Chapter 1

Introduction

This beginning chapter will provide a high-level overview of the topics related to the basic drivers and transformation of electricity industry around the world. With that tremendous change come challenges and complex issues. One of the key developments in this transformation is the development of electricity markets. This is the main topic of this book. In fact, the primary and paramount goal of an electric power system operation is to maintain a high level of reliability. Under a restructured environment, this goal of system reliability is achieved via a market mechanism. Understanding electricity markets requires both basic understanding and advanced knowledge of electrical power engineering principles, microeconomic theories, and optimization methods from the field of operations research. Therefore, the fundamentals of these topics will be covered in the first few chapters.

1.1 ELECTRIC POWER SYSTEM

Electricity is indispensable for a modern society. The marvels of a modern life that we enjoy today cannot be possible without electricity. The importance of electricity is without questions. So, how do we get electricity?

In general, electricity is generated from electric generating sources located far from the load centers, then transmitted over long distances using transmission lines, and distributed to the load customers which include factories, offices, and homes. The entire chain of this system is known as electric power system.

The electric power system as we know of today was developed more than a 100 years ago. It generally consists of generation, transmission, and distribution subsystems. The entire chain of business from generation to transmission and distribution to load customers for a particular service area is owned by a single entity, known as an electric power company or electric utility company. The electric power company

© 2017 by The Institute of Electrical and Electronics Engineers, Inc. Published 2017 by John Wiley & Sons, Inc.
Electricity Markets

is either owned and operated by a national government or can be a public company owned by investors, but operated by management and employees of the company. Therefore, electric power industry is an important part of a country’s infrastructure. For the last two decades, the electricity industry around the world has undergone a tremendous transformation. This transformation is from a traditional structure of an electric power industry typically owned by national governments or public investors (as in investor-owned utilities) towards a structure that is exposed to a competitive market environment. This transformation in electricity industry was preceded by similar transformations in other industries such as airlines, trucking, and natural gas industries. In the case of an electric utility owned by a national government, this transformation is in the form of privatization first, then the privatized company is exposed to an open, competitive market environment. This was the case for electricity industry restructuring in Argentina. In the case of an investor-owned utility as in the United States, the generation part of the business was separated from the wires part (transmission and distribution systems) of the same company. This generation business is either divested to an independent company or completely formed as a separate subsidiary of the original utility. This is equivalent to the functional unbundling of an existing vertically integrated company.

The key outcome of this entire industry transformation, which is generally known as electricity industry restructuring, is the development and establishment of electricity markets. This is achieved by breaking up generation services into a separate, more competitive segment of the industry while the transmission and distribution parts of the utility service largely remain a regulated monopoly service. Because of unbundling of services (generation vs. transmission and distribution), these services have to be priced separately on a customer’s bill.

Generally, in an electricity market, generators (generator owners) compete among each other to have an opportunity to supply electricity to serve load customers at the other end of the wires. However, the transmission and distribution parts of the system (electric power system) are not open for competition because it is generally believed that the wires business is subject to a natural monopoly behavior. A firm with natural monopoly enjoys significant economies of scale. It has to be properly regulated due to potential market power issues.

Therefore, the competition among generators is one of the key developments when the electric power industry was restructured. As a consequence, the analysis of the strategic interactions among the competing generators becomes an important subject to explore. These topics will be covered in more detail in later chapters. Natural monopoly part of the system, that is, transmission and distribution system, is still regulated because it will create more inefficiencies in the system if more than one firm are allowed to compete for wires business. One way to effectively regulate the network system is to form an independent entity that would control and operate the network only with or without the ownership of these facilities. While such entities may carry different names, such as independent system operator (ISO), transmission system operator (TSO), or regional transmission organization (RTO), the key functions of
these entities are essentially the same. The mandate of these entities is to operate and manage the network system in a fair, least-cost, and most-efficient manner so that generators can compete effectively on a level playing field. The primary goal of operating the network in such a manner is to increase the economic efficiency of the system, and thus increase the social welfare. However, there might be some variations among these system operators in the areas of ownership, non-profit or for-profit, financial and capital structures, and governance. The list here is not exhaustive, but just descriptive. These topics are beyond the scope of this book.

In the electricity market setting, electricity is treated as another commodity. However, electricity must be generated simultaneously with demand which constantly fluctuates. As a result, an additional capacity, called the reserve margin, must be available to compensate for planned and unplanned outages of generating plants as well as spikes in demand. In a sense, the unique characteristics of electricity provide challenges unlike any of the other industries that has been deregulated. Sometimes, some sort of intervention is needed to ensure adequate supply. There are some imperfections in the competitive wholesale market operations, so some kind of reforms or interventions are generally needed.

1.2 ELECTRICITY INDUSTRY RESTRUCTURING IN THE UNITED STATES

The electric power system in North America is divided into three large regions: Eastern Interconnection, Western Interconnection, and ERCOT Interconnection, where ERCOT stands for Electric Reliability Council of Texas, as shown in Figure 1.1. Each interconnection operates its own system with small ties to other interconnections. The nominal system frequency for the entire system, including all three interconnections, is 60 Hz.

1.2.1 Key Drivers for Electricity Industry Restructuring

It is generally believed that the following are the key reasons and drivers behind the electricity industry restructuring:

1. Technological changes
2. High electricity costs
3. Overall system inefficiencies
4. Higher environmental restrictions

Technological changes have been an important driver to allow the implementation of competitive schemes in an industry which had been historically considered as a natural monopoly. New technologies make it economical for competitors to provide
Electricity Markets

North American Electric Reliability Corporation Interconnections

Figure 1.1 Electric Power System in North America.

electric generation services to electricity consumers, particularly industrial customers, which were traditionally served by incumbent utilities. Legal authority given to large industrial users to bypass the local utility provided more impetus to the industry restructuring.

In large part, the action was prompted by the burden of having a higher or the highest electricity costs in the country, which created hardships for residential consumers and handicapped many businesses from competing on a “level playing field” with companies located outside the region. For example, New England was one of the first regions of the country to restructure the industry. The persistently high cost of electricity which put the region at a competitive disadvantage was another driving force behind the push for further competition in the generation sector.

Another key driver in restructuring efforts was the environmental protection whose goal is to reduce atmospheric emissions from generating electricity. More rigorous air emission standards and regulations led to the construction of new natural gas-fired
generating plants which, in turn, led to emission reduction and air-quality improvements. The new cleaner generators have displaced the older, inefficient, and polluting generating plants. Environmental protection rules, such as the Clean Air Act and subsequent federal rules along with the state’s air quality regulations led to increased environmental benefits. The key pollutants that caused global environmental issues are sulfur dioxide (SO$_2$) which is responsible for acid rain, nitrogen oxide (NO$_x$) which produces smog, and carbon dioxide (CO$_2$) which is one of the key drivers of global warming.

The main objective of industry restructuring was to create a fair and reliable market for competition in generating electricity while ensuring equal access to transmission grids. The other objectives were to achieve lower electricity rates and enhance economic growth. Once established, the wholesale market treats electricity as a commodity with prices set not by regulators, but by market rules and the balance between supply and demand.

### 1.2.2 Pre-Federal Energy Regulatory Commission Order 2000

Traditionally, the majority of the electric utilities in the United States is formed as investor-owned utilities (IOUs). Some utilities are owned by the federal government and some are owned by municipalities and cooperatives. The vertically integrated utilities are granted franchise areas with the exclusive right to provide electric service. In exchange for this monopoly right, almost every aspect of their business was regulated by state’s public utility commissions (PUCs) within their state boundaries. State PUCs set the operating standards for electric service, authorize the utilities to invest in new facilities such as power plants, transmission lines, or other equipments needed to meet their customer service obligations, and set the rates that customers pay for electricity service. Electric utilities are responsible for supplying electricity to load customers in their service territories.

The US Congress laid the groundwork for deregulating or restructuring wholesale electricity markets through provisions contained in the Public Utility Regulatory Policies Act of 1978 (PURPA). The Act mandated that regulated electric utilities provide a market for the output of non-utility generating (or power) plants that meet certain size, technology, and environmental criteria. Many state regulators required utilities to sign long-term power purchase contracts with small, independent PURPA generators at the utilities’ then-avoided costs. Power plants that were built pursuant to PURPA represented the beginning of a new class of generators called independent power producers (IPP). Furthermore, pursuant to the state-mandated integrated resource planning processes, regulators required utilities to compare the cost of utility-built generation with that from IPP’s generation and to take the least-cost alternative. This regulatory paradigm resulted in the maturation of the IPP industry across the country.
Electricity Markets

Thereafter, Congress passed the Energy Policy Act of 1992 which advanced the move to competition in wholesale markets. The Act gave Federal Energy Regulatory Commission (FERC) an authority to order utilities to provide transmission access to third parties in the wholesale electricity markets. This began the process of allowing open access to the existing transmission system to non-utility generators. This also created a condition in which there were increased competitions among generators owned by electric utilities and IPPs.

Subsequently, FERC issued Orders 888 and 889 in April 1996, which authorized open and equal access to all utilities’ transmission lines for all electricity producers, thus facilitating wholesale and retail restructuring. These orders called for an accurate calculation and posting of available transfer capability (ATC) and implementation of the Open Access Same-Time Information System (OASIS), requiring transmission owners to open their transmission systems to third parties, giving equal access and fairness to use their transmission facilities to transfer power. In addition to asserting federal jurisdiction over all transmission, FERC Order 888 states that transmission-owning utilities must charge competing utilities the same fees to use their transmission system as they charge themselves. For the most part, FERC sets the transmission rates for wholesale transactions among transacting parties.

A few independent system operators (ISOs) were established to help achieve these and other objectives, although most transmission systems continued to be operated by the owning utilities. The wholesale portion of the US electric power industry has been shaped by FERC major orders dealing with electricity transmission: FERC Order 888–889, and subsequently Order 2000.

1.2.3 Post-Federal Energy Regulatory Commission Order 2000

Despite the push by FERC orders towards more open and fair access to the nation’s transmission system, there were evidences that suggested that there were continued discrimination in the provision of transmission services by vertically integrated utilities against other users of their transmission system. This result may be impeding fully competitive electricity markets. That also implies that these orders failed to fully achieve what they were supposed to accomplish, that is, increased competitiveness of open electricity markets.

Frustrated by these outcomes, which are impediments to open competition, FERC later issued far-reaching “Order 2000” in December 1999 to push and expedite the development of efficient electricity markets by further calling for the formation of regional transmission organizations (RTOs) in various parts of the country. FERC Order 2000 requires FERC jurisdictional utilities to either file a plan by October 15, 2000, to establish an RTO whose function is to independently operate the transmission systems, or if a filing is not made, then each utility must explain why they are not making such a filing.
As envisioned by FERC, RTOs will implement and operate efficient electricity markets and also manage and operate the nation’s transmission grid. FERC believes that RTOs, if established, will bring about the following benefits: increased efficiency, improved congestion management, accurate estimates of total transfer capability (TTC) and ATC, efficient planning of transmission and generation, increased coordination among states, and reduced transaction costs. All of these benefits will help promote competition and efficiency in wholesale electricity markets. The major role of RTOs is to provide fair and reasonable access to the transmission network nationwide. In consequence, electricity consumers would be expected to pay the lowest price possible for reliable service. FERC Order 2000 is a defining moment in the history of electric power system in the United States.

### 1.2.4 Regional Transmission Organization

RTOs, as called for by FERC, must have four minimum characteristics:

1. Independence  
2. Scope and regional configuration  
3. Operational authority  
4. Short-term reliability

RTOs must also perform eight minimum functions:

1. Tariff administration and design  
2. Congestion management  
3. Parallel path flow  
4. Ancillary services  
5. OASIS and TTC/ATC  
6. Market monitoring  
7. Planning and expansion  
8. Interregional coordination

Under Order 2000, the formation of RTOs is voluntary, and their organizational form is quite flexible. RTOs can take the form as not-for-profit ISOs or for-profit TransCo models. The focus is on “characteristics” and “functions.” One of the salient characteristics is that the RTO must serve an appropriate region that must be of sufficient scope and regional configuration to permit the RTO to maintain reliability and effectively perform its required functions.

In general, RTO is a voluntarily formed entity that ensures comparable and non-discriminatory access by electric generators to regional electric transmission systems.
Electricity Markets

RTOs are governed in a manner that renders them independent of the commercial interests of power suppliers who may also own transmission facilities in the region. The RTO assumes operational control of the use of transmission facilities, administers a system-wide transmission tariff applicable to all market participants, and maintains short-term system reliability.

Based on these characteristics, FERC proposed three RTOs in the Eastern Interconnect region: one in the Midwest, one in the Northeast, and one in the Southeast. In the Northeast, FERC tried to facilitate the process of merging three existing ISOs: PJM, New York ISO (NYISO), and ISO New England (ISO-NE), although these efforts were ultimately terminated without achieving an integrated Northeastern RTO. In terms of “scope and regional configuration” characteristics, FERC has not defined geographical boundaries for RTOs, leaving it to the transmission owners to determine appropriate consolidations that are sufficiently regional in size and scope. To date, the FERC-approved RTOs include Midcontinent ISO (MISO), PJM, Southwest Power Pool (SPP), California ISO (CAISO), NYISO, and ISO-NE in the United States. The transmission grid that the ERCOT ISO administers is located solely within the state of Texas and is not synchronously interconnected to the rest of the United States. The transmission of electric energy occurring wholly within ERCOT is not subject to the Commission’s jurisdiction. The regional boundary map of RTOs/ISOs in the United States and Canada as of November 2015, is shown in Figure 1.2.

Figure 1.2 Map of Regional Transmission Organizations in North America. Source: http://www.ferc.gov/industries/electric/indus-act/rto.asp. Public domain.
1.2.5 Post-Regional Transmission Organization

In July 2002, FERC issued its Notice of Proposed Rulemaking on Standard Market Design (SMD NOPR), endorsing a market design that incorporates many of the best practices of the PJM and NYISO markets, such as locational marginal pricing (LMP) and congestion revenue rights (CRRs). An LMP scheme is currently used in PJM, NYISO, ISO-NE, and MISO markets. CRRs are also known as financial transmission rights (FTRs) in PJM and transmission congestion contracts (TCCs) in NYISO. The SMD policy includes far more implications for regional electricity markets than the previous RTO policy (Order 2000) on issues such as power rates, resource planning, and demand management.

FERC issued its NOPR on SMD to establish a uniform market structure and rules for emerging electricity markets. Any market participant who has to buy or sell electricity across two RTOs must currently follow two different tariffs, rules, and protocols. Inconsistent rules across the United States cause market inefficiency and raise costs for customers. FERC believes that SMD, if adopted, will create consistent market rules administered by fair and independent entities, no matter where the electricity is bought or sold. As a consequence, FERC expects SMD to lower costs to customers, to eliminate residual discrimination, to protect against potential market manipulation through market power mitigation measures and oversight, and to create incentives for investment in electric infrastructure, that is, transmission, generation, and demand-side resources with clear transmission policy and planning policies for grid expansion. The major requirements of FERC-proposed SMD are

1. Independent transmission provider (ITP)
2. Independent transmission companies (ITC)
3. Single transmission tariff
4. Long-term bilateral contract market
5. Day-ahead and real-time markets for energy and ancillary services
6. Regional transmission planning
7. LMP for congestion management
8. CRRs for tradable transmission rights
9. Market power monitoring and mitigation
10. Regional resource adequacy requirement
11. Role of states
12. Governance

However, on July 19, 2005, FERC issued an order terminating the SMD proceeding. This was partly due to the numerous criticisms about overreaching its federal
authority over various issues such as power rates, demand forecasting, resource planning, and demand-side management.

In the next sections, electricity industry restructuring in some countries in Latin America, Europe, and Asia are presented.

1.3 ELECTRICITY INDUSTRY RESTRUCTURING IN LATIN AMERICA

Electricity industries in Latin America have undergone an enormous transformation in the 1990s. Basically, three electricity markets were developed in the region: the Central American market, the Andean market, and the Common Market of the Southern Cone. The Southern Cone market is the largest market including Chile, Argentina, and Brazil. The electricity industry restructuring in these markets are briefly described below. The electricity market in Mexico was only recently developed.

1.3.1 Chile

Chile is known as the pioneer of electricity industry reform. Before the restructuring in 1980s, the electric power industry in Chile has a vertically integrated structure which is centrally planned and heavily regulated. The centralized planning and operation were replaced by market-oriented approaches by deregulation and privatization. The objective of electric restructuring is to establish conditions for economic efficiency and to attract private investments.

Chilean Ministry of Energy has jurisdictional authority over the electricity sector. It is responsible for plans, policies, and standards regarding the development of the energy sector. In addition, it grants concessions for hydroelectric power plants, transmission lines, and distribution areas. Under the Ministry of Energy, the Comisión Nacional de Energía (CNE) is a technical agency responsible for studying prices, tariffs, technical standards, and setting tariffs according to the applicable regulations, and generating the electrical infrastructure work plan.

As part of the electricity industry restructuring in Chile, a wholesale electricity market in which the generation sector was opened for competition was developed. The business of transmission and distribution is still regulated due to their monopolistic characteristics. The transmission system is open for access by any legitimate market participants. Network costs are socially allocated. The distribution system is regulated based on some incentives.

In this market environment, at least large electricity consumers are exposed to unregulated market prices while the smaller consumers are protected from price volatility with some pass through of wholesale market prices. The so-called Poolco model in which generators compete under centralized generation dispatch was introduced. The market utilizes two-part pricing schemes: energy pricing and capacity pricing. In energy pricing, short-term marginal cost of energy is used as part of nodal
pricing which considers both generation and transmission constraints. For capacity pricing, capacity payments are made to generators which make their capacities available in the yearly peak demand period (from May to September). The capacity payment depends on availability, start-time, and time to reach a full load energy production. The capacity price is defined by the regulator every 6 months based on the fixed cost of a typical gas-turbine generator.

In the energy market, financial (non-physical) bilateral contracts are also allowed. This is equivalent to the virtual bids which are eligible to participate in the electricity markets in the United States. The generation is centrally dispatched by Centro de Despacho Económico de Carga (CDEC). The economic dispatch is based on hourly marginal cost which is based on the variable costs of thermal generators. The variable cost of thermal generators are audited and hydro units are dispatched based on the cost of water estimated by CDEC. Economic transactions among generators are done based on marginal costs. It has entered into a second stage of reforms with public power purchase agreement (PPA) auctions in a private environment.

1.3.2 Argentina

Argentina began to reform its energy sector as part of a wider economic reform in the early 1990s. The long history of inefficient performance of state-owned utilities was one of the key drivers for the major transformation in the energy sector. The “Electricity and Natural Gas Acts” passed in the early 1990s paved the way for a new regulatory framework. Consequently, state-owned utilities were unbundled both horizontally and vertically as well as privatized. Wholesale markets for both electricity and natural gas were developed. The electricity industry is regulated by an authoritative regulatory body, Ente Nacional Regulador de la Electricidad (ENRE).

Private companies are allowed to participate in electricity generation which was open for competition while transmission and distribution parts of the system were still treated as regulated monopolies. The primary objectives of electricity restructuring in Argentina were to reduce electricity tariff, improve the quality of service, expand consumers’ choices, and improve the economic efficiency. Due to the significant investments in the generation sector and some investments in transmission in the late 1990s, the Argentinean electricity market was one of the most competitive markets globally. The Argentinean model becomes a benchmark for measuring the success of electricity restructuring throughout the world.

To facilitate the development of a wholesale electricity market, an independent system operator (ISO), known as Compañía Administradora del Mercado Mayorista Eléctrico S.A. (CAMMESA) was established. CAMMESA is both a market operator and a market administrator. It provides open access to the market and transmission system to every market participant and establishes market rules. Its main roles entail delivery coordination, responsibility for wholesale price setting, and management of the economic transactions done by Sistema Argentino De Interconexión (SADI) which is the main transmission system.
Electricity Markets

The Argentinean electricity market comprises of both forward (contract) market and spot market. In the forward market, generators and distributors or large users can negotiate freely and sign contracts for electricity which set both prices and quantities for future delivery. In real-time, the electricity users with firm contracts are given priority in the event of shortages provided that the contracted generator is available. In the spot market, energy prices are set hourly on each system node based on the short-run marginal cost. Nodal energy prices also reflect marginal losses produced by generation/load and transmission congestion with local (zonal) pricing. The market does not have transmission rights, such as FTR. Ancillary services are both regulated and market based. For example, generators are obligated to provide frequency regulation (primary and secondary). But, they can trade their obligations among themselves. To provide voltage support, each market participant has to have a sufficient level of reactive power. Deviations from standard operating levels are penalized. Payments for black start services are based on regulated price. Transmission companies are not allowed to trade energy.

1.3.3 Brazil

Restructuring of electric power industry in Brazil followed a similar pattern as those in other Latin American countries. Before the restructuring, electric utilities are owned by the national government, which guarantees a certain level of rate of return. This leads to overinvestment and inefficiencies in the system. Electric utilities own all sectors of the business: generation, transmission, distribution, and retailing. Financial crisis in 1999 led to the payment default of sectoral liabilities and shortage in investment. Brazil started its power sector reform in 1996. The key objectives of this reform are to (1) ensure supply through continuity of expansion, (2) maintain and improve efficiency, (3) provide better service and competitive price setting, (4) provide more choices for consumers, and (5) reduce government debt through nongeneration of new debts and asset privatization.

The new rules, set forth in the restructured environment, were designed to introduce competition in generation and retailing sectors. However, the wires part (transmission and distribution) was still regulated with provisions for open access due to its monopolistic nature. As the result of restructuring, a wholesale energy market was developed, along with an establishment of an independent system operator, Operador Nacional do Sistema Elétrico (ONS), to facilitate the competition. A regulatory agency, Agência Nacional de Energia Elétrica (ANEEL), was also established and most distribution utilities were privatized. The wires part is subject to revenue cap and yardstick competition. For generators and retailers which are exposed to competition, the return on investment is based on their ability to manage risk under stable market rules.

Under its wholesale energy market regime, both generation and transmission resources are centrally dispatched on the least-cost basis by the system operator. There were no market rules or mechanisms that allow generators and load to offer
and bid into the market based on price. Hydro units are dispatched based on their expected opportunity costs which are computed by a multistage stochastic optimization which models the detailed representation of hydro plant operation and inflow uncertainties. Bilateral contracts or other commercial arrangements are not considered in the centralized dispatch.

Market-clearing prices in the wholesale energy market are represented by short-run marginal costs calculated from the Lagrangian multipliers of the stochastic dispatch model. With any electricity market based on short-run marginal cost, the missing money problem is inevitable. In the missing money problem, a certain set of generators did not receive sufficient amount of revenues from the energy market to sustain their business viability. The revenue insufficiency for generators created by short-term spot price leads to an inability to provide sufficient incentives for new generation. In the Brazilian energy market, the prices are generally either volatile or very low due to the predominantly hydro system. The system marginal costs (spot prices) become low when there are surplus energy in the system, and become high when there is a very dry period or drought.

To encourage healthy entrance of new generation, a scheme based on mandatory bilateral contracts was introduced. First, all loads are required to be fully covered by power purchase agreements (PPAs). Second, these financial forward contracts must also be firmed up by actual generation capacity similar to firm energy from hydro plants. Therefore, such new contracts are used as a mandatory mechanism to secure energy supply for potentially growing load so as to facilitate the entry of new generators. To improve the long-term efficiency of the industry, those PPAs are also arranged through competitive auctions.

1.3.4 Mexico

The planned restructuring activity currently underway in Mexico is a prime example to show that more and more countries are interested in opening up their power industries to enjoy the economic benefits that can be potentially brought about by industry restructuring which encourages competition.

The new Law of the Electric Industry (Ley de la Industria Eléctrica), effective August 12, 2014, would allow the private sector to participate freely in the generation and sale of electricity while the electric grid will still be under the operational control of a state-owned agency. The new electric industry law will create a new wholesale electricity market (Mercado Eléctrico Mayorista) to be operated by the national energy control center, Centro Nacional de Control de Energía (CENACE), currently a unit within the federal commission, Comisión Federal de Electricidad (CFE). CENACE will also become the independent system operator for the entire grid. Mexican Ministry of Energy, Secretaría de Energía de México (SENER), and the regulatory authority, Comisión Reguladora de Energía (CRE) will have regulatory oversight and supervisory authority over the wholesale power market.
Electricity Markets

Under the new law, SENER crafted a draft regulation document on the guidelines for the electricity market, *Bases del Mercado Eléctrico*, and sent it to the Federal Commission for Regulatory Improvement (COFEMER) in February 2015. COFEMER is required to conduct a cost/benefit analysis of this new regulation. The guidelines establish the principles for the design and operation of the wholesale electricity market (WEM) including auction rules. All regulations before COFEMER are subject to public comment. After the review and decision by COFEMER, SENER will issue the final guidelines which will become a detailed plan for developing and operating an electricity market.

The key topics contained in the guidelines include staged implementation of the market, system reliability, market operation, operational planning, long-term markets, market monitoring, credit, and billings. The final guidelines will turn into the major protocols for the wholesale market operation. These protocols include (1) “Market Practice Manual” which will describe the principles for instructions and procedures for the administration, operation, and planning of the WEM, (2) “Operational Guidelines” which will include formulas and procedures that are contained in documents different from market practices manual, and (3) “Criteria and Procedures of Operation” which will include specifications, technical notes, and operating criteria required for the implementation of the constituent elements of the market rules in the design of software or daily operations. These protocols are collectively known as “Market Operational Provisions.” The Guidelines and Market Operational Provisions together constitute the Market Rules which is equivalent to the tariffs issued by ISO/RTOs in the United States.

Components of WEM to be governed by the market rules include (1) day-ahead market and real-time market for energy and ancillary services, (2) capacity market, (3) market for clean energy certificates, (4) auctions for medium-term energy, (5) auctions for long-term capacity, clean energy, and clean energy certificates, and (6) auctions for financial transmission rights.

The key feature of Mexican WEM is the phased implementation of its various market components. For example, energy and ancillary services market will be implemented in two phases. Phase one will include day-ahead and real-time markets, as well as import/export transactions but exclude demand bidding and virtual bidding. Phase one market is slated to be tested in September 2015 and be fully operational on December 31, 2015. Phase two will include hour-ahead market, demand bidding by controllable resources, and virtual bidding subject to offer validation by market surveillance unit. Both testing and operation of phase two will occur in 2018. Capacity market will have two phases (phase one operational in November 2015 and phase two operational in November 2016).

The general characteristics of Mexican wholesale electricity market are as follows. CENACE will determine the economic dispatch for the entire system after receiving offers/bids from sellers/buyers. Then for each system node, it will calculate the market prices (equivalent to LMPs) which will include system energy price, congestion price, and incremental loss price. Some ancillary services, such as regulation reserves,
spinning reserves, and operating reserves, will be competitively supplied through the market while reactive power, and black start will be regulated by CRE.

1.4 ELECTRICITY INDUSTRY RESTRUCTURING IN EUROPE

Much of the European continent is covered by the European Union (EU) which is a unique economic and political partnership among 28 European countries (now 27 after Britain’s referendum on June 23, 2016 to leave EU). According to the provisions of European Directive 96/92/EC and then replaced by the Directive 2003/54/EC, the reform of the electricity sector in the EU countries involved the unbundling of electricity generation and trading from the regulated activities of transmission and distribution. Once-monopolistic state-owned electric utilities were broken up to form separate generation and transmission/distribution companies. Competition in the generation sector was introduced while the wires business is still regulated. The primary objectives of industry reform are to establish a feasible and competitive wholesale electricity market which will provide electricity prices to both consumers and generators, guarantee the system security, and ensure an efficient utilization of the resources. The first European countries that embraced the industry reform were England and Wales, and Norway in the 1990s. After that period, almost all European countries have liberalized their power industry and developed their national electricity markets.

EU directives further advocated for gradual opening of national electricity markets to competition, development of common rules for the internal market (generation, transmission, and distribution), non-discriminatory third-party access to transmission networks, and non-discriminatory market-based solutions for cross-border capacity allocation. The directives also encouraged increasing share of electricity to be produced from renewable energy sources and increased trading for greenhouse gas emission allowances.

The electricity market in Europe is a collection of electricity markets in each individual country. Some countries such as Spain and Germany have full-fledged national markets while others are trying to gradually open up similar markets. In a typical national electricity market, the day-ahead market is cleared by matching supply offers and demand bids without considering any network-related constraints. This day-ahead market clearing is typically done by power exchanges. In real-time, the transmission system operators (TSOs) responsible for their respective operating territories schedule the generation according to the day-ahead market outcome. If there is any congestion in real-time by dispatching generation in such a way, the system operators will redispatch generators so as not to overload the system. As such, the system operators also operate the balancing markets (aka real-time markets) in which prices are determined in real-time. These prices form the basis for compensating some generators up for dispatching up and for compensating some generators down
Electricity Markets

for dispatching down. This model of market operation and system operation in European electricity markets is different from the US model in which the market clearing for both day-ahead/real-time markets and system operator functions are jointly done by a single entity. The generic function of the market operator is to facilitate the trading of electricity among sellers, buyers, and traders. This arrangement of electricity trading is generally done by power exchanges in European countries. The goal is to balance demand and supply as well as to discover the market prices for electricity. The reliable operation of the power system is the responsibility of an independent network operator (INO) or TSO.

Power exchanges are auction-based market-clearing mechanisms which generally operate a spot market which includes day-ahead and intraday markets. In the day-ahead auction market, trading of electricity takes place one day ahead for delivery of electricity the next day. Sellers, buyers, and traders of electricity submit their orders electronically, after which supply and demand are compared and the market price is calculated for each hour of the following day. The intraday market can be used to satisfy short-term needs of electricity or to sell short-term overcapacities. Hourly products and flexible block products can be traded. Power exchanges publish the power prices for their own regions and also allow trading of natural gas, coal, CO$_2$ emission allowances and their derivatives. In some countries, the transmission capacity allocation is managed in the power exchanges in an implicit fashion for congestion management.

The power exchanges in EU electricity markets include EPEX Spot (France, Germany, Austria, and Switzerland), APX (the United Kingdom, Netherlands, and Belgium), Nord Pool Spot (Nordic and Baltic region), OMIE (Iberian Peninsula), Omel (Spain), IPEX (Italy), and PXE (Central Europe). These power exchanges differ to some extent from country to country with respect to market design, regulatory framework, and the background of electricity industry.

EU is intent on pushing for integration of EU national electricity markets. In 2014, day-ahead power markets across 21 European nations were linked through a process known as market coupling. Market coupling is a mechanism for integrating markets which allows two or more wholesale electricity market areas (normally corresponding to a national territory) to be merged into a single market area, as long as there are sufficient transmission capacities available among those markets. With market coupling, the daily cross-border transmission capacities among the various areas are not sold separately (explicitly auctioned) among the market parties, but is implicitly made available via energy transactions on power exchanges on either side of the border (hence the term implicit auction). Buyers and sellers on a power exchange can match their bids and offers submitted via another power exchange as if it was as in one single market area, without the need to separately acquire the corresponding transmission capacities necessary to transport electricity between the two (or more) market areas.

The move was intended to smooth price differences among nations through better control of cross-border power flows. It allows traders to bid for energy on local
exchanges, which then automatically allocate cross-border capacity based on price differences with neighbors. It was believed that market coupling can lead to price convergence which can foster more competition. There were also plans to expand that market coupling to intraday markets as well as balancing markets in all EU nations.

Once the market clears and prices are announced, the TSO operates the power system based on the generation schedule determined from the market. For each national market, this step is done by the TSOs in each country. Typically, there is a single TSO for each country except Germany in which there are four TSOs responsible for different regional networks. European TSOs are entities operating independently from the other electricity market players and are responsible for the bulk transmission of electric power on the main high-voltage electric networks. TSOs provide grid access to the electricity market players (i.e., generating companies, traders, suppliers, distributors, and directly connected customers) according to the non-discriminatory and transparent rules. In order to ensure the security of supply, they also guarantee the safe operation and maintenance of the system. In many countries, TSOs are also responsible for the development of the grid infrastructure (system planning). For example, Swissgrid is the TSO in Switzerland while Réseau de Transport d’Électricité (RTE) is the TSO in France.

For the entire European transmission system, all TSOs form a larger pan-European entity called European Network of Transmission System Operator for Electricity (ENTSO-E). ENTSO-E was established and given legal mandates by the EU’s third legislative package for the internal energy market in 2009, which aims at further liberalizing the gas and electricity markets in the EU. However, the generation ownership in the EU internal electricity market is still concentrated in Endesa (Spain), Electrabel (Belgium), Vattenfall (Sweden), ENEL (Italy), E.ON and RWE (Germany), and EDF (France). The market design in the EU countries may have to be changed to accommodate the dual goals of energy supply increase from the renewable energy sources and decarbonization of electricity supply.

In the next sections, the development and status of three national markets—the United Kingdom, Nordic, and France—are presented.

1.4.1 The United Kingdom

The United Kingdom is comprised of four countries: England, Wales, Scotland, and Northern Ireland. Up until 1990, the electricity supply industry in England and Wales was under the government ownership. As a vertically integrated monopoly, the Central Electricity Generating Board (CEGB) owns and operates the generation and transmission, and sells electricity to 12 regional area boards (ABs). The regional entities were responsible for distributing and selling electricity to final consumers. In Scotland, there were two vertically integrated Boards: Scottish Power and Scottish and Southern. In Northern Ireland, the Northern Ireland Electricity (NIE) owns and operates an isolated system of transmission and distribution networks.
Electricity Markets

CEGB was a government-owned utility based on the model of cost-of-service. However, due to the excessive capital costs, high cost of indigenous coal, and low return on assets, the CEGB was restructured and privatized in 1990. It was believed that private ownership and profit motive can provide better incentives than state control approach. The restructuring in England and Wales also represented a model for power sector reform around the world.

Initially, the restructuring involved breaking up CEGB into a separate transmission-only company (National Grid), and three generation companies (National Power, PowerGen, and Nuclear Electric). A power pool was created and generation market was opened for free entry and competition. The market design of the British wholesale electricity market, known as the Power Pool is as follows. The system operator forecasts the demand for each 30-minute period 24 hours ahead. Generator owners submit bid of their choice to the Pool. Then, submitted bids are sorted from the lowest to the highest order and the highest bid needed to just meet the forecasted demand for each 30-minute period sets the pool price, as in uniform-price auction rule. Additionally, successful bidders are paid a capacity charge which can become significant if generation supply is just sufficient to meet the demand. Wholesale buyers must purchase their electricity requirement from the Pool and pay the Pool price including capacity payment and charges for ancillary services. External to the pool arrangement, bilateral contracts can be struck between any willing buyers and sellers of electricity. In fact, the bilateral contracts accounted for more than 90% of electricity consumption in this pool market design.

While customers with peak loads of more than 1 MW were able to choose their suppliers from 1990, customers with peak load of more than 100 kV were allowed to choose their suppliers from 1994. Since 1999, the remaining part of the electric system (below 100 kV peak load) was opened up for competition. Since that period of privatization, there are more than 30 major power producers operating in Great Britain at the end of 2013.

After privatization, the transmission company (National Grid) was owned by the 12 privatized regional electricity companies, but was floated on the stock exchange in 1995. National Grid has owned and operated the high-voltage transmission system in England and Wales linking generators to distributors and some large customers. The UK transmission system is linked to continental Europe via an interconnector to France under the English Channel. It also has an interconnection with the Netherlands under the North Sea since 2011.

There were some serious concerns about the Power Pool arrangement including high concentration in the generation market, low confidence in the Pool by wholesale buyers for their power purchases, and issue of price signals for the contract markets. For these and other reasons, the British government decided in 1997 to abandon the wholesale market design including the Power Pool that was implemented in 1990. In March 2001, the New Electricity Trading Arrangements (NETA) was introduced in England and Wales to replace the previous Power Pool with new ways to trade electricity. These arrangements were based on the bilateral trading between generators,
Introduction

suppliers, traders, and customers by matching among bids by buyers and sellers via open-access power exchanges (PXs). They were designed to be more efficient and provide greater choices for market participants, while maintaining the operation of a secure and reliable electricity system. The system included forwards and futures markets, a balancing mechanism to enable the National Grid, the transmission system operator, to balance the system, and a settlement process. In the balancing market, the system operator solicits more generator bids if the system-forecast demand is higher than demand bids by the buyers in PX or reduces generation output if the forecast demand is lower than the demand bids.

Up until March 2005, the electricity industry in Scotland, Northern Ireland, and England and Wales was operated independently although all three grid systems are interconnected by transmission ties. Since April 2005, under the British Electricity Trading and Transmission Arrangements (BETTA) introduced under the Energy Act of 2004, the electricity systems of England and Wales and Scotland were integrated. Under this arrangement, National Grid operates a single Great Britain transmission network including the Scottish transmission system.

The electricity supply industry in Northern Ireland has been in private ownership since 1993 with Northern Ireland Electricity (NIE) responsible for power procurement, transmission, distribution, and supply in the Province. Generation is provided by three private sector companies who own the four major power stations. In December 2001, the link between Northern Ireland’s grid and that of Scotland was inaugurated. A link between the Northern Ireland grid and that of the Irish Republic was re-established in 1996 to facilitate the transfer of electricity between the two countries. However, on November 1, 2007, the two grids were fully integrated and a joint body “Single Electricity Market Operator (SEMO)” was set up by System Operator for Northern Ireland (SONI) and Eirgrid from the Republic of Ireland to oversee the new single market. In July 2012, an interconnector between the Irish Republic and Wales began operations.

In 1989, a new regulatory office known as the Office of Electricity Regulation (Offer) was formed to regulate the electricity businesses in the United Kingdom. In 2000, it was merged with the Office of Gas Regulation (Ofgas) to form the new Office of Gas and Electricity Markets (Ofgem). Ofgem is an independent national regulatory authority and regulates both gas and electricity industries. The primary role of this office is to protect the interests of existing and future consumers of electricity and gas in the United Kingdom while promoting competition. This regulatory body has a similar role as FERC in the United States.

1.4.2 Nordic Countries

Norway was the first of the Nordic countries to deregulate its power markets. The Energy Act of 1990 formed the basis for deregulation in the other Nordic countries. In 1991, Norwegian Parliament’s decision to deregulate the market for trading of
electricity energy went into effect. Two years later, Statnett Marked AS, a fully owned subsidiary of Statnett, was established as an independent company with the goal of providing neutrality and impartiality in operating the electricity market. Total volume in the first operating year was 18.4 TWh, at a value of 1.55 billion Norwegian Krone (NOK). The new framework for an integrated Nordic power market contracts was made to the Norwegian Parliament in 1995. Together with Nord Pool’s license for cross-border trading, given by the Norwegian Water Resources and Energy Administration, this framework laid the foundation for spot trading at Nord Pool. A year later, a joint Norwegian–Swedish power exchange was established. The exchange was renamed Nord Pool ASA.

Finland joined Nord Pool ASA in 1998. A year later, Elbas was launched as a separate market for balance adjustment in Finland and Sweden. Elspot area trade began July 1, the same year. The Nordic market became fully integrated as Denmark joined the exchange in 2000. In 2002, Nord Pool’s spot market activities were organized in a separate company, Nord Pool Spot AS. Eastern Denmark joined the Elbas market in 2004.

In 2005, Nord Pool Spot opened the Kontek bidding area in Germany, which geographically gives access to the Vattenfall Europe Transmission control area. The following year, Nord Pool Spot launched Elbas in Germany. The Western Denmark joined the Elbas market in 2007. The new Elspot trading system, SESAM, was set into production. 2008 saw the highest turnover and market share recorded in the company’s history until then. In 2009, Norway joined the Elbas intraday market. The European Market Coupling Company relaunched the Danish–German market coupling on November the same year. Nord Pool Spot implemented a negative price floor in Elspot.

In 2010, Nord Pool Spot and NASDAQ OMX Commodities launched the UK market N2EX. Nord Pool Spot opened a bidding area in Estonia and delivered the technical solution for a new Lithuanian market place. Bidding area was opened in Lithuania by Nord Pool Spot in 2012 while Elspot bidding area was opened in Latvia in 2013.

In 2011, Elbas was licensed to APX and Belpex as the intraday market in the Netherlands and Belgium, respectively. Intraday market, Elbas, was introduced in both Latvia and Lithuania in 2013. Nord Pool Spot took sole ownership of the UK market in 2014. North-Western European power markets were coupled. In 2015, Nord Pool Spot was appointed Nominated Electricity Market Operator (NEMO) across 10 European power markets: Austria, Denmark, Estonia, Finland, France, GB, Latvia, Lithuania, the Netherlands, and Sweden. Nord Pool Spot was rebranded to Nord Pool in 2016. Nord Pool was appointed NEMO in Bulgaria and Germany. Nord Pool has worked with Independent Bulgarian Energy Exchange (IBEX) in opening the Bulgarian day-ahead power market, on January 19, 2016, that will be extended with an intraday market at a later stage. Nord Pool has also worked with Croatian Power Exchange (CROPEX) in launching the day-ahead power market in Croatia on
February 10, 2016. The new CROPEX day-ahead market was operational as a part of the EU-wide multiregional coupling (MRC).

1.4.3 France

The electricity market in France is used to illustrate another example of a national electricity market. In France, the transmission system is owned and operated by French transmission system operator, Réseau de Transport d’Electricité (RTE). It also operates a balancing mechanism and cross-border capacity allocation mechanism. In the balancing mechanism, RTE ensures supply–demand balance in real-time, guarantees sufficient operating reserves, and resolves network congestions. France has transmission ties with England (the United Kingdom), Spain, Belgium, Germany, Switzerland, and Italy. Therefore, France is one of the keystone countries for European electricity network and market. Its generation mix is dominated by nuclear technology followed by hydro and coal. Also, France is, primarily, an exporter of electricity to its neighboring countries because of its cheaper supply of electricity.

French electricity market was gradually opened since 1999 with portions of load becoming eligible for participation in the market. In July 2007, all of the loads participated in the entire market. Generation supply is also dominated by Électricité de France (EDF) which is mostly owned by the French government. EDF generation made up of about 75–80% of total generation supply in France. The rest of electricity supply came from other competing suppliers. Therefore, the generation market is highly concentrated. In the wholesale market, trading of power is done using bilateral contracts and via power exchanges. The energy industry including both electricity and gas industries, is regulated by an independent regulatory body known as Commission de Régulation de l’Énergie (CRE) which was created in 2000.

1.5 ELECTRICITY INDUSTRY RESTRUCTURING IN ASIA

The most notable electricity market in Asia is the well-developed electricity market in South Korea. Singapore also has a well-developed market while Japan and China are planning to establish such a market.

1.5.1 South Korea

In 1999, the South Korean government set up the “Basic Plan” for the electricity industry restructuring. The basic plan includes implementations of three phases: (1) “Cost-Based Pool” (CBP) (2000–2002), (2) “Two-Way Bidding Pool” (TWBP) (2003–2008), and (3) retail competition (since 2009). In addition to designing the
Electricity Markets

basic plan for the implementation of the CBP market, the operating system for market is designed, and resource scheduling and commitment (RSC) are introduced. The flagship organization, known as Korea Power Exchange (KPX) was established in 2000. Operation of the simulated CBP market was started. At the end of 2000, the Korean government enacted the revised “Electricity Business Act (EBA)” to implement the electricity industry restructuring.

In April 2001, Korean Electricity Regulatory Commission (KOREC) was established under the ministry of commerce, industry and energy (MOCIE), now ministry of trade, industry and energy (MOTIE). The major responsibilities of KOREC include creating a fair and competitive environment for electricity companies by creating standards and rules for the electricity industry, supervising electric companies so that they abide by the rules, resolving disputes among market participants (generator companies and consumers), monitoring and investigating anti-competitive behavior of market participants, enforcing corrective measures for market rule violations, and introducing competition via the restructuring of power industry and review issues related to the rights of electricity consumers.

In 2001, electricity market rules and detailed guidelines were approved by MOCIE. KPX acquired establishment permission and the wholesale electricity market was officially opened on April 2, 2001. The market has the following characteristics that are designed to minimize the restructuring risks that appeared in the initial stages of the market as well as to stimulate more competition.

First, all electricity traders are obligated to participate in the electricity market (pool) in accordance with the EBA’s article 31. However, EBA’s article 8 allows some exception for these generating companies which have power purchase agreements (PPA) with the Korea Electric Power Corporation (KEPCO). These companies can provide power to KEPCO without trading through the pool. The Act also approves financial contracts for differences (CfD) for market participants who seek to avoid risks.

Second, the Korean electricity market has paid different trading settlements depending on the generator types to stabilize market prices since its opening. The initial market has two sub-markets: “baseload market” and “non-baseload market.” The rationale behind this distinction between two such sub-markets was that power generators such as nuclear and coal-fired units can be generally classified into baseload generators which have high fixed costs but low variable costs. On the other hand, generators such as LNG and oil-fired units can be classified into non-baseload generators which have low fixed costs but high variable costs. While baseload generators can maintain stable prices because they are less affected by external factors such as fuel prices and foreign exchange rates, non-baseload generators are more susceptible to such variables. The two-tier pricing system was implemented in 2000 when the baseload plants accounted for 81% of total capacity while the non-baseload generators accounted for the rest. Under such circumstances, pricing based on uniform pricing system (e.g., system marginal price, SMP) could trigger volatility in the wholesale electricity market because prices can swing significantly if non-baseload generators,
affected by external factors, set the market price. That can also impact the profitability of generator owners, such as KEPCO and other IPPs.

In 2007, a new form of regulated baseload market price program was introduced in place of abolishing baseload marginal price (BLMP) program. The capacity price of the baseload plants was reduced to the level of non-baseload generators in the same year. In 2008, the regulated baseload market was revised again and thus the two-tier pricing system (baseload and non-baseload) was improved into a single SMP. However, the two-tier pricing structure has been technically maintained by applying the SMP coefficient to the generators which are practically owned by KEPCO, which has over 50% of generator market share. In 2012, the target generators to stabilize market prices started including the coal-fired centrally dispatched generators of private companies. In 2013, the “soft price cap” rule was established to set price cap as the reference price for capacity price and to adjust the settlements by applying the lower price between the market price and the price cap.

Third, generators are mandated to provide ancillary services in accordance with dispatch instructions from KPX. By market rules, scheduled generators must provide ancillary services such as automatic generation control (AGC), governor-free, reasonable reserve margin, reactive power supply, black starts and others which are not compensated during the initial state of market operation. Practical ancillary services settlements were prepared in May 2002, and by readjusting the compensation of governor-free and AGC, actual settlement standards were set up in September 2006. These standards were intended to support the stable operation of power system by properly compensating generators which provide required ancillary services to the system.

Fourth, the operational mode of pumped-storage generators has significant effect on both system and market operations. Thus, the operation of pumped-storage generators has been steadily improved to minimize the operational cost and stabilize the system operation in the market. Consequently, the rules on “price setting scheduling (PSE)” and settlement methods of pumped-storage generators were revised in the electricity market rules in 2011 and 2012. In the new rule, both generation capacity and pumping demand of pumped-storage generators were considered in scheduling PSE. Generators are also encouraged to optimize the operation of their pumped-storage generators. The goal is to minimize the operational cost of the system, strengthen the market price signal and enhance the market efficiency.

Trading payments in the electricity market consists of capacity payments (CP), scheduled-energy-trading payments (SEP), and uplift settlement charges. A SEP is settled in the market for the energy actually generated in accordance with the quota allotted in the PSE. The uplift settlement is the difference between the settlement based on the PSE that does not consider network or generator constraints and the actual settlement made as a result of secure power system operation. It is composed of constrained-on (CON) that is not allocated in the PSE, but generated by power system constraints and constrained-off (COFF) that is allotted in the PSE, but not generated by power system constraints. Capacity payment is made based on the generators’
Electricity Markets

availability declared by power producers until 1 day before the trading day. Capacity price reflects the investment cost and fixed cost of operating the generators. The reference capacity price is annually decided by selecting a standard power plant and calculating the capacity price applicable to that standard power plant.

The Korean electricity market is operated by the following procedures: assessment of power generation costs, system demand forecast, bidding, setting up PSE, determination of SMP, set up of generation schedule, real-time generation including CON and COFF, metering, and settlements. The key feature of Korean electricity market is that it is a CBP where generators are only allowed to bid quantity but not price. Therefore, variable cost curves have to be calculated for setting the market price. As the variable costs cannot be accurately identified in real-time, the actual variable costs are determined a month earlier by assessing the variable cost factors of each power plant.

One day before a trading day, KPX forecasts demand for the next day on hourly basis. Bidding is open until the 10:00 a.m. of the previous day of the trading day. Unlike other electricity markets that allow for bidding both supply quantity and price simultaneously, the bidders in the CBP can bid only the hourly availability of their generators. The PSE is determined based on demand forecast, cost per generator, and availability information of generators to meet system demand at the least-cost. At this stage, only the technical characteristics of power generators are considered while ignoring other constraints such as transmission constraints, heating supply constraints, fuel constraints, and others. Then, the SMP is set by hourly marginal costs based on the PSE. The final SMP is announced by 3:00 p.m. 1 day before the trading day. The real-time operation schedule for the actual power system on the trading day is determined after considering several system constraints such as transmission and fuel constraints while meeting the system demand at the least-cost. On the trading day, power is generated and delivered based on real-time system conditions. Then, the amount of generation by each generator is measured in real-time and settled by the hourly market price.

1.6 RELIABILITY AS A PARAMOUNT GOAL

The single most important purpose of the power system operation is to supply and deliver electricity to final consumers in a reliable manner. At the same time, this must be done in the least-cost manner. This is easier said than done because power system has many components which have complex relationships and intricate dependencies among each other. Sometimes, the degree of interdependencies among these components is such that a failure of a single system element can lead to a failure of the entire system. For example, a failure of a single element can trigger the failures of multiple elements causing a phenomenon known as cascading failure. The loss of power in certain portions of the system is called brownout. The loss of power triggered by the failure or collapse of the entire power system is known as blackout. The blackout is
Introduction

the ultimate system condition that must be avoided at all possible, but not necessarily at all cost.

In the case of a failure of a single system element, this failed element must be removed or isolated from the system as soon as possible before that particular failure triggers the chain reaction to the rest of the system. The goal is to maintain the integrity of the rest of the system. The time needed to remove this failed element can be a few seconds. Automated removal mechanism using sophisticated relays can do this job. After the first isolation, relays will try to reconnect it with the rest of the system after a few seconds. If the failed element cannot be reconnected properly after some attempts, it will be disconnected until the root cause of the problem is identified and resolved by other means.

Unfortunately, any element in the system can fail at any time for any reason. Those elements include a branch of a transmission line, a synchronized generator, a transformer, or other system equipment. System reliability is comprised of two aspects: security and adequacy. The security of the power system is the ability of the system to withstand a disturbance, large and small, due to failures of some system components. After the disturbance, the system must be restored back to a steady-state condition. Only then, we can say that the system is reliably secure.

Reliable operation of a power system also requires another condition in which the generation resources are sufficiently available. This condition is known as resource adequacy or simply adequacy. It is a prerequisite condition for the reliable operation of power system. If the available generation resources are not adequate, it would be extremely challenging, if not impossible, to reliably operate the system. Rolling brownouts or blackout can be inevitable for a system with inadequate resources. Such resources can also be a reliable import power from the neighboring systems. In general, import power are less reliable than the generation resources owned and dispatchable by the system. On the other hand, for a system with more than adequate resources, it would be much easier to manage the system and reliable system operation is certainly achievable.

Often times, the status of the transmission network is not given full attention. In fact, having more than enough generation resources is a necessary but insufficient condition. The adequate resources must be complemented by a robust network structure. If the network structure is not robust, power cannot be reliably delivered to final consumers even if there are adequate resources. The weak network structure can cause transmission bottlenecks which will prevent the low-cost power to reach to all final consumers. As a consequence, the reliability of the system can be in peril.

The ever-changing nature of the availability of generation resources and to some extent that of the network structure availability would only make the task of power system operation ever more challenging. This would be a continuous test for the power system operator to get prepared and overcome those challenges so as to deliver electricity to consumers in both reliable and least-cost manners.

So, how much should be spent to achieve an absolutely reliable operation of the system and possibly avoid the blackout at all times? There is no easy answer to this
Electricity Markets

question. If there is any answer, it would largely depend on how much that society is willing to spend to achieve this purpose. On the other hand, is it really worth to spend exorbitant amount of money to achieve a 100% system reliability? In the next section, we will discuss how to achieve this goal via a market mechanism.

1.6.1 Reliability via the Electricity Market Mechanism

How can an electricity market help achieve the goal of reliable operation of a power system? The answer to this question depends on how the market is structured in a particular system. Again, the ultimate goal of the power system operation is to supply and deliver the electricity to final consumers in a reliable manner. How about the cost or economics of supplying that power? The better goal should be the reliable operation of power system in the most economic manner. How can we achieve this?

In a traditional vertically integrated structure, this decision is made by each individual utility which owns the entire supply chain. Under an electricity market structure, the generation sector is open for competition. The underlying theory is that increased economic efficiency can be achieved if the generation sector is exposed to competition and thus, the cost of electricity generation can be lowered. However, with additional structure of electricity market, the complexity of the system also increased because there is one more layer of structure called electricity market operation. In a simple term, the function of an electricity market is to solicit offer/bid from generator/load and determine which set of generators should serve the load and hence must be scheduled for specific market periods. As part of this step, market prices are also determined which would become the basis for determining generator revenues and load payments. The key here is the generation schedule. A traditional utility also determines this generation schedule for its generators in its own operating area. An electricity market also determines similar generation schedule for its own system. So, what is the difference? The key difference lies in how this set of generation schedule is determined. In a utility setting, it is determined by its own decision-making process without much competitive pressures. In a market setting, it is determined by market forces. Some sort of optimization algorithms are used in both settings to determine that generation schedule, called optimal generation schedule or optimal schedule.

Once the generation schedule is finalized, the next step is for the system operator to operate the system based on this unique set of generation schedule for specific market periods. It is assumed that competitive pressures and market forces would eventually keep the cost of generation closer to the marginal cost of generation. Only then, we can say that the system is economically short-run efficient because the electricity market is competitive. In fact, electricity markets are responsible only for the cost or economics of scheduling generators, while the system operation takes care of system reliability. Some electricity markets, at least those in the United States, consider and model the network constraints when finding the optimal schedules and determining the market prices. Most power exchanges in Europe do not consider the network
Introduction

1.7 FURTHER DISCUSSIONS

For many countries, the restructuring of the electric power system and development of electricity markets are still a work-in-progress. Those countries which have made significant progresses are facing new challenges. These progresses are not without setbacks. Sometimes, external factors, such as national economic condition, can cause significant impact on the successful operation of the electricity market. Many have learned from the trials and errors and have moved forward. In retrospect, no two countries have walked the exact path of restructuring. On the other hand, there are other countries which are seriously considering to restructure their power industries and develop electricity markets. For those countries, there are already many lessons that can be learned. These countries can develop better functioning electricity markets by avoiding some obvious mistakes made by their predecessors.

Based on the free market theory, opening up the generation sector to competition can certainly improve the economic efficiency of the system. However, there are significant costs associated with any major activity such as establishing an electricity market. The benefits, realized or perceived, should outweigh the cost to merit such an endeavor.

The other interesting questions would be: can the market sustain itself? In other words, can a market support a condition in which sufficient number of generators are always available to maintain system reliability? If not, what other options do we have?

CHAPTER END PROBLEMS

1.1 The footprint of the operating electricity markets in the United States does not cover the entire country. Some areas of the country do not have operating electricity markets. What are the drivers for these regions not to pursue the path of developing electricity markets? Are the basis of these drivers related to legal, economic, technical or other issues?

1.2 For power utilities owned by national governments, privatization of that national power company is the first step before the generation sector is open for competition which will eventually lead to full-fledged electricity market. Is this condition strictly necessary for successful restructuring of the industry?

1.3 How can we measure whether the activity of restructuring an electric power industry achieved its stated purpose?

1.4 What are the new challenges faced by the more advanced electricity markets such as those in the United States or Europe? State one challenge and describe the potential solution.
FURTHER READING