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Power System Planning (Reliability)

Gerald B. Sheblé
Iowa State University

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Gerald B. Sheblé
Iowa State University

Alireza Khotanzad
Southern Methodist University

N. Dag Reppen
Niskayuna Power Consultants, LLC

James W. Feltes
Power Technologies

Hyde M. Merrill
Merril Energy, LLC

Richard E. Brown
ABB Power T&D Company

13.1 Planning

Gerald B. Sheblé

Capacity expansion decisions are made daily by government agencies, private corporations, partnerships, and individuals. Most decisions are small relative to the profit and loss sheet of most companies. However, many decisions are sufficiently large to determine the future financial health of the nation, company, partnership, or individual. Capacity expansion of hydroelectric facilities may require the commitment of financial capital exceeding the income of most small countries. Capacity expansion of thermal fossil fuel plants is not as severe, but does require a large number of financial resources including bank loans, bonds for long-term debt, stock issues for more working capital, and even joint-venture agreements with other suppliers or customers to share the cost and the risk of the expansion. This section proposes several mathematical optimization techniques to assist in this planning process. These models and methods are tools for making better decisions based on the uncertainty of future demand, project costs, loan costs, technology change, etc. Although the material presented in this section is only a simple model of the process, it does capture the essence of real capacity expansion problems.

This section relies on a definition of electric power industry restructuring presented in (Sheblé, 1999). The new environment within this work assumes that the vertically integrated utility has been segmented into a horizontally integrated system. Specifically, GENCOs, DISTCOs, and TRANSCOs exist in place of the old. This work does not assume that separate companies have been formed. It is only necessary that comparable services are available for anyone connected to the transmission grid.

As can be concluded, this description of a deregulated marketplace is an amplified version of the commodity market. It needs polishing and expanding. The change in the electric utility business environment is depicted generically below. The functions shown are the emerging paradigm. This work outlines the market organization for this new paradigm.

Attitudes toward restructuring still vary from state to state and from country to country. Many electric utilities in the U.S. have been reluctant to change the status quo. Electric utilities with high rates are very reluctant to restructure since the customer is expected to leave for the lower prices. Electric utility companies in regions with low prices are more receptive to change since they expect to pick up more customers. In 1998, California became the first state in the U.S. to adopt a competitive structure, and other states are observing the outcome. Several states on the eastern coast of the U.S. have also restructured. Some offer customer selection of supplier. Some offer markets similar to those established in the United Kingdom, Norway, and Sweden, but not Spain. Several countries have gone to the extreme competitive position of treating electricity as a commodity as seen in New Zealand and Australia. As these markets continue to evolve, governments in all areas of the world will continue to form opinions on what market, operational, and planning structures will suit them best.

Defining a Competitive Framework

There are many market frameworks that can be used to introduce competition between electric utilities. Almost every country embracing competitive markets for its electric system has done so in a different manner. The methods described here assume an electric marketplace derived from commodities exchanges like the Chicago Mercantile Exchange, Chicago Board of Trade, and New York Mercantile Exchange (NYMEX) where commodities (other than electricity) have been traded for many years. NYMEX added electricity futures to their offerings in 1996, supporting this author's previous predictions (Sheblé, 1991; 1992; 1993; 1994) regarding the framework of the coming competitive environment. The framework proposed has similarities to the Norwegian-Sweden electric systems. The proposed structure is partially implemented in New Zealand, Australia, and Spain. The framework is being adapted since similar structures are already implemented in other industries. Thus, it would be extremely expensive to ignore the treatment of other industries and commodities. The details of this framework and some of its major differences from the emerging power markets/pools are described in Sheblé (1999).

These methods imply that the ultimate competitive electric industry environment is one in which retail consumers have the ability to choose their own electric supplier. Often referred to as retail access, this is quite a contrast to the vertically integrated monopolies of the past. Telemarketers are contacting consumers, asking to speak to the person in charge of making decisions about electric service. Depending on consumer preference and the installed technology, it may be possible to do this on an almost real-time basis as one might use a debit card at the local grocery store or gas station. Real-time pricing, where electricity is priced as it is used, is getting closer to becoming a reality as information technology advances. Presently, however, customers in most regions lack the sophisticated metering equipment necessary to implement retail access at this level.

Charging rates that were deemed fair by the government agency, the average monopolistic electric utility of the old environment met all consumer demand while attempting to minimize their costs. During natural or man-made disasters, neighboring utilities cooperated without competitively charging for their assistance. The costs were always passed on to the rate payers. The electric companies in a country or continent were all members of one big happy family. The new companies of the future competitive environment will also be happy to help out in times of disaster, but each offer of assistance will be priced recognizing that the competitor's loss is gain for everyone else. No longer guaranteed a rate of return, the entities participating in the competitive electric utility industry of tomorrow will be profit driven.

Preparing for Competition

Electric energy prices recently rose to more than $7500/MWh in the Midwest (1998) due to a combination of high demand and the forced outage of several units. Many midwestern electric utilities bought energy at that high price, and then sold it to consumers for the normal rate. Unless these companies thought they were going to be heavily fined, or lose all customers for a very long time, it may have been more fiscally responsible to terminate services.

Under highly competitive scenarios, the successful supplier will recover its incremental costs as well as its fixed costs through the prices it charges. For a short time, producers may sell below their costs, but will need to make up the losses during another time period. Economic theory shows that eventually, under perfect competition, all companies will arrive at a point where their profit is zero. This is the point at which the company can break even, assuming the average cost is greater than the incremental cost. At this ideal point, the best any producer can do in a competitive framework, ignoring fixed costs, is to bid at the incremental cost. Perfect competition is not often found in the real world for many reasons. The prevalent reason is *technology change*. Fortunately, there are things that the competitive producer can do to increase the odds of surviving and remaining profitable.

The operational tools used and decisions made by companies operating in a competitive environment are dependent on the structure and rules of the power system operation. In each of the various market structures, the company goal is to maximize profit. Entities such as commodity exchanges are responsible for ensuring that the industry operates in a secure manner. The rules of operation should be designed by regulators prior to implementation to be complete and "fair." *Fairness* in this work is defined to include noncollusion, open market information, open transmission and distribution access, and proper price signals. It could call for maximization of social welfare (i.e., maximize everyone's happiness) or perhaps maximization of consumer surplus (i.e., make customers happy).

Changing regulations are affecting each company's way of doing business and to remain profitable, new tools are needed to help companies make the transition from the old environment to the competitive world of the future. This work describes and develops methods and tools that are designed for the competitive component of the electric industry. Some of these tools include software to generate bidding strategies, software to incorporate the bidding strategies of other competitors, and updated common tools like economic dispatch and unit commitment to maximize profit.

Present View of Overall Problem

This work is motivated by the recent changes in regulatory policies of interutility power interchange practices. Economists believe that electric pricing must be regulated by free market forces rather than by public utilities commissions. A major focus of the changing policies is "competition" as a replacement for "regulation" to achieve economic efficiency. A number of changes will be needed as competition replaces regulation. The coordination arrangements presently existing among the different players in the electric market would change operational, planning, and organizational behaviors.

Government agencies are entrusted to encourage an open market system to create a competitive environment where generation and supportive services are bought and sold under demand and supply market conditions. The open market system will consist of generation companies (GENCOs), distribution companies (DISTCOs), transmission companies (TRANSCOs), a central coordinator to provide independent system operation (ISO), and brokers to match buyers and sellers (BROCOs). The interconnection between these groups is shown in Fig. 13.1.

The ISO is independent and a dissociated agent for market participants. The roles and responsibilities of the ISO in the new marketplace are yet not clear. This work assumes that the ISO is responsible for coordinating the market players (GENCOs, DISTCOs, and TRANSCOs) to provide a reliable power system functions. Under this assumption, the ISO would require a new class of optimization algorithms to perform price-based operation. Efficient tools are needed to verify that the system remains in operation

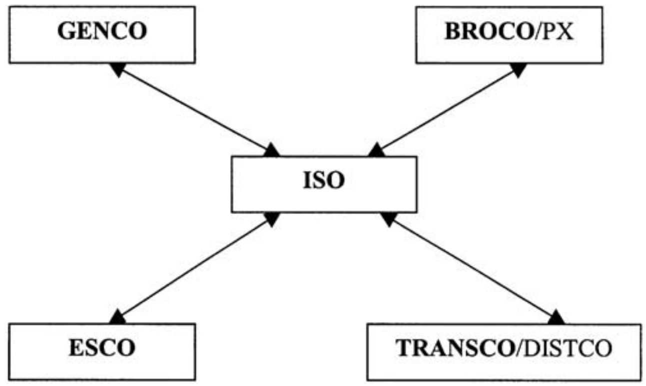

FIGURE 13.1 New organizational structure.

with all contracts in place. This work proposes an energy brokerage model for all services as a novel framework for price-based optimization. The proposed foundation is used to develop analysis and simulation tools to study the implementation aspects of various contracts in a deregulated environment.

Although it is conceptually clean to have separate functions for the GENCOs, DISTCOs, TRANSCOs, and the ISO, the overall mode of real-time operation is still evolving. Presently, two possible versions of market operations are debated in the industry. One version is based on the traditional power pool concept (POOLCO). The other is based on transactions and bilateral transactions as presently handled by commodity exchanges in other industries. Both versions are based on the premise of price-based operation and market-driven demand. This work presents analytical tools to compare the two approaches. Especially with the developed auction market simulator, POOLCO, multilateral, and bilateral agreements can be studied.

Working toward the goal of economic efficiency, one should not forget that the reliability of the electric services is of the utmost importance to the electric utility industry in North America. In the words of the North American Electric Reliability Council (NERC), reliability in a bulk electric system indicates "*the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.*" The council also suggests that reliability can be addressed by considering the two basic and functional aspects of the bulk electric system — adequacy and security. In this work, the discussion is focused on the adequacy aspect of power system reliability, which is defined as the static evaluation of the system's ability to satisfy the system load requirements. In the context of the new business environment, market demand is interpreted as the system load. However, a secure implementation of electric power transactions concerns power system operation and stability issues:

1. *Stability issue*: The electric power system is a nonlinear dynamic system comprised of numerous machines synchronized with each other. Stable operation of these machines following disturbances or major changes in the network often requires limitations on various operating conditions, such as generation levels, load levels, and power transmission changes. Due to various inertial forces, these machines, together with other system components, require extra energy (reserve margins and load following capability) to safely and continuously actuate electric power transfer.
2. *Thermal overload issue*: Electrical network capacity and losses limit electric power transmission. Capacity may include real-time weather conditions as well as congestion management. The impact of transmission losses on market power is yet to be understood.
3. *Operating voltage issues*: Enough reactive power support must accompany the real power transfer to maintain the transfer capacity at the specified levels of open access.

In the new organizational structure, the services used for supporting a reliable delivery of electric energy (e.g., various reserve margins, load following capability, congestion management, transmission losses, reactive power support, etc.) are termed supportive services. These have been called "ancillary services" in the past. In this context, the term "ancillary services" is misleading since the services in question are not ancillary but *closely bundled* with the electric power transfer as described earlier. The open market system should consider all of these supportive services as an integral part of power transaction.

This work proposes that supportive services become a competitive component in the energy market. It is embedded so that no matter what reasonable conditions occur, the (operationally) centralized service will have the obligation and the authority to deliver and keep the system responding according to adopted operating constraints. As such, although competitive, it is burdened by additional goals of ensuring reliability rather than open access only. The proposed pricing framework attempts to become economically efficient by moving from cost-based to price-based operation and introduces a mathematical framework to enable all players to be sufficiently informed in decision-making when serving other competitive energy market players, including customers.

Economic Evolution

Some economists speculate that regional commodity exchanges within the U.S. would be oligopolistic in nature (having a limited numbers of sellers) due to the configuration of the transmission system. Some postulate that the number of sellers will be sufficient to achieve near-perfect competition. Other countries have established exchanges with as few as three players. However, such experiments have reinforced the notion that collusion is all too tempting, and that market power is the key to price determination, as it is in any other market. Regardless of the actual level of competition, companies that wish to survive in the deregulated marketplace must change the way they do business. They will need to develop bidding strategies for trading electricity via an exchange.

Economists have developed theoretical results of how variably competitive markets are supposed to behave under varying numbers of sellers or buyers. The economic results are often valid only when aggregated across an entire industry and frequently require unrealistic assumptions. While considered sound in a macroscopic sense, these results may be less than helpful to a particular company (not fitting the industry profile) that is trying to develop a strategy that will allow it to remain competitive.

Generation companies (GENCOs), energy service companies (ESCOs), and distribution companies (DISTCOs) that participate in an energy commodity exchange must learn to place effective bids in order to win energy contracts. Microeconomic theory states that in the long term, a hypothetical firm selling in a competitive market should price its product at its marginal cost of production. The theory is based on several assumptions (e.g., all market players will behave rationally, all market players have perfect information) that may tend to be true industry-wide, but might not be true for a particular region or a particular firm. As shown in this work, the normal price offerings are based on average prices. Markets are very seldom perfect or in equilibrium.

There is no doubt that deregulation in the power industry will have many far-reaching effects on the strategic planning of firms within the industry. One of the most interesting effects will be the optimal pricing and output strategies generator companies (GENCOs) will employ in order to be competitive while maximizing profits. This case study presents two very basic, yet effective means for a single generator company (GENCO) to determine the optimal output and price of their electrical power output for maximum profits.

The first assumption made is that switching from a government regulated, monopolistic industry to a deregulated competitive industry will result in numerous geographic regions of oligopolies. The market will behave more like an oligopoly than a purely competitive market due to the increasing physical restrictions of transferring power over distances. This makes it practical for only a small number of GENCOs to service a given geographic region.

Market Structure

Although nobody knows the exact structure of the emerging deregulated industry, this research predicts that regional exchanges (i.e., electricity mercantile associations [EMAs]) will play an important role. Electricity trading of the future will be accomplished through bilateral contracts and EMAs where traders

<table>
<tr><td>Level 1</td><td>FERC</td><td>SPUC</td><td>SPUC</td><td>……..…</td><td>SPUC</td></tr>
<tr><td>2</td><td colspan="2" rowspan="2"></td><td>NERC</td><td colspan="2" rowspan="2"></td></tr>
<tr><td>3</td><td>ICA/ISO/RTO</td></tr>
<tr><td>4</td><td>GENCO</td><td>ESCO</td><td>TRANSCO</td><td>DISTCO</td><td>EMA</td></tr>
<tr><td>5</td><td colspan="4">MARKCO</td><td>BROCO</td></tr>
</table>

FIGURE 13.2 Business environmental model.

bid for contracts via a double auction. The electric marketplace used in this section has been refined and described by various authors. Fahd and Sheblé (1992a) demonstrated an auction mechanism. Sheblé (1994b) described the different types of commodity markets and their operation, outlining how each could be applied in the evolved electric energy marketplace. Sheblé and McCalley (1994e) outlined how spot, forward, future, planning, and swap markets can handle real-time control of the system (e.g., automatic generation control) and risk management. Work by Kumar and Sheblé (1996b) brought the above ideas together and demonstrated a power system auction game designed to be a training tool. That game used the double auction mechanism in combination with classical optimization techniques.

In several references (Kumar, 1996a, 1996b; Sheblé 1996b; Richter 1997a), a framework is described in which electric energy is only sold to distribution companies (DISTCOs), and electricity is generated by generation companies (GENCOs) (see Fig. 13.2). The North American Electric Reliability Council (NERC) sets the reliability standards. Along with DISTCOs and GENCOs, energy services companies (ESCOs), ancillary services companies (ANCILCOs), and transmission companies (TRANSCOs) interact via contracts. The contract prices are determined through a double auction. Buyers and sellers of electricity make bids and offers that are matched subject to approval of the independent contract administrator (ICA), who ensures that the contracts will result in a system operating safely within limits. The ICA submits information to an independent system operator (ISO) for implementation. The ISO is responsible for physically controlling the system to maintain its security and reliability.

Fully Evolved Marketplace

The following sections outline the role of a horizontally integrated industry. Many curious acronyms have described generation companies (IPP, QF, Cogen, etc.), transmission companies (IOUTS, NUTS, etc.), and distribution companies (IOUDC, COOPS, MUNIES, etc.). The acronyms used in this work are described in the following sections.

Horizontally Integrated

The restructuring of the electric power industry is most easily visualized as a horizontally integrated marketplace. This implies that interrelationships exist between generation (GENCO), transmission (TRANSCO), and distribution (DISTCO) companies as separate entities. Note that independent power producers (IPP), qualifying facilities (QF), etc. may be considered as equivalent generation companies. Nonutility transmission systems (NUTS) may be considered as equivalent transmission companies. Cooperatives and municipal utilities may be considered as equivalent distribution companies. All companies are assumed to be coordinated through a regional Transmission Corporation (or regional transmission group).

Federal Energy Regulatory Commission (FERC)

FERC is concerned with the overall operation and planning of the national grid, consistent with the various energy acts and public utility laws passed by Congress. Similar federal commissions exist in other government structures. The goal is to provide a workable business environment while protecting the economy, the customers, and the companies from unfair business practices and from criminal behavior. GENCOs, ESCOs, and TRANSCOs would be under the jurisdiction of FERC for all contracts impacting interstate trade.

State Public Utility Commission (SPUC)

SPUCs protect the individual state economies and customers from unfair business practices and from criminal behavior. It is assumed that most DISTCOs would still be regulated by SPUCs under performance-based regulation and not by FERC. GENCOs, ESCOs, and TRANSCOs would be under the jurisdiction of SPUCs for all contracts impacting intrastate trade.

Generation Company (GENCO)

The goal for a generation company, which has to fill contracts for the cash and futures markets, is to package production at an attractive price and time schedule. One proposed method is similar to the classic decentralization techniques used by a vertically integrated company. The traditional power system approach is to use Dantzig-Wolfe decomposition. Such a proposed method may be compared with traditional operational research methods used by commercial market companies for a "make or buy" decision.

Transmission Company (TRANSCO)

The goal for transmission companies, which have to provide services by contracts, is to package the availability and the cost of the integrated transportation network to facilitate transportation from suppliers (GENCOs) to buyer (ESCOs). One proposed method is similar to oil pipeline networks and energy modeling. Such a proposed method can be compared to traditional network approaches using optimal power flow programs.

Distribution Company (DISTCO)

The goal for distribution companies, which have to provide services by contracts, is to package the availability and the cost of the radial transportation network to facilitate transportation from suppliers (GENCOs) to buyers (ESCOs). One proposed method is similar to distribution outlets. Such proposed methods can be compared to traditional network approaches using optimal power flow programs. The disaggregation of the transmission and the distribution system may not be necessary, as both are expected to be regulated as monopolies at the present time.

Energy Service Company (ESCO)

The goal for energy service companies, which may be large industrial customers or customer pools, is to purchase power at the least cost when needed by consumers. One proposed method is similar to the decision of a retailer to select the brand names for products being offered to the public. Such a proposed method may be compared to other retail outlet shops.

Independent System Operator (ISO)

The primary concern is the management of operations. Real-time control (or nearly real-time) must be completely secure if any amount of scheduling is to be implemented by markets. The present business environment uses a fixed combination of units for a given load level, and then performs extensive analysis of the operation of the system. If markets determine schedules, then the unit schedules may not be fixed sufficiently ahead of realtime for all of the proper analysis to be completed by the ISO.

Regional Transmission Organization (RTO)

The goal for a regional transmission group, which must coordinate all contracts and bids among the three major types of players, is to facilitate transactions while maintaining system planning. One proposed method is based on discrete analysis of a Dutch auction. Other auction mechanisms may be suggested. Such proposed methods are similar to a warehousing decision on how much to inventory for a future period. As shown later in this work, the functions of the RTG and the ISO could be merged. Indeed, this should be the case based on organizational behavior.

Independent Contract Administrator (ICA)

The goal for an Independent Contract Administrator is a combination of the goals for an ISO and an RTG. Northern States Power Company originally proposed this term. This term will be used in place of ISO and RTG in the following to differentiate the combined responsibility from the existing ISO companies.

<table>
<tr><th colspan="8">Time Horizon (Months)</th></tr>
<tr><td>0..............1</td><td>2</td><td>.........</td><td>12</td><td>............</td><td>18</td><td>............</td><td>360</td></tr>
<tr><td>Spot Market</td><td colspan="3">Forward Market</td><td colspan="4"></td></tr>
<tr><td colspan="8">Swap Market (Market to Market Contracts)</td></tr>
<tr><td></td><td colspan="6">Futures Market</td><td>Planning Market</td></tr>
</table>

FIGURE 13.3 Interconnection between markets.

Electric Markets

Competition may be enhanced through the various markets: cash, futures, planning, and swap. The cash market facilitates trading in spot and forward contracts. This work assumes that such trading would be on an hourly basis. Functionally, this is equivalent to the interchange brokerage systems implemented in several states. The distinction is that future time period interchange (forward contracts) are also traded.

The futures market facilitates trading of futures and options. These are financially derived contracts used to spread risk. The planning market facilitates trading of contracts for system expansion. Such a market has been proposed by a west coast electric utility. The swap market facilitates trading between all markets when conversion from one type of contract to another is desired. It should be noted that multiple markets are required to enable competition between markets.

The structure of any spot market auction must include the ability to schedule as far into the future as the industrial practice did before deregulation. This would require extending the spot into the future for at least six months, as proposed by this author (Sheblé, 1994). Future month production should be traded for actual delivery in forward markets. Future contracts should be implemented at least 18 months into the future if not 3 years. Planning contracts must be implemented for at least 20 years into the future, as recently offered by TVA, to provide an orderly, predictable expansion of the generation and transmission systems. Only then can timely addition of generation and transmission be assured. Finally, a swap market must be established to enable the transfer of contracts from one period (market) to another.

To minimize risk, the use of option contracts for each market should be implemented. Essentially, all of the players share the risk. This is why all markets should be open to the public for general trading and subject to all rules and regulations of a commodity exchange. Private exchanges, not subject to such regulations, do not encourage competition and open price discovery.

The described framework (Sheblé, 1996b) allows for cash (spot and forward), futures, and planning markets as shown in Fig. 13.3. The *spot market* is most familiar within the electric industry (Schweppe, 1988). A seller and a buyer agree (either bilaterally or through an exchange) upon a price for a certain amount of power (MW) to be delivered sometime in the near future (e.g., 10 MW from 1:00 p.m. to 4:00 p.m. tomorrow). The buyer needs the electricity, and the seller wants to sell. They arrange for the electrons to flow through the electrical transmission system and they are happy. A *forward contract* is a binding agreement in which the seller agrees to deliver an amount of a particular product in a specified quality at a specified time to the buyer. The forward contract is further into the future than is the spot market. In both the forward and spot contracts, the buyer and seller want physical goods (e.g., the electrons). A *futures contract* is primarily a financial instrument that allows traders to lock in a price for a commodity in some future month. This helps traders manage their risk by limiting potential losses or gains. Futures contracts exist for commodities in which there is sufficient interest and in which the goods are generic enough that it is not possible to tell one unit of the good from another (e.g., 1 MW of electricity of a certain quality, voltage level, etc.). A futures *option contract* is a form of insurance that gives the option purchaser the right, but not the obligation, to buy (sell) a futures contract at a given price. For each options contract, there is someone "writing" the contract who, in return for a premium, is obligated to sell (buy) at the strike price (see Fig. 13.3). Both the options and the futures contracts are financial instruments designed to minimize risk. Although provisions for delivery exist, they are not convenient (i.e., the delivery point is not located where you want it to be located). The trader ultimately cancels his position in the futures market, either with a gain or loss. The physicals are then purchased on the spot market to meet demand with the profit or loss having been locked in via the futures contract.

ICA			
Auction Mechanism		Contract Evaluations	
Communication Player to Auction			
Player	Player	Player	Player

FIGURE 13.4 Computerized markets.

Time Line Into Future (Hours)				Information
0...744				Level
GENCO	ESCO	MARKCO	BROCO	Player
Bids	Bids	....	Bids	Communication
Spot	Forward	Futures	Planning	Markets
Swap				Market
ICA/ISO/RTO				Coordination
GENCO	ESCO	MARKCO	BROCO	Players
...	...	...	...	...

FIGURE 13.5 Electric market.

A *swap* is a customized agreement in which one firm agrees to trade its coupon payment for one held by another firm involved in the swap. Finally, a *planning market* is needed to establish a basis for financing long term projects like transmission lines and power plants (Sheblé, 1993).

Computerized Auction Market Structure

Auction market structure is a computerized market, as shown in Fig. 13.4. Each of the agents has a terminal (PC, workstation, etc.) connected to an auctioneer (auction mechanism) and a contract evaluator. Players generate bids (buy and sell) and submit the quotation to the auctioneer. A bid is a specified amount of electricity at a given price. The auctioneer binds bids (matching buyers and sellers) subject to approval of the contract evaluation. This is equivalent to the pool operating convention used in the vertically integrated business environment.

The contract evaluator verifies that the network can remain in operation with the new bid in place. If the network cannot operate, then the match is denied. The auctioneer processes all bids to determine which matches can be made. However, the primary problem is the complete specification of how the network can operate and how the agents are treated comparably as the network is operated closer to limits. The network model must include all constraints for adequacy and security.

The major trading objectives are hedging, speculation, and arbitrage. Hedging is a defense mechanism against loss and/or supply shortages. Speculation is assuming an investment risk with a chance for profit. Arbitrage is crossing sales (purchases) between markets for riskless profit. This work assumes that there are four markets commonly operated: forward, futures, planning, and swaps (Fig. 13.5).

Forward Market: The forward contracts reflect short term future system conditions. In the forward market, prices are determined at the time of the contract but the transactions occur at some future time. Optimization tools for short term scheduling problems can be enhanced to evaluate trading opportunities in the forward market. For example, short term dispatching algorithms, such as economic unit commitment dispatch, can be used to estimate and earn profit in the forward market.

Futures Market: A futures market creates competition because it unifies diverse and scattered local markets and stabilizes prices. The contracts in the futures market are risky because price movements over time can result in large gains or losses. There is a link between forward markets and futures markets that restricts price volatility. *Options* (options contracts) allow the agent to exercise the right to activate a contract or cancel it. Claims to buy are called "call" options. Claims to sell are called "put" options.

A more detailed discussion of an electric futures contract is discussed in Sheblé (1994b). The components include trading unit, trading hours, trading months, price quotation, minimum price fluctuation, maximum daily price fluctuation, last trading day, exercise of options, option strike prices, delivery, delivery period, alternate delivery procedure, exchange of futures for, or in connection with, physicals, quality specifications, and customer margin requirements.

Swap Market: In the swap market, contract position can be closed with an exchange of physical or financial substitutions. The trader can find another trader who will accept (make) delivery and end the trader's delivery obligation. The acceptor of the obligation is compensated through a price discount or a premium relative to the market rate.

The financial drain inflicted on traders when hedging their operations in the futures market is slightly higher than the one inflicted through direct placement in the forward market. An optimal mix of options, forward commitments, futures contracts, and physical inventories is difficult to assess and depends on hedging, constraints imposed by different contracts, and the cost of different contracts. A clearinghouse such as a swap market handles the exchange of various energy instruments.

Planning Market: The growth of transmission grid requires transmission companies to make contracts based on the expected usage to finance projects. The planning market would underwrite equipment usage subject to the long term commitments to which all companies are bound by the rules of network expansion to maintain a fair marketplace. The network expansion would have to be done to maximize the use of transmission grid for all agents. Collaboration would have to be overseen and prohibited with a sufficiently high financial penalty. The growth of the generation supply similarly requires such markets. However, such a market has been started with the use of franchise rights (options) as established in recent Tennessee Valley Authority connection contracts. This author has published several papers outlining the need for such a market. Such efforts are not documented in this work.

Capacity Expansion Problem Definition

The capacity expansion problem is different for an ESCO, GENCO, TRANSCO, DISTCO, and ANSILCO. This section assumes that the ICA will not own equipment but will only administer the contracts between players. The capacity expansion problem is divided into the following areas: generation expansion, transmission expansion, distribution expansion, and market expansion. ESCOs are concerned with market expansion. GENCOs are concerned with generation expansion. TRANSCOs are concerned with transmission expansion. DISTCOs are concerned with distribution expansion. ANSILCOs are concerned with supportive devices expansion. This author views ancillary services as a misnomer. Such services are necessary supportive services. Thus, the term "supportive" will be used instead of ancillary. Also, since supportive devices are inherently part and parcel of the transmission or distribution system, these devices will be assumed into the TRANSCO and DISTCO functions without loss of generality. Thus, ANSILCOs are not treated separately.

Based on the above idealized view of the marketplace, the following generalizations are made. GENCOs are concerned with the addition of capacity to meet market demands while maximizing profit. Market demands include bilateral contracts with the EMA as well as bilateral contracts with ESCOs or with the ICA. ESCOs are concerned with the addition of capacity of supplying customers with the service desired to maintain market share. ESCOs are thus primarily concerned with the processing of information from marketplace to customer. However, ESCOs are also concerned with additional equipment supplied by DISTCOs or TRANSCOs to provide the level of service required by some customers. ESCOs are thus concerned with all aspects of customer contracts and not just the supply of "electrons."

The ICA is concerned with the operation of the overall system subject to the contracts between the buyers and the sellers and between all players with ICA. The overall goal of the ICA is to enable any customer to trade with any other customer with the quick resolution of contract enforcement available through mercantile associations. The ICA maintains the reliability of the network by resolving the unexpected differences between the contracts, real operation, and unplanned events. The ICA has the authority, through contracts, to buy generation services, supportive services, and/or transmission services, or to curtail contracts if the problems cannot be resolved with such purchases as defined in these contracts.

Thus, the ICA has the authority to connect or disconnect generation and demand to protect the integrity of the system. The ICA has the authority to order new transmission or distribution expansion to maintain the system reliability and economic efficiency of the overall system. The economic efficiency is determined by the price of electricity in the cash markets on a periodic basis. If the prices are approximately the same at all points in the network, then the network is not preventing customers from getting to the suppliers. Similarly, the suppliers can get to the buyers. Since all buyers and suppliers are protected from each other through the default clauses of the mercantile agreement, it does not matter which company deals with other companies as the quick resolution of disputes is guaranteed. This strictness of guarantee is the cornerstone of removing the financial uncertainty at the price of a transaction fee to cover the costs of enforcement.

The goal of each company is different but the tools are the same for each. First, the demand must be predicted for future time periods sufficiently into the future to maintain operation financially and physically. Second, the present worth of the expansion projects has to be estimated. Third, the risks associated with each project and the demand-forecast uncertainty must be estimated. Fourth, the acceptable value at risk acceptable for the company has to be defined. Fifth, the value at risk has to be calculated. Sixth, methods of reducing the value at risk have to be identified and evaluated for benefits. Seventh, the overall portfolio of projects, contracts, strategies, and risk has to be assessed. Only then can management decide to select a project for implementation.

The characteristics of expansion problems include:

1. The cost of equipment or facilities should exhibit economies of scale for the same risk level baring technology changes.
2. Time is a primary factor since equipment has to be in place and ready to serve the needs as they arise. Premature installation results in idle equipment. Delayed installation results in lost market share.
3. The risk associated with the portfolio of projects should decrease as time advances.
4. The portfolio has to be revalued at each point when new information is available that may change the project selection, change the strategy, or change the mix of contracts.

The capital expansion problem is often referred to as the "capital budgeting under uncertainty" problem (Aggarwal, 1993). Thus, capital expansion is an exercise in estimating the present net value of future cash flows and other benefits as compared to the initial investment required for the project given the risk associated with the project(s). The key concept is the uncertainty and thus the risk of all business ventures. Uncertainties may be due to estimation (forecasting) and measurement errors. Such uncertainties can be reduced by the proper application of better tools. Another approach is to investment in information technology to coordinate the dissemination of information. Indeed, information technology is one key to the appropriate application of capital expansion.

Another uncertainty factor is that the net present value depends on market imperfections. Market imperfections are due to competitor reactions to each other's strategies, technology changes, and market rule changes (regulatory changes). The options offered by new investment are very hard to forecast. Also the variances of the options to reduce the risk of projects are critical to proper selection of the right project. Management has to constantly revalue the project, change the project (including termination), integrate new information, or modify the project to include technology changes.

Estimates have often been biased by management pressure to move ahead, to not investigate all risks, or to maintain strategies that are not working as planned. Uncertainties in regulations and taxes are often critical for the decision to continue.

There are three steps to any investment plan: investment alternative identification, assessment, selection and management of the investment as events warrant.

The remaining sections outline the necessity of each step by simple models of the problem to be solved at each step. Since simple problems are given, linear programming solution techniques may be used to solve them. Indeed, the theory of optimization can yield valuable insight as to the importance of further investigations. The inclusion of such models is beyond the scope of this work.

Capacity expansion is one aspect of capital budgeting. Marketing and financial investments are also capital budgeting problems. Often, the capacity expansion has to be evaluated not only on the projects merits, but also the merits of the financing bundled with the project.

Other Sections on Planning

The following sections on planning deal with the overall approach as described by Dr. H. Merrill and include sections on forecasting, power system planning, transmission planning, and system reliability. Forecasting demand is a key issue for any business entity. Forecasting for a competitive industry is more critical than for a regulated industry. Transmission planning is discussed based on probabilistic techniques to evaluate the expected advantages and costs of present and future expansion plans. Reliability of the supply is covered, including transmission reliability. The most interesting aspect of the electric power industry is the massive changes presently occurring. It will be interesting to watch as the industry adapts to regulatory changes and as the various market players find their corporate niche in this new framework.

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13.2 Short-Term Load and Price Forecasting with Artificial Neural Networks[1]

Alireza Khotanzad

Artificial Neural Networks

Artificial neural networks (ANN) are systems inspired by research into how the brain works. An ANN consists of a collection of arithmetic computing units (nodes or neurons) connected together in a network of interconnected layers. A typical node of an ANN is shown in Fig. 13.6. At the input side, there are a number of so-called "connections" that have a weight of "W_{ij}" associated with them. The input denoted by X_i gets multiplied by W_{ij} before reaching node j via the respective connection. Inside the neuron, all the individual inputs are first summed up. The summed inputs are passed through a nonlinear single-input, single-output function "S" to produce the output of the neuron. This output in turn is propagated to other neurons via corresponding connections.

While there are a number of different ANN architectures, the most widely used one (especially in practical applications) is the multilayer feed-forward ANN, also known as a multilayer perceptron (MLP), shown in Fig. 13.7. An MLP consists of n input nodes, h so called "hidden layer" nodes (since they are not directly accessible from either input or output side), and m output nodes connected in a feed-forward fashion. The input layer nodes are simple data distributors whereas neurons in the hidden and output layers have an S-shaped nonlinear transfer function known as the "sigmoid activation function," $f(z) = 1/1 + e^{-z}$ where z is the summed inputs.

For hidden layer nodes, the output is:

$$H_j = \frac{1}{1 + \exp\left(-\sum_{i=1}^{n} W_{ij} X_i\right)}$$

where H_j is the output of the jth hidden layer node, $j = 1, \ldots, h$, and X_i represents the ith input connected to this hidden node via W_{ij} with $i = 1, \ldots, n$.

The output of the kth output node is given by

$$Y_k = \frac{1}{1 + \exp\left(-\sum_{j=1}^{h} W_{jk} H_j\right)}$$

where Y_k is the output of the kth output layer node with $k = h + 1, \ldots, m$, and W_{jk} representing connection weights from hidden to output layer nodes.

One of the main properties of ANNs is the ability to model complex and nonlinear relationships between input and output vectors through a learning process with "examples." During learning, known input-output examples, called the training set, are applied to the ANN. The ANN learns by adjusting or adapting the connection weights through comparing the output of the ANN to the expected output. Once the ANN is trained, the extracted knowledge from the process resides in the resulting connection weights in a distributed manner.

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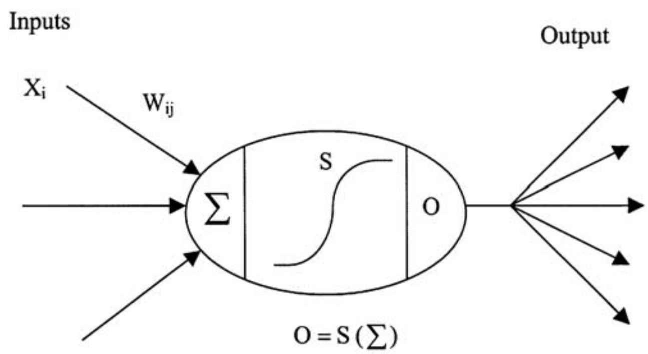

FIGURE 13.6 Model of one node of an ANN.

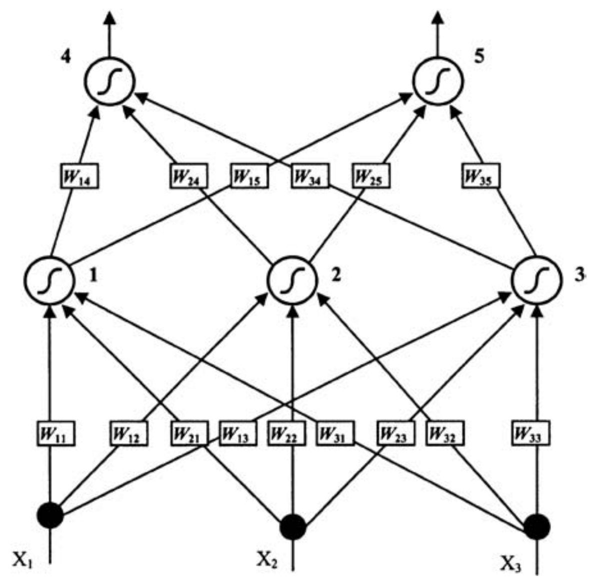

FIGURE 13.7 An example of an MLP with 3 input, 3 hidden, and 2 output nodes.

A trained ANN can generalize (i.e., produce the expected output) if the input is not exactly the same as any of those in the training set. This property is ideal for forecasting applications where some historical data exists but the forecast indicators (inputs) may not match up exactly with those in the history.

Error Back-Propagation Learning Rule

The MLP must be trained with historical data to find the appropriate values for W_{ij} and the number of required neurons in the hidden layer. The learning algorithm employed is the well-known error back-propagation (BP) rule (Rumelhart and McClelland, 1986). In BP, learning takes place by adjusting W_{ij}. The output produced by the ANN in response to inputs is repeatedly compared with the correct answer. Each time, the W_{ij} values are adjusted slightly in the direction of the correct answers by back-propagating the error at the output layer through the ANN according to a gradient descent algorithm.

To avoid overtraining, the cross-validation method is used. The training set is divided into two sets. For instance, if three years of data is available, it is divided into a two-year and a one-year set. The first set is used to train the MLP and the second set is used to test the trained model after every few hundred passes over the training data. The error on the validation set is examined. Typically this error decreases as the number of passes over the training set is increased until the ANN is overtrained, as signified by a rise in this error. Therefore, the training is stopped when the error on the validation set starts to increase.

This procedure yields the appropriate number of epochs over the training set. The entire three years of data is then used to retrain the MLP using this number of epochs.

In a forecasting application, the number of input and output nodes is equal to the number of utilized forecast indicators and the number of desired outputs, respectively. However, there is no theoretical approach to calculate the appropriate number of hidden layer nodes. This number is determined using a similar approach for training epochs. By examining the error over a validation set for a varying number of hidden layer nodes, a number yielding the smallest error is selected.

Adaptive Update of the Weights During Online Forecasting

A unique aspect of the MLPs used in the forecasting systems described in this section is the adaptive update of the weights during online operation. In a typical usage of an MLP, it is trained with the historical data and the weights of the trained MLP are then treated as fixed parameters. This is an acceptable procedure for many applications. However, if the modeled process is a nonstationary one that can go through rapid changes, e.g., variations of electric load due to weather swings or seasonal changes, a tracking mechanism with sensitivity to the recent trends in the data can aid in producing better results.

To address this issue, an adaptive weight adjustment strategy that takes place during online operation is utilized. The MLP is initially trained using the BP algorithm; however, the trained weights are not treated as static parameters. During online operation, these weights are adaptively updated on a sample-by-sample basis. Before forecasting for the next instance, the forecasts of the past few samples are compared to the actual outcome (assuming that actual outcome for previous forecasts have become available) and a small scale error BP operation is performed with this data. This mini-training with the most recent data results in a slight adjustment of the weights and biases them toward the recent trend in data.

Short-Term Load Forecasting

The daily operation and planning activities of an electric utility requires the prediction of the electrical demand of its customers. In general, the required load forecasts can be categorized into short-term, mid-term, and long-term forecasts. The short-term forecasts refer to hourly prediction of the load for a lead time ranging from one hour to several days out. The mid-term forecasts can either be hourly or peak load forecasts for a forecast horizon of one to several months ahead. Finally, the long-term forecasts refer to forecasts made for one to several years in the future.

The quality of short-term hourly load forecasts has a significant impact on the economic operation of the electric utility since many decisions based on these forecasts have significant economic consequences. These decisions include economic scheduling of generating capacity, scheduling of fuel purchases, system security assessment, and planning for energy transactions. The importance of accurate load forecasts will increase in the future because of the dramatic changes occurring in the structure of the utility industry due to deregulation and competition. This environment compels the utilities to operate at the highest possible efficiency, which, as indicated above, requires accurate load forecasts. Moreover, the advent of open access to transmission and distribution systems calls for new actions such as posting the available transmission capacity (ATC), which will depend on the load forecasts.

In the deregulated environment, utilities are not the only entities that need load forecasts. Power marketers, load aggregators, and independent system operators (ISO) will all need to generate load forecasts as an integral part of their operation.

This section describes the third generation of an artificial neural network (ANN) hourly load forecaster known as ANNSTLF (Artificial Neural Network Short-Term Load Forecaster). ANNSTLF, developed by Southern Methodist University and PRT, Inc. under the sponsorship of the Electric Power Research Institute (EPRI), has received wide acceptance by the electric utility industry and is presently being used by over 40 utilities across the U.S. and Canada.

Application of the ANN technology to the load forecasting problem has received much attention in recent years (Bakirtzis et al., 1996; Dillon et al., 1991; Ho et al., 1992; Khotanzad et al., 1998; Khotanzad et al., 1997; Khotanzad et al., 1996; Khotanzad et al., 1995; Lee et al., 1992; Lu et al., 1993; Mohammed et al., 1995; Papalexopoulos et al., 1994; Park et al., 1991; Peng et al., 1993). The function learning property of ANNs enables them to model the correlations between the load and such factors as climatic conditions, past usage pattern, the day of the week, and the time of the day, from historical load and weather data. Among the ANN-based load forecasters discussed in published literature, ANNSTLF is the only one that is implemented at several sites and thoroughly tested under various real-world conditions.

A noteworthy aspect of ANNSTLF is that a single architecture with the same input-output structure is used for modeling hourly loads of various size utilities in different regions of the country. The only customization required is the determination of some parameters of the ANN models. No other aspects of the models need to be altered.

ANNSTLF Architecture

ANNSTLF consists of three modules: two ANN load forecasters and an adaptive combiner (Khotanzad et al., 1998). Both load forecasters receive the same set of inputs and produce a load forecast for the same day, but they utilize different strategies to do so. The function of the combiner module is to mix the two forecasts to generate the final forecast.

Both of the ANN load forecasters have the same topology with the following inputs:

- 24 hourly loads of the previous day
- 24 hourly weather parameters of the previous day (temperatures or effective temperatures, as discussed later)
- 24 hourly weather parameters forecasts for the coming day
- Day type indices

The difference between the two ANNs is in their outputs. The first forecaster is trained to predict the regular (base) load of the next day, i.e., the 24 outputs are the forecasts of the hourly loads of the next day. This ANN will be referred to as the "Regular Load Forecaster (RLF)." On the other hand, the second ANN forecaster predicts the *change* in hourly load from yesterday to today. This forecaster is named the "Delta Load Forecaster (DLF)."

The two ANN forecasters complement each other because the RLF emphasizes regular load patterns whereas the DLF puts stronger emphasis on yesterday's load. Combining these two separate forecasts results in improved accuracy. This is especially true for cases of sudden load change caused by weather fronts. The RLF has a tendency to respond slowly to rapid changes in load. On the other hand, since the DLF takes yesterday's load as the basis and predicts the changes in that load, it has a faster response to a changing situation.

To take advantage of the complimentary performance of the two modules, their forecasts are adaptively combined using the recursive least squares (RLS) algorithm (Proakis et al., 1992). The final forecast for each hour is obtained by a linear combination of the RLF and DLF forecasts as:

$$\hat{L}_{k+1}(i) = \alpha_B(i)\hat{L}_{k+1}^{RLF}(i) + \alpha_C(i)\hat{L}_{k+1}^{DLF}(i), \quad i = 1, \ldots, 24$$

The $\alpha_B(i)$ and $\alpha_C(i)$ coefficients are computed using the RLS algorithm. This algorithm produces coefficients that minimize the weighted sum of squared errors of the past forecasts denoted by J,

$$J = \sum_{k=1}^{N} \beta^{N-k}\left[L_k(i) - \hat{L}_k(i)\right]^2$$

where $L_k(i)$ is the actual load at hour i, N is the number of previous days for which load forecasts have been made, and β is a weighting factor in the range of $0 < \beta \leq 1$ whose effect is to de-emphasize (forget) old data.

The block diagram of the overall system is shown in Fig. 13.8.

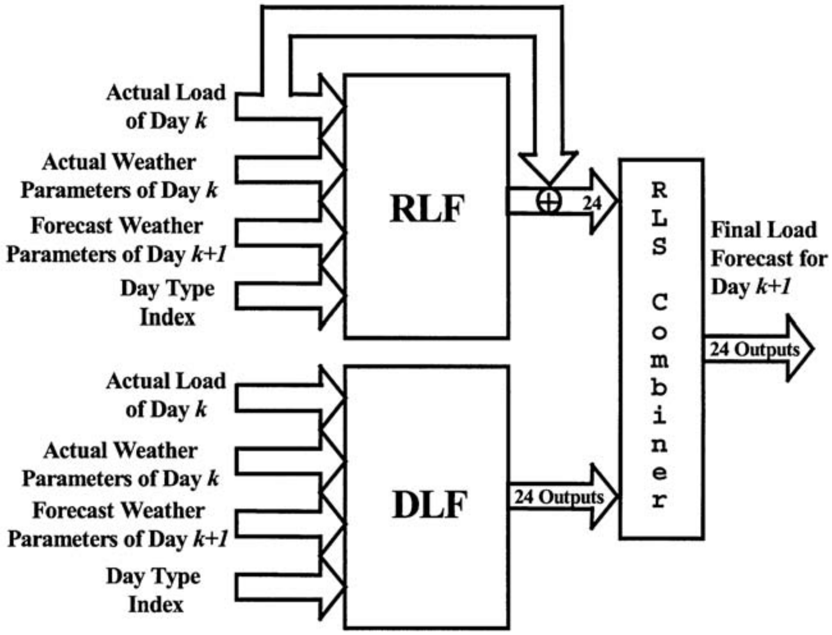

FIGURE 13.8 Block diagram of ANNSTLF.

Humidity and Wind Speed

Although temperature (T) is the primary weather variable affecting the load, other weather parameters, such as relative humidity (H) and wind speed (W), also have a noticeable impact on the load. The effects of these variables are taken into account through transforming the temperature value into an effective temperature, T_eff, using the following transformation:

$$T\_eff = T + \alpha * H$$

$$T\_eff = T - \frac{W * \left(65^{\circ} - T\right)}{100}$$

Holidays and Special Days

Holidays and special days pose a challenge to any load forecasting program since the load of these days can be quite different from a regular workday. The difficulty is the small number of holidays in the historical data compared to the typical days. For instance, there would be three instances of Christmas Day in a training set of three years. The unusual behavior of the load for these days cannot be learned adequately by the ANNs since they are not shown many instances of these days.

It was observed that in most cases, the profile of the load forecast generated by the ANNs using the concept of designating the holiday as a weekend day, does resemble the actual load. However, there usually is a significant error in predicting the peak load of the day. The ANNSTLF package includes a function that enables the user to reshape the forecast of the entire day if the peak load forecast is changed by the user. Thus, the emphasis is placed on producing a better peak load forecast for holidays and reshaping the entire day's forecast based on it.

The holiday peak forecasting algorithm uses a novel weighted interpolation scheme. This algorithm will be referred to as "Reza algorithm" after the author who developed it (Khotanzad et al., 1998). The general idea behind the Reza algorithm is to first find the "close" holidays to the upcoming one in the

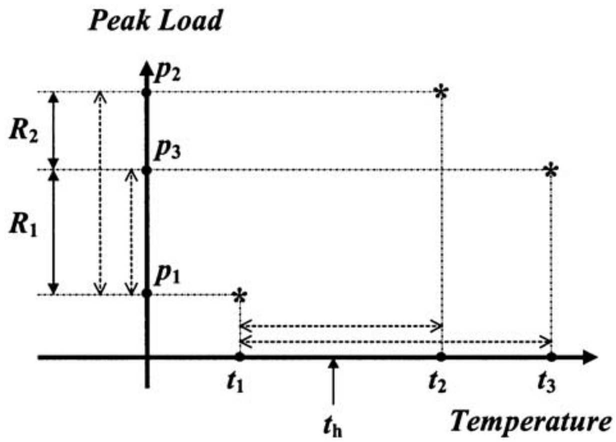

FIGURE 13.9 Example of peak load vs. temperature at peak load for a three-holiday database.

historical data. The closeness criterion is the temperature at the peak-load hour. Then, the peak load of the upcoming holiday is computed by a novel weighted interpolation function described in the following.

The idea is best illustrated by an example. Let us assume that there are only three holidays in the historical data. The peak loads are first adjusted for any possible load growths. Let (t_i, p_i) designate the i-th peak-load hour temperature and peak load, respectively. Fig. 13.9 shows the plot of p_i vs. t_i for an example case.

Now assume that t_h represents the peak-load hour temperature of the upcoming holiday. t_h falls in between t_1 and t_2 with the implication that the corresponding peak load, p_h, would possibly lie in the range of $[p_1, p_2] = R_1 + R_2$. But, at the same time, t_h is also between t_1 and t_3 implying that p_h would lie in $[p_1, p_3] = R_1$. Based on this logic, p_h can lie in either R_1 or $R_1 + R_2$. However, note that R_1 is common in both ranges. The idea is to give twice as much weight to the R_1 range for estimating p_h since this range appears twice in pair-wise selection of the historical data points.

The next step is to estimate p_h for each nonoverlapping interval, R_1 and R_2, on the y axis, i.e., $[p_1, p_3]$ and $[p_3, p_2]$.

For $R_1 = [p_1, p_3]$ interval:

$$\hat{p}_{h1} = \frac{p_3 - p_1}{t_3 - t_1} * (t_h - t_1) + p_1$$

For $R_2 = [p_3, p_2]$ interval:

$$\hat{p}_{h2} = \frac{p_2 - p_3}{t_2 - t_3} * (t_h - t_3) + p_3$$

If any of the above interpolation results in a value that falls outside the respective range, R_i, the closest p_i, i.e., maximum or minimum of the interval, is used instead.

The final estimate of p_h is a weighted average of $\hat{p}_{h1}$ and $\hat{p}_{h2}$ with the weights decided by the number of overlaps that each pair-wise selection of historical datapoints creates. In this case, since R_1 is visited twice, it receives a weighting of two whereas the interval R_2 only gets a weighting coefficient of one.

$$\hat{p}_h = \frac{w_1 * \hat{p}_{h1} + w_2 * \hat{p}_{h2}}{w_1 + w_2} = \frac{2 * \hat{p}_{h1} + 1 * \hat{p}_{h2}}{2 + 1}$$

TABLE 13.1 Utility Information for Performance Study

Utility	No. Days in Testing Period	Weather Variable	Location
1	141	T	Canada
2	131	T	South
3	365	T,H,W	Northeast
4	365	T	East Coast
5	134	T	Midwest
6	365	T	West Coast
7	365	T,H	Southwest
8	365	T,H	South
9	174	T	North
10	275	T,W	Midwest

TABLE 13.2 Summary of Performance Results in Terms of MAPE

		Days-Ahead						
Utility	MAPE OF	1	2	3	4	5	6	7
1	All hours	1.91	2.29	2.53	2.71	2.87	3.03	3.15
	Peak	1.70	2.11	2.39	2.62	2.73	2.94	3.10
2	All hours	2.72	3.44	3.63	3.77	3.79	3.83	3.80
	Peak	2.64	3.33	3.46	3.37	3.42	3.52	3.40
3	All hours	1.89	2.25	2.38	2.45	2.53	2.58	2.65
	Peak	1.96	2.26	2.41	2.49	2.60	2.69	2.82
4	All hours	2.02	2.37	2.51	2.58	2.61	2.65	2.69
	Peak	2.26	2.59	2.69	2.83	2.85	2.93	2.94
5	All hours	1.97	2.38	2.61	2.66	2.65	2.65	2.74
	Peak	2.03	2.36	2.49	2.37	2.49	2.51	2.55
6	All hours	1.57	1.86	1.99	2.08	2.14	2.17	2.18
	Peak	1.82	2.25	2.38	2.50	2.61	2.62	2.63
7	All hours	2.29	2.79	2.90	3.00	3.05	3.10	3.18
	Peak	2.42	2.78	2.90	2.98	3.07	3.17	3.28
8	All hours	2.22	2.91	3.15	3.28	3.39	3.45	3.50
	Peak	2.38	3.00	3.12	3.29	3.40	3.45	3.52
9	All hours	1.63	2.04	2.20	2.32	2.40	2.41	2.50
	Peak	1.83	2.25	2.36	2.51	2.54	2.64	2.78
10	All hours	2.32	2.97	3.25	3.38	3.44	3.52	3.56
	Peak	2.15	2.75	2.93	3.08	3.16	3.27	3.27
Average	All hours	2.05	2.53	2.72	2.82	2.89	2.94	2.99
	Peak	2.12	2.57	2.71	2.80	2.89	2.97	3.03

Performance

The performance of ANNSTLF is tested on real data from ten different utilities in various geographical regions. Information about the general location of these utilities and the length of the testing period are provided in Table 13.1.

In all cases, three years of historical data is used to train ANNSTLF. Actual weather data is used so that the effect of weather forecast errors do not alter the modeling error. The testing is performed in a blind fashion meaning that the test data is completely independent from the training set and is not shown to the model during its training.

One-to-seven-day-ahead forecasts are generated for each test set. To extend the forecast horizon beyond one day ahead, the forecast load of the previous day is used in place of the actual load to obtain the next day's load forecast.

The forecasting results are presented in Table 13.2 in terms of mean absolute percentage error (MAPE) defined as:

TABLE 13.3 Training and Test Periods for the Price Forecaster Performance Study

Database	Training Period	Test Period	MAE of Day-Ahead Hourly Price Forecasts ($)
CALPX	Apr 23, 98–Dec 31, 98	Jan 1, 99–Mar 3, 99	1.73
PJM	Apr 2, 97–Dec 31, 97	Jan 2, 98–Mar 31, 98	3.23

$$MAPE = \frac{100}{N}\sum_{i=1}^{N}\frac{\left|Actual(i) - Forecast(i)\right|}{Actual(i)}$$

with N being the number of observations. Note that the average MAPEs over ten utilities as reported in the last row of Table 13.3 indicate that the third-generation engine is quite accurate in forecasting both hourly and peak loads. In the case of hourly load, this average remains below 3% for the entire forecast horizon of seven days ahead, and for the peak load it reaches 3% on the seventh day. A pictorial example of one-to-seven-day-ahead load forecasts for utility 2 is shown in Fig. 13.10.

As pointed out earlier, all the weather variables (T or T_eff) used in these studies are the actual data. In online usage of the model, weather forecasts are used. The quality of these weather forecasts vary greatly from one site to another. In our experience, for most cases, the weather forecast errors introduce approximately 1% of additional error for one-to-two-days out load forecasts. The increase in the error for longer range forecasts is more due to less accurate weather forecasts for three or more days out.

Short-Term Price Forecasting

Another forecasting function needed in a deregulated and competitive electricity market is prediction of future electricity prices. Such forecasts are needed by a number of entities such as generation and power system operators, wholesale power traders, retail market and risk managers, etc. Accurate price forecasts enable these entities to refine their market decisions and energy transactions leading to significant economic advantages. Both *long-term* and *short-term* price forecasts are of importance to the industry. The long-term forecasts are used for decisions on transmission augmentation, generation expansion, and distribution planning whereas the short-term forecasts are needed for daily operations and energy trading decisions. In this work, the emphasis will be on short-term hourly price forecasting with a horizon extending up to the next 24 hours.

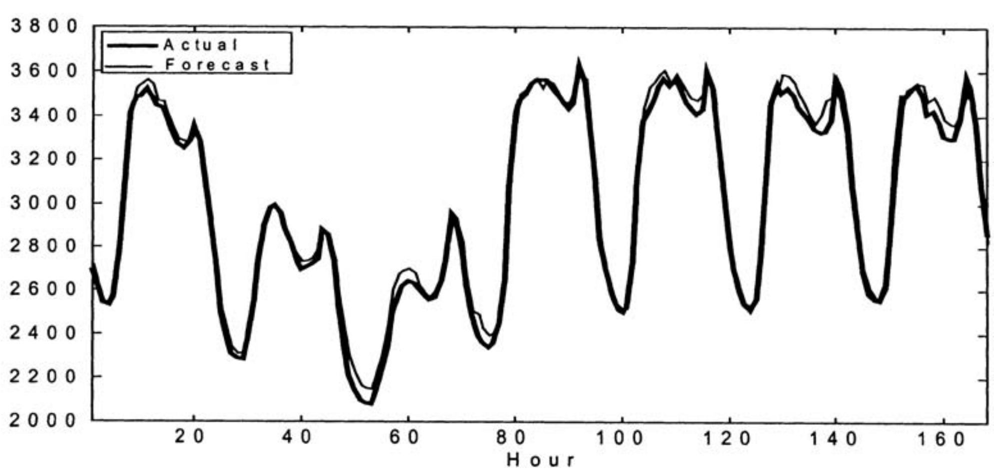

FIGURE 13.10 An example of a one-to-seven-day-ahead load forecast.

In general, energy prices are tied to a number of parameters such as future demand, weather conditions, available generation, planned outages, system reserves, transmission constraints, market perception, etc. These relationships are nonlinear and complex and conventional modeling techniques cannot capture them accurately. In a similar manner to load forecasting, ANNs could be utilized to "learn" the appropriate relationships. Application of ANN technology to electricity price forecasting is relatively new and there are few published studies on this subject (Szkuta et al., 1998).

The adaptive BP MLP forecaster described in the previous section is used here to model the relationship of hourly price to relevant forecast indicators. The system is tested on data from two power pools with good performance.

Architecture of Price Forecaster

The price forecaster consists of a single adaptive BP MLP with the following inputs:

- Previous day's hourly prices
- Previous day's hourly loads
- Next day's hourly load forecasts
- Next day's expected system status for each hour

The expected system status input is an indicator that is used to provide the system with information about unusual operating conditions such as transmission constraints, outages, or other subjective matters. A bi-level indicator is used to represent typical vs. atypical conditions. This input allows the user to account for his intuition about system condition and helps the ANN better interpret sudden jumps in price data that happen due to system constraints.

The outputs of the forecaster are the next day's 24 hourly price forecasts.

Performance

The performance of the hourly price forecaster is tested on data collected from two sources, the California Power Exchange (CALPX) and the Pennsylvania-New Jersey-Maryland Independent System Operator (PJM). The considered price data are the Unconstrained Market Clearing Price (UMCP) for CALPX, and Market Clearing Price (MCP) for PJM. The average of Locational Marginal Prices (LMP) uses a single MCP for PJM. The training and test periods for each database are listed in Table 13.3. Testing is performed in a blind fashion, meaning that the test data is completely independent from the training set and is not shown to the model during its training. Also, actual load data is used in place of load forecast.

The day-ahead forecast results are presented in the first column of Table 13.4 in terms of mean absolute error (*MAE*) expressed in dollars. This measure is defined as:

$$MAE = \frac{100}{N} \sum_{i=1}^{N} \left| Actual\ Price(i) - Forecast\ Price(i) \right|$$

with N being the total number of hours in the test period.

To put these results in perspective, the sample mean and standard deviation of hourly prices in the test period are also listed in Table 13.4. Note the correspondence between MAE and the standard deviation of data, i.e., the smaller standard deviation results in a lower MAE and vice versa.

TABLE 13.4 Results of Performance Study for the Test Period

Database	MAE of Day-Ahead Hourly Price Forecasts ($)	Sample Mean of Actual Hourly Prices ($)	Sample Standard Deviation of Actual Hourly Prices ($)
CALPX	1.73	19.98	5.45
PJM	3.23	17.44	7.67

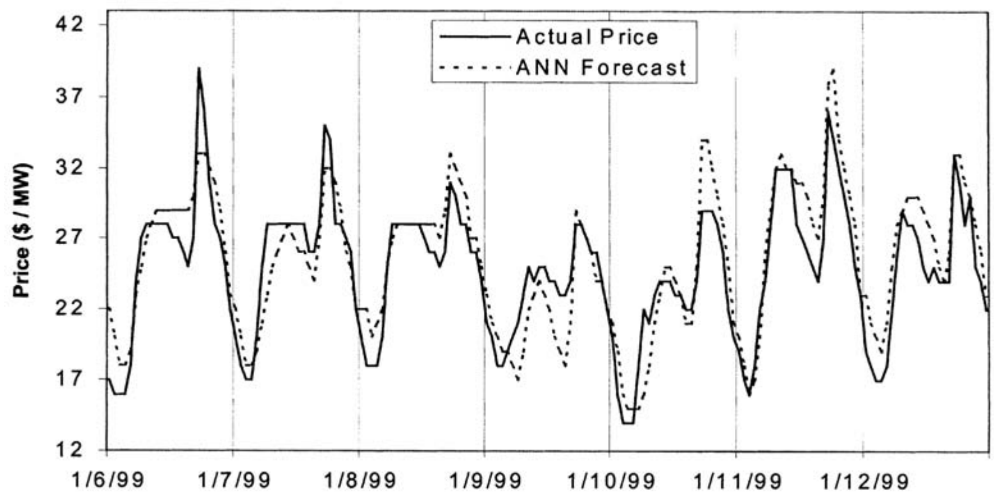

FIGURE 13.11 An example of the ANN price forecaster performance for CALPX price data.

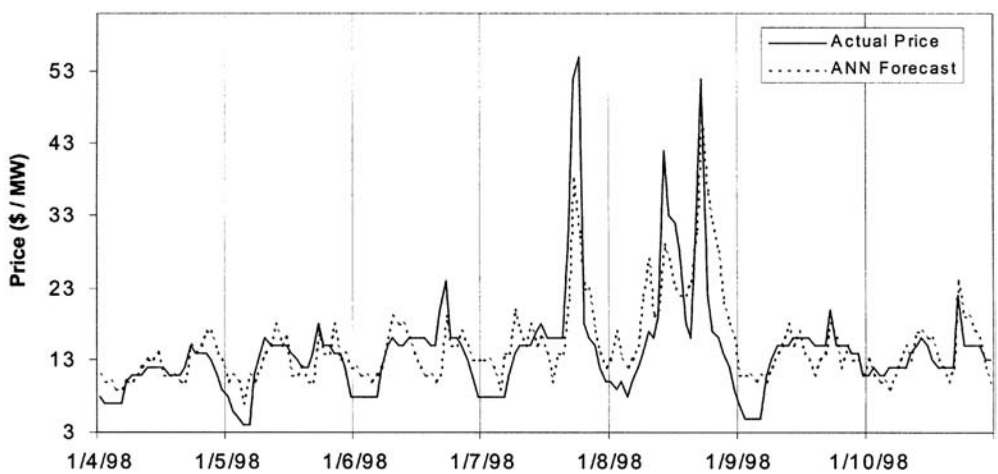

FIGURE 13.12 An example of the price forecaster performance for PJM price data.

Figures 13.11 and 13.12 show a representative example of the performance for each of the databases. It can be seen that the forecasts closely follow the actual data.

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13.3 Transmission Plan Evaluation — Assessment of System Reliability

N. Dag Reppen and James W. Feltes

Bulk Power System Reliability and Supply Point Reliability

Transmission systems must meet performance standards and criteria that ensure an acceptable level of quality of electric service. Service quality means continuity of supply and constancy of voltage waveform and power system frequency. Frequency is typically not an issue in large interconnected systems with adequate generation reserves. Similarly, voltage quality at the consumer connection is typically addressed at the distribution level and not by reinforcing the transmission system. This leaves continuity of power supply as the main criterion for acceptable transmission system performance.

Requirements for continuity of supply are traditionally referred to as power system reliability. Reliability criteria for transmission systems must address both local interruptions of power supply at points in the network as well as widespread interruptions affecting population centers or entire regions. Local and widespread interruptions are typically caused by different types of events and require different evaluation approaches.

Additional transmission facilities will virtually always increase reliability, but this remedy is constrained by the cost of new facilities and environmental impacts of new construction. Reliability objectives, therefore, must be defined explicitly or implicitly in terms of the value of reliable power supply to the consumer and to society at large. Reflecting the different concerns of local interruptions and widespread interruptions, reliability objectives are different for the bulk transmission system than for the local area transmission or subtransmission systems supplying electric power to electric distribution systems. These two aspects of power system reliability will be referred to as bulk power system reliability (Endrenyi et al., 1982, Parts 1 and 2) and supply point reliability.

Bulk Transmission Systems Reliability is Evaluated Using Deterministic Reliability Criteria

A distinguishing characteristic of bulk transmission systems is that severe disturbances arising in them can have widespread impact. Major failures of bulk transmission systems have resulted in interruption of thousands of MW of load and interruption of service to millions of customers. Three important characteristics of reliable bulk transmission system performance are:

1. Low risk of widespread shutdown of the bulk transmission system,
2. Confinement of the extent of bulk transmission system shutdown when it occurs, and
3. Rapid restoration of operation following shutdown of the bulk transmission system.

Most interconnected systems have reliability criteria and design standards that explicitly aim at limiting the risk of widespread shutdowns or blackouts. Such criteria may call for transmission reinforcements or limitations of power transfers across the system. The two other characteristics are addressed by sharpening operating command and control functions and improving control and communication facilities. Therefore, transmission system plans are typically evaluated with respect to reliability criteria that are aimed at limiting the risk of system shutdowns.

The U.S. National Electric Reliability Council (NERC), formed in response to the 1965 Northeast blackout, has developed basic design criteria aimed at reducing the risk of "instability and uncontrolled cascading" that may lead to system blackouts. The various regional reliability councils have interpreted these requirements in various ways and produced additional criteria and guides to address this problem (NERC, 1988). Deterministic criteria for bulk power systems will typically include the following requirements:

1. Test criteria for simulated tests aimed at avoiding overload cascading and instability, including voltage collapse. These test criteria specify in generic form:
   a. the system conditions to be tested: e.g., peak load conditions, lines or generators assumed out on maintenance, transfer levels
   b. the type of failure that initiates a disturbance: e.g., type and location of short circuit
   c. assumptions to be applied regarding the operation of protection systems and other control systems
   d. the allowable limits of system response: line and transformer loading limits, high and low voltage limits, and criteria for stable operation

   The system must be reinforced to meet these criteria.
2. Requirements to test extreme contingencies such as the simultaneous outage of two or more parallel lines or the loss of entire substations. These tests are made to determine and understand the vulnerability of the system to such events. When critical extreme contingencies are identified, steps should be taken to minimize the risk of occurrence of such events.
3. Criteria and guides for protection system design to reduce the risk of critical protection initiated disturbances and for protection misoperation that may aggravate a serious system condition.

Evaluations of the system response to specified severe but rare types of failure events are labeled deterministic. The likelihood of the event specified is not considered, except in a qualitative way when the criteria were created. Since only a small subset of all potentially critical events can be tested, the tests are sometimes referred to as "umbrella" tests. A system that passes these selected tests is believed to have a degree of resiliency that will protect it not only for the specific disturbances simulated, but also for a multitude of other disturbances of similar type and severity.

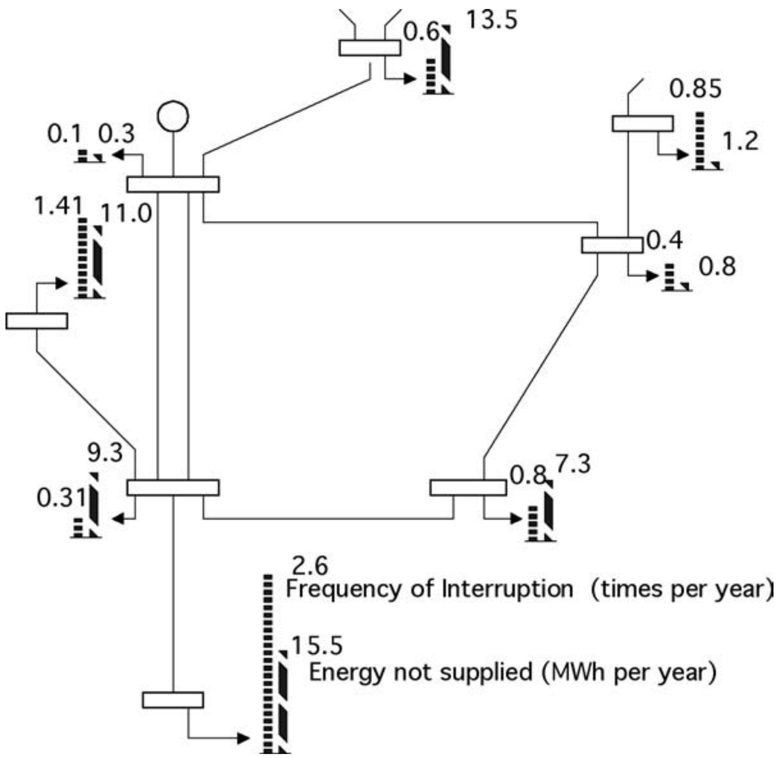

FIGURE 13.13 Prediction of supply point reliability.

Supply Point Reliability is Evaluated Using Either Deterministic or Probabilistic Reliability Criteria

Reliability objectives at the local area transmission or subtransmission level focus on the reliability of supply to specific supply points as shown in Fig. 13.13. Statistically, the reliability of supply may be expressed in terms of the frequency of occurrence of load interruptions, the amount of load interrupted, and the duration of the interruptions. Frequency of interruptions and MWh not served over a period such as a year are commonly used measures for the observed or predicted reliability of power supply to a particular node in a transmission system. Probabilistic reliability methods are required to predict reliability in these terms (Billinton and Allan, 1984; Endrenyi, 1978; Salvaderi et al., 1990). These methods will typically consider more likely events rather than the more extreme and very rare events that can lead to system shutdown. This is justified since system shutdown occurrences are not frequent enough to significantly impact the reliability measures calculated.

While it is practical to perform probabilistic calculations to assess supply point reliability, deterministic simulation tests are also commonly used. As a minimum, deterministic criteria call for load flow testing of all single line and single transformer outages. This is referred to as single contingency testing or N-1 testing. For each of these outages, no line or transformer shall exceed its emergency rating, and no voltage shall violate specified high and low emergency voltage limits. Violation of these criteria calls for system reinforcements. Exceptions are typically made for supply points with low peak demand where it is judged to be too expensive to provide for redundant service. Some utilities use a peak load criterion such as 25 MW, above which redundant transmission connections to a supply point are called for.

Methods for Assessing Supply Point Reliability

Supply point reliability may be assessed in four different ways in order of increasing complexity:

1. **Deterministic:** System alternatives must meet criteria specifying allowable system response to specified contingencies.
2. **Probabilistic — System Trouble:** System alternatives must meet criteria specified in terms of probabilistic reliability indices reflecting risk of unacceptable system response.
3. **Probabilistic — Consumer Impact:** Same as (2), but criteria are specified in terms of consumer impact such as risk of supply interruption or risk of load curtailment.
4. **Cost/Benefit Analysis:** This approach is based on the concept that the proper level of service reliability should be defined by the balance of incremental worth of service reliability improvement and incremental cost of providing that improvement. The approach is also referred to as "effectiveness analysis" or "value based" reliability assessment.

The limitation of the deterministic approach (1) is that it considers only the initial system problems for a few contingencies. These contingencies have typically been selected by committee based on a mixture of judgment, tradition, and experience. If the selected contingencies do not cover all important reliability concerns, the resulting system may be unreliable. If the selected contingencies put undue emphasis on severe but rare events, an unnecessarily expensive system alternative may be selected.

The probabilistic approach (2) aims at eliminating the dependency on judgment in the selection of contingencies by attempting to look at all significant contingencies. In addition, it weighs the importance of the results for each contingency according to the severity of the system problems caused by each contingency and the frequency of occurrence of each contingency.

Approach (3) looks deeper into the problem, in that it is concerned with the impact on the consumer. However, the criteria used to define an acceptable level of reliability are still judgmental. For example, how many interruptions per year would be acceptable or what percentage of total MWh demand is it acceptable to interrupt or curtail? In the cost/benefit approach (4), the criterion for acceptable reliability is implicit in the methodology used.

Reliability Measures — Reliability Indices

Reliability can be measured by the frequency of events having unacceptable impacts on the system or on the consumer, and by the severity and duration of the unacceptable impacts. Thus, there are three fundamental components of reliability measures:

1. Frequency of unacceptable events,
2. Duration of unacceptable events, and
3. Severity of unacceptable events.

From these, other measures, such as probability of unacceptable events, can be derived. An expectation index, such as the loss of load expectation (LOLE) index commonly used to measure the reliability of a generating system is, in its nature, a probability measure. While probability measures have proved useful in generation reliability assessment, they may not be as meaningful in assessing the reliability of a transmission system or a combined generation/transmission system. It is, for example, important to differentiate between 100 events which last 1 sec and 1 event which lasts 100 sec. Since probability measures cannot provide such differentiation, it is often necessary to apply frequency and duration measures when assessing the reliability of transmission systems.

Probabilistic reliability measures or indices can express the reliability improvements of added resources and reinforcements quantitatively. However, several indices are required to capture various reliability aspects. There are two major types of indices: system indices and consumer or load indices (Guertin et al., 1978; Fong et al., 1989). The former concerns itself with system performance and system effects, the latter with the impact on the consumer. The reliability cost measure used in cost/benefit analysis may be classified as a consumer index.

System Indices

Indices suitable for transmission system reliability evaluation may be divided into system problem indices and load curtailment indices.

System problem indices measure frequency, duration, probability, and severity of system problems. Some examples:

- Frequency of circuit overloads (overloads/year),
- Average duration of circuit overloads (hours), and
- Probability of circuit overloads.

Load curtailment indices measure severity in terms of load interrupted or curtailed. The salient characteristic of these indices is that the severity of any event, regardless of the system problems resulting from the event, is expressed in terms of load curtailment. From the three fundamental reliability measures (frequency, duration, and load curtailment), a series of derived reliability indices may be defined as illustrated by the following examples.

Basic Annual Indices

- Frequency of load curtailment $F = \sum_i F_i \left(yr^{-1}\right)$
- Hours of load curtailment $D = \sum_i F_i D_i \left(h\ yr^{-1}\right)$
- Power curtailed $C = \sum_i F_i C_i \left(MW\ yr^{-1}\right)$
- Energy curtailed $E = \sum_i F_i D_i C_i \left(MWh\ yr^{-1}\right)$

where

F_i = frequency of event i (yr^{-1})
D_i = duration of event i (h)
C_i = MW load curtailed for event i (MW)
i = all events for which $C_i > 0$

Energy curtailment (E), expressed in MWh not served, is often referred to as *Energy Not Served* (ENS), *Expected Energy Not Served* (EENS), or *Expected Unserved Energy* (EUE).

Load curtailment indices are sometimes normalized to system size. Two commonly used indices are:

- Power interruption index $C_N = C/CMX\ (yr^{-1})$
- Energy curtailment index $E_N = E/CMX\ (h\ yr^{-1})$

where CMX = peak load for system, area, or bus.

$E_N \times 60$ is referred to as system minutes, the equivalent number of minutes per year of total system shutdown during peak load conditions.

Cost of Interruptions to Consumers

The fact that a sudden interruption of very short duration can have a significant impact and that an outage of 4 h may have a significantly more severe impact than two outages of 2 h each, illustrates the limitations of simple aggregated reliability measures such as MWh not served. This is an important

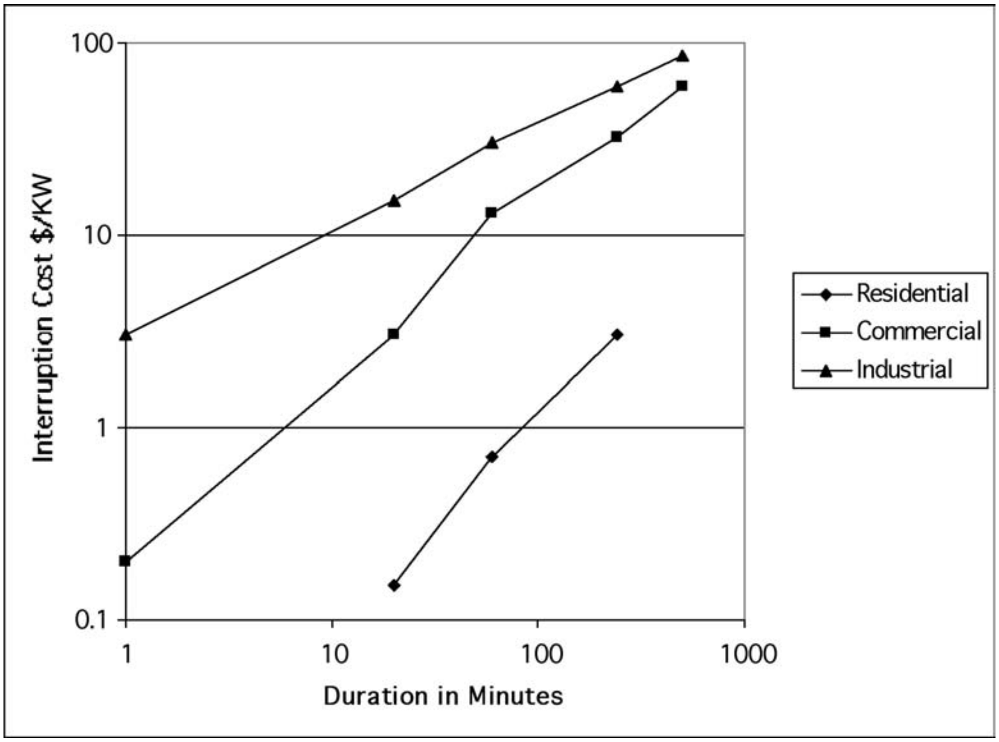

FIGURE 13.14 Illustration of customer damage functions for residential, commercial, and industrial load for process-oriented industrial load. The cost of very short duration outages may be much higher than shown here.

limitation since the various transmission reinforcement options considered may have dramatically different impacts as far as interruption durations are concerned. Since it is difficult to use a multiparameter measure when comparing reinforcement alternatives, a single aggregate measure is much preferred as long as it includes the main reliability factors of concern. The concept of cost to consumers of unreliability expressed in dollars per year has emerged as a practical measure of reliability when comparing transmission reinforcement alternatives. As a measure, reliability cost has the additional important advantage that it can be aggregated with installation cost and operating cost to arrive at a minimum "total cost" design in a cost/benefit analysis.

Conceptually, the annual reliability cost for a group of customers is the aggregated worth the customers put on avoiding load interruptions. In some cases the costs are tangible, allowing reliable dollar cost estimates; in other instances the impacts of interruptions are intangible and subjective, but still real in the eyes of the consumer. Surveys aimed at estimating what consumers would be willing to pay, either in increased rates or for backup service, have been used in the past to estimate the intangible costs of load interruptions. The results of these investigations may be expressed as *Customer Damage Functions,* (CDF), as illustrated in Fig. 13.14 (Mackay and Berk, 1978; Billinton et al., 1983).

Customer damage functions can be used to estimate the dollar cost of any particular load interruption given the amount of load lost and the duration of the interruption. If a customer damage function can be assigned for each supply point, then a cost of interrupted load may be determined.

Outage Models

Generation and transmission outages may be classified in two categories — forced outages and scheduled outages. While forced outages are beyond the control of the system operators, scheduled outages can usually be postponed if necessary to avoid putting the system in a precarious state. These two outage categories must, therefore, be treated separately (Forrest et al., 1985).

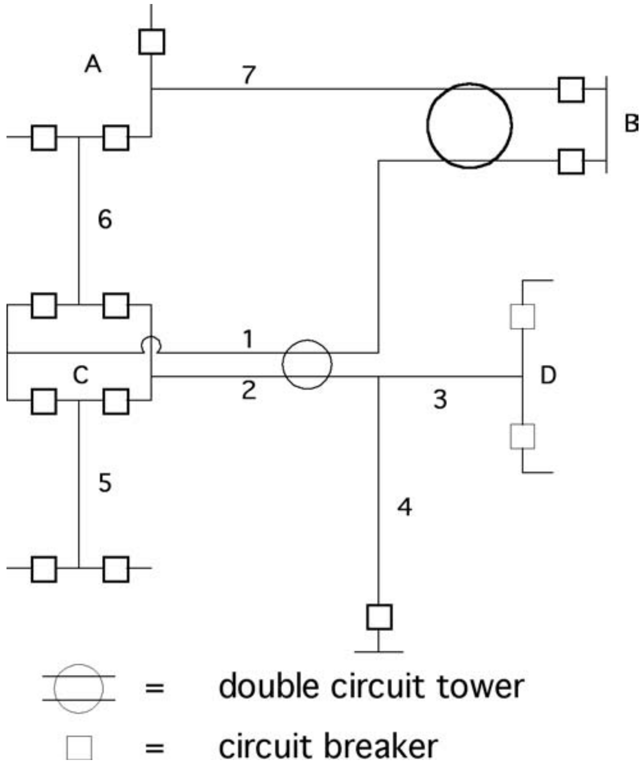

FIGURE 13.15 Sample system illustrating outage types.

Forced Outage Models

The variety and characteristics of forced outage events may be illustrated with reference to Fig. 13.15. Transmission lines and transformers that can be isolated from the system by the opening of circuit breakers are referred to as "elements."

Three categories of forced outage events are recognized:

1. **Single Component Outage Event** — The outage event involves only one element. For example, a fault on circuit 1, cleared by circuit breakers in a normal manner, would only affect circuit 1.
2. **Common Mode Outage Event** — This is a multiple element outage event where a single initiating cause results in multiple element outages where the outages are not consequences of each other. For example, a single lightning stroke taking out both circuits of the double circuit line exiting substation B would be a common mode outage. This event results in the simultaneous outage of circuits 1 and 7.
3. **Substation Related Outage Events** — This is a multiple element outage event that depends on the protection system response to a fault on a component in the substation or on an element connected to the substation. Examples of substation related outage events are:
   a. Stuck breaker — if the breaker common to circuits 1 and 6 is stuck, a fault on either circuits 1 and 6 would result in both circuits out.
   b. Tapped circuits — a fault on circuit 2 would result in circuits 2, 3 and 4 going out together.
   c. Breaker fault –if there is a fault on the breaker common to circuits 1 and 6, both circuits 1 and 6 would be outaged.
   d. Bus section fault — a fault on the bus section in substation B would outage circuits 1 and 7.

A common mode outage event may be combined with substation related outage events. For example, a common mode failure of circuits 1 and 2 would result in an outage event encompassing circuits 1, 2, 3, and 4. Two or more independent outage events from either of the three outage categories may overlap in time, creating more complex outages. Accurate tools for the prediction of reliability measures include most if not all of these outage types.

Probabilistic Reliability Assessment Methods

Probabilistic reliability assessment tools falls in one of two categories (Endrenyi et al., 1982):

1. The contingency enumeration method
2. The Monte Carlo method

In general, the contingency enumeration method is capable of looking at severe and rare events such as transmission events in great detail, but cannot practically look at many operating conditions. In contrast, the Monte Carlo methods are capable of looking at operating conditions in great detail (Noferi et al., 1975). However, from a computational standpoint, it is not possible to capture with precision, the impact of infrequent but severe transmission contingencies. Thus, the two methods are capturing different aspects of the reliability problem.

Contingency Enumeration Approach

The contingency enumeration approach to reliability analysis includes the systematic selection and evaluation of disturbances, the classification of each disturbance according to failure criteria, and the accumulation of reliability indices. Contingency enumeration techniques are structured so as to minimize the number of disturbances that need to be investigated in detail. This is achieved by testing, to the extent possible, only those disturbances that are sufficiently severe to cause trouble and sufficiently frequent to impact the risk indices to be computed.

The contingency enumeration approach is structured as shown in Fig. 13.16. For a specific predisturbance condition, a contingency is selected and tested to determine whether the contingency causes any immediate system problem such as a circuit overload or a bus voltage out of limits. If it does not, a new contingency is selected and tested.

The occurrence of a system problem may by itself be logged as a failure. However, in many cases, it will be possible to adjust generation or phase shifters to relieve overloads and to adjust generator voltages

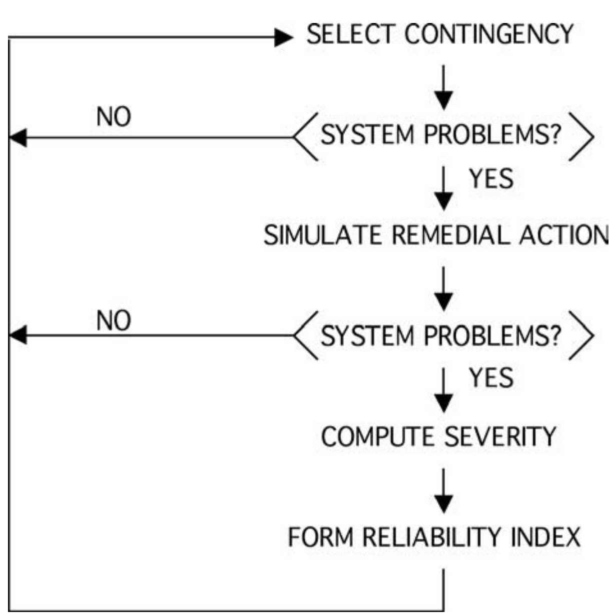

FIGURE 13.16 Contingency enumeration approach.

or transformer taps to bring bus voltages back within range. It is, therefore, of interest to determine whether it is possible to eliminate a system problem by such corrective actions. A failure is logged when corrective actions, short of curtailing consumer loads, are insufficient to eliminate the system problems. The severity of such system problems may be assessed by computing the amount and location of load curtailment necessary to eliminate the problem. In this way, it is possible to compute supply point reliability indices that measure the frequency, duration, and amount of expected load curtailment.

Monte Carlo Approach

Monte Carlo methods (Oliveira et al., 1989) may be sequential or nonsequential. The sequential approach simulates the occurrences of random events through time, recognizing the statistical properties of the various types of events. Typically, the time functions of load and planned generation schedules are established for a period of a year. Starting at the beginning of the year, a sequence of forced shutdown and restoration of transmission and generating equipment is then determined based on random sampling in accordance with the statistical characteristics of the equipment failure processes. The response of the power system during equipment outages is simulated by power flow solutions. Whenever a system condition violating predefined failure criteria is encountered, the occurrence and characteristic of this failure is recorded. At the end of one year of simulation, parameters describing the "observed" reliability of the system can be determined. These parameters may include frequency of equipment overload, frequency of voltage violations, MWh not served, average duration and severity of specified types of failures, etc. This process is illustrated in Fig. 13.17.

One year of simulation constitutes one particular sample scenario governed by the random properties of equipment failure. In order to obtain a measure of the inherent reliability of the system, it is necessary to repeat the simulation over the annual period many times and calculate the reliability measures as the mean of the results obtained over the repeated annual simulations. For reliable systems, several hundred annual simulations may be required to obtain convergence in the reliability measures calculated.

When using the sequential approach, it is possible to model time dependencies between key variables. This allows elaborate modeling of energy limited resources such as hydro plants and pumped hydro. It is also possible to simulate environmental effects such as the occurrence of lightning storms that may impact the failure rate of transmission equipment. A brute-force sequential Monte Carlo simulation would be prohibitively time-consuming when applied to large systems. Practical techniques rely on special sampling techniques and acceptable approximations in power system modeling.

If time dependencies are not essential, the nonsequential approach may be used. In this case, hours of simulation may be selected at random rather than in sequence. For a specific hour, a precontingency state is established including bus loads and matching generation dispatch. When it can be used, the nonsequential approach is typically much faster than the sequential approach.

Comparison of Contingency Enumeration and Monte Carlo Simulation

From the preceding discussion, it is clear that the Monte Carlo method differs from the contingency enumeration method in the way power system states including load, generation dispatch, and component outages are selected. The actual network solution and corrective action models used may be the same or similar for both methods. The major advantage of the Monte Carlo method is the ease with which comprehensive statistics of power system states can be included. This makes the method suitable for computing period reliability indices such as annual indices (CIGRE, 1992).

The Monte Carlo method may not be suitable for estimating the probability or frequency of occurrence of infrequent events. The contingency enumeration method may, therefore, be a more practical approach in system design. In comparing system alternatives to strengthen a local area, the Contingency Enumeration approach will provide consistent and real differences in reliability indices computed for specific situations. Unless the reliability of the alternatives are far apart, it would be very time-consuming and perhaps impractical to obtain acceptable differences in reliability by means of the Monte Carlo method. One way to mitigate this problem is to remove time-consuming calculations from the inner loop of the Monte Carlo calculations. In one approach, which is used to assess the reliability of supply to load centers,

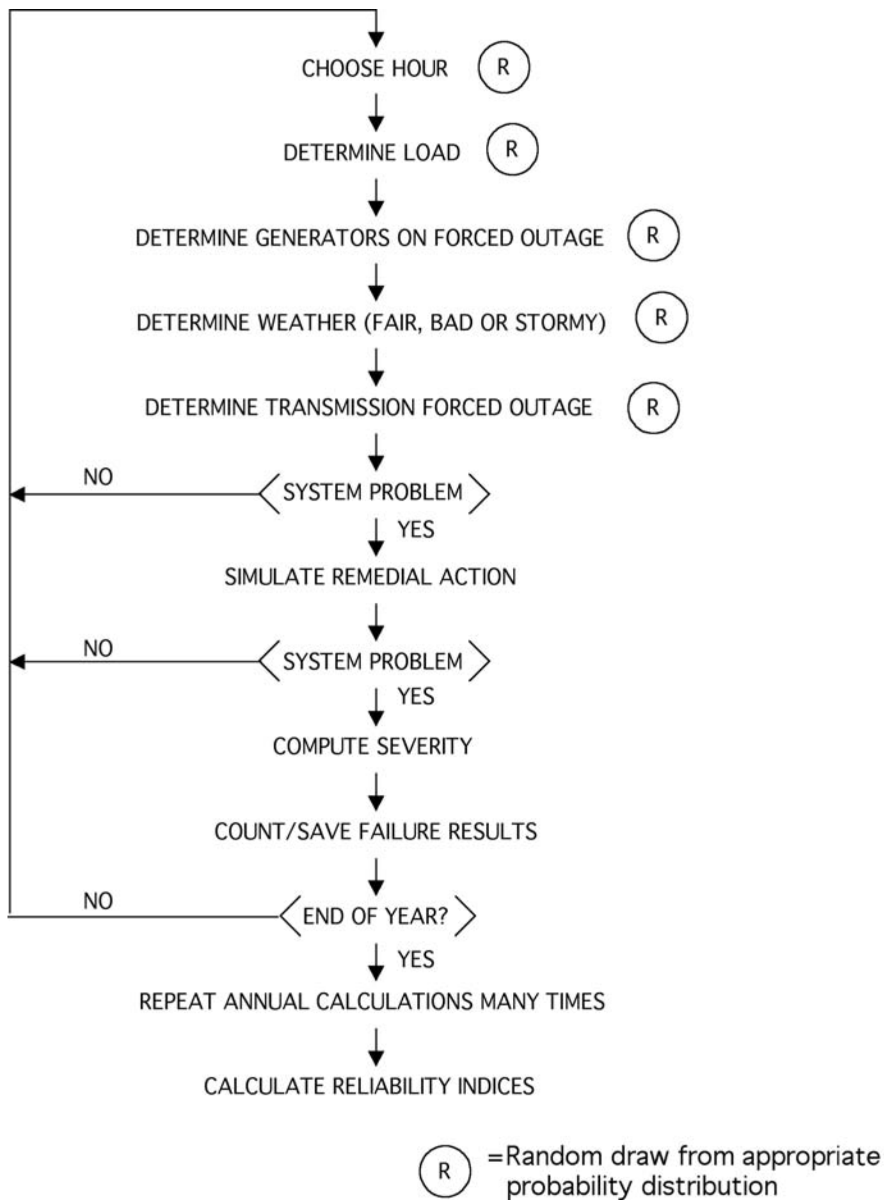

FIGURE 13.17 Possible computational sequence for Monte Carlo method.

the impact of rare transmission failures are obtained from precomputed look-up tables of transmission import limits. Using this approach and various sampling techniques, several thousand years of operation can be simulated in minutes.

Application Examples

The techniques described above are presently used for transmission planning by major utilities. The following examples illustrate some of these methods. The first example uses contingency enumeration while the second example uses Monte Carlo techniques.

Calculation of the Reliability of Electric Power Supply to a Major Industrial Complex

Contingency enumeration techniques were used to assess the reliability of the power supply to a major manufacturing complex (Reppen et al., 1990). In this analysis, the reliability concerns encompassed system events and conditions that are capable of disturbing or shutting down all or portions of the manufacturing processes. The events of concern included initial interruptions, sustained interruptions, overloads, voltage violations, voltage collapse, and overload cascading. The reliability effects of possible system reinforcements in the immediate local power supply area and in the main grid supplying this area were evaluated by a comprehensive probabilistic reliability analysis.

The characteristics of the power system were radial feeds to the plant with provisions for automatic and manual switchover to alternative supply in case of loss of voltage on primary supply feeders, an extensive local 132 kV system, and a regional 300 kV and 420 kV transmission system. Contingency enumeration methods allow detailed modeling of the network, including the modeling of automatic responses of the power system to disturbances such as special relaying schemes for line tripping, generation runback, and load transfer.

Three typical categories of outages — single element outages, independent overlapping outages of multiple elements, and dependent multiple element outages — were considered in the reliability studies. The term "element" encompasses generating units as well as "transmission elements" such as transmission lines, transformers, capacitor banks, and static var devices. The reliability computations included network analysis of outages, classification of failure events according to type and severity, and calculation of reliability indices. Reliability indices representing the predicted frequency of each of the types of failure events were computed as well as load interruption and energy curtailment indices. The indices computed are referred to as annualized indices reflecting the reliability level that would be experienced if the precontingency condition considered should exist for an entire year.

The full analysis included assessment of existing power supply conditions, impact of system reconfiguration on the reliability of supply, reliability effects of system reinforcements, and impact of conditions in the main grid. Here we will concentrate on the reliability effects of system reinforcements. Two reinforcements were analyzed: construction of a new 132 kV line completing a loop at some distance from the plant and construction of a 300 kV ring connecting several of the power supply buses to the plant.

Figure 13.18 presents the results of the investigation using the energy curtailment index defined earlier. The energy curtailment index aggregates the expected loss of energy on an annualized basis. The results indicate that reinforcement A (the remote line) has no significant effect on the reliability of power supply to the plant. Reinforcement B (the 300 kV ring) provides a substantial overall improvement, although there is no significant improvement in the energy curtailment index for the winter case.

While some of the suggested means of improving reliability could have been predicted prior to the analysis, the relative effectiveness of the various actions would not be apparent without a formal reliability analysis. Performing a reliability analysis of this type gives excellent insights into the dominating failure phenomena that govern system performance. The detailed contingency information available promotes understanding of the way systems fail, while the reliability indices computed provide the perspective necessary to make appropriate system design decisions.

Local Area Reliability

The second example considers the task of improving the reliability of electric power to a local area such as a city, major industrial complex, or other load center (Reppen, 1998). In simple terms, the reliability of the supply is a function of the following parameters:

- The load in the area as it fluctuates over time.
- The maximum amount of power that can be imported from the main grid. This import limit varies by maintenance and forced outage of transmission and generating equipment.
- Maximum available local generation at any particular time as it is affected by generation maintenance and forced outages.

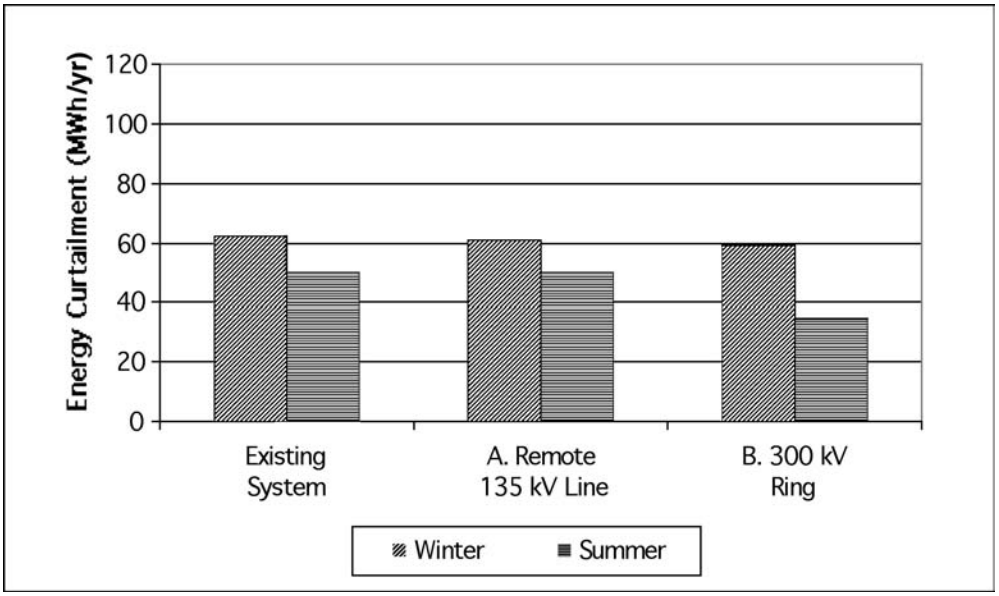

FIGURE 13.18 Benefit of system reinforcements. Annualized energy curtailment (MWh/yr). Sustained interruptions only.

At any particular time, load curtailment will occur if the load exceeds the maximum import capability into the area plus the maximum generation available in the area. Therefore, reliability of supply to consumers in the area can be measured in terms of statistics of load curtailment. Popular load curtailment measures include frequency of interruptions and energy not served (MWh/year). In addition, the expected annual customer interruption cost can be predicted using Monte Carlo techniques that simulate system conditions repeatedly over a time period to develop reliability measures by aggregating and averaging the impacts of individual load curtailment events. This allows the use of interruption cost functions (customer damage function) to estimate the expected annual cost of load interruptions.

Accepting calculated annual interruption costs as a realistic measure of the economic impact on the consumer, one might declare a system reinforcement alternative to be justified from a reliability standpoint if the reduction in interruption cost is greater than the net cost of investment and operation. While such a criterion may not necessarily be appropriate in all cases, it should provide a relevant benchmark in most environments.

Figure 13.19 shows key components of the power supply picture for a small city with a peak load of 210 MW. The city is supplied by two generators totaling 150 MW, and by a 138 kV double circuit transmission line from the main grid. Prime reinforcement options are as follows:

1. Add a new single circuit transmission line as indicated in Fig. 13.19.
2. Add one gas turbine generator of size to be determined.
3. Add two identical gas turbine generators of size to be determined.

Key questions of interest are:

1. Can the line addition be justified on the basis of savings in customer interruption cost?
2. What generator capacities will produce the same reliability improvements as the line addition?
3. What size generators can be justified on the basis of customer interruption?

Figure 13.20 shows results obtained from the Monte Carlo calculations along with the annual fixed charges for investment cost and net annual operating costs. Significant observations that can be made from Fig. 13.20 are:

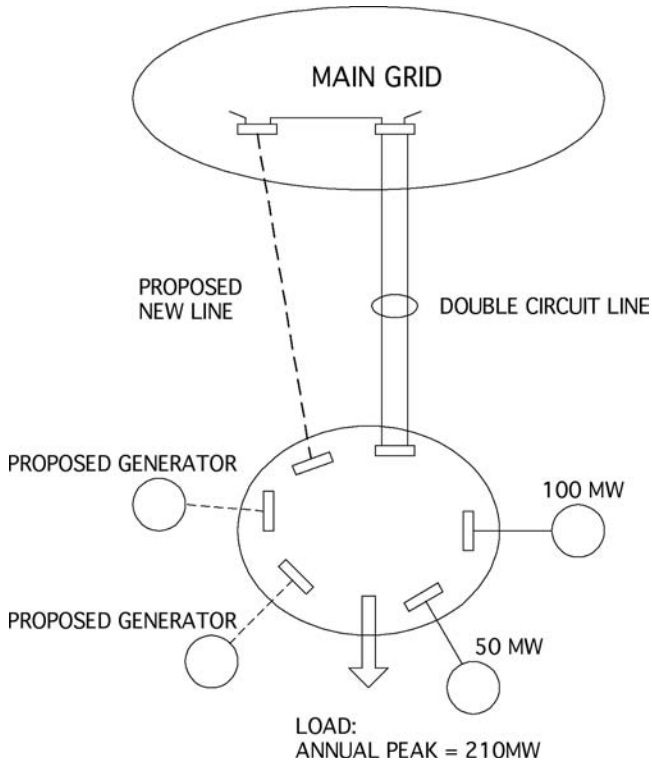

FIGURE 13.19 Power supply configuration for a small city.

- The additions of a new 138 kV line, a 50 MW generator, or two 25 MW generators have approximately the same interruption cost savings. However, the reason for this is that all three alternatives are an effective overkill, reducing the interruption cost to almost 0. If load is anticipated to grow, the line addition will be the better performer at a lower cost.
- One 15 MW to 25 MW generator would give much improved performance and at a cost which can be justified (marginally) based on reliability worth as expressed by the interruption cost curves.
- The line addition is clearly the most cost-effective alternative.

The first set of calculations compared the benefit of reinforcement by transmission or generation. While such additions are typically the most powerful reinforcements from the standpoint of improved reliability, they are typically also the most expensive. In addition, when dealing with small local systems, the natural or cost-effective line and generation additions are often more than what's needed to satisfy reliability needs for the next few years. This is particularly true for low load growth scenarios. Thus, there is a need for less expensive alternatives that typically will have smaller incremental reliability benefits than the addition of transmission lines and generators. The results of four such alternatives are shown in Fig. 13.20:

1. Improve reliability performance of existing generators.
2. Improve grounding of transmission lines.
3. Introduce live line maintenance.
4. Interruptible load contracts.

All of the short term measures except live line maintenance can be justified as the annual interruption cost is greater than the total expense associated with the reliability improvement. Also, live line maintenance and transmission line grounding have too small an impact to be of interest.

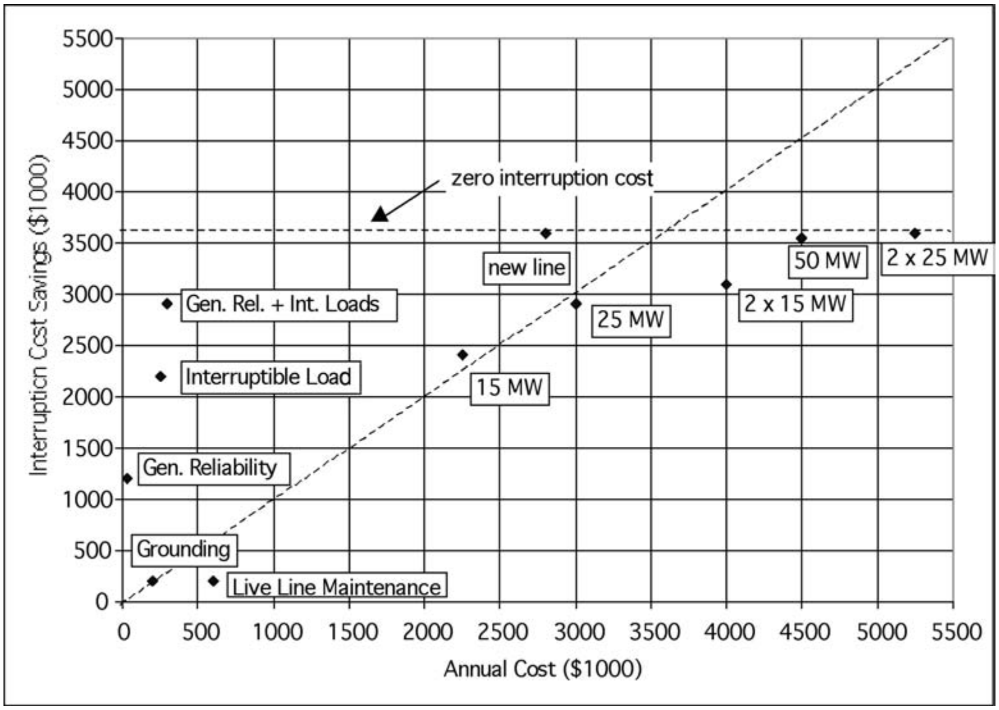

FIGURE 13.20 Annual savings in cost of interruption vs. annual combined investment and operating costs of transmission and generation reinforcements and short term measures. Measures in the upper left triangle can be justified on account of savings in interruption cost.

The most cost effective short term measure comes from improvements in the reliability performance of the 100 MW generator, closely followed by interruptible load contracts. If both of these short term measures are taken, the reliability improvement matches that obtainable from the addition of a 25 MW gas turbine generator and at a much lower cost.

This example illustrates how it is possible to use Monte Carlo reliability calculations to predict and compare the benefit-cost trade-off of transmission and generation reinforcements and various short term measures.

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13.4 Power System Planning

Hyde M. Merrill

Power system planning is the recurring process of studying and determining what facilities and procedures should be provided to satisfy and promote appropriate future demands for electricity. The electric power system as planned should meet or balance societal goals. These include availability of electricity to all potential users at the lowest possible cost, minimum environmental damage, high levels of safety and reliability, etc. Plans should be technically and financially feasible. Plans also should achieve the objectives of the entity doing the planning, including minimizing risk.

The *electric power system* is a force-at-a-distance energy-conversion system. It consists of three principal elements:

- Current- and voltage-producing, transmitting, and consuming hardware,
- Control and protective devices, and
- Planning, operating, commercial, and regulatory practices and procedures.

These definitions are very different from would have appeared on these pages 25 years ago. They no doubt will seem quaint 25 years hence. At this writing, the electric power industry worldwide is experiencing its most dramatic changes in two generations. These changes affect planning, but this section is intended as a practical exposition, not as a history lesson or a prophesy. We therefore will focus on how planning is or should be done today, avoiding flights of fantasy into the past or future (Sullivan, 1977; Stoll et al., 1989; Kahn, 1988; Ringlee, 1989).

Planning considers:

- Options,
- Uncertainties, and
- Attributes.

Options are the choices available to the planner. Uncertainties are parameters whose values are not known precisely or cannot be forecast without error. Attributes are measures of "goodness." Stakeholder objectives are expressed in terms of attributes. Physical, economic, and institutional realities determine how different options and uncertainties affect the attributes.

The planning problem is to identify and choose among options, in the presence of uncertainties, so as to maximize or minimize (as the case may be) the attributes.

Planning Entities

Planners generally are trained as engineers, economists, civil servants, businessmen, or mathematicians. They do power system planning for the following entities:

- Vertically integrated utilities owning generation, transmission, and distribution systems.
- Transmission companies, independent system operators (ISO), and regional transmission organizations (RTO). Transmission companies own transmission assets; the latter do not, but may have some responsibility for their planning.
- Pools or combinations of vertically integrated utilities.

Other organizations do planning studies and higher-level power sector planning. A step removed from the operation and management of the power system, their interest is in seeing that it meets society's goals:

- Various levels of government.
- International development banks.

Still other organizations do power system planning studies, but without system responsibility. They wish to understand the market for various services and how they might compete in it — its economics and technical requirements for entry.

- Independent power producers (IPP) or nonutility generators (NUG). These include qualifying facilities (QF as defined by the U.S. Public Utilities Regulatory Policy Act of 1978) and exempt wholesale generators (EWG as defined by the U.S. Energy Policy Act of 1992). These are subject to less stringent regulation than are utilities. They neither enjoy monopoly protection nor have an obligation to provide electricity at cost-based tariffs.
- Large industrial users.
- Commercial middlemen who buy and sell electrical energy services.
- Investors.

All of these are supported by independent purveyors of planning information. Consultants with specialized analytic skills also do planning studies.

Arenas

Planning is done in several arenas, distinguished by the planning horizon and by the types of options under consideration. These arenas include:

- **Long-term vs. short-term planning**. Economists distinguish these by whether capital investment options are considered. For engineers, long-term planning has a distant horizon (perhaps 30 years for generation and half of that for transmission). Short-term planning considers about 5 years. Operations planning is for as short as a few hours and is not treated here.

- **Generation vs. transmission vs. least-cost planning**. Generation and transmission planning focus on supply options. Least-cost planning includes demand-side options for limiting or shaping load.
- **Products and services**. Some entities provide power (kW) and energy (kWh). Others plan the transmission system. Others provide for auxiliary services (voltage and power control, electrical reserves, etc.). Still others plan for diversified services like conservation and load management.

Other arenas require engineering and economic skills, but are within the purview of a book on business or policy rather than an engineering handbook.

- **Competitive markets**. Strategic planning is particularly concerned with financial and business plans in competitive markets.
- **Sector evolution**. Defining the form of the future power sector, including the relationships between competitive forces, regulation, and the broadest social objectives, is a particularly vital planning function.

The Planning Problem

Options

Power generation, transformer, transmission system, substation, protection, and operation and control options are discussed in other chapters of this handbook. Other options are discussed below.

Planning and Operating Standards or Criteria

Planning and operating criteria have a dual nature: they are both attributes and options. Here we will emphasize the fact that they are options, subject to change. Though they have no intrinsic value, standards or criteria are important for several reasons. Their consistent application allows independent systems to interconnect electrically in symmetrical relationships that benefit all. Criteria can also eliminate the need for planners to ask constantly, "How much reliability, controllability, etc., do I need to provide?" Criteria include:

- Maximum acceptable loss-of-load probability (LOLP) or expected unserved demand, minimum required reserve margins, and similar generation planning standards,
- What constitutes a single contingency (transmission systems are often designed to withstand "any" single contingency) and whether particular single contingencies are excluded because they are unlikely or expensive to forestall,
- Permissible operating ranges (voltages, power flows, frequency, etc.) in the normal or preventative state, the emergency state, and the restorative state, and
- How criteria are to be measured or applied.

Most power systems in industrialized nations are designed and operated so that:

1. With all elements in service, power flows, voltages, and other parameters are within normal ranges of the equipment,
2. The system remains stable after any single contingency, and
3. Power flows, voltages, and other operating parameters are within emergency ranges following any single contingency.

For financial and economic reasons, developing countries choose weaker criteria.

Demand Management

Demand-side planning often is tied to generation planning because it affects the power and energy that the power plants will need to provide. There is no perfect classification scheme for demand-side options. Some overlapping classifications are:

- Indirect load control vs. direct load control by the bulk system operator,
- Power (kW) or energy (kWh) modification or both, and
- Type of end-use targeted.

TABLE 13.5 Appliances and Sectors under Direct Utility Control, U.S. — 1983

Appliance or Sector	Number Controlled	Percent of Total Controlled
Electric water heaters	648,437	43%
Air conditioners	515,252	34%
Irrigation pumps	14,261	1%
Space heating	50,238	3%
Swimming pool pumps	258,993	17%
Other	13,710	1%
Total	**1,500,891**	**100%**
Residential	1,456,212	97%
Commercial	29,830	2%
Industrial	588	—
Agricultural	14,261	1%

Source: New Electric Power Technologies: Problems and Prospects for the 1990s, Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-246, July 1985.

Table 13.5 shows the type of load under direct utility control in the U.S. early in the 1980s, when enthusiasm for demand-side options was especially high.

One of the most effective examples of load control was reported by a German utility. Typical off-peak winter demand was less than 70% of the peak for the same day. An indirect program promoted storage space heaters that use electricity at night, when demand is low, to heat ceramic bricks. During the day, air forced among the bricks transfers the heat to the living space. Within five years the program was so popular that direct control was added to avoid creating nighttime peaks. The winter daily load shape became practically flat.

Market and Strategic Options

Market and strategic options are also important. These range from buying a block of power from a neighboring utility to commodity trading in electricity futures to mergers, divestitures, and acquisitions.

Uncertainties

Uncertainty can seldom be eliminated. Planning and forecasting are linked so that even if the forecasts are wrong, the plans are right (Bjorkland, 1987).

Models of Uncertainty (Schweppe, 1973)

Probabilistic models, where different outcomes are associated with different probabilities, are valid if the probability structure is known. The events involved must occur often enough for the law of large numbers to apply, or else the probabilities will have little relationship to the frequencies of the outcomes. Generation planners have excellent probabilistic reliability models. (Generation and transmission reliability evaluation are treated in more detail in a separate section.)

Unknown-but-bounded (set theoretic) models are used when one or both of the conditions above are not met. For instance, transmission planners design to withstand any of a set of single contingencies, usually without measuring them probabilistically.

Demand Growth

Planners forecast the use of energy (MWh) for a period (e.g., a year) first. They divide this by the hours in the period to calculate average demand, and divide again by the projected load factor (average MW demand/peak MW demand) to forecast peak demand. Three techniques are used most often to forecast energy.

Extrapolation — Exponential growth (e.g., 4%/year) appears as a straight line on semi-log paper. Planners plot past loads on semi-log paper and use a straight edge to extrapolate to the future.

Econometric models — Econometric models quantify relationships between such parameters as economic activity and population and use of electricity. The simplest models are linear or log-linear:

$$D_i = f\left(P, \text{GDP, etc.}\right) = k_1 D_{i-1} + k_2 P_i + k_3 \text{GDP}_i + \ldots \qquad (13.1)$$

D_i = Demand or log(demand) in period i
P_i = Population or log(population) in period i
GDP_i = Gross domestic product or log(gross domestic product) or some measure of local economic activity
k_1, k_2, k_3, etc. are coefficients

Econometric models are *developed* in a trial-and-error process. Variants of Eq. (13.1) are hypothesized and least squares (regression) analysis is used to find values of coefficients that make Eq. (13.1) fit historical data. Econometric models are *used* by first forecasting population, economic activity, etc., and from them calculating future energy demand using Eq. (13.1).

End-use models — First, the number of households is forecast. Then the per-household penetration of various appliances is projected. The average kWh used by each appliance is estimated and is multiplied by the two previous numbers. The results are summed over all types of appliances.

Performance — Extrapolation became suspect after U.S. load forecasts in the 1970s were consistently too high. Econometric modeling is more work but is more satisfying. End-use modeling requires considerable effort but gives the most accurate forecasts of residential load.

Real drivers — One fundamental driver for per-capita load growth is the replacement by electricity of other forms of energy use. The second is the creation of new uses of energy that are uniquely satisfied by electricity.

During the decades when U.S. electric demand grew at over 7% per year, the demand for all forms of energy (of which electricity is a part) grew at about 2% per year. This obviously could not continue: the two cannot cross. The growth of electricity demand began to drop off about 1955, declining noticably in the 1970s and thereafter. The drop in load growth was attributed to the oil crises of the 1970s. Post-1973 conservation played a part, but by then electricity had captured about all the market share it was going to get by replacement and creation of new demands for energy.

In developing countries, both fundamental drivers are limited by the ability of the electric companies to finance the necessary generation and distribution infrastructure, which is very expensive. Demand is also limited by their ability to generate. In industrialized countries, availability of capital and power plant performance are not constraining. In all countries, elasticity reduces demand if electricity is costly. This effect is much stronger in countries with low per-capita income and for energy-intensive industrial load.

Fuel and Water

In the near term, strikes, weather, and natural disasters can interrupt production or delivery. Fuel inventories and the ability to redispatch provide good hedges. In the intermediate term, government action can make fuel available or unavailable. For instance, in 1978, the U.S. Congress forbade burning natural gas by utilities, perceiving that there was a shortage. The shortage became a glut once the U.S. natural gas market was deregulated. In the long term, any single source of fuel is finite and will run out. British coal, which had fueled the industrial revolution, was shut down in the 1990s because it had been worked out.

The more important fuel uncertainties, however, are in price. For instance, Fig. 13.21 shows that the price of crude oil doubled in 1974 and again in 1979. Recognizing the high variability, in 1983 the U.S. Department of Energy forecast a fuzzy band instead of a single trajectory (U.S. Dept. of Energy, 1983). It is interesting that within a year of the publication of this projection, the price of oil had dropped below the low limit of the band, and it has remained there until this writing. Planners must consider extreme possibilities for all uncertainties.

Brazil, Norway, the Pacific Northwest, Quebec, and a number of developing countries are highly dependent on hydropower. Systems usually are planned and operated so that there will not be a shortfall unless one of the worst hydrological years in recorded history recurs.

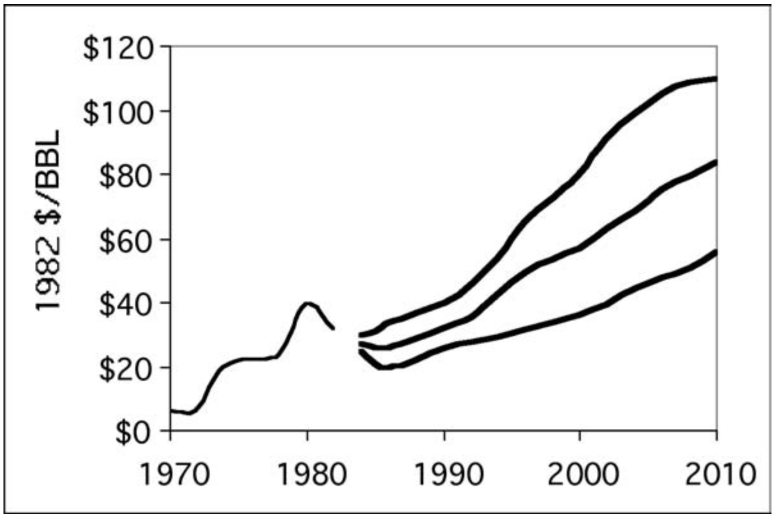

FIGURE 13.21 World oil price projections, 1983.

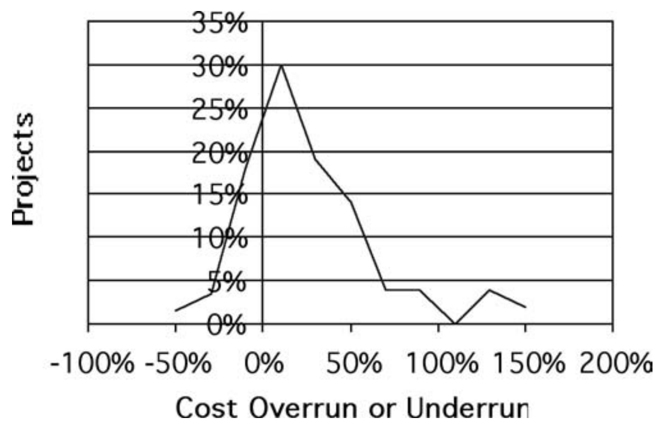

FIGURE 13.22 Budget vs. actual costs, power projects in developing countries.

Construction

Three major construction uncertainties are: How long will it take to build? How much will it cost? Will the project be completed?

A World Bank study of 41 hydro projects revealed that 37% experienced a schedule slip of 30% or more, including 17% with schedule slips of 60%–100% (Crousillat, 1989).

Figure 13.22 shows the range of actual versus budgeted cost for a number of World Bank-financed projects. The distribution is not symmetrical — overruns are much more frequent than under-budget projects. Some of the worst cases in the Fig. 13.22 data occurred during periods of unexpected high inflation (Crousillat, 1989). A 1983 report projected that the cost of some 40 U.S. nuclear plants scheduled for completion by 1990 would be close to normally distributed, with the least expensive costing a bit under $2000/kW and the most expensive three times higher, at $6000/kW (U.S. Dept. of Energy, 1989).

Possibly the most expensive nuclear plant ever built, the Shoreham Plant on Long Island, was completed at a cost of some $16 billion U.S. It was shut down by the state before producing a single kWh of commercial energy.

Technology

New technologies are generally less certain than mature technologies in their cost, construction time, and performance.

Even mature technologies may have important uncertainties. For example, transmission transfer capability is an important measure of transmission system capability. It is usually expressed as a single number, but it is actually a time-varying random variable.

Demand Management

Demand management programs are risky, in part because of uncertainty in the public's response to them. The two major uncertainties are:

- What fraction of eligible customers will respond to a particular program?
- How much will the average customer change his use of electricity?

These uncertainties are affected strongly by the design of the program, the incentives offered, how it is marketed, etc. Carrying out a carefully designed pilot program can reduce the uncertainty. The pilot program should be done in the region of the future commercial program.

Markets and Capital Recovery

For many years, vertically integrated utilities were guaranteed the recovery of all costs, including capital invested, plus a modest but sure profit. The customer paid this and absorbed the market uncertainties. At this writing, the regulated monopoly, cost-recovery market is being replaced in many states and countries by a more competitive market. Some market risks are being transferred from customers to utilities, power marketers, generating companies, speculators, and others.

This creates new uncertainties. For example, in competitive generation markets it is not known which potential generating units will be built. This affects both transmission and generation planning.

Regulation

For the foreseeable future, government will play a key role. The uncertainty in what governments will do propagates into uncertainties in profitability of various players, in market entry, in prices, etc.

For example, in the 1980s, U.S. state and federal governments encouraged utilities to implement demand-side programs. Program costs, and in some cases costs of foregone sales, were recovered through tariffs. The government interest later switched to competitive markets. These markets do not have such a convenient mechanism for encouraging demand-side management. As a result, demand-side programs became less attractive.

Severe Events

High-risk, low-probability events usually are not considered by standard planning practices. For example, transmission planners design so that the system will withstand any single contingency. Planning procedures, criteria, and methods generally ignore several simultaneous or near-simultaneous contingencies. The power system is not designed to withstand them — whether or not it does is happenstance.

In January 1998 an ice storm of unprecedented magnitude struck the northeastern U.S. and Quebec. Ice on transmission lines greatly exceeded design standards. Many towers collapsed. All lines feeding Montreal, and all lines south and east of the city, were on the ground. The government later announced a high-risk, low-probability standard: the system should be designed and operated to prevent loss of more than half of the Montreal load should such an event recur.

Attributes

Attributes measure "goodness" in different ways, from different perspectives. Each stakeholder has objectives; they are expressed in terms of attributes.

Customers of various kinds (residential, commercial, industrial, etc.):

- Cost of electricity
- Other costs absorbed by the customer
- Quality of service (reliability, voltage control, etc.)

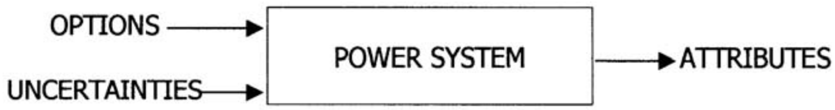

FIGURE 13.23 Options, uncertainties, and attributes.

Investors in various providers of energy and services

- New capital required
- Net income, earnings per share, and other measures of income
- Cash flow, coverage ratios, and other measures of cash use and replacement

Employees

- Security
- Promotion opportunities
- Salaries
- Healthiness and safety of working conditions

Taxpayers

- Tax revenues
- Expenditures from public funds

Neighbors (environmentalists, visitors, local inhabitants, competitors, etc.)

- Emissions or thermal discharges
- Community disruption
- Employment opportunities
- Rights-of-way and other intrusions
- Flooding
- Measures of market power

The list of attributes given above is not complete, and different attributes are important for different studies. Deciding on the planning objectives and the attributes for a given study is an important initial step in power system planning.

Some attributes are measured using complex computer models. For others, approximate or ad hoc models may be adequate or may be the best that is available. The planner calculates how the options and the uncertainties (Fig. 13.23) affect the attributes.

Standards or criteria are surrogates for some attributes that are difficult or impossible to compute.

Planning Processes

Setting Standards or Criteria

Planning objectives often conflict. For example, maximizing reliability and minimizing environmental impacts generally conflict with minimizing costs.

Since all attributes cannot be measured in dollars, achieving the right trade-off can be a difficult socio-technico-economic-institutional problem. Doing this every day would burden the planning process. Having standards avoids having to revisit such judgments continually. For instance, once it is decided that (say) 20% generation reserve provides adequate reliability at an acceptable cost, the planner accepts 20% as a standard and designs to meet it. Testing whether a particular plan meets the reserve criterion is easy; the planner can concentrate on other issues.

Standards should be examined from time to time. If society becomes poorer or richer, its pocketbook may speak for lower or higher standards of service. Changes in technology may justify a change in standards — for instance, development of better scrubbers may make it reasonable to insist on reduced SO_2 or NOx emissions. Increased reliance on electricity may require more reliability: a proposal to shut off the power throughout the U.S. for one minute to salute Edison's death was quashed. Had he died in 1900 instead of 1931, it might have been practical.

Assessment

Forecasts and Projections

Not all uncertainties create risk for every planning study. Those that do for a particular study are identified. Forecasts and projections are developed for these uncertainties.

System State

The state assessment begins with an evaluation of the technical and economic attributes of the present and future power system. Does it and will it satisfy established technical standards? Is it economical? Does it meet other objectives?

Chapter 8 of this handbook, "Power System Analysis and Simulation," describes the analytical tools available to planners. It also describes how these tools are used. The phenomena analyzed are described in Chapters 10 through 12.

Generation Planning

Chapter 2 of this handbook, "Electric Power Generation: Conventional Methods," describes generation planning options and their characteristics. The generation planner does a preliminary selection from among them, recognizing any special features of his planning problem.

Planners measure how the various options would alleviate deficiencies discovered in the assessment step. The effects of various options or combinations of options and the effects of uncertainties on other attributes are also measured.

In particular, planners compute reserve margin or other measures of reliability. They simulate the operation of the system to measure operating cost and to determine if the operation is within acceptable ranges of other parameters.

Transmission Planning

Traditional transmission options and new technologies are described in Chapters 3, 4, 11, 14, and 15 of this handbook. Like the generation planner, the transmission planner makes a preliminary selection based on the needs and development pattern of his system.

For instance, for technical and commercial reasons, a given system will use only a few distinct voltage classes. So a system whose existing transmission consists of 138-kV, 345-kV, and 765-kV equipment will rarely add new circuits at 230 kV or 400 kV, even though these may be popular elsewhere.

Transmission planners then identify a set of specific options and measure how these options in various combinations, along with the important uncertainties, affect the attributes. Load flow, short circuit, and stability analyses are performed to determine if voltages and currents are within acceptable bounds under various system states, and if the system will remain stable for all contingencies. How often and how much the operation of the generation system will be constrained by transmission limitations is an important consideration.

Least-Cost Planning

Least-cost planning is also known as integrated resource planning or integrated demand/supply planning. It considers supply-side options (generally generation options) on a level playing field with demand-side options (generally conservation, indirect load shifting, or direct load control). These options include incentives to encourage utilities and consumers to change energy consumption patterns.

As with generation planning and transmission planning, a preliminary selection weeds out options that are clearly not of interest in a particular area.

The least-cost planning process includes computing values of key attributes for various options and uncertainties.

Making Choices

A key question in generation, transmission, and least-cost planning is: How is one plan selected over another? A few distinctive approaches will be described.

Minimize Revenue Requirements

The planner selects the best option from the ratepayer's perspective. He selects the plan that will minimize the ratepayer's cost of electricity while satisfying reliability, environmental, and other criteria.

The ratepayer's cost — an attribute — is the revenue that the utility will have to collect to recover all operating and capital costs and to earn a commission-approved return on unrecovered investor capital:

$$RR_i(\mathbf{O},\mathbf{U}) = FC_i(\mathbf{O},\mathbf{U}) + VC_i(\mathbf{O},\mathbf{U}) \tag{13.2}$$

$RR_i(\mathbf{O},\mathbf{U})$ = Revenue requirements in period i
$FC_i(\mathbf{O},\mathbf{U})$ = Fixed costs in period i
$VC_i(\mathbf{O},\mathbf{U})$ = Variable costs in period i
$\mathbf{O}$ = A selection of the various options
$\mathbf{U}$ = Realizations or values of the various uncertainties

Fixed costs are independent of how much or how little a piece of equipment is used. Depreciation (recovery of investors' capital), interest on debt, and profit (return on unrecovered capital) are typical fixed costs.

Variable costs — fuel cost — for example, are related to how much a piece of equipment is used. These costs include all system costs, not just the cost of the individual option. For instance, old plants may run less when a new plant is built. The variable cost includes fuel cost for all plants.

To apply this traditional method, the planner must know his company's return rate, which is set by the regulator. In a closely related method, the market defines the cost of electricity and Eq. (13.2) is solved for the internal rate of return (IRR). The option selected is the one that maximizes the IRR, the investor's profit.

Cost-Benefit Analysis

If the benefits exceed the costs, a project is worth doing.

Typically, costs are incurred first, and benefits come later. A dollar of benefit later is not worth the same as a dollar of cost today. Present worth analysis is a way to compare dollars at different times. The basic equation is:

$$P = S \big/ (1+i)^n \tag{13.3}$$

In Eq. (13.3), P is the present worth or equivalent value today of an amount S, n years in the future, with i the discount rate or annual cost of capital.

Cost-benefit analysis is also used to rank mutually exclusive projects — the one with the highest benefit/cost ratio wins.

Multi-Objective Decision Analysis

Utility Function Methods

Table 13.6 compares two options for a new power plant in Utah (Keeney et al., 1981). Which choice is better? The attributes are combined in a utility function of the form:

$$U(x) = k_1\text{Economics} + k_2\text{Environment} + \ldots + k_7\text{Feasibility} \tag{13.4}$$

TABLE 13.6 Attributes: Nuclear Plant vs. Coal Plant

	Wellington Coal Plant	Green River Nuclear Plant
Economics ($/MWh)	60.7	47.4
Environment (corridor-miles)	532.6	500.8
Public disbenefits ($ × 000,000)	15.0	22.6
Tax revenues ($ × 000,000/year)	3.5	1.0
Health lost (equivalent years)	446.7	6.3
Public attitudes	0.33	–1.0
Feasibility	60.0	37.0

From Keeney, R. L. et al., *Decision Framework for Technoloy Choice,* Report EA-2153, Electric Power Research Institute, Palo Alto, CA, 1981. With permission.

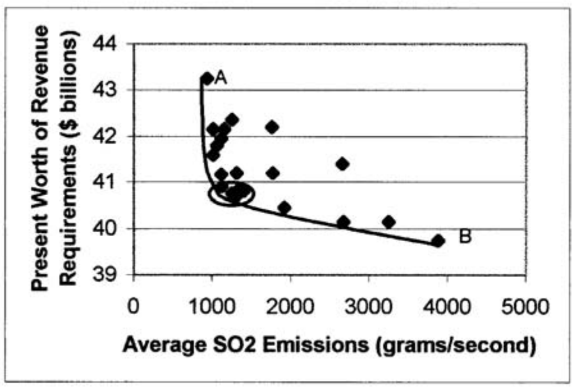

FIGURE 13.24 Trade-off: cost vs. SO_2 emissions.

In Eq. (13.4), x takes on one of two values, "coal" or "nuclear." [The actual functional form for a particular study may be more complicated than Eq. (13.4).] The coefficients k_i reflect the relative importance of each attribute. These coefficients convert the different attributes to a common measure. The choice that minimizes the utility function wins. In this study, for the values of coefficients selected U(coal) was $131.4/MWh; U(nuclear) was $162.9/MWh.

This approach has many variants. Uncertainties can be included, making U(x) a random variable. Work has been done to develop methods for determining the decision-maker's values (the coefficients) and risk tolerance.

Trade-Off Analysis

Trade-off analysis measures each attribute in its natural units, without reducing them all to a common measure, and seeks reasonable compromises at points of saturation or diminishing return. A good compromise will not necessarily optimize any of the attributes, but will come close to optimizing all of them.

For example, Fig. 13.24 shows 22 plans examined in an energy strategy study. The plans in region A minimize SO_2 emissions, but are very costly. The plans in region B are cheap but have high emissions. The plans at the knee of the trade-off curve are at the point of diminishing returns for one attribute against the other. Significant reductions in emissions can be had at little cost by moving from B to the knee. Going beyond the knee toward A will not reduce SO_2 much more but will increase the cost significantly. The plans at the knee come close to minimizing both cost and emissions.

Trade-off analysis can be done graphically for two-attribute problems. More than two attributes cannot be graphed easily but can be analyzed mathematically (Crousillat, 1993).

Risk

Risk is the hazard due to uncertainty. Risk is also associated with decisions. Without uncertainties and alternatives, there is no risk.

System planning, engineering, and operating procedures have evolved to reduce the risks of widespread or local service interruptions. Another section of this handbook describes methods for modeling and enhancing reliability.

Not all risks are included in reliability analysis, however. Much talk about risk is directed to financial risks. Other important risks are not quantified in dollars.

One measure of risk is *robustness*, the likelihood that a particular decision will not be regretted. *Exposure* is the possible loss (in terms of an attribute) under adverse realizations of uncertainties. *Regret* is the difference between the value of an attribute for a particular set of decisions and realizations of uncertainties, and the value of the attribute for optimized decisions with perfect foreknowledge of the uncertainties.

Planners develop *hedges*, options that increase robustness or decrease exposure or regret. Building small generating units instead of large ones is an example; an insurance policy is another (De la Torre et al., 1999).

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13.5 Power System Reliability

Richard E. Brown

The electric power industry began in the late 1800s as a component of the electric lighting industry. At this time, lighting was the only application for electricity, and homes had other methods of illumination if the electricity supply was interrupted. Electricity was essentially a luxury item and reliability was not an issue.

As electricity became more common, new applications began to appear. Examples include electric motors, electric heating, irons, and phonographs. People began to grow accustomed to these new electric appliances, and their need for reliable electricity increased. This trend culminated with the invention of the radio. No nonelectrical appliance could perform the same function as a radio. If a person wanted to listen to the airwaves, electricity was required. As radio sales exploded in the 1920s, people found that reliable electricity was a necessity. By the late 1930s, electricity was regarded as a basic utility (Philipson and Willis, 1999).

As electric utilities expanded and increased their transmission voltage levels, they found that they could improve reliability by interconnecting their system to neighboring utilities. This allowed connected utilities to "borrow" electricity in case of an emergency. Unfortunately, a problem on one utility's system could now cause problems to other utilities. This fact was made publicly evident on November 9, 1965. On this day, a major blackout left cities in the northeastern U.S. and parts of Ontario without power for several hours. Homes and businesses had become so dependent on electricity that this blackout was crippling. Action was needed to help prevent such occurrences from happening in the future.

NERC Regions

The North American Electric Reliability Council (NERC) was formed in 1968 as a response to the 1965 blackout. By this time, reliability assessment was already a mature field and was being applied to many types of engineered systems (Billinton and Allan, 1988; Ramakumar, 1993). NERC's mission is to promote the reliability of the North America's bulk power system (generation and transmission). It reviews past events; monitors compliance with policies, standards, principles, and guides; and assesses future reliability for various growth and operational scenarios. NERC provides planning recommendations and operating guidelines, but has no formal authority over electric utilities.

Since most of the transmission infrastructure in the U.S. and Canada is interconnected, bulk power reliability must look at systems larger than a single utility. The territory covered by NERC is far too large to study and manage as a whole, and is divided into ten regions. These NERC regions are: East Central Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Florida Reliability Coordinating Council (FRCC), Mid-Atlantic Area Council (MAAC), Mid-Atlantic Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP), and the Western Systems Coordinating Council (WSCC). The geographic territories assigned to the ten NERC regions are shown in Fig. 13.25.

Even though there are ten NERC regions, there are only four major transmission grids in the U.S. and Canada: the area associated with the Western Systems Coordinating Council, the area associated with the Electric Reliability Council of Texas, Quebec, and the Eastern United States. These are usually referred to as the Western Interconnection, the ERCOT Interconnection, the Quebec Interconnection, and the Eastern Interconnection. Each of these grids is highly interconnected within their boundaries, but only has weak connections to the other grids. The geographic territories associated with these four interconnections are shown in Fig. 13.25.

NERC looks at two aspects of bulk power system reliability: system adequacy and system security. A system must have enough capacity to supply power to its customers (adequacy), and it must be able to continue supplying power to its customers if some unforeseen event disturbs the system (security). Each of these two aspects of reliability is further discussed below.

System Adequacy Assessment

System adequacy is defined as the ability of a system to supply all of the power demanded by its customers (Billinton and Allan, 1988). Three conditions must be met to ensure system adequacy. First, its available generation capacity must be greater than the demanded load plus system losses. Second, it must be able to transport this power to its customers without overloading any equipment. Third, it must serve its loads within acceptable voltage levels.

System adequacy assessment is probabilistic in nature (Allan et al., 1994; Schilling et al., 1989). Each generator has a probability of being available, P_A, a probability of being available with a reduced capacity,

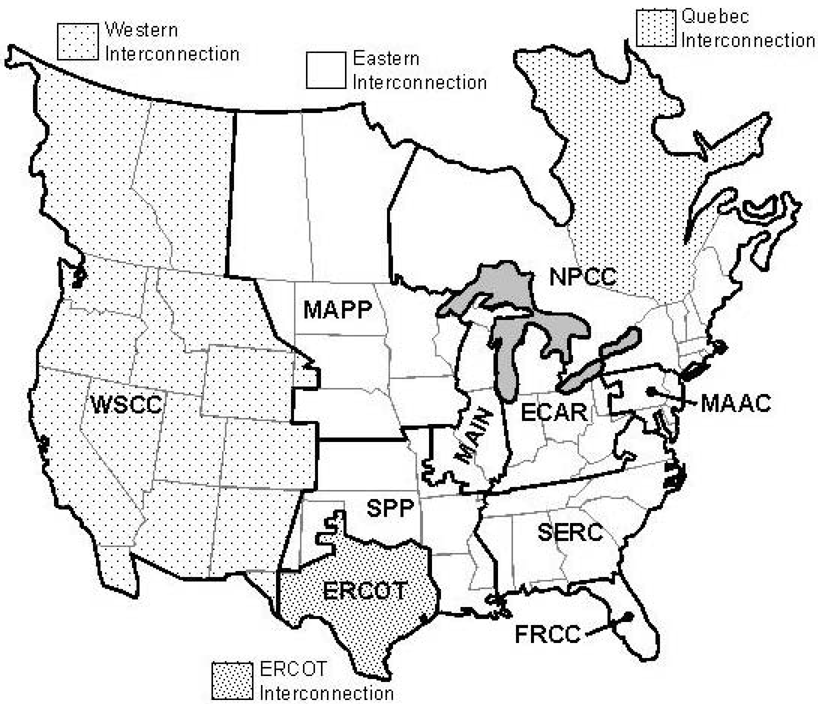

FIGURE 13.25 NERC regions.

TABLE 13.7 Generator State Probabilities

Generator State		
Generator 1	Generator 2	Probability
Available	Available	$P_{A1}\ P_{A2}$
Available	Reduced	$P_{A1}\ P_{R2}$
Available	Unavailable	$P_{A1}\ P_{U2}$
Reduced	Available	$P_{R1}\ P_{A2}$
Reduced	Reduced	$P_{R1}\ P_{R2}$
Reduced	Unavailable	$P_{R1}\ P_{U2}$
Unavailable	Available	$P_{U1}\ P_{A2}$
Unavailable	Reduced	$P_{U1}\ P_{R2}$
Unavailable	Unavailable	$P_{U1}\ P_{U2}$

P_R, and a probability of being unavailable, P_U. This allows the probability of all generator state combinations to be computed. A simple two-generator example is shown in Table 13.7. There are nine possible generator state combinations, and the probability of being in a particular combination is the product of the individual generator state probabilities. In general, if there are n generators and x possible states for each generator, the number of possible generator state combinations is:

$$Generator\ State\ Combinations = x^n \tag{13.5}$$

In addition to generator state combinations, loading behavior must be known. Information is found by looking at historical load bus demand in recent years. For the best accuracy, 8760 hour peak demand curves are used for each load bus. These correspond to hourly peak loads for a typical year. To reduce

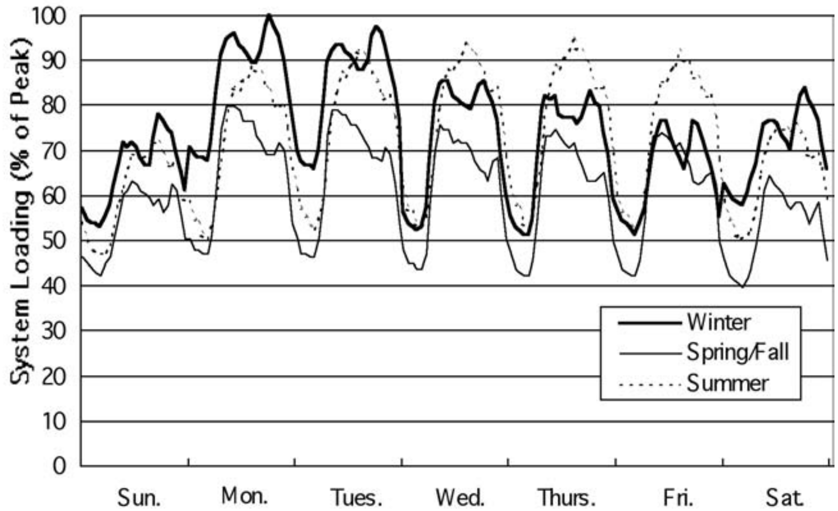

FIGURE 13.26 Weekly load curves by season.

computational and data requirements, it is usually acceptable to reduce each set of 8760-hour load curves to three weekly load curves (168 hours each). These correspond to typical weekly load patterns for winter conditions, spring/autumn conditions, and summer conditions. Weekly load curves can be scaled up or down to represent temperatures that are above or below normal. Sample weekly load curves for a winter peaking load bus are shown in Fig. 13.26.

To perform an adequacy assessment, each generation state combination is compared with all hourly loading conditions. For each combination of generation and loading, a power flow is performed. If the available generation cannot supply the loads or if any constraints are violated, the system is inadequate and certain loads must be shed. After all generation/load combinations are examined, the adequacy assessment is complete.

An adequacy assessment produces the following information for each load bus: (1) the combinations of generation and loading that result in load interruptions, and (2) the probability of being in each of these inadequate state combinations. From this information, it is simple to compute the expected number of interruptions for each load bus, the expected number of interruption minutes for each load bus, and the expected amount of unserved energy for each load bus. These load bus results can then be aggregated to produce the following system indices:

- ***LOLE*** (Loss of Load Expectation) — the expected number of hours per year that the system will have to shed load.
- ***EENS*** (Expected Energy Not Served) — the expected number of megawatt hours per year that a system will not be able to supply.

System adequacy assessment assumes that the transmission system is available. This may not always be the case. A classic example is the 1965 blackout, which was initiated by the unexpected loss of a transmission line. To address such events, system security assessment in required.

System Security Assessment

System security is defined as the ability of a power system to supply all of its loads in the event of one or more contingencies (a contingency is an unexpected event such as a system fault or a component outage). This is divided into two separate areas: static security assessment and dynamic security assessment.

Static security assessment determines whether a power system is able to supply peak demand after one or more pieces of equipment (such as a line or a transformer) are disconnected. The system is tested by removing a piece (or multiple pieces) of equipment from the normal power flow model, rerunning the power flow, and determining if all bus voltages are acceptable and all pieces of equipment are loaded below emergency ratings. If an unacceptable voltage or overload violation occurs, load must be shed for this condition and the system is *insecure*. If removing any single component will not result in the loss of load, the system is *N*-1 *Secure*. If removing any *X* arbitrary components will not result in the loss of load, the system is *N-X Secure*. *N* refers to the number of components on the system and *X* refers to the number of components that can be safely removed.

Performing a static security assessment can be computationally intensive. For example, an *N*-2 assessment on a modest system with 5000 components (1500 buses, 500 transformers, and 3000 lines) will require more than 25 million power flows to be performed. For this reason, contingency ranking methods are often used. These methods rank each contingency based on its likelihood of resulting in load curtailment. Contingencies are examined in order of their contingency ranking, starting with the most severe. If a prespecified number of contingencies are tested and found to be secure, it is assumed that contingencies with less severe rankings are also secure and do not need to be examined.

Static security assessment is based on steady state power flow solutions. For each contingency, it assumes that the system protection has properly operated and the system has reached a steady state. In fact, the power system may not actually reach a steady state after it has been disturbed. Checking whether a system will reach a steady state after a fault occurs is referred to *as dynamic security assessment* (also referred to as *transient security assessment*).

When a fault occurs, the system is less able to transfer power from synchronous generators to synchronous motors. Since the instantaneous power input has not changed, generators will begin to speed up and motors will begin to slow down (analogous to the chain slipping while riding a bicycle). This increases the rotor angle difference between generators and motors. If this rotor angle exceeds a critical value, the system will become unstable and the machines will not be able to regain synchronism. After the protection system clears the fault, the rotor angle difference will still increase since the power transfer limits of the system are still less than the prefault condition. If the fault is cleared quickly enough, this additional increase will not cause the rotor angle difference to exceed the critical angle and the system will return to a synchronous state (ABB Power, 1997).

An example of a transient stability test is shown in Fig. 13.27. This shows the rotor angle difference between a synchronous generator and a synchronous motor during a fault sequence. When the fault occurs, the rotor angle begins to increase. If the fault is not cleared, the rotor angle quickly exceeds the critical angle. If the fault is cleared at 0.3 sec, the rotor angle still increases beyond the critical value. The

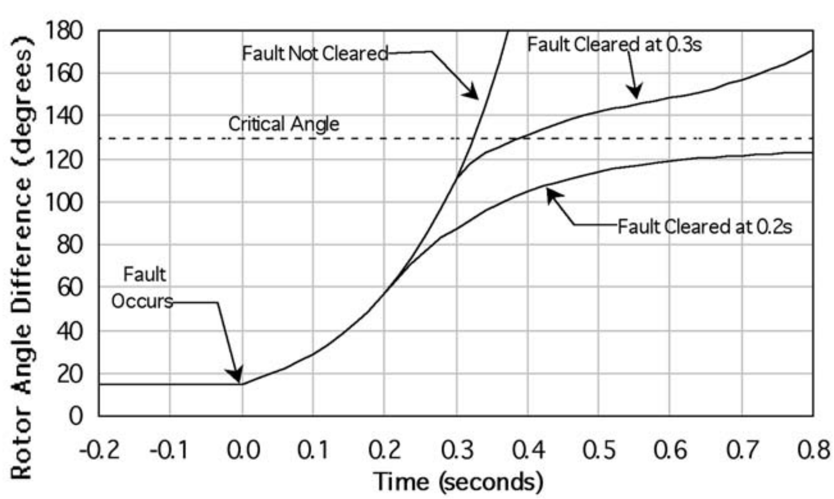

FIGURE 13.27 Dynamic security assessment.

system is dynamically stable for this fault if it is cleared in 0.2 sec. The rotor angle will still increase after the fault occurs, but will stabilize below the critical value.

A dynamic security assessment will consist of many transient stability tests that span a broad range of loading conditions, fault locations, and fault types. To reduce the number of tests required, contingency rankings (similar to static security assessment) can be used.

Probabilistic Security Assessment

Although the "N-1 Criterion" remains popular, it has received much criticism since it treats unlikely events with the same importance as more frequent events. Using the N-1 Criterion, large amounts of money may be spent to reinforce a system against a very rare event. From a reliability perspective, this money *might* be better spent in other areas such as replacing old equipment, decreasing maintenance intervals, adding automation equipment, adding crews, and so on. To make such value judgments, both the impact of each contingency and its probability of occurrence must be considered (Endrenyi, 1978). This is referred to as *probabilistic security assessment*. To do this type of assessment, each piece of equipment needs at least two fundamental pieces of information: the *failure rate* of the equipment (usually denoted λ, in failures per year), and the mean time to repair of the equipment (usually denoted *MTTR*, in hours).

Performing a probabilistic security assessment is similar to a performing a standard static security assessment. First, contingencies are ranked and simulated using a power flow. If a contingency results in the loss of load, information about the number and size of interrupted loads, the frequency of the contingency, and the repair time of the contingency are recorded. This allows quantities such as *EENS* (Expected Energy Not Served) to be easily computed. If contingency i causes kW_i amount of kilowatts to be interrupted, then *EENS* is equal to:

$$EENS = \sum_i kW_i \lambda_i MTTR_i \tag{13.6}$$

It is important to note that this is the *EENS* due to contingencies, and is separate from the *EENS* due to generation unavailability. It is also important to note that this formula assumes that $\lambda_i MTTR_i$ is small when compared to one year. If this is not the case, a component will experience fewer failures per year than its failure rate and the equation must be adjusted accordingly.

Distribution System Reliability

The majority of customer reliability problems stem from distribution systems. For a typical residential customer with 90 min of interrupted power per year, between 70 and 80 minutes will be attributable to problems occurring on the distribution system that it is connected to (Billinton and Jonnavitihula, 1996). This is largely due to radial nature of most distribution systems, the large number of components involved, the sparsity of protection devices and sectionalizing switches, and the proximity of the distribution system to end-use customers.

Since reliability means different things to different people, it is necessary to address the definition of "distribution system reliability" in more detail. In distribution systems, reliability primarily relates to equipment outages and customer interruptions:

- **Outage** — when a piece of *equipment* is deenergized.
- **Momentary interruption** — when a *customer* is deenergized for less than a few minutes.
- **Sustained interruption** — when a *customer* is deenergized for more than a few minutes.

Customers do not, in the strictest sense, experience power outages. Customers experience power interruptions. If power is restored within a few minutes, it is considered a momentary interruption. If not, it is considered a sustained interruption. The precise meaning of "a few minutes" varies from utility to utility, but is typically between 1 and 5 min. The IEEE defines a momentary interruption based on 5 min. (Note: some references classify interruptions into four categories rather than two. Instantaneous interruptions last a few seconds, momentary interruptions last a few minutes, temporary interruptions last a few hours, and sustained interruptions last many hours.)

On a historical note, momentary interruptions used to be considered a "power quality issue" rather than a "reliability issue." It is now generally agreed that momentary interruptions are an aspect of reliability since (1) momentary interruptions can cause substantial problems to all types of customers, and (2) many trade-offs must be made between momentary interruptions and sustained interruptions during system planning, operation, and control. It can also be observed that customer voltage sags, typically considered a power quality issue, are slowly becoming a reliability issue for similar reasons.

Distribution system reliability is not dependent solely upon component failure characteristics. It is also dependent upon how the system responds to component failures. To understand this, it is necessary to understand the sequence of events that occurs after a distribution system fault.

Typical Sequence of Events after an Overhead Distribution Fault

1. The fault causes high currents to flow from the source to the fault location. These high currents may result in voltage sags for certain customers. These sags can occur on all feeders that have a common coupling at the distribution substation.
2. An instantaneous relay trips open the feeder circuit breaker at the substation. This causes the entire feeder to be deenergized. A pause allows the air around the fault to deionize, and then a reclosing relay will close the circuit breaker. If no fault current is detected, the fault has cleared itself and all customers on the feeder have experienced a momentary interruption.
3. If the fault persists, time overcurrent protection devices are allowed to clear the fault. If the fault is on a fused lateral, the fuse will blow and customers on the lateral will be interrupted. If the feeder breaker trips again, the reclosing relay will repeat the reclosing process a preset number of times before locking out. After the feeder breaker locks out, all customers on the feeder will be interrupted.
4. The electric utility will receive trouble calls from customers with interrupted power. It will dispatch a crew to locate the fault and isolate it by opening up surrounding sectionalizing switches. It may also attempt to reconfigure the distribution system in an attempt to restore power to as many customers as possible while the fault is being repaired. Fault isolation can be very fast if switches are motor operated and remotely controlled, but switching usually takes between 15 and 60 min.
5. The crew repairs the faulted equipment and returns the distribution system to its normal operating state.

As can be seen, *a fault on the distribution system will impact many different customers in many different ways*. In general, the same fault will result in voltage sags for some customers, momentary interruptions for other customers, and varying lengths of sustained interruptions for other customers, depending on how the system is switched and how long the fault takes to repair.

Distribution system reliability assessment methods are able to predict distribution system reliability based on system configuration, system operation, and component reliability data (Brown et al., 1996). This ability is becoming increasingly important as the electric industry becomes more competitive, as regulatory agencies begin to regulate reliability, and as customers begin to demand performance guarantees. The most common reliability assessment methods utilize the following process: (1) they simulate a system's response to a contingency, (2) they compute the reliability impact that this contingency has on each customer, (3) the reliability impact is weighted by the probability of the contingency occurring, and (4) steps 1–3 are repeated for all contingencies. Since this process results in the reliability that each customer can expect, new designs can be compared, existing systems can be analyzed, and reliability improvement options can be explored.

Distribution Reliability Indices

Utilities typically keep track of customer reliability by using reliability indices. These are average customer reliability values for a specific area. This area can be the utility's entire service area, a particular geographic region, a substation service area, a feeder service area, and so on. The most commonly used reliability indices give each customer equal weight. This means that a large industrial customer and a small residential customer will each have an equal impact on computed indices. The most common of these *customer reliability indices* are: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Average System Availability Index (ASAI) (IEEE Working Group, 1998). Notice that these indices are redundant. If SAIFI and SAIDI are known, both CAIDI and ASAI can be calculated. Formulae for these indices are:

$$SAIFI = \frac{Total\ Number\ of\ Customer\ Interruptions}{Total\ Number\ of\ Customers\ Served} \quad \text{per year} \tag{13.7}$$

$$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customers\ Served} \quad \text{hours per year} \tag{13.8}$$

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customer\ Interruptions} = \frac{SAIDI}{SAIFI} \quad \text{hours per interruption} \tag{13.9}$$

$$ASAI = \frac{Customer\ Hours\ Service\ Availability}{Customer\ Hours\ Service\ Demand} = \frac{8760 - SAIDI}{8760} \quad \text{per unit} \tag{13.10}$$

Some less commonly used reliability indices are not based on the total number of customers served. The Customer Average Interruption Frequency Index (CAIFI) and the Customer Total Average Interruption Duration Index (CTAIDI) are based upon the number of customers that have experienced one or more interruptions in the relevant year. The Average System Interruption Frequency Index (ASIFI) and the Average System Interruption Duration Index (ASIDI) are based upon the connected kVA of customers (these are sometimes referred to as load-based indices). Formulae for these indices are:

$$CAIFI = \frac{Total\ Number\ of\ Customer\ Interruptions}{Customers\ Experiencing\ 1\ or\ more\ Interruptions} \quad \text{per year} \tag{13.11}$$

$$CTAIDI = \frac{\sum Customer\ Interruption\ Durations}{Customers\ Experiencing\ 1\ or\ more\ Interruptions} \quad \text{hours per year} \tag{13.12}$$

$$ASIFI = \frac{Connected\ kVA\ Interrupted}{Total\ Connected\ kVA\ Served} \quad \text{per year} \tag{13.13}$$

$$ASIDI = \frac{Connected\ kVA\ Hours\ Interrupted}{Total\ Connected\ kVA\ Served} \quad \text{hours per year} \tag{13.14}$$

As momentary interruptions become more important, it becomes necessary to keep track of indices related to momentary interruptions. Since the duration of momentary interruptions is of little consequence, a single frequency related index, the Momentary Average Interruption Frequency Index (MAIFI), is all that is needed. MAIFI, like SAIFI, weights each customer equally (there is currently no load-based index for momentary interruptions). The formula for MAIFI is:

$$MAIFI = \frac{Total\ Number\ of\ Customer\ Momentary\ Interruptions}{Total\ Number\ of\ Customers\ Served} \quad \text{per year} \qquad (13.15)$$

The precise application of MAIFI varies. This variation is best illustrated by an example. Assume that a customer experiences three recloser operations followed by a recloser lockout, all within a period of one minute. Some utilities would not count this event as a momentary interruption since the customer experiences a sustained interruption. Other utilities would count this event as three momentary interruptions and one sustained interruption. Similarly, if a customer experiences three recloser operations within a period of one minute with power being restored after the last reclosure, some utilities would count the event as three momentary interruptions and other utilities would could the event as a single momentary interruption.

Storms and Major Events

When electric utilities compute reliability indices, they often exclude interruptions caused by "storms" and "major events." The definition of a major event varies from utility to utility, but a typical example is when more than 10% of customers experience an interruption during the event. The event starts when the notification of the first interruption is received and ends when all customers are restored service.

In nonstorm conditions, equipment failures are independent events — the failure of one device is completely independent of another device. In contrast, major events are characterized by common-mode failures. This means that a common cause is responsible for all equipment failures. The result is that many components tend to fail at the same time. This puts a strain on utility resources, which can only handle a certain number of concurrent failures (Brown et al., 1997). The most common causes of major events are wind storms, ice storms, and heat waves.

Wind storms refer to linear winds that blow down trees and utility poles. The severity of wind storms is dependent upon sustained wind speed, gust speed, wind direction, and the length of the storm. Severity is also sensitive to vegetation management and the time elapsed since the last wind storm. Since a wind storm will tend to blow over all of the weak trees, a similar storm occurring a few months later may have little impact. A U.S. map showing wind speeds for the worst expected storm in 50 years is shown in Fig. 13.28.

Ice storms refer to ice buildup on conductors. This has four major effects: (1) it places a heavy physical load on the conductors and support structures, (2) it increases the cross-sectional area that is exposed to the wind, (3) ice can break off and cause a conductor to jump into the phase wires located above it, and (4) galloping. Galloping occurs when ice buildup assumes a teardrop shape and acts as an airfoil. During high winds, this can cause conductors to swing wildly and with great force. Ice can also cause problems by accumulating in trees, causing limbs to break off, and causing entire trunks to fall over into power lines.

Heat waves are extended periods of exceedingly hot weather. This hot weather causes electricity demand to skyrocket due to air-conditioning loads. At the same time, conductors cannot carry as much electricity since they cannot transfer heat as effectively to their surroundings. This combination of heavy loading and conductor de-rating can cause overhead wires to become overloaded and sag to dangerous levels. Overloaded cables will cause insulation to lose life. In a worst-case scenario, the maximum power transfer capabilities of the system can be approached, resulting in a voltage collapse condition. Humidity exacerbates the impact of heat waves since it causes air conditioners to consume more energy.

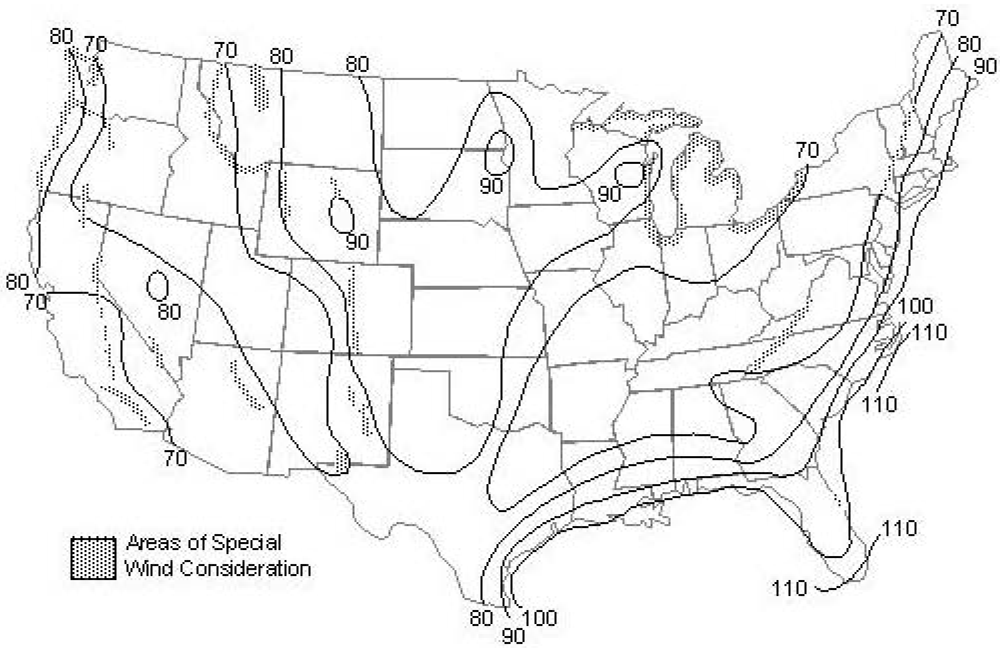

FIGURE 13.28 50-year wind storm (sustained wind speed in mi/hr).

Component Reliability Data

For a reliability model to be accurate, component reliability data must be representative of the system being modeled. Utilities recognize this and are increasing their efforts to keep track of component failure rates, failure modes, repair times, switching times, and other important reliability parameters. Unfortunately, reliability statistics vary widely from utility to utility and from country to country. The range of equipment reliability data that can be found in published literature is shown in Table 13.8.

TABLE 13.8 Equipment Reliability Data

Component	Failure Rate (per year)	MTTR (hours)
	Substation Equipment	
Power transformers	0.015–0.07	15–480
Circuit breakers	0.003–0.02	6–80
Disconnect switches	0.004–0.16	1.5–12
Air insulated buswork	0.002–0.04	2–13
	Overhead Equipment	
Transmission lines[a]	0.003–0.140	4–280
Distribution lines[a]	0.030–0.180	4–110
Switches/fused cutouts	0.004–0.014	1–4
Pole mounted transformer	0.001–0.004	3–8
	Underground Equipment	
Cable[a]	0.005–0.04	3–30
Padmount switches	0.001–0.01	1–5
Padmount transformers	0.002–0.003	2–6
Cable terminations/joints	0.0001–0.002	2–4

[a] Failure rates for lines and cable are per mile.

Because component reliability is very system specific, it is beneficial to calibrate reliability models to historical reliability indices. In this process, component reliability parameters are adjusted until historical reliability indices match computed reliability indices (Brown et al., 1998). The amount that each parameter is adjusted should depend on the confidence of the original value and the sensitivity of the reliability indices to changes in this value. To illustrate, consider an overhead distribution system. A reliability model of this system is created using component reliability data from published literature. Unfortunately, the reliability indices that the model produces do not agree with the historical performance of the system over the past few years. To fix this, the failure rate and repair times of overhead lines (along with other component parameters) can be adjusted until predicted reliability matches historical reliability.

Utility Reliability Problems

To gain a broader understanding of power system reliability, it is necessary to understand the root causes of system faults and system failures. A description of major failure modes is now provided.

Underground Cable

A major reliability concern pertaining to underground cables is electrochemical treeing. Treeing occurs when moisture penetration in the presence of an electric field reduces the dielectric strength of cable insulation. When the dielectric strength is degraded sufficiently, transients caused by lightning or switching can result in dielectric breakdown. Electrochemical treeing usually affects extruded dielectric cable such as cross-linked polyethylene (XLPE) and ethylene-propylene rubber (EPR), and is largely attributed to insulation impurities and bad manufacturing. To reduce failures related to electrochemical treeing, a utility can install surge protection on riser poles (transitions from overhead to underground), can purchase tree-retardant cable, and can test cable reels before accepting them from the manufacturer.

Existing cable can be tested and replaced if problems are found. One way to do this is to apply a DC voltage withstand test (approximately 3 times nominal RMS voltage). Since cables will either pass or not pass this test, information about the state of cable deterioration cannot be determined. Another popular method for cable testing is to inject a small signal into one end and check for reflections that will occur at partial discharge points. Other methods are measuring the power factor over a range of frequencies (dielectric spectroscopy), analyzing physical insulation samples in a lab for polymeric breakdown (degree of polymerization), and using cable indentors to test the hardness of the insulation.

Not all underground cable system failures are due to cable insulation. A substantial percentage occurs at splices, terminations, and joints. Major causes are due to water ingress and poor workmanship. Heat shrink covers can be used to waterproof these junctions and improve reliability.

The last major reliability concern for underground cable is dig-ins. This is when excavation equipment cuts through one or more cables. To prevent dig-ins, utilities should encourage the public to have cable routes identified before initiating site excavation. In extreme cases where high reliability is required, utilities can place cable in concrete-encased duct banks.

Transformer Failures

Transformers are critical links in power systems, and can take a long time to replace if they fail. Through-faults cause extreme physical stress on transformer windings, and are the major cause of transformer failures. Overloads rarely result in transformer failures, but do cause thermal aging of winding insulation.

When a transformer becomes hot, the insulation on the windings slowly breaks down and becomes brittle over time. The rate of thermal breakdown approximately doubles for every 10°C. 10°C is referred to as the "Montsinger Factor" and is a rule of thumb describing the Arrhenius theory of electrolytic dissociation. Because of this exponential relationship, transformer overloads can result in rapid transformer aging. When thermal aging has caused insulation to become sufficiently brittle, the next fault current that passes through the transformer will mechanically shake the windings, a crack will form in the insulation, and an internal transformer fault will result.

Extreme hot-spot temperatures in liquid-filled transformers can also result in failure. This is because the hot spot can cause free bubbles that reduce the dielectric strength of the liquid. Even if free bubbles

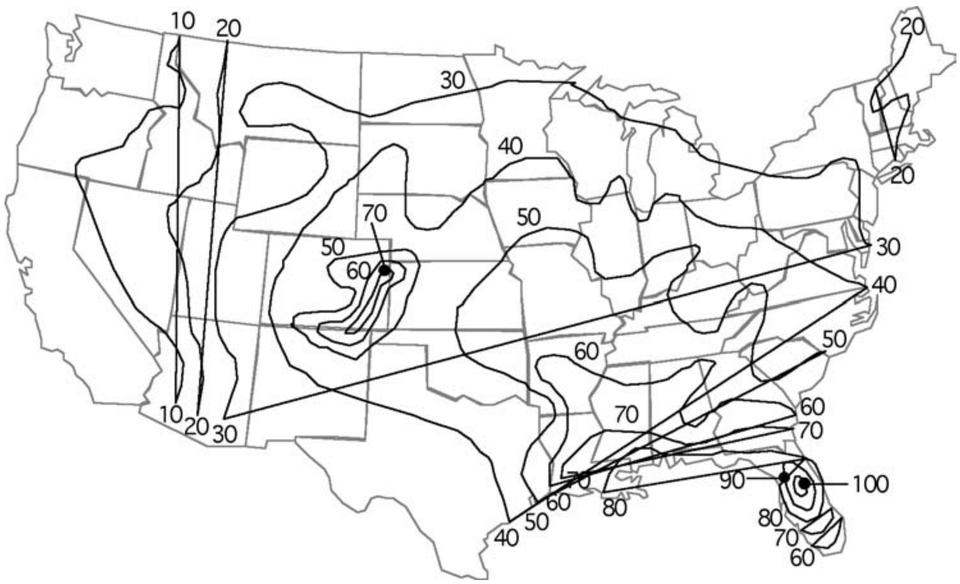

FIGURE 13.29 Number of thunderstorm days per year.

are not formed, high temperatures will increase internal tank pressure and may result in overflow or tank rupture.

Many transformers are fitted with load tap changers (LTCs) for voltage regulation. These mechanically moving devices have historically been prone to failure and can substantially reduce the reliability of a transformer (Willis, 1997). Manufacturers have addressed this problem and new LTC models using vacuum technology have succeeded in reducing failure rates.

Lightning

A lightning strike occurs when the voltage generated between a cloud and the ground exceeds the dielectric strength of the air. This results in a massive current stroke that usually exceeds 30,000 amps. To make matters worse, most strokes consist of multiple discharges within a fraction of a second. Lightning is the major reliability concern for utilities located in high keraunic areas (Burke, 1994). An isokeraunic map for the U.S. is shown in Fig. 13.29.

Lightning can affect power systems through direct strikes (the stroke contacts the power system) or through indirect strikes (the stroke contacts something in close proximity and induces a traveling voltage wave on the power system). Lightning can be protected against by having a high system BIL, by using shield wires, by using surge arrestors to clamp voltages across equipment, and by having a low impedance ground. Direct strikes are virtually impossible to protect against on a distribution system.

Tree Contact

Trees continuously grow, can fall over onto conductors, can drop branches onto conductors, can push conductors together, and can serve as gateway for animals. This is why many utilities spend more on tree trimming than on any other preventative maintenance activity.

When a tree branch bridges two conductors, a fault does not occur immediately. This is because a moist tree branch has a substantial resistance. A small current begins to flow and starts to dry out the wood fibers. After several minutes, the cellulose will carbonize, resistance will be greatly reduced, and a short circuit will occur. Branches brushing against a single phase conductor typically *do not* result in system faults.

Faults due to tree contact can be reduced by using tree wire. This is overhead wire with an insulated jacket similar to cable. Tree wire can be effective, but faults tend to result in conductor burndown since they will not motor (move themselves along the conductor) like faults on bare conductor.

Birds

Birds are the most common cause of animal faults on both transmission systems and air insulated substations. Different types of birds cause different types of problems, but they can generally be classified as nesting birds, roosting birds, raptors, and woodpeckers.

Nesting birds commonly build their homes on transmission towers and in substations. Nesting materials can cause faults, and bird excrement can contaminate insulators. Nesting birds also attract predators such as raccoons, snakes, and cats. These predators can be a worse reliability problem than the birds themselves.

Roosting birds use electrical equipment to rest on or to search for prey. They can be electrocuted by bridging conductors with their wings, and their excrement can contaminate insulators. To prevent birds from roosting, anti-roosting devices can be placed on attractive sites. For locations that cater to thousands of roosting birds, more extreme deterrent methods such as pyrotechnics can be used.

Raptors are birds of prey such as eagles, hawks, ospreys, owls, and vultures. Reliability problems are similar to other roosting and nesting birds, but special consideration may be required since most raptors are protected by the federal government.

Woodpeckers peck holes in wood with their beaks as they search for insects. This does not harm trees (the bark regenerates), but can cause devastating damage to utility poles. This can be prevented by using steel poles, by using repellent, or by tricking a woodpecker into believing that there is already a resident woodpecker (woodpeckers are quite territorial).

Squirrels

Squirrels are a reliability concern for all overhead distribution systems near wooded areas. Squirrels will not typically climb utility poles, but will leap onto them from nearby trees. They cause faults by bridging grounded equipment with phase conductors. Squirrel problems can be mitigated by cutting down nearby access trees or by installing animal guards on insulators.

Snakes

Snakes are major reliability concerns in both substations and underground systems. They can squeeze through very small openings, can climb almost anything, and have the length to easily span phase conductors. Snakes are usually searching for food (birds in substations and mice in underground systems), and removing the food supply can often remove the snake problem. Special “snake fences” are also available.

Insects

It is becoming more common for fire ants to build nests in pad mounted equipment. Their nesting materials can cause short circuits, the ants can eat away at conductor insulation, and they make equipment maintenance a challenge.

Bears, Bison, and Cattle

These large animals do not typically cause short circuits, but degrade the structural integrity of poles by rubbing on guy wires. Bears can also destroy wooden poles by using them as scratching posts, and black bears can climb wooden utility poles. These problems can be addressed by placing fences around poles and guy wire anchors.

Mice, Rats, and Gophers

These rodents cause faults by gnawing through the insulation of underground cable. They are the most common cause of animal-related outages on underground equipment. To make matters worse, they will attract snakes (also a reliability problem). Equipment cabinets should be tightly sealed to prevent these small animals from entering. Ultrasonic devices can also be used to keep rodents away (ultrasonic devices will not keep snakes away).

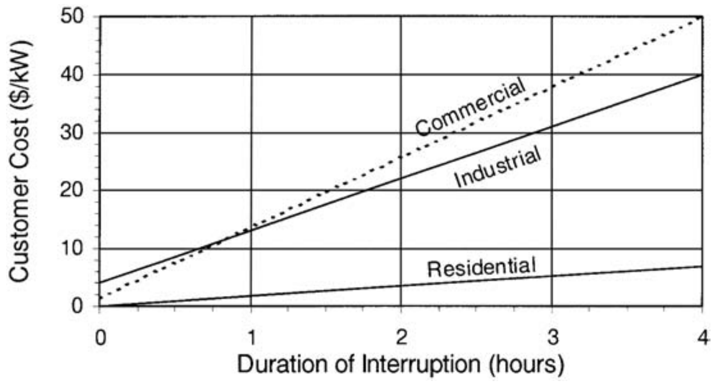

FIGURE 13.30 Typical U.S. customer interruption costs (1999 dollars).

Vandalism

Vandalism can take many different forms, from people shooting insulators with rifles to professional thieves stealing conductor wire for scrap metal. Addressing these reliability problems will vary greatly from situation to situation.

Reliability Economics

When a power interruption occurs, both the utility and the interrupted customers are inconvenienced. The utility must spend money to fix the problem, will lose energy sales during the interruption, and may be sued by disgruntled customers. From the customer perspective, batch processes may be ruined, electronic devices may crash, production may by lost, retail sales may be lost, and inventory (such as refrigerated food) may be ruined.

When a customer experiences an interruption, there is an amount of money that it would be willing to pay to have avoided the interruption. This amount is referred to as the customer's incurred cost of poor reliability, and consists of a base cost plus a time dependent cost. The base cost is the same for all interruptions, relates to electronic equipment shutdown and interrupted processes, and is equivalent to the cost of a momentary interruption. The time dependent cost relates to lost production and extended inconvenience, and reflects that customers would prefer interruptions to be shorter rather than longer.

The customer cost of an interruption varies widely from customer to customer and from country to country. Other important factors include the time of year, the day of the week, the time of day, and whether advanced warning is provided. Specific results are well documented by a host of customer surveys (Billinton et al., 1983; Tollefson et al., 1991; Tollefson et al., 1994; IEEE Std. 493-1990). For planning purposes, it is useful to aggregate these results into a few basic customer classes: commercial, industrial, and residential. Since larger customers will have a higher cost of reliability, results are normalized to the peak kW load of each customer. Reliability cost curves for typical U.S. customers are shown in Fig. 13.30.

Average customer cost curves tend to be linear and can be modeled as an initial cost plus a first order, time dependent cost. Specific customer cost curves may be extremely nonlinear. For example, a meat packing warehouse depending upon refrigeration may be unaffected by interruptions lasting many hours. At a certain point, the meat will begin to spoil and severe economic losses will quickly occur. After the meat spoils, additional interruption time will harm this particular customer much more.

Annual Variations in Reliability

Power system reliability varies from year to year. In a lucky year, a system may have a SAIDI of 30 min. The next year, this exact same system may experience a SAIDI of 8 h. This type of variation is inevitable and must be considered when comparing reliability indices. It is also important to note that the variance of reliability indices will tend to be less for areas serving more customers. Individual customer reliability will tend to be the most volatile, followed by feeder reliability, substation reliability, regional reliability, and so forth.

The importance of annual reliability variance will grow as utilities become subject to performance-based rates and as customer reliability guarantees become more common. These types of contracts expose utilities to new risks that must be understood and managed. Since performance-based contracts penalize and reward utilities based on reliability, annual variations must be understood for fair contracts to be negotiated and managed.

Contractual issues concerning service reliability are becoming important as the electric industry becomes more competitive. Customers can choose between suppliers, and realize that there is a trade-off between reliability and rates. Some customers will demand poor reliability at low rates, and other customers will demand high reliability at premium rates. To address the wide variation in customer needs, utilities can no longer be suppliers of energy alone, but must become suppliers of both energy and reliability. Power system reliability is now a *bona fide* commodity with explicit value for utilities to supply and explicit value that customers demand.

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