Chapter 2: Enhancing the Transmission Network and System Operations

In this chapter, we provide an overview of today's transmission network technologies and power system operations, then discuss new technologies that could help prevent blackouts, increase transmission capacity, and improve system operations. The issues in this chapter are primarily the concern of utility engineers, grid operators, and transmission planners; accordingly, this chapter does not deal with regulatory topics, which are addressed in Chapter 4, or contain policy recommendations. Even so, we believe an understanding of transmission technologies and the operation of the power system provides important context for policy makers.

Section 2.1 provides an introduction to the transmission network and system operations, starting with transmission lines and substations. It then explains how power systems are operated and briefly discusses transmission system reliability. This is followed in Section 2.2 by a description of technologies that could reduce the frequency of major blackouts, including phasor measurement units (PMUs), wide-area measurement systems (WAMS), and flexible alternating current transmission systems (FACTS). We find that phasor measurement units have the potential to greatly benefit the transmission network, but mechanisms for sharing data are immature, and many tools for data analysis have yet to be developed.

Section 2.3 introduces technologies that can facilitate the expansion of the transmission network and describes the fundamental physical characteristics that impose limits on transmission capacity and how these limits determine the technologies most appropriate for long-distance transmission. The section also discusses promising emerging technologies, such as superconductors and dynamic line rating systems, that can increase transmission network utilization and capacity.

Section 2.4 describes a range of new technologies that could enhance system operations. We find that the development of control algorithms that can utilize data from PMUs and exploit the capabilities of FACTS technologies are important areas for research.

The transmission network is the first link between large power generation facilities and electricity customers. It supplies energy at high voltages to substations, where the energy is distributed to loads at lower voltages via the distribution network. The transmission network today operates reliably and efficiently, but a variety of technologies offers the potential to improve system performance. Sophisticated new monitoring systems may reduce the likelihood of rare cascading system failures, which can have serious economic and social consequences. More efficient or lower-impact technologies may help solve problems associated with network expansion, including difficulty in siting new transmission lines to meet growing demand amid increasing pressure to limit environmental impact. And changes in system operation will help incorporate growing penetrations of variable energy resources, like wind and solar generation.

2.1 THE TRANSMISSION NETWORK AND SYSTEM OPERATIONS

In the U.S., the transmission network is divided into three distinct geographic regions called interconnections: the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas (ERCOT) (see Figure 1.2). Only weak electrical links exist between them. Altogether, the U.S. transmission network consists of approximately 170,000 miles of lines at 200 kilovolts (kV) and higher, linking electricity consumers to almost 5,000 large power plants.[i, 1] Table 2.1 contains a breakdown of transmission lines in the U.S. by miles and voltage level. The companies that own and operate these lines range from large investor-owned utilities, which control thousands of miles of lines spread over multiple states, to transmission owners with only a handful of short transmission links.

Table 2.1 Approximate U.S. Transmission Line Miles by Voltage

Line Type	Voltage (kV)	Miles
Alternating Current (ac)	200–299	84,000
	300–399	54,000
	400–599	26,000
	≥ 600	2,400
	Total ac	161,000
Direct Current (dc)	200–299	700
	300–399	0
	400–599	1,800
	≥ 600	0
	Total dc	2,500
	Total	**169,000**

Source: North American Electric Reliability Corporation (NERC) Electricity Supply & Demand Database, http://www.nerc.com/page.php?cid=4|38.

Transmission Lines

Transmission lines carry energy; the rate at which energy flows is measured as power.[ii] Power is proportional to the product of current and voltage; higher voltage and current correspond to higher power. Generators and other devices manipulate the distribution of power among lines by controlling voltages at the two ends of lines (for further explanation on the nature of power flows, see Box B.1 in Appendix B). Power on individual lines cannot be precisely controlled, though new devices discussed later in this chapter are improving the ability of system operators to do so.

Power on individual lines cannot be precisely controlled.

The interconnectedness of the grid compounds the difficulty in controlling power. Multiple transmission lines often intersect at one substation, making it impossible to change the flow on one line without affecting others. As a consequence, energy flowing from one location to another follows multiple paths and may cross jurisdictional boundaries. These so-called loop flows can create adverse or beneficial physical and economic effects in several jurisdictions.

The related problem of congestion results in adverse economic consequences by preventing the least-cost set of generators from supplying load. A transmission line is limited in its capacity—that is, how much power it can carry—by several mechanisms, discussed in Section 2.3. It is impossible to use the least-cost set of

[i] Almost 5,000 generating units with at least 50 megawatts of expected on-peak summer capacity were registered with the North American Electric Reliability Corporation in 2010.

[ii] Though it is energy, not power, that "flows" through transmission lines, it is common industry practice to speak of power flows rather than energy flows. With some exceptions, we use the common industry vernacular in this chapter.

generators to supply additional load when one or more transmission lines reach a limit and are unable to carry the required additional power. When lines are thus congested, other, less economically efficient generators are dispatched to supply the load avoiding the transmission network limits. Such costs can be significant in some cases; the cost of congestion in the PJM Interconnection was estimated to be about 6% of total electricity billings in 2008.[2]

Substations and Voltage Support

Transmission substations house much of the equipment necessary for the normal functioning of the transmission network and system operations. The primary function of transmission substations is to interconnect transmission lines. These lines may all be at the same voltage, or the substation may contain transformers to connect transmission networks of different voltages. These transformers also are necessary to connect the transmission system to the lower-voltage distribution system. Voltage is typically decreased in several steps at substations along the transmission and distribution systems using transformers before reaching customers. In addition, substations provide protection for lines and equipment with devices such as protective relays, circuit breakers, and surge arresters. Finally, substations contain measurement and communication equipment that bring data to control centers and voltage compensation devices that keep voltages within acceptable limits.

Maintaining voltage within a specified range along the entire length of an ac line may require special devices and control procedures. As a line is loaded—that is, as its current is increased—the voltage drop along the line from the generator to the load will increase. The process of bringing the voltage back within acceptable range is known as voltage support or volt-ampere reactive (VAR) support.[iii] Voltage support is necessary to maintain acceptable voltage levels and power transmission capacity as the length and loading of lines increases. Until recently, common practice was to provide voltage support by connecting compensating devices, such as capacitor banks, to the line and controlling their voltage contribution in response to changes in load. Newer technologies employ semiconductor switches and can provide more precise control and faster response to changes in load. These devices are known as static VAR compensators (SVCs) and are one member of a class of new devices comprising flexible ac transmission systems (FACTS), which are discussed later in this chapter.

SVCs are an established technology with many years of operational deployment. The first were installed in the early 1980s, and many more installations have followed in the U.S. and internationally.[3] The decision to use an SVC instead of a capacitor bank is an economic one; the value of the operational benefits of fast and flexible response is balanced against the increased cost and energy losses of the SVC.

FINDING

Technologies exist, which if found to be economically justifiable, could improve the performance of the transmission system.

[iii] VAR is the unit used to measure reactive power, which is present in an ac system when current and voltage are not in phase.

System Operation

Power systems require a level of centralized planning and operation to ensure system reliability. System operators at control centers carry out many of these centralized functions in support of operations, including short-term monitoring, analysis, and control. A single electrical interconnect contains many system operators. For example, in the Eastern Interconnection, system operators at the regional level include the New York Independent System Operator (ISO), ISO New England, Midwest ISO, PJM, Tennessee Valley Authority, Southwest Power Pool, and others. Transmission and generation owners that operate their own assets and coordinate with these regional entities also are called system operators.

Control centers perform three separate functions:

- **Monitoring:** System operators use various displays and alarms to develop awareness of the state of the system.

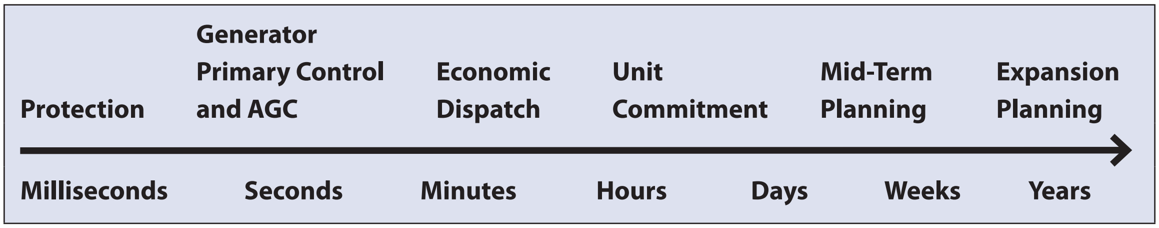
- **Analysis:** Raw data reported to control centers are analyzed using computer tools that can give insight to the current and future state of the grid. This suite of tools is collectively known as an energy management system.

- **Control:** Regional control centers calculate the expected hourly power output of generating units for the next day or days based on projected electricity demand and relay this information to generating units. The decision of which generators should be on or off for the next day is known as unit commitment. The specification of the amount of power each of those committed generators should produce is known as economic dispatch. In areas with traditional vertically integrated utilities, economic dispatch and unit commitment are calculated based on known start-up and fuel costs for generators; in restructured areas, a similar result is obtained through bidding in wholesale markets. Control centers then refine these day-ahead estimates as often as every 5–15 minutes, dispatching each generator to minimize total system costs given the load level, generator availability, and transmission constraints. Control centers also give certain generators a signal that supplements primary generator controls and enables the system to match small changes in load and meet the scheduled power exchanges with neighboring systems. This control mechanism is called automatic generation control.

In addition to these functions, the long-term health of the system is a separate concern that planners at utilities and system operators generally address through appropriate mid- and long-term planning. However, this chapter focuses on transmission operations rather than on planning. Further discussion of transmission planning policy issues can be found in Chapter 4.

A summary of the various generation and transmission operations and planning functions organized by timescale is presented in Figure 2.1. Currently, system control centers are supported by supervisory control and data acquisition (SCADA) systems that report the status of circuit breakers—open or closed—as well as voltage, current, and power levels. Devices called remote terminal units (RTU) located at generators and substations collect this information and send it to the control center every few seconds. Remote terminal units also may receive commands, such as an instruction to open or close a breaker, from system operators. The typical response time for SCADA systems today is several seconds, but some power system phenomena occur in fractions of a second. Important emerging technology, discussed in Section 2.3, has the potential to give operators insight into these faster dynamics.

Figure 2.1 Transmission Operation and Planning Functions by Timescale



Source: I. J. Perez-Arriaga, H. Rudnick, and M. Rivier, "Electric Energy Systems: An Overview," in *Electric Energy Systems: Analysis and Operation*, eds. A. Gomez-Exposito, A. Conejo, and C. Canizares (Boca Raton, FL: CRC Press, 2008), 60.

Note: AGC = automatic generation control.

Transmission Reliability

Reliability is and will continue to be a dominant constraint in transmission planning and operations, but as discussed in Chapter 1, it is difficult to measure. Available data is insufficient to make conclusions about long-term trends in reliability of the U.S. transmission network. The North American Electric Reliability Corporation (NERC) and the U.S. Department of Energy (DOE) gather data on NERC-defined "major events," but these events do not necessarily affect customers.[iv] NERC has begun to improve its practices for gathering and reporting reliability data in the last decade in response to the August 2003 blackout and subsequent legislation. However, much of the new data has been gathered for just a few years or less, not long enough to perform a good evaluation. The most recent and comprehensive report on these positive efforts is the 2011 Risk Assessment of Reliability Performance.[4]

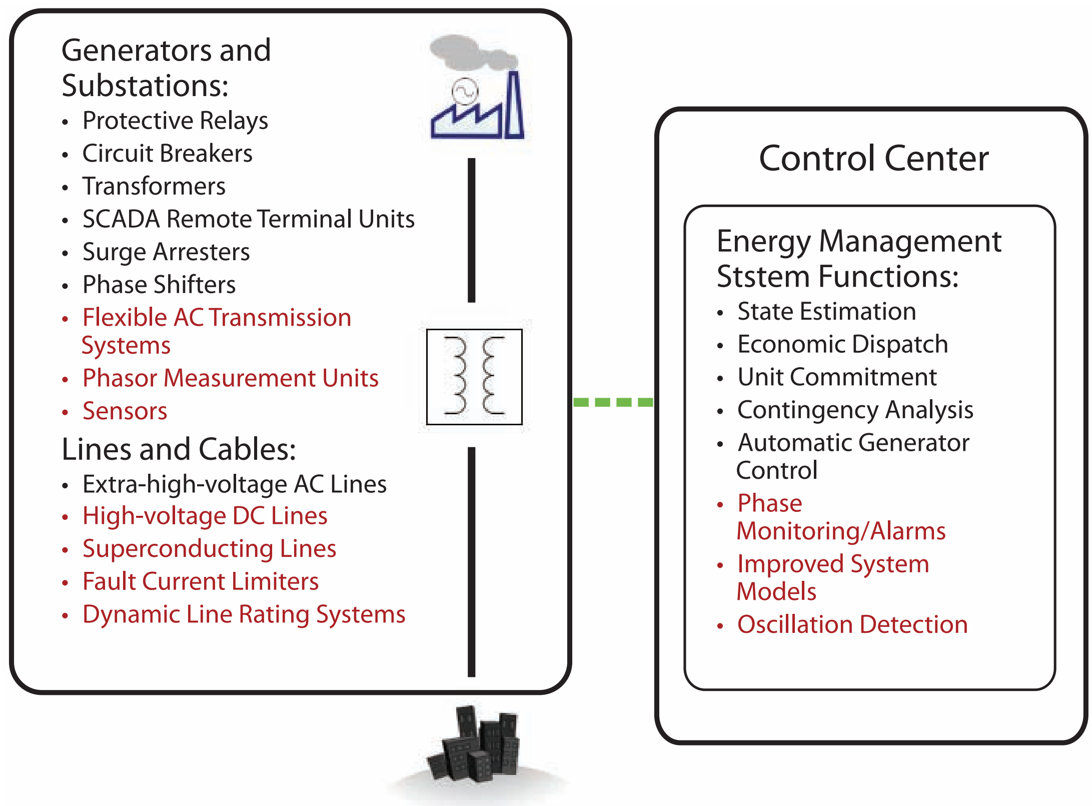
FINDING

Comprehensive and accurate data for assessing trends in the reliability of the U.S. transmission network are not available.

Although it is difficult to measure, the reliability of the U.S. transmission grid clearly faces challenges along three dimensions: anticipating and preventing blackouts; increasing transmission capacity with low environmental impact; and improving system operations, especially to incorporate variable energy resources, such as wind and solar power. Figure 2.2 lists technologies and functions to address these challenges and shows how they fit into the power system. Existing technologies and functions, such as circuit breakers, transformers, and state estimation, are shown in black. Important new technologies and functions, discussed in the remainder of this chapter, are shown in red. Such lists of new technologies have been compiled and discussed elsewhere; for example, the Electric Power Research Institute (EPRI) has performed an analysis of costs and benefits of various technologies[5] and in Europe, transmission operators, equipment manufacturers, universities, and other stakeholders have put together a roadmap of innovative transmission technologies.[6] This figure is meant as a reference for the set of technologies discussed in this chapter, not a comprehensive list of transmission technologies and functions.

[iv] For example, any loss of generation greater than 2,000 megawatts in the Eastern or Western Interconnection and 1,000 megawatts in ERCOT must be reported, regardless of whether the loss of generation affects customers.

Figure 2.2 Transmission Network Technologies and Control Center Functions



Note: Existing technologies and functions are listed in black; new and emerging elements are shown in red.
SCADA = Supervisory control and data acquisition.

2.2 PREVENTING BLACKOUTS

While major blackouts occur only rarely in the U.S., they have serious economic and social consequences. The largest blackout in North American history occurred in 2003, affecting 50 million customers in eight northeastern states and Ontario. The second largest, in 1965, affected 30 million customers. Both blackouts were the result of cascading failures of the power system, in which seemingly small and localized problems caused the system to become unstable and subsequently affect a much wider area. Preventing such blackouts is an important goal that requires monitoring the state of the power system (see Box 2.1). Wide-area measurement systems (WAMS) allow such monitoring to occur on a larger scale than previously possible, enabling system operators to better protect against the most catastrophic class of blackouts. WAMS consist of measurement devices, communications networks, and visualization software; the most critical is an enabling technology called the phasor measurement unit (PMU).

While major blackouts occur only rarely in the U.S., they have serious economic and social consequences.

PMUs measure defining characteristics of voltages and currents at key substations, generators, and load centers, such as cities. System frequency and other quantities often also are measured. Taken together with known line characteristics, these measurements can be used to calculate instantaneous power flows throughout the system.

PMUs report data much more frequently than do SCADA systems, which results in higher-resolution information about system dynamics. Industry standards require that PMUs have a reporting rate of 30 times per second, and many devices are capable of even higher rates. Critically, measurements from all PMUs can be synchronized using GPS time signals, enabling more accurate characterization of system-wide dynamics.

WAMS are currently deployed in many areas, but their usefulness has historically been limited by the small number of accompanying PMUs and software programs to process the raw PMU data. As of early 2010, approximately 250 PMUs were deployed across North America, with more than 850 additional PMUs scheduled to be added between 2010 and 2013 through projects funded by the American Recovery and Reinvestment Act of 2009.[7] Software applications to aggregate and analyze the PMU data and produce actionable information for system operation or planning are critical to realizing the full benefits of PMUs. However, they remain relatively undeveloped today. One such proposed tool is a monitor or alarm that would warn when the voltage phase angle differences between different locations on the transmission network stray beyond predictable ranges, indicating that the system is under stress. The concept of phase angle difference is discussed in more detail in Box B.1 in Appendix B.

BOX 2.1 ESTIMATING THE STATE OF THE POWER SYSTEM

The voltages, currents, and power on all the lines in transmission systems are under continuous monitoring by system operators. These data are used in models of power systems that include the lines, generators, and loads. These models are known as state estimators, and their output is the estimated system state. The state of a power system is a snapshot of the system voltages and currents at one time that operators use to assess the condition of the system and, if needed, take action. For example, operators may use the model results to identify anomalous system conditions, dispatch generation, and avoid stability and thermal limits.

As with any model, the result of the state estimator is only an approximation of the actual system state. One reason is that sensor measurements from the supervisory control and data acquisition system are not sent at the same instant; data may be spread over a period of several seconds, and thus phase angle data cannot be observed. Another is that these data are not always precise. State estimators address these issues by exploiting the redundancy of measurements throughout the system.

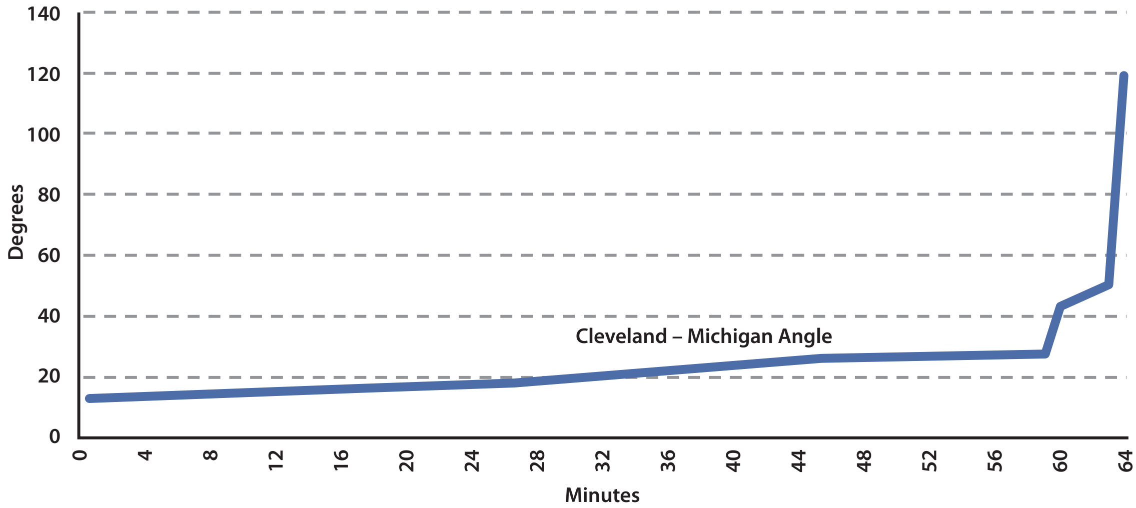
State estimators use an iterative algorithm, and the estimated system state is obtained after several attempts to converge on a solution. The algorithm is not perfect, and state estimators have trouble estimating a system state during unusual or emergency conditions—unfortunately, when they are most needed.

The usefulness of phase angle alarm applications is illustrated in Figure 2.3, which shows the phase angle difference as a function of time between Cleveland and Michigan leading up to the 2003 blackout. Analysis of phase angle measurements revealed a slow divergence nearly an hour before the start of the blackout. Had the PMUs been networked and a real-time phase angle monitoring application been in use at the time, system operators would have had more warning of the impending problem and an opportunity to take remedial action.[8]

The development of phase angle alarms is not trivial. Baseline data must be collected from PMUs over a minimum of several years before alarms or other useful applications can become operational, and these data must be shared with all relevant stakeholders. Only a few early phase angle alarms have been implemented; for example, the Bonneville Power Administration has had a system in operation long enough to establish a baseline for the phase angles at three of its hydroelectric generators. Obtaining baseline data through observation is an important prerequisite for not only phase angle alarms but also for many other potential software applications of synchronized phasor measurements.[v]

To facilitate sharing of synchronized phasor data between regions, NERC created two nondisclosure agreements in February 2010. One agreement is meant for industry entities and covers the confidential sharing of phasor data within the NERC phasor community for operational and reliability purposes. The second agreement covers the sharing of industry phasor data with researchers on a restricted basis for the benefit of the industry as a whole.

Figure 2.3 Cleveland–Michigan Phase Angle Difference Leading Up to the August 2003 Blackout



Source: North American Electric Reliability Corporation Real-Time Application of PMUs to Improve Reliability Task Force, *Real-Time Application of Synchrophasors for Improving Reliability* (Princeton, NJ, 2010), http://www.nerc.com/filez/rapirtf.html.

[v] One other specific benefit of synchronized phasor measurements is mentioned in the next section on increasing transmission capacity.[9]

It remains to be seen whether these agreements will prove effective. As of September 2011, only a limited number of entities had signed these data-sharing agreements.[10] A further concern is that the agreements cover only sharing of measured data, but in order to effectively use the data, information about the underlying network is also required.

These concerns do not warrant immediate action because the agreement is still relatively new, and sufficient sharing of network models may occur organically over time between system operators and some trusted academic research institutions. However, policy makers should be cognizant of this potential research bottleneck.

FINDING

Phasor measurement units have the potential to greatly benefit the transmission network. However, mechanisms for sharing data are immature, and many tools for data analysis have yet to be developed.

2.3 INCREASING TRANSMISSION CAPACITY

As load centers grow and generators are built in new locations, the transmission network's capacity must be enhanced to reliably and economically connect the two. The primary tool applied to this task is the construction of new transmission lines, for they are the fundamental building block of the transmission network. Building new transmission lines can be difficult. New rights-of-way—the land on which lines are built—are very difficult to obtain for political and environmental policy reasons. Projects can stretch over many years, delaying needed network reinforcements. And even planning new transmission lines—a subject covered in more detail in Chapter 4—is complex and requires balancing the details of local transmission networks with long-term strategic regional and interregional objectives.

In this section, we first discuss the fundamental physical characteristics that impose limits to transmission capacity. Next, we present transmission line technologies that can increase capacity. These include extra-high-voltage (EHV) ac and high-voltage direct current (dc) lines, high-voltage transmission overlays, underground cables, and superconductors. Finally, we discuss the potential of PMUs and dynamic line rating (DLR) systems to increase transmission capacity in some situations without building new lines, though these are not long-term substitutes for new infrastructure.

Transmission Capacity Limits

There are three primary constraints on the capacity of a transmission line: the thermal constraint, voltage stability, and transient stability. The first, the thermal constraint, is straightforward. The losses in a line increase its temperature, which in turn causes the line to stretch and sag between supports. At some maximum temperature, or thermal constraint, the sag is sufficient to reduce the line's clearance from ground to a minimum acceptable value.

There are three primary constraints on the capacity of a transmission line: the thermal constraint, voltage stability, and transient stability.

Stability limits are more complicated than the thermal constraint and derive from considerations discussed in Box 2.2. These limits are reached when operators are concerned that an unexpected event might cause system instability. To determine these stability limits, operators must perform an extensive analysis known as an N-1 contingency analysis. It is clear that for any set of normal system conditions, power flows must not cause overheating or system instability. N-1 contingency analysis takes this one step

BOX 2.2 POWER SYSTEM STABILITY

Stability of an alternating current power system refers to its ability to maintain synchronous operation after being subjected to a disturbance. Instability can lead to major negative consequences, from localized power interruptions to widespread blackouts. In general, adequate reserve generation, transmission capacity, and tightly meshed networks contribute to a stable system.

Two of the main forms of stability that concern system operators and planners are transient and voltage stability. They are interrelated, and stability problems of one sort usually give rise to others. Stability classifications are based on the physical nature of stability phenomena, the system variables where that stability phenomena are observed, and the methods of analysis that must be used to address the stability issues.

Transient stability refers to the ability of a transmission line to accept a transient increase in power flow without exceeding the maximum safe voltage angle between the ends of the line.

Voltage stability refers to the ability of a power system to maintain acceptable voltage levels across the network after a disturbance. The most common form of voltage instability is a progressive drop in voltages following a disturbance when the automatic controls associated with some loads push generators and transmission equipment beyond their capabilities.

The description of stability here is a considerable simplification of the precise industry standard classifications, which include several other types of stability. A comprehensive description can be found in P. Kundur et al., "Definition and Classification of Power System Stability IEEE/CIGRÉ Joint Task Force on Stability Terms and Definitions," *IEEE Transactions on Power Systems* 19 (2004): 1387–1401.

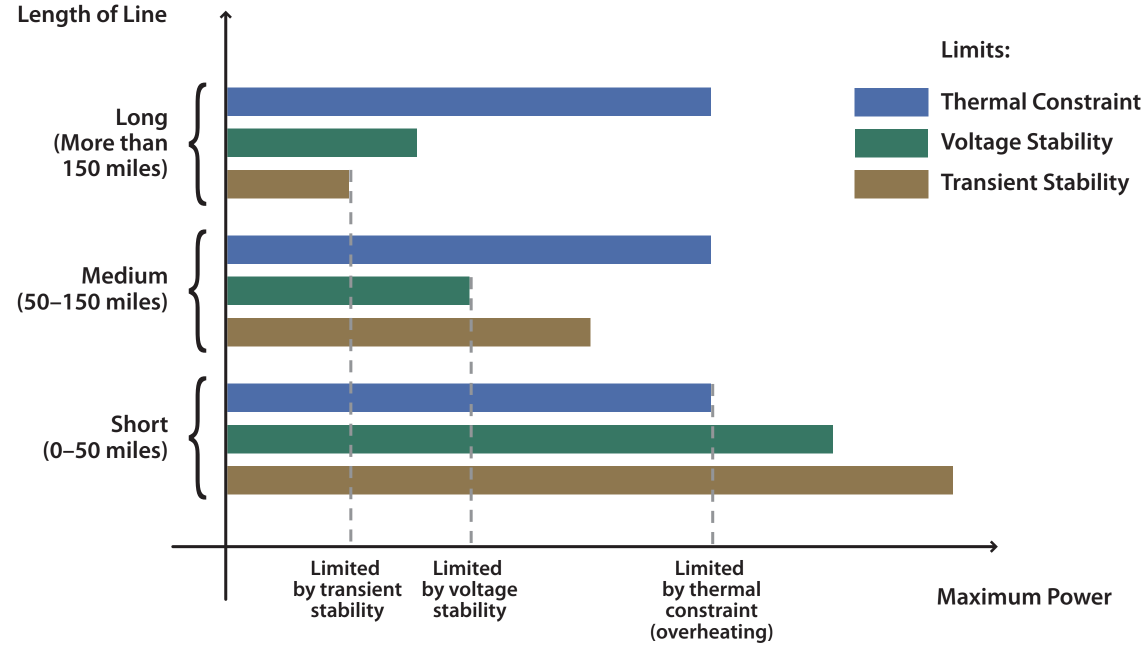
further to ensure that even if any single major system component (such as a large generator or transmission line) is unexpectedly lost, the power flows on network lines still do not violate these limits. Due to the large number of possible situations under which contingencies might occur, this analysis requires expert judgment, time, and computational power.

Figure 2.4 illustrates the typical limiting factors on the power transfer of short, medium, and long lines. The thermal limit has to do with material properties of the line and is constant no matter the length of a line. Since stability is a system property rather than a material property, stability limits change depending on the length of a line and other system conditions. Thermal considerations generally limit power transfer on short lines, while longer lines tend to be stability limited. In particular, power transfer on medium-length lines is usually constrained by voltage stability, while the longest lines are limited by transient stability.

Long-Distance Transmission Technologies

Challenging these physical constraints is increasing political interest in integrating variable energy resources, such as wind and solar, into the grid. These energy resources have gained favor at the federal and state levels, but they are often distant from load centers. The technical capability exists to provide long-distance transmission, but the benefit of access to distant renewable resources must be balanced with the higher cost and difficulty of siting such lines. Striking the proper balance in transmission for distant renewable generation sources is a difficult problem to be addressed through transmission planning policy and regulation, discussed in Chapter 4. Here we discuss the two technologies appropriate for long-distance transmission—extra-high-voltage ac and high-voltage dc, two relatively mature technologies.

Figure 2.4 Three Primary Constraints of Transmission Lines



EHV ac transmission systems have voltages greater than 242 but less than 1,000 kV. The highest in commercial operation in the U.S. is 765 kV, while 345 kV and 500 kV are standard voltage levels.[11] Higher voltage transmission lines have been installed in China, Russia, and Japan, but only China operates its 1,000 kV system at its rated voltage.[vi, 12] Compared to their lower-voltage counterparts, such lines are capable of transmitting more power over longer distances but require larger, more expensive transformers, insulators, and towers, as well as wider rights-of-way. As a result, the highest-voltage ac lines are most economical for large-capacity, long-distance electricity transmission. Installing high-voltage, large-capacity links can improve reliability by allowing neighboring areas to support one another and improving stability characteristics of the network. The length and capacity of a long EHV ac line is typically limited by stability considerations—the longer the line, the lower the capacity limit, though the effective length of lines may be extended by installing voltage support equipment.

Dc lines can be valuable additions to ac transmission networks.

The transmission system consists mainly of ac lines due to their many desirable characteristics, such as the ease of voltage transformation. However, dc lines can be valuable additions to ac transmission networks. High-voltage dc lines are not limited by stability considerations and therefore theoretically are not limited in length. Conductor costs—the cost of the metal which conducts electricity—for dc transmission lines are lower than for ac lines of the same voltage because fewer conductors are necessary and conductor utilization is better. But the cost for dc substations is significantly higher because transformers only work for ac, so more

[vi] Russia and Japan now operate their 1,000 kV lines at 550 kV.

expensive power electronics converter stations are required to convert between ac and dc. And tapping a dc line—that is, connecting a load in the middle of the line—requires a costly and complex converter station instead of a much less expensive transformer as for an ac line.

The electrical losses in an ac/dc converter station are higher than in an ac substation. A rough rule of thumb is that for high-voltage ac lines, total substation losses are approximately 0.5% of rated power, while combined converter station losses from both ends of a traditional high-voltage dc line are approximately 1.5%.[13] However, the losses per mile of a dc line are lower than those of an ac line. Thus, dc is especially suited to long-distance, point-to-point power transmission, where a single generating site connects to a single point on the ac grid.

In the U.S., the ±500 kV Pacific DC Intertie stretches nearly 850 miles from Oregon to Los Angeles; China's ±800 kV dc link from the Xiangjiaba Dam to Shanghai is nearly 1,300 miles long and currently the world's longest and highest-voltage dc link.[14]

One analysis of hypothetical transmission projects compared the cost and electrical losses of 765 kV ac to ±800 kV dc for a 6,000 megawatt transmission link at different distances.[15] For an 800-mile link, the analysis found that electrical losses of the 765 kV ac line at full load would be nearly double those of a ±800 kV dc line and that the up-front cost to build the 765 kV ac line would also be approximately double the cost of the ±800 kV dc line. If the project were a line of only 200 miles, however, the dc option would be slightly more expensive and have approximately the same losses. This case is merely illustrative of the relationships between length of lines and cost/losses of high-voltage ac and dc transmission projects; any real project would be evaluated in a more detailed fashion on many more important criteria, such as long-term system impact on reliability and right-of-way considerations. The least-expensive option is not necessarily the most appropriate.

FINDING

Where long distances separate renewable resources from load centers, dc transmission lines may be economically attractive.

A newer version of high-voltage dc converters known as voltage source converters (VSC) offer the potential for improved system stability and control.[16] And unlike conventional high-voltage dc, VSCs do not require strong ac generation sources at both ends of the line, making it more attractive as a technology to connect variable energy resources. These benefits are made possible by a more flexible type of switch that is used in the converter—a transistor rather than a thyristor.[vii] A dc mesh network using VSC high-voltage dc is envisioned to connect dispersed wind generators in the North Sea with several areas of mainland Europe.[17] So far, this technology has not achieved the highest voltages attainable by traditional high-voltage dc: the highest-voltage link in operation as of 2011 is the ±350 kV Caprivi Link connecting Zambezi and Gerus in Namibia; the capacity of this link is only 300 MW, but new advances in semiconductor devices and dc circuit breakers promise to allow higher voltage levels and capacities within the next few years.[18] VSC high-voltage dc converter stations have somewhat higher energy loss than conventional high-voltage dc stations, though the efficiency of VSC converters is also improving.

[vii] The transistor and thyristor are both semiconductor devices that function as a switch, but they have different characteristics. Thyristor switches can be turned on easily but may only turn off under certain conditions. Transistor switches can be turned on and off easily.

FINDING

The control flexibility of voltage source converters can improve system stability and facilitate the integration of remotely located renewable generation.

Transmission Overlays

In recent years, proposals have been made for high-voltage transmission overlays—a new network of EHV transmission lines superimposed on the existing transmission network.[19] Such transmission overlays could create a more tightly meshed network spanning a large geographic area to facilitate the integration of variable energy resources. However, the benefits of such an overlay, described here, must be valued against the very high cost of constructing such an extensive transmission network, a cost that we do not presume to estimate.

A transmission overlay undoubtedly would have many benefits, including access to better sources of renewable energy, improved reliability, and lower losses. As the U.S.–Canada Power System Outage Task Force notes, "higher voltage lines and more tightly networked lines…are better able to absorb voltage and current swings and thus serve as a barrier to the spread of a [cascading failure]."[20] For a given level of power transmission, losses decrease when voltage is increased, and optimally loaded lines have lower losses than overloaded lines. It is also possible that stronger ties between areas would allow system operators to reduce requirements for costly reserves.

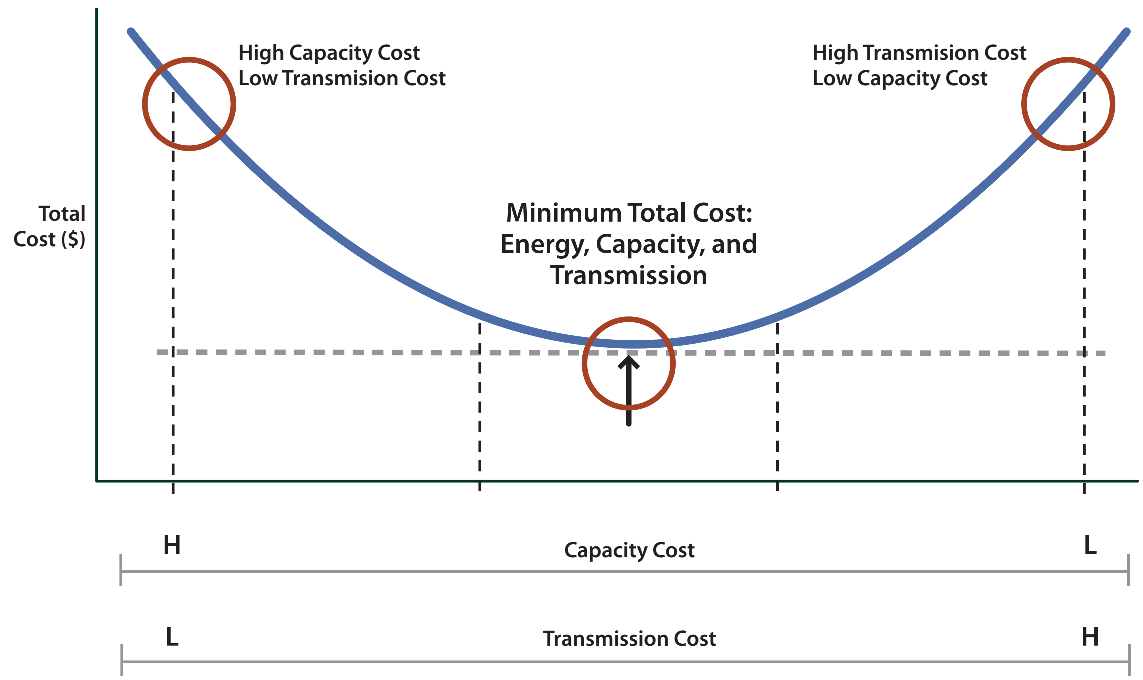
But building a network of high-voltage lines is also costly. Evaluating the full range of costs and benefits of a transmission overlay requires the sort of interregional planning process described in Chapter 4. The Midwest ISO's Regional Generation Outlet Study is an example of a successful system planning exercise at the regional level.[21] The purpose of the study was to support development of transmission portfolios fulfilling the region's renewable portfolio standards at the lowest cost per delivered megawatt hour. These standards dictate that a certain percentage of energy is generated from renewable resources. One key consideration noted in this study is the balance between low transmission costs for wind resources local to load centers and favorable capacity factors of wind resources distant from load centers. This trade-off is illustrated in Figure 2.5. Through detailed analysis of the particular characteristics of the Midwest region, this study concluded the optimal solution to be a transmission overlay serving wind zones of both types, rather than only one or the other: some local wind resources and some distant. Based on this conclusion, the study went on to analyze transmission overlay options and identify a set of promising transmission projects to be used as inputs in the Midwest ISO's transmission planning process.

As noted in Chapter 4, planning processes for interregional areas face both technical and institutional challenges. Interregional renewables integration studies, such as the Eastern Wind Integration and Transmission Study and the Western Wind and Solar Integration Study have shown that integrating high penetrations of renewables is technically feasible through higher-voltage, tightly meshed transmission lines, but a true plan has yet to emerge.[22]

FINDING

Creating a high-voltage transmission overlay is technically feasible and would benefit system operations and facilitate the interconnection of renewables. In the absence of detailed inter-regional planning studies, the features and costs of an optimal future overlay network remain uncertain.

Figure 2.5 Trade-off between Transmission Cost and Capacity Factors



Source: Midwest Independent System Operator, *Regional Generation Outlet Study* (Carmel, IN, 2010).

Underground and Submarine Transmission

Underground or submarine cables are used in locations where overhead lines are impossible or undesirable. A severe constraint when these cables are used for ac transmission is that the high capacitive charging current required generally limits their length to just tens of miles. Dc cables are limited only by electrical losses; the longest submarine dc cable is a 580 kilometer link between Norway and the Netherlands. Despite innovations in insulation materials, the complexity of assembling and installing cables means that cables will remain more expensive than overhead lines.[23] However, the difficulty of siting overhead lines in the U.S. can make underground and submarine cables an attractive option in some areas despite the greater expense.

Superconductors

High-temperature superconductors (HTSCs) have emerged from the research labs within the past decade. Superconductors are materials that have extremely low electrical resistance when cooled below a certain critical temperature, which is different for each superconductor. HTSCs are those that may be cooled using liquid nitrogen, a relatively inexpensive coolant with a boiling point of -196°C. They have a much higher power capacity compared to normal conductors of the same physical size, but are constrained by the difficulty of maintaining adequate cooling. The longest, highest-capacity HTSC cable to date, operating at 138 kV ac, was successfully demonstrated in 2008 with the help of government funding.[24] This project connected two substations separated by 600 meters in the Long Island Power

Authority service territory and overcame several practical technical challenges of superconducting transmission lines, such as the ability to withstand fault currents—abnormally high current levels caused by short circuits on a transmission line. A second stage of this project is under way that will test rapid field repair of the refrigeration system and the ability to make joints between cable sections.[25] High-temperature superconductors are becoming more practical as an option for increasing the capacity of existing cables by replacing them with ac HTSC cables in the same conduits. This is particularly attractive where the cost of conventional alternatives is high, such as in dense urban areas.

Superconductors also may be used to create a device called a fault current limiter (FCL). As its name implies, the purpose of an FCL is to reduce the amount of current that flows under fault conditions—not by isolating it through switches but by introducing a high impedance to reduce the level of current. On some lines, adding an FCL can allow heavier line loading without exceeding the capacity of circuit breakers. Since high impedance is not desirable under normal system conditions, the challenge in designing an FCL is how to insert impedance in the system extremely quickly only when it is needed, under fault conditions. In the case of one simple superconducting FCL design, the impedance is inserted by exploiting the natural limits of superconducting materials. Above some maximum current level, the material reverts from superconducting behavior to a normal conductor having high impedance. While promising, superconductor FCLs have not yet been demonstrated at transmission-level voltages,[viii] though at least two projects hope to achieve this goal within the next two years.[26]

FINDING

HTSC cable technology has been demonstrated as practical and is a promising approach to substantially increasing the capacity of existing cables without the need for new rights-of-way.

Phasor Measurements for Increased Transmission Capacity

In addition to helping prevent blackouts, synchronized PMUs can potentially improve system capacity by allowing operators to take the grid closer to its true stability limit, effectively increasing capacity of some lines without increasing the risk of a blackout. In an early example, an agreement between the California ISO and NERC to share synchronized phasor data is expected to eventually result in a 30% increase in the capacity of the California–Oregon Intertie.[27] Such large increases are not expected to be common because only stability-limited lines have the chance to benefit from the synchronized data. However, increases in the capacity of only a few key transmission lines could result in large economic benefits.

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Dynamic Line Ratings

Dynamic line rating systems also potentially can increase the operational capacity of transmission lines. Historically, system operators have established the thermal limits of lines under seasonal worst-case assumptions; a hot, windless day is an example of a worst-case scenario in the summer. This static limit is often conservative relative to actual conditions. DLR systems measure changing environmental

[viii] This is also true of FCLs constructed by other means, such as using power electronic devices.

conditions and update system models accordingly, increasing transmission capacity limits in all but those few worst-case scenarios. Though dynamic line rating systems can be implemented with a variety of sensors, one design deployed relatively widely today uses just two, one to measure line tension and another to measure air temperature. These two pieces of data allow operators to determine average conductor temperature, the main determinant of a line's thermal limit. DLR systems installed on existing transmission lines have been shown to improve the capacity by 5%–30% depending on conditions.[28]

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DLR systems are particularly attractive in the case of transmission lines linking wind generators to the rest of the transmission network. Wind generators require more transmission capacity when the wind is strongest; conveniently, strong winds are precisely the conditions in which DLR systems improve transmission capacity. However, where wind resources are far from load centers, the long connecting lines needed would tend to be limited by stability rather than thermal properties. DLR systems will not improve the capacity of these lines.

In some extreme weather situations, DLR systems will place more restrictive limits on transmission capacity than traditional static line ratings. Knowledge of true transmission capacity limits means improved reliability at the most critical times of extreme weather, when electric loads are high and systems are their most stressed. This was the case during the 2003 blackout, when static transmission capacity limits for some lines had been set assuming a modest amount of wind would cool wires, when in fact there was hardly any wind.[29] A DLR system would have provided another layer of warning to system operators.

Because a survey of electric service providers in 2009 revealed that only 0.5% of respondent's lines were equipped with DLR systems, DOE has classified the penetration of these systems as "nascent."[30] Based on the positive results of previous deployments, we can expect an increase in penetration of DLR systems between now and 2030.

2.4 IMPROVING SYSTEM OPERATIONS

The challenges of intermittent generation (Chapter 3) and opportunities for advanced demand response schemes (Chapter 7) will create opportunities for technological change in system operations. Notably, energy management systems will need upgrades to accommodate synchronized measurements from PMUs. And power electronics devices, supported by these synchronized measurements, could play a role in advanced control schemes requiring novel communications architectures. The control systems of the future are less understood than many individual technologies discussed in this chapter and should be the subject of R&D efforts by utilities and academic institutions.

Energy Management Systems Integrating PMUs

Energy management systems must be updated if they are to process the additional data available from PMUs. Adding synchronized phasor data to existing state estimators can improve accuracy of the estimated state, resulting in more optimal

The control systems of the future are less understood than many individual technologies.

economic dispatch of generating units. However, these improvements are incremental and do not address the fundamental shortcoming that state estimators sometimes fail when system conditions are unusual. Eventually state estimators could be partially replaced by aPMU-based tool yet to be developed that directly measures rather than estimates system state. Such a tool would be faster and potentially more accurate than state estimators today, and would avoid the problems state estimators have finding a solution during unusual system conditions. This tool would require PMUs to be deployed very widely, at perhaps 30%–50% of all nodes.[31] Concerns about the reliability and accuracy of PMU measurements for critical applications would also need to be addressed. Given the number of PMUs being deployed today, such a system might be feasible only at the highest voltage levels by 2030 and, if developed, would likely supplement rather than replace current state estimators.

FINDING

PMUs could improve the performance of energy management systems by providing real-time data to determine system state faster and more accurately than currently employed state estimation tools. A more extensive deployment of PMUs is required to make this possible.

Advanced Control Schemes

Increased computational power and the availability of more accurate and timely data make possible new approaches to system control. Among these are more sophisticated protection actions, wide-area control systems, and closed-loop control using PMU data.

The most complex control schemes deployed today are called system integrity protection schemes (SIPS),[32] which are comprised of decentralized subsystems that make decisions based on local and wide-area measurements.[33] These system-wide SIPS are normally implemented in cases of large power transfers between regions, when exceeding that line's capacity rating could potentially trigger a catastrophic blackout. In the U.S., system operators primarily in the Western Interconnection have implemented some SIPS. Where a typical protection system would simply isolate the offending line by tripping circuit breakers at either end—potentially sending shock waves through the rest of the system—SIPS use precalculated scenarios to coordinate more intelligent responses. Such responses can include intentionally islanding the two regions,[ix] shedding load, or activating voltage support devices.

Eventually, PMU-supported WAMS could be transformed into wide-area control systems that actively participate in control actions.[34] The concept encompasses a broad range of possible future control schemes. On the one hand, wide-area control could be nothing more than what SIPS are today: protective procedures developed to respond to a specific type of problem. On the other hand, wide-area control could also use closed-loop feedback control to stabilize detected system oscillations.

As these research efforts bear fruit and new tools become available to system operators, control room visualization techniques and operator training will become increasingly important. The control room is already enormously complex, and in a crisis, operators must quickly assimilate a staggering amount of information. Additional tools in the control room must not simply make new information available to operators, but present old and new information in more effective ways. Additionally, operators must train extensively on new tools before they become operational; as a result, new

[ix] An island in this context is a self-contained section of the network, within which load and generation are balanced. Determining where such islands might be created to aid system stability requires careful study of system contingencies, and creating such an island involves switching many circuit breakers and also likely shedding some amount of load within the island to balance load and generation.

NERC standards require a more systematic approach to training than did previous standards.[35] Training includes general familiarization in combination with detailed simulations of potential crises that might occur. The resources and time required to develop appropriate visualization tools and prepare operators to use them should be incorporated into R&D strategies for integrative control systems.

FINDING

Automatic control action based on real-time data from a wide-area network of PMUs represents a major change in system operations. Today, such systems are limited in number and capability. Significant research in control algorithms and improved confidence in the reliability and accuracy of PMU data is needed to make such controls more prevalent.

Flexible Ac Transmission Systems

A critical piece of the advanced control schemes envisioned for the future is FACTS. These employ power electronics that are connected to the transmission network to enable more rapid and flexible control of the system. The basic characteristics of several FACTS devices are summarized in Table 2.2. Each of the devices listed in the table has been deployed on real transmission systems. However, the deployment of devices other than SVCs has been limited because of cost. Integration into more sophisticated control systems could help justify these high costs in some situations.

R&D efforts to reduce costs will be necessary if FACTS are to become a significant factor in power systems of the future. Research on FACTS can be divided into three categories: semiconductor materials, control algorithms within individual FACTS devices, and system-wide control schemes incorporating FACTS. More work is needed in all three areas, but the last two categories are particularly important. Work is also needed to develop strategies to replace highly specific control algorithms, which become obsolete with changes to the transmission network, with algorithms based on a reconfigurable architecture. Research collaborations among system operators, academic institutions, and equipment vendors should be encouraged.

FINDING

To fully realize the improved system benefits of synchronized phasor data, FACTS devices, and other new technologies, control systems leveraging the complementary features of these technologies need to be developed.

Table 2.2 Summary of Main FACTS Devices

Name	Most Suitable Functions
Static VAR Compensator Static Synchronous Compensator	Control voltage level at nodes Improve system stability characteristics
Thyristor-Controlled Series Compensator	Improve system stability characteristics Control flows of power
Unified Power Flow Controller	Control voltage level at nodes Control flows of power Improve system stability characteristics

Information and Communication

New communications infrastructures[x] and architectures will support power system operations in the future. Many methods of data transmittal are used for various communication tasks on the power system today; radio, microwave, power line carrier, and fiber optics are some of the more common media. To accommodate the high bandwidth, latency, and reliability needs of future software applications, fiber optics likely will become more prominent.

One visualization system has begun to show the potential of leveraging modern communications infrastructure to the direct benefit of electricity customers. The Energy Awareness and Resilience Streaming Service (EARSS) was developed at Oak Ridge National Laboratory and draws on data reported by multiple utilities to provide up-to-date information on both the transmission and distribution systems across multiple jurisdictions. The system was used to support emergency and recovery efforts during and after Hurricane Irene in August 2011, a significant improvement over information available during the August 2003 blackout.[36]

More disruptive changes could occur in the architecture of the communication system. Today, most system operational decisions take place at the control center based on data gathered through the SCADA system. Some researchers envision an IT framework that allows different groups of stakeholders to gather information and make intelligent operational decisions autonomously.[37] For example, an electricity customer might have access to information about the price of electricity or other aspects of system status and optimize electricity consumption based on this greater knowledge. Among other things, this would require more seamless sharing of information between transmission and distribution system operators. The big challenge for regulators in deciding whether operators should cede some control to other stakeholders is how to maintain and guarantee the same high level of reliability.

Some researchers envision an IT framework that allows different groups of stakeholders to gather information and make intelligent operational decisions autonomously.

New tools for system operations will be supported by gains in the processing power of computers and new algorithms to take advantage of such gains. Over the past decade, PJM has led an effort to develop and implement new optimization algorithms to help solve the problem of how many generator units to commit each day, and when to commit them. These efforts have resulted in considerable cost savings in several U.S. electricity markets.[38] New approaches to other optimization problems in system operations might result in further substantial savings. For example, recent work has explored the possibility of optimizing transmission switching—adding or removing lines from the transmission network using switches—along with generator production in power flow models.[39]

2.5 CONCLUSIONS AND RECOMMENDATIONS

As noted in Chapter 1, the transmission network today operates reliably and efficiently. But new technologies are available that can improve system performance, offering enhanced reliability, increased capacity, and the ability to better accommodate VERs. No single technology, acting alone, is likely to have a significant impact. However, the combination of multiple technologies into an integrated system of sensors, communications

[x] Chapter 9 is devoted to issues surrounding communications, data security, and privacy.

infrastructure, control equipment, and intelligent management systems will provide significant benefits.

PMUs integrated into wide-area measurement systems with appropriate analysis tools that turn the measured data into actionable information could provide protection from blackouts and increases in system capacity. While PMU hardware exists, and is being installed more widely as a result of ARRA funding, the software and analysis tools necessary to fully capitalize on this investment are yet to be developed and deployed.

Greater control of system voltages and power flow can be achieved through the more extensive deployment of FACTS devices. The rapid control capabilities of these devices can contribute significantly to network control if integrated with PMUs and wide-area measurement systems. However, the current high costs of the most versatile of these devices is inhibiting their widespread deployment. The integration of FACTS devices with emerging wide-area measurement systems can allow their control capabilities to be leveraged to provide even greater benefits and could make their costs more readily justified.

RECOMMENDATION

Research and development efforts should be undertaken to develop 1) the analysis tools necessary to generate actionable information from data acquired from PMUs and 2) the control schemes necessary to make use of this information by realizing the complementary potential of PMUs, FACTS, and other hardware devices.

More widespread PMU data sharing among utilities, system operators, and researchers is essential to development of the needed tools. Confidential data sharing agreements have been created by NERC, but only a limited number of relevant entities have executed them.

RECOMMENDATION

NERC should continue to encourage relevant entities to participate in PMU data-sharing efforts necessary for the effective development and use of PMUs and wide-area measurement systems.

Although industry has been and continues to be engaged in the development of the technologies discussed in this chapter, their full benefit will occur only if there is greater cooperation among utilities in their deployment.

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