

Electric Power Systems Engineering

MARIJA D. ILIC

Carnegie Mellon University
Pittsburgh, Pennsylvania, United States

JOHN ZABORSZKY

Washington University
St. Louis, Missouri, United States



-
1. Introduction
 2. Basic Objectives of EPSE
 3. EPSE Tools for System Operation under Normal Conditions
 4. EPSE for Emergency Operation
 5. Challenges to EPSE in the Changing Industry
 6. Objectives of EPSE as a Function of Changing Industry Structures
 7. A Glimpse into the Future: More Smooth and Secure on a Building Block Structure

Glossary

forced outage or blackout Loss of electrical power due to the shutdown of a major component, such as a power plant, transformer, or transmission line.

gains Increase in signal power, voltage, or current by amplification.

governor A control device on a machine or engine that is used to maintain a steady speed, pressure, or temperature automatically (as by controlling the fuel supply).

load A device or destination to which electrical power is delivered; also, output of a generator or power plant.

primary controller An electrical instrument or set of instruments that serves as the main regulating or guiding device for a mechanical or electrical system.

transformer An electrical device used to transfer electric energy from one circuit to another, especially equipment that produces such a transfer with a change in voltage.

utility A company that performs a public service (such as sewage disposal or supply of gas for heating) subject to government regulation; in this context, an electricity generation/supply company.

This article is devoted to the electric power systems engineering field, focusing on systems aspects of

modeling, analysis, and decision-making tools for operating and planning complex electric power grids. It first describes basic objectives of electric power systems engineering. The primary emphasis of the article is on IT tools and the key challenges that must be overcome to further benefit from using electric power systems engineering (EPSE) tools in support of the electric power industry under restructuring. The material in this article is of direct relevance for managing the electric power systems in a reliable and efficient way without major widespread loss of service to customers.

1. INTRODUCTION

Electric power systems engineering (EPSE) is a subfield of electric power engineering, with the prime concern being performance of an interconnected electric power system. The EPSE subfield has evolved over the past 40 years in response to the industry needs to manage the system (1) securely under unexpected equipment outages and unusually wide variations in load demand patterns and (2) as economically as possible in response to normal load-demand variations. Its growth has been made possible through tremendous progress in the general fields of computers, communications, and control engineering for complex, large-scale systems. Nevertheless, the general tools had to be formulated and made useful in the context of the specific applications to the electric power systems.

This article is being completed the eve after the major blackout in North America that took place on August 14, 2003. Society has once more been caught

by surprise in a widespread industry failure to provide electricity to over 60 million customers for over 24 h. Questions about why such an event spread over very large geographical areas are being asked. A typical belief that an electric power grid has automated protection against cascading failures despite an unexpected failure of a major piece of equipment, such as a transmission line or a power plant, has once more been proven wrong. A related category of questions concerns prevention of massive power failures by isolating only parts of the grid that had to be disconnected. Still other questions focus on what should be done to modernize the electric power grid in order to prevent future cascading failures.

This unplanned coincidence between the blackout and the completion of this article has forced the authors to revisit its earlier version. To the authors, the 2003 blackout represents yet another example of challenges to the operating practices and the information technology (IT)-based methods for facilitating reliable and efficient operation of complex electric power grids. It is, unfortunately, one of many in the long list of hard-to-predict, high-impact, cascading events of this type that have taken place since the early 1960s worldwide. It is hoped that the reader will see several connections between the material in this article and the recent events.

The following quotation from *Dynamics and Control of Large Electric Power Systems*, by Ilic and Zaborszky, briefly summarizes the gradual evolution of the U.S. interconnection and points out the rationale for its present complexity:

The U.S. structure of power-system operation was developing generally during the twentieth century without much awareness or attention to the implications of the evolution of power-system structure. With the gradual infiltration of the computer into on-line operation in the 1950s, a surge of interconnections developed for utilizing the potential for improved efficiency and economy. As is typically the case in human activities, the development took the form of designs for individual cases of construction based only on the local situation of the case and only during normal, stationary system operation. The vital questions of the effects of off-nominal conditions were essentially ignored. A striking example is the omission in new construction of self-starting house units and the total dependence for starting large power plants on power drawn from transmission lines to neighboring stations. This general attitude was the root cause of the famous Northeast Blackout, a cascading system collapse that disabled ten states for approximately 1 week in 1964 followed by a few other large events, such as that occurring in Manhattan in 1967.

After this rude awakening, consciousness of the importance of the structure of the complete system (the

interconnected U.S. electric power system) started to gradually creep into the awareness within the field.

—Ilic and Zaborszky, 2000, p. 642

Also, recent electric power restructuring has created very new challenges to the existing EPSE methods. One of the qualitative changes related to the organizational changes in this industry involves the shift from a top-down coordinated monitoring and decision-making to more distributed information managing and decision-making. This change is opening doors to new technical and pricing paradigms for operating complex power grids in a self-healing manner by the system end users adjusting to the changing conditions in a bottom-up manner.

The most recent blackout, the above quote summarizing the beginnings of EPSE, and the recent industry reorganization all concern on-line information essential for determining the system-wide status beyond single components and single utilities. Since the specifics of particular physical and policy/regulatory phenomena vary with the nature of triggering events and system designs, the complexity of data and difficulty of extracting critical information quickly are issues at the heart of any blackout. The critical physical information may concern frequency-, voltage-, or transmission-related physical phenomena; the importance of these factors is well documented in several post mortem analyses of major blackouts. The critical policy/regulatory information may affect capacity available for managing the system as a whole under forced outage and its valuation or it may concern state versus federal responsibility for building stronger transmission lines for exchanging power under outages.

This article is devoted to the electric power systems engineering subfield of electric power engineering, focusing on systems aspects of modeling, analysis, and decision-making tools for operating and planning complex electric power grids. It first describes basic objectives of electric power systems engineering. The primary emphasis of the article is on IT tools and the key challenges that must be overcome to further benefit from using EPSE for operating and planning electric power systems of the future. The final section describes fundamental challenges to developing EPSE tools in support of the electric power industry under restructuring.

Electric power systems engineering must evolve as the industry needs evolve, both as the industry reorganization takes place and as the new hardware technologies become more available and cost-effective. Much could be improved by supporting the

power grid's on-line operations via carefully designed minimal coordination at its various layers. Doing this correctly remains a tremendous challenge in pursuit of increased system-wide efficiency and ability to prevent huge failures.

2. BASIC OBJECTIVES OF EPSE

The main objectives of EPSE are monitoring, analysis, and decision-making tools for facilitating operations and planning of an electric power system as a whole. The EPSE methods are available for monitoring, analyzing, and controlling electric power grids in a semiautomated manner under normal operating conditions, i.e., when the status of the equipment is as planned. The EPSE approaches to managing the system under forced outages are not as mature in comparison with the tools available for normal operation; instead, these methods are generally utility-specific and based on human expert knowledge about the system. The events on August 14, 2003 confirmed once more that industry practices are not fully capable of preventing widespread power failures under forced equipment outages. Moreover, as the electric power industry restructures and new technologies become more cost-effective, the objectives of electric power systems engineering evolve, requiring novel problem formulations and computer-aided tools for relating often conflicting engineering and economic objectives.

The early stages of electric power engineering were primarily concerned with the design and operation of individual pieces of equipment, power plants, transformers, transmission lines, and the like. However, as the electric power grid has expanded over time, it has become essential to understand the interactions among various system components and the effect of these interactions on the overall quality of electricity service. The quality and cost of power service to customers have greatly improved as a result of optimizing utilization of system-wide resources under normal conditions. IT-based power systems engineering tools for scheduling the electric power generation required to meet the time-varying load demand have been basic to efficient use of the least operating cost power generation. In particular, under normal conditions, the cheapest generation is scheduled and delivered across the power system to supply both forecasted demand and demand fluctuations that are hard to predict. Ideally, under unexpected forced outages of major components (power plants, transformers, or transmission lines), power should be delivered from other parts

of the system so that the load in the affected area remains served. To achieve this, power systems engineering tools have been developed for scheduling short-term generation reserve to supply customers in case major components of power equipment fail as a result of hard-to-predict forced outages.

The software tools for balancing supply and demand under normal conditions are based on implicit assumptions about the electric power system structure. Naturally this structure allows simplification of very complex electric power system dynamics by the separation of operations into subprocesses that evolve at different temporal rates and at various system levels. It is important to use the IT-based tools to assess the validity of the assumptions and underlying algorithms used, as system conditions vary over time. In particular, the useful structure and unique features of complex power system dynamics are typically violated under forced outages. Moreover, industry restructuring may inadvertently lead to qualitatively new power system architectures, which, in turn, will require careful assessment of the software tools used for operating them.

Some of the fundamental policy- and technology-related changes are discussed in Sections 5 and 6 below. A typical power systems architecture characteristic of normal operation and regulated industry is described in Section 2 in preparation for reviewing the IT tools for operating regulated utilities under normal conditions. The most difficult challenges concern trade-offs between efficient operation under normal conditions and the stand-by reserve to be used in case of forced outages. Since the critical events are unknown and are very hard to predict in a timely manner, conventional probabilistic tools are difficult to use for efficient on-line decision-making.

2.1 Basic Structure of Electric Power Systems

A typical organization of today's electric power systems is shown in Fig. 1. The generation and distribution of electric power geographically are accomplished over one single electric network in the United States. Traditionally in the regulated industry, generation is provided in very large quantities at power plants. Under restructuring, small-quantity distributed generation also enters with a naturally limited scope of providing power locally. Electricity consumption ranges from very large levels (factories) to very small levels (residential).

This immense interconnected network inescapably has an internal structure. Generation in very large

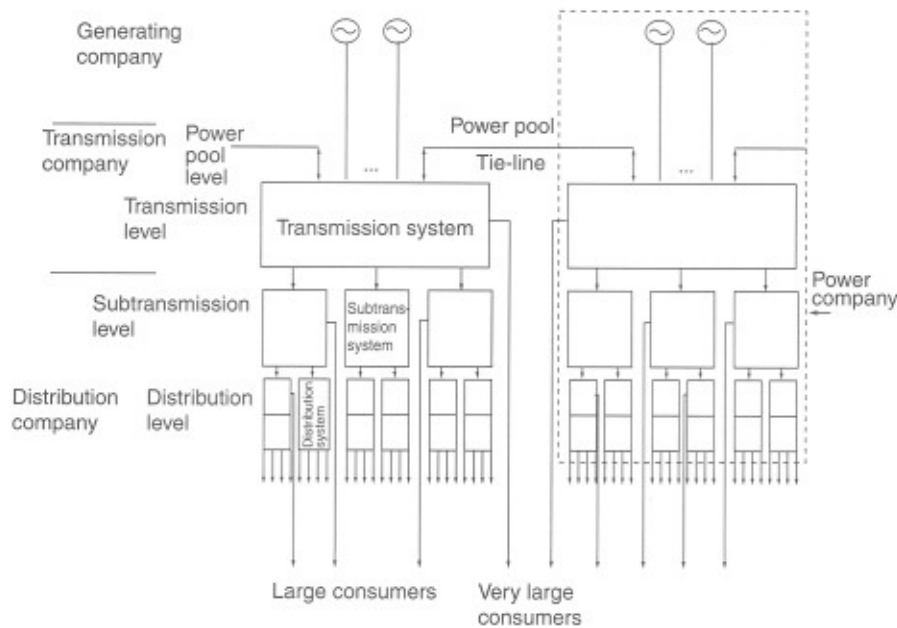


FIGURE 1 Typical organization of existing electric power systems.

quantities in power plants demands high- to very-high-voltage (ranging from 20,000 to 1 million V) transmission line networks. Such networks make up the pool or bulk transmission level network that covers the United States but is also geographically subdivided into large blocks according to ownership, as indicated in Fig. 1. The power distribution process within each geographic bulk transmission block is typically subdivided into geographic subtransmission areas, which historically do not connect to individual generating facilities; instead, only large loads are supplied from the subtransmission networks along with the various distribution sections within each subtransmission area. Finally, the lowest voltage distribution level also splits into two voltage sublevels, ending at the residential households.

The network consists of transmission lines that interconnect nodes, known as buses, at high voltage levels. Different levels of voltage within this structure are interconnected via transformers. Buses are the sole connection points to the transmission system of all equipment:

- (1) the sources, that is, generators;
- (2) the loads, either large and concentrated like an aluminum plant or distributed like the feeding point of subtransmission networks supplying a composition of smaller loads and eventually leading to distribution lines on residential streets;
- (3) reactive-power storage devices, such as capacitor banks or reactors;

- (4) increasingly numerous electronically switched power devices (thyristors), such as static Var compensators, the coupling equipment between the high-voltage (HV) alternating current (AC) bus and the high-voltage direct current (HV-DC) transmission lines, and flexible AC transmission systems (FACTS) devices that are in development;

- (5) series capacitor compensation; and
- (6) lightning arrestors and other equipment connected to a bus by links other than transmission lines.

Buses form large islands of complex equipment connected to the outside world exclusively through the high-voltage lines (AC or DC) of the transmission network.

The business organization of this gigantic system in the traditional regulated sense was single ownership of each vertical column; see Fig. 1. This division preserves the coast-to-coast nature of the total network, but the sale and purchase of power are carried out between companies owning the individual vertical blocks within Fig. 1 under very strict government regulations. In the new industry environment, individual blocks in Fig. 1 are separately owned, and free market trading proceeds for a fee between individually owned transmission blocks under relatively mild government regulation. The above-described strict separation by size is also fading; any amount of power can be bought and sold at any power flow level.

The above-described organizational structure in the regulated industry maps into various power flow levels. The bulk power is transmitted from a very few large power plants to the load centers within a region or from a power pool composed of several subsystems; these subsystems most often are defined as the boundaries of the individual electric power utilities, loosely coupled with the neighboring utilities. The delivery of power between utilities within an electric power pool or within similar horizontal structures occurs by means of an extra-high-voltage (EHV) sparse electric transmission grid, at typical voltages of 500 kV and higher; the pool (or region) level is referred to as a tertiary level. Within each subsystem, the transmission grid is less sparse and at high voltage, typically above 200 kV, known as the secondary level. Finally, major pieces of equipment, such as power plants, transmission lines, transformers, and substations (load centers), are connected to an even lower level voltage network, known as subtransmission; they are referred to as the primary (component) level. The substations are further connected through a low-voltage distribution system to different loads; larger industrial loads are connected at voltage levels similar to the substation voltage level and the smaller loads are progressively connected to lower and lower voltage levels within a distribution system, terminating at the lowest level residential end users.

2.2 Primary Control of an Electric Power System

An electric power system characterized by the above structure serves the basic purpose of producing and distributing electric power to the customers. The system as a whole is operated in anticipation of and in response to the temporal variations in load demand. Electric power is produced by the turbine-generator-governor sets at the power plant locations. The mechanical power is produced by the prime movers. The key control of how much power goes to the network is the governor, which is a local (primary) controller of each modern power plant. Like any other automated controller, a governor has a setpoint and reacts to the deviations from this setpoint automatically. This controller reacts to the frequency deviations from the frequency setpoint value. The faster the turbine turns, the more power is decreased by controlling fuel income to the prime mover by means of a governor (Watt regulator). Standard operating practice has been to adjust the setpoints on governors of generators in each area so that the

anticipated area load is fully supplied and the system frequency is nominal. The mechanical power is then converted to the electric power in generators and distributed via the electric power transmission network to the load centers and further distributed to the individual end users via the local electric distribution networks. It is generally hard to predict load exactly. This results in an imbalance between mechanical power produced and power consumed. In this case, according to Kirchhoff laws, the electric power into each node of the electric power network still equals electric power out of the node instantaneously. If there is not enough mechanical power to supply electric power consumed, the generators slow down, resulting in reduced system frequency.

Most of the electric power transmission today is AC, requiring all power generators to operate at the same nominal frequency. In order to maintain frequency very close to its nominal value, each system has several power plants that participate in so-called automatic generation control (AGC). These plants automatically adjust their electric power output by resetting the setpoints on their governors in response to frequency deviations in each control area. Similarly, power plants have so-called automatic voltage regulators (AVRs), which automatically control reactive power produced by the power plant in order to maintain voltage magnitudes at the location of power plants within acceptable voltage deviations. The voltage regulators are also local (primary) controllers. The setpoints of these controllers are adjusted in anticipation of reactive power consumption on the system to ensure that voltage magnitudes at the consumers' side stay within the acceptable limits. Given a setpoint, the primary AVR regulates the reactive power output of a generator so that the voltage magnitude remains within the threshold of the setpoint. This is very similar to the way the governor responds to frequency deviations by producing real power in order to maintain frequency close to the nominal frequency. Some power plants also have power system stabilizers, which represent more advanced local controllers that respond simultaneously to the deviations in frequency and voltage and/or acceleration and have a faster response to the error than the governors and AVRs. If the power system stabilizers are tuned correctly and are implemented on the key power plants, the electric power system as a whole responds in a much more robust way to major disturbances than if the power plants do not have these controllers.

The response of all primary controllers is tuned for the assumed range of operating conditions. The

tuning is achieved by modeling the rest of the complex system as a simple equivalent circuit. However, it is critical to observe that system operating conditions could deviate significantly from the assumed conditions if either (1) load deviates significantly from the assumed or (2) a piece of major equipment is out of operation. In either case, the primary controllers may not perform their function most effectively because their gains are not adjusted to respond effectively to the new conditions. Re-adjusting these gains in anticipation of or in response to the unusual conditions forms the basis for some form of adaptive control to enable the most effective use of system resources over the wide range of changes in its conditions.

Advanced logic using local measurements in typical primary controllers (e.g., using acceleration measurement in addition to frequency) could contribute significantly to the power plant's ability to adjust better and faster to the changing conditions—such measurements might, for example, result in the development of a controller that would return the system back to its normal frequency and voltage by adapting its power output faster and more effectively. Also, much could be gained from at least partial communication among the primary controllers. This is particularly critical for detecting qualitative changes in system conditions, in order to trigger the change in the logic of the primary controllers determining more adequate settings for the new system conditions. There exist representative examples of the potential gains from wide area measurement systems for stabilizing system conditions under forced outages that would be otherwise uncontrollable without coordination among several controllers; on-load tap changing transformers for regulating voltage at the receiving end of the line have been known to be critical in several voltage problem-related blackouts in France and Belgium; however, the change in their logic when the operating conditions are qualitatively different could potentially prevent these blackouts from occurring.

These seemingly small improvements in primary control of power system equipment could be shown to enhance the ability of the system as a whole to withstand unpredictable difficult conditions without collapsing. The major challenge here is the design of control logic and supporting communications to implement advanced primary control in a robust way—that is, if the controller and/or its communication fail, the system as a whole will still not be affected in a detrimental way. Since this is hard to do with provable robustness, the more common way is

to enhance system performance by adding major redundant hardware for stand-by reserves. Establishing a balance between flexibility and over-design has always been the challenge in EPSE.

2.3 System Protection

Under some major forced outages, the system may not be able to return to the nominal frequency after a fault is cleared. In particular, if a fault is not cleared within the so-called critical clearing time, the basic integrity of the operation is endangered. Computing critical clearing time for complex electric power systems still presents an enormous technical challenge.

At each time-step, the proper commands are generated for correcting the abnormality or protecting the system from its consequences. If no abnormality is observed, then the normal operation proceeds for the next sample interval. If the frequency deviations are large and sustained, the under- and over-frequency protective relays automatically disconnect power plants at which the unacceptable deviations occur. Similarly, if a large transmission line goes out of operation, this could lead to current overload in the neighboring transmission lines. A typical scenario here is that a line becomes shorted as a tree touches it, resulting in an unacceptably large current passing through it, and the over-current protective relay of that line disconnects the line to prevent it from further damage. This further activates the over-current protective relays of other lines and they in turn become disconnected.

Protective relaying plays a tremendous role in preventing particular pieces of equipment from becoming damaged under unusual operating conditions. Recall that protective relaying has evolved around the objective of ensuring the safety of individual pieces of equipment under abnormal conditions. For example, transmission lines are allowed to carry only a certain maximum current, blades on turbines can turn only at the speeds specified by the design specifications, and appliances in households operate without being damaged if the voltage applied to them is within the prespecified thresholds of deviations from the nominal voltage at which they are intended to operate. The principles of setting thresholds on relays have evolved over many years and are often system-specific. The relay settings are not changed dynamically to adapt to the changing operating conditions.

For these reasons, relays are key to the cascading events causing major blackouts. The relay settings and their coordination are critical to the efficient use

of the system as a whole. While it is often difficult to differentiate the role of relays in protecting individual pieces of equipment from their role in the system as a whole, it is known that the malfunctioning of protective relaying has played a critical role in several major blackouts. A typical scenario of a blackout of this type starts by a major piece of equipment undergoing forced outage, which, in turn, causes unacceptable over-currents, over- or under-voltages, or unacceptable frequency deviations somewhere else in the system. This situation then triggers the disconnection of the protective relays in the pieces of the affected equipment for safety reasons, which creates further imbalances in the remaining portion of the system, where the protection disconnects the remaining pieces of the equipment. This ultimately results in the disconnection of all pieces of equipment, known as the system blackout or collapse. An even more difficult scenario is related to the false tripping of a relay, which disconnects a piece of equipment without a forced outage actually causing it. Once this piece of equipment is disconnected, the same cascading process of disconnecting the affected pieces of equipment throughout the systems begins. This scenario is known as a "hidden failure." The need to rethink the overall concept of protective relaying in light of system needs and progress in fast computer/communications technologies was recognized some time ago; it has been only recently that this direction is being revived.

Because of this critical role that protective relays play in affecting the interactions among various pieces of the system, it is important to improve their logic and make them both error-free and more adaptive to the changing conditions. Similarly as for primary controllers, this is possible either through a redundant design or through more communications among relays associated with the individual pieces of equipment as these interact to perform system-wide objectives. With the major breakthroughs in the communications technologies, significant progress is being made toward adaptive relaying. Whereas protective relaying could be viewed as the extreme case of primary control, the two problems have not been viewed this way in the past.

2.4 Structure-Based Hierarchical Operation under Normal Conditions

A typical electric power system of the structure described above has millions of nonuniform components and local primary controllers and relays. One of the major goals of EPSE is to design power system

control for achieving a desired prespecified performance. Despite many years of research and development, it has remained difficult to provide a reliable, flexible methodology for automated tuning and switching of a variety of control equipment spread throughout the system. In addition to the problem of high dimensionality, the development of such general tools is particularly challenging for this class of systems because of the nonuniformity of control components, reflected in their uneven spatial distribution throughout the system as well as in a large spread of response times.

Instead of developing the most general computer tools for any possible condition, current operating practice is much simpler and different under normal conditions than under the forced outages. Under normal conditions, the power systems are operated hierarchically by various control centers and their on-line interactions. Typically, decisions are made by individual control centers about the status of the area (utility, control area) under often strongly implied or explicitly understood assumptions about the status of the rest of the interconnection and their interactions with the neighboring areas. As explained later in more detail, the entire hierarchical control of today's electric power systems is based on the assumption that any system change would primarily affect the system only locally and that the effects on the rest of the system are secondary. This underlies the decentralized logic of the primary controllers and relays; it further underlies decentralized decision-making by individual control areas within the overall system interconnection. These simplifying assumptions, generally valid under normal operation, lead to the hierarchical control with spatially and temporally separable sub-objectives within an otherwise very complex system.

The critical assumptions under which the interconnection is planned and operated are generally violated under some abnormal conditions associated with forced outages and/or large deviations in load demand from its forecast. When the system enters such conditions, many of the software tools routinely used under normal operation are disabled by the system operators and the main decision maker becomes a system operator. In addition to adequacy problems, i.e., the failure of power plants to supply power, the other major aspect of abnormalities concerns unusual power flow patterns through the delivery system that are very different from the conditions assumed when primary controllers and protective relays are set. It is, therefore, at least in concept, clear why these "malfunction" under

emergency conditions. Under forced outages, system survivability is the prime objective and the cost is secondary. This means that in regulated industry different control areas cooperate by sharing stand-by reserves needed for emergency conditions. The system interconnection as a whole is considered to be viable under contingencies when there are no widespread failures affecting service to a large number of customers and the system grid remains intact; i.e., conditions that may trigger disconnecting pieces of equipment automatically for safety are avoided. The entire concept assumes no active participation by the end users in emergencies.

Because an electric power system is operated very differently in these two modes, one of the largest challenges to effective power systems engineering tools has been to classify the system status according to how close it may be to either its normal condition or the abnormal states. This challenge was conceptualized for the first time by DyLiacco, who introduced the classification of power system operation shown in Fig. 2. There are many degrees and many timescales of abnormal operation that are shown in Fig. 2. Conditions are generally assessed as normal when they are stationary and as expected. All equipment is working that is supposed to work; loads, fuel supplies, water, and weather conditions are within the expected ranges. This classification was later enhanced, but its overall philosophy has remained as initially proposed. Using this classification of system status, a system operator is in a position to schedule power for the forecasted demand and leave the rest to automation at the secondary and primary levels or override the automation and rely on an expert system knowledge about the specifics of the area of interest and act in real time to prevent major system-wide failures. It is worth observing, however, that the boundaries between normal and abnormal conditions are not straightforward to establish, making it necessary to use this classification always

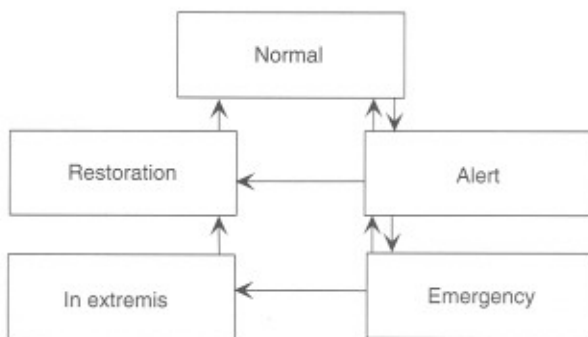


FIGURE 2 Classification of power system operation.

with caution. Requiring much margin between normal and abnormal conditions generally results in subefficient use of the existing resources; also, pushing the system to the boundaries of its secure operation for efficiency reasons could result in less robust and less reliable operation. Balancing these two conflicting objectives is generally very difficult.

2.5 Operating the System by Decision and Control

To actually operate the system within any of the basic conditions defined in Fig. 2 and during intentional or spontaneous transition between them inherently needs to be done in time-steps where the system state is identified at each time and a decision is made regarding control action to be made at each time-step. After these control decisions are set up at each bus system-wide, then the system responds during the interstate intervals, monitored appropriately to provide the basis for decision at the next sampling time.

The system-wide flow of information and action for this process is of immense size and complexity. Its basic structure is summed up in Fig. 3. Note the two columns for decision and for control at each sampling time. The information base—the system-wide measurement data—is indicated as entering at the bottom of the decision column, where the first task is the classification of the system state into basic operating modes of Fig. 2 or the transition between them. Identifying the position of the current system condition within this column represents the decision regarding the phase of the operation. This information is then passed over to the appropriate block into the control column of Fig. 3 for appropriate control action, which then is passed to the appropriate equipment within the system as indicated in Fig. 3. The equipment then carries out the action called for in system-wide control.

Figures 1 through 3 give a summary of the structure and functioning of a nationwide electric power system. The details and their complexity and volume of the contents of this gross frame of the national power system and economics are immense.

3. EPSE TOOLS FOR SYSTEM OPERATION UNDER NORMAL CONDITIONS

EPSE tools have been developed to accommodate the hierarchical structure of typical electric power

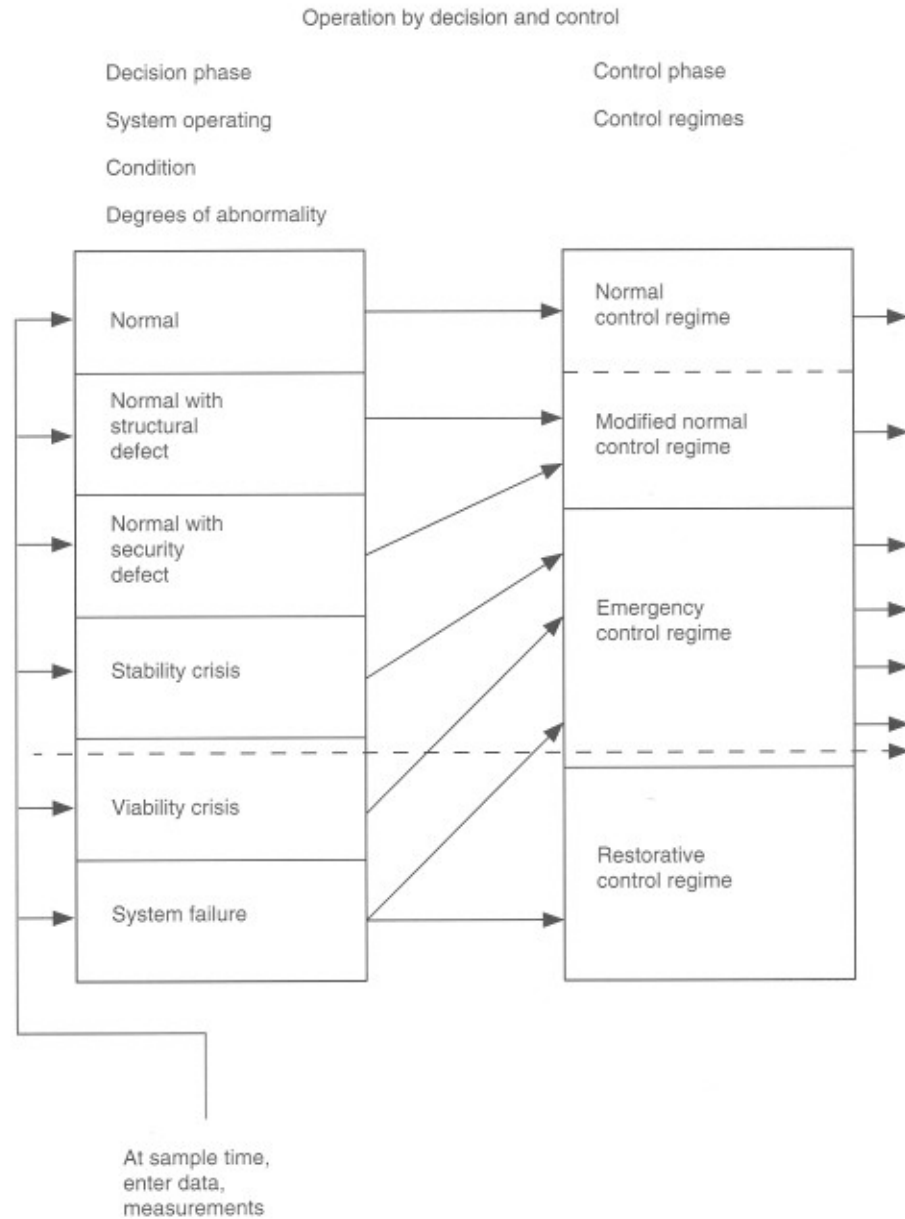


FIGURE 3 Basic structure of system-wide flow of information and action. The dashed line indicates an example of a signal path.

interconnection shown in Fig. 1, horizontally structured into utilities with their own sub-objectives and loosely coupled with the neighboring utilities for sharing generation reserves in case of major equipment outages within the entire interconnection. System monitoring, control, and protection methods are based on these hierarchical structures.

Principal computer-based algorithms for this condition in a decision phase are as follows:

- monitoring and estimation of load and generation;

- static state estimation;
- monitoring of the system loading conditions and security.

Some principal algorithms used for controlling systems under normal operation include the following:

- unit commitment (UC);
- economic dispatch (ED) or optimal power flow (OPF);
- automatic generation control (AGC) to match area real power supply and demand automatically as real power load varies slowly;

- automatic voltage control (AVC) to match area reactive power supply and load and voltage profiles (in some parts of the world only);
- load management.

3.1 System Monitoring

Modern electric power systems are monitored in normal operation to estimate load variations, the status of generators (functional, out for maintenance, or under forced outage), and the status of transmission lines (connected to the rest of the system or shorted out). This information is used as an input to the decision and control phase to balance supply and demand as the system status and levels of load demand vary. In a specific utility area, load variations have typical periodic patterns: annual, seasonal, monthly, weekly, daily, and hourly. Different computer-based methods are used to forecast these system load variations; the long-term forecast (annual and longer) is the hardest and least accurate and the shorter term forecasts are more accurate.

Much progress has been made since the time static state estimation was first introduced to the area of electric power systems. However, this type of estimation is still in use. The basic principle is to use on-line redundant transmission line flow measurements, which estimate false data on the system. The most challenging false data are caused by the incorrectly assumed status of equipment. After many years of researching and developing state estimators, many control centers have them in on-line operations.

The system is also monitored for its proximity to its safe operating limits. The system is generally considered to be in a secure state if none of the operating conditions are violated and the status of the equipment is as expected. The System Control and Data Acquisition System (SCADA) is the basic system in support of area monitoring and decision-making in each control center.

3.2 System Decision and Control

As the loading conditions, power plants' availability status, and the status of transmission lines vary over time, system operators rely heavily on computer-aided software for adjusting overall system resources as needed to supply customers, while maintaining currents/voltage/frequency within the prespecified acceptable threshold of variations. The basic objective of system decision and control in normal

operation is to cover the consumers' demand for power using generating sources available throughout the system.

3.2.1 Objectives under Regulated Industry

- The total operating cost of the full system including transmission losses is minimized.
- The price the consumers pay for power is subject to government regulation and control in such a way that the total cost of estimated power production and delivery is covered with adequate profit margins.
- There is enough power available in the system to cover current load estimated statistically using the past year's records plus adequate reserves to cover deviations of the current load from the estimated values and for emergencies of a first-contingency class.
- The power quality is adequate for consumer satisfaction; that is, voltage and frequency are kept within an adequate viability band and kept sufficiently steady. Note that synchronous time frequency is a courtesy to customers. Much less precision would be enough for engineering purposes.
- The system has security that minimizes outages.

3.2.2 Hierarchies in Regulated Generation Control

The only major changes considered in normal operation are the result of load dynamics. Therefore, power systems dynamics under normal conditions are driven primarily by changes in demand. Typical demand curves exhibit several rates of response, ranging from very fast random variations (order of seconds), through hourly, daily, weekly, and seasonal patterns of larger deviations. In today's hierarchical organization, generation-based scheduling is open-loop for balancing anticipated load on weekly, daily, and hourly bases; the secondary level of control (AGC and/or AVC) is closed-loop, automated, and responsive to the voltage and frequency deviations on a minute-by-minute basis, as the unexpected slow and small load deviations in real and reactive power occur. This power balancing on a minute-by-minute basis is performed by each control area within an electric interconnection for the assumed transmission line flows to the other neighboring areas.

There is very little or no coordination of control areas to adjust their line flow exchanges in near real time; instead, control areas agree how much to exchange for the following day and jointly adjust

their internal resources to implement these agreements. However, since the transmission line flows are not directly controllable in typical AC systems, variations from pre-agreed upon schedules take place in real time. This has not been considered to be a big problem, and utilities have established ways to pay back this inadvertent energy exchange approximately once a month, without any major disturbances to the overall system operations, since the system is operated according to the preventive security criteria for the given regional design. As the line flow patterns between control areas deviate for economic transfers—creating considerably different patterns than originally anticipated when the regional system was planned—mainly for implementing energy trades across control areas, the need for on-line minimal coordination of exchanges between control areas at the regional (tertiary) level and even among the regions may become necessary. Several blackouts, including the August 2003 blackout in the Northeast, clearly indicate the need for such monitoring.

Variations of the hierarchies and their automation can be found throughout the world; for example, the system in the United Kingdom does not have automated frequency control, and, moreover, since the entire system is effectively a single control area, tertiary and secondary levels merge into a single level. On the other hand, the European Interconnection is similar in structure to the U.S. horizontal structure, with the control areas corresponding to the countries, instead of particular utilities, respectively. As the electrically interconnected systems open increasingly to the free energy trades across the traditional control area boundaries, the need for advanced EPSE coordinating tools is becoming more pronounced. The blackout of the Italian electric power grid in September 2003, much in the same way as the U.S. August 2003 blackout, was also related to the failure of pieces of equipment outside the affected network; in this case, it was triggered by the failure of an EHV transmission line interconnecting Italian, French, and Swiss subsystems.

3.2.3 Temporal Separation of Basic Control Functions under Normal Operation

The normal-state standard system control functions are summarized as follows:

- Time frame function;
- 2–3 s Inertia, loads, excitation systems;
- 7–10 s Governors;

- 5–10 min AGC;
- 5–10 min AVC;
- 5–30 min ED/OPF;
- 1–10 h UC, restarting and shutting off units.

3.3 System Control

During normal operation, real power and voltage control functions are separable within a certain decoupling error. The operating practices described here are developed assuming this separation.

3.3.1 Real Power Unit Commitment and Economic Dispatch

The unit commitment and economic dispatch are basic computer-aided tools for optimizing total variable operating costs in industry. This is accomplished by using the least expensive units to supply base load and more expensive units for load following and (load) frequency control. At a control center, the most cost-effective units are scheduled on and off to optimize generation use over daily or weekly time intervals in accordance with coordinated unit commitment. The function is open-loop, performed only for anticipated, not actual, system conditions. The longer term economic efficiency is determined by how power plants are turned on and off and cost optimization is achieved by performing economic dispatch as the information about system loads becomes available through a SCADA system.

3.3.2 Automatic Real Power Generation Control

Of course, the actual current load will virtually never match its statistically estimated value for which generation dispatch is done, and the system frequency is also subject to small fluctuations. Consequently, some form of on-line control will be needed to keep the system frequency close to nominal. The specific control generally depends on the horizontal structure of the given electric power system and it could range from a manual frequency control of an isolated system, as in the United Kingdom, through a hierarchical generation control in a multi-control-area setup, as in the United States.

An important observation concerning frequency control is that even the most advanced hierarchical frequency control is strikingly simple with respect to its on-line information and coordination requirements. The area control error (ACE) is the basic measurement to which AGC reacts to balance supply and demand in each control area in near real time. It is defined as the sum of the weighted deviation of the

control area frequency at each particular sampling instant from the nominal system frequency and the deviation of the net power flow exchange with the neighboring areas measured at the same time from the pre-agreed upon net tie-line flow exchange. This entirely decentralized balancing of supply and demand in the entire electric interconnection comprising several control areas is based on the fact that when the ACE is zero for each area, the system is running exactly on schedule. Therefore, if each area independently controls its generation economically to drive its own ACE to zero, then:

- The actual load for the system is covered;
- The system frequency is as scheduled;
- All net tie-line exchanges are at their scheduled values area by area, thus satisfying the scheduled trades;
- If an area is unable to supply its scheduled net tie-line exchange and drive its own ACE to zero, then system frequency will drop and net tie-line exchanges at other areas will rise to cover the deficiency in the load of the deficient area.

3.3.3 Basic Hierarchical System for Real Power Control

- The top (tertiary, regional, interconnection) level simply adjusts the setpoint frequency to drive the actual system frequency and synchronous time back to normal. This one piece of information, the setpoint frequency, needs to be communicated to all areas. This minimal central action will rearrange the area net tie-line exchanges to balance the entire load. This is known as time-error correction in the regulated industry structure.

- Each area individually acts on the change of frequency setpoint by keeping its ACE to zero. No communication is needed between the areas.

- The system is fully decoupled; the areas do not need to communicate with one another or the center. The center needs only to watch the synchronous time to generate its single control command.

- Primary controllers (governors and power system stabilizers) stabilize very fast transients as the power supply/demand balancing at each control area level is performed through AGC.

It is important to recognize the role of accurate short-term load forecasting: the more accurately and more frequently the load is projected, the more efficient the use of available generation will be. The ED and UC are an integral part of a single complex function whose economic performance and technical

performance are the result of the actual interdependencies of UC and ED, on one side, and the AGC, on the other. For example, it was estimated that the main inefficiency when performing UC comes from leaving unused generation on some regulating units for frequency control. One could envision, with sufficient computing power, that generation control based solely on dynamic economic dispatch and stochastic unit commitment would be sufficient to balance supply and demand in real time without violating frequency quality specifications.

3.3.4 Reactive Power Economic Dispatch

For an interconnected power system to remain viable, the reactive power must balance at each bus. The problem of reactive power dispatch in the regulated industry is generally bundled with the problem of maintaining (load) voltages within the prespecified limits. The (generator) voltage setpoint values are optimized with respect to certain performance criteria subject to the reactive power balance constraints, the load-voltage acceptable limits, and the limits on generator voltages. Although the voltage control of an interconnected large-scale power system is widely recognized as a very important problem, its basic formulations and solutions are often utility-specific. In the U.S. interconnection, voltage control at the secondary (control area) and tertiary (regional) levels is viewed strictly as a static optimization problem. The most common tool for solving this optimization problem is an algorithm based on OPF.

Compared with generation-based frequency control, generation-based reactive power or voltage control is less standardized and less automated. Only a handful of countries in the world have semiautomated reactive power dispatch of generators.

The generation-based reactive power dispatch falls under the category of the OPF. Depending on the actual choice of the optimization criterion, two formulations are of interest:

1. The cost function is the total fuel cost required to supply a given demand.
2. The cost function is the total transmission loss that occurs as power is delivered from the power plants to customers.

An increased severity of voltage-related operating problems has resulted in an effort to make OPF-based formulations more directly related to these problems than the general OPF methods. Among many developments, the most notable are as follows: (1) an improved formulation of the decoupled OPF;

(2) OPF-based optimization of reactive power margins; and (3) an OPF targeted on improving energy transfer over far electrical distances.

3.3.5 A Hierarchical System for Reactive Power/Voltage Control

A qualitatively different approach to the voltage-control design is hierarchical and is based on temporal separation of reactive power fluctuations and corresponding control levels. Similar to the hierarchical real power-frequency control schemes, the approach is based on decomposing a large system into control areas equipped with decentralized closed-loop secondary-level voltage controllers. A close look into this approach indicates that the objectives of a hierarchical voltage control scheme are analogous to the objectives of frequency control; the main objective at the secondary (control area) level of voltage control is, for example, to update setpoints of generator exciters to maintain voltages at critical ("pilot") points within the prespecified deviations as the reactive power demand and generation deviate from their scheduled (anticipated) values. The hierarchical control for the regulated industry, based on the systematic implementations in several European countries, is often referred to as AVC.

3.3.6 Load Management

It has been well understood for quite some time that having an active response to the changing system conditions seen in frequency and voltage deviations from their nominal values by the end users could significantly contribute to a more robust performance of the system as a whole. In basically the same way that the control area supply/demand imbalance (seen in its ACE) becomes reduced by increasing generation, one could decrease control area load and drive ACE back to zero. Responsive load management is particularly important at times of unexpected shortage in generation and transmission capacity, as well as for using less costly generation reserves instead of peaking units under normal operation.

Except for some early experiments known as demand-side management programs, customers have largely remained passive power consumers. As the industry restructures, the need for more system conditions and price-responsive load will increase. The early vision of homeostatic control, in which all end users react to local deviations in frequency and demand in an automated way, could go a very long way toward more efficient use of resources under

normal conditions and reduced reserves for emergency conditions. Sections 5 and 6 state that price-responsive load is the key to the well-functioning electricity markets; the difficult question is providing on-line incentives to the end users to respond at the value as seen by themselves.

4. EPSE FOR EMERGENCY OPERATION

The ultimate challenge to electric power systems engineering at its present stage is reflected in the lack of model-based analytic tools and algorithms for detecting abnormalities in system operation and for deciding what actions to take as the abnormal situation evolves. The classification of potential abnormal modes of operation according to the famous DyLiacco diagram shown in Fig. 2 and its later enhancements suggests that the following operating modes could occur: alert mode and emergency mode.

This section briefly summarizes the tools for monitoring and responding under these abnormal conditions.

4.1 System Monitoring

4.1.1 Alert Operating Mode

SCADA-based monitoring could detect a situation in which conditions are normal; the system is viable and within the acceptable operating constraints. However, the structure has been altered from what was expected by an earlier event—a transmission line is missing, for example. If this is detected, the operating mode is recognized to be under an alert condition.

4.1.2 Emergency Operating Mode

The emergency conditions could be reflected in several different system-wide problems, ranging from stability and viability crisis through system failure. This division, however, is not clear-cut. The conditions overlap, but normally one dominates. Take in sequence:

4.1.2.1 Stability Crisis The system is in a momentary dynamic state, typically caused by a fault, which is sufficiently violent to endanger the integrity of the system.

4.1.2.2 Viability Crisis The system in its present condition is incapable of operating within voltage,

current, frequency, etc., operating constraints, given the available generation and transmission capability for the existing load demand. This condition could result from a fault and is then often preceded by a stability crisis. Nonviable conditions can, however, come on quietly, for instance, if major generation or other equipment does not become available when it is scheduled to come on-line for peak demand.

4.1.2.3 Integrity Crisis The integrity of the system is violated—for instance, load was dropped or the portion of the system is dropped off. Principally, this is a severe and extensive accumulation of stability and viability crises or the damage left by them with islanding and blackout patches in the system. During the crisis phase, events are still occurring and a struggle is still going on to avoid as much disintegration as possible.

4.1.2.4 Restoration This is an extensive and collective control (generally interpreted) effort to remedy the damage left by any combination of the three crises.

4.2 System Decision and Control

4.2.1 Alert Operating Mode

The principal operating algorithms are as for the normal operating mode, but, in addition, future consequences of the structural change must be evaluated and, if necessary, remedied. For example, the structural change may violate security constraints while approaching peak load. Industry practice is preventive in this operating mode, in the sense that the system is operated so that it meets normal operating constraints when any one of the most likely and most severe unexpected structural changes (contingencies) takes place. It is often cost-inefficient because it does not allow for least-cost use of resources without considering future events. To circumvent this problem, the operating limits under structural changes are allowed to be less restrictive in the alert mode than in the normal mode. For example, typically accepted voltage variations under normal operation are within 2% or 0.002 per unit, and in the alert mode they are relaxed to 5%. When a more severe structural change occurs, it may bring the system very close to the limits of acceptable operating constraints. For such conditions, economic criteria are overruled by the security criteria. Different ancillary algorithms for readjusting network flows, bringing on new, more expensive

generation, modifying load dispatch, etc., are used to assist the operator under these conditions.

Moreover, since the system operation is still normal under the alert state, the control tools and actions of the normal state are used. The special alert-state control actions consist primarily of equipment switching and changes in control setpoints and schedules to improve security.

4.2.2 Emergency Operating Mode

The decision and control actions in emergency mode are often left to the human operator and are often dependent on the specifics of a particular control area or region. At best, off-line computer-based analysis is performed for scenarios of interest and particular procedures are in place in case the particular scenario occurs. Model-based simulations of such scenarios are generally very time-consuming and are therefore not feasible as on-line means of facilitating decision-making and control in emergency situations, when time is critical. One of the typical decisions concerns the so-called critical clearing time, i.e., the longest time of fault duration, so that when the fault is removed, the system can still return to its normal operation. The following are representative decision and control actions characteristic of an emergency operating mode.

4.2.2.1 Stability Crisis Some of the principal control tools can be:

- Local structural control or protective relaying to eliminate faulty components and local control actions to preserve system stability.
- Stability augmentation utilizing FACTS, technologies, breaking resistors, load skipping, etc.
- Load dropping or major structural changes to separate the system in the least objectionable manner when integrity cannot be maintained. Note that this action pushes the system into the integrity crisis or an *in extremis* condition.

4.2.2.2 Viability Crisis Principal algorithms in an approximate order of increasing undesirability include:

- Frequency reduction of the AGC type;
- Use of spinning reserves or cold reserves;
- Special measures, such as fast turbine run-back;
- Help from neighboring areas;
- Exploiting time-limited overload capability of the equipment;
- Special measures, such as voltage reduction;

- First-stage structural control, such as starting a new generation, returning equipment from maintenance, or load dropping (for minutes or hours);
- Second-stage structural control-islanding involving separation of a power network into parts, some of which are not supplied with power.

4.2.2.3 Integrity Crisis The tools are mostly the same as for the stability and viability crisis.

4.2.2.4 Restoration The main processes taking place during restoration are reconnection of the islands and restoration of loads. This is, of course, an operation by itself and it has been researched extensively over time.

5. CHALLENGES TO EPSE IN THE CHANGING INDUSTRY

Over the past decades, the electric power industry has been undergoing major organizational changes. It is critical to recognize that an electric power structure, along with the objectives and performance metrics used in various EPSE methods for monitoring, decision-making, and on-line operations of a complex electric power system, must be posed in the context of each specific industry structure. The interplay between technical, economic, and policy signals over various time horizons and among various industry layers is fundamental to the overall system performance as a whole. One of the more difficult tasks of EPSE even for fully regulated industry has been how to establish the right balance between system robustness to unexpected events, such as forced outages, and the efficient use of the existing equipment under normal conditions. In other words, the tradeoffs between system security/reliability and the economics of providing power to the end users have been generally difficult to mediate. The performance metrics of the system as a whole have been affected by the utility-dependent performance metrics within the system. Basic security criteria adopted by the regulated industry are discussed above; all software tools for monitoring and decision-making in control centers are based on these well-established objectives.

Electric power restructuring has brought about many fundamental changes to the way EPSE might be performed in the future. To start with, a once vertically integrated utility with a single objective of

supplying its native customers has become unbundled into power supply, transmission, and distribution businesses and/or functions. Delivery and consumption are becoming businesses with their own objectives, typically not aligned with the objectives of the power suppliers. In addition, the service is provided through some forms of markets, with marketers managing both the physical, forced outage-related risks and the financial risks with the objectives of making their own profits. Design of markets for various services (delivery, voltage, frequency control) in addition to the basic power market is at rudimentary stages. Providing electric power service competitively asks for complex new economic and policy designs, with a full understanding of their overall effects on the system and the unbundled market participants themselves.

The EPSE tools in support of electric power provision in these evolving industry structures are still rudimentary. One thing is certain, although not widely recognized: it is going to be impossible to continue using the same EPSE models, analysis, and decision-making tools developed for the regulated industry to manage effectively the power system under restructuring. This lack of understanding of the gaps between the engineering tools and market objectives has already caused unexpected outcomes. The remainder of this section briefly summarizes evolving EPSE concepts. The last part of this section provides a possible systems view for bridging this gap between regulated and restructured industry models. The section explains how potentially new paradigms for the electric power system may be based on distributed decision-making by all market participants actively pursuing their sub-objectives under incomplete information. Minimal coordination at various industry layers in order to ensure well-understood performance metrics is the ultimate goal. This challenge is briefly elaborated at the end.

6. OBJECTIVES OF EPSE AS A FUNCTION OF CHANGING INDUSTRY STRUCTURES

6.1 EPSE Tools for Vertically Unbundling Industry

6.1.1 Objectives in Deregulated Industry

- Suppliers can obtain the maximum price for their product competitively established in free

commodities market-type economy restricted only in the sense of the rules of exchange.

- Consumers of electric power can pay the lowest price for their purchase competitively established in a free commodities market-type economy restricted only in the sense of the rules of exchange. Note that this may work fine for large customers who can effectively trade at the commodities market to their advantage. Small customers cannot effectively do that, which raises the difficult question of how to establish the price of the power at individual homes, with the potential outcome to retain some kind of government regulation in this area.

- There is enough power available in the system to cover the current load of the system for emergencies of a first contingency class.

- The power supply quality is adequate for consumer satisfaction; that is, voltage and frequency are kept within an adequate viability band and sufficiently steady.

- The system has security to minimize outages.

6.1.2 Evolution from the Hierarchical Operation into Open Access Operation

In the changing power industry, balancing supply and demand in real time is generally market-based. Three qualitatively different market mechanisms are of interest: (1) the primary electricity market(s) for supplying anticipated demand; (2) various “ancillary” markets for ensuring that system conditions remain within prespecified limits as demand deviates in real time from its anticipated pattern; and (3) transmission markets for delivering power requested by (1) and (2).

These markets are necessary for ensuring that the system conditions remain within their technically acceptable limits as power is provided competitively. Here, only some fundamental changes needed in EPSE tools for serving the new industry are summarized.

In addition to the temporal decomposition-based hierarchies present in load dynamics, further temporal decompositions are emerging via the establishment of electricity markets whose on-line decision-making evolves at daily, hourly, and even near-real-time rates. Two observations are relevant here for effective on-line use of generation in deregulated industry: (1) the distinction between predicted and real time is no longer as pronounced as when unit commitment is done assuming demand to be known for the entire next day and (2) it is, therefore, conceptually difficult to “unbundle” the economic

generation scheduling process, assuming the predicted load from the on-line control function for responding to unexpected load fluctuations.

Furthermore, some customers are willing to accept power interruptions in exchange for a lower price of electricity—that is, generation is beginning to be provided by some customers on a nonfirm basis. This is a qualitative change from the utility’s unconditional obligation to serve and charge its connected customer the same price of electricity over time. This raises a fundamental question about the inherent temporal decomposition of load dynamics and the conceptual applicability of hierarchical power systems operation under competition.

Finally, a transmission grid is managed as a regulated monopoly in a multiownership environment, but is expected to serve markets (1) and (2), which are competitive. This asymmetry of regulatory structure within the single electric interconnection intended to be used in an open access manner, without recognizing ownership boundaries, is creating tremendous challenges for operating the transmission grid consistently. Because of this, systematic policy/regulatory frameworks for moving toward value-based transmission service need to be introduced.

6.2 EPSE for Operating the System under Open Access

Operating under open access implies, at least in principle, the ability for power suppliers to competitively serve customers across utility boundaries within an electric power interconnection. The hierarchical operation in regulated industry must be modified to facilitate delivering power across the boundaries of former control areas established in the old industry without endangering the reliability of the interconnection as a whole. As power is traded across the control areas, each control area must monitor these exchanges in order to balance the remaining needs for power to the customers that it serves as a provider of last resort. The interconnection is being used for power flow patterns different than the flow patterns expected under the originally intended system control and protection design. These market-driven exchanges could result in much stronger couplings among the control areas and, therefore, could require some degree of on-line coordination of flow exchanges between the control areas in order to operate the interconnection as a whole reliably. EPSE tools for coordinating control

areas while enabling power trading across control areas do not yet exist.

One possible approach to operating the interconnection under open access would be a market-based approach to (1) ensuring enough capacity, both generation and transmission, for reliable service and (2) giving incentives to the end users to adjust in an on-line way to the changing technical and/or economic conditions. An early vision of the 20th century electric power operation was introduced by Fred Schweppe: all end users react to variations in local frequency and voltage and the system remains in homeostasis, or balance. The success of this concept, borrowed from biology, must obey two key rules: (1) all end users must respond and (2) the right automation must be implemented. The ongoing industry restructuring has not yet provided a regulatory/policy framework in support of this technological vision.

Furthermore, although the technology for automated participation by the end users is available, it is not cost-effective when implemented by each end user, independent of its size and characteristics. Instead, what are available are cost-effective technologies for managing very large consumers or groups of smaller end-users. Although in concept there should not be any difference between one large end user of X megawatts and several smaller users whose total use is X megawatts, there is a very big difference between two end users of the same average X-megawatt energy consumption, where one end user is adaptive to the system conditions (by "shaving" its peak consumption by redistributing the needs to a different time of the day and/or by reducing its nonessential consumption during extreme system conditions) and the second end user is completely nonresponsive to the system conditions and requires an unconditional supply without considerations for the overall system conditions.

To implement price-responsive energy consumption on-line, communications begin to play a very different new role than in the hierarchical operation under regulation. For an open access system to work well, it becomes necessary to have on-line communication of important technical and/or economic information (1) between the aggregator of various end users and (2) between the aggregators and energy providers, transmission providers, and system operators as well as among several system operators within the interconnection. Note that, at least in principle, a bundled production could be provided by the sellers of power with the delivery service included or the

aggregator at the end user's side would look for the best combination of subservices as needed by the end users represented by this aggregator.

A highly effective paradigm of this type has not been actively pursued due to the lack of regulatory policy incentives to differentiate quality of service and value of these differences. In today's industry under restructuring, there is hardly any incentive to the end users to respond to the system conditions, since the service is cost-based with the costs more or less equally distributed among all end users according to their average X-megawatt consumption. The final part of this section provides a possible vision of futuristic EPSE tools that, given the right policy incentives, could lead to the value-based provision of quality of service under open access.

6.3 EPSE for Risk Management under Open Access

As the industry reorganizes, it has become necessary to differentiate between the physical and the financial risks. Major physical risks concern system-wide failures like that experienced during the 2003 blackout, reflected in a fundamental inability of the system to operate as intended and to deliver according to the prespecified performance metrics. This could take place for a variety of reasons, such as (1) under-design of system hardware for the perceived needs; (2) poor on-line IT-based monitoring, control, and protection coordination of various individual pieces of equipment; (3) human error; and (4) nonresponsive power consumption. The society must take it as given that some very-low-probability, potentially high-impact triggering events will happen. It is, however, not obvious at all how eliminating any of the reasons (1)–(5) would fully guard against widespread system failures. The individual relays and breakers very rarely fail to disconnect pieces of equipment that they are responsible for. However, in order to minimize the effects of triggering events on the system as a whole, the tradeoffs between designing an "optimal grid" for the anticipated use under normal and abnormal conditions and developing novel EPSE tools for managing these physical risks under open access must be understood and managed. No matter how robust the hardware design in place, its system-wide use is not going to be as effective as possible without good software tools.

The role of EPSE software tools in managing physical risks in complex electric power grids has been grossly underestimated. Consequently, the tools are

very rudimentary and very little technology transfer has been attempted. In particular, feed-forward software tools for scheduling available resources for the predicted load are well established for the regulated industry, as reviewed in Section 3. The software and hardware options for managing resources under open access are much more complex than in the regulated industry. EPSE tools for distributed decisions by market participants and by the system operators, in particular with the load being an active decision maker, must be developed. The old industry has been characterized by being truly risk-averse. As the levels of risk-taking become more diverse under open access, EPSE tools must be developed as a means of decision-making by those taking risks.

6.4 Toward EPSE-Supported Protocols under Open Access

Given a strong movement toward the industry restructuring along with an emergence of cost-effective technologies for producing, delivering, and consuming power in qualitatively different ways than in the past, it is essential to develop EPSE tools for flexible provision of service to the end users according to their choice. Instead of pursuing the rigid hierarchical control of the past and/or over-designing the system, an IT framework would provide flexibility in delivery and consumption.

The underlying technological weaknesses that led to the major blackouts of 1966 (Northeast), 1975 (Northeast), 1996 (California), and 2003 (Northeast) are best corrected with information and control technologies. The first weakness is simplistic equipment protection and control. When system conditions evolve to threaten individual pieces of equipment, such as a line, transformer, or generator, protection devices respond by removing that equipment from service. This increases the stress on other parts of the system, possibly causing their protection to act, and so on. The result can be a large-scale cascading blackout. A better alternative would be to shift resources to aid the equipment first threatened, avoiding a blackout altogether. This requires that local controllers of power plants, transmission lines, and consumer consumption act quickly in a coordinated manner to relieve system stress before protective action is required.

Unfortunately, controllers cannot identify emergency conditions and are not flexible enough to act in a coordinated manner, and the protection devices lack the information and decision-making abilities

required to postpone their actions. The second weakness is the inability to quickly detect that the system is not operating as desired, because of equipment failure or unusual power demand somewhere within the very large and complex electric power grid. In particular, if individual operators could quickly recognize that their region is under stress, then they could adjust their own resources fast enough to keep operation under control or at least minimize the extent of a blackout. Today's operators do not have the information to do so because there is no on-line monitoring at the regional level or higher. Taken together, these two weaknesses result in a lack of information, flexibility, and coordination that will inevitably lead to future large-scale blackouts as demand increases. With economically minimal investment in information and control technology, this need not be the case.

To improve system operation, the protection and control of equipment, such as power plants, transformers, transmission lines, and loads, must first be improved. This is a challenge because the system response to protection and control actions under stress may be different than under the conditions for which the protection and controls were initially built and tuned. Typical assumptions under normal operation are that (1) the local effects of protection and control are much stronger than their effects elsewhere on the system and (2) producing more power when frequency and voltage drop always helps. These two assumptions are frequently violated when the system is under stress, requiring more on-line information about the rest of the system and more advanced logic to decide how to act.

Next, an on-line coordinated exchange of power between utilities and larger regions of the electric power grid in the United States and Canada must be implemented. This will allow the system operators to better manage large-scale system operation. Managing the entire interconnected grid on-line as a single system is not possible for a variety of technical and business reasons. Instead, a multilayer IT-based framework is required for the system to support the delivery of power between arbitrary generators and consumers. This framework must (1) allow all system users to adjust to changing conditions; (2) allow all consumers to communicate their short- and long-term demands for power and its delivery; (3) have clearly defined technical and contractual responsibilities for the performance of all users; and (4) monitor and control power exchanges between all utilities and regions. Such a framework would facilitate the evolution of the rigid grid of today to an

Internet-like grid in which the users decide when and how to use the system. Not only will this improve reliability, but it will permit value-based reliability in which users pay more (or less) for more (or less) reliable power.

The same IT-based framework for power system management can also support long-term forward markets for reliable service by providing current and future system needs for that service. The money paid in advance for reliable service could be invested in the information and control technology required to implement it. Having forward reliability markets would avoid unpopular regulatory decisions to increase the price of electricity without a good understanding of customer needs for reliable service and their willingness to pay for it. It would also promote the value-based evolution of the grid according to customer needs.

An adequately reliable power system will most economically come from investment in information and control technology. Improvements in system protection and control, built on an IT framework for on-line reliable service, and the forward markets for reliable service complement each other. One without the other does not work and both are long overdue.

7. A GLIMPSE INTO THE FUTURE: MORE SMOOTH AND SECURE ON A BUILDING BLOCK STRUCTURE

7.1 The Current Bulk Power Transmission Network

The electric power system in its present state is a dynamic system of enormous size coast to coast, operating at an equilibrium state that is stable under the slight perturbations imposed by normal load variations. However, faults or mistakes must always be expected even in the best of equipment—and even in humans. An abnormal sudden change like the loss of a large power-generating plant or a large, vital transmission line abruptly changes the system equilibria, including the current operating state, potentially drastically. While the system is trying to move automatically (too fast for human interference) to a new equilibrium, the huge difference in energy present in the network before and after the change between the two operating equilibria is left to swing freely over the system in giant energy waves, the postfault transient oscillation, which challenge the current, voltage, or power-carrying capacity, i.e., the backbone strength of equipment such as transmission

lines, generators, and transformers. It is the system operators' duty to maintain a loading condition by their dispatch activity at all times for the existing loading of the system without system breakup for all fault contingencies. Through existing advanced technology including power electronics, computer, and communication, this effort can be successful most of the time, but not always, and one should not forget the new emergence of terrorist possibilities.

7.2 Reorganizing Bulk Power Transmission Network to Building Block Structures Individually Controlled by a Computer Control Center

Drastic dangers call for drastic remedies. The authors' group, led by John Zaborsky, has been developing such a drastic remedy by mostly retaining its currently used power equipment, but rearranging the structure of the interplay of the power system and its controlling computer and communication system for maximum effectiveness.

Recent events served as a reminder that the current power system is vulnerable to widespread failure caused by the failure of even one major component. This vulnerability derives from the fact that after such a failure the system becomes a substantially different one and the operating equilibria cease to be equilibria in the new system. However, the states in the new state space will generally lie in the region of attraction of one of the new equilibria, which in turn will lie quite close to their existing ones except in the disturbed area, so they should move to their new position through a dynamic transient unless the system is becoming unstable. The latter results from the fact that each of the components (building blocks) carries a large amount of energy at an equilibrium and in AC this energy is swinging across any connection at 120 cycles.

So, at either of the equilibria (before or after the event), each building block will carry two components of energy:

- Type 1: the steady state energy content of the building block in the new system after the event.
- Type 2: the difference between the energy content of the building block at the time of the event and the type 1 energy content.

Each of these should be available in the computer control center as it is planning the postevent operation of the system after the event.

7.3 The Outline of the Management of the Envisioned Approach

The proposed new, building block (for example, power plants or generators, or major loads, such as aluminum plant, capacitor banks) structure eliminates any direct control interaction between individual building blocks even if they are neighbors but not their physical dynamic interconnection through the bulk power network system. The only information and control command exchange exists between the control centers and individual building blocks before and after the disturbance.

Each of the individual building blocks in their current physical state contains an amount of energy of type 1. This energy will differ from the energy at the state assigned by the control center to the blocks. In effect, the distribution of the type 1 energy defines the operating state of the system.

The excess energy (type 2) becomes the free swinging power in the system postevent transient oscillation, unless it is eliminated by draining it out or in locally at each of the bulk transmission buses into storage capacitors and then fed back smoothly into the system by routine dispatch (such storage already exists sporadically in the power system). While the excess energy is thus drained out or in (if available in storage) at individual buses, the system voltages and current are sliding on smoothly under dispatch control without wild swinging with only a perturbation ripple, provided enough generation is available. If not, i.e., in an emergency, the central computer control will order dropping of loads in priority order and then they will be reconnected when possible.

In fact, the system may already be broken up into disjoint pieces (e.g., in a disaster situation). If so, the building block structure allows the control centers to make the separate pieces by themselves viable by load dropping and set them up like "individual power companies" to run independently of one another while still connected to the control center until their regular connection can be restored. This approach outlined above can become an effective defense in emergencies of the 9/11 or the New York 2003 type.

7.4 Summary of the Process for Building Block Use Operated and Controlled by the Computer Control Center

In summary, the envisioned building block structure of the power system has the following distinguishing features:

- The system is restructured as a mosaic of building blocks, such as generators, power plant buses, and transmission lines.
- Building blocks are connected only to their neighbors.
- Each block has only one single control command connection going to the system's computer control centers. There is no control command connection, i.e., input, directly between two building blocks, even if they are direct neighbors physically.
- The one single communication between each individual building block and the control center carries full report of the dynamic state of that particular building block to the control center and control command instruction to the block.
- The control center sends to each building block a command to adjust one particular system state variable (located inside in that block) to an assigned value, using a single-variable feedback loop control producing a single control signal input generated independently within the building block for setting the state variable of the block.
- On the basis of block-by-block information received by the control center about components of the system state in each block and the information the center has about the demands on the system, the control center computes the type 1 energy content required for stable operation of the system in each of its blocks.
- Note that this computation is simply the steady-state stable "load flow" for the system.
- Block by block, this information is deducted from the present energy contents of the block.
- This difference is drained in or out (depending on whether it carries a plus or minus sign) of the storage equipment at each particular block.
- The result is that the system has slid over into its desired steady state value.
- No violent transients exist to cause new failures.
- Note that on an all-DC bulk power system, this result derives automatically but it applies as described on a conventional mixed AC and DC bulk power system—with the addition of some more power electronic equipment.

In either case (all HV-DC or conventional bulk transmission), the dynamics of the system trajectories in the state space will change instantly and smoothly to that of the postevent system composition without transient waves but the energy controls of the energy storage devices (typically capacitor banks) will shift virtually unilaterally, to its post event form.

Note the following:

- The above assumes the system to be linear around its operating equilibria and that its response is instantaneous, assumptions that are true only approximately. It needs to be proven that on the actual systems this would cause only a tolerable perturbation around the operating point in case of faults.

- This approach exploits the full potential of power electronics to achieve maximum possible smoothness and security of the system operation without violent transient swings that can cause the spreading of major faults (e.g., East Coast 1965, 2003).

- This, however, requires installation of some power electronics, computer, and storage equipment, which need to be properly analyzed.

- The economy of such full restructuring of the current bulk power system needs to be established to fully utilize the current technology of power system electronics, computers, and communications, even if it requires only the addition of a moderate amount of equipment but major restructuring of their operation into a building block base.

In conclusion, as briefly summarized here, this approach assumes linearity and instant response (both of which can only be approximated, leaving the question: how well?) and assumes that it would be possible to drain out the type 2 energy at each building block so that the system would find itself in the new equilibrium position with no transient. Without any such draining process, as is happening today, the type 2 energy differences create a violent transient, which is proven to cause new faults since it creates highly abnormal voltages, currents, etc., on the equipment until it is dissipated through the line losses and radiation.

With what is proposed here, the system—that is, the bulk power transmission network—would possess a smoothly varying equilibrium state without any over-voltages or currents and hence without the spreading of the disturbances and system breakup following a major fault as in New York 2003 or a 9/11-type attack.

SEE ALSO THE FOLLOWING ARTICLES

Electrical Energy and Power • Electric Power: Critical Infrastructure Protection • Electric Power Generation: Fossil Fuel • Electric Power Generation: Valuation of Environmental Costs • Electric Power Measurements and Variables • Electric Power Reform: Social and Environmental Issues • Electric Power: Traditional Monopoly Franchise Regulation and Rate Making • Electric Power: Transmission and Generation Reliability and Adequacy

Further Reading

- Amin, M. (Ed.). (2002). Complex networks. *IEEE Control Systems Magazine*, February 2002.
- Chen, J., Thorp, J. S., and Parashar, M. (2001). "Analysis of Electric Power System Disturbance Data," Hawaii International Conference on System Sciences (HICSS-34), Maui, Hawaii, January 2001.
- Cohn, N. (1977). "Research Opportunities in the Control of Bulk Power and Energy Transfers on Interconnected Systems," Special Report on Power System Planning and Operations: Future Problems and Research Needs, EPRI E-377-SR.
- Fink, L., and Carlsen, K. (1978). Operating under stress and strain. *IEEE Spectrum* March, 48-53.
- Ilic, M., Galiana, F. D., and Fink, L. (Eds.). (1998). "Electric Power Systems Restructuring: Engineering and Economics." Kluwer Academic, Dordrecht, the Netherlands/Norwell, MA.
- Ilic, M. D., and Liu, S. X. (1996). "Hierarchical Power Systems Control: Its Value in a Changing Electric Power Industry, Advances in Industrial Control." Springer-Verlag, London.
- Ilic, M. D., and Zaborszky, J. (2000). "Dynamics and Control of Large Electric Power Systems." Wiley-Interscience, New York.
- Interconnected Operations Services. (1996). NERC WG Report.
- Joskow, P., and Schmalensee, R. (1983). "Markets of Power: An Analysis of Electric Utility Deregulation." MIT Press, Cambridge, MA.
- Schweppe, M., Caramanis, F., Tabors, R., and Bohn, R. (1988). "Spot Pricing of Electricity." Kluwer Academic, Dordrecht, the Netherlands/Norwell, MA.
- Zaborszky, J., and Ilic, M. (2001). Exploring the potential of the all DC (ADC) bulk power systems. In "Proceedings of the Bulk Power System Dynamics and Control V," August 26-31, 2001, Onomichi, Japan." [Plenary paper]
- Zaborszky, J., and Ilic, M. (1999). "General Structure of the Regulated, Deregulated and Other Generation Dispatch." IEEE Power Tech '99 Conference, Budapest, Hungary, Paper No. BPT-440-21.