

Chapter 1: Challenges, Opportunities, and Major Recommendations

This chapter gives an overview of the study and introduces our major findings and recommendations. Section 1.1 provides a brief description of the grid's current structure and performance, which serve as initial conditions for our analysis. (Readers may consult Appendix A for a brief history of the U.S. grid and Appendix B for additional information on the technical operation of electric power systems.)

Section 1.2 then outlines challenges and opportunities that the grid will confront over the next two decades: incorporating variable energy sources like wind and solar; handling the charging of electric vehicles; adjusting distribution systems to accommodate small-scale, distributed electric generators; meeting emerging workforce needs; making the best use of new technologies to ensure reliability and efficiency under changing conditions; and responding to issues presented by the vast increase of data communications within the grid. Along the way some of the study's key findings are summarized.

Section 1.3 then presents the major recommendations that flow from these concerns, organized by area of industry and government policy response: the transmission system, the distribution system, cybersecurity and privacy, research and development, and the need for improved data development and sharing of information. Section 1.4 concludes with brief remarks about the level of urgency attached to these issues.

Hailed as the “supreme engineering achievement of the 20th century” by the National Academy of Engineering,¹ the U.S. electric power grid serves more than 143 million residential, commercial, and industrial customers² through more than 6 million miles of transmission and distribution lines owned by more than 3,000 highly diverse investor-owned, government-owned, and cooperative enterprises.³ In 2009, electric generation consumed 41% of the nation's primary energy—up from 14% in 1949—underscoring the great and growing national importance of the grid's efficiency and reliability.⁴

The electric power system is composed of four interacting physical elements: energy generation, high-voltage transmission, lower-voltage distribution, and energy consumption, or load. Two less tangible elements are also important: the operational systems that protect and control the physical elements, and the

regulatory and governance structures that shape the system's evolution. The term “grid” as used in this report refers not only to the physical transmission and distribution systems that link generators to ultimate loads but also the associated operational, regulatory, and governance structures. Appendix A briefly summarizes the history of the U.S. grid.

This study considers the evolution of the U.S. electric grid over the next two decades—a period long enough to permit significant change but short enough to make it unlikely that unforeseen technologies will have significant impacts on the system.ⁱ Even though this is likely to be a period of slow growth in the U.S. demand for electricity by historical standards, public policies and a variety of technological and economic changes will alter

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ⁱ An excellent brief overview of many of the issues considered in this report is provided by P. L. Joskow, “Creating a Smarter U.S. Electricity Grid,” *Journal of Economic Perspectives*, forthcoming.

both the demand for and supply of electricity in challenging ways. If regulatory policies and the technologies employed in the grid do not change, it is likely to be difficult to maintain acceptable reliability and electric rates. Technologies exist that can meet these challenges effectively, but only if a number of regulatory policies are changed, necessary

- The need to maintain instantaneous balance of supply and demand, limits on transmission line capacities, and other features require central coordination of short-term system operations.ⁱⁱ

This chapter assumes essentially no additional knowledge of the workings of electric power systems, but some parts of later chapters may be hard to understand without more background. Readers who would like more background or encounter material they find difficult are urged to consult Appendix B.

1.1 TODAY'S ELECTRIC GRID

In natural gas, trucking, railroads, airlines, and telecommunications—industries with a history of deep and ongoing government involvement—federal policy was substantially reformed after 1970 to reflect market realities. In contrast, despite dramatic changes in the electric power sector, federal policies established in the 1930s and even earlier still play a central role in that sector. The federal government primarily has added new policies on top of old ones, unlike the European Union and many other nations that have adopted comprehensive new structures based on competitive wholesale and retail electricity markets and centrally managed networks subject to incentive-based regulation.

In this section, we first discuss the organization of the U.S. electric power industry. Even though state boundaries do not affect the flow of electricity and thus have no natural role in the design or operation of the electric power sector, state regulators retain considerable authority. The U.S. does not have a comprehensive national electricity policy, and regulatory regimes differ substantially among states.

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research and development is performed, and important data are compiled and shared. Several features of electric power systems are fundamental to their structure and operation:

- It is generally not economically feasible to store electricity in bulk. The widespread deployment of new storage technologies and/or high penetrations of electric vehicles may someday change this, but these developments are unlikely before 2030.
- It follows that electric power systems must vary the supply of electricity to meet minute-to-minute changes in demand and in the output of variable energy sources such as wind and solar generators. Power systems must be built with enough capacity to meet expected peak demand with some excess capacity for safety.
- Electricity flows through many transmission paths from generators to customers, and individual flows cannot be controlled with precision.
- An electric grid is a natural monopoly; it would be prohibitively expensive to have multiple overlapping grids in any region.

ⁱⁱ As we discuss in later chapters, this last requirement has implications for many policies, including the role and design of competitive electricity markets.⁵

The result is substantial regional differences. Organized wholesale markets for power are central in some areas and nonexistent in others. Subsidies of various sorts for public and cooperative entities are important in some regions but not at all in others.

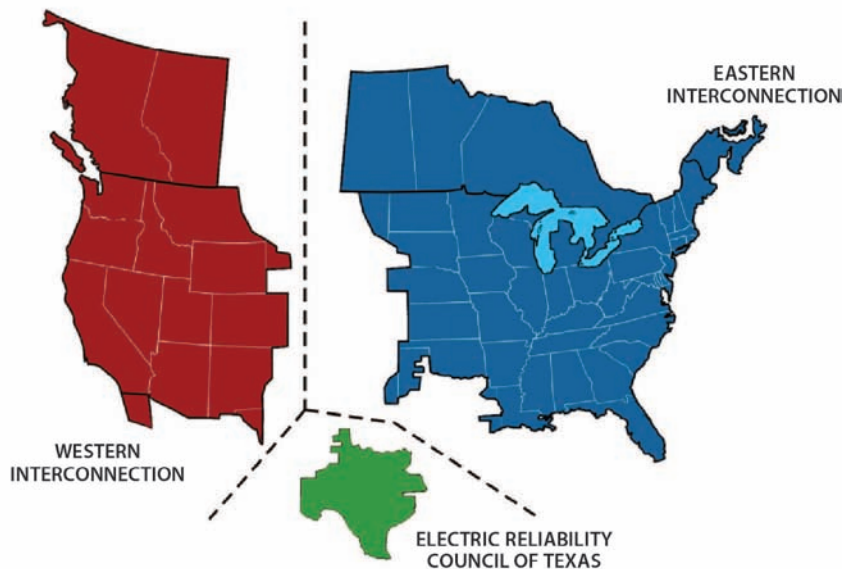
We then turn to a discussion of the industry’s performance. The industry has done reasonably well relative to available international benchmarks, despite working within a policy regime not conducive to efficiency. Because the grid is currently functioning well, however, adequate support for fundamental policy reform may be unlikely to emerge in the near term. Thus for the most part we take today’s policy regime as given, but, as Section 1.3 makes clear, we believe that some policy changes are necessary to prevent a deterioration of the grid’s performance in light of emerging challenges.

Structure

At the highest level, the electric power system of the continental U.S. consists of three independently synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). They are linked by only a few low-capacity direct current (dc) lines. These three grids, shown in Figure 1.1, account for 73%, 19%, and 8%, respectively, of U.S. electricity sales.⁶

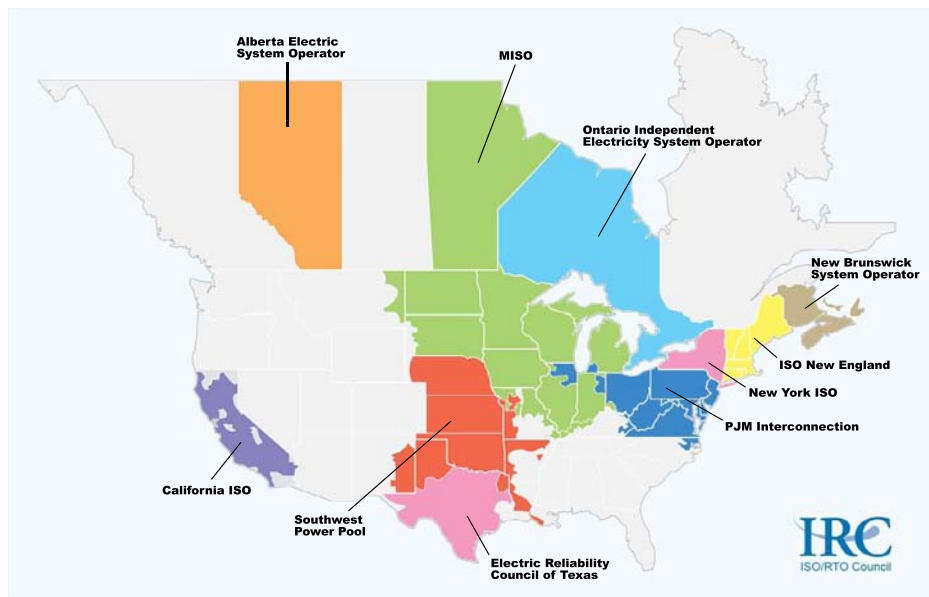
For a variety of reasons, discussion of which are beyond the scope of this study, organized wholesale markets do not exist in large parts of the nation, despite national policy supporting competitive wholesale markets with open,

Figure 1.1 Interconnections of the North American Electric Grid



Source: U.S. Department of Energy, http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/NERC_Interconnection_1A.pdf.

Figure 1.2 Regions with Organized Electricity Markets



Source: ISO/RTO Council, <http://www.isorto.org>. Copyright © ISO/RTO Council, all rights reserved.

non-discriminatory access to transmission systems (see Figure 1.2). Nonetheless, this policy has major implications for the transmission grid. Where it has been implemented, it has led to organized markets with important common elements.

Figure 1.2 shows the geographic scope of organized wholesale electricity markets, which are operated by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) that do not own generators or serve retail customers. These markets now cover two-thirds of the U.S. population and meet about two-thirds of U.S. demand. Box 1.1 provides an overview of the operation of these markets. In the Southeast, the traditional vertically integrated utility model is dominant, while in the West, particularly the Pacific Northwest, federal, municipally owned, and cooperative enterprises play an important role in the industry.

Within these broad areas are 107 so-called balancing authorities, shown in Figure 1.3,

which are responsible for balancing the supply and demand for power in real time in specified areas. A glance at this map makes plain the strong influence of history. New York, New England, and Texas are each tightly integrated and have one balancing authority each, while Arkansas and Arizona each have eight and Florida has eleven. These differences plainly do not reflect differences in levels of supply or demand or in system complexity.

Physically, the U.S. electric grid currently consists of approximately 170,000 miles of high-voltage (above 200 kilovolts or kV) electric transmission lines and associated equipment,⁷ and almost 6 million miles of lower-voltage distribution lines.⁸ These include approximately 2,400 miles of 765 kV alternating current (ac) lines, the highest voltage lines in operation in the U.S., and more than 3,000 miles of 500 kV dc lines.⁹ Several hundred entities currently own parts of the transmission or bulk power system.¹⁰ Investor-owned utilities own about 66% of the system, and federal enterprises own 14%. The rest is divided among other publicly

BOX 1.1 WHOLESALE ELECTRICITY MARKETS

In those areas of the country with wholesale electricity markets, the ISO or RTO functions as both the operator of the system and the financial exchange for wholesale energy sales. Selling wholesale electric energy begins with a bidding process whereby generators offer an amount of energy (MWh) for sale during specific periods of the next day at a specific price (\$/MWh). These offers are arranged by the ISO/RTO in ascending order called the “bid stack” and the generators are dispatched (told to generate) in this order until generation matches load. All the generators that are dispatched receive the same compensation called the “clearing price”—the offer of the last generator dispatched. The actual process is more complicated than this simple explanation, incorporating such parameters as the time required to start the generator, out-of-economic-order dispatch due to congestion or reliability concerns, and security constraints. Some base-load generators, such as nuclear plants, are costly to shut down or bring back on line, and will offer their energy at a price of zero to ensure that they are always dispatched. In some cases of very light load these generators may offer their energy at a negative price to guarantee they remain on line since the cost of stopping and starting outweighs the negative energy price. Consequently the cost of wholesale energy can swing wildly during a day—from near zero to near \$1,000/MWh depending on load and the state of the generator fleet—

though such a swing is not a usual occurrence. (For comparison, the average retail price of electricity in the U.S. is around \$100/MWh.)

Some generators that use renewable energy—wind and solar mainly—have essentially zero variable costs, and the subsidies they receive for generation permit them to bid a negative price and still receive positive compensation for their energy. While zero bids from renewable generators reduce the market clearing price, they do not necessarily result in savings to society because the true cost of the renewable energy is the clearing price plus the subsidy.

The majority of energy is traded through long-term bilateral contracts, where a buyer and a seller agree on a fixed price over a set period. Energy is still bought and sold in the real-time market as described above, but contracted sales are settled by a side transaction between the seller and buyer that accounts for the real-time price the parties paid and received. For a real-time price below the contract price the buyer pays the seller the difference, and for a price higher than the contract the seller pays the difference to the buyer.

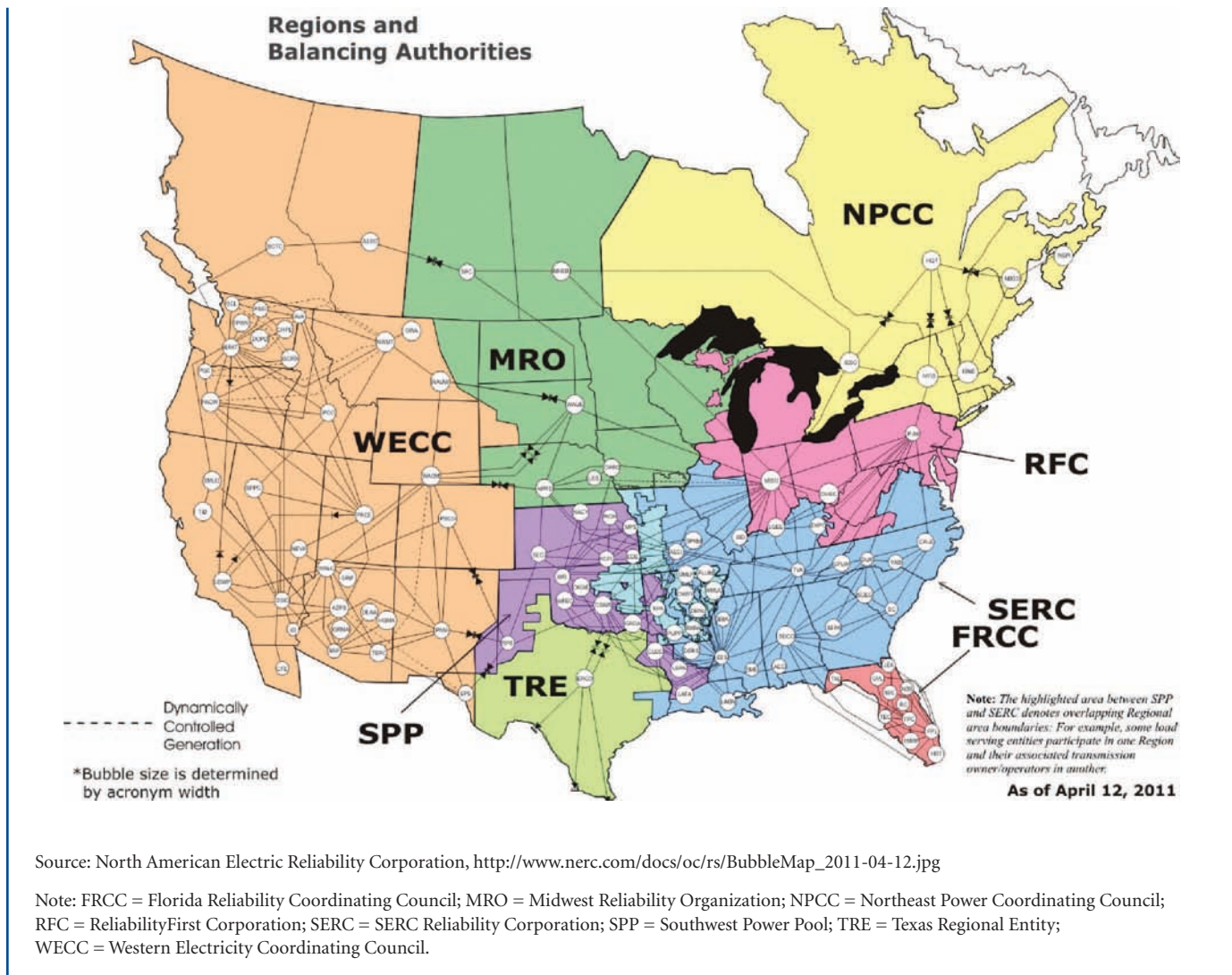
In addition to energy, the electricity market has a number of other “products,” the treatment of which varies from region to region. Among these are ancillary services, such as reserves of various types and capacity, which is designed to ensure that there is enough “iron in the ground” to meet future needs.

owned entities (7%), cooperatives (6%), independent transmission companies (4%), and others (3%). The U.S. Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electricity sales and transmission rates.

The U.S. grid serves about 125 million residential customers, 17.6 million commercial customers, and 775,000 industrial customers.¹¹

In aggregate, these categories of customers account for 37%, 36%, and 27% of electricity use, respectively. On average, commercial customers pay about 8% less per kilowatt hour (kWh) for electricity than residential customers, while industrial customers pay about 40% less, in part because these large customers can take power at higher voltages and incur lower delivery costs.

Figure 1.3 Balancing Authorities in the North American Electric Grid, 2011



At the distribution level, about 3,200 organizations provide electricity to retail customers.¹² Nearly 2,200 are publicly owned—six by the federal government and the rest by states and municipalities—but they account for only 16%

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of electricity sold. Another 818 are cooperatives, which in aggregate account for 10.5% of kWh sales. In some areas of the country,

particularly the Pacific Northwest, municipally owned and cooperative utilities benefit substantially from preferred access to low-cost power from federal projects. Only 242 distribution entities are investor owned, but they account for 66% of electricity sales. Their retail rates are regulated by state public utility commissions (PUCs). Finally, about 7.5% of retail sales are accounted for by retail power marketers that do not provide distribution services.

In some states (and in much of Europe), some customers can purchase electricity from competing retail suppliers, with the distribution utility remaining as the owner of the distribution network and the sole (regulated, cooperative, or government-owned) supplier of distribution services. Currently, there is little or no retail competition of this sort in 35 states. Fifteen states and the District of Columbia have active retail choice programs for residential electricity customers, but only in Texas do more than 15% of those customers purchase power from a competitive supplier.¹³ In those same jurisdictions, commercial and industrial customers can choose among multiple suppliers, and in at least nine states and the District of Columbia more than 60% of large commercial and industrial customers have switched to competitive suppliers.¹⁴

At the generation level, in 2007, investor-owned utilities accounted for 42% of U.S. electricity generation.¹⁵ Cooperatives and federal systems, including the Tennessee Valley Authority, each accounted for about 4%. Publicly owned systems organized at the state or municipal level accounted for another 8%. As a consequence of the structural reforms described in Appendix A, the remaining 42% was provided by independent power producers that do not serve retail customers. These enterprises mainly operated in regions with organized wholesale markets.

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As a result of the layering of historical policy decisions and the lack of a comprehensive, shared vision of system structure or function, the U.S. electric power system today operates under a fragmented and often inconsistent policy regime.

Performance

The U.S. grid is often referred to as “anti-quoted” or “broken” in the popular press and, occasionally, in technical publications.¹⁶ However, assessing the performance of a system as complex as the U.S. electric grid is not a simple task. International comparisons and even comparisons within the U.S. are difficult because of differing geography, rates of growth, and definitions of performance measures. Systems that have grown more rapidly recently, for instance, on average will have newer equipment. Comparisons over time may reveal nothing more than the advance of technology driven by vendor R&D. Moreover, because there are diminishing returns to investing to increase efficiency and reliability, and perfection is unattainable at any cost, it is possible not just to underinvest but also to overinvest in these and other dimensions of performance.

An important measure of the performance of a transmission and distribution system is the fraction of energy generated that is lost due to heating of transmission and distribution lines and of other components. That fraction has fallen significantly over time in the U.S. As Figure 1.4 shows, losses in transmission and distribution decreased from more than 16% in the late 1920s to less than 7% today.ⁱⁱⁱ This reflects investments in transmission and distribution systems, the development and deployment of more efficient transformers and other equipment, and transmission at higher voltages.

ⁱⁱⁱ Losses are measured as the difference between energy generated and energy delivered to customers and thus in practice include losses due to theft. Theft is not considered to be important in the U.S. today, but it is significant in some other nations.

Figure 1.4 U.S. Transmission and Distribution Losses, 1926 to 2009

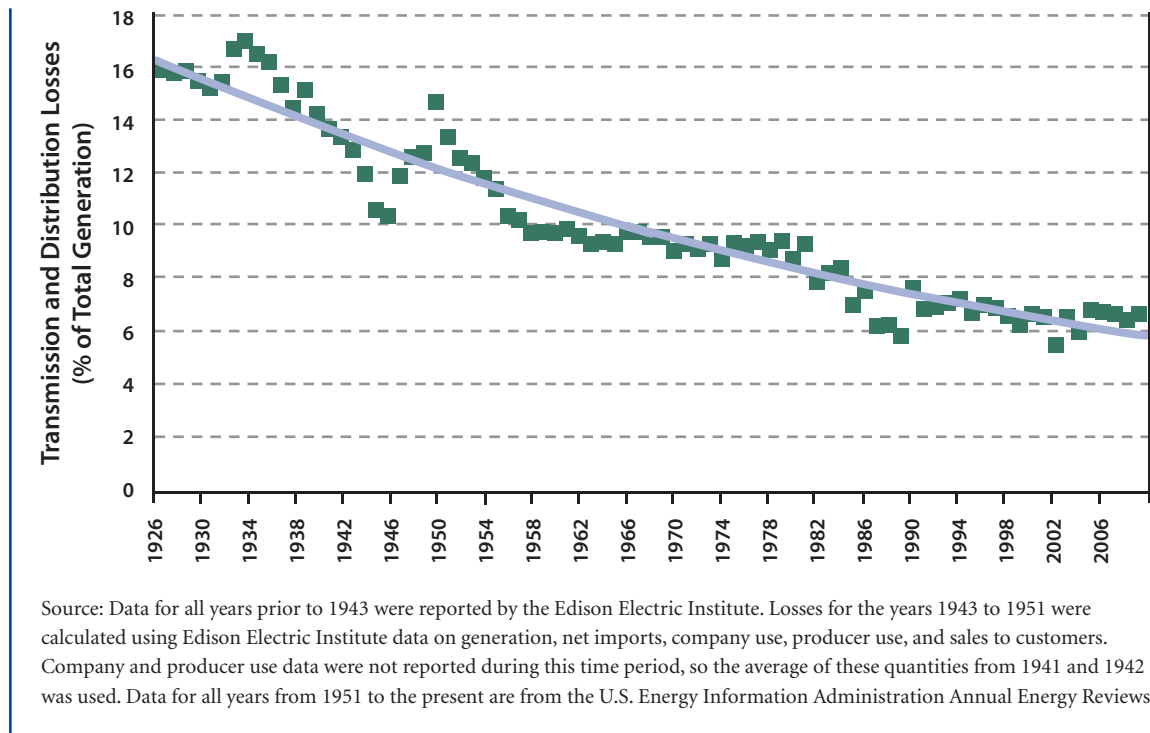


Figure 1.5 Transmission and Distribution Losses for Selected Countries, 2008

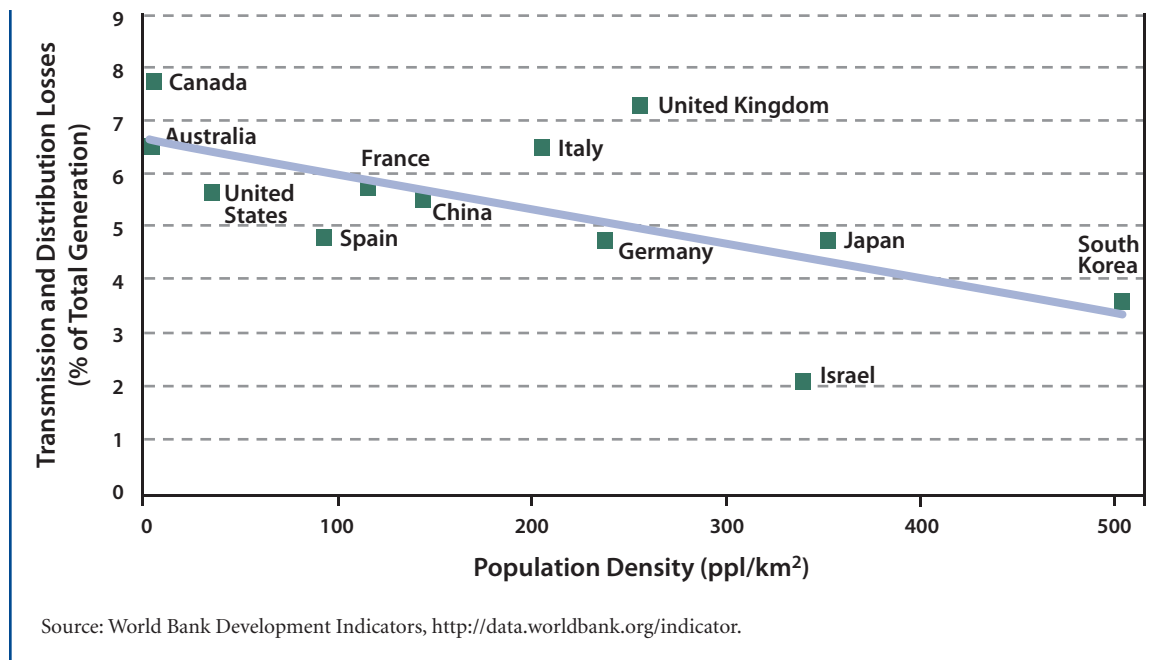


Figure 1.5 indicates that U.S. losses are comparable to those of other wealthy countries with systems that also have substantial amounts of older equipment, but it cannot indicate whether U.S. losses are higher or lower than would be optimal. This figure also suggests that losses tend to decline somewhat with increasing population density, all else equal, as one would expect. At the same time, the data for Italy, where losses due to theft are said to be unusually high, and the United Kingdom, which has a relatively old grid, indicate that other factors may often be even more important than density.

Another important dimension of performance is reliability. Increases in transmission voltage and many other significant, less visible technological advances have contributed to the grid's reliability. Protective relaying enabled the detection and isolation of system faults, for instance, and high-speed reclosing circuit breakers and relaying allowed transmission lines to be reenergized after a fault automatically in less than a few seconds. Lightning arrestors allowed the effects of lightning strikes to be contained automatically.

As a result of these and other advances, customers in the U.S. can expect to experience between 1.5 and 2 power interruptions per year and between 2 and 8 hours without power.¹⁷ This is on par with most European countries, where customers generally experience from less than 1 interruption per year to almost 3.¹⁸ There is great variation between reliability in urban and rural areas, with power unavailable in U.S. urban areas averaging between 30 seconds and five minutes per year versus between nine hours and almost four days in rural areas.¹⁹

Data on outages are neither comprehensive nor consistent, however. Most outages occur within distribution systems, but only 35 U.S. states require utilities to report data on the impact

of all outages on consumers, and reporting standards and practices differ.²⁰ It is accordingly impossible to make comprehensive comparisons across space or over time. In particular, the treatment of very short interruptions varies between states in the U.S.

and between different countries, so counts of outages cannot be usefully compared. Minutes of

outage per customer year is not much affected by these definitional differences, but data are nonetheless incomplete, and differences in national circumstances will clearly affect performance. At the bulk power level, data on major disturbances and unusual occurrences have been reported to the U.S. Department of Energy (DOE) since the 1970s and to the North American Electric Reliability Corporation (NERC), which has responsibility for the reliability of the bulk power system, since 1984. However, these data are not consistent, complete, or necessarily accurate, and they cannot reliably be used to assess changes in the reliability of the bulk power system over time.²¹

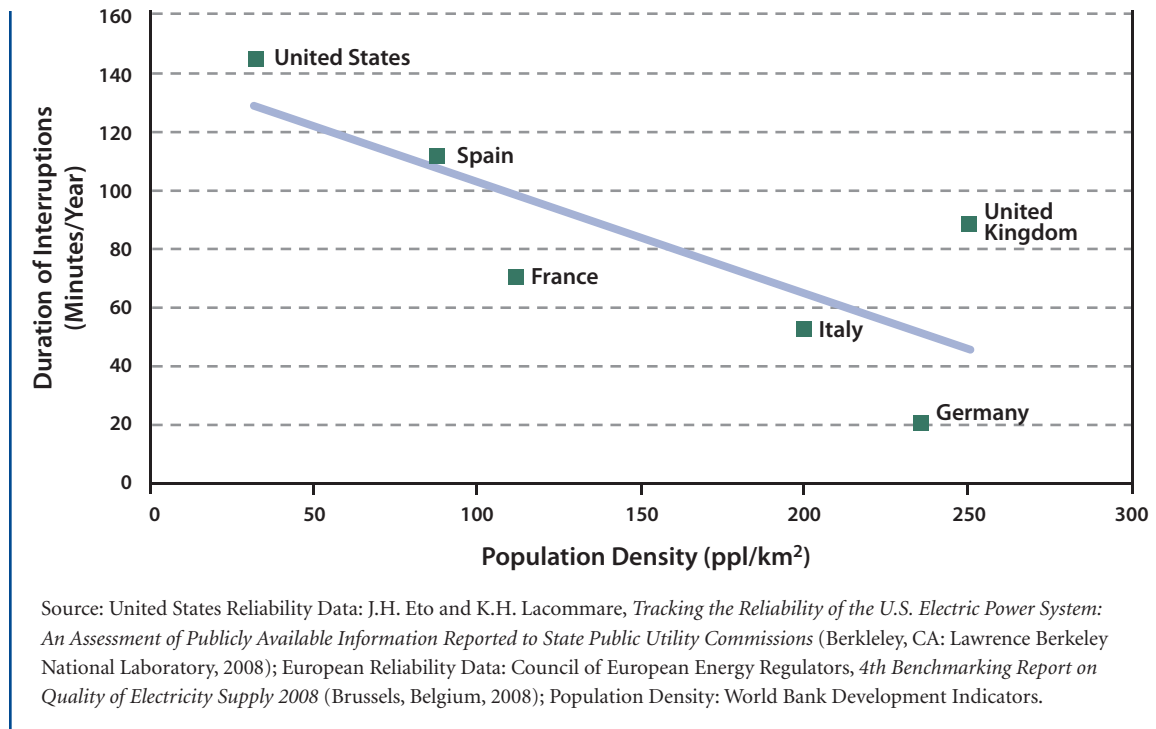
Figure 1.6 provides a comparison of minutes of outage per year in the U.S. and several European nations. Here, the U.S. is not out of line with other industrialized nations when we account for differences in population density (which correlates with the degree of urbanization). Such comparisons cannot reveal whether U.S. reliability is too low, too high, or optimal, given the benefits of reducing outages and the costs of doing so.

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Data are not available to quantitatively and accurately assess the reliability of the U.S. electric grid, particularly its changes over time. However, what data are available indicate the reliability of the U.S. grid is in line with that of other developed countries.

Data on outages are neither comprehensive nor consistent.

Figure 1.6 Average Duration of Interruptions for Selected Countries, 2006



A final dimension of performance involves the use of new technology to increase productivity. The U.S. electric utility industry has historically devoted a very small fraction of its revenues to R&D, instead relying primarily on its suppliers for innovation. U.S. utilities have sometimes

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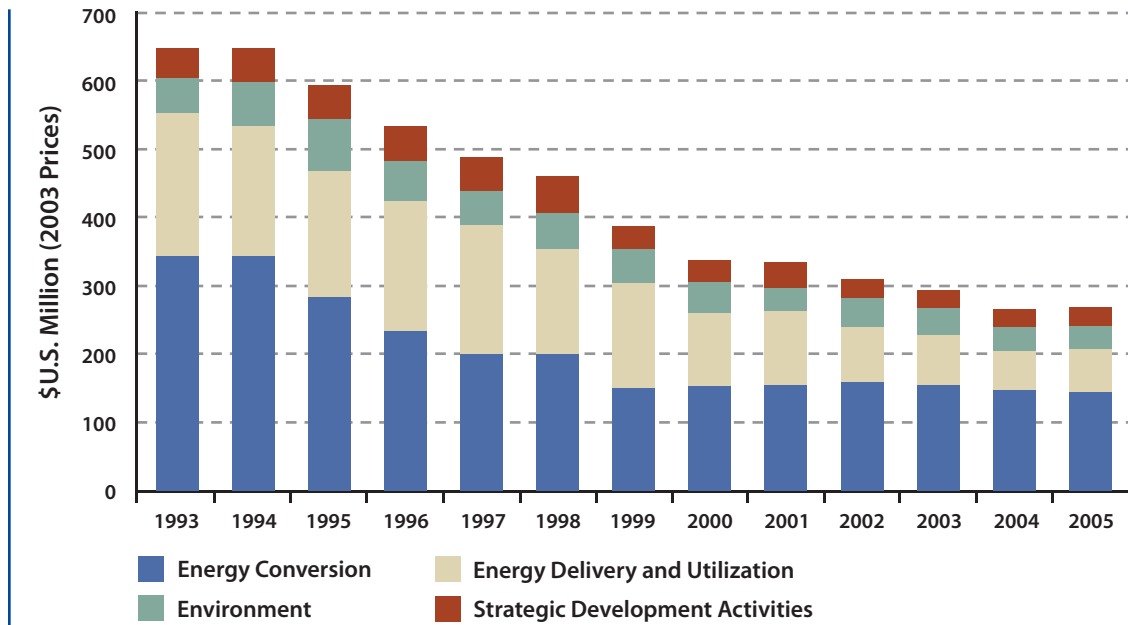
collaborated with vendors on R&D activities and have participated in collaborative research through the Electric Power Research Institute (EPRI), a nonprofit consortium founded in 1973. In recent years, however, utilities have shifted away from longer-term, collaborative projects and toward shorter-term proprietary efforts.²² Moreover, investor-owned utilities, which account for almost all nonfederal utility R&D spending, reduced their R&D budgets

beginning in the 1990s, spending on average less than 1% of their revenues on R&D.

Figure 1.7 shows a steady decline in collaborative R&D spending through EPRI. The decrease in utility R&D funding reflects, in part, reluctance among utilities to incur—and regulators to approve—R&D expenditures as federal and state policies pursued more industry competition, particularly during the 1990s.

Productivity improvement in the electric power industry has historically been rapid relative to most other industries. This is reflected in a decline in real retail prices until the 1970s, as shown in Appendix A. The lack of a long-term decline in later years suggests that the difference may have decreased, but comparisons to other industries remain relatively favorable: the Bureau of Labor Statistics shows that over the 1987 to 2008 period, output per labor hour rose at an annual rate of 2.4% in power generation and supply, as compared to 2.1% in the overall private nonfarm business sector.²³

Figure 1.7 Collaborative Research in the U.S. through the Electric Power Research Institute



Source: T. Jamasb and M. Pollitt, “Liberalisation and R&D in Network Industries: the Case of the Electricity Industry,” *Research Policy* 37 (2008): 995–1008.

Data on broader measures of productivity do not seem to exist, and quantitative international comparisons do not seem possible. Anecdotal evidence from some vendors suggest that U.S. utilities, particularly those that are investor owned, have been less willing to deploy new technologies in recent years than their foreign counterparts. But without better data there is no way to verify, let alone quantify, this difference or its effects.

1.2 CHALLENGES AND OPPORTUNITIES

Even though the U.S. electric grid is not broken today, emerging challenges, if not met, could substantially degrade the system’s reliability and efficiency over the next few decades. This section briefly introduces the main challenges the grid will face between now and 2030, the technologies that can be used to deal with them effectively, and important challenges posed by deployment of some of those technologies. The

findings presented below are developed and supported in detail in later chapters.

Renewable Generation

Unlike prior studies in the MIT “*Future of*” series, we do not assume a carbon-constrained world. Even in the absence of a broad federal initiative to reduce carbon dioxide emissions, however, federal and state subsidies and regulations are tilting the playing field in favor of low-carbon generating technologies. Beginning in the late 1970s, the federal government has supported the deployment of renewable energy sources—particularly geothermal, biomass, wind, and solar—through accelerated depreciation and, since the mid-1980s, tax credits for either production or investment, though support has been inconsistent over time.²⁴ All states now provide tax credits or other incentives for investment in renewable energy,²⁵ and 29 states and the District of

Columbia have renewable portfolio standards, which generally require utilities to obtain specified percentages of energy from designated renewable sources.

Renewables other than hydropower accounted for 4.2% of U.S. generation in 2010.²⁶ There is enormous regional variation: in California, for instance, renewables other than large hydro facilities accounted for 13.7% of electricity supply.²⁷ A number of states have set very ambitious requirements for renewables expansion: in California renewables other than small hydro plants will be required to account for 33% of electricity supply by 2020.²⁸ The EIA projects that even if support for renewables is not increased, but current federal policies are simply continued beyond their sunset dates, renewables other than hydropower will account for 57% of the increase in generation between 2010 and 2030, and wind and solar will account for over half of the non-hydro increase.²⁹

Two features of these technologies pose potential problems for the electric grid. First, unlike most other generating technologies, the output of wind and solar generators varies considerably over time and is imperfectly predictable. For this reason, they and some other technologies are labeled “variable energy resources,” or VERs. At low levels of penetration, VERs pose no new issues, but, as Chapter 3 discusses and several European systems have experienced, as penetration increases, demand minus VER generation (that is, the net load that must be met by other generators) becomes noticeably more variable and difficult to predict than demand alone. The system and its operation must be modified, at some cost, to handle this variability if reliability is to be maintained.³⁰ In particular as Chapter 3 notes, few incentives exist today for investments that add generation flexibility to power systems with organized

markets or for operating in a flexible manner, though power system flexibility will become more important as the penetration of VERs increases.

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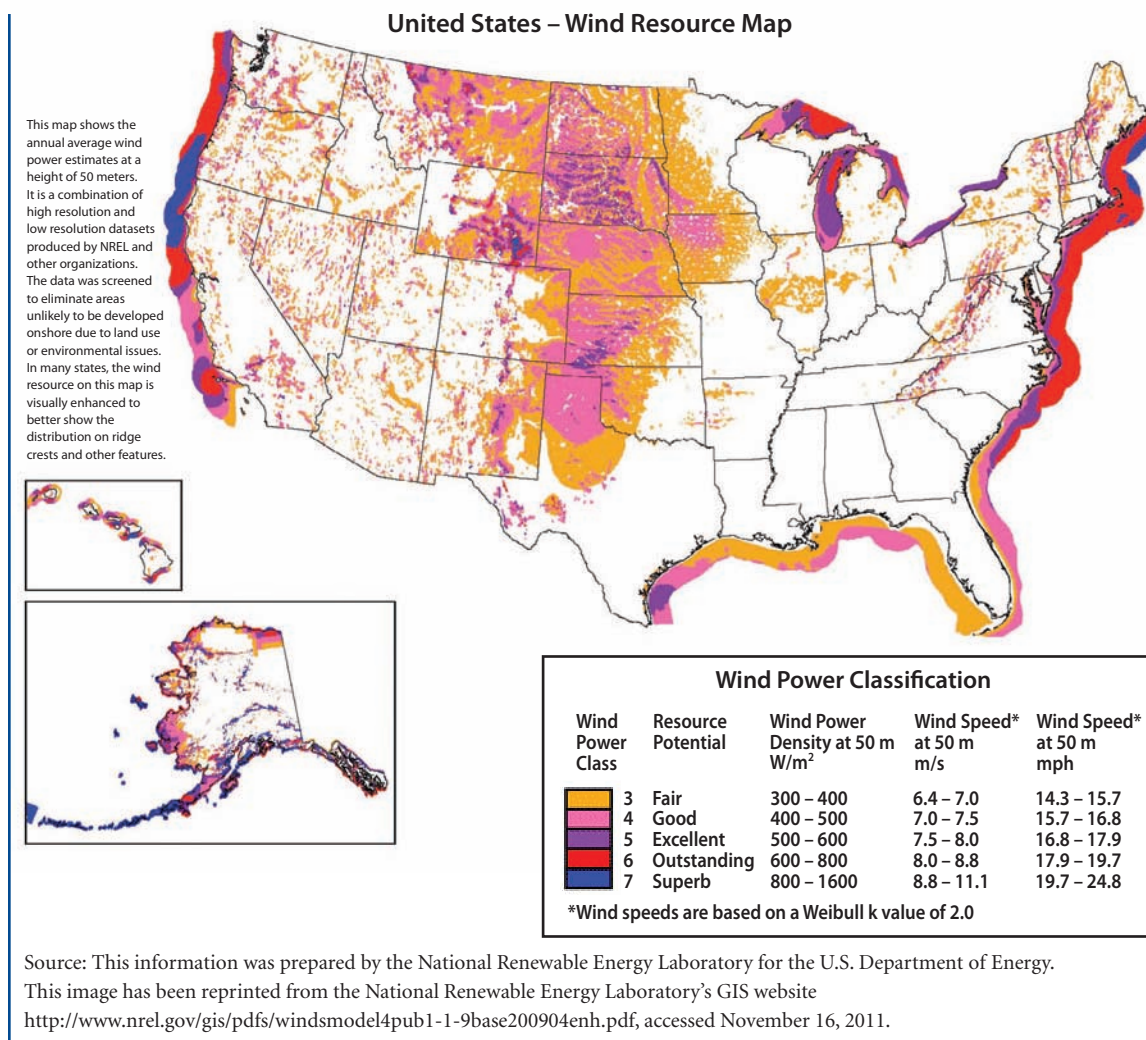
Devising and deploying mechanisms to provide incentives for investment in flexible generation and for operating flexibly within the system will become increasingly important as the penetrations of wind and solar generation increase.

Second, many of the most promising sites for wind and solar generators are located far from major load centers. As Figure 1.8 indicates, the most attractive wind resources are in the “wind belt” that stretches north from Texas through the Dakotas to the Canadian border. The U.S. also has significant offshore wind potentials on both the East and West Coasts. While these offshore resources are closer to major load centers, the costs of offshore wind installations are generally considerably greater than onshore facilities in good locations. Similarly, the prime locations for solar power are in the nearly cloud-free and sparsely populated desert Southwest, as shown in Figure 1.9.^{iv}

Exploiting these variable energy resources will require building more transmission than if fossil-fueled or nuclear generating plants built relatively close to load centers were driving system expansion. The use of very long transmission lines can cause technical problems and compromise system stability. In addition, as Chapter 4 explains, existing transmission planning tools are inadequate for wide-area planning, and current cost-allocation methods need improvement.

^{iv} Figure 1.9 relates to concentrated solar power generation, in which direct sunlight heats a working fluid (oil, historically), which is then used to generate steam to power a turbine. Photovoltaic systems are more tolerant of clouds (diffuse light) and hence perform well across a broader swath of the U.S. south.

Figure 1.8 Location of U.S. Wind Resources



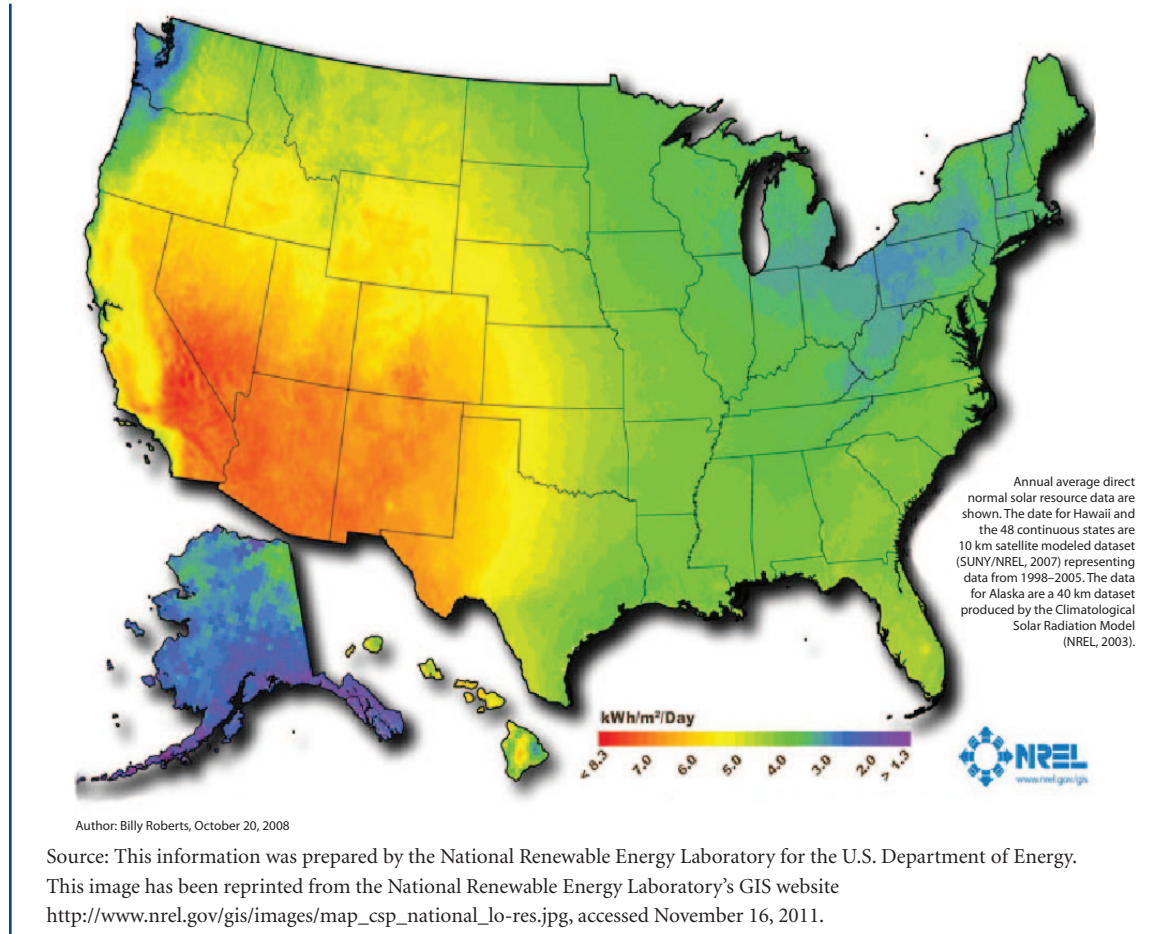
Cost allocation and siting have been particularly contentious for transmission facilities that cross state borders or the 30% of U.S. land managed by federal agencies. The Federal Power Act of 1935 made siting of all transmission lines a matter for the states rather than FERC, and lines that cross land managed by federal agencies need the approval of those agencies.^v Consequently, the construction of interstate transmission facilities requires the consent of multiple state regulators and, sometimes, one or more federal agencies.

In some regions of the country, this process is facilitated by the historic cooperation of states within an ISO's territory. But as a general matter, the special difficulties of siting boundary-crossing transmission facilities will pose an obstacle to the efficient integration of renewable generation.³¹

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^v In contrast to the Federal Power Act of 1935, the Natural Gas Act of 1938 as amended in 1947, gave the predecessor of FERC the right of eminent domain to site interstate natural gas pipelines. Interstate pipelines were already important in the natural gas industry in the 1930s, while interstate transmission of electricity was much less important than it is now or likely will be in the future.

Figure 1.9 Location of U.S. Concentrated Solar Power Resources



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Efficiently increasing the penetration of grid-scale renewable generation while maintaining reliability will require modifications to power system design and operation. In addition, processes for planning transmission system expansion, allocating facility costs, and, particularly, siting interstate transmission facilities will need to be reformed.

Electric Vehicles and Greater Demand Variability

Although growth in electricity demand is not likely to emerge as an important source of disruption in the next few decades,^{vi} electricity demand has changed and is likely to continue to change in ways that pose challenges to the system. The first of these has been a substantial increase in power demand during select hours of the year. Historically, several factors have contributed to this trend, which has resulted in an increasing ratio of system peak loads to average loads and falling capacity utilization.

^{vi} Between 1949 and 1973, electricity use in the U.S. grew at an average annual rate of 8.3%, and the system was able to meet that demand with only sporadic difficulty. Even with rising prices after 1973, electricity use grew at an average annual rate of 2.5% in the 1973 to 2006 period. In contrast, the EIA's reference case projection is for growth to average only about 0.9% per year between 2010 and 2030.³²

Figure 1.10 illustrates this change for New York and New England.

This figure shows load duration curves expressed as percentages of peak hour demand to facilitate comparisons. It shows, for instance, that in the 1980–1984 period in both New York and New England, demand exceeded 80% of its peak for only about 1,000 hours—about 11.4% of the time. Because power systems need to be sized to meet peak loads with a reserve margin for reliability, more than 20% of generation capacity (and, roughly, transmission and distribution capacity) was in use less than 12% of the time. The costs of that idle capacity must be covered by ratepayers, and the more that must be spent to build and maintain rarely used assets, the higher electricity rates must be.

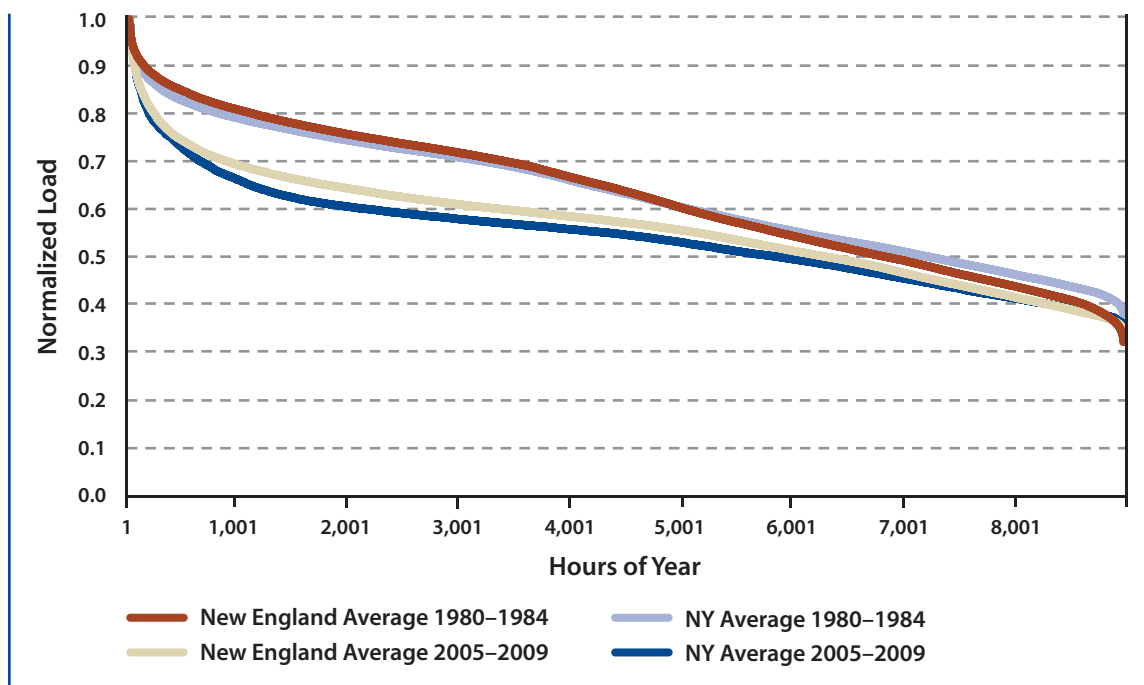
Figure 1.10 also shows that, in the following quarter century, the problem grew appreciably worse. By 2005–2009, in both New York and New England, demand exceeded 70% of its peak for only about 1,000 hours so that more than 30% of capacity was in use less than 12% of

the time. Not only does this trend raise average costs because of the need to pay for capital that is idle most of the time, it exacerbates the need to build new generation plants and transmission lines and thus the problem of siting them, since all new facilities must go in somebody’s backyard.

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Among the factors that have contributed to the increasing severity of this problem are the spread of air-conditioning and the declining market share of industrial use of electricity. Between 1981 and 2001, the fraction of U.S. homes with air-conditioning rose from 57.3% to 75.5%.³³ This served to raise power demand most substantially in the hottest hours of the hottest summer days, which generally correspond to system peaks. We suspect this factor to have been particularly important in

Figure 1.10 Normalized Load Duration Curves for New England and New York



New York and New England in the period shown in Figure 1.10.

A second factor that may have been more important in other regions is the relative decline in industrial use of electricity. On average during 1950 to 1959, industrial customers accounted for half of retail sales of electricity.³⁴ Industrial plants often run around the clock all year, so the more important industrial load is, the flatter the load duration curve tends to be. The relative importance of industrial customers has declined steadily since the 1950s, however, and on average in the 2000 to 2009 period, they accounted for only 28% of retail sales. This has made load duration curves steeper.

Looking ahead, these trends are likely to continue, and their adverse effects on capacity utilization may be exacerbated by the spread of electric vehicles (EVs), which include plug-in hybrids and battery electric vehicles. About 94% of the energy used in the U.S. transportation system comes from petroleum, and more than half of crude oil and petroleum products are imported.³⁵ Increasing the penetration of EVs is often viewed as an attractive means of reducing dependence on imported oil. As Chapter 5 discusses, although their penetration generally is projected to be slow at the national level under current policies,³⁶ these vehicles cannot be ignored, even in the near term. EVs are expected to achieve high levels of penetration quickly in some high-income areas with environmentally conscious consumers. Whenever and wherever they are deployed in large numbers, their impact on the grid will depend on when they are charged. If they are charged when commuters return home, as seems most likely under current policies, they could add significantly to system peak loads, worsening the problem depicted in Figure 1.10. On the other hand, measures that

encouraged overnight charging could increase demand when it would otherwise be low, thus tending to flatten load duration curves.

FINDING

Ongoing changes in the character of electricity demand and the future penetration of electric vehicles will, in the absence of other changes, tend to accelerate the decline in capacity utilization in the electric power system. This, in turn will increase electricity costs.

Distributed Generation

Existing policies at state and federal levels favor distributed generation from low-carbon sources, and these policies seem likely to continue. At the federal level, personal and corporate tax incentives encourage distributed generators, which are small-scale systems, generally connected to distribution networks. Most states have programs that subsidize distributed generation.³⁷ The California feed-in tariff program for small-scale renewable generation, particularly rooftop solar units, is perhaps the most visible of these.³⁸ In addition, 46 states and the District of Columbia have what are called “net metering” programs, which compensate end users for generating their own energy at the retail electricity rate rather than the wholesale cost of energy.³⁹ The difference between these rates is mainly the fixed cost of distribution (and, sometimes, transmission), which is typically recovered by per-kWh charges. When an end user increases generation, the system saves only the wholesale cost of energy. Under net metering, however, the end user saves both this wholesale cost and the per-kWh charge used to recover fixed network costs. Thus net metering provides

an additional subsidy to distributed generation of all sorts that may encourage uneconomic penetration.

At low levels of penetration, distributed generation simply reduces the load at individual substations. At high levels of penetration, however, distributed generation can exceed load at the substation level, causing unusual distribution flow patterns with power flowing from the substation into the transmission grid. The systems involved are currently not designed to handle such reverse flows, however. In fact, this condition can produce high-voltage swings, which can be detrimental to customer equipment. High levels of penetration can also add to the stress on electrical equipment, such as circuit breakers, and complicate the ability to operate the distribution system, particularly during emergencies and planned outages. Additional monitoring and new standards for operation, protection, and control will be necessary to enable significant penetration of distributed generation. Enabling such penetration in a cost-effective manner would require incremental investment by the distribution utility, while distributed generation would reduce its sales. Current regulatory frameworks do not provide adequate incentives for such investments.

FINDING

High penetration of distributed generation complicates the design and operation of distribution systems. Net metering provides a subsidy to distributed generation, and utilities have inadequate incentives to make investments necessary to accommodate it.

Aging Workforce

Even if it faced none of the challenges discussed above, the electric power industry would need to rejuvenate its workforce in order to maintain current levels of performance. Prompted by the results of a National Science Foundation workshop on this topic in November 2007, the Power & Energy Society of the Institute of Electrical and Electronics Engineers (IEEE) founded the U.S. Power and Energy Engineering Workforce Collaborative (PWC) to lead efforts to strengthen the U.S. power and energy workforce.⁴⁰ In a widely cited April 2009 report, the PWC noted that approximately 45% of U.S. electric utility engineers would be eligible for retirement or could leave engineering for other reasons in the subsequent five years.⁴¹ A 2008

University power engineering programs have languished over the past several decades due to the increasing popularity of other electrical engineering subdisciplines and a lack of research funding to support graduate students.

survey conducted by the Center for Energy Workforce Development, an industry consortium, indicated that workforce attrition could amount to 40%–50% by 2013 across a wide range of power industry technical job categories, including lineworkers, pipefitters and pipelayers, engineers, plant operators, and technicians.⁴² Beyond retirements, meeting the challenges and realizing the opportunities discussed in this study will also require many industry professionals to learn new skills and knowledge.⁴³ Unfortunately, university power engineering programs have languished over the past several decades due to the increasing popularity of other electrical engineering subdisciplines and a lack of research funding to support graduate students.⁴⁴ Furthermore, a recent survey

indicated that approximately 40% of power engineering faculty members at U.S. universities will become eligible for retirement within the next five years, and 27% are expected to retire.⁴⁵ While it is difficult to predict exactly how many new engineers will be needed between now and 2030, there appears to be a significant gap between anticipated industry demands and both the pipeline of students entering power engineering and the faculty in place to train them.

Fortunately, industry workforce challenges have received increasing attention in the past several years. Among other efforts, the PWC has published a detailed action plan with recommendations for a wide range of industry stakeholders.⁴⁶ The DOE also recently awarded \$100 million to 52 workforce training and development efforts.⁴⁷ These projects are expected to help train as many as 30,000 workers and develop a variety of power system education programs. It is too early to tell whether these efforts will be sufficient to ensure the availability of a qualified technical workforce, however, and the issue will likely continue to receive attention in the years ahead.

FINDING

Because of its aging workforce and the nature of emerging challenges, the electric utility industry faces a near-term shortage of skilled workers, particularly power engineers. While this problem has been widely recognized, it remains to be seen whether efforts to deal with it will prove adequate.

Technologies for Reliability and Efficiency

The electric power system is built to handle periodic equipment failures, primarily by rapidly disconnecting lines or generators where problems occur. To guard against the negative consequences of contingencies in the bulk power system, such as the loss of a generator or transmission line, system operators maintain a prescribed level of generation reserves and updated procedures for reacting to unexpected

Innovative technologies can improve operator knowledge about the state of the transmission system and thus make possible more efficient and reliable operation.

events. These measures work well most of the time, and customers are often unaware when problems occur on the bulk power system. Customers more often observe failures of the distribution system. If a tree limb takes down a distribution line, for instance, many utilities do not know where to send a repair truck until multiple customers have reported the outage.

As discussed in Chapter 2, innovative technologies can improve operator knowledge about the state of the transmission system and thus make possible more efficient and reliable operation. On the transmission system, phasor measurement units (PMUs) are powerful devices that provide rich streams of frequent, time-stamped data on transmission system conditions that system operators can use to anticipate contingencies, reduce the risk of wide-area blackouts, enhance system efficiency, and improve system models. With funding from the American Recovery and Reinvestment Act of 2009, PMUs are being widely deployed, but work is needed to network these devices into systems, convert data from these systems to actionable information, and employ this information in the control of the grid.

In addition to PMUs, flexible alternating current transmission system (FACTS) devices based on advances in power electronics can provide greater control of voltages and power flows throughout the bulk power system.

FACTS and other new technologies can allow more power to be transmitted on existing lines without increasing the risk of failure, but historically the incremental benefits generally have not justified the associated costs. Higher penetration of VERs is likely to increase the value of deploying these technologies in the transmission system.

Compared to the transmission network, the distribution system uses more basic, inexpensive monitoring and control equipment. This is cost-effective, as there are far more miles of distribution lines than transmission lines, and each distribution line serves fewer customers than a transmission line. There are many technologies to enhance the distribution system, as Chapter 6 explains, including distribution management system software, more accurate control of voltages, automatic reconfiguration of distribution circuits, and advanced metering infrastructure (AMI). AMI, for instance, will enable system operators to detect an outage and identify its cause within minutes, even if no customers call.

Because it is often more cost-effective to invest in monitoring and control systems at the transmission level than the distribution level, many available technologies have not yet been widely implemented at the distribution level. Moreover, in recent years U.S. utilities and regulators have tended to avoid investments in unfamiliar technologies perceived to have uncertain payoffs. Given the many new challenges that will confront distribution systems in the next 20 years, some modernization and enhancement will surely be appropriate, but

each system is different, and cost is always an important consideration in the choice of technology.

In addition, as discussed in Chapter 6, a variety of new and emerging technologies, including advanced metering systems, can receive price information based on the real-time cost of providing electricity and can transmit usage information every few minutes. This makes it possible to provide real-time incentives to reduce system peaks caused by central air-conditioning, vehicle charging, and other loads, resulting in more efficient use of grid assets and thus lower rates. As Chapter 7 notes, however, the effective use of these technologies to make electricity demand more sensitive to system conditions will require changes in regulatory policy to encourage the deployment of relatively novel pricing regimes, to which customer response, especially at the retail level, is poorly understood.

FINDING

New technologies have the potential to improve the reliability and efficiency of bulk power systems by enhancing operators' ability to observe and control these systems. Technologies similarly can enhance distributions systems and make demand more responsive to real-time costs, but effective use of these technologies will require changes in regulatory policy.

BOX 1.2 THE “SMART GRID”

The term “smart grid” has been used to refer to a wide variety of electric grid modernization efforts and ideas over the past several years. While uses of the term vary throughout industry, government, and the public, it is perhaps best described as the expanded use of new communications, sensing, and control systems throughout all levels of the electric grid. Many industry websites have been created to try to make sense of the flood of “smart grid” ideas, concepts, and products originating from industry, organizations, and individuals. These websites include SmartGrid.gov (www.smartgrid.gov), the Smart Grid Information Clearinghouse (www.sgiclearinghouse.org/), and IEEE’s Smart Grid site (<http://smartgrid.ieee.org/>).

In the U.S., Title XIII of the Energy Independence and Security Act of 2007 established the development of the smart grid as national policy and identified it as a broad collection of ambitious goals, some of which seem only loosely connected to the grid’s intelligence, as follows:

SEC. 1301. STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID.

It is the policy of the United States to support the modernization of the Nation’s electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cybersecurity.
3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy efficiency resources.
5. Deployment of ‘smart’ technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6. Integration of ‘smart’ appliances and consumer devices.
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage airconditioning.
8. Provision to consumers of timely information and control options.
9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

The scope of this study is broader than many definitions of the smart grid. However, we do consider the technologies that are core to most smart grid discussions. For example, phasor measurement units, devices that have the potential to equip bulk system operators with greater real-time knowledge of the state of the bulk transmission system, are discussed in Chapter 2; applications that are enabled by the deployment of sensors and communications throughout distribution networks are described in Chapter 6; and advanced metering infrastructure investments are discussed in Chapter 7. Chapter 9 analyzes many of the challenges related to expanded data communications use, including cybersecurity and information privacy challenges.

Because the term “smart grid” means different things to different people and because its meanings are evolving, we have avoided reliance on the term in this report. We have focused instead on the broad goal of making the grid of the future more resilient, secure, efficient, and reliable amid a variety of emerging challenges and, perhaps, to enable the provision of desirable new services. Seizing opportunities related to recent or anticipated technical innovations can further these goals.

Cybersecurity and Privacy

The interconnection of small, local power systems enhanced reliability overall but made possible wide-area blackouts. Similarly, the increasing use of new sensing and automated response technologies will enhance reliability and efficiency overall but create new problems.

As explained in Chapter 9, increasing amounts of data will be exchanged among meters, other sensors, and various computers and control facilities through a complex communications system that must follow standards that allow various components to interoperate now and in the future, when later generations of equipment are installed. Since no communications system can be completely free from errors, the future grid must be designed to mitigate the consequences of data errors. More chilling is the possibility of deliberate sabotage via computers and data communications, the sort of cyberattacks that other industries have experienced. The existence of more communications nodes and channels facilitates the placement of malicious data into the system; in addition, greater reliance on automated responses to system conditions that may be misreported can make it more difficult to prevent serious damage.

With the collection, transmission, processing, and storage of increasing amounts of information also comes heightened concern for protecting the privacy of that information.

With the collection, transmission, processing, and storage of increasing amounts of information also comes heightened concern for protecting the privacy of that information. As advanced metering is implemented, information on personal habits will be available to electric companies at a level never before

envisioned by today's utilities, nor by today's policy makers. Information about the operation of the electric grid itself will soon be available at a level of detail that will be of value to those with both commercial and malicious interests.

Deciding who has access rights to these personal data and ensuring consumers' privacy will be an important consideration in the design and operation of grid communications networks. Many governments have passed laws protecting the privacy of personal information, although not yet specifically electricity usage information. Utilities and related organizations will have to develop systems and procedures to protect the privacy of grid information to satisfy the concerns of customers and their governments.

FINDING

Greater reliance on data communications in the grid increases the importance of standardization for interoperability and of cybersecurity and raises serious issues of privacy.

1.3 MAJOR RECOMMENDATIONS

This section highlights what we consider the most important elements of the more than 20 specific recommendations developed in later chapters and discusses some of our related findings and conclusions. We present recommended policy changes affecting transmission, pricing and regulation of distribution, and cybersecurity. Major recommendations for research and analysis and for data development and sharing are collected in the final subsections below.

Two broad points deserve mention here. First, the adoption of coherent and stable national policies on greenhouse gas emissions, electric vehicles, and renewable and distributed

generation would enhance investment incentives and thereby accelerate the appropriate evolution of the grid. Second, support for organized wholesale electricity markets along with open, nondiscriminatory access to the transmission grid has been repeatedly affirmed as national policy, but development and expansion of the reach of open access and nondiscrimination is still a work in progress.

Support for organized wholesale electricity markets along with open, nondiscriminatory access to the transmission grid has been repeatedly affirmed as national policy.

These policies are of central importance for the transmission grid, and organized electricity markets with many common market design elements will continue to define the framework within which they can be effectively implemented.

Bulk Power and Transmission Systems

As generation from wind and solar power grows in importance, power systems will have to become more flexible to be better able to respond to substantial changes in the output of these variable resources. System operators here and, especially, in Europe are aware of the problems involved, and solutions are being developed. It seems clear that real or virtual consolidation of small balancing areas would be helpful, as would requiring new VER generators to meet performance specifications appropriate for operation in a high-VER future. And, as we noted earlier, mechanisms to ensure that power systems are adequately flexible will become more important in the future.

As the electric power system has become increasingly interconnected, the importance of transmission lines that cross state borders or federal lands has also increased. And, as discussed earlier, public policies favoring

renewable generation are likely to accelerate this trend because many of the best wind and solar resources are far from major load centers.

Transmission system expansion in many regions is routinely planned on a multistate basis, and attempts at interconnection-wide planning are under way. FERC Order No. 1000, issued in July 2011, should significantly increase wide-area planning of transmission systems and rationalize the allocation of the costs of transmission facilities that cross regional boundaries. We nonetheless believe the public interest would be served if the affected parties went beyond the order's planning requirements and established permanent and collaborative processes for transmission planning at the interconnection level that combine top-down and bottom-up approaches. Similarly, while Order 1000 only requires the development of bilateral cost-allocation procedures for interregional projects, we believe all affected parties should develop a single procedure for each interconnection. In that procedure, as Chapter 4 explains, costs should be allocated as closely as practical in proportion to anticipated benefits and other efficiency-enhancing principles should be followed.

Under current law, states retain the primary role in siting transmission facilities, and their interests sometimes conflict.

Under current law, states retain the primary role in siting transmission facilities, and their interests sometimes conflict. Any involved state can block a multistate project. Moreover, federal agencies with missions that include purposes unrelated to energy manage 30% of U.S. lands; they can and do exercise the power to block or delay the construction of transmission lines across these lands in cases of perceived conflict with other land management missions.

The federal government has addressed this type of structural problem before. In 1938, recognizing the growing importance of interstate natural gas pipelines, Congress gave FERC authority to site these facilities, now including the power of eminent domain. In recognition of the increasing importance of interstate electricity transmission, the Energy Policy Act of 2005 contained a section that was intended to give FERC useful backup siting authority in the event states disapproved construction of multistate electricity transmission facilities. As Chapter 4 discusses, however, subsequent court decisions have effectively annulled that section. While the Obama administration has recently taken steps to streamline federal agency participation in some siting decisions by creating the Renewable Energy Rapid Response Task Force, the current system for siting transmission facilities remains a significant barrier to efficient expansion of the grid.

Some have argued that in the interest of efficiency, FERC should have sole siting authority over major projects, as it does over interstate natural gas pipelines. Others contend that giving FERC effective backstop authority would create a process more sensitive to states' legitimate concerns. While both approaches clearly have strengths and weaknesses, adopting either would be a significant and important improvement over the status quo.

RECOMMENDATION

New legislation should grant FERC enhanced siting authority for major transmission facilities that cross state boundaries or federal lands (Chapter 4).

Pricing and Distribution Regulation

As noted earlier, in recent decades the ratio of peak electricity demand to average demand has increased, and this trend is likely to continue. Since an essential requirement of a power system is the ability to meet peak demand, these developments have reduced capacity utilization and thereby increased average cost and, ultimately, retail rates. The penetration of electric vehicles may exacerbate this trend unless their owners can be induced to charge them in off-peak periods. Even greater savings may be realized by making other loads, including commercial and industrial HVAC systems and residential appliances, similarly responsive to system conditions. Existing studies suggest that regulators and utilities can achieve this using a combination of dynamic pricing—in which retail prices vary over short time intervals to reflect the often dramatic changes in the actual cost of providing electricity—combined with technology to automate response to price changes.

The behavior of residential consumers faced with dynamic pricing is not yet adequately understood.

Many large commercial and industrial customers now operate under dynamic pricing. We believe such pricing regimes will be widespread options, if not the default, for residential consumers also by the end of our study period in 2030, with third parties generally enabled to compete to provide equipment to automate response to price changes. However, response automation technologies are not yet mature, in part because the behavior of residential consumers faced with dynamic pricing is not yet adequately understood, and residential dynamic pricing requires substantial investment in AMI to measure usage over short time intervals. Substantial AMI investments have recently been funded through the Recovery Act of 2009, and some state regulators have

mandated universal AMI deployment. But movement toward the dynamic pricing regimes that AMI enables has been slow. Given the enormous potential value of dynamic pricing of electricity, regulators and utilities should exploit the important learning opportunity the Recovery Act-supported and regulator-mandated investments in AMI have provided to develop efficient paths to universal dynamic pricing—and then to follow those paths.

RECOMMENDATION

With the cooperation of their regulators, utilities that have committed to AMI systems should begin a transition to dynamic pricing for all customers and publicly share data from their experiences (Chapter 7).

Utilities that have not committed to AMI systems and for which the operational benefits of these systems are less than their cost should take advantage of the option to learn from early adopters before making a decision to invest. For jurisdictions with wholesale electricity markets, effective competition in the retail sales of electricity may stimulate innovation in ways to make dynamic pricing both acceptable to consumers (and regulators) and effective in modifying demand.

Electricity pricing also needs to be changed to deal with the growth of distributed generation and energy efficiency initiatives. Utilities currently recover the largely fixed costs of transmission and distribution networks through volumetric charges per kilowatt hour of use, a practice that distorts the relative prices of central station generation and distributed generation. Under this regime, a customer who generates electricity on-site rather than purchasing it from the local distribution utility saves both the energy charge and the distribution charge for that electricity, but the utility

saves only the corresponding generation cost because the cost of distribution is almost entirely unchanged. (Indeed, if a high concentration of distributed generation required modification of the distribution system, that fixed cost may be increased.) This outcome is the same regardless of the energy source—clean solar or dirty diesel—used by the distributed generator. The remedy is straightforward, at least in principle: recover fixed network costs mainly through nonvolumetric charges.

RECOMMENDATION

State regulators and those who supervise government-owned and cooperative utilities should recover fixed network costs primarily through customer charges that may differ among customers but should not vary with kilowatt-hour consumption (Chapter 8).

These fixed charges could depend on indicators of customers' need for network capacity. For example, customer groups that are expected to contribute more to local peak demand based on their pattern of prior consumption could pay a higher fixed charge than customer groups that are expected to contribute less. Systems that continue to rely significantly on volumetric charges for cost recovery should improve utility incentives by decoupling utility revenues from short-run changes in sales.

Coping efficiently with the integration of distributed generation, electric vehicles, and demand response in coming years will require significant investments in new and emerging technologies that will be riskier than most recent investments in distribution systems; they will aim to provide new capabilities, not just expand capacity in traditional ways. While the technical problems associated with these new challenges are real, they do not appear to be serious. However, the tendency of traditional

regulatory systems to encourage excessively conservative behavior is likely to become more and more expensive over time if increasingly attractive opportunities to enhance efficiency and reduce cost through innovation are not exploited. As Chapter 8 discusses, this is an important problem—but one without an obvious solution, since both regulators and utilities seem to be punished for bad outcomes but not rewarded for good ones. Nonetheless, regulatory innovations are necessary to provide adequate incentives for investments in unfamiliar technologies while also ensuring that the returns on these investments are shared appropriately with ratepayers.

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Communications, Cybersecurity, and Privacy

As data communications becomes more important in the grid, so will problems of cybersecurity and issues of privacy. As the grid evolves, it will be critical to maintain interoperability of different types and generations of components over a variety of networks with, most likely, a variety of owners. The National Institute of Standards and Technology (NIST) is overseeing the complicated process of developing the relevant interoperability standards. This process is critical, and it should be encouraged and supported. In addition, there are ongoing debates about the use of spectrum and the roles of public and private networks. Resolution of the former debate rests with the FCC, while we expect that opportunities for both public and private networks will exist unless the regulatory environment treats them unequally.

As communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyberattacks.

As communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyberattacks.

Response and recovery, in addition to preparedness, will thus be important components of cybersecurity. NERC is responsible for standards development and compliance for the bulk power system, but no entity has comparable nationwide responsibility for distribution systems. State PUCs (which are generally responsible only for investor-owned distribution systems), municipal electric systems, cooperatives, and other public systems generally lack the expertise necessary to deal with cybersecurity issues. While the consequences of a successful attack on the bulk power system are potentially much greater than an attack at the distribution level, the boundary between transmission and distribution has become increasingly blurred, and distribution-level cybersecurity risks deserve serious attention. NIST is facilitating the development of cybersecurity standards broadly, but it does not have an operational role. Thus no organization currently has responsibility for overseeing grid cybersecurity across all aspects of grid operations.

RECOMMENDATION

The federal government should designate a single agency to have responsibility for working with industry and to have the appropriate regulatory authority to enhance cybersecurity preparedness, response, and recovery across the electric power sector, including both bulk power and distribution systems (Chapter 9).

This may require new legislation, and legislative proposals designating either a combination of FERC and DOE or the Department of Homeland Security (DHS) have been advanced. The various agencies each have both strengths and weaknesses for such a designation; the capabilities of any agency can be enhanced to address its relevant weaknesses, but ongoing jurisdictional confusion raises security concerns, underscoring the need for action. Once a lead agency has been designated, it should take all necessary steps to ensure that it has appropriate expertise by working with other relevant federal agencies, NERC, state PUCs, public power authorities, and such expert organizations as IEEE and EPRI.

Finally, the issues involved in the use and protection of customer electric usage data are complex, particularly because of the many different and evolving views of consumers, utilities, and regulators. These issues continue to be actively debated in several states. Coordination across states will be necessary to mitigate concerns of companies that operate in multiple jurisdictions and of their customers, as data on both companies and their customers cross state boundaries.

Research and Analysis

As noted earlier, the electric utility industry traditionally has relied primarily on its suppliers for the innovation that has driven its productivity growth. Supplier R&D naturally has focused on equipment that can be sold to utilities. Additional efforts in several non-equipment related research areas relevant to tomorrow's grid are likely to have substantial payoffs, and these are not likely to attract traditional equipment vendors. They include the development of computational tools and well-designed social science-based studies of customer response to dynamic pricing regimes, perhaps supported by response automation, that have been made possible by recent AMI investments.

Currently, electric utilities generally lack both appropriate financial incentives and the expertise necessary to perform either type of research and development, but the industry should nonetheless be able to support the modest but sustained efforts required. For this to happen, regulators will need to recognize that technical progress benefits consumers broadly and permit modest increases in utility R&D budgets. It will also likely be necessary for the industry to reverse the downward trend in cooperative R&D spending and make appropriate use of cooperative funding through EPRI, one or more independent system operators, and project-specific coalitions.

New algorithms, software, and communication systems are required to integrate PMUs and FACTS devices effectively into system operations. The Recovery Act has funded expansion of PMU penetration in the grid. Like the Recovery Act-financed investment in AMIs, this investment provides an important learning opportunity. If shared, data generated by existing PMUs can be used to develop algorithms and establish baselines for future operational tools that can monitor and control networks with greater PMU and FACTS penetration.

Existing planning methods cannot do multiperiod optimization under uncertainty for networks with anything approaching the complexity of the Eastern or even the Western Interconnection.

The wider the area over which transmission planning is done, the more complex the problem becomes. Existing planning methods cannot do multiperiod optimization under uncertainty for networks with anything approaching the complexity of the Eastern or even the Western Interconnection. As noted earlier, the grid is becoming more closely coupled at the interconnection level partially because of the challenge of efficiently

integrating remote renewable generators. As discussed earlier, some interconnection-level planning efforts are under way, and FERC's Order No. 1000 calls for an expansion of the geographic scope of planning processes. The development of new planning methods, discussed in Chapter 4, thus has a high potential payoff.

As noted earlier, perfect protection from cyberattacks is not possible. There will be a successful attack at some point. It is thus important for the involved government agencies (i.e., NIST, DOE, FERC, and DHS), working with the private sector in a coordinated fashion, to support the research necessary to develop best practices for response to and recovery from cyberattacks on transmission and distribution systems, so that such practices can be widely deployed.

Finally, as discussed earlier, the industry should use the first round of AMI deployments to learn how best to employ the capabilities of these systems and response automation technologies to make electricity demand more responsive to system conditions. Among other things, further research on consumer reactions to dynamic pricing is needed, and effective consumer engagement and education strategies must be designed and tested in the field.

RECOMMENDATION

The electric power industry should fund additional research and demonstration projects to develop: computational tools that will exploit the potential of new hardware to improve monitoring and control of the bulk power system (Chapter 2); methods for wide-area transmission planning (Chapter 4); processes for response to and recovery from cyberattacks (Chapter 9); and understanding of consumer response to alternative pricing/response automation systems (Chapter 7).

Data Development and Sharing

In the course of this project, we have been struck repeatedly by shortcomings in the data available on the U.S. electric grid to researchers and to decision makers in both government and industry. Even though this problem has been observed and commented upon repeatedly, it persists.⁴⁸

Sometimes available data are not shared as widely as would be beneficial. Sometimes potentially valuable data are simply not collected or are compiled in ways that limit their usefulness. Good data are critical inputs to good decisions regarding the grid, especially in the unfamiliar situations in which public and private actors will increasingly find themselves.

One promising recent initiative has been undertaken to enhance high-value data sharing. In February 2010, NERC created two nondisclosure agreements to facilitate sharing PMU data. Unfortunately, a year and a half later, many utilities with significant PMU deployment activity had not yet signed these agreements. If this initiative fails to achieve the hoped-for results, the benefits of PMUs may not be realized. The responsible federal agencies should take steps to ensure that the critical data at issue are shared appropriately.

We have identified three additional areas in which ensuring the appropriate availability of useful data would be particularly valuable. While network data on the Western Interconnection are available at a level of detail adequate to support analysis, such data are not available for the more complex Eastern Interconnection. This inhibits both wide-area planning and the improvement of wide-area planning methods. Obviously, the general availability of detailed data on the U.S. bulk power system would raise serious security concerns, but federal agencies have a good deal of experience making

We have been struck repeatedly by shortcomings in the data available on the U.S. electric grid.

confidential data available for use in research while ensuring that confidentiality is not violated and data are not copied.

In this regard, we note that there is a lack of information currently available on projects that had been funded through DOE's Smart Grid Demonstration Program and Smart Grid Investment Grants initiatives. Achieving the full potential of these distribution system technology demonstration projects will require that data on both successes and failures are shared widely. Several websites, including www.smartgrid.gov and www.sgiclearinghouse.org, have been established to disseminate information about these projects. As results become available, it is imperative that resources such as these are effectively used to share data and lessons learned.

Electric utility customers care about reliability, customer service, and other dimensions of performance as well as cost, and those concerns are arguably increasing as the share of energy used to power computers and other complex electronic equipment rises. While regulators have at times considered performance in an ad hoc, case-specific fashion when setting allowable rates of return, a more systematic approach would almost certainly produce better results. Some U.S. regulators and many abroad have accordingly begun to establish explicit, formal incentives based on performance metrics. But, as noted earlier, many jurisdictions do not even require utilities to report data on reliability in a useful form, let alone data on efficiency or other aspects of performance. The lack of comprehensive, comparable data hinders regulators' attempts to evaluate utilities over time or make useful comparisons across utilities, especially those in different jurisdictions. To the ultimate benefit of all stakeholders, development and publication of standardized cost and performance metrics would facilitate assessment of utility outcomes and make it easier for regulators to provide meaningful incentives for good performance.

RECOMMENDATION

FERC should require that detailed data on the U.S. bulk power system be compiled and made appropriately available (Chapter 4). DOE should work to ensure that comprehensive data from its Smart Grid projects are widely shared (Chapter 6). State regulators and others supervising distribution utilities should require utilities to compile and publish standardized metrics of utility cost, reliability, and other dimensions of performance (Chapter 8).

1.4 CONCLUDING REMARKS

Between now and 2030, the electric grid will confront significant new challenges and inevitably undergo major changes. Despite alarmist rhetoric, there is no crisis here. But we do not advise complacency. The environment in which the grid will operate will change substantially in the next two decades. If the grid is to evolve with minimal disruption despite the challenges ahead and if electricity rates and levels of reliability are to be acceptable, decision makers in government and industry need to continue to focus on meeting the system's challenges. A range of system-level issues need to be addressed, and new technologies need to be used as appropriate. Regulators should seek to develop policies that better align incentives of participants in electricity markets (including consumers) with policy goals. The industry needs to conduct research in key areas and both collect and share important data.

We are encouraged by recent levels of awareness, concern and, in some key areas, action. But the journey to the electric grid of 2030 has begun, and there will be plenty of surprises along the way. As this study indicates, much can and should be done now to smooth the potentially very bumpy road ahead.

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