73] While the Transco is a stand-alone transmission company, FERC does permit the affiliation with another public utility that may own generation or distribution assets.[74] Transcos often own transmission within a defined service territory with the costs recovered under FERC-approved, cost-based rates.

Merchant transmission developers. Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities are recovered through negotiated rates instead of cost-based rates.[75] Owners of merchant transmission must recoup their costs through negotiated access charges paid by generators and/or load-serving utilities. A merchant transmission developer assumes all financial risk for developing its transmission project and constructing the proposed transmission.[76]

Under FERC Order No. 1000, the potential solutions for meeting regional transmission needs may become subject to competitive bidding by utilities and merchant transmission developers. In response, the ownership profile of the transmission system in any particular region may become increasingly comprised of multiple parties. FERC Order No. 1000 defined several terms to help better capture these multiple roles.

- Incumbent transmission developer/provider. An entity that develops a transmission project within its own retail distribution service territory or footprint.[77] The use by FERC of the phrase "or footprint" is meant to convey that an entity can be an incumbent transmission provider/developer without having a retail distribution service territory.[78] As such, a Transco that owns the transmission system in a specific service territory would be the incumbent transmission provider in that service territory.

- Nonincumbent transmission developer. An entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint.[79] Merchant transmission developers, which recover costs through negotiated rates instead of cost-based rates, are a subset of nonincumbent transmission developers.[80] Nonincumbent transmission developers also include developers who recover costs through FERC-approved, cost-based rates.

- Non-public utility transmission providers (NTPs) are transmission providers not under FERC jurisdiction such as transmission-owning cooperatives and municipalities.[81]

Planning Coordinators

Planning Coordinators (also known as Planning Authorities) include RTOs, government power authorities, and electric utilities who have taken on the responsibility of coordinating, facilitating, integrating, and evaluating transmission facilities. Each Planning Coordinator is responsible for assessing the reliability of its assigned region, and coordinating planning with adjoining regions. Planning Coordinators evaluate, develop, document, and report on expansion plans for each individual transmission planning area within the Planning Coordinator regional boundaries. The Planning Coordinator must also assess whether the integrated transmission plan meets reliability needs, and, if not, provide alternative solutions.

Planning Coordinators also investigate the viability of constructing transmission lines for economic reasons. Through this process, the transmission plans for each Planning Coordinator's assigned region are integrated and evaluated to ensure that the regional transmission system will be reliable and that economic factors are considered. Utilities generally will act as the transmission planner for their local areas within a Planning Coordinator's regional boundaries. The utilities work closely with the Planning Coordinator to integrate their local transmission planning process with the regional process.

Transmission Operators, Reliability Coordinators, and ISOs/RTOs

Transmission Operators are responsible for the reliable operation and maintenance of the transmission system within their purview. Transmission Operator is a NERC-defined and registered entity; Transmission Operators can also be Transmission Owners and/or Reliability Coordinators.

Reliability Coordinators perform similar duties but sometimes for a wider area that covers multiple transmission operators. Reliability Coordinators also analyze the day-ahead dispatch plan of each Balancing Authority within its territory to assure that transmission reliability is not jeopardized. Transmission Operators develop transmission maintenance schedules based on the maintenance plans of the Transmission Owner(s) and provide these schedules to the Reliability Coordinator for review.

Reliability Coordinators review transmission and generation outage schedules to identify reliability concerns.

For areas with an RTO/ISO, the RTO/ISO registers as both the Reliability Coordinator and Transmission Operator with NERC, and assigns some of the Transmission Operator tasks to its members.

Generators

The owners of generating plants rely on transmission to get the power they generate to end-use customers. They secure long-term access to transmission by acquiring transmission rights, either physical or financial. Generators are responsible for paying to interconnect to the grid. They are responsible for building and owning the equipment needed for them to tie into the transmission system, as well as for paying for upgrades to the transmission system that are required for their project to reliably be connected to the grid.

FERC requires that all generators be provided access to the transmission grid through an Open Access Transmission Tariff (OATT). In addition to requiring an OATT, FERC also works to ensure open access to transmission by requiring, through Orders 888, 889, and 890, that all generators on the grid be provided the same level of information about the transmission system in real time through the Open Access Same-Time Information System (OASIS).

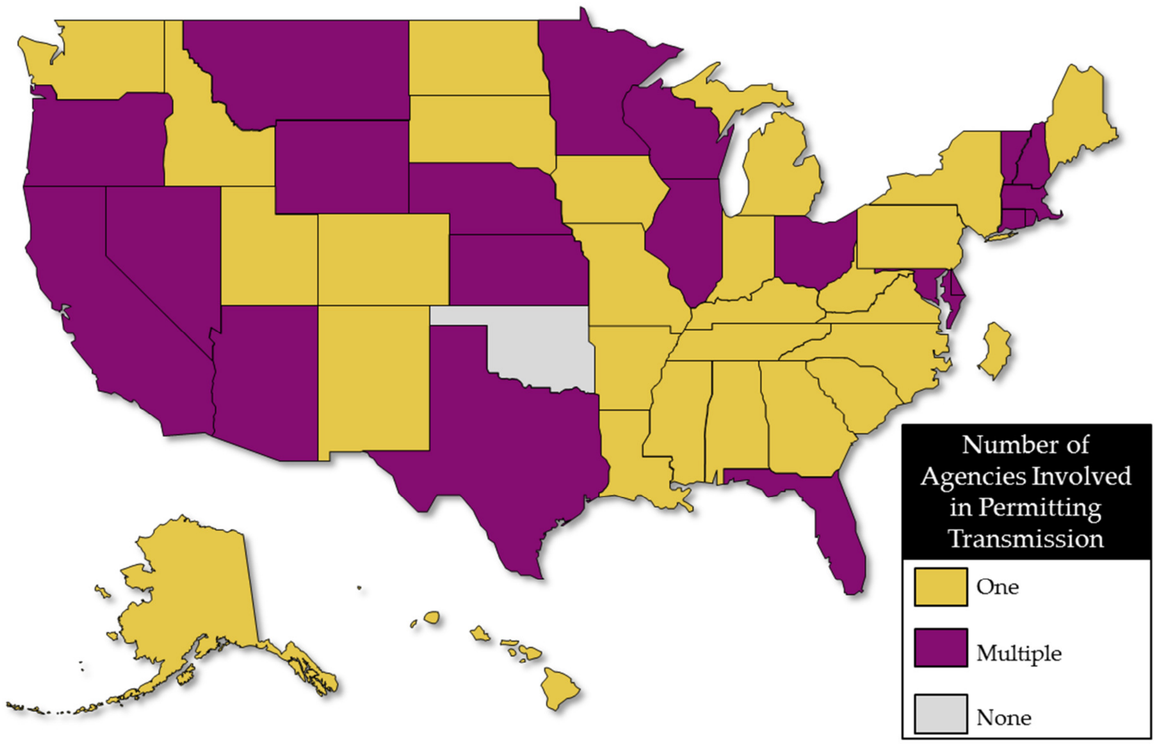
Distribution Companies

Utilities that own distribution networks and provide service to retail customers, but do not own generation or transmission, are called distribution-only utilities or transmission-dependent utilities. The term distribution company is broader, referring to any company that provides service to retail customers. Distribution companies include distribution-only utilities as well as companies that own transmission (called transmission and distribution utilities) and those that own transmission and generation (called vertically integrated utilities). Distribution companies need transmission in order to get the power generated by generating plants to their customers.

Appendix B Overview of State Transmission Siting and Approval Process

Siting of transmission projects is the regulatory responsibility of the states; only those projects that pass through federal lands, international borders, or National Corridors require regulatory approvals at the federal level. Each state develops its own set of regulations for siting transmission lines within its borders. As shown in Figure 26, most states authorize either one or multiple agencies with oversight of siting transmission projects although the project characteristics that require any specific agency's involvement differ among states.

Figure 26. State Transmission Permitting Process – Number of State Agencies Involved



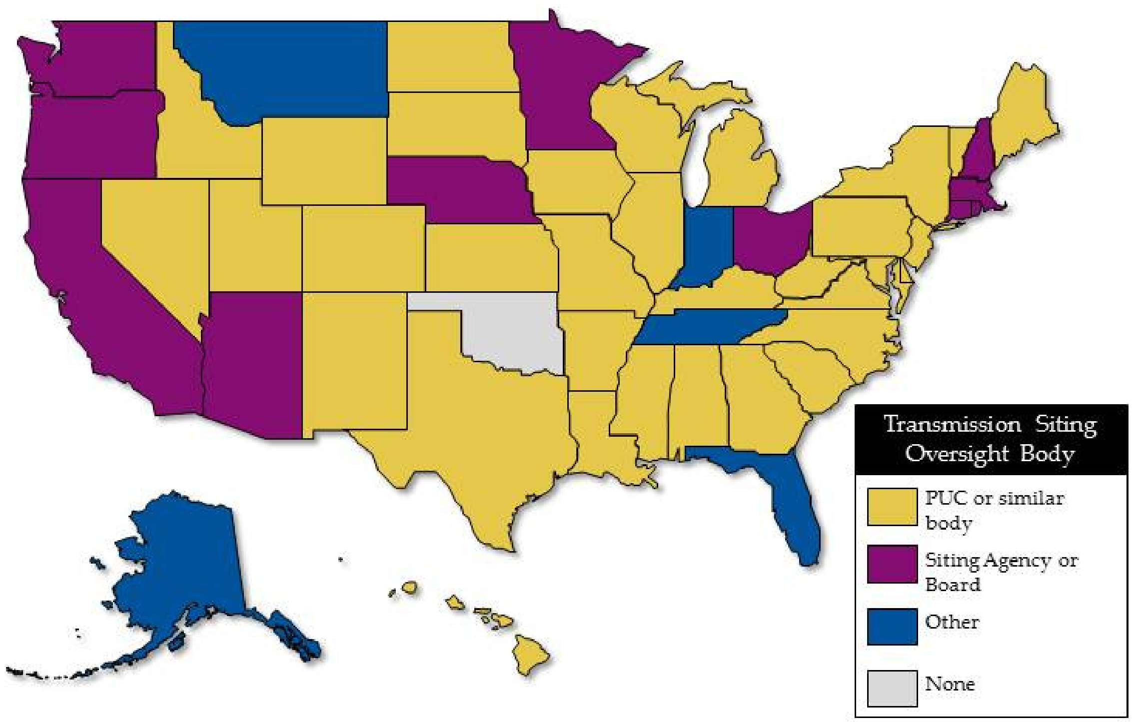
Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

The agency that is the sole or primary agency overseeing the transmission permitting process varies state by state. As shown in Figure 27, many states place the state Public Utility Commission (PUC) or similar body (such as a Public Service Commission or Corporation Commission) in charge of permitting transmission.

In other states a siting board or siting agency is tasked with permitting transmission. These siting agencies are typically made up of members from various related state agencies, such as the PUC and the environmental state agency, and sometimes include governor-appointed representatives from industry and/or public advocates.

In a few states, the primary agency overseeing transmission permitting does not fall into either of these categories, and is typically the environmental state agency or, in the case of Tennessee, a federal entity (the Tennessee Valley Authority).

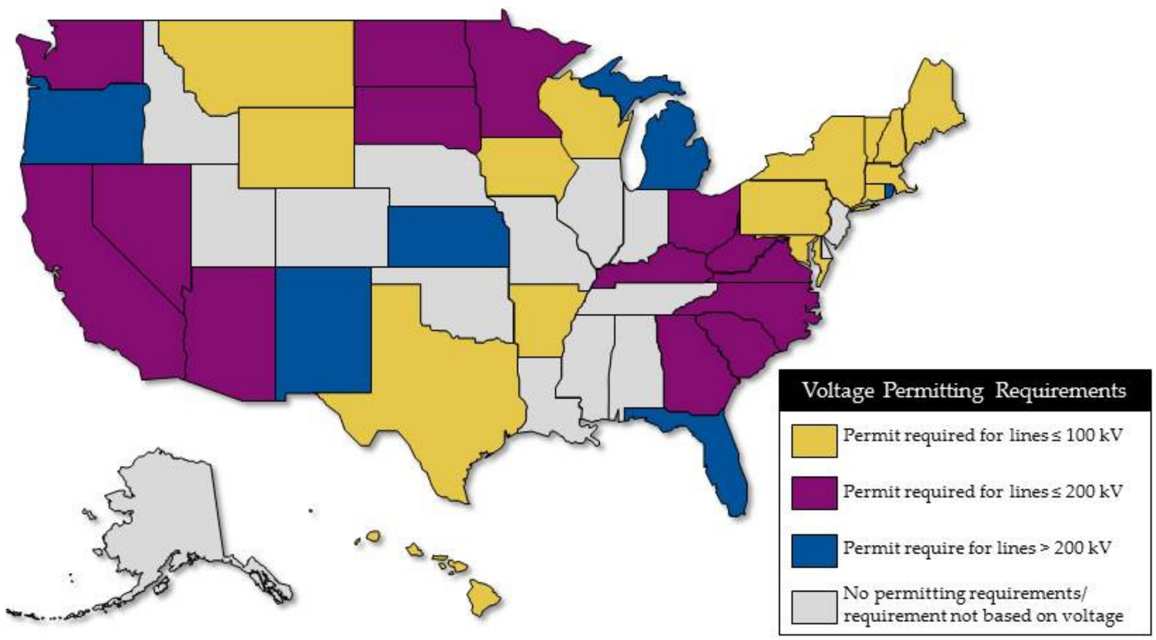
Figure 27. State Transmission Permitting Process – Primary Agency Involved



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

Some states require that all transmission lines be permitted before they begin construction, but others either only have requirements for lines of certain voltage levels or have additional requirements for lines of certain voltage levels. An overview of the states with voltage-based transmission siting requirements can be seen in Figure 28 and Table 4.

Figure 28. State Transmission Permitting by Voltage Level



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory, October 2013)

Table 4. State Transmission Permitting by Voltage

No Voltage Specification	46 to 69 kV	100 kV	115 to 138 kV	150 to 200 kV	230 kV	345 kV
Alabama	Connecticut	Arkansas	Arizona	California	Florida	Michigan
Alaska	Hawaii	New Hampshire	Kentucky	Georgia	Kansas	Rhode Island
Colorado	Iowa	New York	North Dakota	Minnesota	New Mexico	
Delaware	Maine	Pennsylvania	Ohio	Nevada	Oregon	
Idaho	Maryland	Wisconsin	South Carolina	North Carolina		
Illinois	Massachusetts		South Dakota	West Virginia		
Indiana	Montana		Virginia			
Louisiana	Texas		Washington			
Mississippi	Vermont					
Missouri	Wyoming					
Nebraska						
New Jersey						
Oklahoma						
Tennessee						
Utah						

Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

For a detailed description of the transmission siting and approval prices in each state, see the source used for this appendix: Edison Electric Institute's (EEI's) *State Generation & Transmission Siting Directory*.

Appendix C The Cost of Building Transmission

Transmission is expensive to build, and costs vary widely based on a number of characteristics of any given transmission project. Costs differ based on the voltage of the line, the length of the line, the terrain, and the equipment used to connect one line to another. Costs also differ based on the transmission structures on which the lines are strung, and the right of way needed for the transmission line, as well as a variety of other potential characteristics specific to any given project.

The costs provided in Table 5 for different line voltages and other components are taken from the 2012 Eastern Interconnection Planning Collaborative (EIPC) Phase II report.[82] The figures cited in Table 5 are "base costs," and there were significant variations in these costs among the various EIPC regions. Specific transmission costs will vary significantly across the country depending upon location, population density, geographical terrain, and local siting requirements.

Table 5. Example Transmission Costs for New Facilities

Line/Description	Unit	Base Cost
<230 kV Single Circuit Line, 300 MW Capability	$/Mile	$1,100,000
230 kV Single Circuit Line, 600 MW Capability	$/Mile	$1,150,000
230 kV Single Circuit Line, 900 MW Capability	$/Mile	$1,580,000
230 kV Double Circuit Line, 1,200 MW Capability	$/Mile	$1,800,000
345 kV Underground Line, 500 MW Capability	$/Mile	$19,750,000
345 kV Single Circuit Line, 900 MW Capability	$/Mile	$2,100,000
345 kV Single Circuit Line, 1,800 MW Capability	$/Mile	$2,500,000
345 kV Underground Line, 1,800 MW Capability	$/Mile	$25,000,000
345 kV Double Circuit Line, 3,600 MW Capability	$/Mile	$2,800,000
345 kV Underground Line, 3,600 MW Capability	$/Mile	$28,000,000
500 kV Single Circuit Line, 2,600 MW Capability	$/Mile	$3,450,000
765 kV Single Circuit Line, 4,000 MW Capability	$/Mile	$5,550,000
500 kV HVDC Bi-pole Line, 3,500 MW Capability	$/Mile	$1,600,000
<230 kV Substation, 4 Bay	$	$7,750,000
230 kV Substation, 4 Bay	$	$9,500,000
345 kV Substation, 4 Bay	$	$16,000,000
500 kV Substation, 4 Bay	$	$26,500,000
765 kV Substation, 4 Bay	$	$44,000,000
230 kV Transformer	$	$5,500,000

Line/Description	Unit	Base Cost
345 kV Transformer	$	$8,500,000
500 kV Transformer	$	$22,750,000
765 kV Transformer	$	$42,500,000
High-Voltage Direct Current Terminal (both ends)	$	$550,000,000

Source: 2012 EIPC Phase II Report

Appendix D Simplified Explanation of Basic Technical Electricity Terms

Electric power comes in two forms: alternating current (AC) and direct current (DC). In power systems, AC is generally a sine wave, while DC is a constant value. These forms are characterized by the behavior of their waveforms: AC alternates between positive and negative polarity with respect to ground, while DC does not. By the beginning of the twentieth century, AC power systems became standard worldwide.

Frequency. Frequency is the rate at which AC changes from positive to negative polarity, measured in cycles per second, or hertz (Hz). There are currently two widespread world standards for power system frequency: 50 Hz in most of Europe and Asia, and 60 Hz in North America.

Voltage. Voltage is the difference in electric potential between two points in an electric circuit. A difference in potential causes electric charges to flow from one place to another. Voltage is measured in volts (V). In an AC system, the voltage oscillates in a sine wave; thus, the voltage is generally measured in terms of an averaging mechanism root-mean-square (RMS).

AC RMS Voltage. RMS voltage is obtained by squaring the values of the voltage over one complete sine-wave cycle, determining its average value, and then taking the square root of that average. The result is that $V_{RMS} = V_{PEAK} / \sqrt{2} = 0.707\ V_{PEAK}$. For a U.S. household system that oscillates between positive and negative 170 volts (the V_{PEAK}), the $V_{RMS} = 0.707\ (170\ V) = 120$ volts. Thus, the common designation of a household electric outlet as "120 volts AC" refers to the RMS value of the voltage. The voltages of power system components, such as transformers and transmission lines, are also generally given in RMS terms.

Current. Current is the flow rate of electric charge. In an electric circuit, charge flows from a point of higher voltage to a point of lower voltage through a conductor, just as water flows from a higher spot to a lower one through a pipe. Current is measured in amperes. As is the case for voltage, AC currents are generally described in terms of their RMS values.

Resistance and Conductance. Conductance describes the ability of an object, such as an electric wire, to allow electric currents to flow. The opposite of conductance is resistance, which describes how much the object resists the flow of current. Resistance is measured in ohms (Ω). For a given material, the longer the wire is, the greater its resistance, and the larger in diameter the wire is, the smaller its resistance.

Resistive Losses. When current flows against a resistance, some of its energy is lost in the form of heating. Very high voltages are used in transmission in order to reduce resistive losses. In general, line losses are inversely proportional to the square of the sending voltage; this is true for AC lines as well as DC.

Impedance, Reactance, Inductance, and Capacitance. AC circuits involve not only resistance but other physical phenomena that impede the flow of current. These are inductance and capacitance, referred to collectively as reactance. When AC currents pass through a reactance, some of the energy is temporarily stored in electro-magnetic fields. Voltage decreases when current flows across a reactance, just as it does across a resistance. For AC circuits, passing through an inductance causes an AC current waveform to fall behind, or lag, the voltage waveform. Passing through a capacitance causes AC current to move ahead of, or lead, the voltage. Equivalent amounts of capacitance and inductance cancel each other out.

Ohm's Law. Ohm's Law describes the relationship between voltage (V), current (I), and resistance (R) across any element of a DC electric circuit: $V = I*R$. Thus, for a fixed value of resistance, if the voltage is made larger, the current will decrease, and vice versa.

Power and Energy. Power is the rate of energy flow over time, that energy being measured in watts (W). For a DC circuit, the power passing through any element of the DC circuit is the product of the voltage across it and the current passing through it (Ohm's Law). The energy delivered by a power system is measured in watt-hours. See below for AC power.

AC Power Components: Real, Reactive, and Apparent. For AC systems, there are three kinds of power: real, reactive, and apparent. Real power is what is consumed by resistances, and is measured in watts. Reactive power is consumed by reactances, and is measured in volt-amperes reactive, or VAR. Apparent power is the complex sum of real and reactive power, and is measured in volt-amperes, or VA. Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports the voltages that must be controlled for system reliability. Apparent power is what must be supplied by the generators in a power system to meet the system's electrical load, whereas end use is generally measured in terms of real power only.

Loads and Power Factors. An electrical load is the power drawn by an end-use device or customer connected to the power system. Loads can be resistive or reactive, and are often a combination of both. The extent to which a load is resistive is measured by its power factor (p.f.). Power factor is equal to the cosine of the phase angle difference between the current and voltage waveforms through the load: p.f. = $\cos \phi$. When the power factor is at its maximum value of one, the load is purely resistive. The smaller the power factor, the greater the reactive power component of the load. Inductive loads, such as electric motors, have a lagging power factor, and are said to consume reactive power. Capacitive loads have a leading power factor and are said to be sources of reactive power.

Calculating Power in AC Systems. For an AC circuit, the apparent power passing through an element of the AC circuit is the product of the RMS voltage across it and the RMS current passing through it. (This is the analog to the DC power calculation noted above.) The apparent power can be separated into its reactive and real power components using the power factor. Real power (watts) is equal to the product of the RMS voltage, the RMS current, and the power factor. Reactive power (vars) is equal to the product of the RMS voltage, the RMS current, and the $\sin \phi$ (where ϕ is the phase difference between the current and voltage waveforms). Reactive loads can have a large effect on line losses, because the current flowing through a line, and the associated heating, is a function of apparent power (reactive power plus real power) rather than just real power.

Three-Phase Systems. Residential current is generally single-phase AC power, but the rest of the power system from generation to secondary distribution employs three-phase AC. This means that transmission lines have three separate conductors, each carrying one-third of the power. The waveforms of the voltage in each phase are separated by 120°. That is, taking one voltage as the reference, the other two voltages are delayed in time by one-third and two-thirds of one cycle of the electric current. There are two major reasons that three-phase power became dominant. The first is that as long as the electrical loads on each phase are kept roughly balanced, only three wires are required to transmit power. Normally, any electric circuit requires both an "outbound" and "return" wire to make a complete circuit. Balanced three-phase circuits provide their own return; thus, only three, rather than six, wires are required to transmit the same amount of power as three comparable single-phase systems. Second, three-phase motors can be smaller and more efficient than comparable single-phase equipment.

Voltage in Three-Phase Systems. The voltage in 3-phase systems can be specified in two different ways. One is <u>phase to ground</u>, which is the voltage between any one of the three phases and ground. The other is <u>phase to phase</u>, which is the voltage between any two of the three phases. Power lines are conventionally described by their phase to phase voltage, also called the line voltage. Phase to phase voltage is greater than phase to ground voltage by a factor of the square root of three. Thus, a 500 kV line has a phase to phase voltage of 500 kV, and a phase to ground voltage of 500 kV/$\sqrt{3}$ = 289 kV. In both cases, the voltage referred to is the RMS value.

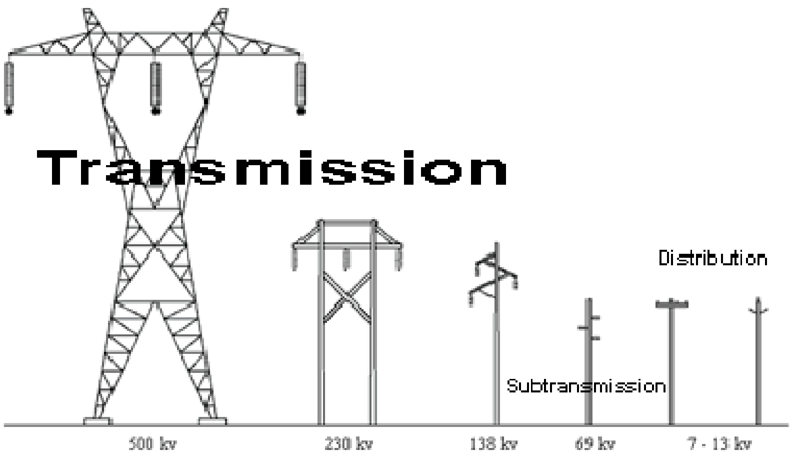
Power in Three-Phase Systems. The amount of power transmitted in a three-phase system is three times the power in each line. For example, the apparent power transmitted by a 500 kV circuit with a current of 1,000 amperes (1 kA), is $\sqrt{3}$ * 500 kV * 1 kA, or 866 MVA. The real and reactive components can be calculated easily if the load power factor or phase difference is known (see above).

See the main source for this Appendix: "Multi-Dimensional Issues in International Electric Power Grid Interconnections", Chapter 2, "Technical Aspects of Grid Interconnection", published by the United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, for a more in-depth explanation of the above terms.

Appendix E Pictures of Transmission Facilities

This appendix provides diagrams and pictures of some of the main components that make up the transmission (and distribution) system.

Figure 29. Transmission Structures



Source: OSHA Electric Power Illustrated Glossary

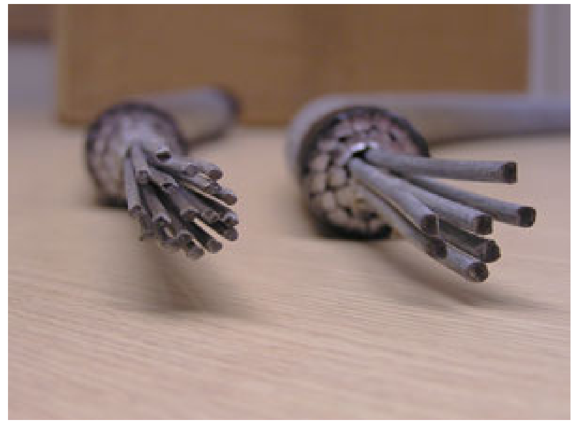
Figure 30. Transmission Substation

Source: OSHA Electric Power Illustrated Glossary

Figure 31. Distribution Station

Source: OSHA Electric Power Illustrated Glossary

Figure 32. Overhead Cable



Source: Minnesota Public Radio

Figure 33. Pole-type Current Transformer

Source: OSHA Electric Power Illustrated Glossary

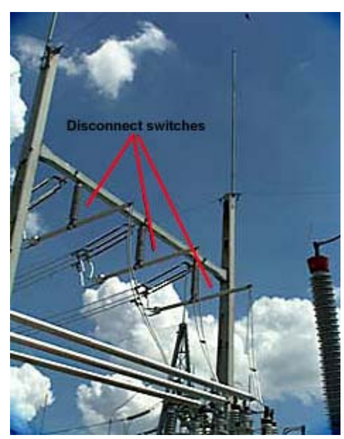
Figure 34. 400-kV Current Transformer

Source: OSHA Electric Power Illustrated Glossary

Figure 35. Power Transformers

Source: OSHA Electric Power Illustrated Glossary

Figure 36. Substation Disconnect Switches



Source: OSHA Electric Power Illustrated Glossary

Figure 37. High-Voltage Underground Cables

Source: OSHA Electric Power Illustrated Glossary

Figure 38: Air Circuit Breaker

Source: OSHA Electric Power Illustrated Glossary

Figure 39. Capacitor Bank

Source: OSHA Electric Power Illustrated Glossary

Figure 40. Circuit Switches

Source: OSHA Electric Power Illustrated Glossary

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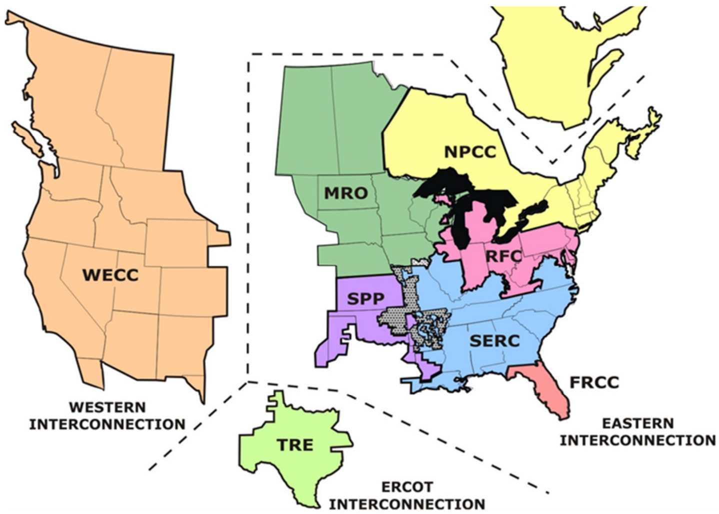
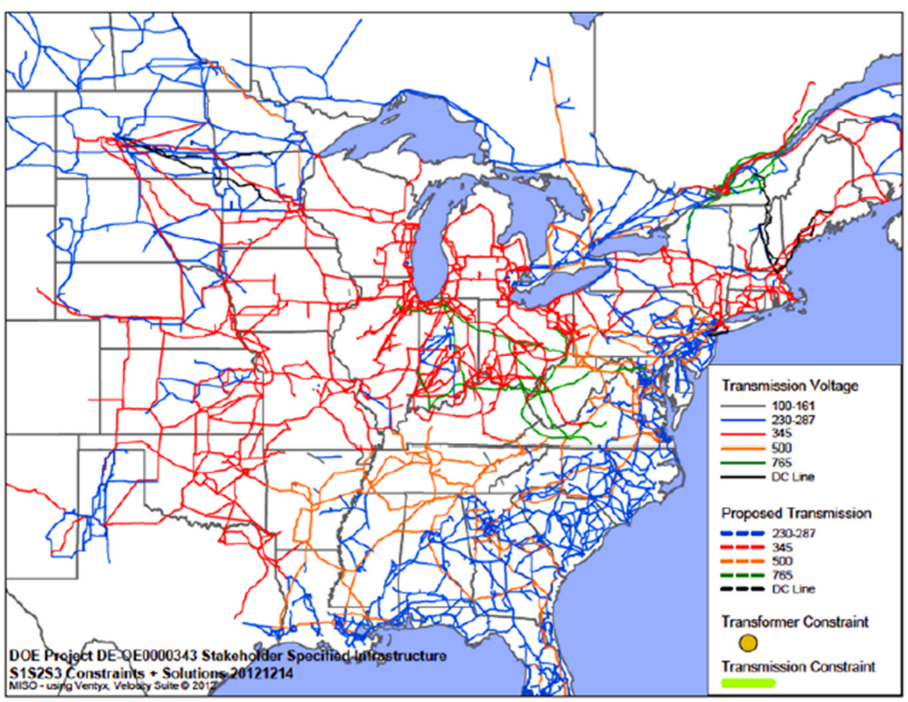
Appendix F Map of NERC Regions and U.S. Interconnections

Figure 41. U.S. Interconnections and NERC Regions



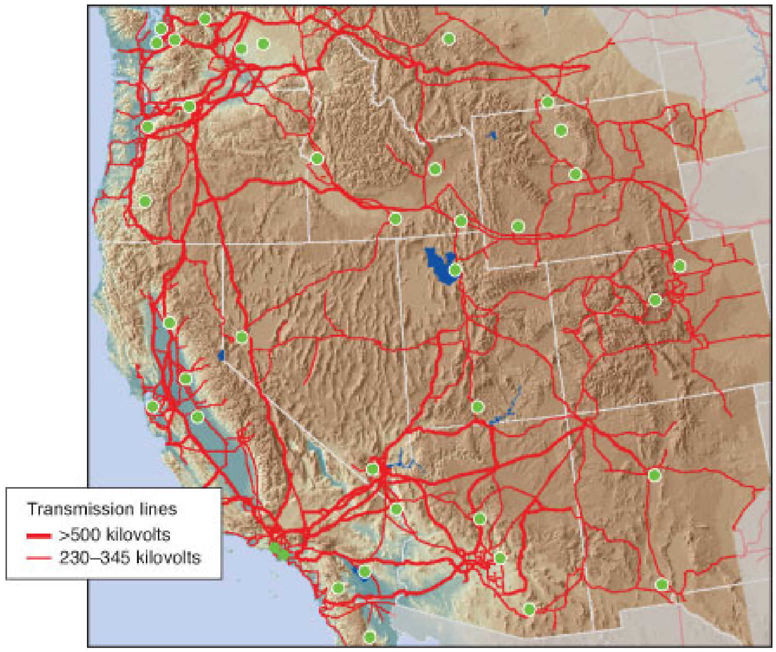
Source: NERC

Figure 42. Eastern Interconnection Transmission (230 kV and above)



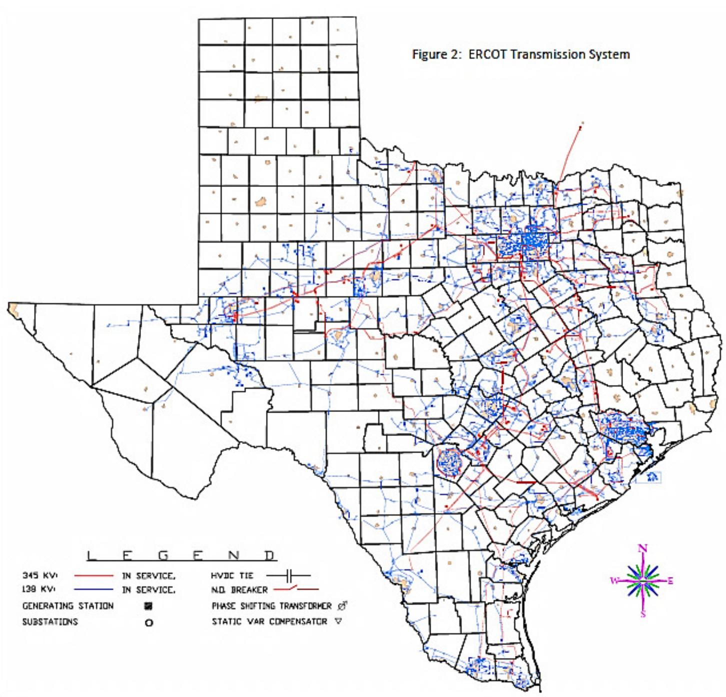
Source: EIPC (Existing and stakeholder specified transmission, Phase 2 Report, Figure A1-1)

Figure 43. Western Interconnection Transmission (230 kV and above)



Source: Lawrence Livermore National Laboratory

Figure 44. Texas Interconnection



Source: ERCOT

Appendix G The Evolution of FERC Electricity Policy and Rules

The Federal Energy Regulatory Commission (FERC) is a federal agency housed in the U.S. Department of Energy. In 1920, Congress established the Federal Power Commission (FPC) to coordinate hydroelectric projects under federal control. In 1928, Congress voted to give the FPC funds to permanently hire their borrowed staff. Two years later, the Federal Power Act established a five-member, bipartisan commission to run the FPC. FERC was created in 1977 by Department of Energy Organization Act. FERC took the place of the Federal Power Commission, which was dissolved by that same act.

This appendix provides a timeline and brief overview of the legislation and regulatory orders related to FERC's regulation of the electric system.

For further details, see the main source for this timeline at http://www.ferc.gov/students/ferc/history.asp.

1920 – Federal Power and Water Act

In 1920 the Federal Power and Water Act established the Federal Power Commission (FPC), which included the Secretaries of War, Interior, and Agriculture.

1935 – Federal Power Act

In 1935 the Federal Power Act (FPA) assigned the regulation of interstate wholesale electricity transactions to the FPC. The FPA also:

- Changed the makeup of the FPC to five commissioners nominated by the President to serve five year terms; no more than three commissioners are to be from the same political party
- Encouraged voluntary interconnection between utilities
- Required wholesale rates and contracts be filed and regulated based on the cost to provide service and a reasonable return

1935 – Public Utility Holding Company Act

Also in 1935 the Public Utility Holding Company Act (PUHCA) required that utility holding companies either limit their services to one state, and thus be regulated by that state, or file with and be regulated by the Securities Exchange Commission (SEC). Under PUHCA, utility holding companies could not own non-utility businesses.

- Most utility holding companies chose to limit themselves to one state to avoid regulation by the SEC

1977 – Department of Energy Organization Act

In 1977 the Department of Energy Organization Act established the Department of Energy (DOE), dissolved the FPC, and gave its oversight authority to a new entity within the DOE: the Federal Energy Regulatory Commission (FERC).

1978 – Public Utilities Regulatory Policies Act

In 1978 the Public Utilities Regulatory Policies Act (PURPA) was passed in response to a number of events and trends, including the oil embargo, perceived natural gas shortages, increases in the cost to build nuclear electric generation, and the impacts of environmental regulation on power plants. A few highlights of PURPA are (1)Utilities were required to buy power from Qualified Facilities (QFs) at a price set by the state regulator; (2) Gave FERC the authority to require one utility to provide another utility with transmission service, if it was in the public interest; (3) Strengthened FERC's ability to order interconnections based on public interest

1992 – Energy Policy Act

The goal of the Energy Policy Act of 1992 (EPAct 92) was to encourage market-based approaches. The EPAct 92:

- Modifies PUHCA and FPA
- Exempts some generators from PUHCA and PURPA
- Requires utilities to provide transmission service to other utilities for sale or resale of electricity
- Requires utilities to enlarge their transmission system where necessary
- Sets a target for an open access transmission system where transmission owners are compensated for use of their system

1996 – FERC Orders 888 and 889

FERC issued Orders 888 and 889 in response to the EPAct 92. The orders were designed to remove obstacles to competition in wholesale energy markets by requiring open access to transmission. Specifically, the orders: (1) Require utilities to file an OATT, use the OATT for their own generation, and develop an OASIS system, and (2) Clarify the definition of an ISO

1999 – FERC Order 2000

FERC Order 2000, issued in 1999, encourages the voluntary formation of RTOs and places them in charge of tariff design, OASIS, transmission planning, and interregional coordination.

2005 – Energy Policy Act

The Energy Policy Act of 2005 (EPAct05) repealed PUHCA, exempted utilities from buying power from QFs that have access to a market, and strengthened FERC's authority to require interconnections and one utility to provide transmission service to another.

2006 – FERC Orders 670, 671, 672, 679, 681, 688, and 689

FERC issued a number of orders in 2006:

1. FERC Order 670 – anti-fraud, anti-manipulation rules
2. Order 671 – tighter QF thermal efficiency requirements
3. Order 672 – formation of ERO
4. Order 679 – transmission pricing reforms to encourage infrastructure investment
5. Order 681 – requires long-term firm transmission rights be made available in markets
6. Order 688 – eliminated ownership restrictions of QFs
7. Order 689 – construction permits for transmission siting rules

2007 – FERC Orders 697 and 890

In 2007, FERC issued:

- Order 697 – addressed market power in generation and transmission companies
- Order 890 – amends Orders 888/889, updates the pro forma OATT, requires 9 principles of transmission planning: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation for new projects

2010 – FERC Order 1000

Order 1000, issued by FERC in 2011, places a number of requirements on transmission planners, including:

- Each public utility transmission provider must participate in a regional transmission planning and cost allocation process, and coordinate with each neighboring transmission planning region to determine if there are cost-effective solutions to their mutual transmission needs
- Regional cost allocation process must satisfy 6 principles
- Local and regional transmission planning must take public policy into account
- Removal of the Right of First Refusal (ROFR) from tariffs

Implementation of Order 1000 is ongoing, and a number of important questions regarding the interrelationship between state authority over transmission siting, inclusion of new projects in a regional transmission plan, and the integrated resource planning of generation and transmission at the state level will be addressed by federal and state policymakers.

NAVIGANT

Appendix H Overview of NERC

The North American Electric Reliability Corporation (NERC) is the FERC-designated Electricity Reliability Organization (ERO) for the United States. NERC develops and enforces reliability standards; monitors the Bulk-Power System (BPS); assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel.

According to the NERC website:

> *The North American Electric Reliability Corporation is a not-for-profit entity whose mission is to ensure the reliability of the Bulk-Power System in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the Bulk-Power System through system awareness; and educates, trains and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. Entities under NERC's jurisdiction are the users, owners and operators of the Bulk-Power System, which serves more than 334 million people.*

Congress created an ERO through the Energy Policy Act of 2005. The Federal Energy Regulatory Commission (FERC) certified NERC as the ERO on July 20, 2006, and provides governmental oversight. NERC also is subject to oversight by governmental authorities in Canada. In addition, industry stakeholders participate in NERC's processes through various committees and subgroups.

NERC develops, implements, and enforces mandatory Reliability Standards for the Bulk-Power System in accordance with Section 215 of the Federal Power Act. The statute requires users, owners, and operators of the Bulk-Power System in the United States to be subject to FERC-approved NERC Reliability Standards. This includes the development of standards designed to ensure the protection of cyber assets that may impact the reliable operations of the transmission grid.

NERC assesses and reports on the reliability and adequacy of the North American Bulk-Power System divided into the eight Regions. The users, owners, and operators of the Bulk-Power System within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

NERC defines a reliable Bulk-Power System as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity. NERC divides reliability into two categories:

- **Adequacy:** Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources refer to a combination of electricity generating and transmission facilities that produce and deliver electricity, and demand-response programs that reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.

- **Security:** For decades, NERC and the bulk power industry defined system security as the ability of the Bulk-Power System to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. The Bulk-Power System must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

NERC is governed by a Board of Trustees comprised of 10–12 independent trustees and the president and chief executive officer of NERC. Trustees have expertise in electricity operations and reliability; legal, market, financial and regulatory matters; and familiarity with regional system operation issues. Trustee selection reflects geographic diversity. Trustees are independent of the industry and must commit to serving the public interest and representing the reliability concerns of the entire North American electricity system. Trustees are elected by the Member Representatives Committee and serve for a term of three years. NERC is overseen by the Federal Energy Regulatory Commission and governmental authorities in Canada.

NERC Reliability Standards

Within the United States, other than Alaska and Hawaii, all users, owners, and operators of the BES must comply with the Reliability Standards. The complete text of these standards can be downloaded from NERC's website (www.nerc.com).

NERC's standards fall into the following categories, each represented by an abbreviation in the NERC Standard Number.

- BAL: Resource and Demand Balancing
- CIP: Critical Infrastructure Protection
- COM: Communications
- EOP: Emergency Preparedness and Operations
- FAC: Facilities Design, Connections, and Maintenance
- INT: Interchange Scheduling and Coordination
- IRO: Interconnection Reliability Operations and Coordination
- MOD: Modeling, Data, and Analysis
- NUC: Nuclear Plant Interface Coordination
- PER: Personnel Performance, Training, and Qualifications
- PRC: Protection and Control
- TOP: Transmission Operations
- TPL: Transmission Planning
- VAR: Voltage and Reactive

NERC laid out, in their 2014-2016 Reliability Standards Development Plan, their strategy for reaching a "steady-state" of reliability standards by the end of 2015, which they define as "a stable set of clear, concise, high-quality, and technically sound Reliability Standards that are results-based, including retirement of requirements that do little to promote reliability."

New, modification to, or retirement of standards are driven by FERC directives, priority rankings by NERC's Steering Committee, and the results of an Independent Expert Review Panel (IERP) report completed in 2013. NERC posts a spreadsheet tracking its ongoing project schedule and status on its website (www.nerc.com). NERC's prioritization for 2014 is shown in Table 6.

Table 6. NERC Reliability Standards Development Plan

Prioritization	Project Number	Project Title
High	2008-02	Undervoltage Load Shedding
	2009-02	Real-Time Reliability Monitoring and Analysis Capabilities
	2013-03	Geomagnetic Disturbance Mitigation Measured (Stage 2)
	2009-03	Emergency Operations
Medium	2007-11	Disturbance Monitoring
	2010-05.2	Phase 2 of Protection System Misoperations: SPS/RAS
		Periodic Review of BAL-004, -005, and -006
	2012-09	IRO Review
Low	2010-02	Connecting New Facilities to the Grid
	2010-08	Functional Model Glossary Revisions
	2012-13	NUC Review
Pending Input	2007-17.3	Protection System Maintenance and Testing Auxiliary Relays
	2010-13.3	Generator Relay Loadability Stable Power Swings

Source: NERC Reliability Standards Development plan 2014-2016, approved by Board of Trustees November 7, 2013

For additional information, see www.NERC.com.

Appendix I Overview of DOE Transmission-Related Activities

Among many other objectives, the U.S Department of Energy (DOE) has made modernizing the nation's energy infrastructure a priority. The Office of Electricity Delivery and Energy Reliability (OE) is the lead office at DOE with respect to electricity transmission issues. OE's mission is to lead national efforts to modernize the electric grid; enhance security and reliability of the infrastructure; and facilitate recovery from disruptions to the energy supply. OE's main activities in each area are summarized below.

Advanced Grid Integration. Fosters the deployment of smart grid systems and technologies to enhance the reliability, efficiency, and security of the electric power grid. Since 2009, under the American Recovery and Reinvestment Act of 2009 (ARRA), DOE and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant (SGIG) projects involving more than 200 participating electric utilities and other organizations to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid operations. OE is managing these projects through completion in 2015.

Power Systems Engineering Research and Development. Works to accelerate discovery and innovation in electric transmission and distribution technologies and create "next generation" devices, software, tools, and techniques to help modernize the electric grid. Projects are planned and implemented in concert with partners from other federal programs; electric utilities; equipment manufacturers; regional, state, and local agencies; national laboratories; and universities. Current priorities include Smart Grid research and development, energy storage, and cybersecurity for energy delivery systems.

Energy Infrastructure Modeling and Analysis. Supports the development of a reliable, secure, resilient, and advanced U.S. energy infrastructure through activities such as electric system modeling, synchrophasor-based tool development, transmission reliability research, reliability assessments, energy security modeling and visualization, and energy infrastructure risk analyses (see Chapter 7).

National Electricity Delivery. Provides technical assistance to states, regional entities, and tribes to help them develop and improve their programs, policies, and laws that will facilitate the development of reliable and affordable electricity infrastructure. Also authorizes the export of electricity, issues permits for the construction of cross-border transmission lines, and is leading efforts to improve the coordination of federal transmission permitting on federal lands, as follows:

- **Coordination of Federal Transmission Authorizations** under section 216(h) to the Federal Power Act, which requires that DOE act as the lead agency for purposes of coordinating all applicable federal authorizations and related environmental reviews required to site an electric transmission facility.

- **Interconnection-Wide Transmission Planning Initiative.** DOE is promoting collaborative long-term analysis and planning for the Eastern, Western and Texas electricity interconnections, which will help states, utilities, grid operators, and others prepare for future growth in energy demand, renewable energy sources, and Smart Grid technologies. This represents the first-ever effort to take a collaborative, comprehensive look across each of the three transmission interconnections to assess transmission needs for future electricity scenarios.
- **Energy Corridors on Federal Lands.** DOE, the U.S. Bureau of Land Management, and other cooperating federal agencies have released a Draft Programmatic Environmental Impact Statement supporting designation of energy transport corridors on federal lands in 11 western states.
- **National Electric Transmission Congestion Study.** OE performs ongoing analysis of the Eastern and Western Interconnects to identify major electric transmission constraints. The Energy Policy Act (EPAct) of 2005 requires DOE to publish a National Electric Transmission Congestion Study every three years (see Chapter 4).
- **Presidential Permits and Export Authorizations.** OE authorizes the export of electric energy to Canada and Mexico and issues permits for the construction, connection, operation, and/or maintenance of electric transmission facilities at the international border (see Chapter 4).
- **Federal Power Act Section 202(c) Emergency Orders.** Under FPA section 202(c), during the continuance of a war in which the U.S. is engaged or when an emergency exists, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

Infrastructure Security and Energy Restoration. Leads efforts for securing the U.S. energy infrastructure against all hazards, reducing the impact of disruptive events, and responding to and facilitating recovery from energy disruptions, in collaboration with industry and state and local governments. Works with the Department of Homeland Security, the Federal Energy Regulatory Commission, and other national, regional, state, and local government and commercial organizations to:

- Support the national critical infrastructure protection program
- Analyze infrastructure vulnerabilities and recommend preventive measures
- Help other agencies prepare for and respond to energy emergencies and minimize the consequences of an emergency
- Conduct emergency energy operations during a declared emergency or national security special event in accordance with the National Response Plan
- Develop, implement, and maintain a national energy cyber security program

See http://energy.gov/oe/office-electricity-delivery-and-energy-reliability for more information.

Appendix J Glossary of Terms

This appendix defines terms related to transmission and transmission planning. For further reading, see the following resources, which were used to develop this glossary:

- *Edison Electric Institute Glossary of Electric Industry Terms published April 2005*
- *Energy Central Glossary available online at http://www.energycentral.com/reference/glossary*
- *NERC Glossary of Terms Used in NERC Reliability Standards updated October 30, 2013 and available online at http://www.nerc.com/files/glossary_of_terms.pdf*
- *PJM Glossary available online at http://www.pjm.com/Home/Glossary.aspx*
- *Transmission Hub Transmission 101: Glossary available online at http://transmissionhub.com/transmission-101/glossary.php*
- *U.S. Energy Information Administration (EIA) Electricity Glossary available online at http://www.eia.gov/tools/glossary/?id=electricity*

Additional sources include the American Public Power Association (APPA), Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), New York Independent System Operator (NYISO), Independent System Operator of New England (ISO-NE), and Jack Casazza and Frank Delea's Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations (published by IEEE and Wiley in 2010).

A

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

Aggregator: any marketer, broker, public agency, city, county, or special district that combines the loads of multiple end-use customers in negotiating the purchase of electricity, the transmission of electricity, and other related services for these customers.

Allowance for Funds Used During Construction (AFUDC): an amount recorded by a company to represent the cost of those funds used to finance construction work in progress.

Alternating Current (AC): electric current that periodically reverses direction, usually 100 or 120 times per second (50 or 60 cycles per second or 50/60 Hz) (See also Current, and Direct Current).

Ampere (amp): unit of measure of an electric current, proportional to the quantity of electrons flowing through a conductor past a given point in one second (one amp is produced by an electric force of 1 volt acting across a resistance of 1 ohm, or one coulomb passing in one second).

Ancillary Services: services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system; may include black start service, load regulation, spinning reserve, non-spinning reserve, replacement reserve, frequency response service, and voltage support.

Apparent Power: the product of the voltage (volts) and current (amperes) of a circuit, comprises both real and reactive power and is generally divided by 1,000 and designated in kilovoltamperes (kVA).

Area Control Error (ACE): instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias.

Automatic Generation Control: equipment that automatically adjusts the output of generation units in a control area to keep generation and load in balance in real time and to maintain its interchange schedule in addition to its share of frequency regulation.

Auxiliary Power Supply: the power required for operation of generation station accessory equipment necessary for the operation of a generating station.

Availability: a measure of time a generating unit, transmission line or other facility is capable of providing service, whether or not it actually is in service.

Available Transfer Capacity (ATC): a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin (See Transfer Capability).

Avoided Cost: the minimum amount an electric utility is required to pay an independent power producer, under the PURPA regulations of 1978, equal to the costs the utility calculates it avoids in not having to produce that power.

B

Balancing Authority: the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within its area, and supports interconnection frequency in real time.

Base Load Generation: the part of electricity demand which is continuous, and does not vary over a 24-hour period; or the minimum amount of electric power delivered or required over a given period of time at a steady rate.

Black Start Capability: the ability of a generating unit or station of being started without an outside electrical power supply.

Blackout: loss of the electric power to an area.

British Thermal Unit (Btu): the amount of heat energy required to raise the temperature of one pound of water by 1 degree Fahrenheit at one atmosphere pressure.

Brownout: a system voltage reduction in response to a shortage of power relative to demand; though service is not disrupted completely, causes, for example, a dimming of lights.

Bulk Power System: a term commonly applied to the portion of an electric system that includes electrical generation resources and the bulk transmission system (lines operated at voltages of 100 kV or higher).

Bundled Utility Service: where energy, transmission, and distribution services, as well as ancillary and retail services, are provided by one entity.

C

Customer Average Interruption Duration Index (CAIDI): the average length of an interruption, weighted by the number of customers affected, for customers interrupted during a specific time period:

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customer\ Interruptions}$$

Capacitor: a device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. It is installed in substations and on poles. Usually it is installed to correct an unwanted condition in an electrical system.

Capacity: generator capacity: The maximum output, commonly expressed in megawatts (MW), that a generating unit, generating station, or other electrical apparatus can supply to system load, adjusted for ambient conditions (See also Nameplate Capacity).

Capacity Benefit Margin (CBM): amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Factor: the ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.

Capacity Margin: the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads, calculated as the difference between net capability and system maximum load requirements (peak load):

$$Capacity\ Margin = \frac{Resources - Peak\ Firm\ Demand}{Resources}$$

(See also Reserve Margin).

Capacity Market: market that provides economic incentives to attract investment in new and existing supply-side, and often demand-side, capacity resources as needed to maintain bulk power system reliability requirements (See also Forward Capacity Market, Installed Capacity Market, and Reliability Pricing Model).

Capacity Reserve: the amount of generating capacity a central power system must maintain to meet peak loads.

Certificate of Public Convenience and Necessity: a special permit, commonly issued by a state commission, which allows a utility to engage in business, construct facilities or perform some other service. The commission involved may attach any reasonable terms and conditions that public convenience and necessity may require (name used for this certificate and its precise definition may vary by state).

Cogeneration: see Combined Hear and Power (CHP).

Coincident Peak Demand: the sum of two or more peak loads that occur in the same time interval (See also non-coincident peak demand).

Combined Heat and Power (CHP): the simultaneous production of electric energy and useful thermal energy for industrial, commercial, heating or cooling purposes.

Congestion: a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Construction Work in Progress (CWIP): a subaccount in the utility plant section of the balance sheet representing the sum of the balances of work orders for utility plant in process of construction but not yet placed in service.

Contract Path: a specific contiguous electrical path from a Point of Receipt to a Point of Delivery for which transfer rights have been contracted.

Copper Sheet: a hypothetical electrical system in which all generator and loads are interconnected without transmission congestion or losses.

Critical Energy Infrastructure Information (CEII): specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that relates details about the production, generation, transmission, or distribution of energy; could be useful to a person planning an attack on critical infrastructure; is exempt from mandatory disclosure under the Freedom of Information Act; and gives strategic information beyond the location of the critical infrastructure.

Current: a measure of the velocity of the flow of electric charge, measured in amperes or amps.

Curtailment: a reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

D

Day-Ahead Market: a day-ahead forward market in which market participants may submit offers to sell and bids to buy energy and ancillary services. The results are posted daily and are financially binding.

Day-Ahead Schedule: schedule, prepared by a Scheduling Coordinator or the Independent System Operator before the beginning of a trading day, that indicates the levels of generation and demand scheduled for each settlement period for that trading day.

Demand: the rate at which electric energy is used at a given instant or averaged over a designated interval of time, typically measured in kilowatts (kW) or megawatts (MW).

Demand Response (DR): changes in electric use by resources on the demand side (end-use customers) from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when system reliability is jeopardized.

Derating: a decrease in the available capacity of an electric generating unit, commonly due to system or equipment modification, or environmental, operational, or reliability considerations.

Direct Current (DC): the movement of an electric charge from negative to positive that flows continuously in only one direction (See also Current and Alternating Current (AC)).

Distributed Generation: a small generator, typically 10 megawatts or smaller, that is sited at or near load, that is attached to the distribution grid, and can serve as a primary or backup energy source; technologies include combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics.

Distribution Factor: the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility or Flowgate.

Distribution System: the network of wires and equipment that is dedicated to delivering electric energy from the transmission system to an end user at a lower voltage than the transmission system.

Disturbance: an unplanned event that produces an abnormal system condition.

Diversity: characteristic of a variety of electric loads where individual maximum demands usually occur at different times (See also Load Diversity).

Diversity Factor: the ratio of the sum of the non-coincident maximum demands of two or more loads to their coincident maximum demand for the same period.

E

Economic Dispatch: the start-up, shutdown, and operation of individual generating units to obtain the most economical production of electricity for customers.

Electric Reliability Council of Texas (ERCOT): the Independent System Operator (ISO) for approximately 85% of the State of Texas.

Element: any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Embedded Cost: monies already spent for investment in plant and operating expenses.

Energy: broadly defined, energy is the ability to do work; electrical energy is generated by a generator, which converts other forms of energy into electrical energy that is then transmitted through the electric transmission and distribution systems.

Energy Efficiency: the ratio of service or output provided to energy input (e.g., lumens to watts in the case of light bulbs); services provided can include buildings-sector end uses such as lighting, refrigeration, and heating, industrial processes, or vehicle transportation; differs from conservation in that it provides energy reductions without sacrifice of service.

Energy Information Administration (EIA): since October 1977, the Energy Information Administration (EIA) of the Department of Energy (DOE) has been responsible for collecting and publishing statistical data on energy production, consumption, prices, resources, and projections of supply and demand.

Energy Policy Act 2005 (EPAct): addressed energy production in the United States, including: energy efficiency, renewable energy, oil and gas, coal, Tribal energy, nuclear matters and security, vehicles and motor fuels, including ethanol, hydrogen, electricity, energy tax incentives, hydropower and geothermal energy, and climate change technology; the EPAct reaffirmed a commitment to wholesale power markets, strengthened FERC's regulatory tools, and provided for the development of a stronger energy infrastructure (See Chapter 3 and Appendix G).

Energy Policy Act of 1992: a comprehensive federal act generally designed to improve the efficiency of energy use in the United States, which created a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Utility Holding Company Act (PUHCA) of 1935 and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid (see Chapter 3 and Appendix G).

Energy Services Company: an energy entity that provides service to a retail or end-use customer.

Equivalent Forced Outage Rate (EFOR): the proportion of hours in a year that a unit is unavailable because of forced outages.

Expected Unserved Energy (EUE): the expected amount of energy curtailment per year due to demand exceeding available capacity, usually expressed in MWh.

Extra High Voltage: generally, voltage of 345,000 volts (345kV) or higher.

F

FACTS (Flexible Alternative Current Transmission System): a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.

Fault: a physical condition, such as a short circuit, a broken wire, or an intermittent connection, that results in the failure of a component or facility of the transmission system to transmit electrical power in a manner for which it was designed.

Federal Energy Regulatory Commission (FERC): an independent regulatory agency within the U.S. Department of Energy (DOE) which regulates the transmission and wholesale sales of electricity in interstate commerce and administers accounting and financial reporting regulations and conduct of jurisdictional companies.

Federal Power Act (FPA): enacted in 1920, and amended in1935, the Act established guidelines for the federal regulation of a utility's sales in interstate commerce. The Federal Energy Regulatory Commission (FERC) is now charged with the administration of this law.

Federal Power Commission (FPC): the predecessor agency of the Federal Energy Regulatory Commission (FERC), the FPC was created by the Federal Water Power Act on June 10, 1920 and was originally charged with regulating the electric power and natural gas industries; it was abolished on September 30, 1977, when the U.S. Department of Energy (DOE) was created, and its functions were divided between the DOE and FERC.

Feeder: an electric line for supplying electric energy within an electric service area or sub-area.

FERC: see Federal Energy Regulatory Commission.

Firm Capacity: power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions (See also Non-Firm Capacity).

Firm Transmission Service: transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility (See also Non-Firm Transmission Service and Point-to-Point Transmission Service).

Fixed Costs: costs that do not change or vary with usage, output, or production.

Flowgate: designated point on the transmission system mathematically capturing one or more monitored transmission lines or elements.

Forced Outage: the shutdown of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Forced Outage Rate: the percentage of time that a power system, or a component of that system such as a generating unit, is unavailable due to unexpected equipment failures.

Forward Capacity Market (FCM): capacity market administered by the Independent System Operator of New England (ISONE).

Franchised Service Territory: area in which a utility system is required to or has the right to supply electric service to ultimate customers.

Frequency: the number of cycles per second through which an alternating current passes, generally standardized in the United States electric utility industry at 60 cycles per second (60 hertz) (See also Alternating Current).

Frequency Response: either the ability of a system or elements of the system to react or respond to a change in system frequency; or the sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Functional Unbundling: a rate design or corporate organization that offers generation, transmission, or distribution services as stand-alone services with separate charges.

G

Generation Availability Data System (GADS): a computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Shift Factor: characteristic that describes a generator's impact on a flowgate.

Gigawatt (GW): a unit of power equal to one billion watts or 1,000 megawatts; one gigawatt of electricity generated would power between 800,000 and one million homes.

Gigawatt Hours (GWh): a unit of measurement used to describe the amount of electricity produced or consumed; one gigawatt-hour is equal to one billion watt-hours or 1,000 megawatt hours.

Grid: an interconnected network of electric transmission lines, and related facilities.

Gross Generation: the total amount of electric energy produced by the generating units in a generation station(s) measured at the generator terminals.

H

Heat Rate: a measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour (kWh), computed by dividing the total energy content of fuel burned for electric generation by the resulting net generation:

$$Heat\ Rate = \frac{Energy\ content\ of\ fuel\ (Btu)}{Net\ generation\ (kWh)}$$

(See also Incremental Heat Rate).

Hertz (HZ): a unit of electricity system frequency equal to one cycle per second (See also Frequency).

Holding Company: usually means a Corporation (parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies; unless an exemption is available, under the Public Utility Holding Company Act (PUHCA) all holding companies whose subsidiaries are engaged in the electric utility business or in retail distribution of natural manufactured gas must register with the Securities and Exchange Commission (SEC) and limit the operations of each holding company system to a "single integrated public utility system" with only "such other businesses as are reasonably incidental or economically necessary or appropriate to the operations of [the]...system," and comply with various regulations regarding the financing and operation of the holding company system (See also Public Utility Holding Company and Public Utility Holding Company Act).

Hourly System Lambda: a term, commonly given to the incremental cost that results from the economic dispatch calculation, which represents the cost of the next kilowatt hour that could be produced from economical dispatchable units on the system.

Hub: a group of nodes, also called buses, within a pre-determined region and at which individual Locational Marginal Prices (LMPs) are calculated, for which the individual LMP values are averaged to create a single pricing reference.

I

Impedance: a characteristic of a circuit that is representative of the combined resistance and reactance of that circuit.

Inadvertent Interchange: difference between net actual energy flow and net scheduled energy flow into or out of a Balancing Area.

Incremental Cost: the component of the total cost of generator operation that varies as the output varies; the cost of the next increment of generation (the next megawatt), expressed in dollars per megawatt hour or in mills per kilowatt-hour (See also Marginal Cost).

Incremental Heat Rate: the rate of a change in heat input per unit of time to the corresponding change in power output (See also Heat Rate).

Incumbent transmission developer/provider: an entity that develops a transmission project within its own retail distribution service territory or footprint See Nonincumbent transmission developer/provider).

Independent power producer (IPP): a corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.

Independent Transmission Company: a stand-alone, for-profit transmission business; can be project-focused (focus on individual merchant or regulated transmission projects), can own and operate existing regulated transmission systems, and can refer to transmission companies affiliated with incumbent utilities that look beyond the incumbent's footprint.

Independent System Operator (ISO): an independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system (See also Regional Transmission Organization).

Installed Capacity (ICAP): generating capacity that is physically on the ground and has a defined value.

Installed Capacity (ICAP) Market: capacity market administered by the New York Independent System Operator (NYISO).

Integrated Resource Planning: a process by which utilities and regulatory commissions assess the cost of, and choose among, various resource options.

Interchange: energy or capacity transferred from one electric company or power pool to another.

Interchange Transaction: an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.

Interconnection: a connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a non-utility generator (including a distributed generation facility) to a control area or system.

Interstate Commerce (FERC definition): sales where transportation of natural gas, oil, or electricity crosses state boundaries. Interstate sales are subject to FERC jurisdiction.

Inverter: a circuit for converting direct current (DC) electrical power to alternating current (AC).

Investor Owned Utility (IOU): a privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

ISO: see Independent System Operator.

K

Kilovolt Ampere (kVA): one kilovolt ampere equals 1,000 volt amperes (See Volt Amperes).

Kilowatt (KW): a unit of power that is equal to 1,000 watts.

Kilowatt Hours (KWh): the basic unit of electric energy equal to one kilowatt (kW) of power supplied to or taken from an electric circuit steadily for one hour; one kWh equals 1,000 watt-hours.

L

Load Center: a limited geographical area where large amounts of power are used by customers.

Load Diversity: the condition that exists when the peak demands of a variety of electric customers occur at different times.

Load Duration Curve: a nonchronological, graphical summary of demand levels with corresponding time durations using a curve, which plots demand magnitude (power) on one axis and percent of time that the magnitude occurs on the other axis.

Load Factor: the ratio of the average load supplied to the peak or maximum load during a designated period; may also be derived by multiplying the kWh in a given period by 100, and dividing by the product of the maximum demand in kW and the number of hours in the same period.

Load Following: an electric system's process of regulating its generation to follow the changes in the customers' demand.

Load Forecasting: estimate of electrical demand or energy consumption at some future time.

Load Pocket: an area on the electrical system that, because of transmission limitations, must have internal generation resources available because the area cannot be served entirely by external sources.

Load Profiles: information on a customer's usage over a period of time, usually a 24-hour period.

Load Shape: a curve on a chart showing power (kW) supplied (on the horizontal axis) plotted against time of occurrence (on the vertical axis), and illustrating the varying magnitude of the load during the period covered.

Load Shift Factor: a factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored flowgate.

Load Shifting: a load shape objective that involves moving loads from peak periods to off-peak periods.

Load-Serving Entity: an entity that secures energy and transmission service to serve the electrical demand and energy requirements of its end-use customers.

Local Distribution Utility (LDU): the utility that delivers electricity to a retail customer's home or business along the distribution poles, wires and other necessary equipment, that the LDU either owns or operates.

Locational Marginal Price (LMP): the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.

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

Loss of Load Expectation (LOLE): a reliability measure that shows the expected number of days in the year when the daily peak demand exceeds the available generating capacity, obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year (referred to as Loss of Load Hours or Hourly Loss of Load Expectation if hourly demands are used in the calculation instead of daily peak demands).

Loss of Load Hours (LOLH): a reliability measure that shows the expected number of hours in the year when the hourly peak demand exceeds the available generating capacity, obtained by calculating the probability of hourly peak demand exceeding the available capacity for each hour and adding these probabilities for all the hours in the year.

Loss of Load Probability (LOLP): a reliability measure that shows the probability of daily peak demand exceeding the available generating capacity in a year, i.e. Loss of Load Expectation (LOLE) shown as a percentage (can also be calculated for Loss of Load Hours).

Losses: the general term applied to energy and capacity lost in the operation of an electric system, which occur principally in the form of waste-heat on the transmission and distribution system.

M

Maintenance Outages: the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility.

Marginal Cost: the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs; the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity (See also Incremental Cost).

Market Monitors: independent organizations responsible for monitoring compliance with the rules, standards, procedures, and practices of energy markets.

Market Power: the ability of any market trader with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases.

Maximum Demand: highest demand of the load within a specified period of time.

Mcf: one thousand cubic feet (of gas).

Megawatt Hours (MWh): a unit of measurement used to describe the amount of electricity produced or consumed, equal to one million watt-hours or one thousand kilowatt-hours.

Megawatts (MW): a unit of power, equal to one million watts or one thousand kilowatts; MWe refers to electric output from a generator, MWt to thermal output from a reactor or heat source (e.g., the gross heat output of a reactor itself, typically three times the MWe figure).

Merchant Generation: generation not owned and operated by an electric utility and that sells its output to wholesale customers.

Merchant Transmission: transmission not owned and operated by an electric utility and that sells its transmission capacity to wholesales customers.

Municipally-Owned Utility: a power utility system owned and operated by a local jurisdiction, such as a city, county, irrigation district, drainage district, or a political subdivision or agency of a State.

N

NAESB: see North American Energy Standards Board.

Nameplate Capacity: the full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturers.

Native Load: the end-use customers that the Load-Serving Entity is obligated to serve.

NERC: see North American Electric Reliability Corporation.

Net Capability: see Net Summer Capability and Net Winter Capability.

Net Generation: gross generation less kilowatt-hours used at the generating station(s) (See also Gross Generation).

Net Summer Capability: the steady hourly output which generating equipment is expected to supply to system load (exclusive of auxiliary) power as demonstrated by test at the time of summer peak demand.

Net Winter Capability: the steady hourly output which generating equipment is expected to supply to system load (exclusive of auxiliary) power as demonstrated by test at the time of winter peak demand.

Network Integration Transmission Service: a service that allows a transmission customer to use the entire transmission network to deliver power from one or more generating sources to one or more customer loads.

Non-Coincident Peak Demand: the sum of two or more individual demands which do not occur in the same demand interval; meaningful only when considering demands within a limited period of time, such as day, week, month, or season, and usually for not more than one year.

Non-Firm Capacity: power-producing capacity supplied or available under an arrangement that does not have the guaranteed continuous availability feature of firm capacity (See also Firm Capacity).

Non-Firm Transmission Service: point-to-point transmission service reserved and/or scheduled on an as-available basis (See also Firm Transmission Service and Point-to-Point Transmission Service).

Nonincumbent transmission developer: an entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the "incumbent" for purposes of the project.

Non-Spinning Reserve: an ancillary service that provides operating reserve not connected to the system but capable of serving demand within a specific time, or interruptible load that can be removed from the system in a specified time; generally, that specified time is ten minutes (See also Capacity Reserve and Spinning Reserve).

North American Electric Reliability Corporation (NERC): a nonprofit corporation formed in 2006 as the successor to the North American Electric Reliability Council established to develop and enforce mandatory reliability standards for the bulk electric system, with the fundamental goal of maintaining and improving the reliability of that system; NERC consists of regional reliability entities covering the interconnected power regions of the contiguous United States, Canada, and Mexico and is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

North American Energy Standards Board (NAESB): energy industry organization that serves as a forum for the development and promotion of standards in an effort to provide a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

O

Obligation to Serve: the obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates set for that service.

Off-Peak Energy: energy supplied during periods of relatively low system demands as specified by the supplier (See also On-Peak Energy).

Ohm: the unit of measurement of electrical resistance; one ohm is the resistance of a circuit element when a voltage of one volt is applied and results in a current of one ampere.

Ohm's Law: the relationship between voltage, current, and resistance or impedance; for Direct Currents voltage equals current multiplied by resistance:

$$Voltage\ (V) = Current\ (I) \times Resistance\ (R)$$

for Alternating Currents impedance replaces resistance, such that voltage equals current multiplied by impedance:

$$Voltage\ (V) = Current\ (I) \times Impedance\ (Z)$$

One Day in 10 Years Resource Adequacy Standard: resource adequacy criterion where the load is expected to be curtailed no more than once every ten years (See also Reliability Measures).

On-Peak Energy: energy supplied during periods of relatively high system demands as specified by the supplier.

Open Access Same Time Information Service (OASIS): an electronic information system that allows users to instantly receive data on the current operating status and transmission capacity of a transmission provider; standards for OASIS were established by FERC in Order No. 889.

Open Access Transmission Tariff (OATT): electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission (FERC) requiring the Transmission Service Provider to furnish all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.

P

Pancaked Transmission Rates: the accumulation of multiple transmission access fees charged transmission consumers by each owner of the transmission lines on which the power flows.

Peak Demand: the maximum load, or usage, of electrical power occurring in a given period of time, typically a day.

Peaking Generation: a generating unit normally operated only during the hours of highest daily, weekly, or seasonal loads; usually designed to meet the portion of load that is above base load.

Planned Outages: the shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Planning Authority: the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Planning Coordinator: see Planning Authority.

Planning Reserve Margin: an industry standard that measures the amount of generation capacity available to meet expected demand in the planning horizon.

Point-to-Point Transmission Service: a service that allows the customer to utilize a specified amount of transmission capacity to transmit power from designated points of receipt to designated points of delivery; a separate service agreement would be required and a separate charge generally would be paid for each pairing of a receipt point with a delivery point under this service (See also Firm Transmission Service and Non-Firm Transmission Service).

Power Factor: the ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit, generally expressed as a percentage ratio.

Power Flow Model: a computerized algorithm that simulates the behavior of the electric system under a given set of conditions and used to compute voltages and flows of real and reactive power through all branches of the system.

Power Pools: 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; can be tight (a group of electric companies that provide reciprocal transmission and/or power generating service for each other, coordinate their planning operations, and generally utilize central dispatch of generating plants) or loose (any multilateral arrangement other than a tight power pool or holding company arrangement).

Probabilistic Risk Assessment (PRA): risk assessment practice that uses probability distributions to characterize variability or uncertainty in risk estimates.

Provider of Last Resort: a legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

Pseudo Tie: a telemetered reading or value that is updated in real time and used as a tie line flow in the Automatic Generation Control/Area Control Error equation but for which no physical tie or energy metering actually exists; the integrated value is used as a metered MWh value for interchange accounting purposes.

Public Utility Holding Company: see Holding Company.

Public Utility Holding Company Act (PUHCA): enacted by the U.S. Congress in 1935 to regulate the large interstate holding companies that monopolized the electric utility industry during the early 20th century (See also Holding Company).

Public Utility Regulatory Policies Act (PURPA): one of five bills signed into law on November 8, 1978, as the National Energy Act, PURPA promotes energy efficiency and increased use of alternative energy sources by encouraging companies to build cogeneration facilities and renewable energy projects by obligating utilities to purchase power from such facilities (called qualifying facilities or QFs); states set the prices and quantities of power the utilities must buy from such facilities (See also Qualifying Facilities).

PUHCA: see Public Utility Holding Company Act.

PURPA: see Public Utility Regulatory Policies Act.

Power Purchase Agreement (PPA): a contract entered into by an independent power producer and an electric utility that specifies the terms and conditions under which electric power will be generated and purchased.

Q

Quick Start Units: generating units with the ability to synchronize and load quickly, generally within 10 minutes.

Qualifying Facility (QF): a cogeneration, renewable energy, or small power production facility that meets certain size, fuel use, ownership, operating, and efficiency criteria established by FERC pursuant to PURPA and has filed with FERC for QF status or has self-certified; QFs are physical generating facilities (See also Public Utility Regulatory Policies Act).

R

Ramping: changing the loading level of a generator in a constant manner over a fixed time (e.g., ramping up or ramping down).

Rate Base: the value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority; generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost.

Rate Class: a group of customers identified as a class and subject to a rate different from the rates of other groups.

Rate Structures: the design and organization of billing charges by customer class to distribute the revenue requirement among customer classes and rating period.

Rating: the operational limits of an electric system, facility, or element under a set of specified conditions.

Reactive Power: the portion of electricity, measured in volt amperes or kilovolt amperes, that establishes and sustains the electric and magnetic fields of alternating-current equipment, it must be supplied to most types of magnetic equipment, such as motors and transformers, and is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.

Regional Reliability Organizations: regional organizations charged with maintaining system reliability even during abnormal bulk power conditions such as outages and unexpectedly high loads.

Regional Transmission Organization: an entity authorized by the federal government as a neutral, independent party to coordinate movement and trade of wholesale electricity across a high-voltage electric grid (See also Independent System Operator).

Regulated Frequency: the frequency that, over a period of time, is regulated to maintain the average frequency at some predetermined value, done in such a way that the deviations from their predetermined value are always small.

Regulating Reserve: generation capable of increasing or decreasing its output in response to a regulating control signal to control for frequency deviations.

Regulation Service: an ancillary service that provides for following the moment-to-moment variations in the demand or supply in a control area and maintaining regulated frequency.

Reliability: the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired, which may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Reliability Coordinator: the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

Reliability Measures: characteristics of an electric system used to measure reliability, such as Expected Unserved Energy (EUE), Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), and Loss of Load Probability (LOLP).

Reliability Pricing Model (RPM): PJM's capacity market used to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEP) process (See also Capacity Market).

Renewable Portfolio Standard (RPS): a mandate, or goal, set to require or promote the use of renewable resources for electric generation. The Standard generally states that a certain percentage of a retail electric provider's overall or new generating capacity or energy sales must be derived from renewable resources, with the percentage increasing gradually over time.

Reserve: see Capacity Reserve.

Reserve Margin: the percentage of installed capacity exceeding the expected peak demand during a specified period, calculated as:

$$Reserve\ Margin = \frac{Resources - Peak\ Firm\ Demand}{Peak\ Firm\ Demand}$$

(See also Capacity Margin).

Reserve Sharing Group: a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group.

Resistance: a material's opposition to the flow of electric current, measured in ohms (Ω) (See also Ohm's Law).

Resource Adequacy: insuring that sufficient electric generation, transmission and demand response infrastructure are available to allow each regional transmission organization or independent transmission provider to balance available generation resources with load requirements at all times.

Resource Planner: the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area (See also Transmission Planner).

Retail Competition: a system under which more than one electric provider can offer to sell to retail customers, and retail customers are allowed to choose more than one provider from whom to purchase their electricity.

Revenue Requirements: the sum total of the revenues required to pay all operating and capital costs of providing service.

Right of First Refusal (ROFR): the right to construct, own and propose cost recovery for any new transmission project that is located within an incumbent transmission owner's service territory and approved for inclusion in a transmission plan developed through FERC guidelines; FERC Order 1000 stated that it is unjust and unreasonable to grant incumbent transmission providers a federal right of first refusal with respect to certain transmission projects because doing so may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, result in the inclusion of higher-cost solutions in the regional plan.

Rights of Way: a corridor of land on which electric lines may be located; the Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines on the land.

RTO: see Regional Transmission Organization.

Rural Electric Cooperative (REC or REMC): a nonprofit, customer-owned electric utility that distributes power in a rural area.

S

Security: the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Security Constrained Economic Dispatch: defined in the Energy Policy Act of 2005 as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities".

Security Coordinator: see Reliability Coordinator

Single Phase Service: service of small electrical loads of residential customers, small commercial customers, and streetlights at 120V/240V and requires less and simpler equipment and infrastructure to support and tends to be less expensive to install and maintain.

Sink: delivery point of a transmission line, also referred to as the Output-, Receiving-, or Load-End.

Siting: the process of determining the ideal location for infrastructure such as transmission lines and generation facilities.

Source: source of electricity on a transmission line, also referred to as the Input-, Generator-, Transmitter-, or Sending-End.

Spinning Reserve: generating units connected to the electrical system and ready to take load, or operating below their rated level (See also Non-Spinning Reserve).

Stability: the ability of a power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Standards of Conduct: standards for transmission providers that were strengthened and simplified through FERC Order No. 717, issued October 16, 2008; the Standards include three primary rules:

- The "independent functioning rule" requires transmission function and marketing function employees to operate independently of each other.
- The "no-conduit rule" prohibits passing transmission function information to marketing function employees.
- The "transparency rule," imposes posting requirements to help detect any instances of undue preference.

Substation: a high-voltage electric system facility used to switch generators, equipment, and circuits or lines in and out of a system and to change AC voltages from one level to another, and/or change alternating current to direct current or direct current to alternating current.

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

Surge: a sudden change in an electrical system's voltage that is capable of damaging electrical equipment, the most severe of which are caused by lightning.

System Average Interruption Duration Index (SAIDI): measure of system reliability defined as the minutes of sustained outages per customer per year.

System Average Interruption Frequency Index (SAIFI): measure of system reliability defined as the number of sustained outages per customer per year.

System Operating Limit: the value (such as MW, MVar, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

T

Telemetering: the ability to read a meter from a distance using electronic communications devices.

Terawatt: one trillion watts.

Thermal Rating: the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements; the capacity or transmission lines, transformers and other equipment is determined by these temperature limits.

Three Phase: electric energy transmitted by three or four wires at relatively high voltages with sinusoidal AC waves that are slightly out-of-phase by 120 degrees so that one is always positive; three-phase AC is the standard for the modern electric power system.

Tie Line: a circuit connecting Balancing Authority Areas.

Tolling: a charge for transmission service.

Total Transfer Capability (TTC): a best estimate of the total transmission or transfer capability of a defined path in a specific direction at a given time.

Transco: a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.

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; units are in terms of electric power, generally expressed in MW; the transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A".

Transfer Distribution Factor (TDF): see Distribution Factor.

Transformer: an electromagnetic device for changing the voltage level of alternating current electricity.

Transient: a momentary change or imbalance in an electric or control system; the term can also refer to a change in nuclear reactor coolant system temperature and/or pressure due to a change in power output of the reactor.

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

Transmission Availability Data System (TADS): a nation-wide system developed by NERC to collect data about transmission.

Transmission Corridor: land zoned to be available for future electricity transmission projects; or a geographic area where transmission congestion or constraints adversely affect consumers.

Transmission Customer Transmission Loading Relief (TLR): a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.

Transmission Planner: the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area (See also Resource Planner).

Transmission Planning: the process of analyzing future reliability and determining future transmission project needs (See also Transmission Planner).

Transmission Reliability Margin (TRM): the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure; TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Transmission Voltages: typically 69,000 V or 69 kV up to 765,000 V or 765 kV.

U

Unbundling: selling various component parts of a product or service separately, usually at a price that reflects costs for only that component of the product or service, for instance selling energy service separately from transmission and distribution service.

Undue Discrimination: for power, a criterion for determining illegal rates or service under the Federal Power Act.

Unforced Capacity (UCAP): in the New York Independent System Operator (NYISO), UCAP is the percentage of installed capacity (ICAP) that is available at any given time; UCAP is the unit used for buying and selling capacity on NYISO's ICAP market.

Uplift Charge: hourly and daily charges to all buyers of energy on the wholesale market to cover the cost of administering the hourly and day-ahead markets, respectively, as well as a monthly charge to cover planning.

V

Value of Lost Load (VOLL): the value that represents a customers' willingness to pay for reliable electricity service, generally measured in dollars per unit of power (i.e. $/kWh or $/MWh).

Variable Costs: costs that change or vary with usage, output or production.

Vertically-Integrated Utility: a utility that owns all the different aspects of making, selling, and delivering a product or service, for instance a utility that owns its own generating plants, transmission system, and distribution lines to provide all aspects of electric service to its customers.

Volt: a unit of measure of voltage; if steadily applied to a circuit having a resistance of one ohm, will produce a current one ampere (See also Voltage).

Volt Ampere: a unit of measure of apparent power (See also Apparent Power).

Volt Ampere Reactive (VARs): a unit of measure of reactive power (See also Reactive Power).

Voltage: a measure of the potential energy in an electric charge; also the force or push of electricity and the effective potential difference between any two conductors or between a conductor and ground.

Voltage Control: the control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Reduction: any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage Support: an ancillary service that is required to maintain transmission and distribution voltages on the grid within acceptable limits.

W

Watt: the unit of electrical power equal to one ampere under a pressure of one volt; also equal to 1/746 horse power.

Watt-Hour: one watt of power expended for one hour.

Western Electricity Coordinating Council (WECC): one of the ten regional reliability councils that make up the North American Electric Reliability Corporation (NERC), formerly called the Western Systems Coordinating Council.

Endnotes

[1] This phenomenon is called electromagnetic induction. See, for example, http://www.ndt-ed.org/EducationResources/HighSchool/Electricity/electroinduction.htm for the basic physics behind this discovery.
[2] The topics and chapters in this white paper follow in part those used in National Council on Electric Policy, "Electricity Transmission, A Primer," June 2004.
[3] PBS, "The American Experience, Edison's Miracle of Light, AC/DC What's the Difference," http://www.pbs.org/wgbh/amex/edison/sfeature/acdc.html.
[4] EIA Energy in Brief, "What is the electric power grid, and what are some challenges it faces?," http://www.eia.gov/energy_in_brief/article/power_grid.cfm.
[5] In a series of cases, beginning with *Munn v. Illinois, 94 U.S. 113 (1876)*, the U.S. Supreme Court began to expand the application of the concept of "public interest" by saying there are certain businesses that are "clothed with a public interest", which may justify government regulation.
[6] EIA, "Annual Outlook for U.S. Electric Power, 1985," DOE/EIA-0474(85) (August 1985), page 3.
[7] In general terms, when intrastate commerce has a substantial effect on interstate commerce, Congress may regulate the activity pursuant to the Commerce Clause. See http://nationalparalegal.edu/conlawcrimproc_public/CongressionalPowers/SubstantialEffect.asp.
[8] PBS, "Frontline, Public vs. Private Power: from FDR to Today," http://www.pbs.org/wgbh/pages/frontline/shows/blackout/regulation/timeline.html.
[9] EIA Energy in Brief, "What is the electric power grid, and what are some challenges it faces?," http://www.eia.gov/energy_in_brief/article/power_grid.cfm.
[10] American Electric Power, "Transmission," http://www.aep.com/about/IssuesAndPositions/transmission/.
[11] PJM, "PJM History," http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx.
[12] ISO-New England, "History," http://www.iso-ne.com/aboutiso/co_profile/history/; Analysis Group, "The New York Independent System Operator: A Ten-Year Review," April 12, 2010; Michigan Public Service Commission, Case No. U-11290, "Electric Restructuring Staff Market Power Discussion Paper," June 5, 1998.
[13] FERC, "Fact Sheet, Energy Policy Act of 2005," August 8, 2006.
[14] FERC Order No. 888, Final Rule, April 24, 1996, Summary.
[15] James Fama, "Keeping the Electricity Moving: NERC Guards the Bulk Power Grid," ASME, March 2011.
[16] DOE, "Top 9 Things You Didn't Know About America's Power Grid," September 20, 2013, http://energy.gov/articles/top-9-things-you-didnt-know-about-americas-power-grid.
[17] 16 USC 824(e). See FERC, "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States," Lawrence R. Greenfield, Associate General Counsel – Energy Markets, Office of the General Counsel; and FERC Order No. 667-A, paragraph 31.
[18] FERC Docket No. RM11-26-000, "Promoting Transmission Investment Through Pricing Reform," November 15, 2012.
[19] FERC Order No. 1000, page 226.
[20] In FERC Order No. 743, FERC clarified that the term Bulk Power System (BPS), used in the FPA, was distinct and more expansive than the NERC-defined term, BES, which determines the enforcement applicability of the Reliability Standards. See "Revision to Electric Reliability Organization Definition of Bulk Electric System," 133 FERC ¶ 61,150 (Order No. 743) (Nov. 2010) at page 36.
[21] National Governors Association, "State Strategies for Accelerating Transmission Development for Renewable Energy," January 20, 2012.
[22] Calif. Wilderness Coalition v. U.S. Department of Energy, No. 08-71074 (9th Cir. Feb. 1, 2011).

[23] *Piedmont Envtl Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).
[24] NERC, "Reliability Functional Model, Version 5," November 2009, page 6.
[25] NERC, "2012 Summer Reliability Assessment," pages 162-3.
[26] FERC Order No. 679, paragraph 201.
[27] FERC Order No. 1000, paragraph 119.
[28] FERC Order No. 1000, paragraph 225.
[29] FERC Order No. 1000-A, paragraph 420.
[30] FERC Order No. 1000, paragraph 225.
[31] FERC, "Order on Rehearing and Clarification," Primary Power LLC, Docket No. ER10-253-001, July 19, 2012, page 2, paragraph 1, footnote 5.
[32] NERC, "Project 2010-17 Definition of Bulk Electric System," November 8, 2013.
[33] NYISO, "NYISO 2012 Reliability Needs Assessment," September 2012, page 26.
[34] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-6.
[35] PJM, "Manual 14B," section 2.3.8.
[36] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-6.
[37] For example, in NPCC, "The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area." See NPCC, "Reliability Reference Directory # 1 Design and Operation of the Bulk Power System," (December 2009), section 5.1.1.
[38] See Astrape Consulting, "The Economic Ramifications of Resource Adequacy White Paper" prepared for EISPC/NARUC, January 2013.
[39] PJM, "Manual 14B," section 1.5.2.
[40] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-11.
[41] NERC, "2013 Long-Term Reliability Assessment, Continued Integration of Variable Generation," pages 22-27.
[42] Ibid.
[43] Ibid.
[44] PJM, "A Survey of Transmission Cost Allocation Issues, Methods and Practices," 2010.
[45] New York v. FERC (00-568) 535 U.S. 1 (2002) 225 F.3d 667.
[46] In some retail open-access states (e.g., New York), transmission rates are bundled with distribution rates and recovered under retail tariffs.
[47] Note that these FERC-related examples would not apply to the Texas Interconnection, Alaska or Hawaii, which are not under FERC jurisdiction.
[48] FERC, Docket No. EL5-121-008, "Order on Rehearing," March 31, 2013.
[49] FERC, Docket No. ER10-1069-000, Southwest Power Pool, Inc., "Order Accepting Tariff Revisions," June 17, 2010.
[50] PJM, "A Survey of Transmission Cost Allocation Issues, Methods and Practices," 2010.
[51] FERC Order No. 1000, paragraph 819 and FERC Order No. 1000-A, paragraph 772.
[52] United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, "Multi-Dimensional Issues in International Electric Power Grid Interconnections, Chapter 2: Technical Aspects of Grid Interconnection".
[53] Ibid.
[54] Ibid.
[55] Ibid.

[56] Ibid.

[57] Ibid.

[58] FERC Staff Report, "Reactive Power Supply and Consumption," Docket No. AD05-1-000, Feb. 4, 2004, Chapter 1.

[59] http://www.ferc.gov/market-oversight/guide/glossary.asp.

[60] Monitoring Analytics, "2013 Quarterly State of the Market Report for PJM: January through September", Section 9.

[61] United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, "Multi-Dimensional Issues in International Electric Power Grid Interconnections, Chapter 2: Technical Aspects of Grid Interconnection".

[62] Ibid.

[63] Ibid.

[64] NAESB, "Transmission Loading Relief Business Practices – Eastern Interconnection".

[65] DOE, Office of Electricity Delivery and Energy Reliability, "Summary of the North American SynchroPhaser Initiative (NASPI) Activity Area".

[66] Ibid.

[67] DOE, Office of Electricity Delivery & Energy Reliability, "Advanced Modeling Grid Research Program," http://energy.gov/oe/technology-development/advanced-modeling-grid-research-program.

[68] DOE, Office of Electricity Delivery and Energy Reliability, "Superconductivity Program Overview".

[69] DOE, Office of Electricity Delivery and Energy Reliability, "Transmission Reliability Program".

[70] NERC, "Cyber Security Standards Transition Guidance," April 11, 2013; FERC, Docket No. RM13-5-000, "Version 5 Critical Infrastructure Protection Reliability Standards," November 22, 2013.

[71] Energy Sector Control Systems Working Group, "Roadmap to Achieve Energy Delivery Systems Cybersecurity," September 2011.

[72] Ibid.

[73] FERC Order No. 679, paragraph 201.

[74] FERC Order No. 679, paragraph 202.

[75] FERC Order No. 1000, paragraph 116.

[76] FERC Order No. 1000, paragraph 163.

[77] FERC Order No. 1000, paragraph 225.

[78] FERC Order No. 1000-A, paragraph 420.

[79] FERC Order No. 1000, paragraph 225.

[80] FERC, Docket No. ER10-253-001, "Order on Rehearing and Clarification," July 19, 2012, page 2, paragraph 1, footnote 5.

[81] FERC Order No. 1000, paragraph 819 and FERC Order No. 1000-A, paragraph 772.

[82] EIPC, "Phase II Report, Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios," Section 5.0, December 2012, http://www.eipconline.com/Phase_II_Documents.html.