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Power System Dynamics and Stability

Richard G. Farmer
Arizona State University

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Prabha Kundur
Powertech Labs, Inc.

Kip Morrison
Powertech Labs, Inc.

John Paserba
Mitsubishi Electric Power Products, Inc.

Juan Sanchez-Gasca
GE Power Systems

Einar Larsen
GE Power Systems

Yakout Mansour
BC Hydro

Vijay Vittal
Iowa State University

Carson W. Taylor
Carson Taylor Seminars

William W. Price
GE Power Systems

J. F. Hauer
Pacific Northwest National Laboratory

W. A. Mittelstadt
Bonneville Power Administration

M. K. Donnelly
Pacific Northwest National Laboratory

W. H. Litzenberger
Bonneville Power Administration

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Rambabu Adapa
Electric Power Research Institute

Peter W. Sauer
University of Illinois at Urbana

Richard G. Farmer
Arizona State University

Bajarang L. Agrawal
Arizona Public Service Company

11.1 Power System Stability — Overview

Prabha Kundur

This introductory section provides a general description of the power system stability phenomena including fundamental concepts, classification, and definition of associated terms. A historical review of the emergence of different forms of stability problems as power systems evolved and of the developments of methods for their analysis and mitigation is presented. Requirements for consideration of stability in system design and operation are discussed.

Basic Concepts

Power system stability is the ability of the system, for a given initial operating condition, to regain a normal state of equilibrium after being subjected to a disturbance. Stability is a condition of equilibrium between opposing forces; instability results when a disturbance leads to a sustained imbalance between the opposing forces.

The power system is a highly nonlinear system that operates in a constantly changing environment; loads, generator outputs, topology, and key operating parameters change continually. When subjected to a transient disturbance, the stability of the system depends on the nature of the disturbance as well as the initial operating condition. The disturbance may be small or large. Small disturbances in the form of load changes occur continually, and the system adjusts to the changing conditions. The system must be able to operate satisfactorily under these conditions and successfully meet the load demand. It must also be able to survive numerous disturbances of a severe nature, such as a short-circuit on a transmission line or loss of a large generator.

Following a transient disturbance, if the power system is stable, it will reach a new equilibrium state with practically the entire system intact; the actions of automatic controls and possibly human operators will eventually restore the system to normal state. On the other hand, if the system is unstable, it will result in a run-away or run-down situation; for example, a progressive increase in angular separation of generator rotors, or a progressive decrease in bus voltages. An unstable system condition could lead to cascading outages and a shut-down of a major portion of the power system.

The response of the power system to a disturbance may involve much of the equipment. For instance, a fault on a critical element followed by its isolation by protective relays will cause variations in power flows, network bus voltages, and machine rotor speeds; the voltage variations will actuate both generator and transmission network voltage regulators; the generator speed variations will actuate prime mover governors; and the voltage and frequency variations will affect the system loads to varying degrees depending on their individual characteristics. Further, devices used to protect individual equipment may

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respond to variations in system variables and thereby affect the power system performance. A typical modern power system is thus a very high-order multivariable process whose dynamic performance is influenced by a wide array of devices with different response rates and characteristics. Hence, instability in a power system may occur in many different ways depending on the system topology, operating mode, and the form of the disturbance.

Traditionally, the stability problem has been one of maintaining synchronous operation. Since power systems rely on synchronous machines for generation of electrical power, a necessary condition for satisfactory system operation is that all synchronous machines remain in synchronism or, colloquially, "in step." This aspect of stability is influenced by the dynamics of generator rotor angles and power-angle relationships.

Instability may also be encountered without the loss of synchronism. For example, a system consisting of a generator feeding an induction motor can become unstable due to collapse of load voltage. In this instance, it is the stability and control of voltage that is the issue, rather than the maintenance of synchronism. This type of instability can also occur in the case of loads covering an extensive area in a large system.

In the event of a significant load/generation mismatch, generator and prime mover controls become important, as well as system controls and special protections. If not properly coordinated, it is possible for the system frequency to become unstable, and generating units and/or loads may ultimately be tripped possibly leading to a system blackout. This is another case where units may remain in synchronism (until tripped by such protections as under-frequency), but the system becomes unstable.

Because of the high dimensionality and complexity of stability problems, it is essential to make simplifying assumptions and to analyze specific types of problems using the right degree of detail of system representation. The following subsection describes the classification of power system stability into different categories.

Classification of Power System Stability

Need for Classification

Power system stability is a single problem; however, it is impractical to deal with it as such. Instability of the power system can take different forms and is influenced by a wide range of factors. Analysis of stability problems, including identifying essential factors that contribute to instability and devising methods of improving stable operation is greatly facilitated by classification of stability into appropriate categories. These are based on the following considerations (Kundur, 1994; Kundur and Morrison, 1997):

- The physical nature of the resulting instability related to the main system parameter in which instability can be observed.
- The size of the disturbance considered indicates the most appropriate method of calculation and prediction of stability.
- The devices, processes, and the time span that must be taken into consideration in order to determine stability.

Figure 11.1 shows a possible classification of power system stability into various categories and subcategories. The following are descriptions of the corresponding forms of stability phenomena.

Rotor Angle Stability

Rotor angle stability is concerned with the ability of interconnected synchronous machines of a power system to remain in synchronism under normal operating conditions and after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators.

The rotor angle stability problem involves the study of the electromechanical oscillations inherent in power systems. A fundamental factor in this problem is the manner in which the power outputs of

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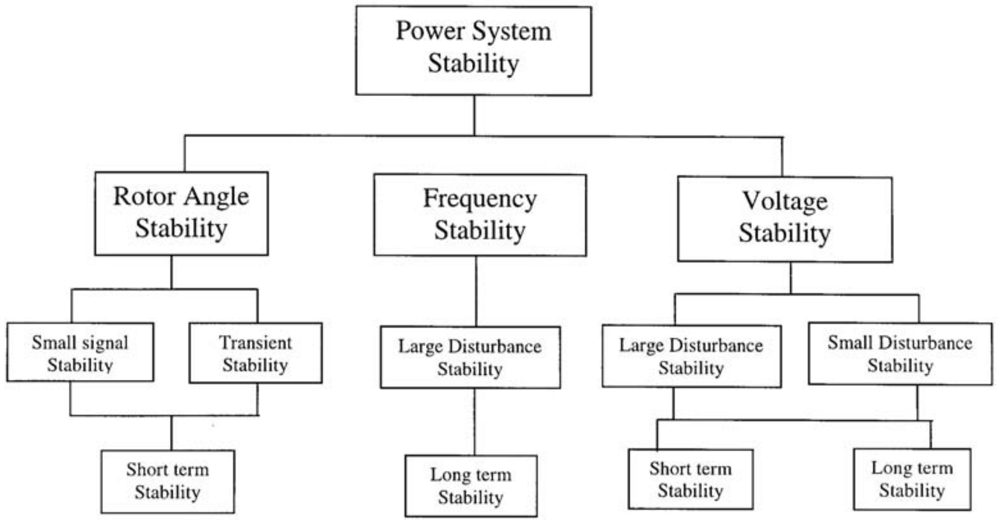

FIGURE 11.1 Classification of power system stability.

synchronous machines vary as their rotor angles change. The mechanism by which interconnected synchronous machines maintain synchronism with one another is through restoring forces, which act whenever there are forces tending to accelerate or decelerate one or more machines with respect to other machines. Under steady-state conditions, there is equilibrium between the input mechanical torque and the output electrical torque of each machine, and the speed remains constant. If the system is perturbed, this equilibrium is upset, resulting in acceleration or deceleration of the rotors of the machines according to the laws of motion of a rotating body. If one generator temporarily runs faster than another, the angular position of its rotor relative to that of the slower machine will advance. The resulting angular difference transfers part of the load from the slow machine to the fast machine, depending on the power-angle relationship. This tends to reduce the speed difference and hence the angular separation. The power-angle relationship, as discussed above, is highly nonlinear. Beyond a certain limit, an increase in angular separation is accompanied by a decrease in power transfer; this increases the angular separation further and leads to instability. For any given situation, the stability of the system depends on whether or not the deviations in angular positions of the rotors result in sufficient restoring torques.

It should be noted that loss of synchronism can occur between one machine and the rest of the system, or between groups of machines, possibly with synchronism maintained within each group after separating from each other.

The change in electrical torque of a synchronous machine following a perturbation can be resolved into two components:

- *Synchronizing torque* component, in phase with a rotor angle perturbation.
- *Damping torque* component, in phase with the speed deviation.

System stability depends on the existence of both components of torque for each of the synchronous machines. Lack of sufficient synchronizing torque results in *aperiodic* or *non-oscillatory instability*, whereas lack of damping torque results in *oscillatory instability*.

For convenience in analysis and for gaining useful insight into the nature of stability problems, it is useful to characterize rotor angle stability in terms of the following two categories:

1. *Small signal* (or *steady state*) *stability* is concerned with the ability of the power system to maintain synchronism under small disturbances. The disturbances are considered to be sufficiently small

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that linearization of system equations is permissible for purposes of analysis. Such disturbances are continually encountered in normal system operation, such as small changes in load.

Small signal stability depends on the initial operating state of the system. Instability that may result can be of two forms: (i) increase in rotor angle through a non-oscillatory or aperiodic mode due to lack of synchronizing torque, or (ii) rotor oscillations of increasing amplitude due to lack of sufficient damping torque.

In today's practical power systems, small signal stability is largely a problem of insufficient damping of oscillations. The time frame of interest in small-signal stability studies is on the order of 10 to 20 s following a disturbance.

2. *Large disturbance rotor angle stability or transient stability*, as it is commonly referred to, is concerned with the ability of the power system to maintain synchronism when subjected to a severe transient disturbance. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship.

   Transient stability depends on both the initial operating state of the system and the severity of the disturbance. Usually, the disturbance alters the system such that the post-disturbance steady state operation will be different from that prior to the disturbance. Instability is in the form of aperiodic drift due to insufficient synchronizing torque, and is referred to as *first swing stability*. In large power systems, transient instability may not always occur as first swing instability associated with a single mode; it could be as a result of increased peak deviation caused by superposition of several modes of oscillation causing large excursions of rotor angle beyond the first swing.

   The time frame of interest in transient stability studies is usually limited to 3 to 5 sec following the disturbance. It may extend to 10 sec for very large systems with dominant inter-area swings.

   Power systems experience a wide variety of disturbances. It is impractical and uneconomical to design the systems to be stable for every possible contingency. The design contingencies are selected on the basis that they have a reasonably high probability of occurrence.

As identified in Fig. 11.1, small signal stability as well as transient stability are categorized as short term phenomena.

Voltage Stability

Voltage stability is concerned with the ability of a power system to maintain steady voltages at all buses in the system under normal operating conditions, and after being subjected to a disturbance. Instability that may result occurs in the form of a progressive fall or rise of voltage of some buses. The possible outcome of voltage instability is loss of load in the area where voltages reach unacceptably low values, or a loss of integrity of the power system.

Progressive drop in bus voltages can also be associated with rotor angles going out of step. For example, the gradual loss of synchronism of machines as rotor angles between two groups of machines approach or exceed 180° would result in very low voltages at intermediate points in the network close to the electrical center (Kundur, 1994). In contrast, the type of sustained fall of voltage that is related to voltage instability occurs where rotor angle stability is not an issue.

The main factor contributing to voltage instability is usually the voltage drop that occurs when active and reactive power flow through inductive reactances associated with the transmission network; this limits the capability of transmission network for power transfer. The power transfer limit is further limited when some of the generators hit their reactive power capability limits. The driving force for voltage instability are the loads; in response to a disturbance, power consumed by the loads tends to be restored by the action of distribution voltage regulators, tap changing transformers, and thermostats. Restored loads increase the stress on the high voltage network causing more voltage reduction. A rundown situation causing voltage instability occurs when load dynamics attempts to restore power consumption beyond the capability of the transmission system and the connected generation (Kundur, 1994; Taylor, 1994; Van Cutsem and Vournas, 1998).

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As in the case of rotor angle stability, it is useful to classify voltage stability into the following subcategories:

1. *Large disturbance voltage stability* is concerned with a system's ability to control voltages following large disturbances such as system faults, loss of generation, or circuit contingencies. This ability is determined by the system-load characteristics and the interactions of both continuous and discrete controls and protections. Determination of large disturbance stability requires the examination of the nonlinear dynamic performance of a system over a period of time sufficient to capture the interactions of such devices as under-load transformer tap changers and generator field-current limiters. The study period of interest may extend from a few seconds to tens of minutes. Therefore, long term dynamic simulations are required for analysis (Van Cutsem et al., 1995).
2. *Small disturbance voltage stability* is concerned with a system's ability to control voltages following small perturbations such as incremental changes in system load. This form of stability is determined by the characteristics of loads, continuous controls, and discrete controls at a given instant of time. This concept is useful in determining, at any instant, how the system voltage will respond to small system changes. The basic processes contributing to small disturbance voltage instability are essentially of a steady state nature. Therefore, static analysis can be effectively used to determine stability margins, identify factors influencing stability, and examine a wide range of system conditions and a large number of postcontingency scenarios (Gao et al., 1992). A criterion for small disturbance voltage stability is that, at a given operating condition for every bus in the system, the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage magnitude (V) decreases as the reactive power injection (Q) at the same bus is increased. In other words, a system is voltage stable if V-Q sensitivity is positive for every bus and unstable if V-Q sensitivity is negative for at least one bus.

The time frame of interest for voltage stability problems may vary from a few seconds to tens of minutes. Therefore, voltage stability may be either a short-term or a long-term phenomenon.

Voltage instability does not always occur in its pure form. Often, the rotor angle instability and voltage instability go hand in hand. One may lead to the other, and the distinction may not be clear. However, distinguishing between angle stability and voltage stability is important in understanding the underlying causes of the problems in order to develop appropriate design and operating procedures.

Frequency Stability

Frequency stability is concerned with the ability of a power system to maintain steady frequency within a nominal range following a severe system upset resulting in a significant imbalance between generation and load. It depends on the ability to restore balance between system generation and load, with minimum loss of load.

Severe system upsets generally result in large excursions of frequency, power flows, voltage, and other system variables, thereby invoking the actions of processes, controls, and protections that are not modeled in conventional transient stability or voltage stability studies. These processes may be very slow, such as boiler dynamics, or only triggered for extreme system conditions, such as volts/hertz protection tripping generators. In large interconnected power systems, this type of situation is most commonly associated with islanding. Stability in this case is a question of whether or not each island will reach an acceptable state of operating equilibrium with minimal loss of load. It is determined by the overall response of the island as evidenced by its mean frequency, rather than relative motion of machines. Generally, frequency stability problems are associated with inadequacies in equipment responses, poor coordination of control and protection equipment, or insufficient generation reserve. Examples of such problems are reported by Kundur et al. (1985); Chow et al. (1989); and Kundur (1981).

Over the course of a frequency instability, the characteristic times of the processes and devices that are activated by the large shifts in frequency and other system variables will range from a matter of

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seconds, corresponding to the responses of devices such as generator controls and protections, to several minutes, corresponding to the responses of devices such as prime mover energy supply systems and load voltage regulators.

Although frequency stability is impacted by fast as well as slow dynamics, the overall time frame of interest extends to several minutes. Therefore, it is categorized as a long-term phenomenon in Fig. 11.1.

Comments on Classification

The classification of stability has been based on several considerations so as to make it convenient for identification of the causes of instability, the application of suitable analysis tools, and the development of corrective measures appropriate for a specific stability problem. There clearly is some overlap between the various forms of instability, since as systems fail, more than one form of instability may ultimately emerge. However, a system event should be classified based primarily on the dominant initiating phenomenon, separated into those related primarily with voltage, rotor angle, or frequency.

While classification of power system stability is an effective and convenient means to deal with the complexities of the problem, the overall stability of the system should always be kept in mind. Solutions to stability problems of one category should not be at the expense of another. It is essential to look at all aspects of the stability phenomena, and at each aspect from more than one viewpoint.

Historical Review of Stability Problems

As electric power systems have evolved over the last century, different forms of instability have emerged as being important during different periods. The methods of analysis and resolution of stability problems were influenced by the prevailing developments in computational tools, stability theory, and power system control technology. A review of the history of the subject is useful for a better understanding of the electric power industry's practices with regard to system stability.

Power system stability was first recognized as an important problem in the 1920s (Steinmetz, 1920; Evans and Bergvall, 1924; Wilkins, 1926). The early stability problems were associated with remote power plants feeding load centers over long transmission lines. With slow exciters and noncontinuously acting voltage regulators, power transfer capability was often limited by steady-state as well as transient rotor angle instability due to insufficient synchronizing torque. To analyze system stability, graphical techniques such as the equal area criterion and power circle diagrams were developed. These methods were successfully applied to early systems which could be effectively represented as two machine systems.

As the complexity of power systems increased, and interconnections were found to be economically attractive, the complexity of the stability problems also increased and systems could no longer be treated as two machine systems. This led to the development in the 1930s of the network analyzer, which was capable of power flow analysis of multimachine systems. System dynamics, however, still had to be analyzed by solving the swing equations by hand using step-by-step numerical integration. Generators were represented by the classical "fixed voltage behind transient reactance" model. Loads were represented as constant impedances.

Improvements in system stability came about by way of faster fault clearing and fast acting excitation systems. Steady-state aperiodic instability was virtually eliminated by the implementation of continuously acting voltage regulators. With increased dependence on controls, the emphasis of stability studies moved from transmission network problems to generator problems, and simulations with more detailed representations of synchronous machines and excitation systems were required.

The 1950s saw the development of the analog computer, with which simulations could be carried out to study in detail the dynamic characteristics of a generator and its controls rather than the overall behavior of multimachine systems. Later in the 1950s, the digital computer emerged as the ideal means to study the stability problems associated with large interconnected systems.

In the 1960s, most of the power systems in the U.S. and Canada were part of one of two large interconnected systems, one in the east and the other in the west. In 1967, low capacity HVDC ties were also established between the east and west systems. At present, the power systems in North America form

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virtually one large system. There were similar trends in growth of interconnections in other countries. While interconnections result in operating economy and increased reliability through mutual assistance, they contribute to increased complexity of stability problems and increased consequences of instability. The Northeast Blackout of November 9, 1965, made this abundantly clear; it focused the attention of the public and of regulatory agencies, as well as of engineers, on the problem of stability and importance of power system reliability.

Until recently, most industry effort and interest has been concentrated on *transient* (*rotor angle*) *stability*. Powerful transient stability simulation programs have been developed that are capable of modeling large complex systems using detailed device models. Significant improvements in transient stability performance of power systems have been achieved through use of high-speed fault clearing, high-response exciters, series capacitors, and special stability controls and protection schemes.

The increased use of high response exciters, coupled with decreasing strengths of transmission systems, has led to an increased focus on *small signal* (*rotor angle*) *stability*. This type of angle instability is often seen as local plant modes of oscillation, or in the case of groups of machines interconnected by weak links, as interarea modes of oscillation. Small signal stability problems have led to the development of special study techniques, such as modal analysis using eigenvalue techniques (Martins, 1986; Kundur et al., 1990). In addition, supplementary control of generator excitation systems, static Var compensators, and HVDC converters is increasingly being used to solve system oscillation problems. There has also been a general interest in the application of power electronic based controllers referred to as FACTS (Flexible AC Transmission Systems) controllers for damping of power system oscillations (IEEE, 1996).

In the 1970s and 1980s, frequency stability problems experienced following major system upsets led to an investigation of the underlying causes of such problems and to the development of long term dynamic simulation programs to assist in their analysis (Davidson et al., 1975; Converti et al., 1976; Stubbe et al., 1989; Inoue et al., 1995; Ontario Hydro, 1989). The focus of many of these investigations was on the performance of thermal power plants during system upsets (Kundur et al., 1985; Chow et al., 1989; Kundur, 1981; Younkins and Johnson, 1981). Guidelines were developed by an IEEE Working Group for enhancing power plant response during major frequency disturbances (1983). Analysis and modeling needs of power systems during major frequency disturbances was also addressed in a recent CIGRE Task Force report (1999).

Since the late 1970s, voltage instability has been the cause of several power system collapses worldwide (Kundur, 1994; Taylor, 1994; IEEE, 1990). Once associated primarily with weak radial distribution systems, voltage stability problems are now a source of concern in highly developed and mature networks as a result of heavier loadings and power transfers over long distances. Consequently, voltage stability is increasingly being addressed in system planning and operating studies. Powerful analytical tools are available for its analysis (Van Cutsem et al., 1995; Gao et al., 1992; Morison et al., 1993), and well-established criteria and study procedures are evolving (Abed, 1999; Gao et al., 1996).

Clearly, the evolution of power systems has resulted in more complex forms of instability. Present-day power systems are being operated under increasingly stressed conditions due to the prevailing trend to make the most of existing facilities. Increased competition, open transmission access, and construction and environmental constraints are shaping the operation of electric power systems in new ways. Planning and operating such systems require examination of all forms of stability. Significant advances have been made in recent years in providing the study engineers with a number of powerful tools and techniques. A coordinated set of complementary programs, such as the one described by Kundur et al. (1994) makes it convenient to carry out a comprehensive analysis of power system stability.

Consideration of Stability in System Design and Operation

For reliable service, a power system must remain intact and be capable of withstanding a wide variety of disturbances. Owing to economic and technical limitations, no power system can be stable for all possible disturbances or contingencies. In practice, power systems are designed and operated so as to be stable for a selected list of contingencies, normally referred to as "design contingencies" (Kundur, 1994).

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Experience dictates their selection. The contingencies are selected on the basis that they have a significant probability of occurrence and a sufficiently high degree of severity, given the large number of elements comprising the power system. The overall goal is to strike a balance between costs and benefits of achieving a selected level of system security.

While security is primarily a function of the physical system and its current attributes, secure operation is facilitated by:

- Proper selection and deployment of preventive and emergency controls.
- Assessing stability limits and operating the power system within these limits.

Security assessment has been historically conducted in an off-line operation planning environment in which stability for the near-term forecasted system conditions is exhaustively determined. The results of stability limits are loaded into look-up tables which are accessed by the operator to assess the security of a prevailing system operating condition.

In the new competitive utility environment, power systems can no longer be operated in a very structured and conservative manner; the possible types and combinations of power transfer transactions may grow enormously. The present trend is, therefore, to use online dynamic security assessment. This is feasible with today's computer hardware and stability analysis software.

Acknowledgment

The classification of power system stability presented in this section is based on the report currently under preparation by a joint CIGRE-IEEE Task Force on Power System Stability Terms, Classification, and Definitions.

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11.2 Transient Stability

Kip Morrison

As discussed in Seciton 11.1, power system stability was recognized as a problem as far back as the 1920s at which time the characteristic structure of systems consisted of remote power plants feeding load centers over long distances. These early stability problems, often a result of insufficient synchronizing torque, were the first emergence of transient instability. As defined in the previous section, *transient stability* is the ability of a power system to remain in synchronism when subjected to large transient disturbances. These disturbances may include faults on transmission elements, loss of load, loss of generation, or loss of system components such as transformers or transmission lines.

Although many different forms of power system stability have emerged and become problematic in recent years, transient stability still remains a basic and important consideration in power system design and operation. While it is true that the operation of many power systems is limited by phenomena such as voltage stability or small-signal stability, most systems are prone to transient instability under certain conditions or contingencies and hence the understanding and analysis of transient stability remain fundamental issues. Also, we shall see later in this section that transient instability can occur in a very short time frame (a few seconds), leaving no time for operator intervention to mitigate problems. It is therefore essential to deal with the problem in the design stage or severe operating restrictions may result.

This section includes a discussion of the basic principles of transient stability, methods of analysis, control and enhancement, and practical aspects of its influence on power system design and operation.

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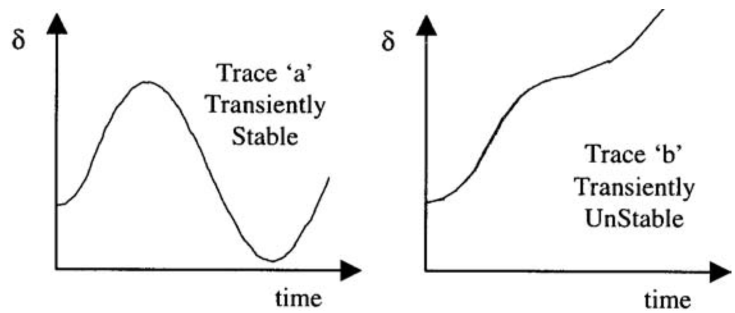

FIGURE 11.2 Typical swing curves.

Basic Theory of Transient Stability

Most power system engineers are familiar with plots of generator rotor angle (δ) versus time as shown in Fig. 11.2. These "swing curves" plotted for a generator subjected to a particular system disturbance show whether a generator rotor angle recovers and oscillates around a new equilibrium point as in trace "a" or whether it increases aperiodically such as in trace "b". The former case is deemed to be transiently stable, and the latter case transiently unstable. What factors determine whether a machine will be stable or unstable? How can the stability of large power systems be analyzed? If a case is unstable, what can be done to enhance stability? These are some of the questions discussed in this section.

Two concepts are essential in understanding transient stability: (i) the swing equation and (ii) the power-angle relationship. These can be used together to describe the equal area criterion, a simple graphical approach to assessing transient stability.

The Swing Equation

In a synchronous machine, the prime mover exerts a mechanical torque T_m on the shaft of the machine and the machine produces an electromagnetic torque T_e. If, as a result of a disturbance, the mechanical torque is greater than the electromagnetic torque, an accelerating torque T_a exists and is given by:

$$T_a = T_m - T_e \tag{11.1}$$

This ignores the other torques caused by friction, core loss, and windage in the machine. T_a has the effect of accelerating the machine which has an inertia J (kg•m^2) made up of the inertia of the generator and the prime mover and, therefore,

$$J\frac{d\omega_m}{dt} = T_a = T_m - T_e \tag{11.2}$$

where t is time in seconds and ω_m is the angular velocity of the machine rotor in mechanical rad/s. It is common practice to express this equation in terms of the inertia constant H of the machine. If ω_{0m} is the rated angular velocity in mechanical rad/s, J can be written as:

$$J = \frac{2H}{\omega_{0m}^2} VA_{base} \tag{11.3}$$

Therefore,

$$\frac{2H}{\omega_{0m}^2} VA_{base} \frac{d\omega_m}{dt} = T_m - T_e \tag{11.4}$$

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And now, if ω_r denotes the angular velocity of the rotor (rad/s) and ω_0 its rated value, the equation can be written as:

$$2H\frac{d\overline{\omega}_r}{dt} = \overline{T}_m - \overline{T}_e \tag{11.5}$$

Finally it can be shown that

$$\frac{d\overline{\omega}_r}{dt} = \frac{d^2\delta}{\omega_0 dt^2} \tag{11.6}$$

where δ is the angular position of the rotor (elec. rad/s) with respect to a synchronously rotating reference frame.

Combining Eqs. (11.5) and (11.6) results in the *swing equation* [Eq. (11.7)], so-called because it describes the swings of the rotor angle δ during disturbances.

$$\frac{2H}{\omega_0}\frac{d^2\delta}{dt^2} = \overline{T}_m - \overline{T}_e \tag{11.7}$$

An additional term $(-K_D\Delta\overline{\omega}_r)$ may be added to the right side of [Eq. (11.7)] to account for a component of damping torque not included explicitly in T_e.

For a system to be *transiently stable* during a disturbance, it is necessary for the rotor angle (as its behavior is described by the swing equation) to oscillate around an equilibrium point. If the rotor angle increases indefinitely, the machine is said to be *transiently unstable* as the machine continues to accelerate and does not reach a new state of equilibrium. In multimachine systems, such a machine will "pull out of step" and lose synchronism with the rest of the machines.

The Power-Angle Relationship

Consider a simple model of a single generator connected to an infinite bus through a transmission system as shown in Fig. 11.3. The model can be reduced as shown by replacing the generator with a constant voltage behind a transient reactance (classical model). It is well known that there is a maximum power that can be transmitted to the infinite bus in such a network. The relationship between the electrical power of the generator P_e and the rotor angle of the machine δ is given by,

$$P_e = \frac{E' E_B}{X_T}\sin\delta = P_{\max}\sin\delta \tag{11.8}$$

where

$$P_{\max} = \frac{E' E_B}{X_T} \tag{11.9}$$

Equation (11.8) can be shown graphically as Fig. 11.4 from which it can be seen that as the power initially increases, δ increases until reaching 90° when P_e reaches its maximum. Beyond $\delta = 90°$, the power decreases until at $\delta = 180°$, $P_e = 0$. This is the so-called power-angle relationship and describes the transmitted power as a function of rotor angle. It is clear from Eq. (11.9) that the maximum power is a function of the voltages of the generator and infinite bus, and more importantly, a function of the transmission system reactance; the larger the reactance (for example, the longer or weaker the transmission circuits), the lower the maximum power.

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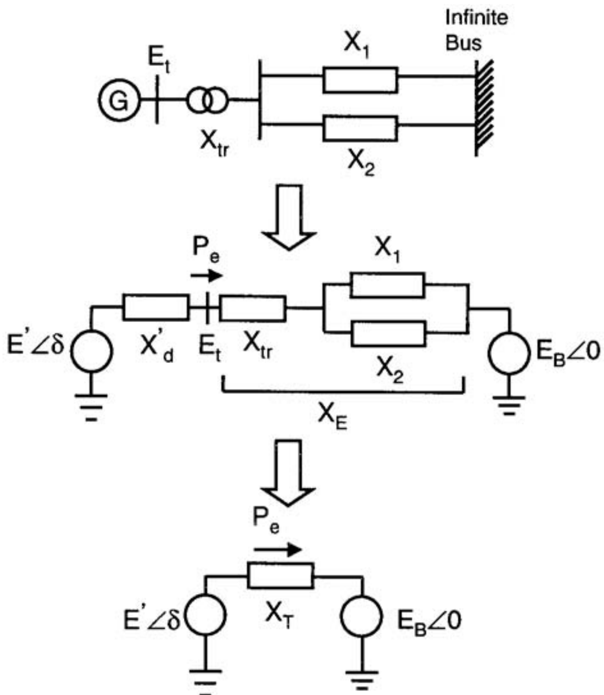

FIGURE 11.3 Single machine system.

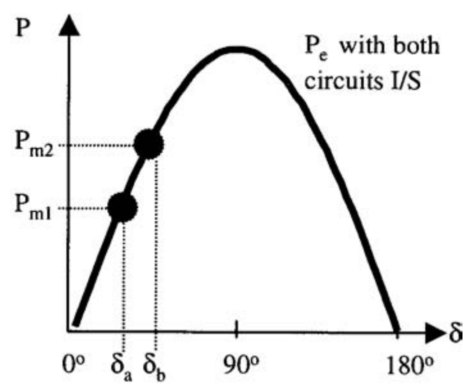

FIGURE 11.4 Power-angle relationship with both circuits in service.

Figure 11.4 shows that for a given input power to the generator P_{m1}, the electrical output power is P_e (equal to P_m) and the corresponding rotor angle is δ_a. As the mechanical power is increased to P_{m2}, the rotor angle advances to δ_b. Figure 11.5 shows the case with one of the transmission lines removed causing an increase in X_T and a reduction P_{max}. It can be seen that for the same mechanical input (P_{m1}), the situation with one line removed causes an increase in rotor angle to δ_c.

The Equal Area Criterion

By combining the dynamic behavior of the generator as defined by the swing equation, with the power-angle relationship, it is possible to illustrate the concept of transient stability using the *equal area criterion*.

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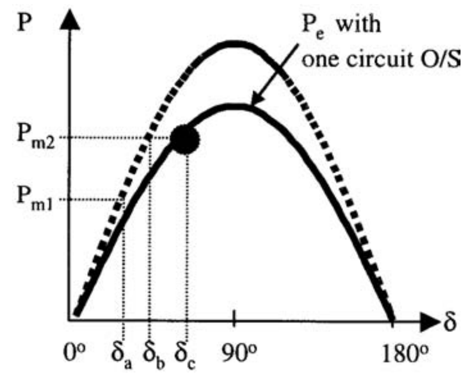

FIGURE 11.5 Power-angle relationship with one circuit out of service.

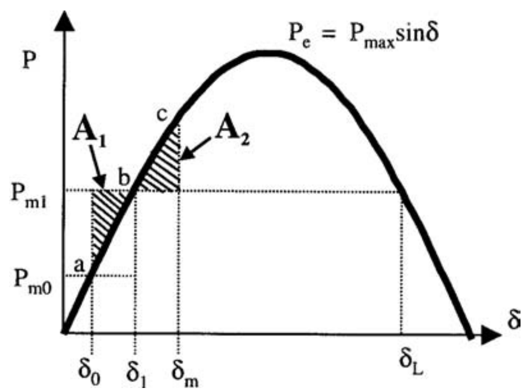

FIGURE 11.6 Equal area criterion for step change in mechanical power.

Consider Fig. 11.6 in which a step change is applied to the mechanical input of the generator. At the initial power P_{m0}, $\delta = \delta_0$ and the system is at operating point "a". As the power is increased in a step to P_{m1}(accelerating power = P_{m1} = P_e), the rotor cannot accelerate instantaneously, but traces the curve up to point "b," at which time $P_e = P_{m1}$ and the accelerating power is zero. However, the rotor speed is greater than the synchronous speed and the angle continues to increase. Beyond "b," $P_e > P_m$ and the rotor decelerates until reaching a maximum δ_{max} at which point the rotor angle starts to return towards "b."

As we will see, for a single machine infinite bus system, it is not necessary to plot the swing curve to determine if the rotor angle of the machine increases indefinitely, or if it oscillates around an equilibrium point. The equal area criterion allows stability to be determined using graphical means. While this method is not generally applicable to multi-machine systems, it is a valuable learning aid.

Starting with the swing equation as given by Eq. (11.7) and interchanging per unit power for torque,

$$\frac{d^2\delta}{dt^2} = \frac{\omega_0}{2H}\left(P_m - P_e\right) \tag{11.10}$$

Multiplying both sides by 2δ/dt and integrating gives

$$\left[\frac{d\delta}{dt}\right]^2 = \int_{\delta_0}^{\delta} \frac{\omega_0\left(P_m - P_e\right)}{H} d\delta \quad \text{or} \quad \frac{d\delta}{dt} = \sqrt{\int_{\delta_0}^{\delta} \frac{\omega_0\left(P_m - P_e\right)}{H} d\delta} \tag{11.11}$$

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δ_0 represents the rotor angle when the machine is operating synchronously prior to any disturbance. It is clear that for the system to be stable, δ must increase, reach a maximum (δ_{max}), and then change direction as the rotor returns to complete an oscillation. This means that dδ/dt (which is initially zero) changes during the disturbance, but must, at a time corresponding to δ_{max}, become zero again. Therefore, as a stability criterion,

$$\int_{\delta_0}^{\delta} \frac{\omega_0}{H}\left(P_m - P_e\right) d\delta = 0. \tag{11.12}$$

This implies that the area under the function $P_m - P_e$ plotted against δ must be zero for a stable system, which requires Area 1 to be equal to Area 2. Area 1 represents the energy gained by the rotor during acceleration and Area 2 represents energy lost during deceleration.

Figures 11.7 and 11.8 show the rotor response (defined by the swing equation) superimposed on the power-angle curve for a stable case and an unstable case, respectively. In both cases, a three-phase fault is applied to the system given in Fig. 11.3. The only difference in the two cases is that the fault clearing time has been increased for the unstable case. The arrows show the trace of the path followed by the rotor angle in terms of the swing equation and power-angle relationship. It can be seen that for the stable case, the energy gained during rotor acceleration is equal to the energy dissipated during deceleration ($A_1 = A_2$) and the rotor angle reaches a maximum and recovers. In the unstable case, however, it can be seen that the energy gained during acceleration is greater than that dissipated during deceleration (since the fault is applied for a longer duration), meaning that $A_1 > A_2$ and the rotor continues to advance and does not recover.

Methods of Analysis of Transient Stability

Modeling

The basic concepts of transient stability presented above are based on highly simplified models. Practical power systems consist of large numbers of generators, transmission circuits, and loads.

For stability assessment, the power system is normally represented using a positive sequence model. The network is represented by a traditional positive sequence powerflow model that defines the transmission topology, line reactances, connected loads and generation, and predisturbance voltage profile.

Generators can be represented with various levels of detail, selected based on such factors as length of simulation, severity of disturbance, and accuracy required. The most basic model for synchronous generators consists of a constant internal voltage behind a constant transient reactance, and the rotating inertia constant (H). This is the so-called classical representation that neglects a number of characteristics: the action of voltage regulators, variation of field flux linkage, the impact of the machine physical construction on the transient reactances for the direct and quadrature axis, the details of the prime mover or load, and saturation of the magnetic core iron. Historically, classical modeling was used to reduce computational burden associated with more detailed modeling, which is not generally a concern with today's simulation software and computer hardware. However, it is still often used for machines that are very remote from a disturbance (particularly in very large system models) and where more detailed model data is not available.

In general, synchronous machines are represented using detailed models that capture the effects neglected in the classical model, including the influence of generator construction (damper windings, saturation, etc.), generator controls, (excitation systems including power system stabilizers, etc.), the prime mover dynamics, and the mechanical load. Loads, which are most commonly represented as static voltage and frequency-dependent components, may also be represented in detail by dynamic models that capture their speed torque characteristics and connected loads. There are a myriad of other devices, such as HVDC lines and controls and static Var devices, which may require detailed representation. Finally,

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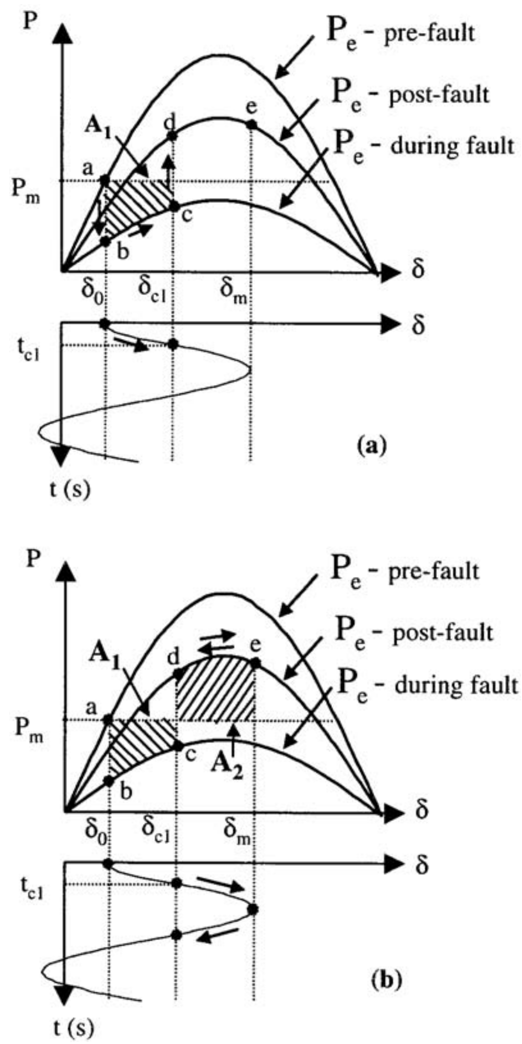

FIGURE 11.7 Equal area criterion for stable case $A_1 = A_2$. (a) Acceleration of rotor. (b) Deceleration of rotor.

system protections are often represented. Models may also be included for line protections (such as mho distance relays), out-of-step protections, loss of excitation protections, or special protection schemes.

Although power system models may be extremely large, representing thousands of generators and other devices producing systems with tens of thousands of system states, efficient numerical methods combined with modern computing power have made time-domain simulation readily available in many commercially available computer programs. It is also important to note that the time frame in which transient instability occurs is usually in the range of 1 to 5 sec, so that simulation times need not be excessively long.

Analytical Methods

To accurately assess the system response following disturbances, detailed models are required for all critical elements. The complete mathematical model for the power system consists of a large number of algebraic and differential equations, including

- Generators stator algebraic equations
- Generator rotor circuit differential equations

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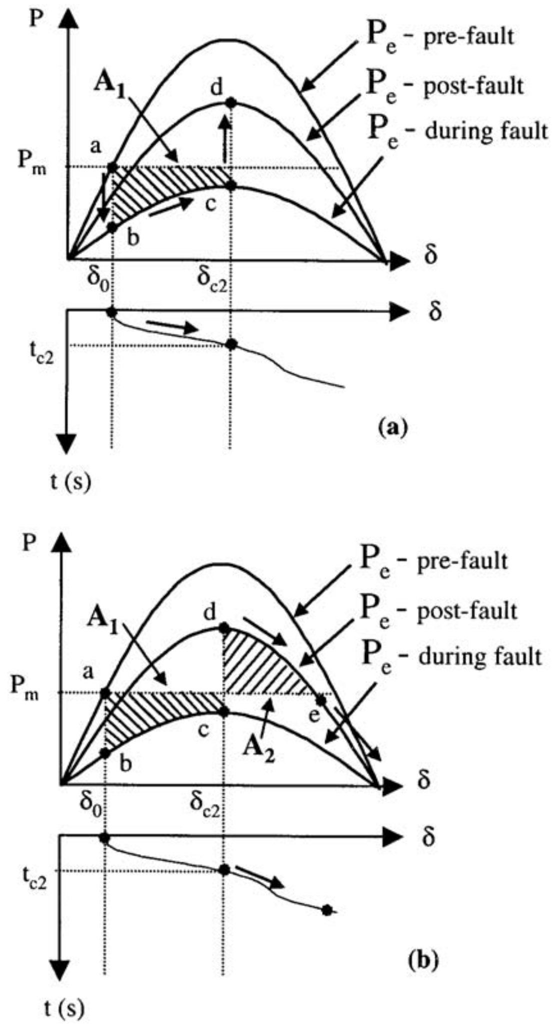

FIGURE 11.8 Equal area criterion for unstable case $A_1 > A_2$. (a) Acceleration of rotor. (b) Deceleration of rotor.

- Swing equations
- Excitation system differential equations
- Prime mover and governing system differential equations
- Transmission network algebraic equations
- Load algebraic and differential equations

While considerable work has been done on *direct methods* of stability analysis in which stability is determined without explicitly solving the system differential equations (see Section 11.5), the most practical and flexible method of transient stability analysis is *time-domain simulation* using step-by-step numerical integration of the nonlinear differential equations. A variety of numerical integration methods are used, including *explicit* methods (such as Euler and Runge-Kutta methods) and *implicit* methods (such as the trapezoidal method). The selection of the method to be used largely depends on the stiffness of the system being analyzed. Implicit methods are generally better suited than explicit methods for systems in which time steps are limited by numerical stability rather than accuracy.

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Simulation Studies

Modern simulation tools offer sophisticated modeling capabilities and advanced numerical solution methods. Although simulation tools differ somewhat, the basic requirements and functions are the same.

Input data:

1. Powerflow: Defines system topology and initial operating state.
2. Dynamic data: Includes model types and associated parameters for generators, motors, protections, and other dynamic devices and their controls.
3. Program control data: Specifies such items as the type of numerical integration to use and time-step.
4. Switching data: Includes the details of the disturbance to be applied. This includes the time at which the fault is applied, where the fault is applied, the type of fault and its fault impedance if required, the duration of the fault, the elements lost as a result of the fault, and the total length of the simulation.
5. System monitoring data: This specifies which quantities are to be monitored (output) during the simulation. In general, it is not practical to monitor all quantities because system models are large and recording all voltages, angles, flows, generator outputs, etc., at each integration time step would create an enormous volume. Therefore, it is common practice to define a limited set of parameters to be recorded.

Output data:

1. Simulation log: This contains a listing of the actions that occurred during the simulation. It includes a recording of the actions taken to apply the disturbance and reports on any operation of protections or controls, or any numerical difficulty encountered.
2. Results output: This is an ASCII or binary file that contains the recording of each monitored variable over the duration of the simulation. These results are examined, usually through a graphical plotting, to determine if the system remained stable and to assess the details of the dynamic behavior of the system.

Factors Influencing Transient Stability

Many factors affect the transient stability of a generator in a practical power system. From the small system analyzed above, the following factors can be identified.

- The post-disturbance system reactance as seen from the generator. The weaker the post-disturbance system, the lower P_{max} will be.
- The duration of the fault clearing time. The longer the fault is applied, the longer the rotor will be accelerated and the more kinetic energy will be gained. The more energy that is gained during acceleration, the more difficult it is to dissipate it during deceleration.
- The inertia of the generator. The higher the inertia, the slower the rate of change of angle and the less the kinetic energy gained during the fault.
- The generator internal voltage (determined by excitation system) and infinite bus voltage (system voltage). The lower these voltages, the lower P_{max} will be.
- The generator loading prior to the disturbance. The higher the loading, the closer the unit will be to P_{max}, which means that during acceleration, it is more likely to become unstable.
- The generator internal reactance. The lower the reactance, the higher the peak power and the lower the initial rotor angle.
- The generator output during the fault. This is a function of the fault location and type of fault.

Transient Stability Considerations in System Design

As outlined previously, transient stability is an important consideration that must be dealt with during the design of power systems. In the design process, time-domain simulations are conducted to assess the

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stability of the system under various conditions and when subjected to various disturbances. Since it is not practical to design a system to be stable under all possible disturbances, design criteria specify the disturbances for which the system must be designed to be stable. The criteria disturbances generally consist of the more statistically probable events which could cause the loss of any system element and typically include three-phase faults cleared in normal time and line-to-ground faults with delayed clearing due to breaker failure. In most cases, stability is assessed for the loss of one element (such as a transformer or transmission circuit) with possibly one element out-of-service predisturbance.

Therefore, in system design, a wide number of disturbances are assessed and if the system is found to be unstable (or marginally stable), a variety of actions can be taken to improve stability. These include the following.

- *Reduction of transmission system reactance*: This can be achieved by adding additional parallel transmission circuits, providing series compensation on existing circuits, and by using transformers with lower leakage reactances.
- *High-speed fault clearing*: In general, two-cycle breakers are used in locations where faults must be removed quickly to maintain stability. As the speed of fault clearing decreases, so does the amount of kinetic energy gained by the generators during the fault.
- *Dynamic braking*: Shunt resistors can be switched in following a fault to provide an artificial electrical load. This increases the electrical output of the machines and reduces the rotor acceleration.
- *Regulate shunt compensation*: By maintaining system voltages around the power system, the flow of synchronizing power between generators is improved.
- *Reactor switching*: The internal voltages of generators, and therefore stability, can be increased by connected shunt reactors.
- *Single pole switching*: Most power system faults are of the single-line-to-ground type. However, in most schemes, this type of fault will trip all three phases. If single pole switching is used, only the faulted phase is removed and power can flow on the remaining two phases, thereby greatly reducing the impact of the disturbance.
- *Steam turbine fast-valving:* Steam valves are rapidly closed and opened to reduce the generator accelerating power in response to a disturbance.
- *Generator tripping*: Perhaps one of the oldest and most common methods of improving transient stability, this approach disconnects selected generators in response to a disturbance. This has the effect of reducing the power that is required to be transferred over critical transmission interfaces.
- *High-speed excitation systems*: As illustrated by the simple examples presented earlier, increasing the internal voltage of a generator has the effect of improving transient stability. This can be achieved by fast-acting excitation systems that can rapidly boost field voltage in response to disturbances.
- *Special excitation system controls:* It is possible to design special excitation systems that can use discontinuous controls to provide special field boosting during the transient period, thereby improving stability.
- *Special control of HVDC links*: The DC power on HVDC links can be rapidly ramped up or down to assist in maintaining generation/load imbalances caused by disturbances. The effect is similar to generation or load tripping.
- *Controlled system separation and load shedding*: Generally considered a last resort, it is often feasible to design system controls that can respond to separate, or island, a power system into areas with balanced generation and load. Some load shedding or generation tripping may also be required in selected islands. In the event of a disturbance, instability can be prevented from propagating and affecting large areas by partitioning the system in this manner. If instability primarily results in generation loss, load shedding alone may be sufficient to control the system.

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Transient Stability Considerations in System Operation

While it is true that power systems are designed to be transiently stable, and many of the methods described above may be used to achieve this goal, in actual practice, systems may be prone to instability. This is largely due to uncertainties related to assumptions made during the design process. These uncertainties result from a number of sources, including:

- *Load and generation forecast:* The design process must use forecast information about the amount, distribution, and characteristics of the connected loads, as well as the location and amount of connected generation. These all have a great deal of uncertainty. If the actual system load is higher than planned, the generation output will be higher, the system will be more stressed, and the transient stability limit may be significantly lower.
- *System topology:* Design studies generally assume all elements in service, or perhaps up to two elements out of service. In actual systems, there are usually many elements out of service at any one time due to forced outages (failures) or system maintenance. Clearly, these outages can seriously weaken the system and make it less transiently stable.
- *Dynamic modeling:* All models used for power system simulation, even the most advanced, contain approximations out of practical necessity.
- *Dynamic data:* The results of time-domain simulations depend heavily on the data used to represent the models for generators and the associated controls. In many cases this data is not known (typical data is assumed) or is in error (either because it has not been derived from field measurements or due to changes that have been made in the actual system controls that have not been reflected in the data).
- *Device operation:* In the design process it is assumed that controls and protection will operate as designed. In the actual system, relays, breakers, and other controls may fail or operate improperly.

To deal with these uncertainties in actual system operation, safety margins are used. Operational (short term) time-domain simulations are conducted using a system model that is more accurate (by accounting for elements out on maintenance, improved short-term load forecast, etc.) than the design model. *Transient stability limits* are computed using these models. The limits are generally in terms of maximum flows allowable over critical interfaces, or maximum generation output allowable from critical generating sources. *Safety margins* are then applied to these computed limits. This means that actual system operation is restricted to levels (interface flows or generation) *below* the stability limit by an amount equal to a defined safety margin. In general, the margin is expressed in terms of a percentage of the critical flow or generation output. For example, operation procedure might be to define the *operating limit* as 10% below the stability limit.

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11.3 Small Signal Stability and Power System Oscillations

John Paserba, Prabha Kundar, Juan Sanchez-Gasca, Einar Larsen

Nature of Power System Oscillations

Historical Perspective

Damping of oscillations has been recognized as important in electric power system operation from the beginning. Indeed before there were any power systems, oscillations in automatic speed controls (governors)

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initiated an analysis by J.C. Maxwell (speed controls were found necessary for the successful operation of the first steam engines). Aside from the immediate application of Maxwell's analysis, it also had a lasting influence as at least one of the stimulants to the development by E.J. Routh in 1883 of his very useful and widely used method to enable one to determine theoretically the stability of a high-order dynamic system without having to know the roots of its equations (Maxwell analyzed only a second-order system).

Oscillations among generators appeared as soon as AC generators were operated in parallel. These oscillations were not unexpected, and in fact, were predicted from the concept of the power vs. phase-angle curve gradient interacting with the electric generator rotary inertia, forming an equivalent mass-and-spring system. With a continually varying load and some slight differences in the design and loading of the generators, oscillations tended to be continually excited. Particularly in the case of hydro-generators there was very little damping, and so amortisseurs (damper windings) were installed, at first as an option. (There was concern about the increased short-circuit current, and some people had to be persuaded to accept them (Crary and Duncan, 1941).) It is of interest to note that although the only significant source of actual negative damping here was the turbine speed governor (Concordia, 1969), the practical "cure" was found elsewhere. Two points are evident and are still valid. First, automatic control is practically the only source of negative damping, and second, although it is obviously desirable to identify the sources of negative damping, the most effective and economical place to add damping may lie elsewhere.

After these experiences, oscillations seemed to disappear as a major problem. Although there were occasional cases of oscillations and evidently poor damping, the major analytical effort seemed to ignore damping entirely. First using analog, then digital computing aids, analysis of electric power system dynamic performance was extended to very large systems, but still representing the generators (and, for that matter, also the loads) in the simple "classical" way. Most studies covered only a short time period, and as occasion demanded, longer-term simulations were kept in bound by including empirically estimated damping factors. It was, in effect, tacitly assumed that the net damping was positive.

All this changed rather suddenly in the 1960s when the process of interconnection accelerated and more transmission and generation extended over large areas. Perhaps the most important aspect was the wider recognition of the negative damping produced by the use of high-response generator voltage regulators in situations where the generator may be subject to relatively large angular swings, as may occur in extensive networks. (This possibility was already well known in the 1930s and 1940s but had not had much practical application.) With the growth of extensive power systems, and especially with the interconnection of these systems by ties of limited capacity, oscillations reappeared. (Actually, they had never entirely disappeared but instead were simply not "seen".) There are several reasons for this reappearance.

1. For intersystem oscillations, the amortisseur is no longer effective, as the damping produced is reduced in approximately inverse proportion to the square of the effective external-impedance-plus-stator-impedance, and so it practically disappears.
2. The proliferation of automatic controls has increased the probability of adverse interactions among them. (Even without such interactions, the two basic controls, the speed governor and the generator voltage regulator, practically always produce negative damping for frequencies in the power system oscillation range: the governor effect, small, and the AVR effect, large.)
3. Even though automatic controls are practically the only devices that may produce negative damping, the damping of the uncontrolled system is itself very small and could easily allow the continually changing load and generation to result in unsatisfactory tie-line power oscillations.
4. A small oscillation in each generator that may be insignificant may add up to a tie-line oscillation that is very significant relative to its rating.
5. Higher tie-line loading increases both the tendency to oscillate and the importance of the oscillation.

To calculate the effect of damping on the system, the detail of system representation has to be considerably extended. The additional parameters required are usually much less well known than are the generator inertias and network impedances required for the "classical" studies. Further, the total damping of a power system is typically very small and is made up of both positive and negative components.

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Thus, if one wishes to get realistic results, one must include all known sources. These sources include: prime movers, speed governors, electrical loads, circuit resistance, generator amortisseurs, generator excitation, and in fact, all controls that may be added for special purposes. In large networks, and particularly as they concern tie-line oscillations, the only two items that can be depended upon to produce positive damping are the electrical loads and (at least for steam-turbine driven generators) the prime mover.

Although it is obvious that net damping must be positive for stable operation, why be concerned about its magnitude? More damping would reduce (but not eliminate) the tendency to oscillate and the magnitude of oscillations. As pointed out above, oscillations can never be eliminated, as even in the best-damped systems, the damping is small, being only a small fraction of the "critical damping." So the common concept of the power system as a system of masses and springs is still valid, and we have to accept some oscillations. The reasons why they are often troublesome are various, depending on the nature of the system and the operating conditions. For example, when at first a few (or more) generators were paralleled in a rather closely connected system, oscillations were damped by the generator amortisseurs. If oscillations did occur, there was little variation in system voltage. In the simplest case of two generators paralleled on the same bus and equally loaded, oscillations between them would produce practically no voltage variation and what was produced would be principally at twice the oscillation frequency. Thus, the generator voltage regulators were not stimulated and did not participate in the activity. Moreover, the close coupling between the generators reduced the effective regulator gain considerably for the oscillation mode. Under these conditions when voltage regulator response was increased (e.g., to improve transient stability), there was little apparent decrease of system damping (in most cases) but appreciable improvement in transient stability. Instability through negative damping produced by increased voltage-regulator gain had already been demonstrated theoretically (Concordia, 1944).

Consider that the system just discussed is then connected to another similar system by a tie-line. This tie-line should be strong enough to survive the loss of any one generator but may be only a rather small fraction of system capacity. Now, the response of the system to tie-line oscillations is quite different from that just described. Because of the high external impedance seen by either system, not only is the positive damping by the generator amortisseurs largely lost, but the generator terminal voltages become responsive to angular swings. This causes the generator voltage regulators to act, producing negative damping as an unwanted side effect. This sensitivity of voltage-to-angle increases as a strong function of initial angle, and thus, tie-line loading. Thus, in the absence of mitigating means, tie-line oscillations are very likely to occur, especially at heavy line loading (and they have on numerous occasions as illustrated in Chapter 3 of CIGRE Technical Brochure No. 111 [1996]). These tie-line oscillations are bothersome, especially as a restriction on the allowable power transfer, as relatively large oscillations are (quite properly) taken as a precursor to instability.

Next, as interconnection proceeds, another system is added. If the two previously discussed systems are designated A and B, and a third system, C, is connected to B, then a chain A-B-C is formed. If power is flowing $\mathbf{A} \rightarrow \mathbf{B} \rightarrow \mathbf{C}$ or $\mathbf{C} \rightarrow \mathbf{B} \rightarrow \mathbf{A}$, the principal (i.e., lowest frequency) oscillation mode is A against C, with B relatively quiescent. However, as already pointed out, the voltages of system B are varying. In effect, B is acting as a large synchronous condenser facilitating the transfer of power from A to C, and suffering voltage fluctuations as a consequence. This situation has occurred several times in the history of interconnected power systems and has been a serious impediment to progress. In this case, note that the problem is mostly in system B, while the solution (or at least mitigation) will be mostly in systems A and C. It would be practically impossible with any presently conceivable controlled voltage support solely in system B to maintain a satisfactory voltage. On the other hand, without system B for the same power transfer, the oscillations would be much more severe. In fact, the same power transfer might not be possible without, for example, a very high amount of series or shunt compensation. If the power transfer is $\mathbf{A} \rightarrow \mathbf{B} \leftarrow \mathbf{C}$ or $\mathbf{A} \leftarrow \mathbf{B} \rightarrow \mathbf{C}$, the likelihood of severe oscillation (and the voltage variations produced by the oscillations) is much less. Further, both the trouble and the cure are shared by all three systems, so effective compensation is more easily achieved. For best results, all combinations of power transfers should be considered.

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Aside from this abbreviated account of how oscillations grew in importance as interconnections grew in extent, it may be of interest to mention the specific case that seemed to precipitate the general acceptance of the major importance of improving system damping, as well as the general recognition of the generator voltage regulator as the major culprit in producing negative damping. This was the series of studies of the transient stability of the Pacific Intertie (AC and DC in parallel) on the west coast of the U.S. In these studies, it was noted that for three-phase faults, instability was determined not by severe first swings of the generators but by oscillatory instability of the post fault system, which had one of two parallel AC line sections removed and thus a higher impedance. This showed that damping is important for transient as well as steady-state stability and contributed to a worldwide rush to apply power system stabilizers (PSS) to all generator voltage regulators as a panacea for all oscillatory ills.

But the pressures of the continuing extension of electric networks and of increases in line loading have shown that the PSS alone is often not enough. When we push to the limit, that limit is more often than not determined by lack of adequate damping. When we add voltage support at appropriate points in the network, we not only increase its "strength" (i.e., increased synchronizing power or smaller transfer impedance), but also improve its damping (if the generator voltage regulators have been producing negative damping) by relieving the generators of a good part of the work of voltage regulation and also reducing the regulator gain. This is so whether or not reduced damping was an objective. However, the limit may still be determined by inadequate damping. How can it be improved? There are at least three options:

1. Add a signal (e.g., line current) to the voltage support device control.
2. Increase the output of the PSS (which is possible with the now stiffer system), or do both as found to be appropriate.
3. Add an entirely new device at an entirely new location. Thus the proliferation of controls, which has to be carefully considered.

Oscillations of power system frequency as a whole can still occur in an isolated system, due to governor deadband or interaction with system frequency control, but is not likely to be a major problem in large interconnected systems. These oscillations are most likely to occur on intersystem ties among the constituent systems, especially if the ties are weak or heavily loaded. This is in a relative sense; an "adequate" tie planned for certain usual line loadings is nowadays very likely to be much more severely loaded and, thus, behave dynamically like a weak line as far as oscillations are concerned, quite aside from losing its emergency pick-up capability. There has always been commercial pressure to utilize a line, perhaps originally planned to aid in maintaining reliability, for economical energy transfer simply because it is there. Now, however, there is also "open access" that may force a utility to use nearly every line for power transfer. This will certainly decrease reliability and may decrease damping, depending on the location of added generation.

Power System Oscillations Classified by Interaction Characteristics

Electric power utilities have experienced problems with the following types of subsynchronous frequency oscillations (Kundur, 1994):

- Local plant mode oscillations
- Interarea mode oscillations
- Torsional mode oscillations
- Control mode oscillations

Local plant mode oscillation problems are the most commonly encountered among the above, and are associated with units at a generating station oscillating with respect to the rest of the power system. Such problems are usually caused by the action of the AVRs of generating units operating at high output and feeding into weak transmission networks; the problem is more pronounced with high response excitation systems. The local plant oscillations typically have natural frequencies in the range of 1 to 2 Hz. Their characteristics are well understood and adequate damping can be readily achieved by using supplementary control of excitation systems in the form of power system stabilizers (PSS).

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Interarea modes are associated with machines in one part of the system oscillating against machines in other parts of the system. They are caused by two or more groups of closely coupled machines being interconnected by weak ties. The natural frequency of these oscillations is typically in the range of 0.1 to 1 Hz. The characteristics of interarea modes of oscillation are complex and in some respects significantly differ from the characteristics of local plant modes (CIGRE Technical Brochure No. 111, 1996; Kundur, 1994).

Torsional mode oscillations are associated with the turbine-generator rotational (mechanical) components. There have been several instances of torsional mode instability due to interactions with the generating unit excitation and prime mover controls (Kundur, 1994):

- Torsional mode destabilization by excitation control was first observed in 1969 during the application of power system stabilizers on a 555 MVA fossil-fired unit at the Lambton generating station in Ontario. The PSS, which used a stabilizing signal based on speed measured at the generator end of the shaft was found to excite the lowest torsional (16 Hz) mode. The problem was solved by sensing speed between the two LP turbine sections and by using a torsional filter (Kundur et al., 1981; Watson and Coultes, 1973).
- Instability of torsional modes due to interaction with speed governing systems was observed in 1983 during the commissioning of a 635 MVA unit at Pickering "B" nuclear generating station in Ontario. The problem was solved by providing an accurate linearization of steam valve characteristics and by using torsional filters (Lee et al., 1986).
- Control mode oscillations are associated with the controls of generating units and other equipment. Poorly tuned controls of excitation systems, prime movers, static var compensators, and HVDC converters are the usual causes of instability of control modes. Sometimes it is difficult to tune the controls so as to assure adequate damping of all modes. Kundur et al. (1981) describe the difficulty experienced in tuning the power system stabilizers at the Ontario Hydro's Nanticoke generating station in 1979. The stabilizers used shaft speed signals with torsional filters. With the stabilizer gain high enough to stabilize the local plant mode oscillation, a control mode local to the excitation system and the generator field referred to as the "exciter mode" became unstable. The problem was solved by developing an alternative form of stabilizer that did not require a torsional filter (Lee and Kundur, 1986).

Although all of these categories of oscillations are related and can exist simultaneously, the primary focus of this section is on the electromechanical oscillations that affect interarea power flows.

Conceptual Description of Power System Oscillations

As illustrated in the previous subsection, power systems contain many modes of oscillation due to a variety of interactions of its components. Many of the oscillations are due to generator rotor masses swinging relative to one another. A power system having multiple machines will act like a set of masses interconnected by a network of springs and will exhibit multiple modes of oscillation. As illustrated previously in the section "Historical Perspective", in many systems, the damping of these electromechanical swing modes is a critical factor for operating in a secure manner. The power transfer between such machines on the AC transmission system is a direct function of the angular separation between their internal voltage phasors. The torques that influence the machine oscillations can be conceptually split into synchronizing and damping components of torque (de Mello and Concordia, 1969). The synchronizing component "holds" the machines in the power system together and is important for system transient stability following large disturbances. For small disturbances, the synchronizing component of torque determines the frequency of an oscillation. Most stability texts present the synchronizing component in terms of the slope of the power-angle relationship, as illustrated in Fig. 11.9, where K represents the amount of synchronizing torque. The damping component determines the decay of oscillations and is important for system stability following recovery from the initial swing. Damping is influenced by many system parameters, is usually small, and can sometimes become negative in the presence of controls,

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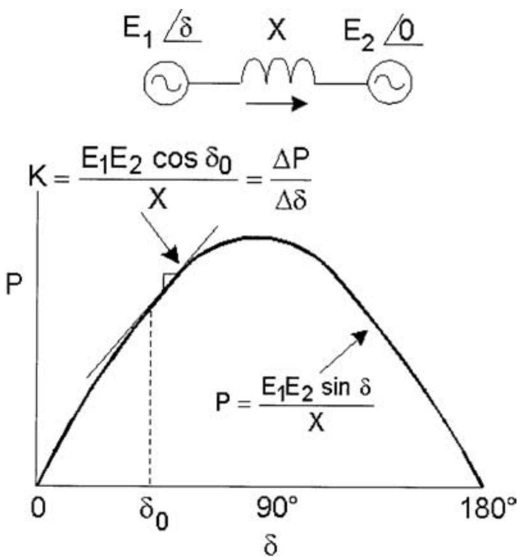

FIGURE 11.9 Simplified power-angle relationship between two AC systems.

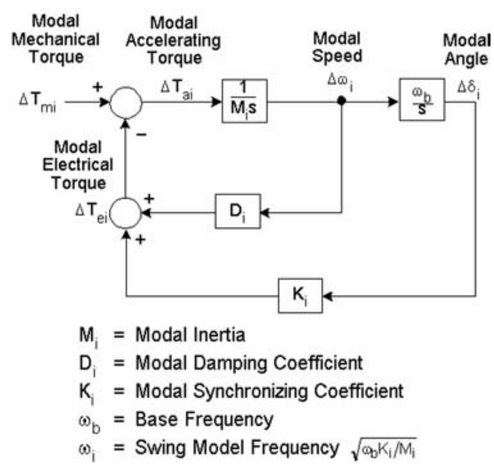

FIGURE 11.10 Conceptual block diagram of a power-swing mode.

(which are practically the only "source" of negative damping). Negative damping can lead to spontaneous growth of oscillations until relays begin to trip system elements or a limit cycle is reached.

Figure 11.10 shows a conceptual block diagram of a power-swing mode, with inertial (M), damping (D), and synchronizing (K) effects identified. For a perturbation about a steady-state operating point, the modal accelerating torque ΔT_{ai} is equal to the modal electrical torque ΔT_{ei} (with the modal mechanical torque ΔT_{mi} considered to be 0). The effective inertia is a function of the total inertia of all machines participating in the swing; the synchronizing and damping terms are frequency dependent and are influenced by generator rotor circuits, excitation controls, and other system controls.

Summary on the Nature of Power System Oscillations

The preceding review leads to a number of important conclusions and observations concerning power system oscillations:

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- Oscillations are due to natural modes of the system and therefore cannot be eliminated. However, their damping and frequency can be modified.
- As power systems evolve, the frequency and damping of existing modes change and new ones may emerge.
- The source of "negative" damping is power system controls, primarily excitation system automatic voltage regulators.
- Interarea oscillations are associated with weak transmission links and heavy power transfers.
- Interarea oscillations often involve more than one utility and may require the cooperation of all to arrive at the most effective and economical solution.
- Power system stabilizers are the most commonly used means of enhancing the damping of interarea modes.
- Continual study of the system is necessary to minimize the probability of poorly damped oscillations. Such "beforehand" studies may have avoided many of the problems experienced in power systems (see Chapter 3 of CIGRE Technical Brochure No. 111, 1996).

It must be clear that avoidance of oscillations is only one of many aspects that should be considered in the design of a power system and so must take its place in line along with economy, reliability, operational robustness, environmental effects, public acceptance, voltage and power quality, and certainly a few others that may need to be considered. Fortunately, it appears that many features designed to further some of these other aspects also have a strong mitigating effect in reducing oscillations. However, one overriding constraint is that the power system operating point must be stable with respect to oscillations.

Criteria for Damping

The rate of decay of the amplitude of oscillations is best expressed in terms of the damping ratio ζ. For an oscillatory mode represented by a complex eigenvalue $\sigma \pm j\omega$, the damping ratio is given by:

$$\zeta = \frac{-\sigma}{\sqrt{\sigma^2 + \omega^2}}$$

The damping ratio ζ determines the rate of decay of the amplitude of the oscillation. The time constant of amplitude decay is $1/|\sigma|$. In other words, the amplitude decays to 1/e or 37% of the initial amplitude in $1/|\sigma|$ seconds or in $1/(2\pi\zeta)$ cycles of oscillation (Kundur, 1994). As oscillatory modes have a wide range of frequencies, the use of damping ratio rather than the time constant of decay is considered more appropriate for expressing the degree of damping. For example, a 5-s time constant represents amplitude decay to 37% of initial value in 110 cycles of oscillation for a 22 Hz torsional mode, in 5 cycles for a 1 Hz local plant mode, and in one-half cycle for a 0.1 Hz interarea mode of oscillation. On the other hand, a damping ratio of 0.032 represents the same degree of amplitude decay in 5 cycles for all modes.

A power system should be designed and operated so that the following criteria are satisfied for all expected system conditions, including postfault conditions following design contingencies:

1. The damping ratio (ζ) of all system modes oscillation should exceed a specified value. The minimum acceptable damping ratio is system dependent and is based on operating experience and/or sensitivity studies; it is typically in the range 0.03 to 0.05.
2. The small-signal stability margin should exceed a specified value. The stability margin is measured as the difference between the given operating condition and the absolute stability limit ($\zeta = 0$) and should be specified in terms of a physical quantity, such as a power plant output, power transfer through a critical transmission interface, or system load level.

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Study Procedure

There is a general need for establishing study procedures and developing widely accepted design and operating criteria with respect to power system oscillations. Tools for the analysis of system oscillations, in addition to determining the existence of problems, should be capable of identifying factors influencing the problem and providing information useful in developing control measures for mitigation.

System oscillation problems are often investigated using nonlinear time-domain simulations as a natural extension to traditional transient stability analysis. However, there are a number of practical problems that limit the effectiveness of using only the time-domain approach:

- The use of time responses exclusively to look at damping of different modes of oscillation could be deceptive. The choice of disturbance and the selection of variables for observing time response are critical. The disturbance may not provide sufficient excitation of the critical modes. The observed response contains many modes, and poorly damped modes may not always be dominant.
- To get a clear indication of growing oscillations, it is necessary to carry the simulations out to 15 s or 20 s or more. This could be time-consuming.
- Direct inspection of time responses does not give sufficient insight into the nature of the oscillatory stability problem; it is difficult to identify the sources of the problem and develop corrective measures.

Spectral estimation (i.e., modal identification) techniques based on Prony analysis may be used to analyze time-domain responses and extract information about the underlying dynamics of the system (Hauer, 1991).

Small-signal analysis (i.e., modal analysis or eigenanalysis) based on linear techniques is ideally suited for investigating problems associated with oscillations. Here, the characteristics of a power system model can be determined for a system model linearized about a specific operating point. The stability of each mode is clearly identified by the system's eigenvalues. Modeshapes and the relationships between different modes and system variables or parameters are identified using eigenvectors (Kundur, 1994). Conventional eigenvalue computation methods are limited to systems up to about 800 states. Such methods are ideally suited for detailed analysis for system oscillation problems confined to a small portion of the power system. This includes problems associated with local plant modes, torsional modes, and control modes. For analysis of interarea oscillations in large interconnected power systems, special techniques have been developed for computing eigenvalues associated with a small subset of modes whose frequencies are within a specified range (Kundur, 1994). Techniques have also been developed for efficiently computing participation factors, residues, transfer function zeros, and frequency responses useful in designing remedial control measures. Powerful computer program packages incorporating the above computational features are now available, thus providing comprehensive capabilities for analyses of power system oscillations (CIGRE Technical Brochure No. 111, 1996; CIGRE Technical Brochure, 2000; Kundur, 1994). For very large interconnected systems, it may be necessary to use dynamic equivalents (Wang et al., 1997). This can only be achieved by developing reduced-order power system models that correctly reflect the significant dynamic characteristics of the interconnected system.

In summary, a complete understanding of power systems oscillations generally requires a combination of analytical tools. Small-signal stability analysis complemented by nonlinear time-domain simulations is the most effective procedure of studying power system oscillations. The following are the recommended steps for a systematic analysis of power system oscillations:

1. Perform an eigenvalue scan using a small-signal stability program. This will indicate the presence of poorly damped modes.
2. Perform a detailed eigenanalysis of the poorly damped modes. This will determine their characteristics and sources of the problem, and assist in developing mitigation measures. This will also identify the quantities to be monitored in time-domain simulations.

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3. Perform time-domain simulations of the critical cases identified from the eigenanalysis. This is useful to confirm the results of small-signal analysis. In addition, it shows how system nonlinearities affect the oscillations. Prony analysis of these time-domain simulations may also be insightful (Hauer, 1991).

Mitigation of Power System Oscillations

In many power systems, equipment is installed to enhance various performance issues such as transient, oscillatory, or voltage stability. In many instances, this equipment is power-electronic based, which generally means the device can be rapidly and continuously controlled. Examples of such equipment applied in the transmission system include a static Var compensator (SVC), static compensator (STATCOM), thyristor-controlled series compensation (TCSC) and Unified Power Flow Controller (UPFC). To improve damping in a power system, a supplemental damping controller can be applied to the primary regulator of one of these transmission devices or to generator controls. The supplemental control action should modulate the output of a device in such a way as to affect power transfer such that damping is added to the power system swing modes of concern. This subsection provides an overview on some of the issues that affect the ability of damping controls to improve power system dynamic performance (CIGRE Technical Brochure No. 111, 1996; CIGRE Technical Brochure, 2000; Paserba et al., 1995; Levine, 1995).

Siting

Siting plays an important role in the ability of a device to stabilize a swing mode. Many controllable power system devices are sited based on issues unrelated to stabilizing the network (e.g., HVDC transmission and generators), and the only question is whether they can be utilized effectively as a stability aid. In other situations (e.g., SVC, STATCOM, TCSC, or UPFC), the equipment is installed primarily to help support the transmission system, and siting will be heavily influenced by its stabilizing potential. Device cost represents an important driving force in selecting a location. In general, there will be one location that makes optimum use of the controllability of a device. If the device is located at a different location, a larger-size device may be needed to achieve the desired stabilization objective. In some cases, overall costs may be minimized with nonoptimum locations of individual devices because other considerations must also be taken into account, such as land price and availability, environmental regulations, etc.

The inherent ability of a device to achieve a desired stabilization objective in a robust manner while minimizing the risk of adverse interactions is another consideration that can influence the siting decision. Most often, these other issues can be overcome by appropriate selection of input signals, signal filtering, and control design. This is not always possible, however, so these issues should be included in the decision-making process for choosing a site. For many applications, it will be desirable to apply the devices in a distributed manner. This approach helps maintain a more uniform voltage profile across the network, during both steady-state operation and after transient events. Greater security may also be possible with distributed devices because the overall system is more likely to tolerate the loss of one of the devices.

Control Objectives

Several aspects of control design and operation must be satisfied during both the transient and the steady-state operation of the power system, before and after a major disturbance. These aspects suggest that controls applied to the power system should:

1. Survive the first few swings after a major system disturbance with some degree of safety. The safety factor is usually built into a Reliability Council's criteria (e.g., keeping voltages above some threshold during the swings).
2. Provide some minimum level of damping in the steady-state condition after a major disturbance (post-contingent operation). In addition to providing security for contingencies, some applications will require "ambient" damping to prevent spontaneous growth of oscillations in steady-state operation.
3. Minimize the potential for adverse side effects, which can be classified as follows:

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   a. Interactions with high-frequency phenomena on the power system, such as turbine-generator torsional vibrations and resonances in the AC transmission network.
   b. Local instabilities within the bandwidth of the desired control action.
4. Be robust so that the control will meet its objectives for a wide range of operating conditions encountered in power system applications. The control should have minimal sensitivity to system operating conditions and component parameters since power systems operate over a wide range of operating conditions and there is often uncertainty in the simulation models used for evaluating performance. Also, the control should have minimum communication requirements.
5. Be highly dependable so that the control has a high probability of operating as expected when needed to help the power system. This suggests that the control should be testable in the field to ascertain that the device will act as expected should a contingency occur. This leads to the desire for the control response to be predictable. The security of system operations depends on knowing, with a reasonable certainty, what the various control elements will do in the event of a contingency.

Closed-Loop Control Design

Closed-loop control is utilized in many power-system components. Voltage regulators, either continuous or discrete, are commonplace on generator excitation systems, capacitor and reactor banks, tap-changing transformers, and SVCs. Modulation controls to enhance power system stability have been applied extensively to generator exciters and to HVDC, SVC, and TCSC systems. A notable advantage of closed-loop control is that stabilization objectives can often be met with less equipment and impact on the steady-state power flows than is generally possible with open-loop controls. While the behavior of the power system and its components is usually predictable by simulation, its nonlinear character and vast size lead to challenging demands on system planners and operating engineers. The experience and intuition of these engineers is generally more important to the overall successful operation of the power system than the many available, elegant control design techniques (Levine, 1995; CIGRE Technical Brochure, 2000).

Typically, a closed-loop controller is always active. One benefit of such a closed-loop control is ease of testing for proper operation on a continuous basis. In addition, once a controller is designed for the worst-case contingency, the chance of a less severe contingency causing a system breakup is lower than if only open-loop controls are applied. Disadvantages of closed-loop control involve primarily the potential for adverse interactions. Another possible drawback is the need for small step sizes, or vernier control in the equipment, which will have some impact on cost. If communication is needed, this could also be a challenge. However, experience suggests that adequate performance should be attainable using only locally measurable signals.

One of the most critical steps in control design is to select an appropriate input signal. The other issues are to determine the input filtering and control algorithm and to assure attainment of the stabilization objectives in a robust manner with minimal risk of adverse side effects. The following subsections discuss design approaches for closed-loop stability controls, so that the potential benefits can be realized on the power system.

Input Signal Selection

The choice of using a local signal as an input to a stabilizing control function is based on several considerations.

1. The input signal must be sensitive to the swings on the machines and lines of interest. In other words, the swing modes of interest must be “observable” in the input signal selected. This is mandatory for the controller to provide a stabilizing influence.
2. The input signal should have as little sensitivity as possible to other swing modes on the power system. For example, for a transmission-line device the control action will benefit only those modes that involve power swings on that particular line. If the input signal was also responsive to local swings within an area at one end of the line, then valuable control range would be wasted in responding to an oscillation that the damping device has little or no ability to control.

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3. The input signal should have little or no sensitivity to its own output, in the absence of power swings. Similarly, there should be as little sensitivity to the action of other stabilizing controller outputs as possible. This decoupling minimizes the potential for local instabilities within the controller bandwidth (CIGRE Technical Brochure, 2000).

These considerations have been applied to a number of modulation control designs, which have eventually proven themselves in many actual applications (see Chapter 5 of CIGRE Technical Brochure No. 111 [1996]). For example, the application of PSS controls on generator excitation systems was the first such study that reached the conclusion that speed or power is the best input signal, with frequency of the generator substation voltage being an acceptable choice as well (Larsen and Swann, 1981; Kundur et al., 1989). For SVCs, the conclusion was that the magnitude of line current flowing past the SVC is the best choice (Larsen and Chow, 1987). For torsional damping controllers on HVDC systems, it was found that using the frequency of a synthesized voltage close to the internal voltage of the nearby generator, calculated with locally measured voltages and currents, is best (Piwko and Larsen, 1982). In the case of a series device in a transmission line (such as a TCSC), the considerations listed above lead to the conclusion that using frequency of a synthesized remote voltage to estimate the center-of-inertia of an area involved in a swing mode is a good choice (Levine, 1995). This allows the series device to behave like a damper across the AC line.

Input-Signal Filtering

To prevent interactions with phenomena outside the desired control bandwidth, low-pass and high-pass filtering must be used for the input signal. In certain applications, notch filtering is needed to prevent interactions with certain lightly damped resonances. This has been the case with SVCs interacting with AC network resonances and modulation controls interacting with generator torsional vibrations. On the low-frequency end, the high-pass filter must have enough attenuation to prevent excessive response during slow ramps of power, or during the long-term settling following a loss of generation or load. This filtering must be considered while designing the overall control as it will strongly affect performance and the potential for local instabilities within the control bandwidth. However, finalizing such filtering usually must wait until the design for performance is completed, after which the attenuation needed at specific frequencies can be determined. During the control design work, a reasonable approximation of these filters needs to be included. Experience suggests that a high-pass break near 0.05 Hz (3 s washout time constant), and a double low-pass break near 4 Hz (40 ms time constant) as shown in Fig. 11.11, is suitable for a starting point. A control design that provides adequate stabilization of the power system with these settings for the input filtering has a high probability of being adequate after the input filtering parameters are finalized.

Control Algorithm

Levine (1995) and CIGRE Technical Brochure (2000) present many control design methods that can be utilized to design supplemental controls for power systems. Generally, the control algorithm for damping leads to a transfer function that relates an input signal(s) to a device output. This statement is the starting point for understanding how deviations in the control algorithm affect system performance.

In general, the transfer function of the control (and input-signal filtering) is most readily discussed in terms of its gain and phase relationship versus frequency. A phase shift of 0° in the transfer function

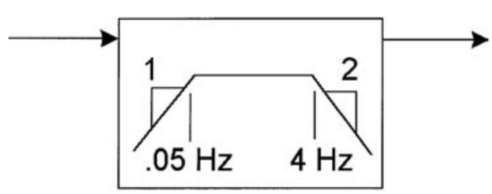

FIGURE 11.11 Initial input signal filtering.

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means that the output is proportional to the input, and, for discussion purposes, is assumed to represent a pure damping effect on a lightly damped power swing mode. Phase lag in the transfer function (up to 90°) translates to a positive synchronizing effect, tending to increase the frequency of the swing mode when the control loop is closed. The damping effect will decrease with the sine of the phase lag. Beyond 90°, the damping effect will become negative. Conversely, phase lead is a desynchronizing influence and will decrease the frequency of the swing mode when the control loop is closed. Generally, the desynchronizing effect should be avoided. The preferred transfer function has between 0° and 45° of phase lag in the frequency range of the swing modes that the control is designed to damp.

Gain Selection

After the shape of the transfer function to meet the desired control phase characteristics is designed, the gain of the control is selected to obtain the desired level of damping. To maximize damping, the gain should be high enough to assure full utilization of the controlled device for the critical disturbances, but no higher, so that risks of adverse effects are minimized. Typically, the gain selection is done analytically with root-locus or Nyquist methods. However, the gain must ultimately be verified in the field (see Chapter 8 of CIGRE Technical Brochure No. 111 [1996]).

Control Output Limits

The output of a damping control must be limited to prevent it from saturating the device being modulated. By saturating a controlled device, the purpose of the damping control would be defeated. As a general rule of thumb for damping, when a control is at its limits in the frequency range of interarea oscillations, the output of the controlled device should be just within its limits (Larsen and Swann, 1981).

Performance Evaluation

Good simulation tools are essential to applying damping controls to power transmission equipment for the purpose of system stabilization. The controls must be designed and tested for robustness with such tools. For many system operating conditions, the only feasible means of testing the system is by simulation, so confidence in the power system model is crucial. A typical large-scale power system model may contain up to 15,000 state variables or more. For design purposes, a reduced-order model of the power system is often desirable (Wang et al., 1997). If the size of the study system is excessive, the large number of system variations and parametric studies required becomes tedious and prohibitively expensive for some linear analysis techniques and control design methods in general use today. A good understanding of the system performance can be obtained with a model that contains only the relevant dynamics for the problem under study. The key situations that establish the adequacy of controller performance and robustness can be identified from the reduced-order model, and then tested with the full-scale model. Note that CIGRE Technical Brochure No. 111 (1996) (CIGRE Technical Brochure, 2000) and Kundur (1994) contain information on the application of linear analysis techniques for very large systems.

Field testing is also an essential part of applying supplemental controls to power systems. Testing needs to be performed with the controller open-loop, comparing the measured response at its own input and the inputs of other planned controllers, against the simulation models. Once these comparisons are acceptable, the system can be tested with the control loop closed. Again, the test results should have a reasonable correlation with the simulation program. Methods have been developed for performing such testing of the overall power system to provide benchmarks for validating the full-system model. Such testing can also be done on the simulation program to help arrive at the reduced-order models (Hauer, 1991; Kamwa et al., 1993) needed for the advanced control design methods (Levine, 1995; CIGRE Technical Brochure, 2000). Methods have also been developed to improve the modeling of individual components. These issues are discussed in great detail in Chapters 6 and 8 of CIGRE Technical Brochure No. 111 (1996).

Adverse Side Effects

Historically in the power industry, each major advance in improving system performance has created some adverse side effects. For example, the addition of high-speed excitation systems over 40 years ago

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caused the destabilization known as the "hunting" mode of the generators. The fix was power system stabilizers, but it took over 10 years to learn how to tune them properly and there were some unpleasant surprises involving interactions with torsional vibrations on the turbine-generator shaft (Larsen and Swann, 1981).

HVDC systems were also found to interact adversely with torsional vibrations [the subsynchronous torsional interaction (SSTI) problem], especially when augmented with supplemental modulation controls to damp power swings. Similar SSTI phenomena exist with SVCs, although to a lesser degree than with HVDC. Detailed study methods have since been established for designing systems with confidence that these effects will not cause trouble for normal operation (Piwko and Larsen, 1982; Bahrman et al., 1980). Another potential adverse side effect is with SVC systems that can interact unfavorably with network resonances. This side effect caused a number of problems in the initial application of SVCs to transmission systems. Design methods now exist to deal with this phenomenon, and protective functions exist within SVC controls to prevent continuing exacerbation of an unstable condition (Larsen and Chow, 1987).

As the available technologies continue to evolve, such as the current industry focus on Flexible AC Transmission Systems (FACTS), new opportunities arise for power system performance improvement. FACTS devices introduce capabilities that may be an order of magnitude greater than existing equipment applied for stability improvement. Therefore, it follows that there may be much more serious consequences if they fail to operate properly. Robust operation and noninteraction of controls for these FACTS devices are critically important for stability of the power system (CIGRE Technical Brochure, 2000; Clark et al., 1995).

Summary

In summary, this section on small signal stability and power system oscillations shows that power systems contain many modes of oscillation due to a variety of interactions among components. Many of the oscillations are due to synchronous generator rotors swinging relative to one another. The electromechanical modes involving these masses usually occur in the frequency range of 0.1 to 2 Hz. Particularly troublesome are the interarea oscillations, which are typically in the frequency range of 0.1 to 1 Hz. The interarea modes are usually associated with groups of machines swinging relative to other groups across a relatively weak transmission path. The higher frequency electromechanical modes (1 to 2 Hz) typically involve one or two generators swinging against the rest of the power system or electrically close machines swinging against each other.

These oscillatory dynamics can be aggravated and stimulated through a number of mechanisms. Heavy power transfers, in particular, can create interarea oscillation problems that constrain system operation. The oscillations themselves may be triggered through some event or disturbance on the power system or by shifting the system operating point across some steady-state stability boundary where growing oscillations may be spontaneously created. Controller proliferation makes such boundaries increasingly difficult to anticipate. Once started, the oscillations often grow in magnitude over the span of many seconds. These oscillations may persist for many minutes and be limited in amplitude only by system nonlinearities. In some cases they cause large generator groups to lose synchronism where part or all of the electrical network is lost. The same effect can be reached through slow cascading outages when the oscillations are strong and persistent enough to cause uncoordinated automatic disconnection of key generators or loads. Sustained oscillations can disrupt the power system in other ways, even when they do not produce network separation or loss of resources. For example, power swings, which are not always troublesome in themselves, may have associated voltage or frequency swings that are unacceptable. Such concerns can limit power transfer even when oscillatory stability is not a direct concern.

Information presented in this section addressing power system oscillations included:

- Nature of oscillations
- Criteria for damping
- Study procedure
- Mitigation of oscillations by control

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As to the priority of selecting devices and controls to be applied for the purpose of damping power system oscillations, the following summarizing remarks can be made.

1. Carefully tuned power system stabilizers (PSS) on the major generating units affected by the oscillations should be considered first. This is because of the effectiveness and relatively low cost of PSSs.
2. Supplemental controls added to devices installed for other reasons should be considered second. Examples include HVDC installed for the primary purpose of long-distance transmission or power exchange between asynchronous regions and SVC installed for the primary purpose of dynamic voltage support.
3. Augmentation of fixed or mechanically switched equipment with power-electronics, including damping controls can be considered third. Examples include augmenting existing series capacitors with a thyristor-controlled portion (TCSC).
4. The fourth priority for consideration is the addition of a new device in the power system for the primary purpose of damping.

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11.4 Voltage Stability

Yakout Mansour

Voltage stability refers to the ability of a power system to maintain its voltage profile under the full spectrum of its operating scenarios so that both voltage and power are controllable at all times.

Voltage instability of radial distribution systems has been well recognized and understood for decades (Venikov, 1970; 1980) and was often referred to as load instability. Large interconnected power networks did not face the phenomenon until late 1970s and early 1980s.

Most of the early developments of the major HV and EHV networks and interties faced the classical machine angle stability problem. Innovations in both analytical techniques and stabilizing measures made it possible to maximize the power transfer capabilities of the transmission systems. The result was increasing transfers of power over long distances of transmission. As the power transfer increased, even when angle stability was not a limiting factor, many utilities have been facing a shortage of voltage support. The result ranged from post contingency operation under reduced voltage profile to total voltage collapse. Major outages attributed to this problem were experienced in the northeastern part of the U.S., France, Sweden, Belgium, Japan, along with other localized cases of voltage collapse (Mansour, 1990). Accordingly, voltage stability imposed itself as a governing factor in both planning and operating criteria of a number of utilities. Consequently, major challenges in establishing sound analytical procedures, quantitative measures of proximity to voltage instability, and margins have been facing the industry for the last two decades.

Voltage instability is associated with relatively slow variations in network and load characteristics. Network response in this case is highly influenced by the slow-acting control devices such as transformer on-load tap changers, automatic generation control, generator field current limiters, generator overload reactive capability, under-voltage load shedding relays, and switchable reactive devices. The characteristics of such devices as to how they influence the network response to voltage variations are generally understood and well covered in the literature. On the other hand, electric load response to voltage variation has only been addressed more recently, even though it is considered the single most important factor in voltage instability.

Generic Dynamic Load-Voltage Characteristics

While it might be possible to identify the voltage response characteristics of a large variety of individual equipment of which a power network load is comprised, it is not practical or realistic to model network load by individual equipment models. Thus, the aggregate load model approach is much more realistic.

Field test results as reported by Hill (1992) and Xu et al. (1996) indicate that typical response of an aggregate load to step-voltage changes is of the form shown in Fig. 11.12. The response is a reflection of the collective effects of all downstream components ranging from OLTCs to individual household loads. The time span for a load to recover to steady-state is normally in the range of several seconds to minutes, depending on the load composition. Responses for real and reactive power are qualitatively similar. It can be seen that a sudden voltage change causes an instantaneous power demand change. This change defines the transient characteristics of the load and was used to derive static load models for angular stability

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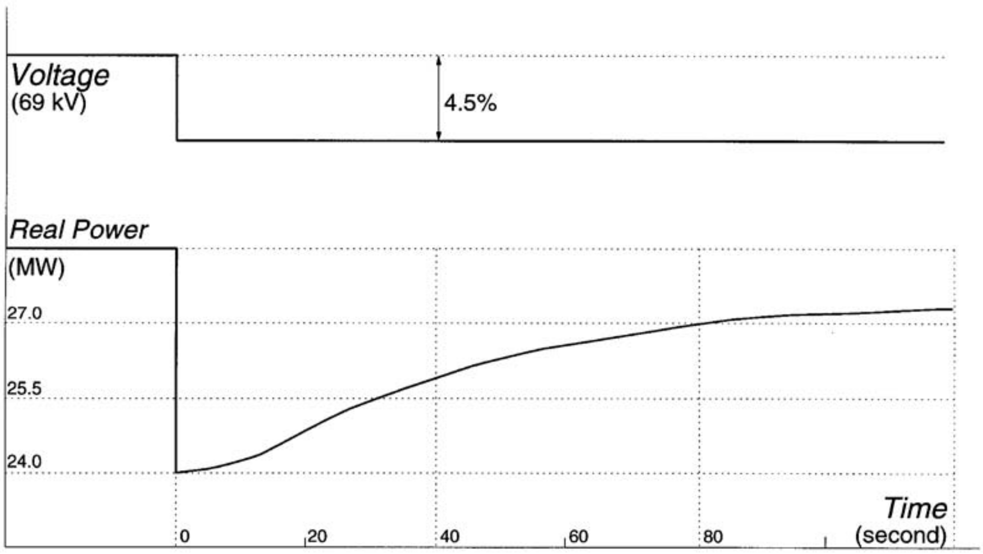

FIGURE 11.12 Aggregate load response to a step voltage change.

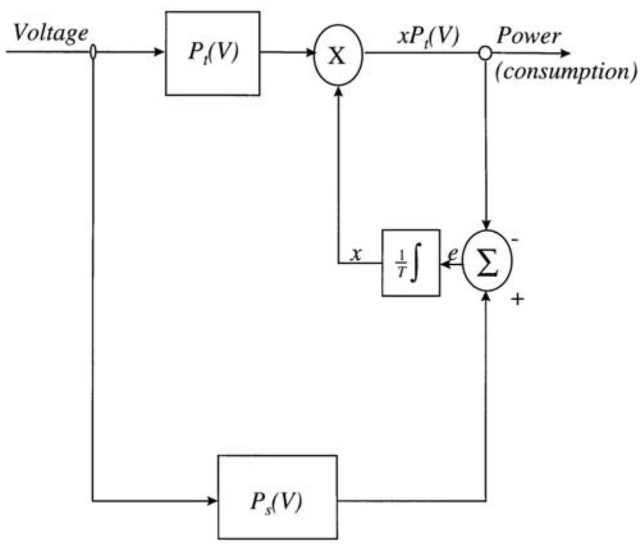

FIGURE 11.13 A generic dynamic load model.

studies. When the load response reaches steady-state, the steady-state power demand is a function of the steady-state voltage. This function defines the steady-state load characteristics known as voltage-dependent load models in load flow studies.

The typical load-voltage response characteristics can be modeled by a generic dynamic load model proposed in Fig. 11.13. In this model (Xu et al., 1993), x is the state variable. $P_t(V)$ and $P_s(V)$ are the transient and steady-state load characteristics, respectively, and can be expressed as:

$$P_t = V^a \quad \text{or} \quad P_t = C_2V^2 + C_1V + C_o$$

$$P_s = P_oV^a \quad \text{or} \quad P_s = P_o\left(d_2V^2 + d_1V + d_o\right)$$

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where V is the per-unit magnitude of the voltage imposed on the load. It can be seen that, at steady-state, state variable x of the model is constant. The input to the integration block, $E = P_s - P$, must be zero and, as a result, the model output is determined by the steady-state characteristics $P = P_s$. For any sudden voltage change, x maintains its predisturbance value initially because the integration block cannot change its output instantaneously. The transient output is then determined by the transient characteristics $P - xP_t$. The mismatch between the model output and the steady-state load demand is the error signal e. This signal is fed back to the integration block that gradually changes the state variable x. This process continues until a new steady-state ($e = 0$) is reached. Analytical expressions of the load model, including real (P) and reactive (Q) power dynamics, are:

$$T_p \frac{dx}{dt} = P_s\left(V\right) - P, P = xP_t\left(V\right)$$

$$T_q \frac{dy}{dt} = Q_s\left(V\right) - Q, Q = yQ_t\left(V\right)$$

$$P_t\left(V\right) = V^a, P_s\left(V\right) = P_o V^a; \quad Q_s\left(V\right) = V^\beta, Q_s\left(V\right) = Q_o V^\beta$$

Analytical Frameworks

The slow nature of the network and load response associated with the phenomenon made it possible to analyze the problem in two frameworks: (1) long-term dynamic framework in which all slow-acting devices and aggregate bus loads are represented by their dynamic models (the analysis in this case is done through dynamic simulation of the system response to a contingency or load variation), or (2) steady-state framework (e.g., load flow) to determine if the system can reach a stable operating point following a particular contingency. This operating point could be a final state or a midpoint following a step of a discrete control action (e.g., transformer tap change).

The proximity of a given system to voltage instability is typically assessed by indices that measure one or a combination of:

- Sensitivity of load bus voltage to variations in active power of the load.
- Sensitivity of load bus voltage to variations in injected reactive power at the load bus.
- Sensitivity of the receiving end voltage to variations in sending end voltage.
- Sensitivity of the total reactive power generated by generators, synchronous condensers, and SVS to variations in load bus reactive power.

Computational Methods

Load Flow Analysis

Consider a simple two-bus system of a sending end source feeding a $P - Q$ load through a transmission line. The family of curves shown in Fig. 11.14 is produced by maintaining the sending end voltage constant while the load at the receiving end is varied at a constant power factor and the receiving end voltage is calculated. Each curve is calculated at a specific power factor and shows the maximum power that can be transferred at this particular power factor. Note that the limit can be increased by providing more reactive support at the receiving end [limit (2) vs. limit (1)], which is effectively pushing the power factor of the load in the leading direction. It should also be noted that the points on the curves below the limit line *Vs* characterize unstable behavior of the system where a drop in demand is associated with a drop in the receiving end voltage leading to eventual collapse. Proximity to voltage instability is usually measured by the distance (in *PU* power) between the operating point on the *P–V* curve and the limit of the same curve.

Another family of curves similar to that of Fig. 11.15 can be produced by varying the reactive power demand (or injection) at the receiving end while maintaining the real power and the sending end voltage constant. The relation between the receiving end voltage and the reactive power injection at the receiving

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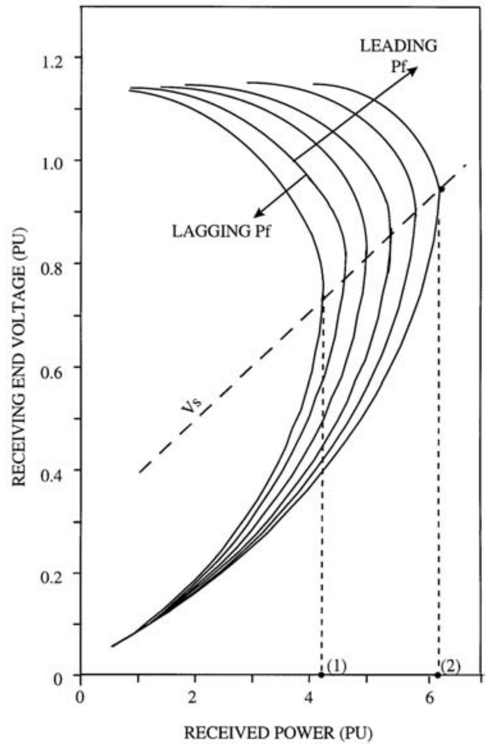

FIGURE 11.14 Pr-Vr characteristics.

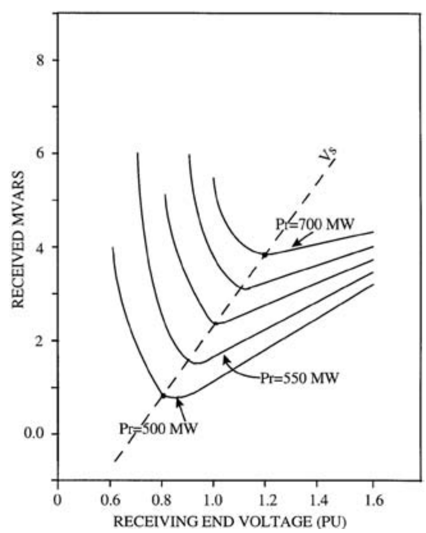

FIGURE 11.15 Q-Vr characteristics.

end is plotted to produce the so called *Q–Vr* curves of Fig. 11.15. The bottom of any given curve characterizes the voltage stability limit. Note that the behavior of the system on the right side of the limit is such that an increase in reactive power injection at the receiving end results in a receiving end voltage rise while the opposite is true on the left side because of the substantial increase in current at the lower voltage, which, in turn, increases reactive losses in the network substantially. The proximity to voltage

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instability is measured as the difference between the reactive power injection corresponding to the operating point and the bottom of the curve. As the active power transfer increases (upwards in Fig. 11.15), the reactive power margin decreases as does the receiving end voltage.

The same family of relations in Figs. 11.14 and 11.15 can be and have been used to assess the voltage stability of large power systems. The *P–V* curves can be calculated using load flow programs. The demand of load center buses are increased in steps at a constant power factor while the generators' terminal voltages are held at their nominal value. The *P–V* relation can then be plotted by recording the MW demand level against a central load bus voltage at the load center. It should be noted that load flow solution algorithms diverge past the limit and do not produce the unstable portion of the *P–V* relation. The *Q–V* relation, however, can be produced in full by assuming a fictitious synchronous condenser at a central load bus in the load center. The *Q–V* relation is then plotted for this particular bus as a representative of the load center by varying the voltage of the bus (now converted to a voltage control bus by the addition of the synchronous condenser) and recording its value against the reactive power injection of the synchronous condenser. If the limits on the reactive power capability of the synchronous condenser is made very high, the load flow solution algorithm will always converge at either side of the *Q–V* relation.

Sequential Load Flow Method

The *P–V* and *Q–V* relations produced results corresponding to an end state of the system where all tap changers and control actions have taken place in time and the load characteristics were restored to a constant power characteristics. It is always recommended and often common to analyze the system behavior in its transition following a disturbance to the end state. Aside from the full long-term time simulation, the system performance can be analyzed in a quasidynamic manner by breaking the system response down into several time windows, each of which is characterized by the states of the various controllers and the load recovery (Mansour, 1993). Each time window can be analyzed using load flow programs modified to reflect the various controllers' states and load characteristics. Those time windows (Fig. 11.16) are primarily characterized by:

1. Voltage excursion in the first second after a contingency as motors slow, generator voltage regulators respond, etc.
2. The period 1 to 20 sec when the system is quiescent until excitation limiting occurs
3. The period 20 to 60 sec when generator over excitation protection has operated
4. The period 1 to 10 min after the disturbance when LTCs restore customer load and further increase reactive demand on generators
5. The period beyond 10 min when AGC, phase angle regulators, operators, etc. come into play

Voltage Stability as Affected by Load Dynamics

Voltage stability may occur when a power system experiences a large disturbance such as a transmission line outage. It may also occur if there is no major disturbance but the system's operating point shifts slowly towards stability limits. Therefore, the voltage stability problem, as other stability problems, must be investigated from two perspectives, the large-disturbance stability and the small-signal stability.

Large-disturbance voltage stability is event-oriented and addresses problems such as postcontingency margin requirement and response of reactive power support. Small-signal voltage stability investigates the stability of an operating point. It can provide such information as to the areas vulnerable to voltage collapse. In this section, the principle of load dynamics affecting both types of voltage stabilities is analyzed by examining the interaction of a load center with its supply network. Key parameters influencing voltage stability are identified. Since the real power dynamic behavior of an aggregate load is similar to its reactive power counterpart, the analysis is limited to reactive power only.

Large-Disturbance Voltage Stability

To facilitate explanation, assume that the voltage dynamics in the supply network are fast as compared to the aggregate dynamics of the load center. The network can then be modeled by three quasi-steady-state

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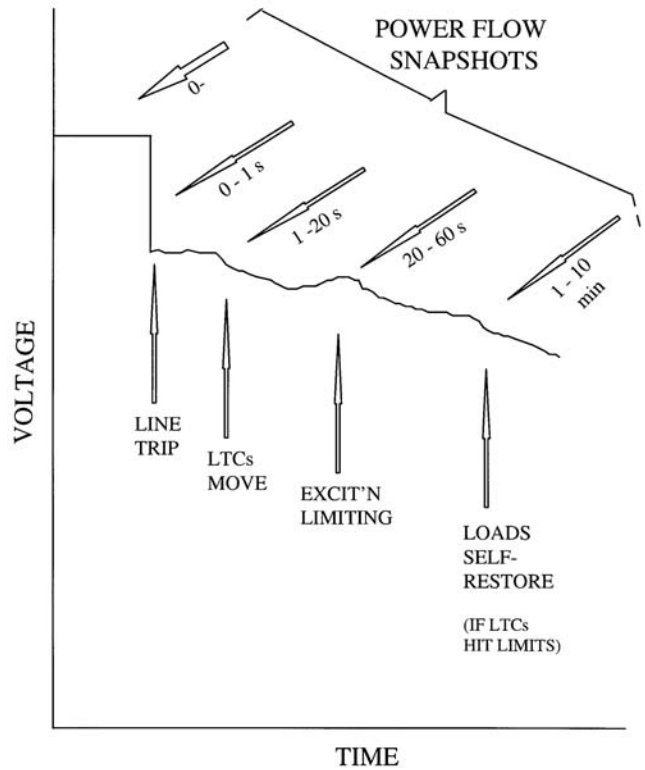

FIGURE 11.16 Breaking the system response down into time periods.

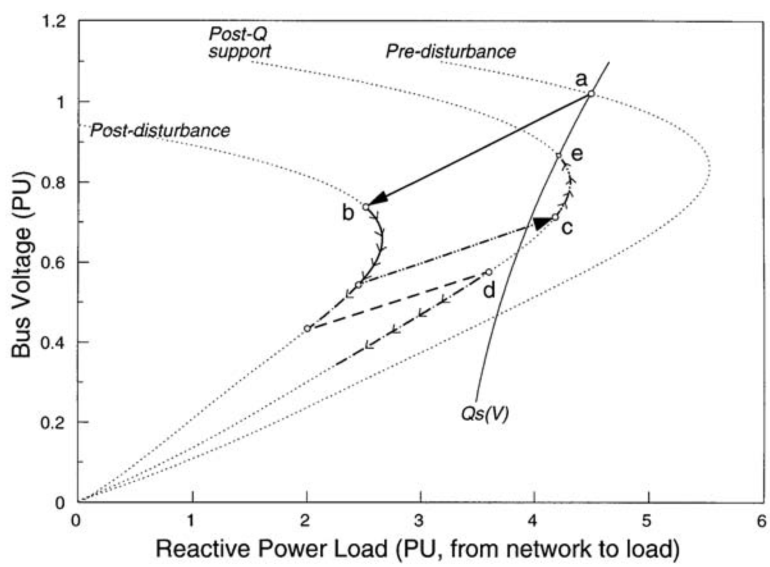

FIGURE 11.17 Voltage dynamics as viewed from V-Q plane.

V–Q characteristics (*QV* curves), predisturbance, postdisturbance and postdisturbance-with-reactive-support, as shown in Fig. 11.17. The load center is represented by a generic dynamic load. This load-network system initially operates at the intersection of the steady-state load characteristics and the predisturbance network *V–Q* curve, point *a*.

The network experiences an outage that reduces its reactive power supply capability to the postdisturbance V–Q curve. The aggregate load responds (see section on Generic Dynamic Load-Voltage Characteristics) instantaneously with its transient characteristics (β = 2, constant impedance in this example) and the system operating point jumps to point *b*. Since, at point *b*, the network reactive power supply is less than load demand for the given voltage:

$$T_q \frac{dy}{dt} = Q_s(V) - Q(V) > 0$$

The load dynamics will try to draw more reactive power by increasing the state variable *y*. This is equivalent to increasing the load admittance if β = 2 or the load current if β = 1. It drives the operating point to a lower voltage. If the load demand and the network supply imbalance persists, the system will continuously operate on the intersection of the postdisturbance V–Q curve and the drifting transient load curve with a monotonically decreasing voltage.

If reactive power support is initiated shortly after the outage, the network is switched to the third V–Q curve. The load responds with its transient chracteristics and a new operating point is formed. Depending on the switch time of reactive power support, the new operating point can be either *c*, for fas response, or *d*, for slow response. At point *c*, power supply is greater than load demand ($Q_s(V) - Q(V) < 0$). The load then draws less power by decreasing its state variable, and as a result, the operating voltage is increased. This dynamic process continues until the power imbalance is reduced to zero, namely a new steady-state operating point is reached (point *e*). On the other hand, for the case with slow response reactive support, the load demand is always greater than the network supply. A monotonic voltage collapse is the ultimate end. A numerical solution technique can be used to simulate the above process. Equations for the simulation are:

$$T_q \frac{dy}{dt} = Q_s(V) = Q(t): \quad Q(t) = yQ_t(V)$$

$$Q(t) = Network(V_s t)$$

where the function *Network* $V_s t$ consists of three polynomials each representing one V–Q curve. Figure 11.17 shows the simulation results in V–Q coordinates. The load voltage as a function of time is plotted in Fig. 11.18. The results demonstrate the importance of load dynamics for explaining the voltage stability problem.

Small-Signal Voltage Stability

The voltage characteristics of a power system can be analyzed around an operating point by linearizing the load flow equations around the operating point and analyzing the resulting sensitivity matrices. Recent breakthroughs in the computational algorithms made those techniques efficient and helpful in analyzing large-scale systems, taking into account virtually all the important elements affecting the phenomenon. In particular, singular value decomposition and modal techniques should be of particular interest to the reader and are thoroughly described by Mansour (1993); Lof et al. (IEEE Paper, 1992); Lof et al. (1992); and Gao et al. (1992).

Mitigation of Voltage Stability Problems

The following methods can be used to mitigate voltage stability problems.

Must-Run Generation. Operate uneconomic generators to change power flows or provide voltage support during emergencies or when new lines or transformers are delayed.

Series Capacitors. Use series capacitors to effectively shorten long lines, thus decreasing the net reactive loss. In addition, the line can deliver more reactive power from a strong system at one end to one experiencing a reactive shortage at the other end.

Shunt Capacitors. Though the heavy use of shunt capacitors can be part of the voltage stability problem, sometimes additional capacitors can also solve the problem by freeing "spinning reactive

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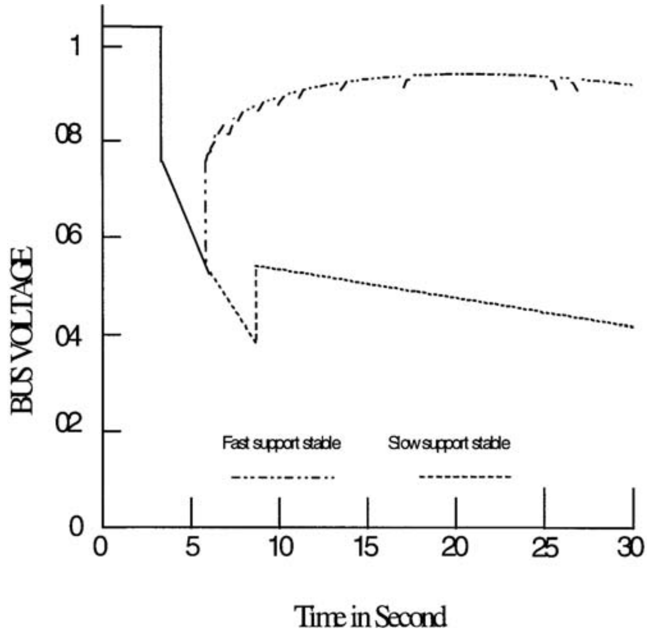

FIGURE 11.18 Simulation of voltage collapse.

reserve" in generators. In general, most of the required reactive power should be supplied locally, with generators supplying primarily active power.

Static Var Compensators (SVC). SVCs, the modern counterpart to the synchronous condenser, are effective in controlling voltage and preventing voltage collapse, but have very definite limitations that must be recognized. Voltage collapse is likely in systems heavily dependent on SVCs when a disturbance exceeding planning criteria takes SVCs to ceiling.

Operate at Higher Voltages. Operating at higher voltage may not increase reactive reserves, but does decrease reactive demand. As such, it can help keep generators away from reactive power limits, and thus help operators maintain control of voltage. The comparison of receiving end *Q–V* curves for two sending end voltages shows the value of higher voltages.

Undervoltage Load Shedding. A small load reduction, even 5 to 10%, can make the difference between collapse and survival. Manual load shedding is used today for this purpose (some utilities use distribution voltage reduction via SCADA), though it may be too slow to be effective in the case of a severe reactive shortage. Inverse time-undervoltage relays are not widely used, but can be very effective. In a radial load situation, load shedding should be based on primary side voltage. In a steady-state stability problem, the load shed in the receiving system will be most effective even though voltages may be lowest near the electrical center (though shedding load in the vicinity of the lowest voltage may be more easily accomplished, and will be helpful).

Lower Power Factor Generators. Where new generation is close enough to reactive-short areas or areas that may occasionally demand large reactive reserves, a .80 or .85 power factor generator may sometimes be appropriate. However, shunt capacitors with a higher power factor generator having reactive overload capability, may be more flexible and economic.

Use Generator Reactive Overload Capability. Generators should be used as effectively as possible. Overload capability of generators and exciters may be used to delay voltage collapse until operators can change dispatch or curtail load when reactive overloads are modest. To be most useful, reactive overload capability must be defined in advance, operators trained in its use, and protective devices set so as not to prevent its use.

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11.5 Direct Stability Methods

Vijay Vittal

Direct methods of stability analysis determine the transient stability (as defined in Section 11.1 and described in Section 11.2) of power systems without explicitly obtaining the solutions of the differential equations governing the dynamic behavior of the system. The basis for the method is Lyapunov's second method, also known as Lyapunov's direct method, to determine stability of systems governed by differential equations. The fundamental work of A. M. Lyapunov (1857-1918) on stability of motion was published in Russian in 1893, and was translated into French in 1907 (Lyapunov, 1907). This work received little attention and for a long time was forgotten. In the 1930s, Soviet mathematicians revived these investigations and showed that Lyapunov's method was applicable to several problems in physics and engineering. This revival of the subject matter has spawned several contributions that have led to the further development of the theory and application of the method to physical systems.

The following example motivates the direct methods and also provides a comparison with the conventional technique of simulating the differential equations governing the dynamics of the system. Figure 11.19 shows an illustration of the basic idea behind the use of the direct methods. A vehicle, initially at the bottom of a hill, is given a sudden push up the hill. Depending on the magnitude of the push, the vehicle will either go over the hill and tumble, in which case it is unstable, or the vehicle will climb only part of the way up the hill and return to a rest position (assuming that the vehicle's motion will be damped), i.e., it will be stable. In order to determine the outcome of disturbing the vehicle's equilibrium for a given set of conditions (mass of the vehicle, magnitude of the push, height of the hill, etc.), two different methods can be used:

1. Knowing the initial conditions, obtain a time solution of the equations describing the dynamics of the vehicle and track the position of the vehicle to determine how far up the hill the vehicle will travel. This approach is analogous to the traditional time domain approach of determining stability in dynamic systems.
2. The approach based on Lyapunov's direct method would consist of characterizing the motion of the dynamic system using a suitable Lyapunov function. The Lyapunov function should satisfy certain sign definiteness properties. These properties will be addressed later in this subsection. A natural choice for the Lyapunov function is the system energy. One would then compute the

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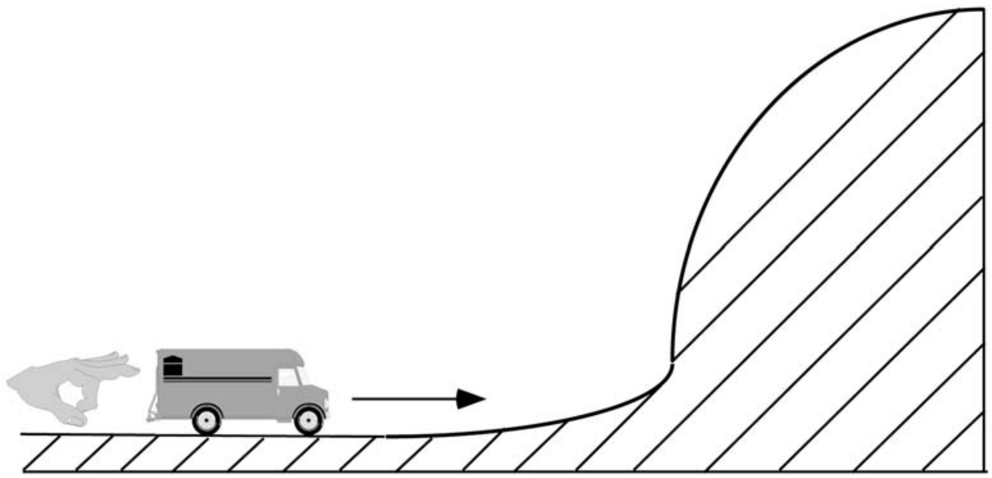

FIGURE 11.19

energy injected into the vehicle as a result of the sudden push, and compare it with the energy needed to climb the hill. In this method, there is no need to track the position of the vehicle as it moves up the hill.

These methods are simple to use if the calculations involve only one vehicle and one hill. The complexity increases if there are several vehicles involved as it becomes necessary to determine (a) which vehicles will be pushed the hardest, (b) how much of the energy is imparted to each vehicle, (c) which direction will they move, and (d) how high a hill must they climb before they will go over the top.

The simple example presented here is analogous to analyzing the stability of a one-machine-infinite-bus power system. The approach presented here is identical to the well-known equal area criterion (Kimbark, 1948; Anderson and Fouad, 1994) which is a direct method for determining transient stability for the one-machine-infinite-bus power system. For a more detailed discussion of the equal area criterion and its relationship to Lyapunov's direct method refer to Pai (1981), chap. 4; Pai (1989), chap. 1; Fouad and Vittal (1992), chap. 3.

Review of Literature on Direct Methods

In the review presented here, we will deal only with work relating to the transient stability analysis of multimachine power systems. In this case the simple example presented above becomes quite complex. Several vehicles which correspond to the synchronous machines are now involved. It also becomes necessary to determine (a) which vehicles will be pushed the hardest, (b) what portion of the disturbance energy is distributed to each vehicle, (c) in which directions the vehicles move, and (d) how high a hill must the vehicles climb before they will go over.

Energy criteria for transient stability analysis were the earliest of all direct methods of multimachine power system transient stability assessment. These techniques were extensions of the equal area criterion to power systems with more than two generators represented by the classical model (Anderson and Fouad, 1994, chap. 2). Researchers from the Soviet Union conducted early work in this area (1930s and 1940s). There were very few results on this topic in Western literature during the same period. In the 1960s the application of Lyapunov's direct method to power systems generated a great deal of activity in the academic community. In most of these investigations, the classical power system model was used. The early work on energy criteria dealt with two main issues: (a) characterization of the system energy, and (b) the critical value of the energy.

Several excellent references that provide a detailed review of the development of the direct methods for transient stability exist. Ribbens-Pavella (1971) and Fouad (1975) are early review papers and provide

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a comprehensive review of the work done in the period 1960–1975. Detailed reviews of more recent work are conducted in Bose (1984), Ribbens-Pavella and Evans (1985), Fouad and Vittal (1988), and Chiang et al. (1995). The following textbooks provide a comprehensive review and also present detailed descriptions of the various approaches related to direct stability methods: Pai (1981), Pai (1989), Fouad and Vittal (1992), Ribbens-Pavella (1971), and Pavella and Murthy (1994). These references provide a thorough and detailed review of the evolution of the direct methods. In what follows, a brief review of the field and the evolutionary steps in the development of the approaches are presented.

Gorev (1971) first proposed an energy criteria based on the lowest saddle point or unstable equilibrium point (UEP). This work influenced the thinking of power system direct stability researchers for a long time. Magnusson (1947) presented an approach very similar to that of Gorev's and derived a potential energy function with respect to the (posttransient) equilibrium point of the system. Aylett (1958) studied the phase-plane trajectories of multimachine systems using the classical model. An important aspect of this work is the formulation of the system equations based on the intermachine movements. In the period that followed, several important publications dealing with the application of Lyapunov's method to power systems appeared. These works largely dealt with the aspects of obtaining better Lyapunov function, and determining the least conservative estimate of the domain of attraction. Gless (1966) applied Lyapunov's method to the one machine classical model system. El-Abiad and Nagappan (1966) developed a Lyapunov function for multimachine system and demonstrated the approach on a four machine system. The stability results obtained were conservative, and the work that followed this largely dealt with improving the Lyapunov function. A sampling of the work following this line of thought is presented in Willems (1968), Pai et al. (1970), and Ribbens-Pavella (1971). These efforts were followed by the work of Tavora and Smith (1972) dealing with the transient energy of a multimachine system represented by the classical model. They formulated the system equations in the Center of Inertia (COI) reference frame and also in the internode coordinates which is similar to the formulation used by Aylett (1958). Tavora and Smith obtained expressions for the total kinetic energy of the system and the transient kinetic energy, which the authors say determines stability. This was followed by work of Gupta and El-Abiad (1976), which recognized that the UEP of interest is not the one with the lowest energy, but rather the UEP closest to the system trajectory. Uyemura et al. (1996) made an important contribution by developing a technique to approximate the path-dependent terms in the Lyapunov functions by path-independent terms using approximations for the system trajectory.

The work by Athay, Podmore, and colleagues (Athay et al., 1979) is the basis for the transient energy function (TEF) method used today. This work investigated many issues dealing with the application of the TEF method to large power systems. These included:

1. COI formulation and approximation of path-dependent terms.
2. Search for the UEP in the direction of the faulted trajectory.
3. Investigation of the Potential Energy Boundary Surface (PEBS).
4. Application of the technique to power systems of practical sizes.
5. Preliminary investigation of higher-order models for synchronous generators.

This work was followed by the work at Iowa State University by Fouad and colleagues (1981), which dealt with the determination of the correct UEP for stability assessment. This work also identified the appropriate energy for system separation and developed the concept of corrected kinetic energy. Details regarding this work are presented in Fouad and Vittal (1992).

The work that followed largely dealt with developing the TEF method into a more practical tool, and with improving its accuracy, modeling features, and speed. An important development in this area was the work of Bergen and Hill (1981). In this work the network structure was preserved for the classical model. As a result, fast techniques that incorporated network sparsity could be used to solve the problem. A concerted effort was also carried out to extend the applicability of the TEF method to realistic systems. This included improvements in modeling features, algorithms, and computational efficiency. Work related to the large-scale demonstration of the TEF method is found in Carvalho et al. (1986). The work

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dealing with extending the applicability of the TEF method is presented in Fouad et al. (1986). Significant contributions to this aspect of the TEF method can also be found in Padiyar and Sastry (1987), Padiyar and Ghosh (1989), and Abu-Elnaga et al. (1988).

In Chiang (1985), Chiang et al. (1987), and Chiang et al. (1988), a significant contribution was made to provide an analytical justification for the stability region for multimachine power systems, and a systematic procedure to obtain the controlling UEP was also developed. Zaborsky et al. (1988) also provide a comprehensive analytical foundation for characterizing the region of stability for multimachine power systems.

With the development of a systematic procedure to determine and characterize the region of stability, a significant effort was directed toward the application of direct methods for online transient stability assessment. This work, reported in Waight et al. (1994) and Chadalavada et al. (1997), has resulted in an online tool which has been implemented and used to rank contingencies based on their severity. Another online approach implemented and being used at B.C. Hydro is presented in Mansour et al. (1995). A recent effort with regard to classifying and ranking contingencies quite similar to the one presented in Chadalavada et al. (1997) is described in Chiang et al. (1998).

Some recent efforts (Ni and Fouad, 1987; Hiskens et al., 1992; Jiang et al., 1995) also deal with the inclusion of FACTS devices in the TEF analysis.

The Power System Model

The classical power system model will now be presented. It is the “simplest” power system model used in stability studies and is limited to the analysis of first swing transients. For more details regarding the model, the reader is referred to Anderson and Fouad (1994), Fouad and Vittal (1992), Kundur (1994), and Sauer and Pai (1998). The assumptions commonly made in deriving this model are:

For the synchronous generators

1. Mechanical power input is constant.
2. Damping or asynchronous power is negligible.
3. The generator is represented by a constant EMF behind the direct axis transient (unsaturated) reactance.
4. The mechanical rotor angle of a synchronous generator can be represented by the angle of the voltage behind the transient reactance.

The load is usually represented by passive impedances (or admittances), determined from the predisturbance conditions. These impedances are held constant throughout the stability study. This assumption can be improved using nonlinear models. See Fouad and Vittal (1992), Kundur (1994), and Sauer and Pai (1998) for more details. With the loads represented as constant impedances, all the nodes except the internal generator nodes can be eliminated. The generator reactances and the constant impedance loads are included in the network bus admittance matrix. The generators’ equations of motion are then given by

$$\begin{aligned} M_i \frac{d\omega_i}{dt} &= P_i - P_{ei} \\ \frac{d\delta_i}{dt} &= \omega_i \qquad i = 1, 2, \ldots, n \end{aligned} \tag{11.13}$$

where

$$P_{ei} = \sum_{\substack{j=1 \\ j \neq i}}^{n} \left[C_{ij} \sin\left(\delta_i - \delta_j\right) + D_{ij} \cos\left(\delta_i - \delta_j\right) \right] \tag{11.14}$$

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P_i $= P_{mi} - E_i^2 G_{ii}$
C_{ij} $= E_iE_jB_{ij}$, $D_{ij} = E_iE_jG_{ij}$
P_{mi} = Mechanical power input
G_{ii} = Driving point conductance
E_i = Constant voltage behind the direct axis transient reactance
ω_i, δ_i = Generator rotor speed and angle deviations, respectively, with respect to a synchronously rotating reference frame
M_i = Inertia constant of generator
B_{ij} (G_{ij}) = Transfer susceptance (conductance) in the reduced bus admittance matrix

Equation (11.13) is written with respect to an arbitrary synchronous reference frame. Transformation of this equation to the inertial center coordinates not only offers physical insight into the transient stability problem formulation in general, but also removes the energy associated with the motion of the inertial center which does not contribute to the stability determination. Referring to Eq. (11.13), define

$$M_T = \sum_{i=1}^{n} M_i$$

$$\delta_0 = \frac{1}{M_T} \sum_{i=1}^{n} M_i$$

then,

$$\begin{aligned} M_T\dot{\omega}_0 &= \sum_{i=1}^{n} P_i - P_{ei} = \sum_{i=1}^{n} P_i - 2\sum_{i=1}^{n-1}\sum_{j=i+1}^{n} D_{ij}\cos\delta_{ij} \\ \dot{\delta}_0 &= \omega_0 \end{aligned} \tag{11.15}$$

The generators' angles and speeds with respect to the inertial center are given by

$$\left.\begin{aligned} \theta_i &= \delta_i - \delta_0 \\ \tilde{\omega}_i &= \omega_i - \omega_0 \end{aligned}\right. \quad i = 1, 2, \ldots, n \tag{11.16}$$

and in this coordinate system the equations of motion are given by

$$\begin{aligned} M_i\dot{\tilde{\omega}}_i &= P_i - P_{mi} - \frac{M_i}{M_T} P_{COI} \\ \dot{\theta}_i &= \tilde{\omega}_i \qquad i = 1, 2, \ldots, n \end{aligned} \tag{11.17}$$

Review of Stability Theory

A brief review of the stability theory applied to the TEF method will now be presented. This will include a few definitions, some important results, and an analytical outline of the stability assessment formulation.

The definitions and results that are presented are for differential equations of the type shown in Eqs. (11.13) and (11.17). These equations have the general structure given by

$$\dot{x}(t) = f(t, x(t)) \tag{11.18}$$

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The system described by Eq. (11.18) is said to be *autonomous* if $\boldsymbol{f}(t, \boldsymbol{x}(t)) \equiv \boldsymbol{f}(\boldsymbol{x})$, i.e., independent of t and is said to be nonautonomous otherwise.

A point $\boldsymbol{x}_0 \in R^n$ is called an *equilibrium point* for the system [Eq. (11.18)] at time t_0 if $\boldsymbol{f}(t, \boldsymbol{x}_0) \equiv 0$ for all $t \geq t_o$.

An equilibrium point $\boldsymbol{x}_e$ of Eq. (11.18) is said to be an isolated equilibrium point if there exists some neighborhood S of $\boldsymbol{x}_e$ which does not contain any other equilibrium point of Eq. (11.18).

Some precise definitions of stability in the sense of Lyapunov will now be presented. In presenting these definitions, we consider systems of equations described by Eq. (11.18), and also assume that Eq. (11.18) possesses an isolated equilibrium point at the origin. Thus, $\boldsymbol{f}(t, \mathbf{0}) = \mathbf{0}$ for all $t \geq 0$**.**

The equilibrium $\boldsymbol{x} = \mathbf{0}$ of Eq. (11.18) is said to be *stable* in the sense of Lyapunov, or simply stable if for every real number $\varepsilon > 0$ and initial time $t_0 > 0$ there exists a real number $\delta(\varepsilon, t_0) > 0$ such that for all initial conditions satisfying the inequality $\|\boldsymbol{x}(t_0)\| = \|\boldsymbol{x}_0\| < \delta$, the motion satisfies $\|\boldsymbol{x}(t)\| < \varepsilon$ for all $t \geq t_0$.

The symbol $\| \, . \, \|$ stands for a norm. Several norms can be defined on an n-dimensional vector space. Refer to Miller and Michel (1983) and Vidyasagar (1978) for more details. The definition of stability given above is unsatisfactory from an engineering viewpoint, where one is more interested in a stricter requirement of the system trajectory to eventually return to some equilibrium point. Keeping this requirement in mind, the following definition of asymptotic stability is presented.

The equilibrium $\boldsymbol{x} = \mathbf{0}$ of Eq. (11.18) is *asymptotically stable* at time t_0 if

1. $\boldsymbol{x} = \mathbf{0}$ is stable at $t = t_0$
2. For every $t_0 \geq 0$, there exists an $\eta(t_0) > 0$ such that $\underset{t\to\infty}{Lim}\left\|\mathrm{x}(t)\right\| \to 0$ whenever $\left\|\mathrm{x}(t)\right\| < \eta$
   (ATTRACTIVITY)

This definition combines the aspect of stability as well as attractivity of the equilibrium. The concept is local, because the region containing all the initial conditions that converge to the equilibrium is some portion of the state space. Having provided the definitions pertaining to stability, the formulation of the stability assessment procedure for power systems is now presented. The system is initially assumed to be at a predisturbance steady-state condition governed by the equations

$$\dot{x}(t) = f^{p}\big(x(t)\big) \qquad -\infty < t \leq 0 \tag{11.19}$$

The superscript p indicates predisturbance. The system is at equilibrium, and the initial conditions are obtained from the power flow solution. At $t = 0$, the disturbance or the fault is initiated. This changes the structure of the right-hand sides of the differential equations, and the dynamics of the system are governed by

$$\dot{x}(t) = f^{f}\big(x(t)\big) \qquad 0 < t \leq t_{cl} \tag{11.20}$$

where the superscript f indicates faulted conditions. The disturbance or the fault is removed or cleared by the protective equipment at time t_{cl}. As a result, the network undergoes a topology change and the right-hand sides of the differential equations are again altered. The dynamics in the postdisturbance or postfault period are governed by

$$\dot{x}(t) = f\big(x(t)\big) \qquad t_{cl} < t \leq \infty \tag{11.21}$$

The stability analysis is done for the system in the postdisturbance period. The objective is to ascertain asymptotic stability of the postdisturbance equilibrium point of the system governed by Eq. (11.21). This is done by obtaining the domain of attraction of the postdisturbance equilibrium and determining if the initial conditions of the postdisturbance period lie within this domain of attraction or outside it. The domain of attraction is characterized by the appropriately determined value of the transient energy function. In the literature survey presented previously, several approaches to characterize the domain of

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attraction were mentioned. In earlier approaches (El-Abiad and Nagappan, 1966; Tavora and Smith, 1972), this was done by obtaining the unstable equilibrium points (UEP) of the postdisturbance system and determining the one with the lowest level of potential energy with respect to the postdisturbance equilibrium. This value of potential energy then characterized the domain of attraction. In the work that followed, it was found that this approach provided very conservative results for power systems. In Gupta and El-Abiad (1976), it was recognized that the appropriate UEP was dependent on the fault location, and the concept of closest UEP was developed. An approach to determine the domain of attraction was also presented by Kakimoto and colleagues (1978; 1981) based on the concept of the potential energy boundary surface (PEBS). For a given disturbance trajectory, the PEBS describes a "local" approximation of the stability boundary. The process of finding this local approximation is associated with the determination of the stability boundary of a lower dimensional system (see Fouad and Vittal [1992], chap. 4 for details). It is formed by joining points of maximum potential energy along any direction originating from the postdisturbance stable equilibrium point. The PEBS constructed in this manner is orthogonal to the equipotential curves. In addition, along the direction orthogonal to the PEBS, the potential energy achieves a local maximum at the PEBS. In Athay et al. (1979), several simulations on realistic systems were conducted. These simulations, together with the synthesis of previous results in the area led to the development of a procedure to determine the correct UEP to characterize the domain of attraction. The results obtained were much improved, but in terms of practical applicability there was room for improvement. The work presented in Fouad et al. (1981) and Carvalho et al. (1986) made several important contributions to determining the correct UEP. The term *controlling UEP* was established, and a systematic procedure to determine the controlling UEP was developed. This will be described later. In Chiang et al. (1985; 1987; 1988), a thorough analytical justification for the concept of the controlling UEP and the characterization of the domain of attraction was developed. This provides the analytical basis for the application of the TEF method to power systems. These analytical results in essence show that the stability boundary of the postdisturbance equilibrium point is made up of the union of the stable manifolds of those unstable equilibrium points contained on the stability boundary. The boundary is then approximated locally using the energy function evaluated at the controlling UEP. The conceptual framework of the TEF approach is illustrated in Fig. 11.20.

The Transient Energy Function

The TEF can be derived from Eq. (11.17) using first principles. Details of the derivation can be found in Pai (1981), Pai (1989), Fouad and Vittal (1992), Athay et al. (1979). For the power system model considered in Eq. (11.17), the TEF is given by

$$V = \frac{1}{2}\sum_{i=1}^{n} M_i \tilde{\omega}_i^2 - \sum_{i=1}^{n} P_i\left(\theta_i - \theta_i^{s2}\right) - \sum_{i=1}^{n-1}\sum_{j=i+1}^{n}\left[C_{ij}\cos\left(\theta_{ij} - \theta_{ij}^{s2}\right) - \int_{\theta_i^{s2}+\theta_j^{s2}}^{\theta_i+\theta_j} D_{ij}\cos\theta_{ij}\, d\left(\theta_i + \theta_j\right)\right] \quad (11.22)$$

where $\theta_{ij} = \theta_i - \theta_j$.

The first term on the right-hand side of Eq. (11.22) is the kinetic energy. The next three terms represent the potential energy. The last term is path dependent. It is usually approximated (Uyemura et al., 1996; Athay et al., 1979) using a straight line approximation for the system trajectory. The integral between two points θ^a and θ^b is then given by

$$I_{ij} = D_{ij}\frac{\theta_i^b - \theta_i^a + \theta_j^b - \theta_j^a}{\theta_{ij}^b - \theta_{ij}^a}\left(\sin\theta_{ij}^b - \sin\theta_{ij}^a\right). \quad (11.23)$$

In Fouad et al. (1981), a detailed analysis of the energy behavior along the time domain trajectory was conducted. It was observed that in all cases where the system was stable following the removal of a

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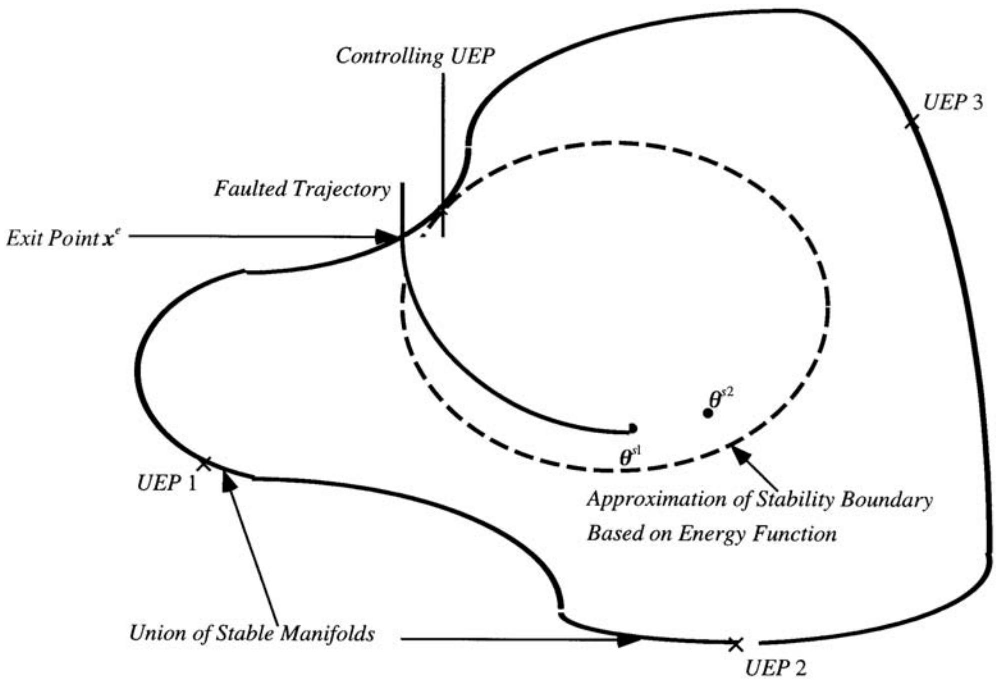

FIGURE 11.20

disturbance, a certain amount of the total kinetic energy in the system was not absorbed. This indicates that not all the kinetic energy created by the disturbance, contributes to the instability of the system. Some of the kinetic energy is responsible for the intermachine motion between the generators and does not contribute to the separation of the severely disturbed generators from the rest of the system. The kinetic energy associated with the gross motion of k machines having angular speeds $\tilde{\omega}_1, \tilde{\omega}_2, \ldots, \tilde{\omega}_k$ is the same as the kinetic energy of their inertial center. The speed of the inertial center of that group and its kinetic energy are given by

$$\tilde{\omega}_{cr} = \sum_{i=1}^{k} M_i \tilde{\omega}_i \Bigg/ \sum_{i=1}^{k} M_i \tag{11.24}$$

$$V_{KE_{cr}} = \frac{1}{2}\left[\sum_{i=1}^{k} M_i\right]\left(\tilde{\omega}_{cr}\right)^2 \tag{11.25}$$

The disturbance splits the generators of the system into two groups: the critical machines and the rest of the generators. Their inertial centers have inertia constants and angular speeds M_{cr}, $\tilde{\omega}_{cr}$ and M_{sys}, $\tilde{\omega}_{sys}$, respectively. The kinetic energy causing the separation of the two groups is the same as that of an equivalent one-machine-infinite-bus system having inertia constant M_{eq} and angular speed $\tilde{\omega}_{eq}$ given by

$$\begin{aligned} M_{eq} &= \frac{M_{cr} \times M_{sys}}{M_{eq} + M_{sys}} \\ \tilde{\omega}_{eq} &= \left(\tilde{\omega}_{cr} - \tilde{\omega}_{sys}\right) \end{aligned} \tag{11.26}$$

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and the corresponding kinetic energy is given by

$$V_{KE_{corr}} = \frac{1}{2} M_{eq} \left(\tilde{\omega}_{eq}\right)^2 \tag{11.27}$$

The kinetic energy term in Eq. (11.22) is replaced by Eq. (11.27).

Transient Stability Assessment

As described previously, the transient stability assessment using the TEF method is done for the final postdisturbance configuration. The stability assessment is done by comparing two values of the transient energy V. The value of V is computed at the end of the disturbance. If the disturbance is a simple fault, the value of V at fault clearing V_{cl} is evaluated.

The other value of V that largely determines the accuracy of the stability assessment is the critical value of V, V_{cr}, which is the potential energy at the controlling UEP for the particular disturbance being investigated.

If $V_{cl} < V_{cr}$, the system is stable, and if $V_{cl} > V_{cr}$, the system is unstable. The assessment is made by computing the energy margin ΔV given by

$$\Delta V = V_{cr} - V_{cl} \tag{11.28}$$

Substituting for V_{cr} and V_{cl} from Eq. (11.22) and invoking the linear path assumption for the path dependent integral between the conditions at the end of the disturbance and the controlling UEP, we have

$$\begin{aligned}\Delta V = & -\frac{1}{2} M_{eq} \tilde{\omega}_{eq}^{cl^2} - \sum_{i=1}^{n} P_i \left(\theta_i^u - \theta_i^{cl}\right) \\ & - \sum_{i=1}^{n-1} \sum_{j=i+1}^{n} \left[C_{ij} \left(\cos\theta_{ij}^u - \cos\theta_{ij}^{cl}\right)\right] - D_{ij} \frac{\theta_i^u - \theta_i^{cl} + \theta_j^u - \theta_j^{cl}}{\left(\theta_{ij}^u - \theta_{ij}^{cl}\right)} \left(\sin\theta_{ij}^u - \sin\theta_{ij}^{cl}\right)\end{aligned} \tag{11.29}$$

where $(\theta^{cl}, \tilde{\omega}^{cl})$ are the conditions at the end of the disturbance and $(\theta^u, \mathbf{0})$ represents the controlling UEP. If ΔV is greater than zero the system is stable, and if ΔV is less than zero, the system is unstable. A qualitative measure of the degree of stability (or instability) can be obtained if ΔV is normalized with respect to the corrected kinetic energy at the end of the disturbance (Fouad et al., 1981).

$$\Delta V_n = \Delta V \big/ V_{KE_{corr}} \tag{11.30}$$

For a detailed description of the computational steps involved in the TEF analysis, refer to Fouad and Vittal (1992), chap. 6.

Determination of the Controlling UEP

A detailed description of the rationale in developing the concept of the controlling UEP is provided in Fouad and Vittal (1992), section 5.4. A criterion to determine the controlling UEP based on the normalized energy margin is also presented. The criterion is stated as follows. The postdisturbance trajectory approaches (if the disturbance is large enough) the controlling UEP. This is the UEP with the lowest normalized potential energy margin. The determination of the controlling UEP involves the following key steps:

1. Identifying the correct UEP.
2. Obtaining a starting point for the UEP solution close to the exact UEP.
3. Calculation of the exact UEP.

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Identifying the correct UEP involves determining the advanced generators for the controlling UEP. This is referred to as the mode of disturbance (MOD). These generators generally are the most severely disturbed generators due to the disturbance. The generators in the MOD are not necessarily those that lose synchronism. The computational details of the procedure to identify the correct UEP and obtain a starting point for the exact UEP solution are provided in Fouad and Vittal (1992), section 6.6. An outline of the procedure is provided below:

1. Candidate modes to be tested by the MOD test depend on how the disturbance affects the system. The selection of the candidate modes is based on several disturbance severity measures obtained at the end of the disturbance. These severity measures include kinetic energy and acceleration. A ranked list of machines is obtained using the severity measures. From this ranked list, the machines or group of machines at the bottom of the list are included in the group forming the rest of the system and $V_{KE_{corr}}$ is calculated. In a sequential manner, machines are successively added to the group forming the rest of the system and $V_{KE_{corr}}$ is calculated and stored.
2. The list of $V_{KE_{corr}}$ calculated above is sorted in descending order and only those groups within 10% of the maximum $V_{KE_{corr}}$ in the list are retained.
3. Corresponding to the MOD for each of the retained groups of machines in step 2, an approximation to the UEP corresponding to that mode is constructed using the postdisturbance stable equilibrium point. For a given candidate mode, where machines *i* and *j* are contained in the critical group, an estimate of the approximation to the UEP for an *n*-machine system is given by $\left[\hat{\theta}_{ij}^{u}\right]^T = \left[\theta_1^{s2}, \theta_2^{s2}, \dots, \left[\pi - \theta_i^{s2}\right], \dots, \left[\pi - \theta_j^{s2}\right], \dots, \theta_n^{s2}\right]$. This estimate can be further improved by accounting for the motion of the COI, and using the concept of the PEBS to maximize the potential energy along the ray drawn from the estimate and the postdisturbance stable equilibrium point θ^{s2}.
4. The normalized potential energy margin for each of the candidate modes is evaluated at the approximation to the exact UEP, and the mode corresponding to the lowest normalized potential energy margin is then selected as the mode of the controlling UEP.
5. Using the approximation to the controlling UEP as a starting point, the exact UEP is obtained by solving the nonlinear algebraic equation given by

$$f_i = P_i - P_{mi} - \frac{M_i}{M_T} P_{COI} = 0 \quad i = 1, 2, \dots, n \tag{11.31}$$

The solution of these equations is a computationally intensive task for realistic power systems. Several investigators have made significant contributions to determining an effective solution. A detailed description of the numerical issues and algorithms to determine the exact UEP solution are beyond the scope of this handbook. Several excellent references that detail these approaches are available. These efforts are described in Fouad and Vittal (1992), section 6.8.

The BCU (Boundary Controlling UEP) Method

The BCU method (Chiang et al., 1985, 1987, 1988) provides a systematic procedure to determine a suitable starting point for the controlling UEP solution. The main steps in the procedure are as follows:

1. Obtain the faulted trajectory by integrating the equations

$$\begin{aligned} M_i \dot{\tilde{\omega}}_i &= P_i^f - P_{ei}^f - \frac{M_i}{M_T} P_{COI}^f \\ \dot{\theta}_i &= \tilde{\omega}_i, \quad i = 1, 2, \dots, n \end{aligned} \tag{11.32}$$

Values of θ obtained from Eq. (11.32) are substituted in the postfault mismatch equation given by Eq. (11.31). The exit point $\boldsymbol{x}^e$ is then obtained by satisfying the condition $\sum_{i=1}^{n} -f_i \tilde{\omega}_i = 0$.

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2. Using θ^e as the starting point, integrate the associated gradient system equations given by

$$\begin{aligned}
\dot{\theta}_i &= P_i - P_{ei} - \frac{M_i}{M_T} P_{COI}, \quad i = 1, 2, \ldots, n-1 \\
\theta_n &= -\sum_{i=1}^{n-1} M_i \theta_i \Big/ M_n
\end{aligned} \tag{11.33}$$

   At each step of the integration, evaluate $\sum_{i=1}^{n} |f_i| = F$ and determine the first minimum of F along the gradient surface. Let θ^* be the vector of rotor angles at this point.
3. Using θ^* as a starting point in Eq. (11.31), obtain the exact solution for the controlling UEP.

Applications of the TEF Method and Modeling Enhancements

The preceding subsections have provided the important steps in the application of the TEF method to analyze the transient stability of multimachine power systems. In this subsection, a brief mention of the applications of the technique and enhancements in terms of modeling detail and application to realistic power systems is provided. Inclusion of detailed generator models and excitation systems in the TEF method are presented in Athay et al. (1979), Fouad et al. (1986), and Waight et al. (1994). The sparse formulation of the system to obtain more efficient solution techniques is developed in Bergen and Hill (1981), Abu-Elnaga et al. (1988), and Waight et al. (1994). The application of the TEF method for a wide range of problems including dynamic security assessment are discussed in Fouad and Vittal (1992), chaps. 9–10; Chadalavada et al. (1997); and Mansour et al. (1995). The availability of a qualitative measure of the degree of stability or instability in terms of the energy margin makes the direct methods an attractive tool for a wide range of problems. The modeling enhancements that have taken place and the continued development in terms of computational efficiency and computer hardware, make direct methods a viable candidate for online transient stability assessment (Waight et al., 1994; Chadalavada et al., 1997; Mansour et al., 1995). This feature is particularly effective in the competitive market environment to calculate operating limits with changing conditions. There are several efforts underway dealing with the development of direct methods and a combination of time simulation techniques for online transient stability assessment. These approaches take advantage of the superior modeling capability available in the time simulation engines, and use the qualitative measure provided by the direct methods to derive preventive and corrective control actions and estimate limits. This line of investigation has great potential and could become a vital component of energy control centers in the near future.

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11.6 Power System Stability Controls[1]

Carson W. Taylor

Power system synchronous or angle instability phenomenon limits power transfer, especially where transmission distances are long. This is well recognized and many methods have been developed to improve stability and increase allowable power transfers.

The synchronous stability problem has been fairly well solved by fast fault clearing, thyristor exciters, power system stabilizers, and a variety of other stability controls such as generator tripping. Fault clearing of severe short circuits can be less than three cycles (50 ms for 60 Hz frequency), and the effect of the faulted line outage on generator acceleration and stability may be greater than that of the fault itself.

Nevertheless, requirements for more intensive use of available generation and transmission, more onerous load characteristics, greater variation in power schedules, and industry restructuring pose new concerns. Recent large-scale power failures have heightened the concerns.

In this section we describe the state-of-the art of power system angle stability controls. Controls for voltage stability are described in another section of this chapter and in other literature (CIGRE Brochure No. 101, 1995; CIGRE Brochure No. 128, 1998; IEEE THO 596-7 PWR, 1993; Taylor 1994; Van Cutsem and Vournas, 1998).

We emphasize controls employing relatively new technologies that have actually been implemented by electric power companies, or that are seriously being considered for implementation. The technologies include applied control theory, power electronics, microprocessors, signal processing, transducers, and communications.

Power system stability controls must be effective and robust. Effective in an engineering sense means "cost-effective." Control robustness is the capability to operate appropriately for a wide range of power system operating and disturbance conditions.

Review of Power System Synchronous Stability Basics

Many publications, for example CIGRE Brochure No. 111 (1996), Kundur (1994), and IEEE Discrete Supplementary Controls Task Force (1978), describe the basics, which are briefly reviewed here. Power generation is largely by synchronous generators, which may be interconnected over thousands of kilometers in very large power systems. Thousands of generators must operate in synchronism during normal and disturbance conditions. Loss of synchronism of a generator or group of generators with respect to another group of generators is termed *instability* and could result in expensive widespread power blackouts.

The essence of synchronous stability is balance of individual generator electrical and mechanical torques as described by Newton's second law applied to rotation:

$$J\frac{d\omega}{dt} = T_m - T_e$$

where J is the moment of inertia of the generator and prime mover, ω is speed, T_m is mechanical prime mover torque, and T_e is electrical torque related to generator electric power output. The generator speed determines the generator rotor angle changes relative to other generators. Figure 11.21 shows the basic "swing equation" block diagram relationship for a generator connected to a power system.

The conventional equation form and notation are used. The block diagram is explained as follows:

[1]This section is adapted from Chapter 1 of the CIGRE report, *Advanced Angle Stability Controls* (1999), which is based on U.S. government work not covered by copyright.

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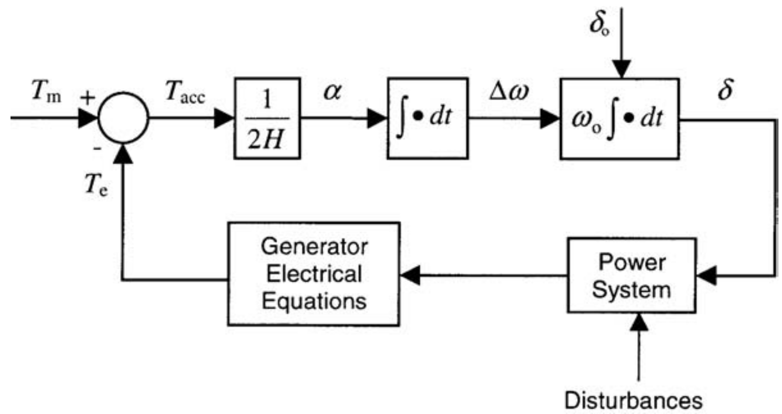

FIGURE 11.21 Block diagram of generator electromechanical dynamics.

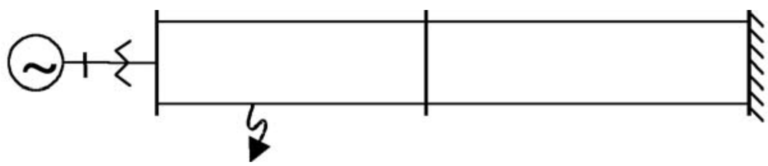

FIGURE 11.22 Remote power plant to large system. Short-circuit location is shown.

- The inertia constant, H, is proportional to the moment of inertia and is the kinetic energy at rated speed divided by the generator MVA rating. Units are MW-seconds/MVA, or seconds.
- T_m is mechanical torque in per unit. As a first approximation it is assumed to be constant. It is, however, influenced by speed controls (governors) and prime mover and energy supply system dynamics.
- ω_o is rated frequency in radians/second.
- δ_o is predisturbance rotor angle in radians relative to a reference generator.
- The power system block comprises the transmission network, loads, power electronic devices, and other generators/prime movers/energy supply systems with their controls. The transmission network is generally represented by algebraic equations. Loads and generators are represented by algebraic and differential equations.
- Disturbances include short circuits, and line and generator outages. A severe disturbance is a three-phase short circuit near the generator. This causes electric power and torque to be zero, with accelerating torque equal to T_m. (Although generator current is very high for the short circuit, the power factor, active current, and active power are close to zero.)

The generator electrical equations block represents the internal generator dynamics. Figure 11.22 shows a simple conceptual model: a remote generator connected to a large power system by two parallel transmission lines with an intermediate switching station. With some approximations adequate for a second or more following a disturbance, the Fig. 11.23 block diagram is realized. The basic relationship between power and torque is $P = T\omega$. Since speed changes are quite small, power is considered equal to torque in per unit. The generator representation is a constant voltage, E', behind a reactance. The transformer and transmission lines are represented by inductive reactances. Using the relation $S = E'I^*$, the generator electrical power is the well-known relation:

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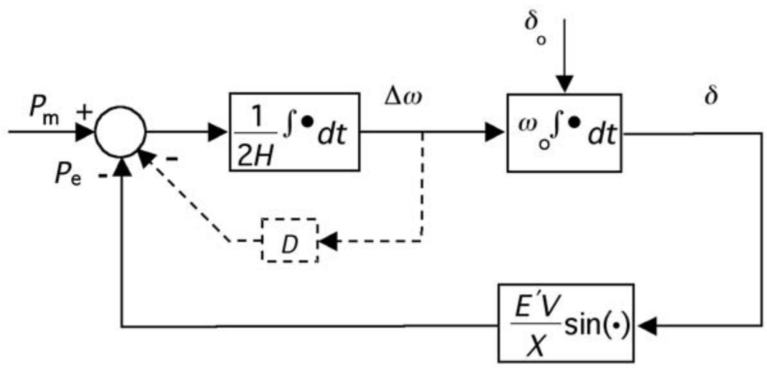

FIGURE 11.23

$$P_e = \frac{E'V}{X}\sin\delta$$

where V is the large system (infinite bus) voltage and X is the total reactance from the generator internal voltage to the large system. The above equation approximates characteristics of a detailed, large-scale model, and illustrates that the power system is fundamentally a highly nonlinear system for large disturbances.

Figure 11.24a shows the relation graphically. The predisturbance operating point is at the intersection of the load or mechanical power characteristic and the electrical power characteristic. Normal stable operation is at δ_o. For example, a small increase in mechanical power input causes an accelerating power that increases δ to increase P_e until accelerating power returns to zero. The opposite is true for the unstable operating point at $\pi - \delta_o$. δ_o is normally less than 45°.

During normal operation, mechanical and electrical torques are equal and a generator runs at close to 50 or 60 Hz rated frequency. If, however, a short circuit occurs (usually with removal of a transmission line), the electric power output will be partially blocked from reaching loads (momentarily) and the generator (or group of generators) will accelerate with increase in generator speed and angle. If the acceleration relative to other generators is too great, synchronism will be lost. Loss of synchronism is an unstable, runaway situation with large variations of voltages and currents that will normally cause protective separation of a generator or a group of generators. Following short-circuit removal, the electrical torque and power developed as angle increases will decelerate the generator. If deceleration reverses angle swing prior to $\pi - \delta_o'$, stability can be maintained at new operating point δ_o' (Fig. 11.24). If the swing is beyond $\pi - \delta_o'$, accelerating power/torque again becomes positive resulting in runaway increase in angle and speed, and instability. Figure 11.24a illustrates the equal area stability criterion for "first swing" stability. If the decelerating area (energy) above the mechanical power load line is greater than the accelerating area below the load line, stability is maintained.

Stability controls increase stability by decreasing the accelerating area or increasing the decelerating area. This may be done by either increasing the electrical power–angle relation, or by decreasing the mechanical power input.

For small disturbances, the block diagram, Fig. 11.23, can be linearized. The block diagram would then be that of a second-order differential equation oscillator. For a remote generator connected to a large system, the oscillation frequency is 0.8 to 1.1 Hz.

Figure 11.23 also shows a damping path (dashed, damping power/torque in phase with speed) that represents mechanical or electrical damping mechanisms in the generator, turbine, loads, and other devices. Mechanical damping arises from the turbine torque-speed characteristic, friction and windage, and components of prime mover control in phase with speed. At an oscillation frequency, the electrical

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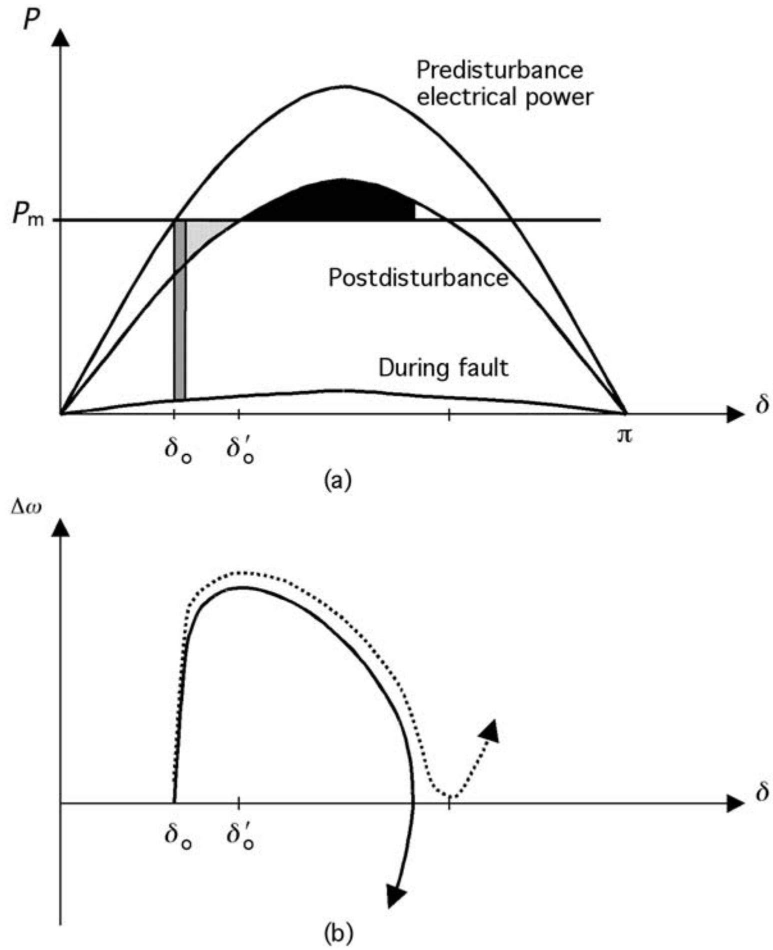

FIGURE 11.24 (a) Power angle curve and equal area criterion. Dark shading for acceleration energy during fault. Light shading for additional acceleration energy because of line outage. Black shading for deceleration energy. (b) Angle-speed phase plane. Dotted line is for unstable case.

power can be resolved into a component in phase with angle (synchronizing power) and a quadrature (90° leading) component in phase with speed (damping power). Controls, notably generator automatic voltage regulators with high gain, can introduce negative damping at some oscillation frequencies. (In any feedback control system, high gain combined with time delays can cause positive feedback and instability.) For stability, the net damping must be positive for both normal conditions and for large disturbances with outages.

Stability controls may also be added to improve damping. In some cases, stability controls are designed to improve both synchronizing and damping torques of generators.

The above analysis can be generalized to large systems. For first swing stability, synchronous stability between two critical groups of generators is of concern. For damping, many oscillation modes are present, all of which require positive damping. The low frequency modes (0.1–0.8 Hz) are most difficult to damp. These modes represent interarea oscillations between large portions of a power system.

Concepts of Power System Stability Controls

Figure 11.25 shows the general structure for analysis of power system stability and for development of power system stability controls.

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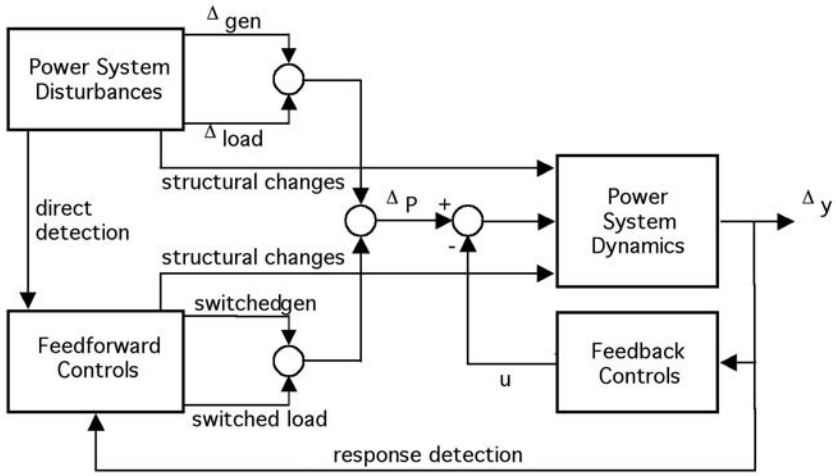

FIGURE 11.25 General power system structure showing stability controls. (From Hauer, J. F., Robustness Issues in Stability Control of Large Electric Power Systems, in *32nd IEEE Conf. Decision and Control,* San Antonio, TX, Dec. 15–17, 1993. With permission.)

Stability problems typically involve disturbances such as short circuits, with subsequent removal of faulted elements. Generation or load may be lost, resulting in generation–load imbalance and frequency excursions. These disturbances stimulate power system electromechanical dynamics. Improperly designed or tuned controls may contribute to stability problems; as mentioned, one example is negative damping torques caused by generator automatic voltage regulators.

Because of power system synchronizing and damping forces (including the feedback controls shown on Fig. 11.25), stability is maintained for most disturbances and operating conditions.

Feedback Controls

The most important feedback (closed-loop) controls are the generator excitation controls (automatic voltage regulator often including power system stabilizer). Other feedback controls include prime mover controls, controls for reactive power compensation such as static var systems, and special controls for HVDC links. These controls are generally linear, continuously active, and based on local measurements.

There are, however, interesting possibilities for very effective discontinuous feedback controls with microprocessors facilitating implementation. Discontinuous controls have certain advantages over continuous controls. Continuous feedback controls are potentially unstable. In complex power systems, continuously controlled equipment may cause adverse modal interactions (Hauer, 1989). Modern digital controls, however, can be discontinuous, and take no action until variables are out-of-range. This is analogous to biological systems (that have evolved over millions of years) that operate on the basis of excitatory stimuli (Studt, 1998).

Bang-bang discontinuous control can operate several times to control large amplitude oscillations, providing time for linear continuous controls to become effective.

If stability is a problem, generator excitation control including power system stabilizers should be high performance.

Feedforward Controls

Also shown on Fig. 11.25 are specialized feedforward (open-loop) controls that are a powerful stabilizing force for severe disturbances and for highly stressed operating conditions. Short circuit or outage events can be directly detected to initiate preplanned actions such as generator or load tripping, or reactive power compensation switching. These controls are rule-based, with rules developed from simulations (i.e., pattern recognition). These "event-based" controls are very effective since rapid control action prevents electromechanical dynamics from becoming stability threatening.

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"Response-based" feedforward controls are also possible. These controls initiate stabilizing actions for arbitrary disturbances that cause significant "swing" of measured variables.

Feedforward controls such as generator or load tripping can ensure a postdisturbance equilibrium with sufficient region of attraction. With fast control action the region of attraction can be small compared to requirements with only feedback controls.

Feedforward controls have been termed discrete supplementary controls (IEEE, 1978), special stability controls (IEEE, 1996), special protection systems, remedial action schemes, and emergency control systems (Djakov et al., 1998).

Feedforward controls are very powerful. Although the reliability of special stability controls is often an issue (IEEE/CIGRE, 1996), adequate reliability can be obtained by design. Generally, controls are required to be as reliable as primary protective relaying. Duplicated or multiple sensors, redundant communications, and duplicated or voting logic are common (Dodge et al., 1990). Response-based controls are often less expensive than event-based controls because fewer sensors and communications paths are needed.

Undesired operation by some feedforward controls are relatively benign, and controls can be "trigger happy." For example, infrequent misoperation or unnecessary operation of HVDC fast power change, reactive power compensation switching, and transient excitation boosting may not be very disruptive. Misoperation of generator tripping (especially of steam-turbine generators), fast valving, load tripping, or controlled separation, however, are disruptive and costly.

Synchronizing and Damping Torques

Power system electromechanical stability means that synchronous generators and motors must remain in synchronism following disturbances — with positive damping of rotor angle oscillations ("swings"). For very severe disturbances and operating conditions, loss of synchronism (instability) occurs on the first forward swing within about one second. For less severe disturbances and operating conditions, instability may occur on the second or subsequent swings because of a combination of insufficient synchronizing and damping torques at synchronous machines.

Effectiveness and Robustness

Power systems have many electromechanical oscillation modes, and each mode can potentially become unstable. Lower frequency interarea modes are the most difficult to stabilize. Controls must be designed to be effective for one or more modes, and must not cause adverse interactions for other modes.

There are recent advances in robust control theory, especially for linear systems. For real nonlinear systems, emphasis should be on knowing uncertainty bounds and on sensitivity analysis using detailed nonlinear, large-scale simulation. For example, the sensitivity of controls to different operating conditions and load characteristics must be studied. Online simulation using actual operating conditions reduces uncertainty, and can be used for control adaptation.

Actuators

Actuators may be mechanical or power electronic. There are tradeoffs between cost and performance. Mechanical actuators (circuit breakers) are lower cost, and are usually sufficiently fast for electromechanical stability (e.g., two-cycle opening time, five-cycle closing time). They have restricted operating frequency and are generally used for feedforward controls.

Circuit breaker technology and reliability have improved in recent years (CIGRE Task Force 13.00.1, 1995; Brunke et al., 1994). Bang-bang control (up to perhaps five operations) for interarea oscillations with periods of two seconds or longer is feasible (Furumasu and Hasibar, 1992). Traditional controls for mechanical switching have been simple relays, but advanced controls can approach the sophistication of controls of, for example, thyristor-switched capacitor banks.

Power electronic phase control or switching using thyristors has been widely used in generator exciters, HVDC, and static var compensators. Newer devices, especially gate-turn-off thyristors, now have voltage

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and current ratings sufficient for high-power transmission applications. Advantages of power electronic actuators are very fast control, unrestricted switching frequency, and minimal transients.

For economy, existing actuators should be used to the extent possible. These include generator excitation and prime mover equipment, HVDC equipment, and circuit breakers. For example, infrequent generator tripping may be cost-effective compared to new power electronic actuated equipment.

Reliability Criteria

Experience shows that instability incidents are usually not caused by three-phase faults near large generating plants that are typically specified in deterministic reliability criteria. Rather they are the result of a combination of unusual failures and circumstances. The three-phase fault reliability criterion is often considered an *umbrella* criterion for less predictable disturbances involving multiple failures such as single-phase short circuits with "sympathetic" tripping of unfaulted lines. Of main concern are multiple *related* failures involving lines on the same right-of-way or with common terminations.

Types of Power System Stability Controls and Possibilities for Advanced Control

Stability controls are of many types, including:

- Generator excitation controls
- Prime mover controls, including fast valving
- Generator tripping
- Fast fault clearing
- High-speed reclosing, and single-pole switching
- Dynamic braking
- Load tripping and modulation
- Reactive power compensation switching or modulation (series and shunt)
- Current injection by voltage source inverter devices (STATCOM, UPFC, SMES, battery storage)
- Fast phase angle control
- HVDC link supplementary controls
- Adjustable-speed (doubly fed) synchronous machines
- Controlled separation and underfrequency load shedding

We will summarize these controls. Chapter 17 of Kundur (1994) provides considerable additional information. Torizuka and Tanaka (1998) describe the use of many of these controls in Japan.

Excitation Control

Generator excitation controls are a basic stability control. Thyristor exciters with high ceiling voltage provide powerful and economical means to ensure stability for large disturbances. Modern automatic voltage regulators and power system stabilizers are digital, facilitating additional capabilities such as adaptive control and special logic (IEEE, 1997; Bollinger et al., 1993; Hajagos and Gerube, 1998; Arcidiancone et al., 1998).

Excitation control is almost always based on local measurements. Therefore, full effectiveness may not be obtained for interarea stability problems where the normal local measurements are not sufficient. Line drop compensation (Rubenstein and Walkley, 1957; Dehdashti et al., 1988) is one method to increase the effectiveness (sensitivity) of excitation control, and improve coordination with static var compensators that normally control transmission voltage with small droop.

Several forms of discontinuous control have been applied to keep field voltage near ceiling levels during the first forward interarea swing (Kundur, 1994; Lee and Kundur, 1986; Taylor et al., 1993). Referring to

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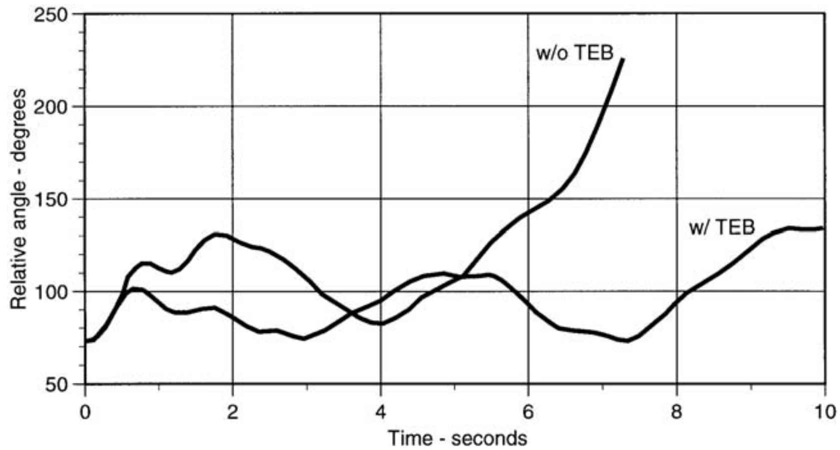

FIGURE 11.26 Rotor angle swing of Grand Coulee Unit 19 in Pacific Northwest relative to the San Onofre nuclear plant in Southern California. The effect of transient excitation boosting (TEB) at the Grand Coulee Third Power Plant following bipolar outage of the Pacific HVDC Intertie (3100 MW) is shown. (From Taylor, C. W., et al., Transient excitation boosting at Grand Coolee Third Power Plant, *IEEE Trans. on Power Syst.*, 8, 1291–1298, August 1993. With permission.)

the above discussion of angle measurement for stability control, the control described in Kundur (1994) and Lee and Kundur (1986) computes change in rotor angle locally from the power system stabilizer (PSS) speed change signal. The control described by Taylor et al. (1993) is a feedforward control that injects a decaying pulse into the voltage regulators at a large power plant following direct detection of a large disturbance. Figure 11.26 shows simulation results using this Transient Excitation Boosting — TEB.

Prime Mover Control Including Fast Valving

Fast power reduction (fast valving) at accelerating sending-end generators is an effective means of stability improvement. Use has been limited, however, because of the coordination required between characteristics of the electrical power system, the prime mover and prime mover controls, and the energy supply system (boiler).

Digital prime mover controls facilitate addition of special features for stability enhancement. Digital boiler controls, often retrofitted on existing equipment, may improve the feasibility of fast valving.

Fast valving is potentially lower cost than tripping of turbo-generators. Kundur (1994) and Bhatt (1996) describe investigations and recent implementations of fast valving. Sustained fast valving may be necessary for a stable postdisturbance equilibrium.

Generator Tripping

Generator tripping is an effective (cost-effective) control especially if hydro units are used. Tripping of fossil units, especially gas- or oil-fired units, may be attractive if tripping to house load is possible and reliable. Gas-turbine and combined-cycle plants constitute a large percentage of new generation. Occasional tripping of these units is feasible and can become an attractive stability control in the future.

Most generator tripping controls are event-based (based on outage of generating plant outgoing lines or outage of tie lines). Several advanced response-based generator tripping controls, however, have been implemented.

The Automatic Trend Relay (ATR) has been implemented at the Colstrip generating plant in eastern Montana (Stigers et al., 1997). The plant consists of two 330 MW units and two 700 MW units. The microprocessor-based controller measures rotor speed and generator power, and computes acceleration and angle. Tripping of 16–100% of plant generation is based on eleven trip algorithms involving acceleration, speed, and angle changes. Because of the long distance to Pacific Northwest load centers, the ATR has operated many times, both desirably and undesirably. There are proposals to use voltage angle

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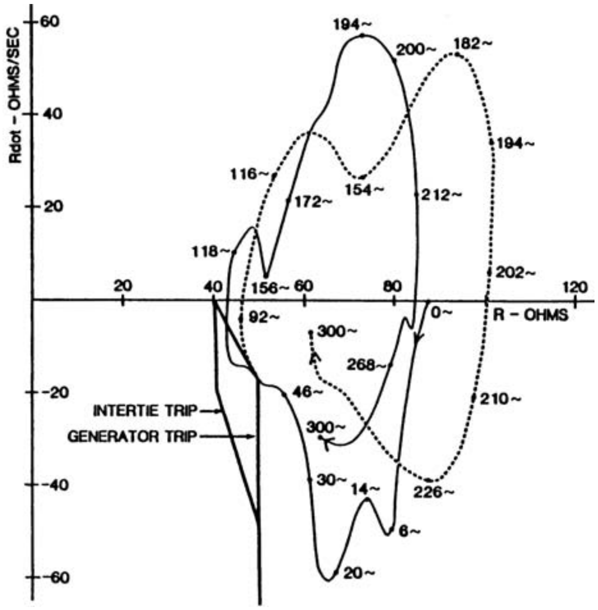

FIGURE 11.27 *R–R*dot phase plane for loss of Pacific HVDC Intertie (2000 MW). Solid trajectory is without additional generator tripping. Dashed trajectory is with additional 600 MW of generator tripping initiated by the *R–R*dot controller generator trip switching line. (From Haner et al., Experience with the R-Rdot out-of-step relay, *IEEE Trans. on Power Delivery,* PWRD-1, 2, 35–39, April 1986. With permission.)

measurement information (Colstrip 500-kV voltage angle relative to Grand Coulee and other Northwest locations) to adaptively adjust ATR settings, or as additional information for trip algorithms. Another possibility is to provide speed or frequency measurements from Grand Coulee and other locations to base algorithms on speed difference rather than only Colstrip speed (Kosterev et al., 1998).

A Tokyo Electric Power Company stabilizing control predicts generator angle changes and decides the minimum number of generators to trip (Matsuzawa et al., 1995). Local generator electric power, voltage, and current measurements are used to estimate angles. The control has worked correctly for several actual disturbances.

The Tokyo Electric Power Company is also developing an emergency control system that uses a predictive prevention method for step-out of pumped storage generators (Kojima et al., 1997; Imai et al., 1998). In the new method, the generators in TEPCO's network, which swing against their local pumped storage generators after serious faults, are treated as an external power system. The parameters in the external system, such as angle and moment of inertia, are estimated using local online information, and the behavior of local pumped storage generators is predicted based on equations of motion. Control actions (the number of generators to be tripped) are determined based on the prediction.

Haner et al. (1986) describe response-based generator tripping using a phase-plane controller. The controller is based on the apparent resistance — rate-of-change of apparent resistance (*R–R*dot) phase plane, which is closely related to an angle difference — speed difference phase plane between two areas. The primary use of the controller is for controlled separation of the Pacific AC Intertie. Figure 11.27 shows simulation results where 600 MW of generator tripping reduces the likelihood of controlled separation.

Fast Fault Clearing, High Speed Reclosing, and Single-Pole Switching

Clearing time of close-in faults can be less than three cycles using conventional protective relays and circuit breakers. Typical EHV circuit breakers have two-cycle opening time. One-cycle breakers have been developed (Berglund et al., 1974), but special breakers are seldom justified. High magnitude short circuits may be detected as fast as one-fourth cycle by nondirectional overcurrent relays. Ultra high-speed

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traveling wave relays are also available (Esztergalyos et al., 1978). With such short clearing times, and considering that most EHV faults are single-phase, the removed transmission lines or other elements may be the major contributor to generator acceleration. This is especially true if nonfaulted equipment is removed by "sympathetic" relaying.

High speed reclosing is an effective method of improving stability and reliability. Reclosing is before the maximum of the first forward angular swing, but after 30–40 cycle time for arc extinction. During a lightning storm, high-speed reclosing keeps the maximum number of lines in service. High speed reclosing is effective when unfaulted lines trip because of relay misoperations.

Unsuccessful high-speed reclosing into a permanent fault can cause instability and can also compound the torsional duty imposed on turbine-generator shafts. Solutions include reclosing only for single-phase faults, and reclosing from the weak end with hot-line checking prior to reclosing at the generator end. Communication signals from the weak end indicating successful reclosing can also be used to enable reclosing at the generator end (Behrendt, 1996).

Single-pole switching is a practical means to improve stability and reliability in extra high voltage networks where most circuit breakers have independent pole operation (IEEE Committee, 1986; Belotelov et al., 1998). Several methods are used to ensure secondary arc extinction. For short lines, no special methods are needed. For long lines, the four-reactor scheme (Knutsen, 1962; Kimbark, 1964) is most commonly used. High speed grounding switches may be used (Hasibar et al., 1981). A hybrid reclosing method used by Bonneville Power Administration employs single-pole tripping, but with three-pole tripping on the backswing followed by rapid three-pole reclosure; the three-pole tripping ensures secondary arc extinction (IEEE Committee, 1986).

Single-pole switching may necessitate positive sequence filtering in stability control input signals.

For advanced stability control, signal processing and pattern recognition techniques may be developed to detect secondary arc extinction (Finton et al., 1996; Djuric and Terzija, 1995). Reclosing into a fault is avoided and single-pole reclosing success is improved.

High speed reclosing or single-pole switching may not allow increased power transfers because deterministic reliability criteria generally specifies permanent faults. Nevertheless, fast reclosing provides "defense-in-depth" for frequently occurring single-phase temporary faults and false operation of protective relays. The probability of power failures because of multiple line outages is greatly reduced.

Dynamic Braking

Shunt dynamic brakes using mechanical switching have been used infrequently (Kundur, 1994). Normally the insertion time is fixed. One attractive method not requiring switching is neutral-to-ground resistors in generator step-up transformers. Braking automatically results for ground faults, which are most common.

Often generator tripping, which helps ensure a post-disturbance equilibrium, is a better solution.

Thyristor switching of dynamic brakes has been proposed. Thyristor switching or phase control minimizes generator torsional duty (Bayer et al., 1996), and can be a subsynchronous resonance countermeasure (Donnelly et al., 1993).

Load Tripping and Modulation

Load tripping is similar in concept to generator tripping but is at the receiving end to reduce deceleration of receiving-end generation. Interruptible industrial load is commonly used. For example, Taylor et al. (1981) describe tripping of up to 3000 MW of industrial load following outages during power import conditions.

Rather than tripping large blocks of industrial load, it may be possible to trip low priority commercial and residential load such as space and water heaters, or air conditioners. This is less disruptive and the consumer may not even notice brief interruptions. The feasibility of this control depends on implementation of direct load control as part of demand side management, and on the installation of high-speed communication links to consumers with high-speed actuators at load devices. Although unlikely because

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of economics, appliances such as heaters could be designed to provide frequency sensitivity by local measurements.

Load tripping is also used for voltage stability. Here the communication and actuator speeds are generally not as critical.

It is also possible to modulate loads such as heaters to damp oscillations (Samuelsson and Eliasson, 1997; Kamwa et al., 1998; Dagle, 1997).

Clearly, load tripping or modulation of small loads will depend on the economics, and the development of fast communications and actuators.

Reactive Power Compensation Switching or Modulation

Controlled series or shunt compensation improves stability, with series compensation generally being the most powerful. For switched compensation, either mechanical or power electronic switches may be used. For continuous modulation, thyristor phase control of a reactor (TCR) is used. Mechanical switching has the advantage of lower cost. The operating times of circuit breakers are usually adequate, especially for interarea oscillations. Mechanical switching is generally single insertion of compensation for synchronizing support. In addition to previously mentioned advantages, power electronic control has advantages in subsynchronous resonance performance.

For synchronizing support, high-speed series capacitor switching has been used effectively on the North American Pacific AC intertie for over 25 years (Kimbark, 1966). The main application is for full or partial outages of the parallel Pacific HVDC intertie (event-driven control using transfer trip over microwave radio). Series capacitors are inserted by circuit breaker opening; operators bypass the series capacitors some minutes after the event. Response-based control using an impedance relay was also used for some years, and new response-based controls are being investigated.

Thyristor-based series compensation switching or modulation has been developed, with several installations in service or planned (Cristi et al., 1992; Piwko et al., 1994; Zhou et al., 1988). Thyristor-controlled series compensation (TCSC) allows significant time-current dependent increase in series reactance over nominal reactance. With appropriate controls, this increase in reactance can be a powerful stabilizing force.

Thyristor-controlled series compensation was chosen for the 1020 km, 500-kV intertie between the Brazilian North–Northeast networks and the Brazilian Southeast network (Gama et al., 1998). The TCSCs at each end of the intertie are modulated using line power measurements to damp low-frequency (0.12 Hz) oscillations. Figure 11.28, from commissioning field tests (Gama, 1999), shows the powerful stabilizing benefits of TCSCs.

Zhou et al. (1998) describe a TCSC application in China for integration of a remote power plant using two parallel 500-kV transmission lines (1300 km). Transient stability simulations indicate that 25% thyristor-controlled compensation is more effective than 45% fixed compensation. Several advanced TCSC control techniques are promising. The state-of-the-art is to provide both transient stability and damping control modes.

Zhou and Liang (1999) surveyed TCSC stability controls, providing 85 references.

For synchronizing support, high speed switching of shunt capacitor banks is also effective. Again on the Pacific AC intertie, four 200 MVAr shunt banks are switched for HVDC and 500-kV AC line outages (Furumasu and Hasibar, 1992); new response-based controls are being investigated.

High speed mechanical switching of shunt banks as part of a static var system is common. For example, the Forbes SVS near Duluth, Minnesota, includes two 300 MVAr 500-kV shunt capacitor banks (Sybille et al., 1996). Generally, it is effective to augment power electronic controlled compensation with fixed or mechanically switched compensation.

Static var compensators are applied along interconnections to improve synchronizing and damping support. Voltage support at intermediate points allow operation at angles above 90°. SVCs are modulated to improve oscillation damping. One study (CIGRE, 1996; Larsen and Chow, 1987) showed line current magnitude to be the most effective input signal. Synchronous condensers can provide similar benefits,

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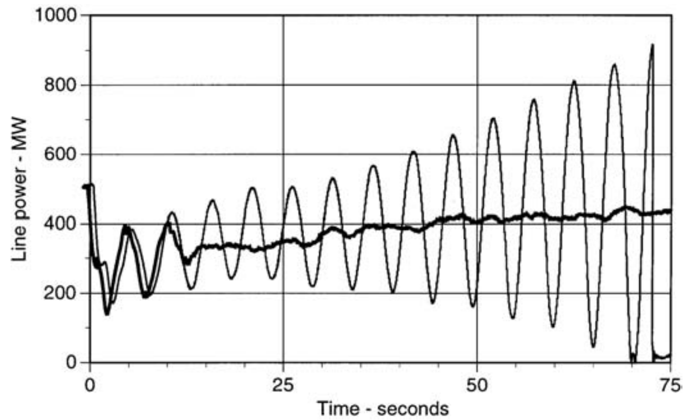

FIGURE 11.28 Effect of TCSCs for trip of a 300 MW generator in the North–Northeast Brazilian network. Results are from commissioning field tests in March 1999. The thin line without TCSC power oscillation damping shows interconnection separation after 70 seconds. The thick line with TCSC power oscillation damping shows rapid oscillation damping.

but are not competitive today with power electronic control. Available SVCs in load areas may be used to indirectly modulate load to provide synchronizing or damping forces.

Digital control allows many new control strategies. Gains in supervision and optimization adaptive control are common. For series or shunt power electronic devices, control mode selection allows bang-bang control, synchronizing versus damping control, and other nonlinear and adaptive strategies.

Current Injection by Voltage Source Inverters

Advanced power electronic controlled equipment employ gate turn-off thyristors. Reactive power injection devices include static compensator (STATCOM), static synchronous series compensator (SSSC), and unified power flow controller (UPFC). CIGRE Task Force 38.01.07 (1996) describes the use of these devices for oscillation damping.

As with conventional thyristor-based equipment, it is often effective for voltage source inverter control to also direct mechanical switching.

Voltage source inverters may also be used for real power series or shunt injection. Superconducting magnetic energy storage (SMES) or battery storage is the most common. For angle stability control, injection of real power is more effective than reactive power.

For transient stability improvement, SMES can be smaller MVA size and lower cost than a STATCOM. SMES is less location-dependent than a STATCOM.

Fast Voltage Phase Angle Control

Voltage phase angles, and thereby rotor angles, can be directly and rapidly controlled by power electronic controlled series compensation (discussed above) or phase shifting transformers. This provides powerful stability control. Although one type of thyristor-controlled phase shifting transformer was developed over fifteen years ago (Stemmler and Güth, 1982), high cost has presumably prevented installations. Fang and MacDonald (1998) describe an application study.

The unified power flow controller incorporates GTO-thyristor phase shifting and series compensation control, and one installation (not a transient stability application) is in service (Rahman et al., 1997).

One concept employs power electronic series or phase shifting equipment to control angles across an interconnection within a small range (Christensen, 1997). On a power–angle curve, this can be visualized as keeping high synchronizing coefficient (slope of power–angle curve) during disturbances.

Bonneville Power Administration developed a novel method for transient stability by high speed 120° phase rotation of transmission lines between networks losing synchronism (Cresap et al., 1981). This

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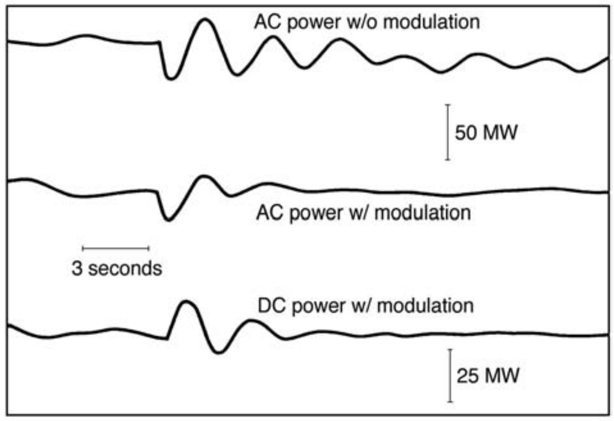

FIGURE 11.29 System response to Pacific AC Intertie series capacitor bypass with and without DC modulation. (From Cresap et al., Operating experience with modulation of the Pacific HVDC intertie, *IEEE Trans. on Power Appar. and Syst.,* PAS-98, 1053–1059, July/August 1978. With permission.)

technique is very powerful (perhaps too powerful!) and raises reliability and robustness issues, especially in the usual case where several lines form the interconnection. It has not been implemented.

HVDC Link Supplementary Controls

HVDC DC links are installed for power transfer reasons. In contrast to the above power electronic devices, the available HVDC converters provide the actuators so that stability control is inexpensive. For long distance HVDC links within a synchronous network, HVDC modulation can provide powerful stabilization, with active and reactive power injections at each converter. Control robustness, however, is a concern.

HVDC link stability controls are described in CIGRE (1996), IEEE (1991), and reports by Cresap et al. (1978). The Pacific HVDC Intertie modulation control implemented in 1976 is unique in that a remote input signal from the parallel Pacific AC Intertie was used (Cresap et al., 1978). Figure 11.29 shows commissioning test results.

Adjustable Speed (Doubly Fed) Synchronous Machines

CIGRE (1996) summarizes stability benefits of adjustable speed synchronous machines that have been developed for pumped storage applications in Japan. Fast digital control of excitation frequency enables direct control of rotor angle.

Controlled Separation and Underfrequency Load Shedding

For very severe disturbances and failures, maintaining synchronism may not be possible or cost effective. Controlled separation based on out-of-step detection or parallel path outages mitigates the effects of instability. Stable islands are formed, but underfrequency load shedding may be required in islands that were importing power.

Advanced controlled separation schemes are described in Ohura et al. (1990), Haner et al. (1986), Taylor et al. (1983), and Centeno et al. (1997). Recent proposals advocate use of voltage phase angle measurements for controlled separation.

Dynamic Security Assessment

Control design and settings, along with transfer limits, are usually based on off-line simulation (time and frequency domain), and on field tests. Controls must then operate appropriately for a variety of operating conditions and disturbances.

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Recently, however, online dynamic (or transient) stability/security assessment software has been developed. State estimation and online power flow determine the base operating conditions. Simulation of potential disturbances is then based on actual operating conditions, reducing uncertainty of the control environment. Dynamic security assessment is presently used to determine arming levels for generator tripping controls (Mansour et al., 1995; Ota et al., 1996).

With today's computer capabilities, hundreds or thousands of large-scale simulations may be run each day to provide an organized database of system stability properties. Security assessment is made efficient by techniques such as fast screening and contingency selection, and smart termination of strongly stable or unstable cases. Parallel computation is straightforward using multiple workstations for different simulation cases; common initiation may be used for the different contingencies.

In the future, dynamic security assessment may be used for control adaptation to current operating conditions. Another possibility is stability control based on neural network or decision tree pattern recognition. Dynamic security assessment provides the database for pattern recognition techniques. Pattern recognition may be considered data compression of security assessment results.

Industry restructuring requiring near real-time power transfer capability determination may accelerate the implementation of dynamic security assessment, facilitating advanced stability controls.

"Intelligent" Controls

Mention has already been made of rule-based controls and pattern recognition based controls.

As a possibility, Chiang and Wong (1995) describes a sophisticated self-organizing neural fuzzy controller (SONFC) based on the speed–acceleration phase plane. Compared to the angle–speed phase plane, control tends to be faster and both final states are zero (using angle, the postdisturbance equilibrium angle is not known in advance). The controllers are located at generator plants. Acceleration and speed can be easily measured/computed using, for example, the techniques developed for power system stabilizers.

The SONFC could be expanded to incorporate remote measurements. Dynamic security assessment simulations could be used for updating/retraining of the neural network fuzzy controller. The SONFC is suitable for generator tripping, series or shunt capacitor switching, HVDC control, etc.

Effect of Industry Restructuring on Stability Controls

Industry restructuring will have much impact on power system stability. New, frequently changing power transfer patterns cause new stability problems. Most stability and transfer capability problems must be solved by new controls and new substation equipment, rather than by new transmission lines.

Different ownership of generation, transmission, and distribution makes necessary power *system* engineering more difficult. New power industry standards along with ancillary services mechanisms are being developed. Controls such as generator or load tripping, fast valving, higher than standard exciter ceilings, and power system stabilizers may be ancillary services. In large interconnections, independent grid operators or security coordination centers may facilitate dynamic security assessment and centralized stability controls.

Experience from Recent Power Failures

Recent cascading power outages demonstrated the impact of control and protection failures, the need for "defense-in-depth," and the need for advanced stability controls.

The July 2, 1996, and August 10, 1996, power failures (WSCC, 1996; Taylor and Erickson, 1997; Hauer et al., 1997; Kosterev et al., 1999) in western North America showed need for improvements and innovations in stability control areas such as:

- Fast insertion of reactive power compensation, and fast generator tripping using response-based controls.
- Special HVDC and SVC control.

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- Power system stabilizer design and tuning.
- Controlled separation.
- Power system modeling and data validation for control design.
- Adaptation of controls to actual operating conditions.

Summary

Power system angle stability can be improved by a wide variety of controls. Some methods have been used effectively for many years, both at generating plants and in transmission networks. New control techniques and actuating equipment are promising.

We provide a broad survey of available stability control techniques with emphasis on implemented controls, and on new and emerging technology.

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11.7 Power System Dynamic Modeling

William W. Price

Modeling Requirements

Analysis of power system dynamic performance requires the use of computational models representing the nonlinear differential-algebraic equations of the various system components. While scale models or analog models are sometimes used for this purpose, most power system dynamic analysis is performed

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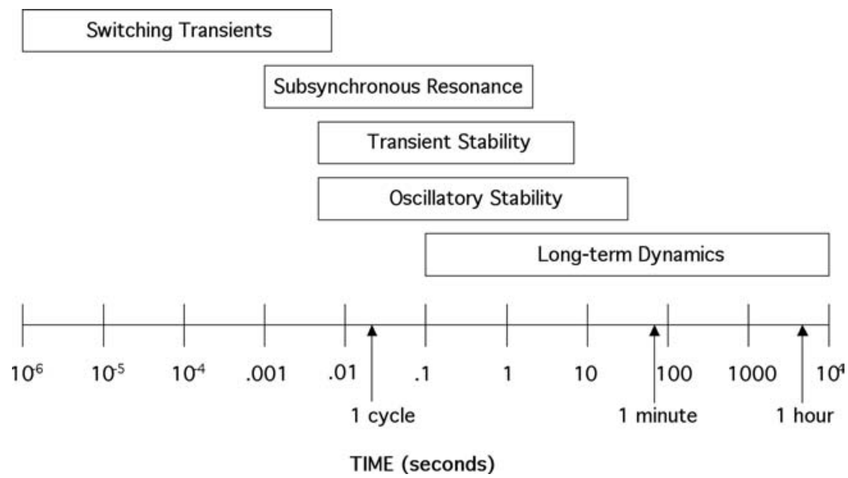

FIGURE 11.30 Time scale of power system dynamic phenomena.

with digital computers using specialized programs. These programs include a variety of models for generators, excitation systems, governor-turbine systems, loads, and other components. The user is therefore concerned with selecting the appropriate models for the problem at hand and determining the data to represent the specific equipment on his or her system. The focus of this article is on these concerns.

The choice of appropriate models depends heavily on the time scale of the problem being analyzed. Figure 11.30 shows the principal power system dynamic performance areas displayed on a logarithmic time scale ranging from microseconds to days. The lower end of the band for a particular item indicates the smallest time constants that need to be included for adequate modeling. The upper end indicates the approximate length of time that must be analyzed. It is possible to build a power system simulation model that includes all dynamic effects from very fast network inductance/capacitance effects to very slow economic dispatch of generation. However, for efficiency and ease of analysis, normal engineering practice dictates that only models incorporating the dynamic effects relevant to the particular performance area of concern be used.

This section focuses on the modeling required for analysis of power system stability, including transient stability, oscillatory stability, voltage stability, and frequency stability. For this purpose, it is normally adequate to represent the electrical network elements (transmission lines and transformers) by algebraic equations. The effect of frequency changes on the inductive and capacitive reactances is sometimes included, but is usually neglected, since for most stability analysis the frequency changes are small. The modeling of the various system components for stability analysis purposes is discussed in the remainder of this section. For greater detail, the reader is referred to (Kundur, 1994) and the other references cited below.

Generator Modeling

The model of a generator consists of two parts: the acceleration equations of the turbine-generator rotor, and the generator electrical flux dynamics.

Rotor Mechanical Model

The acceleration equations are simply Newton's Second Law of Motion applied to the rotating mass of the turbine-generator rotor, as shown in block diagram form in Fig. 11.31. The following points should be noted:

1. The inertia constant (H) represents the stored energy in the rotor in MW-seconds, normalized to the MVA rating of the generator. Typical values are in the range of 3 to 15, depending on the type and size of the turbine-generator. If the inertia (J) of the rotor is given in kg-m/sec, H is computed as follows:

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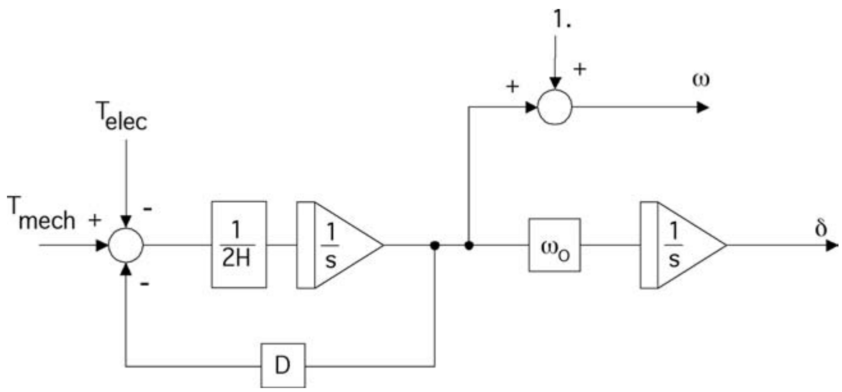

FIGURE 11.31 Generator rotor mechanical model.

$$H = 5.48 \times 10^{-9} \frac{J\left(RPM\right)^2}{MVARating} \; MW\text{-}sec/MVA$$

2. Sometimes the mechanical power and electrical power are used in this model instead of the corresponding torques. Since power equals torque multiplied by rotor speed, the difference is small for operation close to nominal speed. However, there will be some effect on the damping of oscillations (*IEEE Trans.,* Feb. 1999).
3. Most models include the damping factor (D) shown in Fig. 11.31. It is used to model oscillation damping effects that are not explicitly represented elsewhere in the system model. The selection of a value for this parameter has been the subject of much debate (*IEEE Trans.,* Feb. 1999). Values from 0 to 4 or higher are sometimes used. The recommended practice is to avoid the use of this parameter by including sources of damping in other models, e.g., generator amortisseur and eddy current effects, load frequency sensitivity, etc.

Generator Electrical Model

The equivalent circuit of a three-phase synchronous generator is usually rendered as shown in Fig. 11.32. The three phases are transformed into a two-axis equivalent, with the direct (d) axis in phase with the rotor field winding and the quadrature (q) axis 90 electrical degrees ahead. For a more complete discussion of this transformation and of generator modeling, see IEEE Std. 1110-1991. In this equivalent circuit, r_a and L_ℓ represent the resistance and leakage inductance of the generator stator, L_{ad} and L_{aq} represent the mutual inductance between stator and rotor, and the remaining elements represent rotor windings or equivalent windings. This equivalent circuit assumes that the mutual coupling between the rotor windings and between the rotor and stator windings are the same. Additional elements can be added (IEEE Std. 1110-1991) to account for unequal mutual coupling, but most models do not include this since the data is difficult to obtain and the effect is small.

The rotor circuit elements may represent either physical windings on the rotor or eddy currents flowing in the rotor body. For solid-iron rotor generators such as steam-turbine generators, the field winding to which the DC excitation voltage is applied, is normally the only physical winding. However, additional equivalent windings are required to represent the effects of eddy currents induced in the body of the rotor. Salient-pole generators, typically used for hydro-turbine generators, have laminated rotors with lower eddy currents. However, these rotors often have additional amortisseur (damper) windings embedded in the rotor.

Data for generator modeling are usually supplied as synchronous, transient, and subtransient inductances and open circuit time constants. The relationships between these parameters and the equivalent network elements are shown in Table 11.1. Note that the inductance values are often referred to as

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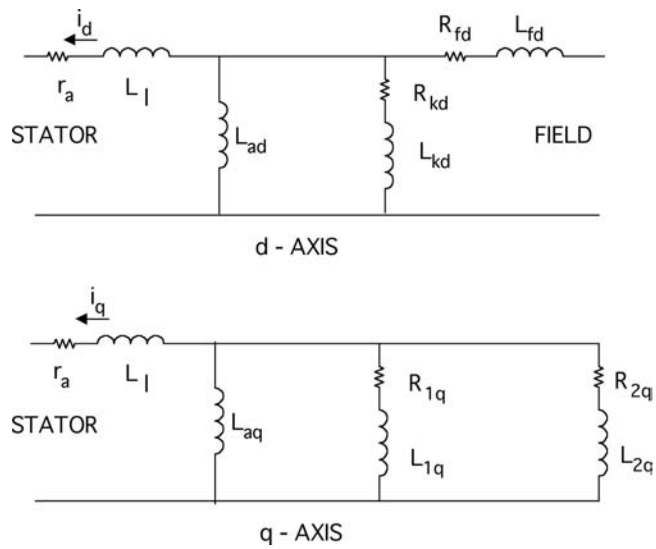

FIGURE 11.32 Generator equivalent circuit.

TABLE 11.1 Generator Parameter Relationships

	d-axis	q-axis
Synchronous inductance	$L_d = L_\ell + L_{ad}$	$L_q = L_\ell + L_{aq}$
Transient inductance	$L'_d = L_\ell + \dfrac{L_{ad}L_{fd}}{L_{ad} + L_{fd}}$	$L'_q = L_\ell + \dfrac{L_{aq}L_{1q}}{L_{aq} + L_{1q}}$
Subtransient inductance	$L''_d = L_\ell + \dfrac{L_{ad}L_{fd}L_{kd}}{L_{ad}L_{fd} + L_{ad}L_{kd} + L_{fd}L_{kd}}$	$L''_q = L_\ell + \dfrac{L_{aq}L_{1q}L_{2q}}{L_{aq}L_{1q} + L_{aq}L_{2q} + L_{1q}L_{2q}}$
Transient open circuit time constant	$T'_{do} = \dfrac{L_{ad} + L_{fd}}{\omega_0 R_{fd}}$	$T'_{qo} = \dfrac{L_{aq} + L_{1q}}{\omega_0 R_{1q}}$
Subtransient open circuit time constant	$T''_{do} = \dfrac{L_{ad}L_{fd} + L_{ad}L_{kd} + L_{fd}L_{kd}}{\omega_0 R_{kd}\left(L_{ad} + L_{fd}\right)}$	$T''_{qo} = \dfrac{L_{aq}L_{1q} + L_{aq}L_{2q} + L_{1q}L_{2q}}{\omega_0 R_{2q}\left(L_{aq} + L_{1q}\right)}$

reactances. At nominal frequency, the per unit inductance and reactance values are the same. However, as used in the generator model, they are really inductances, which do not change with changing frequency.

These parameters are normally supplied by the manufacturer. Two values are often given for some of the inductance values, a saturated (rated voltage) and unsaturated (rated current) value. The unsaturated values should be used, since saturation is usually accounted for separately, as discussed below.

For salient-pole generators, one or more of the time constants and inductances may be absent from the data, since fewer equivalent circuits are required. Depending on the program, either separate models are provided for this case or the same model is used with certain parameters set to zero or equal to each other.

Saturation Modeling

Magnetic saturation effects may be incorporated into the generator electrical model in various ways. The data required from the manufacturer is the open-circuit saturation curve, showing generator terminal voltage vs. field current. If the field current is given in amperes, it can be converted to per unit by dividing by the field current at rated terminal voltage on the air-gap (no saturation) line. (This value of field

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current is sometimes referred to as AFAG.) Often the saturation data for a generator model is input as only two points on the saturation curve, e.g., at rated voltage and 120% of rated voltage. The model then automatically fits a curve to these points.

The open circuit saturation curve characterizes saturation in the d-axis only. Ideally, saturation of the q-axis should also be represented, but the data for this is difficult to determine and is usually not provided. Some models provide an approximate representation of q-axis saturation based on the d-axis saturation data (IEEE Std. 1110-1991).

Excitation System Modeling

The excitation system provides the DC voltage to the field winding of the generator and modulates this voltage for control purposes. There are many different configurations and designs of excitation systems. Stability programs usually include a variety of models capable of representing most systems. These models normally include the IEEE standard excitation system models, described in IEEE Standard 421.5 (1992). Reference should be made to that document for a description of the various models and typical data for commonly used excitation system designs.

The excitation system consists of several subsystems, as shown in Fig. 11.33. The excitation power source provides the DC voltage and current at the levels required by the generator field. The excitation power may be provided by a rotating exciter, either a DC generator or an AC generator (alternator) and rectifier combination, or by rectifiers supplied from the generator terminals (or other AC source). Excitation systems with these power sources are often classified as "DC," "AC," and "static," respectively. The maximum (ceiling) field voltage available from the excitation power source is an important parameter. Depending on the type of system, this ceiling voltage may be affected by the magnitude of the field current or the generator terminal voltage, and this dependency must be modeled since these values may change significantly during a disturbance.

The automatic voltage regulator (AVR) provides for control of the terminal voltage of the generator by changing the generator field voltage. There are a variety of designs for the AVR, including various means of ensuring stable response to transient changes in terminal voltage. The speed with which the field voltage can be changed is an important characteristic of the system. For the "DC" and most of the "AC" excitation systems, the AVR controls the field of the exciter. Therefore, the speed of response is limited by the exciter's time constant. The speed of response of excitation systems is characterized according to IEEE Standard 421.2 (1990).

A power system stabilizer (PSS) is frequently, but not always, included in an excitation system. It is designed to modulate the AVR input in such a manner as to contribute damping to intermachine oscillations. The input to the PSS may be generator rotor speed, electrical power, or other signals. The PSS usually is designed with linear transfer functions whose parameters are tuned to produce positive damping for the range of oscillation frequencies of concern. It is important that reasonably correct values be used for these parameters. The output of the PSS is limited, usually to ±5% of rated generator terminal voltage, and this limit value must be included in the model.

The excitation system includes several other subsystems designed to protect the generator and excitation system from excessive duty under abnormal operating conditions. Normally, these limiters and protective modules do not come into play for analysis of transient and oscillatory stability. However, for longer-term simulations, particularly related to voltage instability, overexcitation limiters (OEL) and under-excitation limiters (UEL) may need to be modeled. While there are many designs for these limiters, typical systems are described in *IEEE Trans.* (Dec. and Sept., 1995).

Prime Mover Modeling

The system that drives the generator rotor is often referred to as the prime mover. The prime mover system includes the turbine (or other engine) driving the shaft, the speed control system, and the energy supply system for the turbine. The following are the most common prime mover systems:

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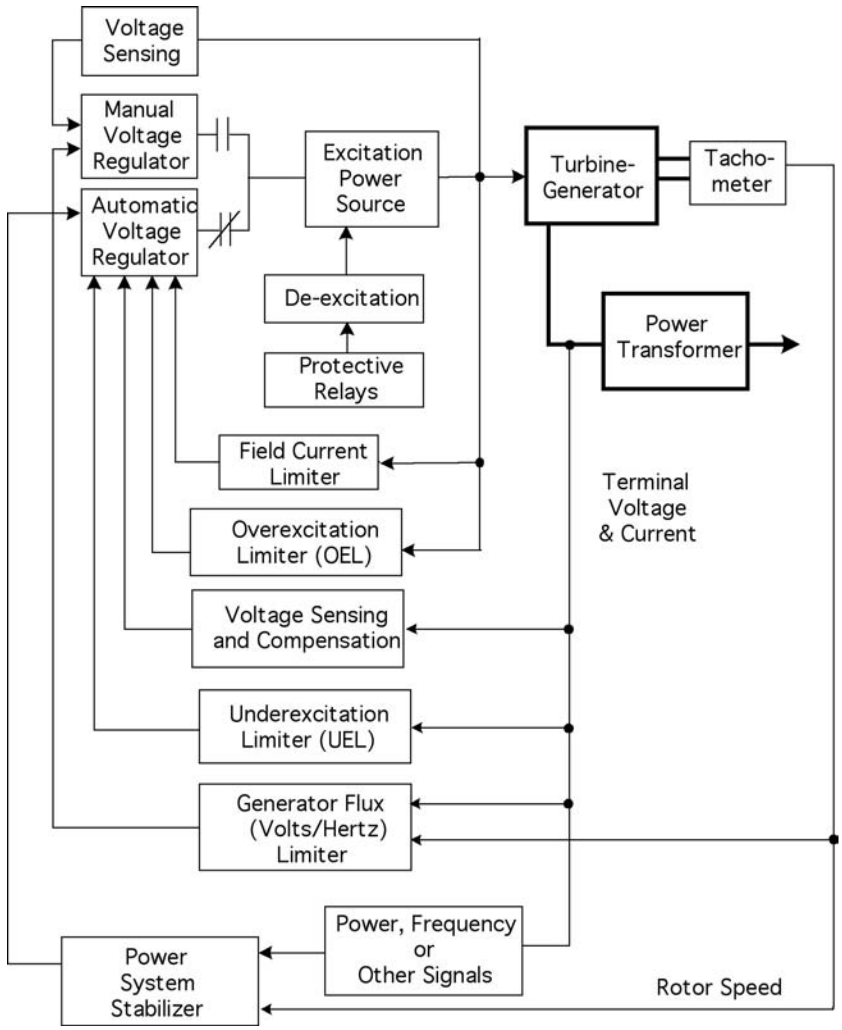

FIGURE 11.33 Excitation system model structure.

- Steam turbine
  - Fossil fuel (coal, gas, or oil) boiler
  - Nuclear reactor
- Hydro turbine
- Combustion turbine (gas turbine)
- Combined cycle (gas turbine and steam turbine)

Other less common, and generally smaller prime movers include wind turbine, geothermal steam turbine, solar thermal steam turbine, and diesel engine.

For analysis of transient and oscillatory stability, greatly simplified models of the prime mover are sufficient since, with some exceptions, the response times of the prime movers to system disturbances are slow compared with the time duration of interest, typically 10 to 20 sec or less. For simple transient stability analysis of only a few seconds duration, the prime mover model may be omitted altogether by assuming that the mechanical power output of the turbine remains constant. An exception is for a steam-turbine system equipped with "fast valving" or "early valve actuation" (EVA). These systems are designed

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to reduce turbine power output rapidly for nearby faults by quickly closing the intercept valves between the high-pressure and low-pressure turbine sections (Younkins et al., 1987).

For analysis of disturbances involving significant frequency excursions, the turbine and speed control (governor) systems must be modeled. Simplified models for steam and hydro turbine-governor systems are given in *IEEE Trans.* (Dec. 1973; Feb. 1992) and these models are available in most stability programs. Models for gas turbines and combined cycle plants are less standard, but typical models have been described in several references (Rowan, 1983; Hannett and Khan, 1993; *IEEE Trans.,* Aug. 1994).

For long-term simulations involving system islanding and large frequency excursions, more detailed modeling of the energy supply systems may be necessary. There are a great many configurations and designs for these systems. Models for typical systems have been published (*IEEE Trans.,* May 1991). However, detailed modeling is often less important than incorporating key factors that affect the plant response, such as whether the governor is in service and where the output limits are set.

For a fossil fuel steam plant, the coordination between the speed control and steam pressure control systems has an important impact on the speed with which the plant will respond to frequency excursions. If the governor directly controls the turbine valves (boiler-follow mode), the power output of the plant will respond quite rapidly, but may not be sustained due to reduction in steam pressure. If the governor controls fuel input to the boiler (turbine-follow mode), the response will be much slower but can be sustained. Modern coordinated controls will result in an intermediate response to these two extremes. The plant response will also be slowed by the use of "sliding pressure" control, in which valves are kept wide open and power output is adjusted by changing the steam pressure.

Hydro plants can respond quite rapidly to frequency changes if the governors are active. Some reduction in transient governor response is often required to avoid instability due to the "nonminimum phase" response characteristic of hydro turbines, which causes the initial response of power output to be in the opposite of the expected direction. This characteristic can be modeled approximately by the simple transfer function: $(1 - sT_w)/(1 + sT_w/2)$. The parameter T_w is called the water starting time and is a function of the length of the penstock and other physical dimensions. For high-head hydro plants with long penstocks and surge tanks, more detailed models of the hydraulic system may be necessary.

Gas (combustion) turbines can be controlled very rapidly, but are often operated at maximum output (base load), as determined by the exhaust temperature control system, in which case they cannot respond in the upward direction. However, if operated below base load, they may be able to provide output in excess of the base load value for a short period following a disturbance, until the exhaust temperature increases to its limit. Typical models for gas turbines and their controls are found in Rowan (1983) and *IEEE Trans.* (Feb. 1993).

Combined cycle plants come in a great variety of configurations, which makes representation by a typical model difficult (*IEEE Trans.,* 1994). The steam turbine is supplied from a heat recovery steam generator (HRSG). Steam is generated by the exhaust from the gas turbine(s), sometimes with supplementary firing. Often the power output of the steam turbine is not directly controlled by the governor, but simply follows the changes in gas turbine output as the exhaust heat changes.

Load Modeling

For dynamic performance analysis, the transient and steady-state variation of the load P and Q with changes in bus voltage and frequency must be modeled. Accurate load modeling is difficult due to the complex and changing nature of the load and the difficulty in obtaining accurate data on its characteristics. Therefore, sensitivity studies are recommended to determine the impact of the load characteristics on the study results of interest. This will help to guide the selection of a conservative load model or focus attention on where load modeling improvements should be sought.

For most power system analysis purposes, "load" refers to the real and reactive power supplied to lower voltage subtransmission or distribution systems at buses represented in the network model. In addition to the variety of actual load devices connected to the system, the "load" includes the intervening distribution feeders, transformers, shunt capacitors, etc. and may include voltage control devices, including

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automatic tap-changing transformers, induction voltage regulators, automatically switched capacitors, etc.

For transient and oscillatory stability analysis, several levels of detail can be used, depending on the availability of information and the sensitivity of the results to the load modeling detail. *IEEE Trans.* (May 1993 and Aug. 1995) discuss recommended load modeling procedures. A brief discussion is given below.

1. **Static load model** — The simplest model is to represent the active and reactive load components at each bus by a combination of constant impedance, constant current, and constant power components, with a simple frequency sensitivity factor, as shown in the following formula:

$$P = P_0\left[P_1\left(\frac{V}{V_0}\right)^2 + P_2\left(\frac{V}{V_0}\right) + P_3\right]\left(1 + L_{DP}\Delta f\right)$$

$$Q = Q_0\left[Q_1\left(\frac{V}{V_0}\right)^2 + Q_2\left(\frac{V}{V_0}\right) + Q_3\right]\left(1 + L_{DQ}\Delta f\right)$$

   If nothing is known about the characteristics of the load, it is recommended that constant current be used for the real power and constant impedance for the reactive power, with frequency factors of 1 and 2, respectively. This is based on the assumption that typical loads are about equally divided between motor loads and resistive (heating) loads.

   Most stability programs provide for this type of load model, often called a ZIP model. Sometimes an exponential function of voltage is used instead of the three separate voltage terms. An exponent of 0 corresponds to constant power, 1 to constant current, and 2 to constant impedance. Intermediate values or larger values can be used if available data so indicates. The following, more general model, permitting greater modeling flexibility, is recommended in *IEEE Trans.* (August 1995):

$$P = P_0\left[K_{PZ}\left(\frac{V}{V_0}\right)^2 + K_{PI}\left(\frac{V}{V_0}\right) + K_{PC} + K_{P1}\left(\frac{V}{V_0}\right)^{n_{PV1}}\left(1 + n_{PF1}\Delta f\right) + K_{P2}\left(\frac{V}{V_0}\right)^{n_{PV2}}\left(1 + n_{PF2}\Delta f\right)\right]$$

$$Q = Q_0\left[K_{QZ}\left(\frac{V}{V_0}\right)^2 + K_{QI}\left(\frac{V}{V_0}\right) + K_{QC} + K_{Q1}\left(\frac{V}{V_0}\right)^{n_{QV1}}\left(1 + n_{QF1}\Delta f\right) + K_{Q2}\left(\frac{V}{V_0}\right)^{n_{QV2}}\left(1 + n_{QF2}\Delta f\right)\right]$$

2. **Induction motor dynamic model** — For loads subjected to large fluctuations in voltage and/or frequency, the dynamic characteristics of the motor loads become important. Induction motor models are usually available in stability programs. Except in the case of studies of large motors in an industrial plant, individual motors are not represented. But one or two motor models representing the aggregation of all of the motors supplied from a bus can be used to give the approximate effect of the motor dynamics (Nozari et al., 1987). Typical motor data are given in the General Electric Company *Load Modeling Reference Manual* (1987).
3. **Detailed load model** — For particular studies, more accurate modeling of certain loads may be necessary. This may include representation of the approximate average feeder and transformer impedance as a series element between the network bus and the bus where the load models are connected. For long-term analysis, the automatic adjustment of transformer taps may be represented by simplified models. Several load components with different characteristics may be connected to the load bus to represent the composition of the load.

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Load modeling data can be acquired in several ways, none of which are entirely satisfactory, but contribute to the knowledge of the load characteristics:

1. **Staged testing of load feeders —** Measurements can be made of changes in real and reactive power on distribution feeders when intentional changes are made in the voltage at the feeder, e.g., by changing transformer taps or switching a shunt capacitor. The latter has the advantage of providing an abrupt change that may provide some information on the dynamic response of the load as well as the steady-state characteristics. This approach has limitations in that only a small range of voltage can be applied, and the results are only valid for the conditions (time of day, season, temperature, etc.) when the tests were conducted. This type of test is most useful to verify a load model determined by other means.
2. **System disturbance monitoring** — Measurements can be made of power, voltage, and frequency at various points in the system during system disturbances, which may produce larger voltage (and possibly frequency) changes than can be achieved during staged testing. This requires installation and maintenance of monitors throughout the system, but this is becoming common practice on many systems for other purposes. Again, the data obtained will only be valid for the conditions at the time of the disturbance, but over time many data points can be collected and correlated.
3. **Composition-based modeling —** Load models can also be developed by obtaining information on the composition of the load in particular areas of the system. Residential, commercial, and various types of industrial loads are composed of various proportions of specific load devices. The characteristics of the specific devices are generally well-known (General Electric Company, 1987). The mix of devices can be determined from load surveys, customer SIC classifications, and from typical compositions of different types of loads (General Electric Company, 1987).

Transmission Device Models

For the most part, the elements of the transmission system, including overhead lines, underground cables, and transformers, can be represented by the same algebraic models used for steady-state (power flow) analysis. Lines and cables are normally represented by a pi-equivalent with lumped values for the series resistance and inductance and the shunt capacitance. Transformers are normally represented by their leakage inductance, resistance, and tap ratio. Transformer magnetizing inductance and eddy current (no-load) losses are sometimes included.

Other transmission devices that require special modeling include high-voltage direct current (HVDC) systems (Kundur, 1994) and power electronic (PE) devices. The latter includes static Var compensators (SVC) (*IEEE Trans.,* Feb. 1994) and a number of newer devices (TCSC, STATCON, UPFC, etc.) under the general heading of flexible AC transmission systems (FACTS) devices. Many of these devices have modulation controls designed to improve the stability performance of the power system. It is therefore important that these devices and their controls be accurately modeled. Due to the developmental nature of many of these technologies and specialized designs that are implemented, the modeling usually must be customized to the particular device.

Dynamic Equivalents

It is often not feasible or necessary to include the entire interconnected power system in the model being used for a dynamic performance study. A certain portion of the system that is the focus of the study, the “study system,” is represented in detail. The remainder of the system, the “external system,” is represented by a simplified model that is called a dynamic equivalent. The requirements for the equivalent depend on the objective of the study and the characteristics of the system. Several types of equivalents are discussed below.

1. **Infinite bus** — If the external system is very large and stiff, compared with the study system, it may be adequate to represent it by an infinite bus, that is, a generator with very large inertia and

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very small impedance. This is often done for studies of industrial plant power systems or distribution systems that are connected to higher voltage transmission systems.

2. **Lumped inertia equivalent** — If the external system is not infinite with respect to the study system but is connected at a single point to the study system, a simple equivalent consisting of a single equivalent generator model may be used. The inertia of the generator is set approximately equal to the total inertia of all of the generators in the external area. The internal impedance of the equivalent generator should be set equal to the short-circuit (driving point) impedance of the external system viewed from the boundary bus.
3. **Coherent machine equivalent** — For more complex systems, especially when interarea oscillations are of interest, some form of coherent machine equivalent should be used. In this case, groups of generators in the external system are combined into single lumped inertia equivalents if these groups oscillate together for interarea modes of oscillation. Determination of such equivalents requires specialized calculations for which software is available (Price et al., 1978; Price et al., 1996).

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11.8 Direct Analysis of Wide Area Dynamics

J. F. Hauer, W. A. Mittelstadt, M. K. Donnelly,
W. H. Litzenberger, and Rambabu Adapa

The material to follow deals with the direct analysis of power system dynamic performance. By "direct" we mean that the analysis is performed on the physical system, and that any use of system models is secondary. Many of the tools and procedures are as applicable to simulated response as to measured response, however. Comparison of the results thus obtained is strongly recommended as a means to test model validity.

The resources needed for direct analysis of a large power system represent significant investments in measurement systems, mathematical tools, and staff expertise. New market forces in the electricity industry require that the "value engineering" of such investments be considered very carefully. Many guidelines for this can be found in collective utility experience of the Western Systems Coordinating Council (WSCC), in western North America.

Dynamic Information Needs: The WSCC Breakup of August 10, 1996

Large power systems are very rich in information that can be developed from direct measurements of dynamic behavior. Progressive electrical utilities are developing comprehensive data acquisition facilities. The emerging critical path challenge is to extract essential information from this data, and to distribute the pertinent information where and when it is needed. Otherwise, system control centers will be progressively inundated by potentially valuable data that they are not yet able to fully utilize.

New factors are rapidly compounding this problem. Utility restructuring promises to sharply increase the need for measurement-based information while shrinking the time frame in which it must be produced and distributed. In addition, financial pressures dictate that cost recovery for the requisite technology investments be prompt and low risk.

These issues were brought into sharp and specific focus by the massive breakup experienced by the Western North American Power System on August 10, 1996. The mechanism of failure (though perhaps not the cause) was a transient oscillation under conditions of high power transfer on long paths that had been progressively weakened through a series of seemingly routine transmission line outages. Later analysis of monitor records, as in Fig. 11.34, provides many indications of potential oscillation problems. Verbal accounts also suggest that less direct indications of a weakened system were observed by system operators for some hours, but that there had been no means for interpreting them. It is very likely that, buried within the measurements already at hand, lay the information that system behavior was abnormal and that the system itself was vulnerable.

Utility restructuring, through several mechanisms, is making it impossible to predict system vulnerabilities as accurately or as promptly as the increasingly volatile market demands. It is quite possible that standard planning models could not have predicted the August 10 breakup, even if the conditions leading up to it had been known in full detail. This situation has deep roots and many ramifications (WSCC Work Group, 1990; Hauer and Hunt, 1996; Stahlkopf and Wilhelm, 1997; Kosterev et al., 1999; Hauer and Taylor, 1998; Taylor, 1999). Correcting the situation will require many years of concerted effort on many fronts.

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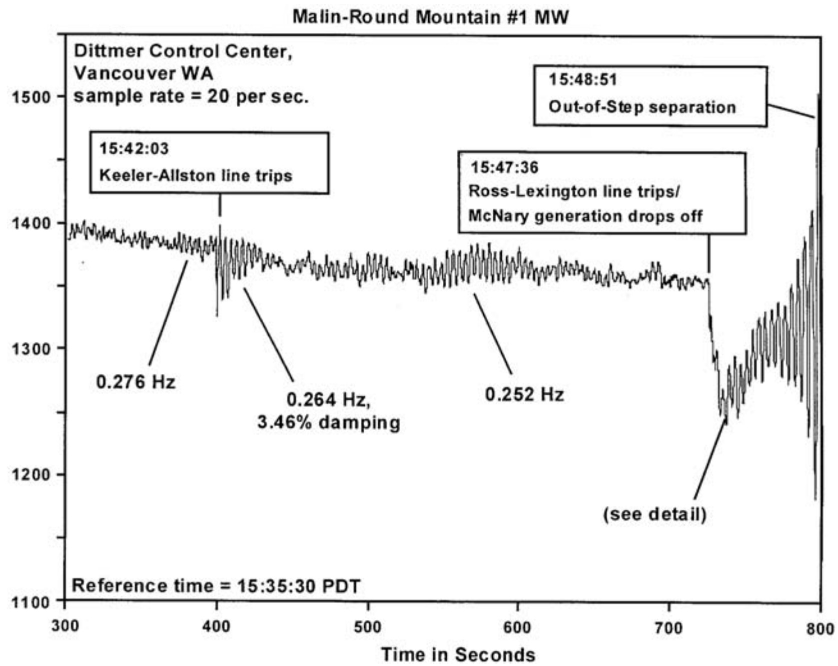

FIGURE 11.34 Oscillation buildup for the WSCC breakup of August 10, 1996.

An interim solution is to reinforce capabilities for predicting system vulnerability with the capability to detect and recognize its symptoms as evidenced in dynamic measurements. This can also be viewed as a form of measurement-based dynamic security assessment (DSA). In the Western Power System, the technology and infrastructure that this requires are being developed as extensions of the DOE/EPRI Wide Area Measurement System (WAMS) Project and related efforts (Hauer et al., 1997; Hauer et al., Jan. 1999; Hauer et al., May 1999).

Background

Comprehensive monitoring of a large power system is a long step beyond the monitoring of local devices or even regional performance. Developing a suitable investment plan calls for close attention to emerging information needs and information technologies. Even more important — perhaps decisively so — are the interutility practices and infrastructure through which dynamic information resources are collectively reinforced and operated.

Timeliness of the information is becoming an increasingly important consideration. The pace of utility restructuring strongly encourages more aggressive use of power delivery assets, which translates into progressive encroachment upon customary operating margins. This can greatly increase the need for direct evidence concerning the proximity and nature of safe operating limits.

The Western North America power system provides a useful example of the agencies at work. Driven by stability considerations, and in an earlier regulatory environment, the member utilities of the Western North America power system have made significant progress in the development of monitor facilities for examining system behavior. This development, coordinated through the WSCC, is a collective response to their shared needs for measurement-based information about system characteristics, model fidelity, and operational performance (WSCC Work Group, 1990; Hauer and Hunt, 1996; Kosterev et al., 1999).

Utility restructuring is now carrying these and all utilities toward the future in large abrupt steps. Infrastructure development for acquiring wide-area dynamic information started in response to technical needs in a cost-based environment. Its value in the new price-based environment is likely to be much higher through direct services such as

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- **Real-time determination of transmission capacities —** assuming necessary progress with mathematical tools.
- **Early detection of system problems —** this enables cost reductions through performance-based maintenance, and provides a safety check on network loading.
- **Refinement of planning, operation, and control processes —** essential to best use of transmission assets.

Such an infrastructure can also provide indirect benefits as an enterprise network (*IEEE Spectrum*, July 1991; Grenier and Metes, 1992), or "people net." It is a proven means through which a wide range of technical skills can be accessed and shared among the utilities as a virtual technology staff. This may be very important to the future power system, especially in situations where difficult stability problems constrain the use of transmission assists.

An Overview of WSCC WAMS

Collectively, in response to the needs that utilities share in operating their facilities, these efforts are leading toward an integrated dynamic information network that spans the entire WSCC system. WSCC WAMS is evolving as a hierarchical network of dynamic monitors, plus the information tools and general infrastructure necessary for effective use of the acquired data. Data sources are of many kinds, and they may be located anywhere in the power system. This is also true for those who need the data, or those who need various kinds of information extracted from the data.

It would not be practical or sufficient to just collect all WAMS data at one location and then permit users to retrieve it as needed. Data volume and information demands call for distributed storage and management. Central to this is a WAMS Information Manager having enough "intelligence" to route data and manage archives on the basis of the information contained. This issue is pursued in a later section.

Direct Sources of Dynamic Information

There are a variety of means by which dynamic information can be extracted from a large power system. These include

- Disturbance analysis
- Ambient noise measurements
  - spectral signatures
  - open-loop/closed-loop spectral comparisons
  - correlation analysis
- Direct tests with
  - low level noise inputs
  - mid-level inputs with special waveforms
  - high level pulse inputs
  - network switching

Each has its own merits, disadvantages, and technical implications (Hauer et al., 1999; Hauer, 1995; Phadke, 1993; EPRI, Dec. 1993; Hauer et al., 1995; Hauer, 1996). For comprehensive results, at best cost, a sustained program of direct power system analysis will draw upon all of these in combinations that are tailored to the circumstances at hand.

Some of these operations, such as network switching tests, are outside the usual scope of power system monitoring. All of them represent required functionalities for the WAMS infrastructure, however, and for the monitor facilities within it. *Monitoring is a subset of measurement operations.* Even so, it is the monitor facilities that provide the backbone for the dynamic information infrastructure.

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From a functional standpoint, wide-area monitoring for a large power system involves the following general functions:

- **Disturbance monitoring**: characterized by large signals, short event records, moderate bandwidth, and straightforward processing. Highest frequency of interest is usually in the range of 2 Hz to perhaps 5 Hz. Operational priority tends to be very high.
- **Interaction monitoring**: characterized by small signals, long records, higher bandwidth, and fairly complex processing (such as correlation analysis). Highest frequency of interest ranges to 20–25 Hz for rms quantities, but may be substantially higher for direct monitoring of phase voltages and currents. Operational priority is variable with the application and usually less than for disturbance monitoring.
- **System condition monitoring**: characterized by large signals, very long records, very low bandwidth. Usually performed with data from SCADA or other EMS facilities. Highest frequency of interest is usually in the range of 0.1 Hz to perhaps 2 Hz. Core processing functions are simple, but associated functions such as state estimation and dynamic or voltage security analysis can be very complex. Operational priority tends to be very high.

These functions are all quite different in their objectives, priorities, technical requirements, and information consumers. At many utilities they are supported by separate staff structures and by separate data networks.

What is a Monitor?

The power system contains many devices that can serve as monitors for some processes and purposes. This document narrows the field somewhat, through the following definition:

> A *monitor* is any device that automatically records power system data, either selectively or continuously, according to some mechanism that permits the data to be retrieved later for analysis and display.

With exceptions as noted, present attention is further restricted to monitors that record one or more of the following:

- Dynamic "swing" interactions among generators and loads through an interconnecting electrical transmission system.
- The performance of specific facilities involved in swing interactions. This includes generators, loads, and control systems.

This focus excludes most digital fault recorders and SCADA systems, since their typical record lengths and data rates are (respectively) not adequate for capturing swing dynamics. Network condition monitors might be included, depending upon the specifics of the device.

Overall, *monitor facilities* often contain a wide range of recording devices that are not swing monitors. The ubiquitous (and underutilized) digital fault recorder, or DFR, is a particulary good example of this. The facilities may also include devices that have little or no direct recording capability, but that do provide essential "intelligence" to overall facility performance. It is becoming established practice to classify all of the aforementioned devices as *intelligent electronic devices*, or IEDs (Smith, 1996; Carolsfeld, 1997). Drawing upon this terminology, just about any modern measurement system reduces to an IED network.

Monitor System Functionalities

The primary rule in power system measurements is to *record good data, and keep them safe!* These are two distinct functions and both call for close attention. If monitor facilities are used to support direct tests, then an even more important rule enters the picture, which is to *do no harm to the power system.* In both cases it is the measurement of low-level interactions that define the most rigorous functionality requirements to the overall measurement system. This is due, in part, to long recording periods plus the need to resolve very small changes in large signals (Hauer, 1995).

There is a more demanding need, however — the evaluation of system dynamic performance in nearly real time (NRT). This is particularly critical during staged tests when a close balance must be maintained

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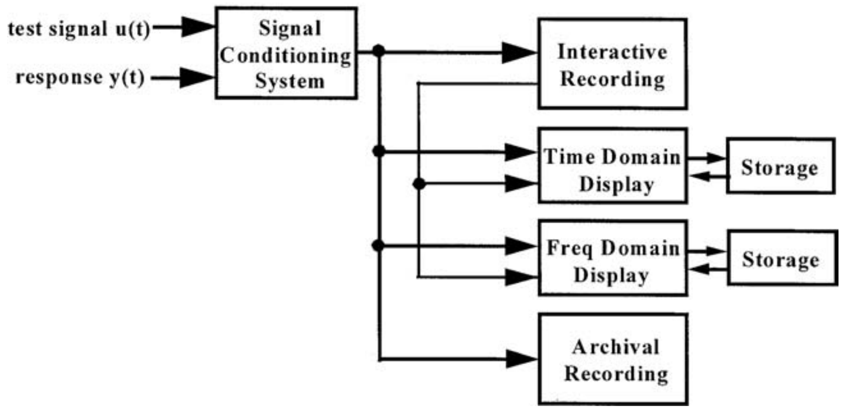

FIGURE 11.35 Information functions in measurement of low level interactions.

between system security and the quality of test results. It is also important during routine monitor operations as a means for identifying important data and for generation of operator alerts.

Figure 11.35, with the test signal deleted for the case of passive monitoring, represents core information functions that are needed in both situations. The functions are:

- **Signal conditioning**, to assure the measurement quality and prompt observability of important signal features.
- **Archival recording**, to assure safekeeping of important results. This should be as comprehensive as possible, and include all phases of testing that involve switching operations or application of test signals.
- **Interactive recording,** to permit prompt examination of data that cannot be fully assessed in real time. This also provides backup recording of high priority signals.
- **Time domain display,** to permit frequent review of signal waveforms for evidence of data quality and emerging trouble on the power system.
- **Frequency domain display**, to permit frequent review of signal spectra for evidence of data quality and possible trouble on the power system.

The NRT displays permit appropriate actions to be taken by the test team or monitor operations staff. In some cases the analysis tools underlying these displays are also used in event detection logic (EDL) to trigger automatic functions such as accessory data capture, information routing, or operator alerts.

Figure 11.35 represents a paradigm that is fundamental to low level measurements of power system dynamics. Not all monitors are interaction monitors, and many interaction monitors lack some of the functions shown. *The required functionality resides in the overall measurement system*. Figure 11.35 will reappear in many expanded forms throughout the sections to follow.

Event Detection Logic

Data recording in an individual monitor is either selective or continuous. In selective recording, data "snapshots" are collected upon command of "trigger logic." This requires that dynamic event signatures be detected in real time — otherwise useful data is lost. Continuous recording requires very similar logic, but uses it to sort records already captured according to their information content.

Triggers for initiating data capture can be classified in several ways. A "manual vs. automatic" classification provides

- manual
  - local
  - remote

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- automatic
  - pre-scheduled
  - internal event detection
  - cross-trigger (from another monitor or IED)

Another classification is

- external
  - local manual
  - remote manual
  - prescheduled (clock initiated)
  - cross-trigger (from another monitor or IED)
- internal event detection

This highlights the fact that EDL is fundamentally different from some other triggers. EDL is also a core issue in monitor design and operation, whether recording is selective or continuous.

There are four basic factors involved in detecting the onset of a dynamic event. They are

- magnitude
- persistence
- frequency content
- context

A simple disturbance trigger might examine just magnitude and persistence, in tests of form "Do the latest M samples each exceed threshold T(M)?" (Hauer and Vakili, 1990). It is useful to think of the context factor as adjusting such thresholds to system conditions, such as network stress or the operational status of key system resources.

A partial list of signatures through which events can be detected, and perhaps recognized, includes the following:

- Steps or swings in tieline power.
- Large change, or rate of change, in bus voltage or frequency.
- Sustained or poorly damped oscillations, perhaps in conjunction with some other event.
- Large increase in system noise level.
- Increase of system activity in some critical frequency band.
- Unusual correlation or phasing between fluctuations in two given signals.

The tools needed to extract useful signature information from measured data range from straightforward heuristics to very advanced methods of signal analysis. Recognition of the underlying events calls for pattern recognition logic to match extracted signatures against known event templates.

Monitor Architectures

The vast majority of dynamic monitors only capture data for disturbances that are strongly observable in the monitor inputs. The "trigger to archive" or "snapshot" monitor in Fig. 11.36 is typical. A circulating prehistory buffer retains the most recently acquired data, assuring that a certain amount of information will be provided about system conditions before the disturbance is detected. Trigger logic causes the disturbance to be recorded as one or more data snapshots in the motor archives. The device shown also has the following accessory features:

- External trigger inputs for initiating data capture.
- Flags and alarms sent out to indicate the triggering condition.

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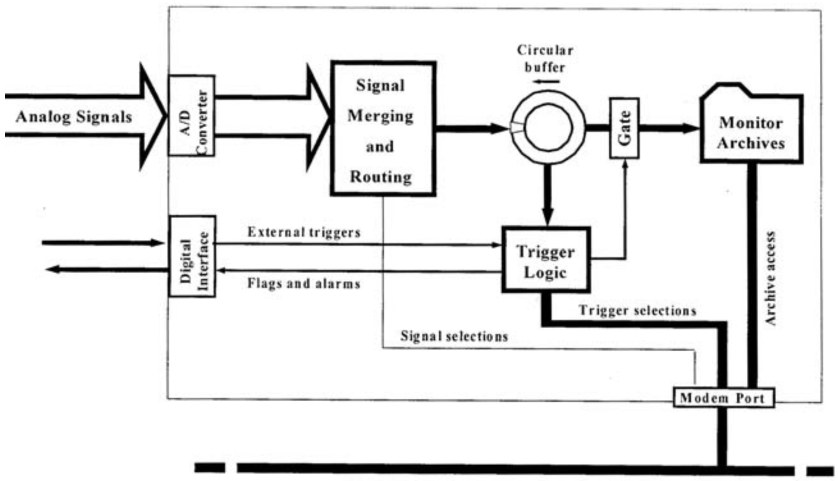

FIGURE 11.36 A simple "snapshot" disturbance monitor.

- External control of monitor settings via a modem port.
- Retrieval of archive data via a modem port.

The triggered monitor uses a rather conservative architecture that is necessary and appropriate when substantial amounts of data must be captured at high rates (as in digital fault recording). The reliance upon triggered recording — together with a general tendency toward short records and even shorter prehistories–are serious handicaps in wide area measurements, however.

WSCC experience suggests that triggered data capture does not provide an adequate basis for wide-area measurements. Even rather large events may not be sensed by trigger logic that is remote from the site of the disturbance. Records for a cascading failure that develops slowly, from some fairly small initiating event, are very unlikely to present a comprehensive view of the mechanism by which the small failure propagated into a very large one.

Figure 11.37 illustrates the point. The record there, collected on BPA's earlier Power System Disturbance Monitor, indicates peak-to-peak 0.7 Hz swings of roughly 900 MW on the Pacific AC Intertie (PACI). However, as is usual with triggered monitors, it failed to capture the all-important interval during which

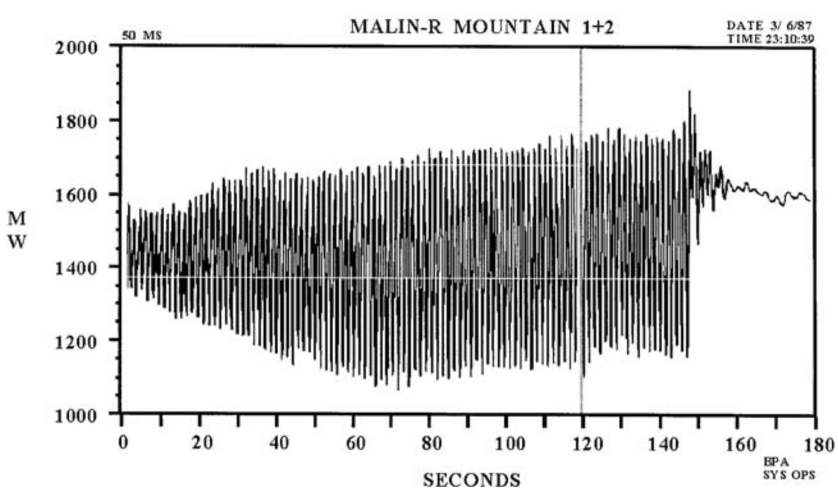

FIGURE 11.37 Western system oscillations of March 6, 1987 (sum for two parallel circuits).

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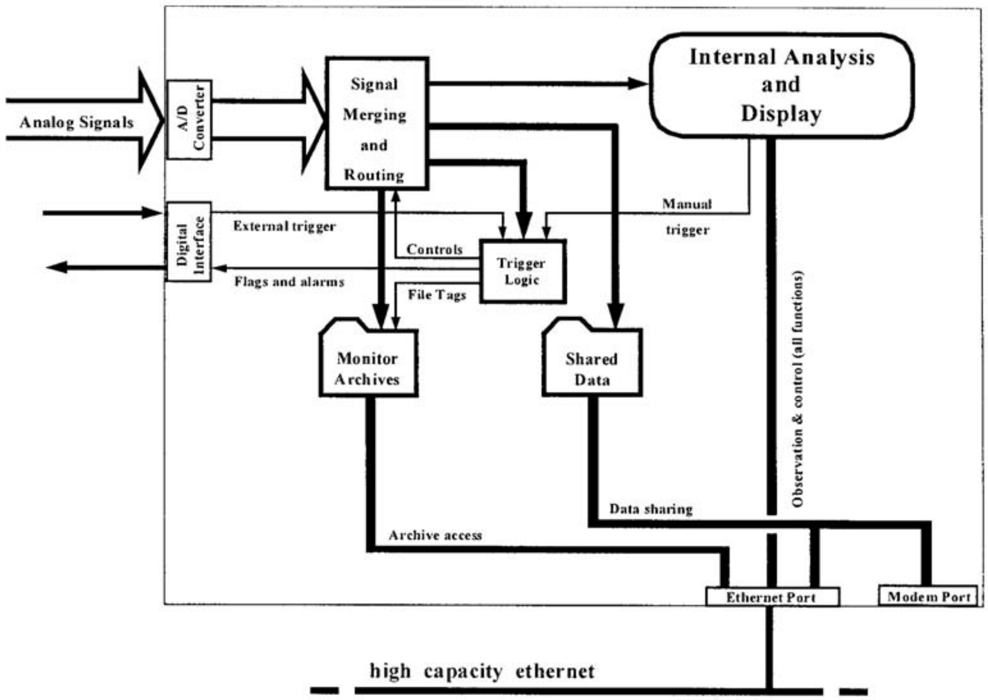

FIGURE 11.38 Basic architecture for a continuously recording monitor.

the oscillations started. Without this, whatever indications there may have been to warn system operators of pending trouble remain unknown.

Some triggered monitors can support interaction measurements under manual control, provided that their storage capabilities and analog to digital (A/D) resolution are sufficient. Their functionality in this mode of operation is similar to that of a high-quality tape recorder. The more "intelligent" functions expected of a monitor are lost, and sorting through the data can become a very laborious manual exercise. Monitors that are explicitly designed to operate in a continuous recording mode are a far better option.

Figure 11.38 shows a basic "stream to archive" monitor that, typically, will maintain a continuous data record for periods ranging to several weeks. While triggers are used, their role is rather different than for a triggered monitor. Data capture in a continuous monitor *does not* depend upon trigger logic. Instead, trigger logic is used to:

- **tag the acquired data** in ways indicating its likely value. Factors in this are:
  - the magnitude, duration, and frequency content of dynamic activity.
  - the context in which the data were acquired — e.g., event specific external triggers and system stress levels (from condition monitoring).
- **generate external flags or alarms** when data values reach critical levels.

The value tags will also determine such matters as the priority, routing, archiving level, compression, and retention time for the associated data. In a fully developed monitor system, the value tags will be amended by an Archive Scanner that automatically reviews and restructures collective monitor archives.

This continuous monitor also has some accessory features beyond those in Fig. 11.36. These are

- Real-time analysis and display, with an option for manual triggering.
- NRT data sharing through the computer network.

The next architecture takes the functionality progression several steps further.

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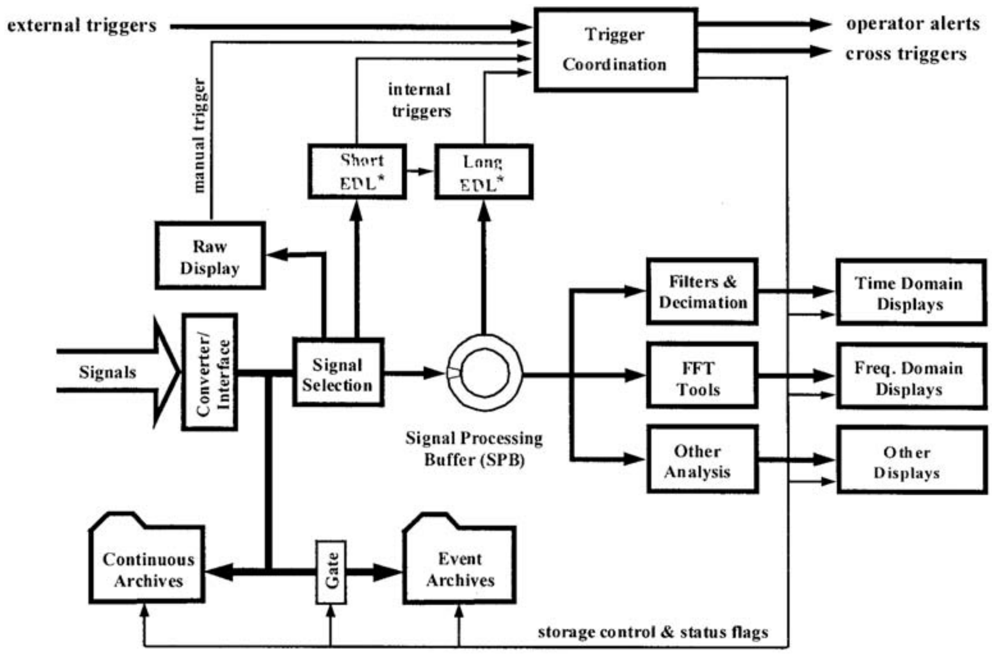

FIGURE 11.39 A continuous monitor combining short and long EDL.

Figure 11.39 shows a configuration that is representative of a mature interactions monitor that is operating in a manned substation or in a system control center. Absence of an indicated perimeter for the monitor reflects the fact that this might well be a locally networked facility, containing several computers or other IEDs plus linkages to the energy management system (EMS).

The indicated triggers are both external and internal, manual and automatic. The internal automatic triggers are classified as short or long (fast or slow), depending upon length of the data segment needed by the associated event detection logic. Short EDL can work with a short block of recent data and is usually sufficient for disturbance monitoring.

A distinguishing feature in this architecture is the signal processing buffer (SPB) used for advanced triggers (in the long EDL) and in special displays. SPB functionality is essential for extracting interaction signatures, and for presenting those signatures to operations staff for their interpretation and review. At hardware level, however, this functionality can be distributed among one or more buffers internal to the monitor itself plus external buffers for shared access to the record stream at file level.

A next step in monitor refinement is to enhance the EDL and trigger coordination functions of Fig. 11.39 through artificial intelligence. Figure 11.40 represents a Diagnostic Event Scanner (DES) suitable for this purpose, and for the Archive Scanner mentioned earlier.

Monitor Network Topologies

With respect to their architecture, monitor facilities consist of

- **Central monitors** that continually scan signals from transducers, and similar instruments, that are communicated from remote sites.
- **Distributed monitor networks,** which are found in a variety of general forms
- **Local monitors,** for which remote access is usually weak and manually initiated.

BPA operates a centralized monitor system, based at the Dittmer Control Center, that is interlaced with an expanding network of remote monitors and secondary recording devices. Many of the remote monitors provide local or regional surveillance over some important parts of the control system. The

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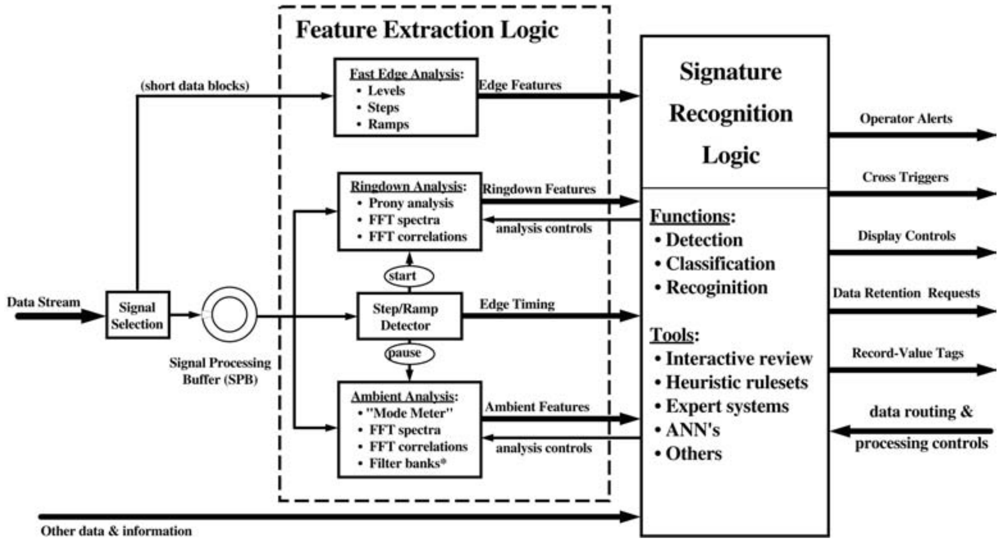

FIGURE 11.40 Diagnostic Event Scanner (DES) within a continuous monitor.

general strategy is to collect essential signals (including alarms) from such sites on the central monitors, at modest data rates, and to perform comprehensive high-speed monitoring locally. In most cases, the high-speed data is immediately available to site operators, but is selectively forwarded to the control center or to system analysts.

BPA has three central monitors at or near the Dittmer Control Center (Fig. 11.41). The newest of these, based upon BPA's rapidly evolving Phasor Data Concentrator (PDC), is discussed a bit later. The other two, the Power System Analysis Monitor (PSAM) and the Dittmer PPSM, are indicated in Fig. 11.42.

The PSAM and PPSM have access, in parallel, to several hundred analog signals. Most of these signals represent power flowing within the BPA service area and contain useful information at frequencies up to perhaps 2 Hz. Signals associated with control projects are an increasingly common exception to this. They ordinarily use 20 Hz channels and the corresponding transducers, if any, tend to be conventional electronic units modified for either a 2 Hz or 20 Hz bandwidth.

In this arrangement, the 2 Hz signals present a comprehensive view of interarea "swing" dynamics visible in BPA interchanges, plus information about voltages, reactive flow, important loads, and automatic generation control (AGC). The 20 Hz signals convey a necessary minimum of essential information about controller behavior. They also facilitate alignment and cross analysis of central monitor records with more comprehensive local recordings. The total communications burden for this mixture of central plus distributed monitoring is much less than for a fully centralized monitor system. Furthermore, much of the data can be moved with adequate speed and reliability using general purpose computer networking technology.

This deployment of remote monitors on a general network represents an evolutionary step in the gradual transition from analog technology to digital. Direct replacement of BPA's present point-to-point analog communications by digital channels of comparable bandwidth and resolution (about 14 bits, after filtering) would be needlessly expensive at this time. Best use of digital technology will call for new architectures, which should readily accommodate the rapid product enhancements so characteristic of the "information age."

The third monitor system at the Dittmer Control Center is entirely digital. The system consists of multiple Phasor Measurement Units (PMUs) that are linked together by one or more PDC units. The PMUs are synchronized digital transducers that stream their data, in real time, to the Dittmer PDC(s). The general functions and topology for this network resemble those for the Dittmer PSAM and PPSM. Data quality for the phasor technology appears to be very high, however, and secondary processing of the acquired phasors can provide a broader range of signal types.

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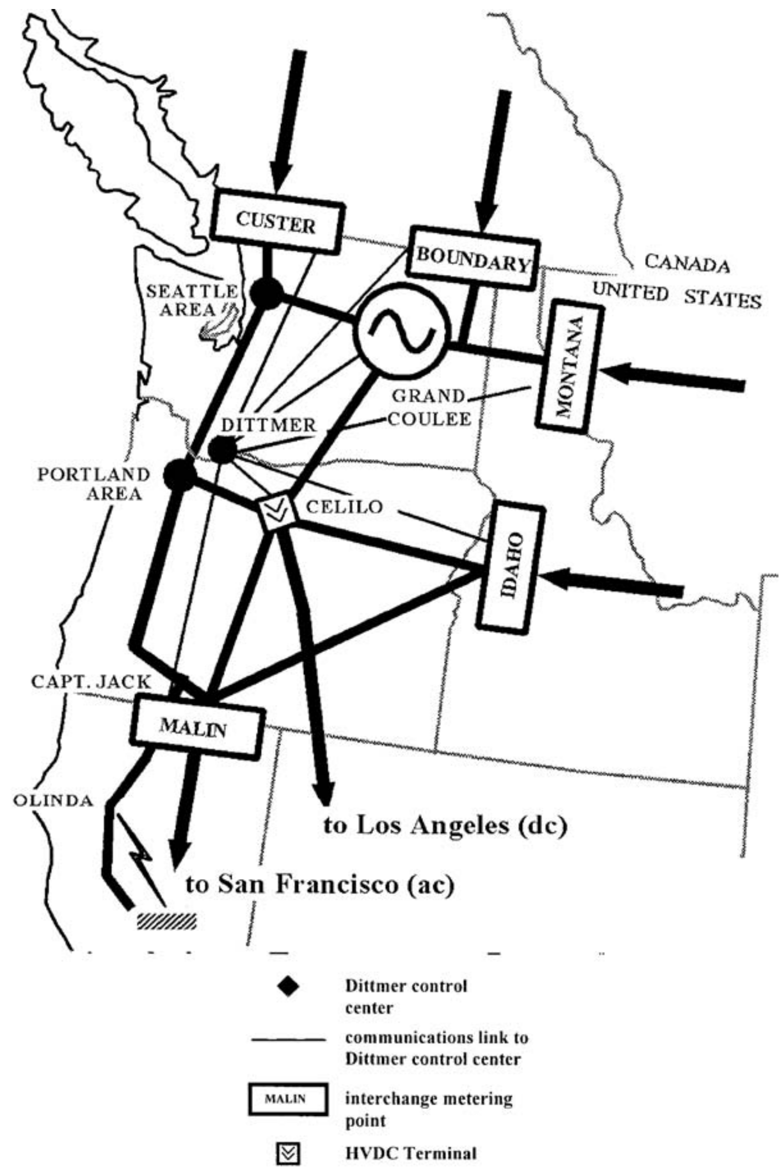

FIGURE 11.41 BPA central monitor coverage.

Phasor networks provide their best value in applications that are mission-critical, and that involve truly wide area measurements. Both factors encourage real-time data links among regional phasor networks. This can be accomplished at both the PMU and the PDC levels. Connecting a PMU to multiple PDC units is straightforward and has already been done. Selective forwarding of PDC signals to other PDC units seems feasible and is under very active development. A copy of the BPA PDC became operational at Southern California Edison (SCE) facilities in mid-1998, and another copy became operational at WAPA in November 1998. The resulting network is evolving toward a topology of the sort indicated in Fig. 11.43.

Central monitor systems, though very effective, are not a complete answer:

- They do not serve information needs at local or regional level.
- The dedicated communications can be very expensive.

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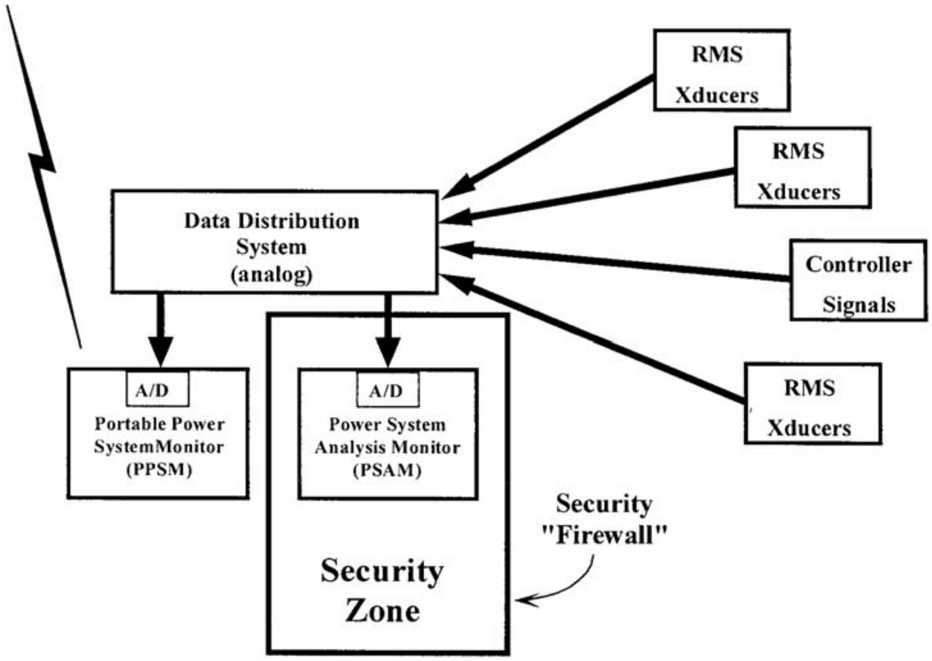

FIGURE 11.42 Topology of BPA central monitor system for analog signals.

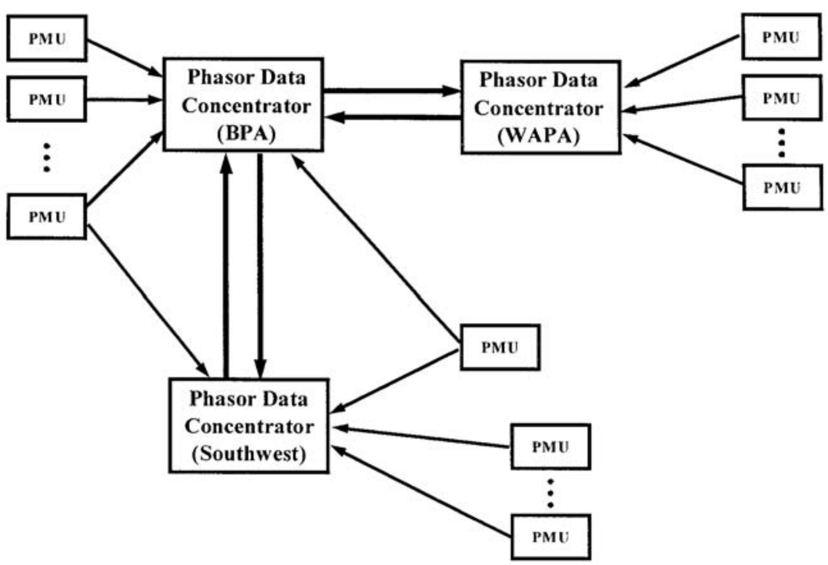

FIGURE 11.43 Partial topology of the emerging WSCC phasor measurements network.

- Communication failures may cause important data to be lost.
- Data rates and data volumes for some dynamic processes are so high that continuous transmission to central facilities is not practical. This is especially likely for high performance control systems.
- Under normal circumstances, a lot of data are too mundane to merit the costs of continuous transmission. Transmission should be selective, and based upon information value.

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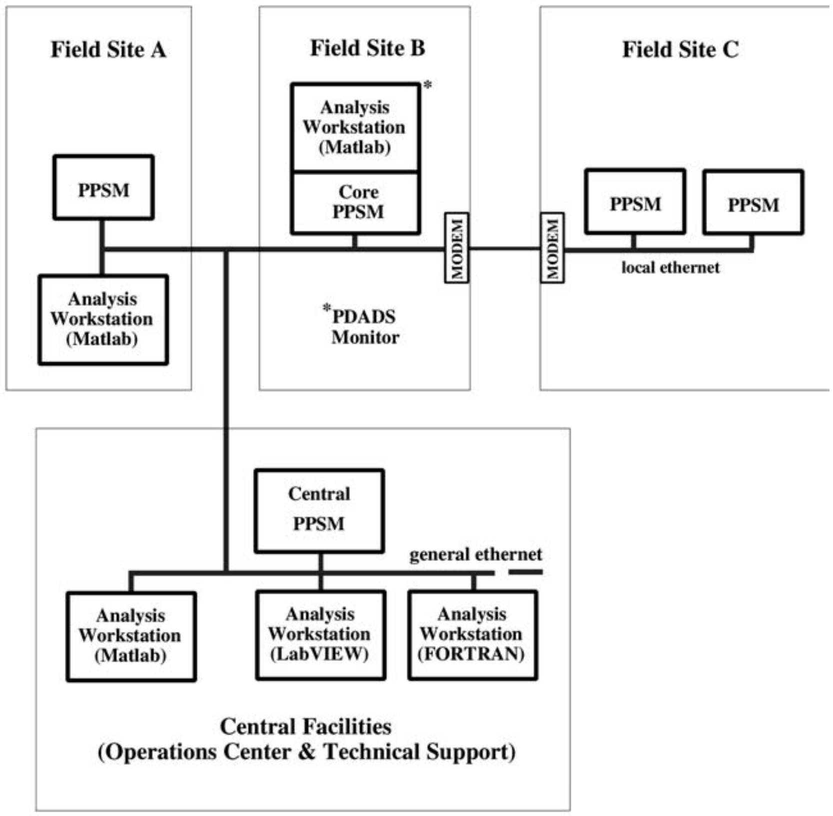

FIGURE 11.44 A distributed network for dynamic information.

In many situations, better performance and better "value engineering" can be obtained through distributed monitor networks, in which local storage and selective messaging minimize reliance upon dedicated communications.

Distributed monitor networks can take many forms, ranging from dial-up access among sites to NRT communication of data and information on full-time computer networks. A general computer network permits a much wider range of functions and technologies than those of the central monitors represented in Figs. 11.42 and 11.43. It is particularly valuable for broadening the staff support base for monitor operations.

Figure 11.44 shows a dynamic information network that represents the topology and functionalities associated with distributed regional monitoring. The nomenclature there is based upon BPA/PNNL elements of the WAMS technology package. A "monitor" in this context generally means a *measurements workstation*, consisting of

- a "core monitor" or *data capture unit* (DCU).
- one or more *analysis toolsets* . Most of this functionality is applied to data already captured but, as indicated in Figs. 11.35 and 11.38, some may be used in near real time.

The analysis toolsets, when operated separately from the DCU, provide an *analysis workstation*.

The following comments apply to the network of Fig. 11.44:

- All monitor units and most workstations can communicate with one another.
- PPSM data capture (in the DCU) follows the logic shown in Fig. 11.38. Continuous recording is customary but optional.

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- PPSM units normally include LabVIEW® analysis station capabilities suitable for initial analysis of captured data. For in-depth analysis and design, this is augmented or replaced by a more advanced package based upon Matlab® (plus imbedded FORTRAN®).
- The diagram for Field Site B shows a PPSM variant in which the LabVIEW analysis tool has been replaced by a more extensive Matlab toolset for combined analysis and design. The result is a Portable Dynamic Analysis and Design System (PDADS).
- Analysis in the FORTRAN environment is often performed on larger computers that do not communicate readily with the PPSM or other workstations. Then the communications may be limited to data transfers only.

In point of fact, there are two monitor types shown in Fig. 11.44. The standard PPSM is entirely a LabVIEW-based virtual instrument (Santori, 1990; Schoukens, 1993). It finds its best uses in field analysis or in predefined environments where "pushbutton" analysis is appropriate. The other monitor is an extended PPSM that uses the standard LabVIEW DCU, while turning to Matlab to support its more advanced functions (Hauer et al., 1997; Matlab Reference Guide).

This network topology is suitable when security requirements are modest. Dial-in modems can be particularly inviting points for external attack, however, and they may not be suitable for applications that need a high level of data security (Jones and Skelton, 1999).

Networks of Networks

A well-evolved monitor system will necessarily involve a mixture of technologies, data sources, functions, operators, and data consumers. In broad terms,

- **Required functionalities** are determined by who must see what, when, and in what form.
- **System configuration** is strongly influenced by geography, ownership, selected technology, and the technology already in service (legacy systems).
- **Investment value** is strongly enhanced through:
  - selective use of IEDs to supervise, integrate, or replace legacy systems.
  - organization of IEDs (including monitors) into local, regional, and wide area networks appropriate to their functions and technologies.

The choices that a particular utility will make are strongly colored by its operating and business requirements and more generally by the value it places upon information.

Overall, the forces at work strongly favor wide area measurement systems that evolve as "networks of networks." There are a lot of advantages to this. Interleaving networks that have different topologies and different base technologies can make the overall network much more reliable, while broadening the alternatives for value engineering. It also permits networks to be operated on the basis of ownership. The ability of a utility to retain data until it is no longer sensitive (delayed release) will almost certainly prove necessary for information sharing in the new power system.

Figure 11.45 shows interleaved networks of PMU, PPSM, and DSM units (plus analysis workstations). These devices are proprietary to Macrodyne, BPA/PNNL, and Power Technologies Inc. In this case,

- The PMU network has dedicated microwave communications in addition to dial-up links.
- The DSM "network" consists of individual units, accessed from a DSM base unit via dial-up links.
- The PPSM network serves in several roles. In addition to advanced monitor functions, it also provides the PMU and DSM units with:
  - alternate communication paths, via the computer network.
  - local, high volume archiving.
  - analysis and display functions available both on site and through remote teleoperation.

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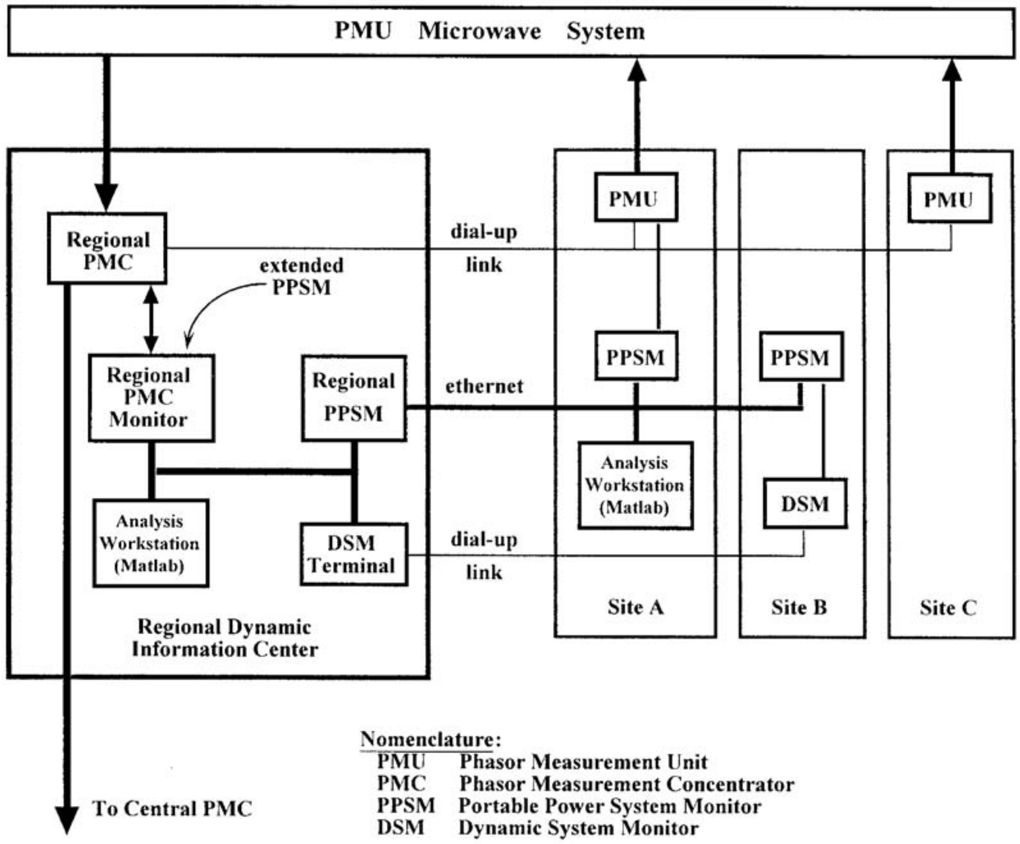

FIGURE 11.45 Interleaved networks of PMU, PPSM, and DSM units (plus analysis workstations).

Typical network details are shown in Figs. 11.46 and 11.47. Note that Fig. 11.46 indicates yet another layer of networking, for a digital transducer network. This could range from a basic PMU/PMT configuration to the highly versatile Integrated Object Network produced by Power Measurement, Ltd. (Carolsfeld, 1997).

Figure 11.47 represents a local measurement network developing for the 500 kV Thyristor Controlled Series Capacitor (TCSC) that was installed at BPA's Slatt substation under an EPRI FACTS project (Piwko et al., 1995; Hauer et al., 1996; Trudnowski et al., 1996). The functionalities there are highly desirable for any large control project. Guidelines for network organization are that:

- Any monitor (DFR, DSM, PPSM), through the local area network (LAN), triggers data collection on the others according to its own rules.
- The PPSM can supervise and control all other monitors or major instruments. All measurements are available to the PPSM for local display and analysis, for archiving, or for routing to other locations on the wide area network (WAN).
- The WAN permits remote observation and control of all devices in the measurement LAN through the PPSM.
- The PPSM can extract real time data from any other PPSM on the WAN and incorporate that data into its own processing.
- Every monitor, and the majority of major instruments can be accessed through a telephone connection as a (lower performance) backup to WAN failure.

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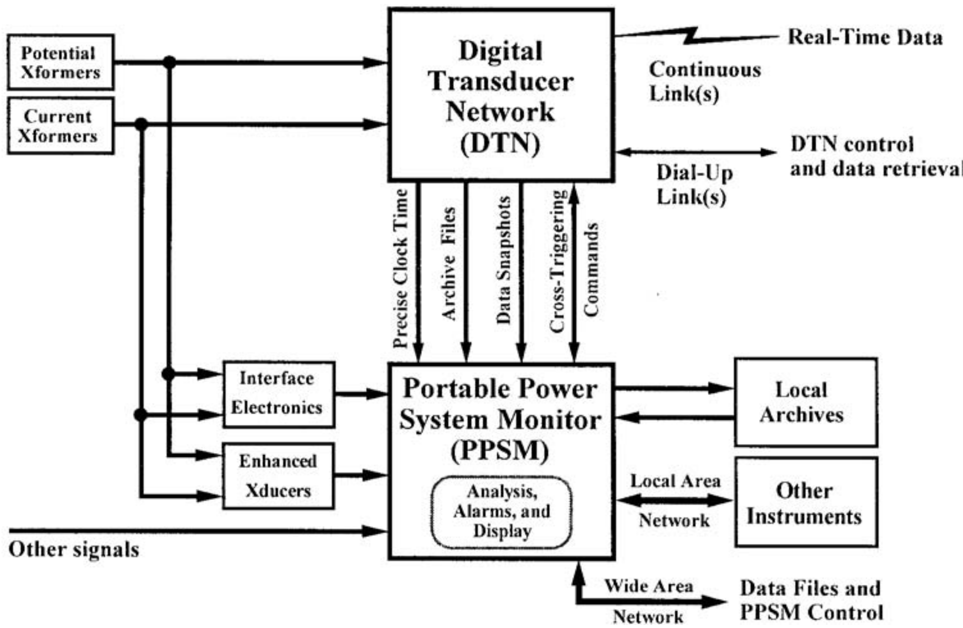

FIGURE 11.46 PPSM interconnections to local transducers.

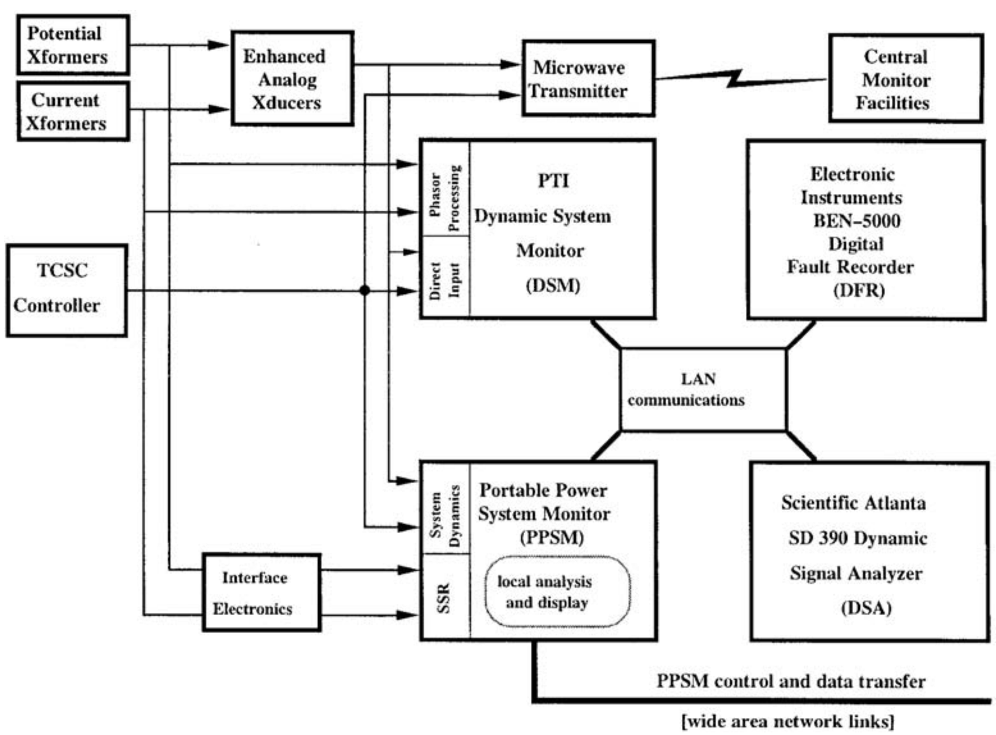

FIGURE 11.47 Monitor organization local to the Slatt TCSC.

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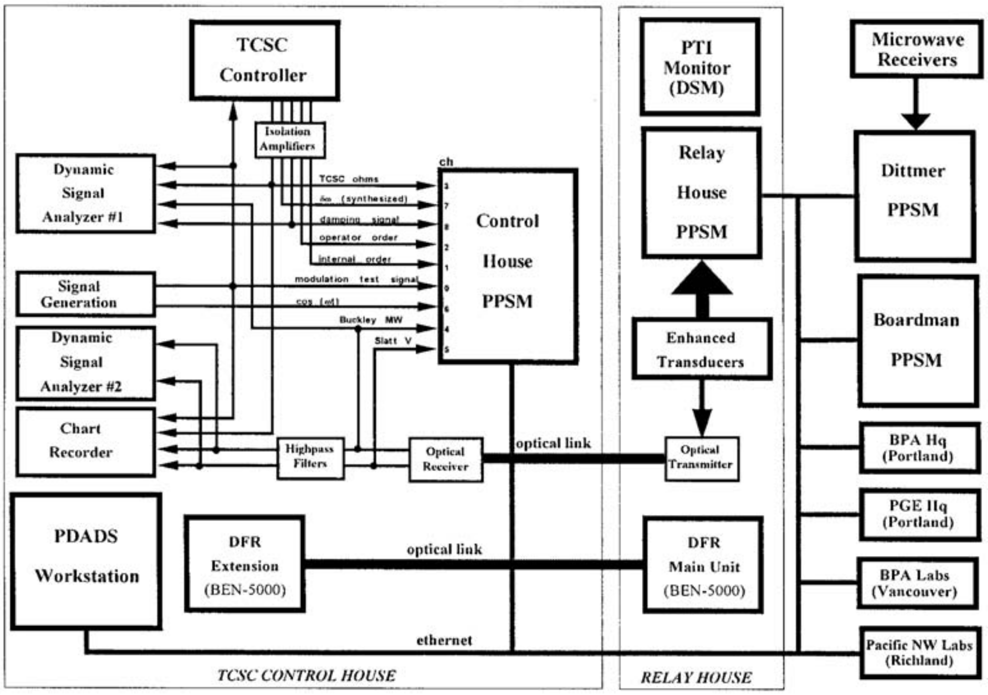

FIGURE 11.48 Slatt measurement network for TCSC modulation tests of June 6–7, 1994.

In addition to its usual functions, the DFR is used for waveform recording in controller performance tests. The DSA, by itself, is not quite a monitor. It does have good recording capabilities and it is readily networked. It is quite clearly a rather advanced IED and a valuable addition to overall monitor facilities.

Figure 11.48 provides an expanded view of the Slatt measurement network and of the regional network containing it. Information facilities of this kind are particularly valuable for certification and operation of major control systems such as the TCSC. For example, control engineers can perform wide area performance tests without the cost and delay of special purpose communication links. Staged tests can be supported remotely, with a minimum of travel, and technical staff can time-share that support across several projects while remaining in their normal work areas. *Workteam functionality* is a major requirement source in the proper design of dynamic information networks.

The final network to consider in this "network of networks," then, is the "people net." As indicated in Fig. 11.48, the TCSC Project draws upon remote technical support from three institutions (BPA, PNNL, and Portland General Electric) at four different locations. Some of this support was provided interactively during commissioning tests (Hauer et al., 1999), and all of it is available as needed.

Developing the proper interfaces between the "people net" and the monitor network(s) is critical to value engineering of the dynamic information system. The information users determine *who must know what, when, and in what form*. The information providers must deal with *who must do what, when, and with what tools*. Various aspects of these questions are treated below. The very important issue of placing a value on the information itself is reserved for separate discussion.

WSCC Experience in Monitor Operations

A competent monitor network is the "backbone" of the dynamic information infrastructure and it is a fundamental requirement for wide area control (CIGRE Task Force 38.01.07, 1996; CIGRE Task Force

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38.02.17, 1999; CIGRE Task Force 38.03.17, 1999). We should expect (or hope) that most of measurement functions will be mundane ones, performed unobtrusively under routine operating conditions. However, the network must stand ready to provide mission-critical services with little or no warning. Some examples of high value support are

- Early warnings of trouble arising on the system or in specific equipment.
- Integrated recording and information sharing for major system disturbances.
- Real-time recording and analysis during tests of controller performance, or of wide area system dynamics.
- Recording of anomalous system behavior that is too intermittent for scheduled examination.

The reader is advised that these are performance objectives, and that they might not be fully mature operational realities.

The WSCC utilities, individually and collectively, have been comparatively aggressive in their development of monitor facilities (Hauer et al., 1999; Clark et al., 1992; Taylor et al., 1996; Taylor and Erikson, 1997; Martin, 1992; Agee and Girgis, 1996). Operation of those facilities has revealed a number of general problems:

- ***Of the triggered monitors installed on the system,*** expect no more than 50% to provide good records for a major disturbance. Leading problems are:
  - failure to detect the event (i.e., to trigger data capture)
  - failure to trigger soon enough, or to "retrigger" often enough during protracted disturbances.
  - inadequate data storage.
  - overwriting of stored data before they have been downloaded to secure archives.
  - monitor out of service.
  - monitor failure from loss of supply power.
- ***Of the continuous monitors installed on the system,*** expect about 90% to provide good records for a major disturbance. Leading problems are:
  - monitor out of service.
  - monitor failure from loss of supply power.
- ***The value of a particular event record*** may be higher for some other utility than for its owner. This situation may not be recognized for several days after the event, in which case the record may well have been deleted from the data system.
- ***Determination of predisturbance conditions,*** though fundamental to subsequent model studies, is seriously hampered by sparse monitor coverage plus failure to retain relevant EMS data.
- ***Operations staff are very cautious*** about high-level staged tests, and becoming more so (see Hauer and Hunt, 1996 and comments by Scottish Power in CIGRE Task Force 38.01.07, 1996). Better use must be made of chance disturbances, plus low-level ("non-intrusive") tests and measurements.
- ***Very few triggered monitors*** are designed for low level tests and measurements. These are the defining tasks for a continuous interactions monitor such as BPA's PPSM and PDC.
- ***Necessary tools and skills*** for conducting staged tests and extracting dynamic information from measured data, are not evenly distributed among the utilities. Some mechanism is needed for sharing these resources (and their costs) to meet shared utility needs.
- ***An emergency response plan*** is needed to assure safe retention and prompt integration of measured data following major disturbances. It is *not realistic* to task primary operations staff with this function, and it is one that should be automated anyway.

The WAMS effort and the WAMS technologies are directly rooted in this experience.

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