1 Overview of the Electric Utility Industry

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When electricity was first made available in the late nineteenth century, it was through central stations serving a group of nearby customers. Generation and distribution was localized and long-haul transmission was not yet in the picture. Demand for the service was high with a larger and larger distribution network being covered. Systems once isolated from one another were becoming interconnected. Out of this emerged the basic operating structure of the grid still in place today:

1. Large power plants generate electricity* and transmit it at high-voltage levels
2. To interconnected transmission lines that transmit electricity over long distances
3. To distribution substations where a transformer steps down the voltage†
4. To deliver it over relatively short distances to a network of smaller, local transformers, which step the voltage down further to levels safe and appropriate for the homes or businesses it serves

* Most large power plants function in a similar fashion: using an energy source to drive a rotating turbine attached to a generator. These turbines can be driven by water, wind steam, or hot gases. Steam requires nuclear fission or the burning of a fossil fuel like coal, while hot gases require the burning of natural gas or oil. A combined cycle plant uses both hot gases and steam—they typically burn natural gas in a gas turbine and use the excess heat to create steam to power a steam turbine.

† Transmission lines carry *alternating current* (AC) electricity at voltages ranging from 110,000 V (110 kV) to 1,200,000 V (1.2 MV), which are eventually stepped down to 110/220 V for residential use. When electricity is transmitted at higher voltage levels, less of it is lost along the way; *line loss* is currently about 7% in the United States. *Direct current* or DC power may be more suitable for transmitting power over long distances if the reduced energy loss offsets the required investment in stations at each end of the line to convert it back to AC.

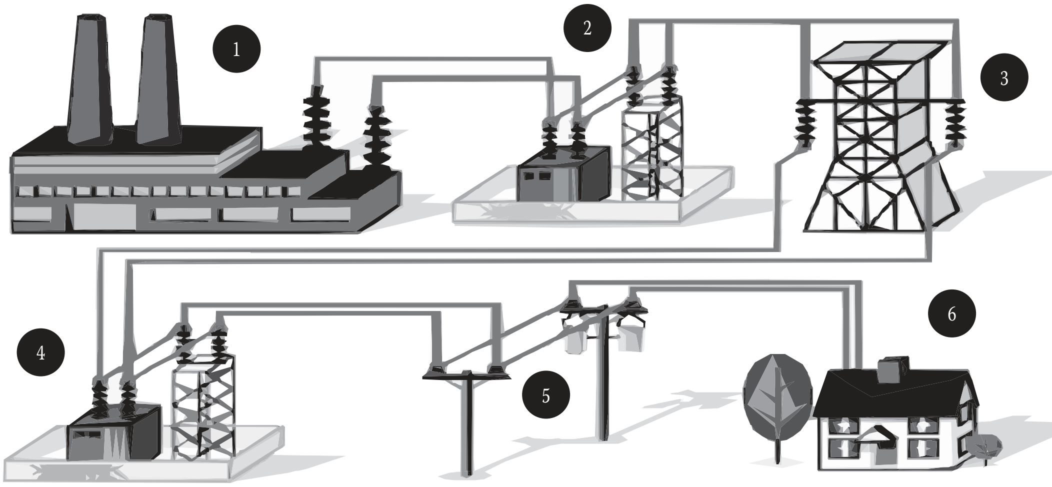

FIGURE 1.1 Electric utility interconnection overview. (Courtesy of the Advisory Board of the Utility Executive Course, University of Idaho, Moscow, ID.)

These elements are illustrated in Figure 1.1 including (1) a power plant, (2) a transmission substation, (3) a transmission line, (4) a distribution substation, (5) a distribution line/transformer, and (6) an end user.

While the basic operating structure of the grid has largely remained the same over the decades, the practices used to plan and operate the grid and the regulatory structures that govern the industry have evolved substantially since that time. The history of the industry, in particular the United States, is essentially a timeline of regulatory responses to a relatively small number of key events.

While electric power is now available to approximately 4.8 billion people around the world, more than 1.8 billion people are left "in the dark" with no, or very limited, access to electricity. Developing nations continue to lag in the provision of electricity to their citizenry. Globally, more than 1.6 billion electricity meters are installed at end-use locations (houses, apartments, commercial establishments, and industrial sites and factories), measuring usage information that provides the global electric utility industry with revenues of more than one trillion dollars annually.

This chapter aims to provide context for the more focused, technical chapters that follow. A full understanding of the new challenges and opportunities the industry will face over the coming decades requires an understanding of the factors that have shaped the utility industry's history. The regulatory structures that exist today will also fundamentally shape the development of the smart grid. The enormity and complexity of the electricity delivery network, coupled with its social, economic, regulatory, and political operating environments, directly impact the understanding, acceptance, and ultimate promotion of the smart grid.

1.1 UNITED STATES: HISTORICAL PERSPECTIVE

The electric utility industry in the United States today is highly fragmented, operating under a variety of different industry and regulatory structures. Much of the heterogeneity is a result of the history of the industry and the strong influence of ever-evolving regulatory structures. There are over 3100 investor-owned utilities, municipals, cooperatives, and federal and state agencies that deliver electric power in the United States today. These entities collectively deliver electric power across 50 states, 3 interconnections, and 8 distinct "reliability regions" and own over 160,000 miles of high-voltage transmission lines, 60,000 transmission and distribution substations, and millions of miles of distribution networks. This vast and intricate network keeps the lights on and systems running for over 142 million residential, commercial, industrial, and governmental customers.[1]

1.1.1 Electrification and Regulation

When electricity was first made available in the late nineteenth century, it was provided by relatively small central stations serving a group of nearby customers. Generation and distribution were initially highly localized. However, demand for electric service grew quickly leading to the development of larger and larger distribution networks. Rapid technology improvements also enabled improvements in both electric power generation and transport. Systems once isolated from one another eventually became *interconnected*. Eventually, the interconnection of localized systems led to substantial industry consolidation by the end of the 1920s.

The interconnection of once isolated systems brought both benefits and risks. The biggest benefit was that generation could be shared among distribution networks. Since power plants have significant economies of scale, this allowed electricity to become cheaper to produce. Reliability was also improved as the failure of a local generator could be offset by another generator farther away—without customers even knowing that there had been a problem. Such was, and is the case, the vast majority of the time. However, the fact that localized distribution networks were now interdependent exposed utilities to the risk of disruptive events miles away. Eventually, the interconnection of localized systems led to substantial industry consolidation by the end of the 1920s.

This consolidation resulted in a handful of holding companies controlling more than 80% of the U.S. electric power market. While utilities had been state regulated since as early as 1907, the state public utility commissions (PUCs)* had limited or no control over the actions of interstate holding companies. These holding companies were often highly leveraged† and financial failures were not uncommon. In addition, some holding companies were being operated essentially as "pyramid schemes," in which resources were transferred from utilities at the bottom to the parent company at the top—to the benefit of a small number of large investors at the expense of ratepayers and smaller investors. For a service as vital as electricity to the economy, this was an unsustainable situation. It was eventually addressed in the 1930s during a wave of legislative reform that followed the stock market crash of 1929.

The *Public Utility Holding Company Act of 1935* (PUHCA), in particular, had an enormous impact on the structure of the industry. In sum, this legislation

1. Broke up the large holding companies that dominated the industry
2. Gave the Federal Power Commission (predecessor of today's Federal Energy Regulatory Commission or FERC)‡ power over activities that crossed state jurisdictional boundaries, such as electric transmission and wholesale power pricing
3. Gave the Securities and Exchange Commission (SEC) the power to regulate holding companies in a way that state PUCs never could

* PUC is a general term for a state regulatory agency. State regulatory agencies can go by a variety of names.

† Excessively reliant on debt to fund their activities.

‡ The FERC is an independent regulatory agency within the Department of Energy. According to its most recent strategic plan, its top priorities remain interstate/national matters: (1) promote the development of a strong energy infrastructure, (2) support competitive markets, and (3) prevent market manipulation. At present, FERC is composed of up to five commissioners appointed by the President for 5 year terms, with one appointed by the President to be the Chair. No more than three commissioners can belong to the same political party and there is no Presidential or Congressional review of the FERC's decisions.

In direct response to the *cross-subsidization** that took place in the pyramid schemes of the 1920s, PUHCA required new cost accounting complexities that remain today in nearly all utility holding companies. PUHCA regulation is also the reason why the parent companies of most investor-owned utilities† are typically based in the United States with holdings concentrated within the industry (i.e., not industrial conglomerates) and why most mergers and acquisitions take place between geographically contiguous entities. Simply put, policymakers preferred the electric industry to be run by local electric companies, not by outside speculators, and this legislation helped accomplish that goal.

It was a noble plan, though not without its flaws. For one, as the world around it changed, the ability of utilities to adapt was greatly limited by the PUHCA. For example, utilities were constrained in their ability to reduce operating risk by diversifying their activities. PUHCA was also a "deal-breaker" for many acquisition opportunities; nonenergy businesses would essentially have had to overhaul their business model (i.e., divest nonenergy businesses) and subject themselves to higher levels of regulatory scrutiny in order to "buy in" to the industry.

1.1.2 Northeast Blackout of 1965

From 1935 to 1965, the utility industry was stable and relatively uneventful. Transmission interconnection had become so pervasive that isolated power systems in the continental United States were essentially nonexistent. Oversight of these interdependencies was in place via the North American Power Systems Interconnection Committee (NAPSIC)—which had been formed by the industry in the early 1960s to help ensure effective governance of the nation's transmission system—and by *regional reliability councils*.‡

However, on November 9, 1965, a confluence of events—a minor power surge, an improperly configured system protection component, and extremely cold weather pushing the electric system near peak capacity—triggered a cascading blackout that affected 25 million people in parts of New York, New Jersey, New England, and Ontario. A review of what happened and why it happened revealed that effective governance of the nation's transmission system had not been ensured—specifically, that interconnection pervasiveness was not accompanied by the appropriate level of interconnection planning and operations. In other words, though a utility's service reliability was heavily dependent on the reliability of its neighbor utilities, this did not prevent independent operating standards and procedures, system protection schemes, and restoration practices from evolving. In response to constituent outcry about the blackout, more formalized oversight was legislated through the *Electric Reliability Act of 1967*.

As part of this Act, external scrutiny of the industry increased. The North American Electric Reliability Council (NERC) was formed on June 1, 1968, as a successor to the NAPSIC. Its charter was to promote electric reliability, adequacy, and security by driving utilities to common policies and procedures. Also, out of the *Electric Reliability Act of 1967* came the impetus for large-scale energy management systems (EMSs) that utilities use to efficiently and reliably remotely monitor and control their transmission networks and the development of SCADA systems to remotely monitor and control distribution networks.

* Funding one entity with the assets and resources of another.

† Investor-owned utilities serve the largest number of customers in the United States. In addition to investor-owned utilities, there is another classification of utilities called publicly owned utilities. Publicly owned utilities are often referred to as "municipals" (municipality-owned) or "cooperatives" (customer-owned), the latter typically serving rural areas.

‡ Regional reliability councils remain in place today, covering the continental United States and much of Canada. Examples of reliability councils include the Northeast Power Coordinating Council (NPCC), the Electric Reliability Council of Texas (ERCOT), and the Western Electricity Coordinating Council (WECC).

1.1.3 Energy Crisis of 1973–1974

The Arab oil embargo of 1973 and 1974 drove the U.S. economy into recession and prompted unprecedented interest in conservation and renewable energy. For the first time since average retail price data have been tracked, the *real** cost to the consumer for electricity increased. In *nominal*† terms, electric bills essentially doubled from 1973 to the end of the decade. In response, many electric utilities shifted their marketing focus from consumption to conservation—promoting investment in home insulation, higher-efficiency heating and air conditioning equipment, and other energy efficiency measures through financial assistance programs to residential and business customers. The federal government also attempted to promote more-efficient generation technologies and to encourage new players to enter into the generation market through the Public Utility Regulatory Policies Act (PURPA).

Put forth as part of the National Energy Act of 1978, PURPA created incentives for nonutilities (e.g., chemical refineries, paper mills) to produce power, and required utilities to buy that power. In order to create enough of an incentive for these nonutilities to make the necessary upfront investment, certain risks were transferred from the nonutility to the utility (and, therefore, ultimately to its customers). This was done through purchased power contracts, which were often long term in nature. When oil prices fell during the 1980s, these *cogeneration* contracts proved to be a significant drag on utility earnings—and on the energy efficiency PURPA sought to promote. Ultimately, PURPA was used by many utilities in their arguments that less regulation, not more, was needed to drive efficiencies in the electric industry.

1.1.4 Deregulation

The first major attempt at deregulation of the electric power industry was the *Energy Policy Act of 1992*, which sought to drive efficiency in the industry through wholesale‡ competition. As airline deregulation had driven down prices in the 1980s, it was believed that the price of electricity to the end user would go down if the price of generation to the electric delivery company was determined by a free market. Many economists argued that electricity was not a natural monopoly, but rather the *delivery* of electricity was; *generation* of electricity was not. If power plants could be exposed to competition, it was believed, then the most efficient generation operations would prevail and prices would drop below those set by state regulators.

Policymakers and regulators recognized the potential for new electricity markets to be *gamed*—rules manipulated and loopholes exploited, to the benefit of a few at the expense of the many. It was understood that control over transmission assets—the high-voltage lines that link power plants (generation) and customers (distribution)—could be used to stifle competition. In anticipation of this, FERC was given the ability to mandate utilities to provide access to the transmission grid, preventing them from keeping competition out of their market by denying the entry of outside power to the transmission "highway." Policymakers also understood the value of information related to transmission, and created *standards of conduct* designed to ensure that all players in the marketplace had access to the same information at the same time§ and to keep information from finding its way from the regulated side of utilities to the deregulated side—an information flow that could create a significant competitive advantage for a utility's generation business.

* Net of inflation.
† Inclusive of inflation.
‡ The wholesale market is where bulk power is bought and sold by grid operators based on immediate or long-term system load levels, while the retail market—which was deregulated in certain states later in the 1990s—is where electric supply choices can be made by the end user.
§ This is done through OASIS—open access same-time information system.

FERC relied heavily on *independent system operators* (ISOs) and *regional transmission operators* (RTOs)* to help ensure a functioning marketplace for wholesale electricity. ISOs and RTOs were given responsibility for managing transmission assets that in most cases are owned by one utility but essential to multiple utilities. ISO and RTOs were established across a wide number of states and regions in the late 1990s in the United States including California, Texas, New York, New England, the Mid-Atlantic, and the Midwest, as depicted in the map on the following page. If it had been in FERC's power to do so, it would have mandated—in the interest of marketplace efficiencies—that all transmission assets be governed and operated by an independent agency such as an ISO or RTO. However, FERC did not—and still does not—have this authority. Not all state PUCs or utilities believed that their interests would be best served by abdicating transmission asset responsibility to an independent agency. As a result, RTOs and ISOs help oversee only about two-thirds of the nation's electricity consumption (Figure 1.2).

The results of restructuring have been mixed. In the PJM market and in Texas, for example, deregulation has been considered a very real success. In California, as described in the following, it was, at least at first, a very vivid disaster. The difference between success and failure in these situations has often boiled down to specific details of market design.

1.1.5 Western Energy Crisis of 2000–2001

> In the final analysis, it doesn't matter what you crazy people in California do, because I've got smart guys who can always figure out how to make money.—Enron CEO Ken Lay to the Chairman of the California Power Authority (2000)

> I inherited the energy deregulation scheme which put us all at the mercy of the big energy producers. We got no help from the Federal government. In fact, when I was fighting Enron and the other energy companies, these same companies were sitting down with Vice President Cheney to draft a national energy strategy.—California Governor Gray Davis (2003)

On September 23, 1996, deregulation of the electric market was passed into law in California by unanimous vote of the state legislature. This legislation required that investor-owned utilities (i.e., Pacific Gas and Electric in the North, Southern California Edison in the South, and San Diego Gas and Electric) divest their generation business. Power plants were sold off to independent power producers (e.g., Enron, Mirant, Reliant, Williams, Dynegy, AES), who would then sell this energy to the regulated utilities responsible for power delivery to residential and business customers.

Of great concern to the utilities were *stranded assets*—capital that they had previously invested and which, under the new rules, they would be unable to recover. In return for asset recovery, the utilities agreed to retail price caps. Though the price the utilities would be paying to purchase energy would change with the market, the amount the utilities could pass on to the customer was fixed. It can take several decades for bad legislation to become apparent. In California, it took less than 5 years.

The spot market for electricity began operating in April of 1998. Caps were removed from wholesale prices in May of 2000, while caps remained on retail prices. Energy prices began to rise in May of 2000. Rolling blackouts first started in June 2000 and lasted through May 2001, including 2 days in mid-March when 1.5 million customers were affected. A State of Emergency was declared in January 2001, with the state of California having to step in for the utilities (which were essentially insolvent due to rising wholesale prices and retail price caps) to buy power at market rates and financed through significant levels of long-term debt. Pacific Gas & Electric filed for bankruptcy in April 2001. Southern California Edison nearly did the same. In aggregate, the two utilities took on

* U.S. ISOs and RTOs include California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Midwest ISO (MISO), New York ISO (NY ISO), New England RTO, PJM Interconnection (PJM), and Southwest Power Pool (SPP). Some of these overlap with regional reliability councils.

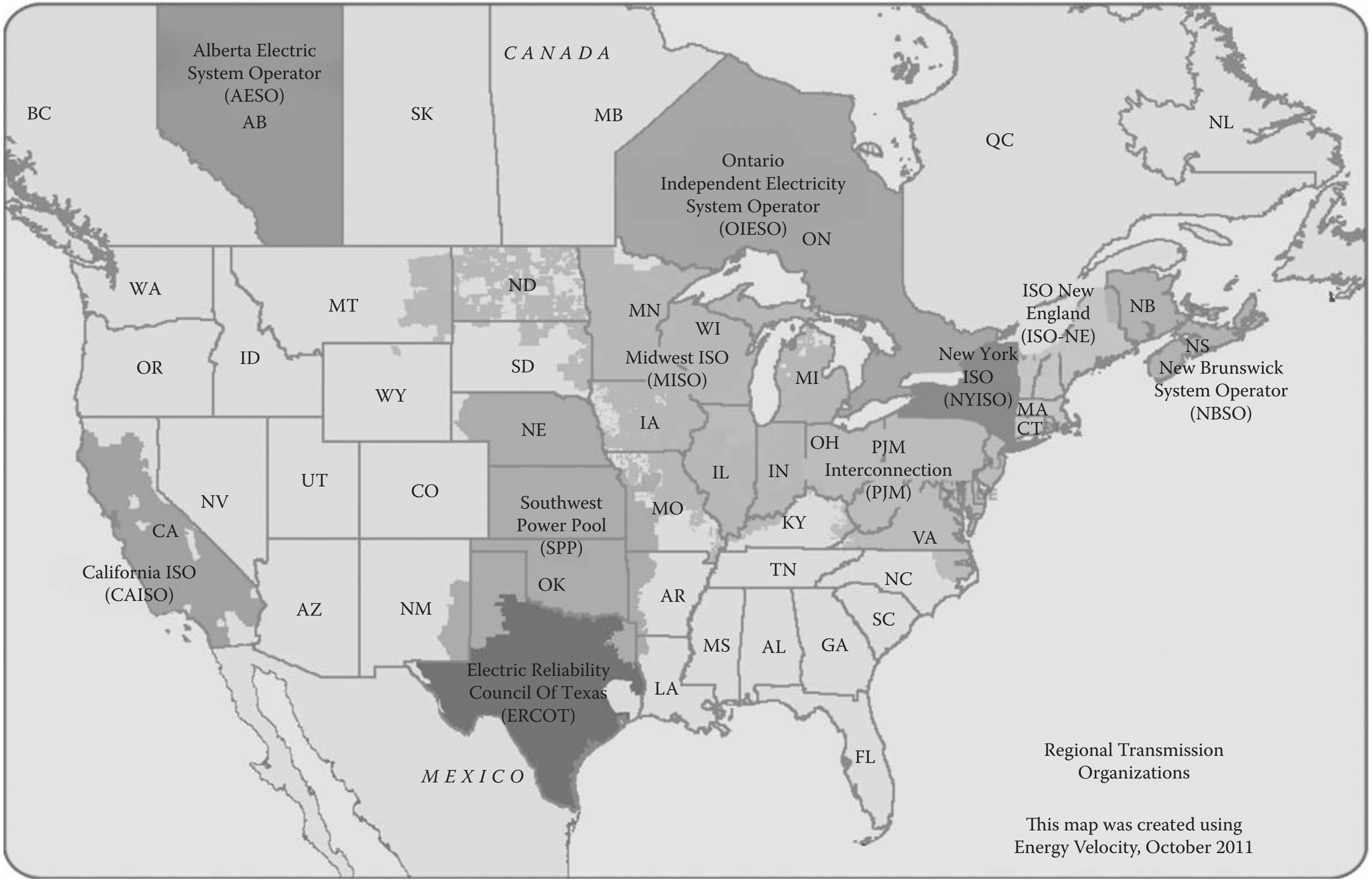

FIGURE 1.2 Regional Transmission Organizations. (From FERC, Washington, DC.)

an additional $20B in debt and saw their credit ratings* downgraded to the level of junk bonds. The State of Emergency was not lifted until November 13, 2003.

As it was happening, there was no consensus on the key factor driving the Western Energy Crisis. In retrospect, it was a combination of the following:

- *Weather:* It was hot and dry. The worst Pacific Northwest hydroelectric year in history drove down supply and unusually hot weather over much of the West drove up demand—with drought-fueled fires knocking out key transmission lines along the way.
- *Capacity:* From 1993 to 1999, California's peak load demand had grown by over 15% while growth in capacity was virtually nonexistent. In addition, the ability to easily exchange power back and forth throughout the region was constrained by transmission line capacity.
- *Flawed market design:* Utilities reduce their exposure to energy supply fluctuations through a number of strategies, most notably long-term, fixed-cost (aka *hedged*) power contracts. During the summer of 2000, only 50% of the energy purchased by California utilities was hedged compared to 85%–90% by utilities in the PJM market. Market rules forced California utilities to be excessively reliant on the inherently riskier *spot market* (i.e., "that day's price") to meet demand.
- *Corporate malfeasance:* The flaws in the deregulated marketplace were being manipulated, most notably by Enron. One of the most common techniques involved the exploitation of supply constraints to drive up prices. Wholesale energy companies' business models often focus on peak demand days—and the ability to meet that demand using *peaking units*†—as a key driver of profitability. Enron's business model involved *creating* peak demand days by shutting off power plants for unplanned maintenance and then selling their remaining capacity into the market at exorbitant rates to meet the needs of a captive market. This is just one example of the many schemes that Enron employed to game the market.
- *Failed oversight:* It is evident now that California and FERC were operating under an inconsistent set of assumptions. An implicit assumption was made by the California legislature that FERC would play a role in keeping out-of-state interests from manipulating the market. An implicit assumption was made by FERC that the wholesale markets they were advocating could and would be designed in a manner that did not require extensive oversight to prevent manipulation.

Though labeled a state or regional crisis, the impact of this series of events was felt well beyond California and the West, extending throughout the industry as the market responded to the dramatic levels of uncertainty in what had historically been a relatively stable industry. Any number of statistics could underscore this point, but here is one particularly striking one that captures the state of the industry in the first years of the new century: Over the 3 year period from 2000 to 2002, there were 65 upgrades compared to 342 downgrades of electric utility credit ratings.

The California crisis also substantially slowed the momentum that had emerged for markets in the late 1990s. In the years that followed, some regions publically considered reverting to the traditional model of industry regulation (though no regions actually switched) and no new ISOs/RTOs were formed. FERC has repeatedly reaffirmed its support for wholesale market competition over the past decade and those regions with organized markets continue to evolve their market designs. However, today only about two-thirds of the nation's electricity consumption occurs in regions with organized wholesale markets.

* Third-party assessments of a company's ability to repay its debts.

† Peaking power plants that can be brought on-line and off-line quickly, as opposed to base load power plants that require much more time to "turn on and off."

It is unclear if or when further deregulation will occur in the U.S. electric power industry. Today, the electric power industry in the United States remains in a state of partial deregulation. While many utilities continue to operate in open wholesale and retail markets, the Enron debacle is still fresh in enough people's minds to dampen any enthusiasm for expanding deregulation further. Though the Western Energy Crisis in the United States had everything to do with wholesale markets and little to do with retail markets, the distinction is not clear in the public's mind—and the impact on existing or proposed regulatory reform efforts has been significant. The industry remains in a state of partial consolidation, with merger and acquisition activity well below the pace projected by many in recent years.

1.1.6 Northeast Blackout of 2003

Only a couple of years after the California crisis, August 14, 2003, saw a massive power outage that affected 50 million people in Michigan, Indiana, Ohio, Pennsylvania, Maryland, New York, Vermont, Connecticut, and Ontario. As with the Northeast Blackout of 1965, the initial cause was a fairly innocuous one that eventually triggered a system imbalance that cascaded across neighboring utilities. The investigation eventually identified the root cause to be a handful of high-voltage transmission lines—which, by the laws of physics, sag (literally) as load increases—coming into contact with overgrown trees in Ohio and going off-line. As with the Northeast Blackout of 1965, failures in other parts of the system protection process allowed this outage to spread wider—specifically, a problem that caused alarms on First Energy's EMS to go unnoticed.

In addition, as with the Northeast Blackout of 1965, the governmental response to this issue has been to legislate greater oversight of the industry. As part of the *Energy Policy Act of 2005*, FERC was authorized to designate a national Electric Reliability Organization (ERO). On July 20, 2006, FERC certified NERC as the ERO for the United States. With this designation, NERC's *guidelines* for system operation and reliability became *standards*. This Act gave NERC the power to exact financial penalties for entities operating out of compliance with the standards.

As should be readily apparent, the history of the electric power industry is one in which a relatively small number of disruptive events (major blackouts, market manipulation) resulted in significant governmental responses to those events. Because legislation rarely is written in a manner that allows it to adapt to changes in the marketplace, the impact of governmental intervention on the structure of the industry is felt for years to come and not always in the manner in which it was intended.

1.2 OTHER WORLD REGIONS*

Globally, electric power is now available to approximately 4.8 billion people. However, more than 1.8 billion people are left "in the dark" with no, or very limited, access to electricity. Developing nations continue to lag in the provision of electricity to their citizenry. Globally, more than 1.6 billion electricity meters are installed at end-use locations (houses, apartments, commercial establishments, and industrial sites and factories), measuring usage information that provides the global electric utility industry with revenues of more than 1 trillion dollars annually.

There are about 43,000 medium and large electric power generating facilities outside of North America providing electricity to people in more than 200 countries. These power stations transmit electricity through a network of about 58,000 transmission substations, with more than 120,000 large and very large power transformers installed. There are approximately 190,000 distribution substations outside of North America and about 25,000 industrially operated substations.

* *Source:* Newton-Evans Research Company internal estimates.

1.2.1 Western and Eastern Europe

Western European nations have a total of about 19,300 generating facilities providing electricity to over 400 million residents via a strongly interconnected (mainland international) transmission network. The HV/EHV network includes more than 14,000 transmission substations, some 44,000 primary distribution substations, and thousands more of secondary distribution substations. Nearly 60% of the western European power generation capacity can be found in just three countries (Germany, France, and the United Kingdom).

Central and eastern European nations have an installed power generation base of more than 2700 large and medium plants, with a capacity of more than 425 GW. Most residents of central and eastern Europe have access to electricity. There are more than 12,000 transmission substations and 32,000 distribution substations in the combined central-eastern European region.

Some of the world's largest electric power utilities are found in western Europe, where state-run or quasi-state-owned utilities dominate in some countries (EDF in France, EDP in Portugal, ENEL in Italy), while some nations have 5–20 major electric utilities (United Kingdom, Denmark, the Netherlands, Spain, and others). A few countries (e.g., Germany and Switzerland) have scores or hundreds of small municipal or rural area utilities with a few large to very large urban utilities.

In Eastern Europe, a number of countries continue to operate state-controlled electric power companies. In the forefront of these is Russia's UES, generating and transmitting electricity to about 60 mid-size to quite large distribution utilities in the country's larger cities. Russia accounts for just over one-half of the total generating capacity for the entire central and eastern European region; Ukraine is second and Poland third in generating capacity and in populations served with electricity.

1.2.2 Latin America

Two countries (Brazil and Mexico) dominate the Central and South American regions in terms of population (300 million out of a region-wide 565 million inhabitants), electricity production (about 55% of the total); and in the investment in existing T&D infrastructure. Argentina and Venezuela are next in terms of the status of electricity infrastructure development.

The entire region provides about 250 GW of electric production capacity, has nearly 5,000 transmission substations and 18,000 distribution substations already in operation. There are still millions of residents in the region without access to electricity, but each year brings some progress with new areas being served by power utilities and by micro-grid developments based on renewable energy sources.

Latin American countries are home to about 3600 large and medium power generation facilities, most of which are hydropower facilities (other than Mexico). Some of the world's largest hydropower facilities are found in South America, including the world-class Itaipu Binacional hydropower facility, just behind China's Three Gorges in terms of its production capacity (12,600 MW).

1.2.3 Middle East and Africa

The Middle Eastern countries of the Mashreq and Maghreb regions provide more than 200 GW of mostly gas (and oil)-fired electric power capacity to more than 350 million users out of a total of about 400 million residents. More than one-half of the region's inhabitants reside in three countries (Egypt, Turkey, and Iran). There are more than 4200 transmission substations delivering power to about 100 million end use electric power sites.

The African nations currently rely on coal-fired plants for the majority of electricity generation, but coal is expected to be overtaken by gas-fired plants by 2020. Nonetheless, coal consumption continues to increase, with new plants being largely combined cycle gas fueled facilities.

Sub-Saharan African nations have about 750 million inhabitants, but only 90 GW of electricity production capacity. More than one-half of the existing generating capacity is in South Africa. There are an estimated 450 million or more people in sub-Saharan Africa without direct access to a reliable electric power supply. As renewable energy production methods develop and their costs decrease, African countries will be able to adopt them more rapidly than at present.

1.2.4 Asia–Pacific Region

This vast region includes the two most populous, rapidly developing nations in the world, India and China. Across the expanse of the Asia–Pacific region, there are more than 14,000 large power generation facilities in operation. China and India both have more than 2150 of the large (mostly coal-fired) power plants in the region.

South Asia as a subregion includes 1.6 billion people, with less than 200 GW of electricity production capacity, of which India holds the major share of people (1.1 billion) and electricity production capacity (160 GW). The country also has most of the substations in the region (about 17,500 out of about 22,000 in total). Pakistan and Bangladesh are other large countries of South Asia neighboring India, together having 315 million residents, but only about 32 GW of capacity.

Other Asian and Pacific countries have more than 2.1 billion inhabitants, of which 1.3 billion live in China. China accounts for about one-half of this regions electricity production capacity and one-half of the power delivery infrastructure. Japan is second in terms of electricity production and delivery infrastructure, though Indonesia is a more populous country (235 million Indonesians and 127 million Japanese). South Korea is third in electricity production and delivery, with 49 million residents.

The entire Asia–Pacific and South Asian regions represent more than one-half of the world's population and have invested greatly to account for about 30% of the world's electricity production capacity.

Non-OECD (Organization for Economic Co-operation and Development) countries in Asia will be making impressive gains in the use of renewable energy production, but the reliance on coal-fired plants, primarily in China, is still expected to double by 2020.

1.3 UTILITY REGULATORY SYSTEMS

The nature of the electric industry cannot be understood without understanding the nature of how the industry is regulated. The electric industry is, arguably, the most externally controlled industry in the United States and the majority of nations around the world. The impact of this regulation on how and why utilities do what they do cannot be overstated.

Regulatory oversight of electric utilities is necessary because they are natural monopolies. The term *natural monopoly* applies to industries where the best outcome, in terms of the societal interest, will be one and only one provider of that good or service in a given market. Society does not benefit, the reasoning goes, when overlapping subway systems, water mains, or electric delivery networks are attempted.

The most common natural monopoly occurs in a market where the cost of entry is exceedingly high—such as a "poles and wires" company or any other entity for which significant capital resources are required to "open up shop." Investors will not fund any venture without some reasonable assurance that they will be able to earn a return on their investment. If multiple entities are allowed to build competing distribution networks, then no such assurance exists that any of these entities will be able to earn a return on the capital they have invested. Rational investors anticipate this and therefore they will not put capital toward stringing wires on poles unless they are guaranteed to be the sole provider of electricity to that market.

With monopoly, however, comes market power—specifically the power to set profit-maximizing prices with no concern for a competitive pricing. No rational public policymaker will agree to such a sole-provider arrangement without being able to control prices.

So, a deal is struck: in order for a society to benefit from the provision of a vital service, (1) public policymakers grant an exclusive franchise to an entity to provide electricity to homes and businesses and (2) the entity must agree to a customer service obligation and consent to pricing controls and third-party oversight.

Electric power utilities are always subject to some form of regulation or oversight. This can be at the national, regional, or local level. For example, in the United States, investor-owned utilities are regulated by FERC and state PUCs, while municipal and cooperative utilities are regulated by local communities and/or boards of directors made up of their members. Many countries throughout the world have national regulatory bodies including OFGEM in the United Kingdom, Commission de Regulation de l'Energie in France, CRE in Mexico, and so on. In many Middle Eastern and African countries, the regulatory function is provided by the ministry of energy.

The design of regulatory systems has a strong impact on incentives for shareholder-owned utilities. The nature of these incentives will also have important impacts on the pace of smart grid development throughout the world. For example, because a regulated utility serves 100% of their designated market, customer growth is driven not by product-based or price-based competition but by the underlying growth in the market as a whole. Further, because prices are fixed by regulatory tariffs, utilities are severely limited in their ability to drive revenue increases through pricing strategies. In addition, because prices are set by regulatory tariffs, utilities often give regulatory relationship management the same or greater emphasis than customer relationship management. In fact, some will argue that the regulator is the customer.

Profitability is determined largely by an administratively determined regulated rate of return on a utility's asset base, so great emphasis is placed by the utilities on investing capital in a prudent manner and on the preparation and defense of rate cases. To grossly oversimplify the rate-making process, utilities and regulators reach agreement on

1. What assets are essential to service delivery (i.e., the *rate base*)
2. What an appropriate rate of return on those assets should be

With these two variables in place, an allowable annual return (i.e., net income as a percentage of assets) can be calculated. Rates for different classes of customers are then set, which are projected to result in that level of return. This does not eliminate all variability in a utility's earnings, but it does create a far more predictable environment than that in which a typical nonregulated entity operates.

Profitability is determined in the following way:

- Utilities can make very large capital investments and take on relatively high levels of debt with a much lower degree of uncertainty than an unregulated company. The business case for such an investment is driven primarily by the regulatory recoverability of the investment rather than—at unregulated companies—by the anticipated impact of the investment on revenue or expense.
- The distinction between capital costs (spending that ends up on the company's books as an asset, such as the labor and equipment required to put a new transformer in service) and operating costs (spending that does not end up on the company's books as an asset, such as an administrator's salary) is nontrivial. Expense that can be charged to an asset should eventually earn the utility a regulated rate of return.

With profitability capped by a regulated rate of return on the asset base, utilities have at times had a disincentive to drive down spending. For example, a utility with a regulated rate of return of 10% generates significant operational efficiencies that allow it to earn a rate of return of 12%, only to have to "return" those excess earnings to the ratepayers during the next rate case. This phenomenon has contributed to a number of recent trends, including utilities going many years between rate cases, utilities proposing rate caps to regulators in return for other concessions, and utilities and regulators establishing *performance-based rates* in which rate of return is driven by factors other than cost of service (e.g., service levels).

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REFERENCE

1. U.S. Energy Information Administration (EIA), http://www.eia.gov/