1300 *MW coal-fired power plant (Courtesy of American Electric Power Company)*

1

INTRODUCTION

Electrical engineers are concerned with every step in the process of generation, transmission, distribution, and utilization of electrical energy. The electric utility industry is probably the largest and most complex industry in the world. The electrical engineer who works in that industry will encounter challenging problems in designing future power systems to deliver increasing amounts of electrical energy in a safe, clean, and economical manner.

The objectives of this chapter are to review briefly the history of the electric utility industry, to discuss present and future trends in electric power systems, to describe the restructuring of the electric utility industry, and to introduce PowerWorld Simulator—a power system analysis and simulation software package.

CASE STUDY The following article describes the restructuring of the electric utility industry that has been taking place in the United States and the impacts on an aging transmission infrastructure. Independent power producers, increased competition in the generation sector, and open access for generators to the U.S. transmission system have changed the way the transmission system is utilized. The need for investment in new transmission and transmission technologies, for further refinements in restructuring, and for training and education systems to replenish the workforce are discussed [8].

The Future Beckons: Will the Electric Power Industry Heed the Call?

CHRISTOPHER E. ROOT

Over the last four decades, the U.S. electric power industry has undergone unprecedented change. In the 1960s, regulated utilities generated and delivered power within a localized service area. The decade was marked by high load growth and modest price stability. This stood in sharp contrast to the wild increases in the price of fuel oil, focus on energy conservation, and slow growth of the 1970s. Utilities quickly put the brakes on generation expansion projects, switched to coal or other nonoil fuel sources, and significantly cut back on the expansion of their networks as load growth slowed to a crawl. During the 1980s, the economy in many regions of the country began to rebound. The 1980s also brought the emergence of independent power producers and the deregulation of the natural gas wholesale markets and pipelines. These developments resulted in a significant increase in natural gas transmission into the northeastern United States and in the use of natural gas as the preferred fuel for new generating plants.

During the last ten years, the industry in many areas of the United States has seen increased competition in the generation sector and a fundamental shift in the role of the nation's electric transmission system, with the 1996 enactment of the Federal Energy Regulatory Commission (FERC) Order No. 888, which mandated open access for generators to the nation's transmission system. And while prices for distribution and transmission of electricity remained regulated, unregulated energy commodity markets have developed in several regions. FERC has supported these changes with rulings leading to the formation of independent system operators (ISOs) and regional transmission organizations (RTOs) to administer the electricity markets in several regions of the United States, including New England, New York, the Mid-Atlantic, the Midwest, and California.

The transmission system originally was built to deliver power from a utility's generator across town to its distribution company. Today, the transmission system is being used to deliver power across states or entire regions. As market forces increasingly determine the location of generation sources, the transmission grid is being asked to play an even more important role in markets and the reliability of the system. In areas where markets have been restructured, customers have begun to see significant benefits. But full delivery of restructuring's benefits is being impeded by an inadequate, underinvested transmission system.

If the last 30 years are any indication, the structure of the industry and the increasing demands placed on the nation's transmission infrastructure and the people who operate and manage it are likely to continue unabated. In order to meet the challenges of the future, to continue to maintain the stable, reliable, and efficient system we have known for more than a century and to support the continued development of efficient competitive markets, U.S. industry leaders must address three significant issues:

- an aging transmission system suffering from substantial underinvestment, which is exacerbated by an out-of-date industry structure
- the need for a regulatory framework that will spur independent investment, ownership, and management of the nation's grid
- an aging workforce and the need for a succession plan to ensure the existence of the next generation of technical expertise in the industry.

ARE WE SPENDING ENOUGH?

In areas that have restructured power markets, substantial benefits have been delivered to customers in the form of lower prices, greater supplier choice, and environmental benefits, largely due to the development and operation of new, cleaner generation. There is, however, a growing recognition that the delivery of the full value of restructuring to customers has been stalled by an inadequate transmission system that was not designed for the new demands being placed on it. In fact, investment in the nation's electricity infrastructure has been declining for decades. Transmission investment has been falling for a quarter century at an average rate of almost US$50 million a year (in constant 2003 U.S. dollars), though there has been a small upturn in the last few years. Transmission investment has not kept up with load growth or generation investment in recent years, nor has it been sufficiently expanded to accommodate the advent of regional power markets (see Figure 1).

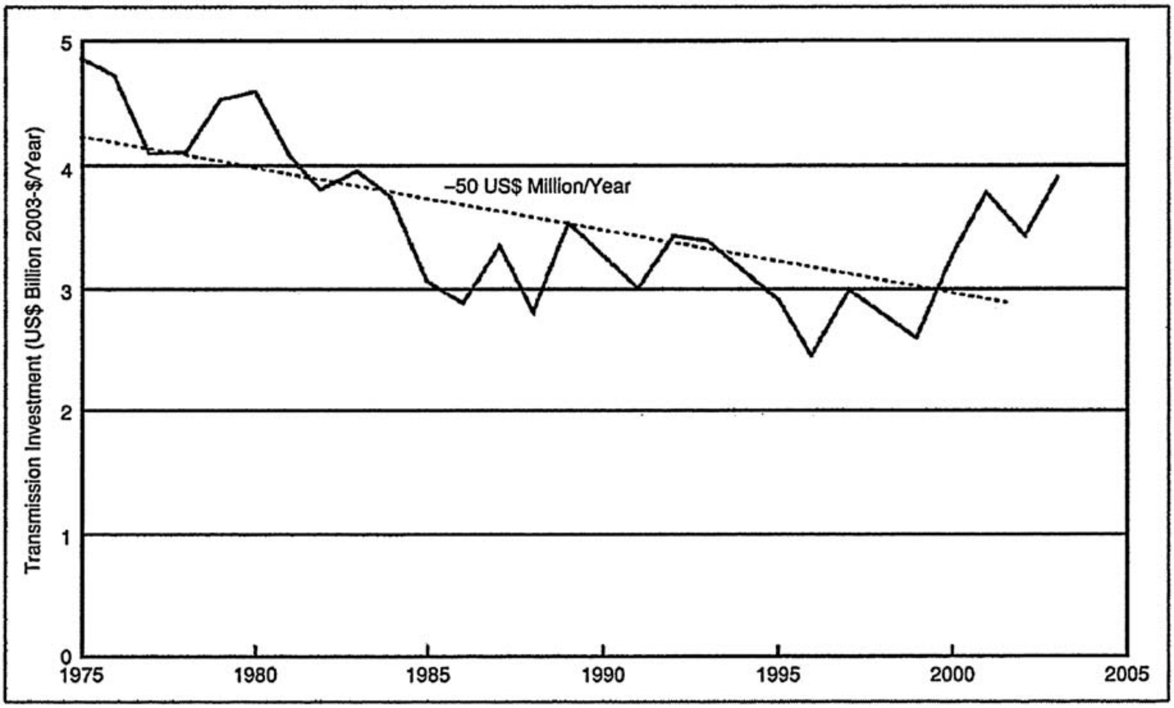

Figure 1
Annual transmission investments by investor-owned utilities, 1975–2003 (Source: Eric Hirst, "U.S. Transmission Capacity: Present Status and Future Prospects," 2004. Graph used with permission from the Edison Electric Institute, 2004. All rights reserved)

TABLE 1 Transmission investment in the United States and in international competitive markets

Country	Investment in High Voltage Transmission (>230 kV) Normalized by Load for 2004–2008 (in US$M/GW/year)	Number of Transmission-Owning Entities
New Zealand	22.0	1
England & Wales (NGT)	16.5	1
Denmark	12.5	2
Spain	12.3	1
The Netherlands	12.0	1
Norway	9.2	1
Poland	8.6	1
Finland	7.2	1
United States	4.6 (based on representative data from EEI)	450 (69 in EEI)

Outlooks for future transmission development vary, with Edison Electric Institute (EEI) data suggesting a modest increase in expected transmission investment and other sources forecasting a continued decline. Even assuming EEI's projections are realized, this level of transmission investment in the United States is dwarfed by that of other international competitive electricity markets, as shown in Table 1, and is expected to lag behind what is needed.

The lack of transmission investment has led to a high (and increasing in some areas) level of congestion-related costs in many regions. For instance, total uplift for New England is in the range of US$169 million per year, while locational installed capacity prices and reliability must-run charges are on the rise. In New York, congestion costs have increased substantially, from US$310 million in 2001 to US$525 million in 2002, US$688 million in 2003, and US$629 million in 2004. In PJM Interconnection (PJM), an RTO that administers electricity markets for all or parts of 14 states in the Northeast, Midwest, and Mid-Atlantic, congestion costs have continued to increase, even when adjusted to reflect PJM's expanding footprint into western and southern regions.

Because regions do not currently quantify the costs of constraints in the same way, it is difficult to make direct comparisons from congestion data between regions. However, the magnitude and upward trend of available congestion cost data indicates a significant and growing problem that is increasing costs to customers.

THE SYSTEM IS AGING

While we are pushing the transmission system harder, it is not getting any younger. In the northeastern United States, the bulk transmission system operates primarily at 345 kV. The majority of this system originally was constructed during the 1960s and into the early 1970s, and its substations, wires, towers, and poles are, on average, more than 40 years old. (Figure 2 shows the age of National Grid's U.S. transmission structures.) While all utilities have maintenance plans in place for these systems, ever-increasing congestion levels in many areas are making it increasingly difficult to schedule circuit outages for routine upgrades.

The combination of aging infrastructure, increased congestion, and the lack of significant expansion in transmission capacity has led to the need to carefully prioritize maintenance and construction, which in turn led to the evolution of the science of asset management, which many utilities have adopted. Asset management entails quantifying the risks of not doing work as a means to ensure that the highest priority work is performed. It has significantly helped the industry in maintaining reliability. As the assets continue to age, this combination of engineering, experience, and business risk will grow in importance to the industry. If this is not done well, the impact on utilities in terms of reliability and asset replacement will be significant.

And while asset management techniques will help in managing investment, the age issue undoubtedly will require substantial reinvestment at some point to replace the installed equipment at the end of its lifetime.

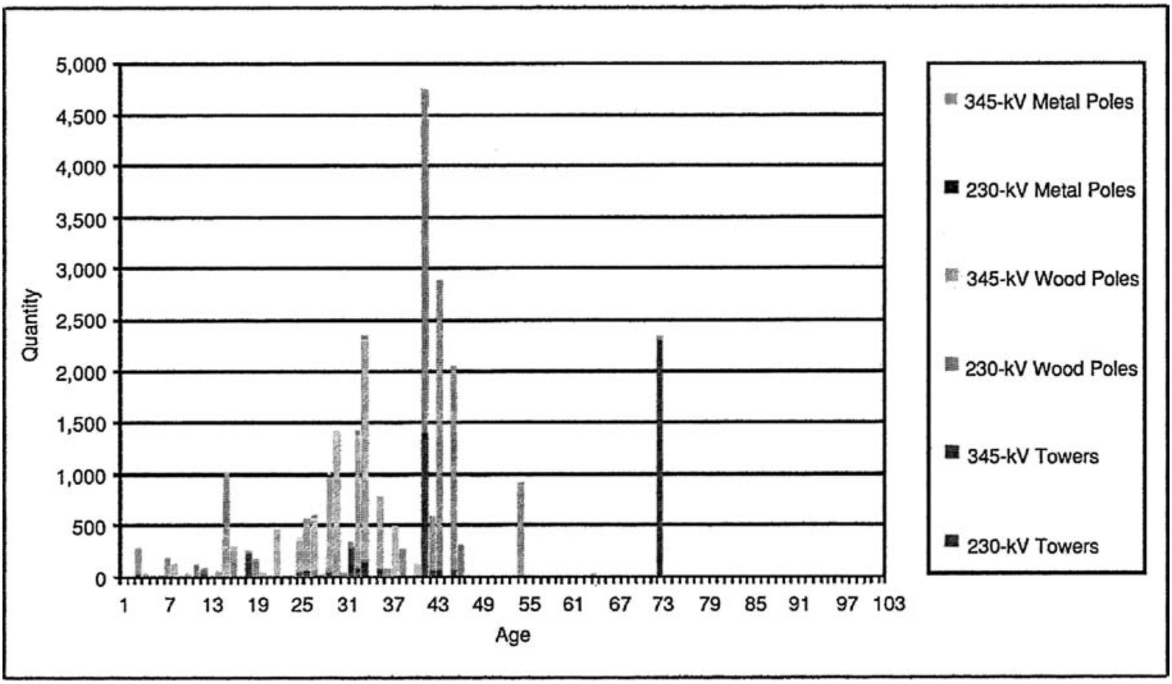

Figure 2
Age of National Grid towers and poles

TECHNOLOGY WILL HAVE A ROLE

The expansion of the transmission network in the United States will be very difficult, if not impossible, if the traditional approach of adding new overhead lines continues. Issues of land availability, concerns about property values, aesthetics, and other licensing concerns make siting new lines a difficult proposition in many areas of the United States. New approaches to expansion will be required to improve the transmission networks of the future.

Where new lines are the only answer, more underground solutions will be chosen. In some circumstances, superconducting cable will become a viable option. There are several companies, including National Grid, installing short superconducting lines to gain experience with this newly available technology and solve real problems. While it is reasonable to expect this solution to become more prevalent, it is important to recognize that it is not inexpensive.

Technology has an important role to play in utilizing existing lines and transmission corridors to increase capacity. Lightweight, high-temperature overhead conductors are now becoming available for line upgrades without significant tower modifications. Monitoring systems for real-time ratings and better computer control schemes are providing improved information to control room operators to run the system at higher load levels. The development and common use of static var compensators for voltage and reactive control, and the general use of new solid-state equipment to solve real problems are just around the corner and should add a new dimension to the traditional wires and transformers approach to addressing stability and short-term energy storage issues.

These are just a few examples of some of the exciting new technologies that will be tools for the future. It is encouraging that the development of new and innovative solutions to existing problems continues. In the future, innovation must take a leading role in developing solutions to transmission problems, and it will be important for the regulators to encourage the use of new techniques and technologies. Most of these new technologies have a higher cost than traditional solutions, which will place increasing pressure on capital investment. It will be important to ensure that appropriate cost recovery mechanisms are developed to address this issue.

INDUSTRY STRUCTURE

Another factor contributing to underinvestment in the transmission system is the tremendous fragmentation that exists in the U.S. electricity industry. There are literally hundreds of entities that own and operate transmission. The United States has more than 100 separate control areas and more than 50 regulators that oversee the nation's grid. The patchwork of ownership and operation lies in stark contrast to the interregional delivery demands that are being placed on the nation's transmission infrastructure.

Federal policymakers continue to encourage transmission owners across the nation to join RTOs. Indeed, RTO/ISO formation was intended to occupy a central role in carrying forward FERC's vision of restructuring, and an extraordinary amount of effort has been expended in making this model work. While RTOs/ISOs take a step toward an independent, coordinated transmission system, it remains unclear whether they are the best long-term solution to deliver efficient transmission system operation while ensuring reliability and delivering value to customers.

Broad regional markets require policies that facilitate and encourage active grid planning, management, and the construction of transmission upgrades both for reliability and economic needs. A strong transmission infrastructure or network platform would allow greater fuel diversity, more stable and competitive energy prices, and the relaxation (and perhaps ultimate removal) of administrative mechanisms to mitigate market power. This would also allow for common asset management approaches to the transmission system. The creation of independent transmission companies (ITCs), i.e., companies that focus on the investment in and operation of transmission independent of generation interests, would be a key institutional step toward an industry structure that appropriately views transmission as a facilitator of robust competitive electricity markets. ITCs recognize transmission as an enabler of competitive electricity markets. Policies that provide a more prominent role for such companies would align the interests of transmission owners/operators with those of customers, permitting the development of well-designed and enduring power markets that perform the function of any market, namely, to drive the efficient allocation of resources for the benefit of customers. In its policy statement released in June 2005, FERC reiterated its commitment to ITC formation to support improving the performance and efficiency of the grid.

Having no interest in financial outcomes within a power market, the ITC's goal is to deliver maximum value to customers through transmission operation and investment. With appropriate incentives, ITCs will pursue opportunities to leverage relatively small expenditures on transmission construction and management to create a healthy market and provide larger savings in the supply portion of customer's bills. They also offer benefits over nonprofit RTO/ISO models, where the incentives for efficient operation and investment may be less focused.

An ideal industry structure would permit ITCs to own, operate, and manage transmission assets over a wide area. This would allow ITCs to access economies of scale in asset investment, planning, and operations to increase throughout and enhance reliability in the most cost-effective manner. This structure would also avoid ownership fragmentation within a single market, which is a key obstacle to the introduction of performance-based rates that benefit customers by aligning the interests of transmission companies and customers in reducing congestion. This approach to "horizontal integration" of the transmission sector under a single regulated for-profit entity is key to establishing an industry structure that recognizes the transmission system as a market enabler and provider of infrastructure to support effective competitive markets. Market administration would be contracted out to another (potentially nonprofit) entity while generators, other suppliers, demand response providers, and load serving entities (LSEs) would all compete and innovate in fully functioning markets, delivering still-increased efficiency and more choices for customers.

REGULATORY ISSUES

The industry clearly shoulders much of the responsibility for determining its own future and for taking the steps necessary to ensure the robustness of the nation's transmission system. However, the industry also operates within an environment governed by substantial regulatory controls. Therefore, policymakers also will have a significant role in helping to remove the obstacles to the delivery of the full benefits of industry restructuring to customers. In order to ensure adequate transmission investment and the expansion of the system as appropriate, the following policy issues must be addressed:

- *Regional planning:* Because the transmission system is an integrated network, planning for system needs should occur on a regional basis. Regional planning recognizes that transmission investment and the benefits transmission can deliver to customers are regional in nature rather than bounded by state or service area lines. Meaningful regional planning processes also take into account the fact that transmission provides both reliability and economic benefits. Comprehensive planning processes provide for mechanisms to pursue regulated transmission solutions for reliability and economic needs in the event that the market fails to respond or is identified as unlikely to respond to these needs in a timely manner. In areas where regional system planning processes have been implemented, such as New England and PJM, progress is being made towards identifying and building transmission projects that will address regional needs and do so in a way that is cost effective for customers.
- *Cost recovery and allocation:* Comprehensive regional planning processes that identify needed transmission projects must be accompanied by cost recovery and allocation mechanisms that recognize the broad benefits of transmission and its role in supporting and enabling regional electricity markets. Mechanisms that allocate the costs of transmission investment broadly view transmission as the regional market enabler it is and should be, provide greater certainty and reduce delays in cost recovery, and, thus, remove obstacles to provide further incentives for the owners and operators of transmission to make such investment.
- *Certainty of rate recovery and state cooperation:* It is critical that transmission owners are assured certain and adequate rate recovery under a regional planning process. Independent administration of the planning processes will assure that transmission enhancements required for reliability and market efficiency do not unduly burden retail customers with additional costs. FERC and the states must work together to provide for certainty in rate recovery from ultimate customers through federal and state jurisdictional rates.
- *Incentives to encourage transmission investment, independence, and consolidation:* At a time when a significant increase in transmission investment is needed to ensure reliability, produce an adequate platform for competitive power markets and regional electricity commerce, and to promote fuel diversity and renewable sources of supply, incentives not only for investment but also for independence and consolidation of transmission are needed and warranted. Incentives should be designed to promote transmission organizations that acknowledge the benefits to customers of varying degrees of transmission independence and reward that independence accordingly. These incentives may take the form of enhanced rates of return or other financial incentives for assets managed, operated, and/or owned by an ITC.

The debate about transmission regulation will continue. Ultimately, having the correct mixture of incentives and reliability standards will be a critical factor that will determine whether or not the nation's grid can successfully tie markets together and improve the overall reliability of the bulk transmission system in the United States. The future transmission system must be able to meet the needs of customers reliably and support competitive markets that provide them with electricity efficiently. Failure to invest in the transmission system now will mean an increased likelihood of reduced reliability and higher costs to customers in the future.

WORKFORCE OF THE FUTURE

Clearly, the nation's transmission system will need considerable investment and physical work due to age, growth of the use of electricity, changing markets, and how the networks are used. As previously noted, this will lead to a required significant increase in capital spending. But another critical resource is beginning to become a concern to many in the industry, specifically the continued availability of qualified power system engineers.

Utility executives polled by the Electric Power Research Institute in 2003 estimated that 50% of the technical workforce will reach retirement in the next 5–10 years. This puts the average age near 50, with many utilities still hiring just a few college graduates each year. Looking a few years ahead, at the same time when a significant number of power engineers will be considering retirement, the need for them will be significantly increasing. The supply of power engineers will have to be great enough to replace the large numbers of those retiring in addition to the number required to respond to the anticipated increase in transmission capital spending.

Today, the number of universities offering power engineering programs has decreased. Some universities, such as Rensselaer Polytechnic Institute, no longer have separate power system engineering departments. According to the IEEE, the number of power system engineering graduates has dropped from approximately 2,000 per year in the 1980s to 500 today. Overall, the number of engineering graduates has dropped 50% in the last 15 years. Turning this situation around will require a long-term effort by many groups working together, including utilities, consultants, manufacturers, universities, and groups such as the IEEE Power Engineering Society (PES).

Part of the challenge is that utilities are competing for engineering students against other industries, such as telecommunications or computer software development, that are perceived as being more glamorous or more hip than the power industry and have no problem attracting large numbers of new engineers.

For the most part, the power industry has not done a great job of selling itself. Too often, headlines focus on negatives such as rate increases, power outages, and community relations issues related to a proposed new generation plant or transmission line. To a large extent, the industry also has become a victim of its own success by delivering electricity so reliably that the public generally takes it for granted, which makes the good news more difficult to tell. It is incumbent upon the industry to take a much more proactive role in helping its public—including talented engineering students—understand the dedication, commitment, ingenuity, and innovation that is required to keep the nation's electricity system humming. PES can play an important role in this.

On a related note, as the industry continues to develop new, innovative technologies, they should be documented and showcased to help generate excitement about the industry among college-age engineers and help attract them to power system engineering.

The utilities, consultants, and manufacturers must strengthen their relationships with strong technical institutions to continue increasing support for electrical engineering departments to offer power systems classes at the undergraduate level. In some cases, this may even require underwriting a class. Experience at National Grid has shown that when support for a class is guaranteed, the number of students who sign up typically is greater than expected. The industry needs to further support these efforts by offering presentations to students on the complexity of the power system, real problems that need to be solved, and the impact that a reliable, cost-efficient power system has on society. Sponsoring more student internships and research projects will introduce additional students and faculty to the unique challenges of the industry. In the future, the industry will have to hire more nonpower engineers and train them in the specifics of power system engineering or rely on hiring from overseas.

Finally, the industry needs to cultivate relationships with universities to assist in developing professors who are knowledgeable about the industry. This can take the form of research work, consulting, and teaching custom programs for the industry. National Grid has developed relationships with several northeastern U.S. institutions that are offering courses for graduate engineers who may not have power backgrounds. The courses can be offered online, at the university, or on site at the utility.

This problem will only get worse if industry leaders do not work together to resolve it. The industry's future depends on its ability to anticipate what lies ahead and the development of the necessary human resources to meet the challenges.

CONCLUSIONS

The electric transmission system plays a critical role in the lives of the people of the United States. It is an ever-changing system both in physical terms and how it is operated and regulated. These changes must be recognized and actions developed accordingly. Since the industry is made up of many organizations that share the system, it can be difficult to agree on action plans.

There are a few points on which all can agree. The first is that the transmission assets continue to get older and investment is not keeping up with needs when looking over a future horizon. The issue will only get worse as more lines and substations exceed the 50-year age mark. Technology development and application undoubtedly will increase as engineers look for new and creative ways to combat the congestion issues and increased electrical demand—and new overhead transmission lines will be only one of the solutions considered.

The second is that it will be important for further refinement in the restructuring of the industry to occur. The changes made since the late 1990s have delivered benefits to customers in the Northeast in the form of lower energy costs and access to greater competitive electric markets. Regulators and policymakers should recognize that independently owned, operated, managed, and widely planned networks are important to solving future problems most efficiently. Having a reliable, regional, uncongested transmission system will enable a healthy competitive marketplace.

The last, but certainly not least, concern is with the industry's future workforce. Over the last year, there has been significant discussion of the issue, but it will take a considerable effort by many to guide the future workforce into a position of appreciating the electricity industry and desiring to enter it and to ensure that the training and education systems are in place to develop the new engineers who will be required to upgrade and maintain the electric power system.

The industry has many challenges, but it also has great resources and a good reputation. Through the efforts of many and by working together through organizations such as PES, the industry can move forward to the benefit of the public and the United States as a whole.

ACKNOWLEDGMENTS

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BIOGRAPHY

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1.1

HISTORY OF ELECTRIC POWER SYSTEMS

In 1878, Thomas A. Edison began work on the electric light and formulated the concept of a centrally located power station with distributed lighting serving a surrounding area. He perfected his light by October 1879, and the opening of his historic Pearl Street Station in New York City on September 4, 1882, marked the beginning of the electric utility industry (see Figure 1.1). At Pearl Street, dc generators, then called dynamos, were driven by steam engines to supply an initial load of 30 kW for 110-V incandescent lighting to 59 customers in a one-square-mile (2.5-square-km) area. From this beginning in 1882 through 1972, the electric utility industry grew at a remarkable pace—a growth based on continuous reductions in the price of electricity due primarily to technological acomplishment and creative engineering.

The introduction of the practical dc motor by Sprague Electric, as well as the growth of incandescent lighting, promoted the expansion of Edison's dc systems. The development of three-wire 220-V dc systems allowed load to increase somewhat, but as transmission distances and loads continued to increase, voltage problems were encountered. These limitations of maximum distance and load were overcome in 1885 by William Stanley's development of a commercially practical transformer. Stanley installed an ac distribution system in Great Barrington, Massachusetts, to supply 150 lamps. With the transformer, the ability to transmit power at high voltage with corresponding lower current and lower line-voltage drops made ac more attractive than dc. The first single-phase ac line in the United States operated in 1889 in Oregon, between Oregon City and Portland—21 km at 4 kV.

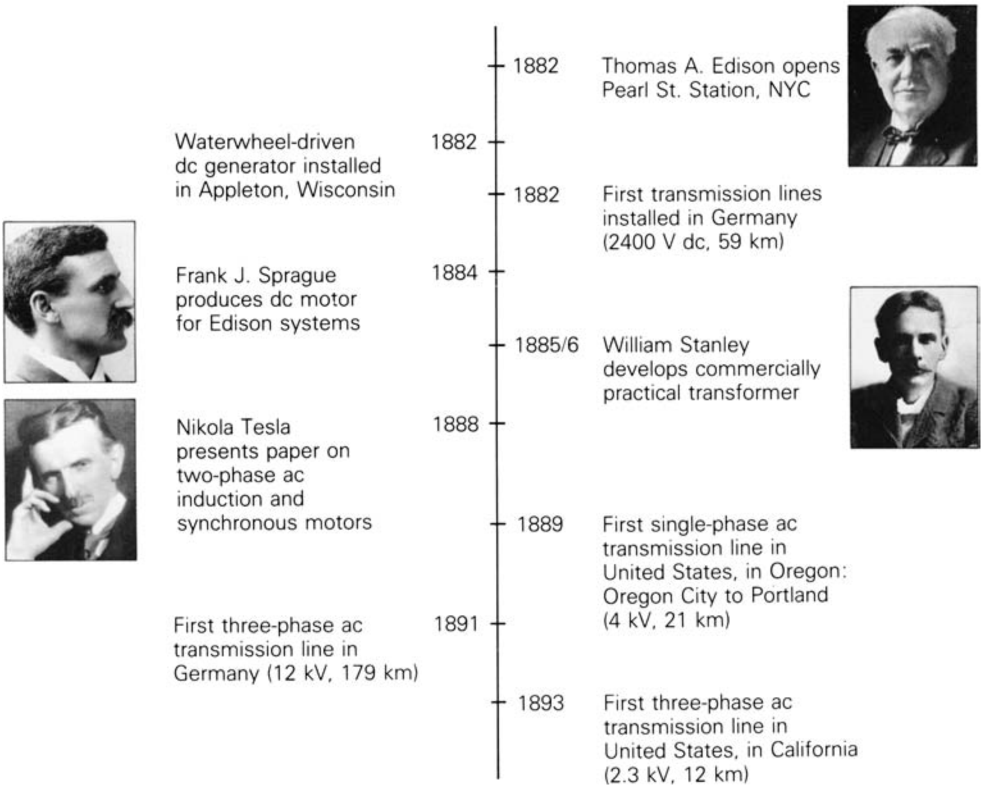


FIGURE 1.1 Milestones of the early electric utility industry [1] (H.M. Rustebakke et al., Electric Utility Systems Practice, 4th Ed. (New York: Wiley, 1983). Reprinted with permission of John Wiley & Sons, Inc. Photos courtesy of Westinghouse Historical Collection)

The growth of ac systems was further encouraged in 1888 when Nikola Tesla presented a paper at a meeting of the American Institute of Electrical Engineers describing two-phase induction and synchronous motors, which made evident the advantages of polyphase versus single-phase systems. The first three-phase line in Germany became operational in 1891, transmitting power 179 km at 12 kV. The first three-phase line in the United States (in California) became operational in 1893, transmitting power 12 km at 2.3 kV. The three-phase induction motor conceived by Tesla went on to become the workhorse of the industry.

In the same year that Edison's steam-driven generators were inaugurated, a waterwheel-driven generator was installed in Appleton, Wisconsin. Since then, most electric energy has been generated in steam-powered and in water-powered (called hydro) turbine plants. Today, steam turbines account for more than 85% of U.S. electric energy generation, whereas hydro turbines account for about 6%. Gas turbines are used in some cases to meet peak loads. Also, the addition of wind turbines into the bulk power system is expected to grow considerably in the near future.

Steam plants are fueled primarily by coal, gas, oil, and uranium. Of these, coal is the most widely used fuel in the United States due to its abundance in the country. Although many of these coal-fueled power plants were converted to oil during the early 1970s, that trend has been reversed back to coal since the 1973–74 oil embargo, which caused an oil shortage and created a national desire to reduce dependency on foreign oil. In 2008, approximately 48% of electricity in the United States was generated from coal [2].

In 1957, nuclear units with 90-MW steam-turbine capacity, fueled by uranium, were installed, and today nuclear units with 1312-MW steam-turbine capacity are in service. In 2008, approximately 20% of electricity in the United States was generated from uranium from 104 nuclear power plants. However, the growth of nuclear capacity in the United States has been halted by rising construction costs, licensing delays, and public opinion. Although there are no emissions associated with nuclear power generation, there are safety issues and environmental issues, such as the disposal of used nuclear fuel and the impact of heated cooling-tower water on aquatic habitats. Future technologies for nuclear power are concentrated on safety and environmental issues [2, 3].

Starting in the 1990s, the choice of fuel for new power plants in the United States has been natural gas due to its availability and low cost as well as the higher efficiency, lower emissions, shorter construction-lead times, safety, and lack of controversy associated with power plants that use natural gas. Natural gas is used to generate electricity by the following processes: (1) gas combustion turbines use natural gas directly to fire the turbine; (2) steam turbines burn natural gas to create steam in a boiler, which is then run through the steam turbine; (3) combined cycle units use a gas combustion turbine by burning natural gas, and the hot exhaust gases from the combustion turbine are used to boil water that operates a steam turbine; and (4) fuel cells powered by natural gas generate electricity using electrochemical reactions by passing streams of natural gas and oxidants over electrodes that are separated by an electrolyte. In 2008, approximately 21% of electricity in the United States was generated from natural gas [2, 3].

In 2008, in the United States, approximately 9% of electricity was generated by renewable sources and 1% by oil [2, 3]. Renewable sources include conventional hydroelectric (water power), geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Renewable sources of energy cannot be ignored, but they are not expected to supply a large percentage of the world's future energy needs. On the other hand, nuclear fusion energy just may. Substantial research efforts have shown nuclear fusion energy to be a promising technology for producing safe, pollution-free, and economical electric energy later in the 21st century and beyond. The fuel consumed in a nuclear fusion reaction is deuterium, of which a virtually inexhaustible supply is present in seawater.

The early ac systems operated at various frequencies including 25, 50, 60, and 133 Hz. In 1891, it was proposed that 60 Hz be the standard frequency in the United States. In 1893, 25-Hz systems were introduced with the

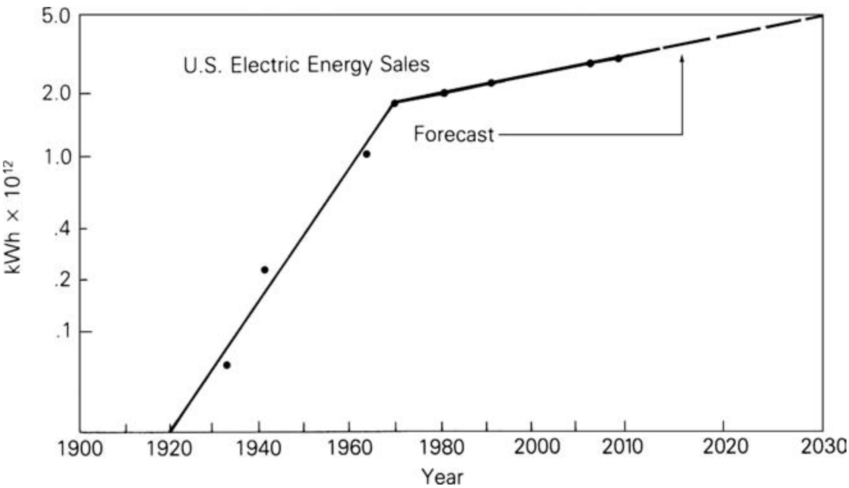


FIGURE 1.2

Growth of U.S. electric energy consumption [1, 2, 3, 5] (H. M. Rustebakke et al., Electric Utility Systems Practice, 4th ed. (New York: Wiley, 1983); U.S. Energy Information Administration, Existing Capacity by Energy Source—2008, www.eia.gov; U.S. Energy Information Administration, Annual Energy Outlook 2010 Early Release Overview, www.eia.gov; M.P. Bahrman and B.K. Johnson, "The ABCs of HVDC Transmission Technologies," IEEE Power & Energy Magazine, 5, 2 (March/April 2007), pp. 33–44)

synchronous converter. However, these systems were used primarily for railroad electrification (and many are now retired) because they had the disadvantage of causing incandescent lights to flicker. In California, the Los Angeles Department of Power and Water operated at 50 Hz, but converted to 60 Hz when power from the Hoover Dam became operational in 1937. In 1949, Southern California Edison also converted from 50 to 60 Hz. Today, the two standard frequencies for generation, transmission, and distribution of electric power in the world are 60 Hz (in the United States, Canada, Japan, Brazil) and 50 Hz (in Europe, the former Soviet republics, South America except Brazil, and India). The advantage of 60-Hz systems is that generators, motors, and transformers in these systems are generally smaller than 50-Hz equipment with the same ratings. The advantage of 50-Hz systems is that transmission lines and transformers have smaller reactances at 50 Hz than at 60 Hz.

As shown in Figure 1.2, the rate of growth of electric energy in the United States was approximately 7% per year from 1902 to 1972. This corresponds to a doubling of electric energy consumption every 10 years over the 70-year period. In other words, every 10 years the industry installed a new electric system equal in energy-producing capacity to the total of what it had built since the industry began. The annual growth rate slowed after the oil embargo of 1973–74. Kilowatt-hour consumption in the United States increased by 3.4% per year from 1972 to 1980, and by 2.1% per year from 1980 to 2008.

Along with increases in load growth, there have been continuing increases in the size of generating units (Table 1.1). The principal incentive to build larger units has been economy of scale—that is, a reduction in installed cost per kilowatt of capacity for larger units. However, there have also been steady improvements in generation efficiency. For example, in 1934 the average heat rate for steam generation in the U.S. electric industry was

TABLE 1.1

Growth of generator sizes in the United States [1] (H. M. Rustebakke et al., Electric Utility Systems Practice, 4th Ed. (New York: Wiley, 1983). Reprinted with permission of John Wiley & Sons, Inc.)

Hydroelectric Generators		Generators Driven by Single-Shaft, 3600 r/min Fossil-Fueled Steam Turbines	
Size (MVA)	Year of Installation	Size (MVA)	Year of Installation
4	1895	5	1914
108	1941	50	1937
158	1966	216	1953
232	1973	506	1963
615	1975	907	1969
718	1978	1120	1974

18,938 kJ/kWh, which corresponds to 19% efficiency. By 1991, the average heat rate was 10,938 kJ/kWh, which corresponds to 33% efficiency. These improvements in thermal efficiency due to increases in unit size and in steam temperature and pressure, as well as to the use of steam reheat, have resulted in savings in fuel costs and overall operating costs.

There have been continuing increases, too, in transmission voltages (Table 1.2). From Edison's 220-V three-wire dc grid to 4-kV single-phase and 2.3-kV three-phase transmission, ac transmission voltages in the United States have risen progressively to 150, 230, 345, 500, and now 765 kV. And ultra-high voltages (UHV) above 1000 kV are now being studied. The incentives for increasing transmission voltages have been: (1) increases in transmission distance and transmission capacity, (2) smaller line-voltage drops, (3) reduced line losses, (4) reduced right-of-way requirements per MW transfer, and (5) lower capital and operating costs of transmission. Today, one 765-kV three-phase line can transmit thousands of megawatts over hundreds of kilometers.

The technological developments that have occurred in conjunction with ac transmission, including developments in insulation, protection, and control, are in themselves important. The following examples are noteworthy:

1. The suspension insulator
2. The high-speed relay system, currently capable of detecting short-circuit currents within one cycle (0.017 s)
3. High-speed, extra-high-voltage (EHV) circuit breakers, capable of interrupting up to 63-kA three-phase short-circuit currents within two cycles (0.033 s)
4. High-speed reclosure of EHV lines, which enables automatic return to service within a fraction of a second after a fault has been cleared
5. The EHV surge arrester, which provides protection against transient overvoltages due to lightning strikes and line-switching operations

TABLE 1.2

History of increases in three-phase transmission voltages in the United States [1] (H. M. Rustebakke et al., Electric Utility Systems Practice, 4th Ed. (New York: Wiley, 1983). Reprinted with permission of John Wiley & Sons, Inc.)

Voltage (kV)	Year of Installation
2.3	1893
44	1897
150	1913
165	1922
230	1923
287	1935
345	1953
500	1965
765	1969

6. Power-line carrier, microwave, and fiber optics as communication mechanisms for protecting, controlling, and metering transmission lines
7. The principle of insulation coordination applied to the design of an entire transmission system
8. Energy control centers with supervisory control and data acquisition (SCADA) and with automatic generation control (AGC) for centralized computer monitoring and control of generation, transmission, and distribution
9. Automated distribution features, including advanced metering infrastructure (AMI), reclosers and remotely controlled sectionalizing switches with fault-indicating capability, along with automated mapping/facilities management (AM/FM) and geographic information systems (GIS) for quick isolation and identification of outages and for rapid restoration of customer services
10. Digital relays capable of circuit breaker control, data logging, fault locating, self-checking, fault analysis, remote query, and relay event monitoring/recording.

In 1954, the first modern high-voltage dc (HVDC) transmission line was put into operation in Sweden between Vastervik and the island of Gotland in the Baltic sea; it operated at 100 kV for a distance of 100 km. The first HVDC line in the United States was the $\pm$400-kV (now $\pm$500 kV), 1360-km Pacific Intertie line installed between Oregon and California in 1970. As of 2008, seven other HVDC lines up to 500 kV and eleven back-to-back ac-dc links had been installed in the United States, and a total of 57 HVDC lines up to 600 kV had been installed worldwide [4].

For an HVDC line embedded in an ac system, solid-state converters at both ends of the dc line operate as rectifiers and inverters. Since the cost of an HVDC transmission line is less than that of an ac line with the same capacity, the additional cost of converters for dc transmission is offset when the line is long enough. Studies have shown that overhead HVDC transmission is economical in the United States for transmission distances longer than about 600 km. However, HVDC also has the advantage that it may be the only feasible method to:

1. interconnect two asynchronous networks;
2. utilize long underground or underwater cable circuits;
3. bypass network congestion;
4. reduce fault currents;
5. share utility rights-of-way without degrading reliability; and
6. mitigate environmental concerns [5].

In the United States, electric utilities grew first as isolated systems, with new ones continuously starting up throughout the country. Gradually, however,

FIGURE 1.3 Major transmission in the United States—2000 [8] (© North American Electric Reliability Council. Reprinted with permission)

neighboring electric utilities began to interconnect, to operate in parallel. This improved both reliability and economy. Figure 1.3 shows major 230-kV and higher-voltage, interconnected transmission in the United States in 2000. An interconnected system has many advantages. An interconnected utility can draw upon another's rotating generator reserves during a time of need (such as a sudden generator outage or load increase), thereby maintaining continuity of service, increasing reliability, and reducing the total number of generators that need to be kept running under no-load conditions. Also, interconnected utilities can schedule power transfers during normal periods to take advantage of energy-cost differences in respective areas, load diversity, time zone differences, and seasonal conditions. For example, utilities whose generation is primarily hydro can supply low-cost power during high-water periods in spring/summer, and can receive power from the interconnection during low-water periods in fall/winter. Interconnections also allow shared ownership of larger, more efficient generating units.

While sharing the benefits of interconnected operation, each utility is obligated to help neighbors who are in trouble, to maintain scheduled intertie transfers during normal periods, and to participate in system frequency regulation.

In addition to the benefits/obligations of interconnected operation, there are disadvantages. Interconnections, for example, have increased fault currents that occur during short circuits, thus requiring the use of circuit breakers with higher interrupting capability. Furthermore, although overall system reliability and economy have improved dramatically through interconnection, there is a remote possibility that an initial disturbance may lead to a regional blackout, such as the one that occurred in August 2003 in the northeastern United States and Canada.

1.2 PRESENT AND FUTURE TRENDS

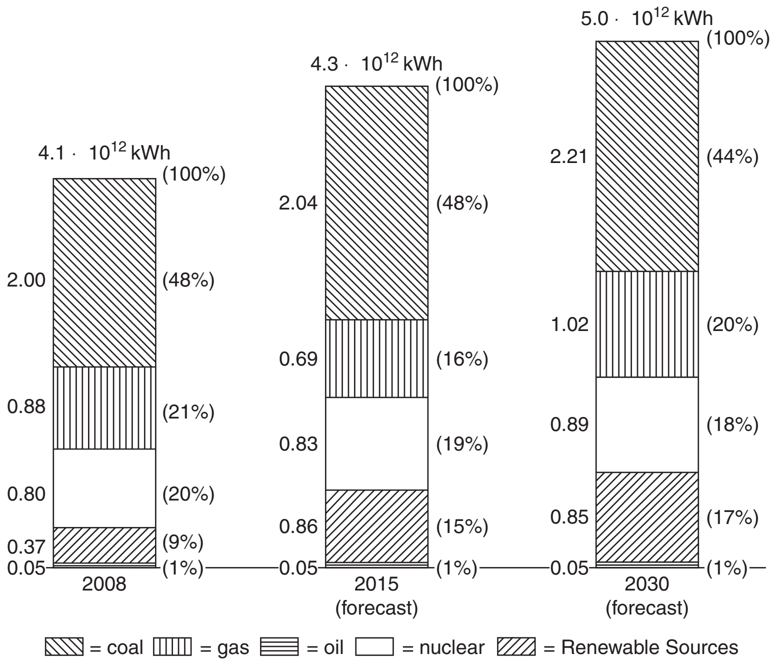
Present trends indicate that the United States is becoming more electrified as it shifts away from a dependence on the direct use of fossil fuels. The electric power industry advances economic growth, promotes business development and expansion, provides solid employment opportunities, enhances the quality of life for its users, and powers the world. Increasing electrification in the United States is evidenced in part by the ongoing digital revolution. Today the United States electric power industry is a robust, \$342-billion-plus industry that employs nearly 400,000 workers. In the United States economy, the industry represents 3% of real gross domestic product (GDP) [6].

As shown in Figure 1.2, the growth rate in the use of electricity in the United States is projected to increase by about 1% per year from 2008 to 2030 [2]. Although electricity forecasts for the next ten years are based on economic and social factors that are subject to change, 1% annual growth rate is considered necessary to generate the GDP anticipated over that period. Variations in longer-term forecasts of 0.5 to 1.5% annual growth from 2008 to 2030 are based on low-to-high ranges in economic growth. Following a recent rapid decline in natural gas prices, average delivered electricity prices are projected to fall sharply from 9.8 cents per kilowatt-hour in 2008 to 8.6 cents per kilowatt-hour in 2011 and remain below 9.0 cents per kilowatt-hour through 2020 [2, 3].

Figure 1.4 shows the percentages of various fuels used to meet U.S. electric energy requirements for 2008 and those projected for 2015 and 2030. Several trends are apparent in the chart. One is the continuing use of coal. This trend is due primarily to the large amount of U.S. coal reserves, which, according to some estimates, is sufficient to meet U.S. energy needs for the next 500 years. Implementation of public policies that have been proposed to reduce carbon dioxide emissions and air pollution could reverse this trend. Another trend is the continuing consumption of natural gas in the long term with gas-fired turbines that are safe, clean, and more efficient than competing technologies. Regulatory policies to lower greenhouse gas emissions could accelerate a switchover from coal to gas, but that would require an increasing supply of deliverable natural gas. A slight percentage decrease in nuclear fuel consumption is also evident. No new nuclear plant has been

FIGURE 1.4

Electric energy generation in the United States, by principal fuel types [2, 3] (U.S. Energy Information Administration, Existing Capacity by Energy Source—2008, www.eia.gov; U.S. Energy Information Administration, Annual Energy Outlook 2010 Early Release Overview, www.eia.gov)



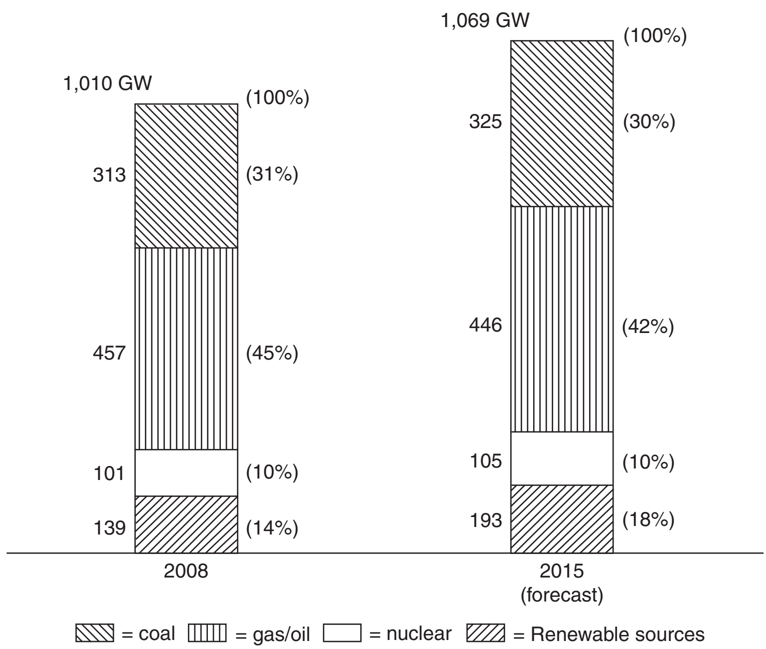
Renewable sources include conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power ordered in the United States for more than 30 years. The projected growth from 0.80×10^{12} kWh in 2008 to 0.89×10^{12} kWh in 2030 in nuclear generation is based on uprates at existing plants and some new nuclear capacity that is cost competitive. Safety concerns will require passive or inherently safe reactor designs with standardized, modular construction of nuclear units. Also shown in Figure 1.4 is an accelerating increase in electricity generation from renewable resources in response to federal subsidies supported by many state requirements for renewable generation.

Figure 1.5 shows the 2008 and projected 2015 U.S. generating capability by principal fuel type. As shown, total U.S. generating capacity is projected to reach 1,069 GW (1 GW = 1000 MW) by the year 2015. This represents a 0.8% annual projected growth in generating capacity, which is slightly above the 0.7% annual projected growth in electric energy production. The projected increase in generating capacity together with lowered load forecasts have contributed to generally improved generating capacity reserve margins for most of the United States and North America [2, 3, 7].

As of 2008, there were 584,093 circuit km of existing transmission (above 100 kV) in the United States, with an additional 50,265 circuit km (already under construction, planned, and conceptual) projected for the ten-year period from 2008 to 2018. The North American Electric Reliability Council (NERC) has identified bulk power system reliability and the integration of variable renewable generation (particularly wind and solar generation)

FIGURE 1.5

Installed generating capability in the United States by principal fuel types [2] (U.S. Energy Information Administration, Existing Capacity by Energy Source—2008, www.eia.gov)



Net Summer Capacities

Renewable sources include conventional & pumped storage hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power as the predominant reasons for projected transmission additions and upgrades. NERC has concluded that while recent progress has been made in the development of transmission, much work will be required to ensure that planned and conceptual transmission is sited and built. NERC also concludes that significant transmission will be required to "unlock" projected renewable generation resources. Without this transmission, the integration of variable generation resources could be limited [7].

Siting of new bulk power transmission lines has unique challenges due to their high visibility, their span through multiple states, and potentially the amount of coordination and cooperation required among multiple regulating agencies and authorities. A recent court decision to limit the Federal Energy Regulatory Commission's (FERC's) siting authority will lengthen the permit issuing process and cause new transmission projects, particularly multiple-state or regional projects from moving forward in timely manner. This creates a potential transmission congestion issue and challenges the economic viability of new generation projects [7].

Growth in distribution construction roughly correlates with growth in electric energy construction. During the last two decades, many U.S. utilities converted older 2.4-, 4.1-, and 5-kV primary distribution systems to 12 or 15 kV. The 15-kV voltage class is widely preferred by U.S. utilities for new installations; 25 kV, 34.5 kV, and higher primary distribution voltages are also utilized. Secondary distribution reduces the voltage for utilization by commercial and residential customers. Common secondary distribution voltages in the United States are 240/120 V, single-phase, three-wire; 208Y/120 V, three-phase, four-wire; and 480Y/277 V, three-phase, four-wire.

Transmission and distribution grids in the United States as well as other industrialized countries are aging and being stressed by operational uncertainties and challenges never envisioned when they were developed many decades ago. There is a growing consensus in the power industry and among many governments that smart grid technology is the answer to the uncertainties and challenges. A smart grid is characterized by the followling attributes:

1. Self-healing from power system disturbances;
2. Enables active participation by consumers in demand response;
3. Operates resiliently against both physical and cyber attacks;
4. Provides quality power that meets 21st century needs;
5. Accommodates all generation and energy storage technologies;
6. Enables new products, services, and markets; and
7. Optimizes asset utilization and operating efficiency.

The objective of a smart grid is to provide reliable, high-quality electric power to digital societies in an environmentally friendly and sustainable manner [9].

Utility executives polled by the Electric Power Research Institute (EPRI) in 2003 estimated that 50% of the electric-utility technical workforce in the United States will reach retirement in the next five to ten years. And according to the Institute of Electrical and Electronics Engineers (IEEE), the number of

U.S. power system engineering graduates has dropped from approximately 2,000 per year in the 1980s to 500 in 2006. The continuing availability of qualified power system engineers is a critical resource to ensure that transmission and distribution systems are maintained and operated efficiently and reliably [8].

1.3 ELECTRIC UTILITY INDUSTRY STRUCTURE

The case study at the beginning of this chapter describes the restructuring of the electric utility industry that has been ongoing in the United States. The previous structure of large, vertically integrated monopolies that existed until the last decade of the twentieth century is being replaced by a horizontal structure with generating companies, transmission companies, and distribution companies as separate business facilities.

In 1992, the United States Congress passed the Energy Policy Act, which has shifted and continues to further shift regulatory power from the state level to the federal level. The 1992 Energy Policy Act mandates the Federal Energy Regulatory Commission (FERC) to ensure that adequate transmission and distribution access is available to Exempt Wholesale Generators (EWGs) and nonutility generation (NUG). In 1996, FERC issued the "MegaRule," which regulates Transmission Open Access (TOA).

TOA was mandated in order to facilitate competition in wholesale generation. As a result, a broad range of Independent Power Producers (IPPs) and cogenerators now submit bids and compete in energy markets to match electric energy supply and demand. In the future, the retail structure of power distribution may resemble the existing structure of the telephone industry; that is, consumers would choose which generator to buy power from. Also, with demand-side metering, consumers would know the retail price of electric energy at any given time and choose when to purchase it.

Overall system reliability has become a major concern as the electric utility industry adapts to the new horizontal structure. The North American Electric Reliability Council (NERC), which was created after the 1965 Northeast blackout, is responsible for maintaining system standards and reliability. NERC coordinates its efforts with FERC and other organizations such as the Edison Electric Institute (EEI) [10].

As shown in Figure 1.3, the transmission system in North America is interconnected in a large power grid known as the North American Power Systems Interconnection. NERC divides this grid into ten geographic regions known as coordinating councils (such as WSCC, the Western Systems Coordinating Council) or power pools (such as MAPP, the Mid-Continent Area Power Pool). The councils or pools consist of several neighboring utility companies that jointly perform regional planning studies and operate jointly to schedule generation.

The basic premise of TOA is that transmission owners treat all transmission users on a nondiscriminatory and comparable basis. In December 1999, FERC issued Order 2000, which calls for companies owning transmission systems to put transmission systems under the control of Regional Transmission Organizations (RTOs). Several of the NERC regions have either established Independent System Operators (ISOs) or planned for ISOs to operate the transmission system and facilitate transmission services. Maintenance of the transmission system remains the responsibility of the transmission owners.

At the time of the August 14, 2003 blackout in the northeastern United States and Canada, NERC reliability standards were voluntary. In August 2005, the U.S. Federal government passed the Energy Policy Act of 2005, which authorizes the creation of an electric reliability organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants. As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all users, owners, and operators of the bulk power system in the United States, and made compliance with those standards mandatory and enforceable. Reliability standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces.

The objectives of electric utility restructuring are to increase competition, decrease regulation, and in the long run lower consumer prices. There is a concern that the benefits from breaking up the old vertically integrated utilities will be unrealized if the new unbundled generation and transmission companies are able to exert market power. Market power refers to the ability of one seller or group of sellers to maintain prices above competitive levels for a significant period of time, which could be done via collusion or by taking advantage of operational anomalies that create and exploit transmission congestion. Market power can be eliminated by independent supervision of generation and transmission companies, by ensuring that there are an ample number of generation companies, by eliminating transmission congestion, and by creating a truly competitive market, where the spot price at each node (bus) in the transmission system equals the marginal cost of providing energy at that node, where the energy provider is any generator bidding into the system [11].

1.4 COMPUTERS IN POWER SYSTEM ENGINEERING

As electric utilities have grown in size and the number of interconnections has increased, planning for future expansion has become increasingly complex. The increasing cost of additions and modifications has made it imperative that utilities consider a range of design options, and perform detailed studies of the effects on the system of each option, based on a number of assumptions:

normal and abnormal operating conditions, peak and off-peak loadings, and present and future years of operation. A large volume of network data must also be collected and accurately handled. To assist the engineer in this power system planning, digital computers and highly developed computer programs are used. Such programs include power-flow, stability, short-circuit, and transients programs.

Power-flow programs compute the voltage magnitudes, phase angles, and transmission-line power flows for a network under steady-state operating conditions. Other results, including transformer tap settings and generator reactive power outputs, are also computed. Today's computers have sufficient storage and speed to efficiently compute power-flow solutions for networks with 100,000 buses and 150,000 transmission lines. High-speed printers then print out the complete solution in tabular form for analysis by the planning engineer. Also available are interactive power-flow programs, whereby power-flow results are displayed on computer screens in the form of single-line diagrams; the engineer uses these to modify the network with a mouse or from a keyboard and can readily visualize the results. The computer's large storage and high-speed capabilities allow the engineer to run the many different cases necessary to analyze and design transmission and generation-expansion options.

Stability programs are used to study power systems under disturbance conditions to determine whether synchronous generators and motors remain in synchronism. System disturbances can be caused by the sudden loss of a generator or transmission line, by sudden load increases or decreases, and by short circuits and switching operations. The stability program combines power-flow equations and machine-dynamic equations to compute the angular swings of machines during disturbances. The program also computes critical clearing times for network faults, and allows the engineer to investigate the effects of various machine parameters, network modifications, disturbance types, and control schemes.

Short-circuits programs are used to compute three-phase and line-to-ground faults in power system networks in order to select circuit breakers for fault interruption, select relays that detect faults and control circuit breakers, and determine relay settings. Short-circuit currents are computed for each relay and circuit-breaker location, and for various system-operating conditions such as lines or generating units out of service, in order to determine minimum and maximum fault currents.

Transients programs compute the magnitudes and shapes of transient overvoltages and currents that result from lightning strikes and line-switching operations. The planning engineer uses the results of a transients program to determine insulation requirements for lines, transformers, and other equipment, and to select surge arresters that protect equipment against transient overvoltages.

Other computer programs for power system planning include relay-coordination programs and distribution-circuits programs. Computer programs for generation-expansion planning include reliability analysis and loss-of-load probability (LOLP) programs, production cost programs, and investment cost programs.

1.5 POWERWORLD SIMULATOR

PowerWorld Simulator (PowerWorld) version 15 is a commercial-grade power system analysis and simulation package that accompanies this text. The purposes of integrating PowerWorld with the text are to provide computer solutions to examples in the text, to extend the examples, to demonstrate topics covered in the text, to provide a software tool for more realistic design projects, and to provide the readers with experience using a commercial grade power system analysis package. To use this software package, you must first install PowerWorld, along with all of the necessary case files onto your computer. The PowerWorld software and case files can be downloaded by going to the www.powerworld.com/GloverSarmaOverbye webpage, and clicking on the **DownLoad PowerWorld Software and Cases for the 5th Edition** button. The remainder of this section provides the necessary details to get up and running with PowerWorld.

EXAMPLE 1.1 Introduction to PowerWorld Simulator

After installing PowerWorld, double-click on the PW icon to start the program. Power system analysis requires, of course, that the user provide the program with a model of the power system. With PowerWorld, you can either build a new case (model) from scratch or start from an existing case. Initially, we'll start from an existing case. PowerWorld uses the common Ribbon user interface in which common commands, such as opening or saving a case, are available by clicking on the blue and white PowerWorld icon in the upper left-hand corner. So to open a case click on the icon and select **Open Case.** This displays the Open Dialog. Select the Example 1.1 case in the Chapter 1 directory, and then click Open. The display should look similar to Figure 1.6.

For users familiar with electric circuit schematics it is readily apparent that Figure 1.6 does NOT look like a traditional schematic. This is because the system is drawn in what is called one-line diagram form. A brief explanation is in order. Electric power systems range in size from small dc systems with peak power demands of perhaps a few milliwatts (mW) to large continent-spanning interconnected ac systems with peak demands of hundreds of Gigawatts (GW) of demand ($1 \text{ GW} = 1 \times 10^9$ Watt). The subject of this book and also PowerWorld are the high voltage, high power, interconnected ac systems. Almost without exception these systems operate using three-phase ac power at either 50 or 60 Hz. As discussed in Chapter 2, a full analysis of an arbitrary three-phase system requires consideration of each of the three phases. Drawing such systems in full schematic form quickly gets excessively complicated. Thankfully, during normal operation three-phase systems are usually balanced. This permits the system to be accurately modeled as an equivalent single-phase system (the details are discussed in Chapter 8, *Symmetrical Components*). Most power system analysis packages, including PowerWorld,

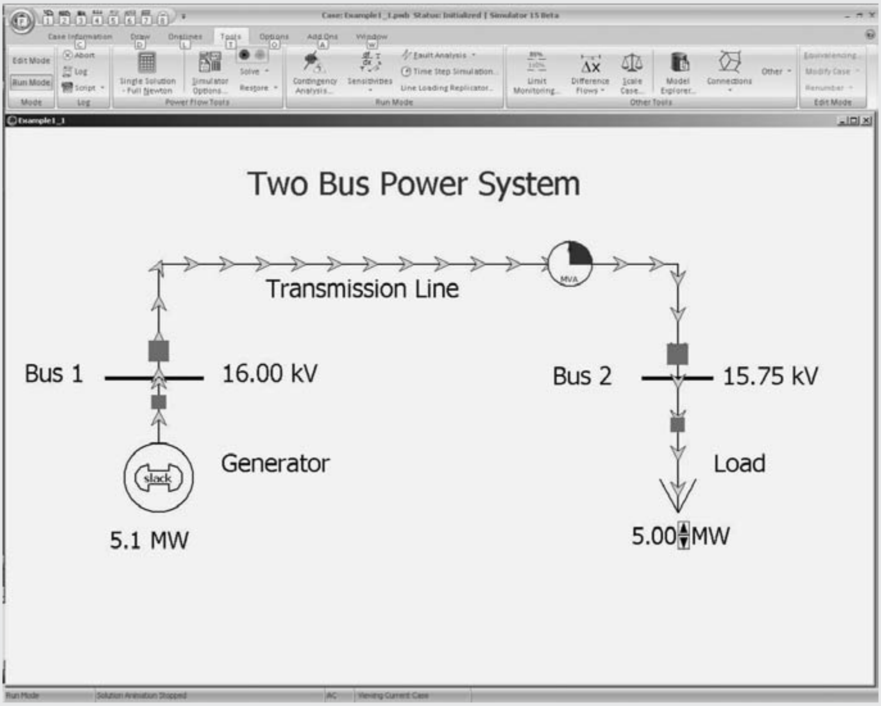


FIGURE 1.6
Example power system

use this approach. Then connections between devices are then drawn with a single line joining the system devices, hence the term ''one-line'' diagram. However, do keep in mind that the actual systems are three phase.

Figure 1.6 illustrates how the major power system components are represented in PowerWorld. Generators are shown as a circle with a ''dog-bone'' rotor, large arrows represent loads, and transmission lines are simply drawn as lines. In power system terminology, the nodes at which two or more devices join are called buses. In PowerWorld thicker lines usually represent buses; the bus voltages are shown in kilovolts (kV) in the fields immediately to the right of the buses. In addition to voltages, power engineers are also concerned with how power flows through the system (the solution of the power flow problem is covered in Chapter 6, *Power Flows*). In PowerWorld, power flows can be visualized with arrows superimposed on the generators, loads, and transmission lines. The size and speed of the arrows indicates the direction of flow. One of the unique aspects of PowerWorld is its ability to animate power systems. To start the animation, select the **Tools** tab on the Ribbon and then click on the green and black arrow button above **Solve** (i.e., the ''Play'' button). The one-line should spring to life! While the one-line is being animated you can interact with the system. Figure 1.6 represents a simple power system in which a generator is supplying power to a load through a 16 kV distribution system feeder. The solid red blocks on the line and load represent circuit breakers. To open, a circuit breaker simply click on it. Since the load is series connected to the generator, clicking on any of the circuit breakers isolates the load from the generator resulting in a blackout. To restore the system click again on the circuit breaker to close it and then again select the button on the **Tools** ribbon. To vary the load click on the up or down arrows between the load value and the "MW" field. Note that because of the impedance of the line, the load's voltage drops as its value is increased.

You can view additional information about most of the elements on the one-line by right-clicking on them. For example right-clicking on the generator symbol brings up a local menu of additional information about the generator, while right-clicking on the transmission line brings up local menu of information about the line. The meaning of many of these fields will become clearer as you progress through the book. To modify the display itself simply right-click on a blank area of the one-line. This displays the one-line local menu. Select **Oneline Display Options** to display the Oneline Display Options Dialog. From this dialog you can customize many of the display features. For example, to change the animated flow arrow color select the "Animated Flows" from the options shown on the left side of the dialog. Then click on the green colored box next to the "Actual MW" field (towards the bottom of the dialog) to change its color.

There are several techniques for panning and/or zooming on the one-line. One method to pan is to first click in an empty portion of the display and then press the keyboard arrow keys in the direction you would like to move. To zoom just hold down the Ctrl key while pressing the up arrow to zoom in, or the down arrow to zoom out. Alternatively you can drag the one-line by clicking and holding the left mouse button down and then moving the mouse–the one-line should follow. To go to a favorite view from the one-line local menu select the **Go To View** to view a list of saved views.

If you would like to retain your changes after you exit PowerWorld you need to save the results. To do this, select the PowerWorld icon in the upper left portion of the Ribbon and then **Save Case As**; enter a different file name so as to not overwrite the initial case. One important note: PowerWorld actually saves the information associated with the power system model itself in a different file from the information associated with the one-line. The power system model is stored in *.pwb files (PowerWorld binary file) while the one-line display information is stored in *.pwd files (PowerWorld display file). For all the cases discussed in this book, the names of both files should be the same (except the different extensions). The reason for the dual file system is to provide flexibility. With large system models, it is quite common for a system to be displayed using multiple one-line diagrams. Furthermore, a single one-line diagram might be used at different times to display information about different cases. ■

EXAMPLE 1.2 PowerWorld Simulator—Edit Mode

PowerWorld has two major modes of operations. The Run Mode, which was just introduced, is used for running simulations and performing analysis. The Edit Mode, which is used for modifying existing cases and building new cases, is introduced in this example. To switch to the Edit Mode click on the

Edit Mode button, which is located in the upper left portion of the display immediately below the PowerWorld icon. We'll use the edit mode to add an additional bus and load as well as two new lines to the Example 1.1 system.

When switching to the Edit Mode notice that the Ribbon changes slightly, with several of the existing buttons and icons disabled and others enabled. Also, the one-line now has a superimposed grid to help with alignment (the grid can be customized using the Grid/Highlight Unlinked options category on the One-line Display Options Dialog). In the Edit Mode, we will first add a new bus to the system. This can be done graphically by first selecting the **Draw** tab, then clicking on the **Network** button and selecting **Bus**. Once this is done, move the mouse to the desired one-line location and click (note the **Draw** tab is only available in the Edit Mode). The Bus Options dialog then appears. This dialog is used to set the bus parameters. For now leave all the bus fields at their default values, except set Bus Name to "Bus 3" and set the nominal voltage to 16.0; note that the number for this new bus was automatically set to the one greater than the highest bus number in the case. The one-line should look similar to Figure 1.7. You may wish to save your case now to avoid losing your changes.

By default, when a new bus is inserted a "bus field" is also inserted. Bus fields are used to show information about buses on the one-lines. In this case the new field shows the bus name, although initially in rather small fonts. To change the field's font size click on the field to select it, and then select the **Format** button (on the Draw Ribbon) to display the Format dialog. Click on the **Font** tab and change the font's size to a larger value to make it easier to see.

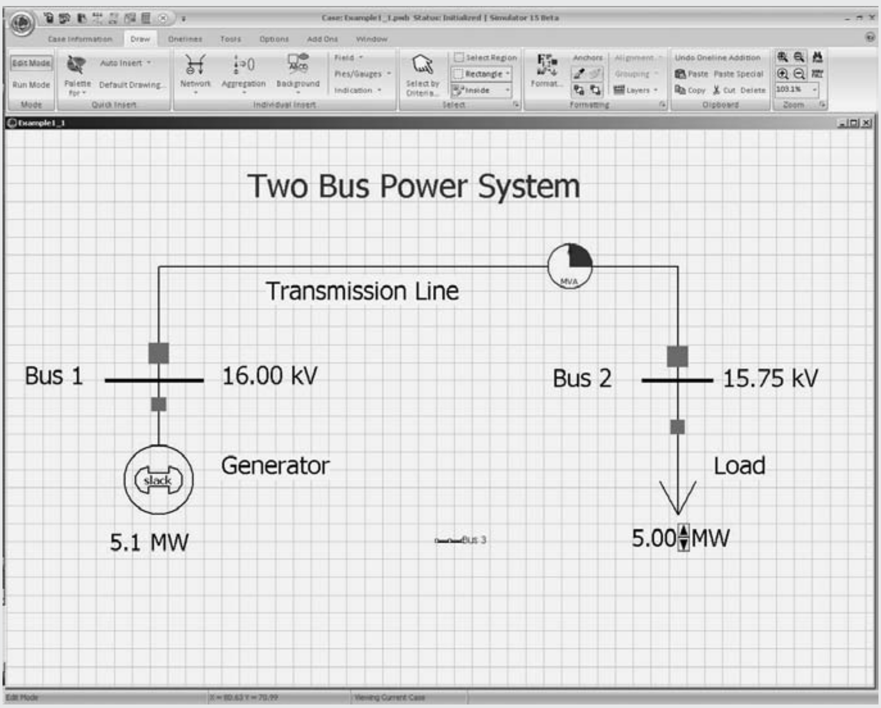


FIGURE 1.7

Example 1.2—Edit Mode view with new bus

You can also change the size of the bus itself using the Format dialog, Display/Size tab. Since we would also like to see the bus voltage magnitude, we need to add an additional bus field. On the Draw ribbon select **Field, Bus Field**, and then click near bus 3. This displays the Bus Field Options dialog. Make sure the bus number is set to 3, and that the "Type of Field" is Bus Voltage. Again, resize with the **Format, Font** dialog.

Next, we'll insert some load at bus 3. This can be done graphically by selecting **Network, Load**, and then clicking on bus 3. The Load Options dialog appears, allowing you to set the load parameters. Note that the load was automatically assigned to bus 3. Leave all the fields at their default values, except set the orientation to "Down," and enter 10.0 in the Constant Power column MW Value field. As the name implies, a constant power load treats the load power as being independent of bus voltage; constant power load models are commonly used in power system analysis. By default PowerWorld "anchors" each load symbol to its bus. This is a handy feature when changing a drawing since when you drag the bus the load and all associated fields move as well. Note that two fields showing the load's real (MW) and reactive (Mvar) power were also auto-inserted with the load. Since we won't be needing the reactive field right now, select this field and then select click **Delete** (located towards the right side of the **Tools** Ribbon) to remove it. You should also resize the MW field using the **Format, Font** command.

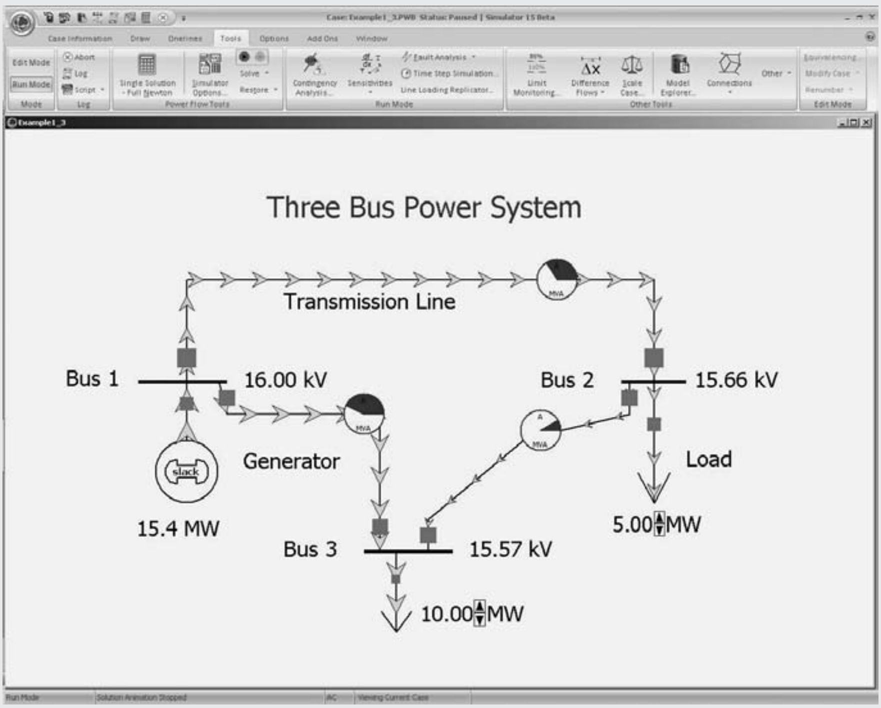
Now we need to join the bus 3 load to the rest of the system. We'll do this by adding a line from bus 2 to bus 3. Select **Network, Transmission Line** and then click on bus 2. This begins the line drawing. During line drawing PowerWorld adds a new line segment for each mouse click. After adding several segments place the cursor on bus 3 and double-click. The Transmission Line/Transformer Options dialog appears allowing you to set the line parameters. Note that PowerWorld should have automatically set the "from" and "to" bus numbers based upon the starting and ending buses (buses 2 and 3). If these values have not been set automatically then you probably did not click exactly on bus 2 or bus 3; manually enter the values. Next, set the line's Series Resistance (R) field to 0.3, the Series Reactance (X) field to 0.6, and the MVA Limits Limit (A) field to 20 (the details of transformer and transmission line modeling is covered in Chapters 3 through 5). Select OK to close the dialog. Note that Simulator also auto-inserted two circuit breakers and a round "pie chart" symbol. The pie charts are used to show the percentage loading of the line. You can change the display size for these objects by right-clicking on them to display their option dialogs. ■

EXAMPLE 1.3 PowerWorld Simulator—Run Mode

Next, we need to switch back to Run Mode to animate the new system developed in Example 1.2. Click on the **Run Mode** button (immediately below the **Edit Mode** button), select the **Tools** on the ribbon and then click the green and black button above **Solve** to start the simulation. You should see the arrows flow from bus 1 to bus 2 to bus 3. Note that the total generation is now about 16.2 MW, with 15 MW flowing to the two loads and 1.2 MW lost to the wire resistance. To add the load variation arrows to the bus 3 load right click on the load MW field (not the load arrow itself) to display the field's local menu. Select **Load Field Information Dialog** to view the Load Field Options dialog. Set the "Delta per Mouse Click" field to "1.0," which will change the load by one MW per click on the up/down arrows. You may also like to set the "Digits to Right of Decimal" to 2 to see more digits in the load field. Be sure to save your case. The new system now has one generator and two loads. The system is still radial, meaning that a break anywhere on the wire joining bus 1 to bus 2 would result in a blackout of all the loads. Radial power systems are quite common in the lower voltage distribution systems. At higher voltage levels, networked systems are typically used. In a networked system, each load has at least two possible sources of power. We can convert our system to a networked system simply by adding a new line from bus 1 to bus 3. To do this switch back to Edit Mode and then repeat the previous line insertion process except you should start at bus 1 and end at bus 3; use the same line parameters as for the bus 2 to 3 line. Also before returning to Run Mode, right click on the blue "Two Bus Power System" title and change it to "Three Bus Power System." Return to Run Mode and again solve. Your final system should look similar to the system shown in Figure 1.8. Note that now you can open any single line and still supply both loads—a nice increase in reliability!

FIGURE 1.8

Example 1.3—new three-bus system



With this introduction you now have the skills necessary to begin using PowerWorld to interactively learn about power systems. If you'd like to take a look at some of the larger systems you'll be studying, open PowerWorld case Example 6.13. This case models a power system with 37 buses. Notice that when you open any line in the system the flow of power immediately redistributes to continue to meet the total load demand. ■

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