Power System Transient Stability Study Fundamentals

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Introduction

For years, system stability was a problem almost exclusively to electric utility engineers. Small independent power producers (IPPs) and co-generation (co-gen) companies were treated as part of the load and modelled casually. Today, the structure of the utility industry is going through a revolutionary change under the process of deregulation. A full-scale competition in the generation market is on the horizon. Increasing numbers of industrial and commercial facilities have installed local generation, large synchronous motors, or both. The role of IPP/co-gen companies and other plants with on-site generation in maintaining system stability is a new area of interest in power system studies. When a co-generation plant (which, in the context of this chapter, is used in reference to any facility containing large synchronous machinery) is connected to the transmission grid, it changes the system configuration as well as the power flow pattern. This may result in stability problems both in the plant and the supplying utility. Figure 1 and Figure 2 are the time-domain simulation results of a system before and after the connection of a co-generation plant. The increased magnitude and decreased damping of machine rotor oscillations shown in these figures indicate that the system dynamic stability performance has deteriorated after the connection. This requires joint studies between utility and co-gen systems to identify the source of the problem and develop possible mitigation measures.

Stability fundamentals

Definition of stability

Fundamentally, stability is a property of a power system containing two or more synchronous machines. A system is stable, under a specified set of conditions, if, when subjected to one or more bounded disturbances (less than infinite magnitude), the resulting system response(s) are bounded. After a disturbance, a stable system could be described by variables that show continuous oscillations of finite magnitude (AC voltages and currents, for example) or by constants, or both. In practice, engineers familiar with stability studies expect that oscillations of machine rotors should be damped to an acceptable level within 6 s following a major disturbance. It is important to realize that a system that is stable by definition can still have stability problems from an operational point of view (oscillations may take too long to decay to zero, for example).

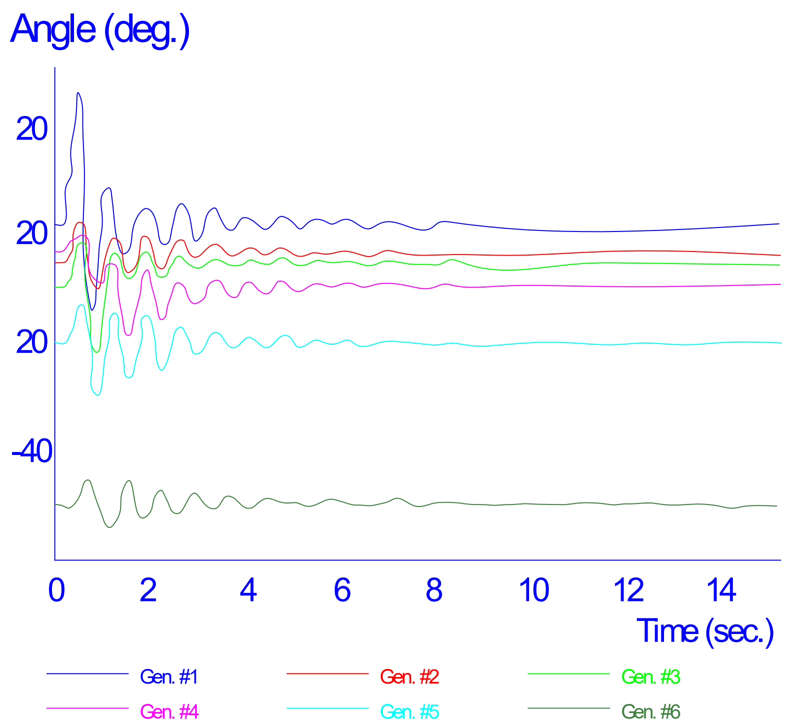

Figure 1—System response – No co-gen plant

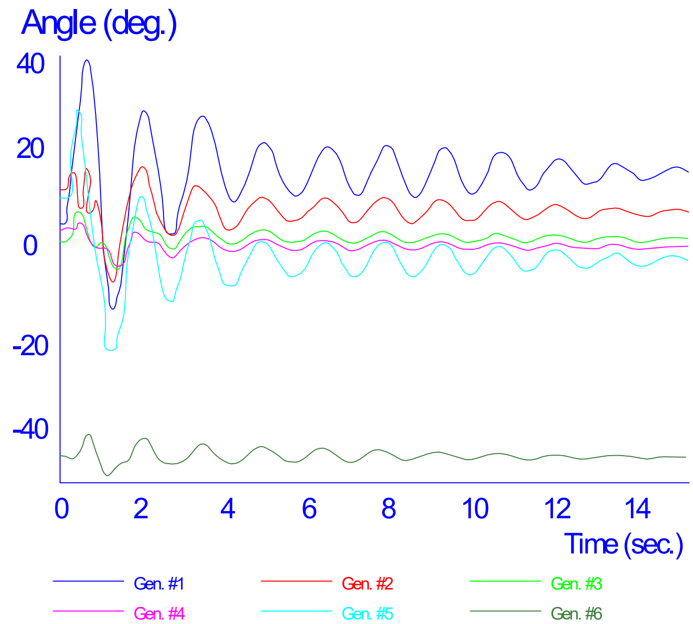

Figure 2—Low-frequency oscillation after the connection of the co-gen plant

Steady-state stability

Although the discussion in the rest of this chapter revolves around stability under transient and/or dynamic conditions, such as faults, switching operations, etc., there should also be awareness that a power system can become unstable under steady-state conditions. The simplest power system to which stability considerations apply consists of a pair of synchronous machines, one acting as a generator and the other acting as a motor, connected together through a reactance (see Figure 3). (In this model, the reactance is the sum of the transient reactance of the two machines and the reactance of the connecting circuit. Losses in the machines and the resistance of the line are neglected for simplicity.)

If the internal voltages of the two machines are E_G and E_M and the phase angle between them is θ, it can easily be demonstrated that the real power transmitted from the generator to the motor is:

$$P = \frac{E_G E_M}{X} \sin\theta$$

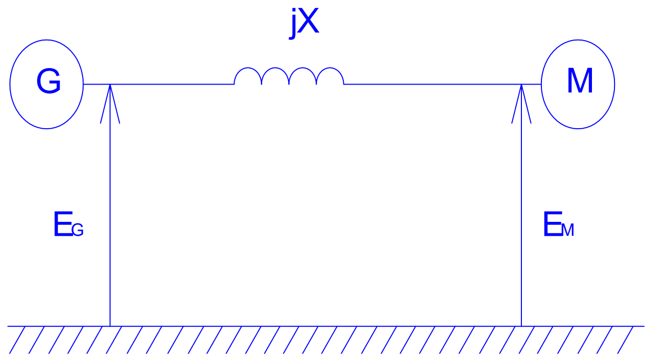

Figure 3—Simplified two-machine power system

The maximum value of *P* obviously occurs when θ = 90°. Thus

$$P_{max} = \frac{E_G E_M}{X}$$

This is the steady-state stability limit for the simplified two-machine system. Any attempt to transmit more power than P_{max} will cause the two machines to pull out of step (loose synchronism with each other) for particular values of internal voltages.

This simple example shows that at least three electrical characteristics of a power system affect stability. They are as follows:

- Internal voltage of the generator(s)
- Reactance(s) of the machines and transmission system
- Internal voltage of the motor(s), if any

The higher the internal voltages and the lower the system and machine reactances, the greater the power that can be transmitted under steady-state conditions.

Transient and dynamic stability

The preceding look at steady-state stability serves as a background for an examination of the more complicated problem of transient stability. This is true because the same three electrical characteristics that determine steady-state stability limits affect transient stability. However, a system that is stable under steady-state conditions is not necessarily stable when subjected to a transient disturbance.

Transient stability means the ability of a power system to experience a sudden change in generation, load, or system characteristics without a prolonged loss of synchronism. To see how a disturbance affects a synchronous machine, consider the steady-state characteristics described by the steady-state torque equation first.

$$T = \frac{\pi P^2}{8} \varphi_{SR} F_R \sin \delta_R$$

where

T is the mechanical shaft torque

P is the number of poles of machine

φ_{SR} is the air-gap flux

F_R is the rotor field MMF

δ_R is the mechanical angle between rotor and stator field lobes

The air-gap flux φ_{SR} stays constant as long as the internal voltage (which is directly related to field excitation) at the machine does not change and if the effects of saturation of the iron are neglected. Therefore, if the field excitation remains unchanged, a change in shaft torque T will cause a corresponding change in rotor angle δ_R. (This is the angle by which, for a motor, the peaks of the rotating stator field lead the corresponding peaks of the rotor field. For a generator, the relation is reversed.) Figure 4 graphically illustrates the variation of rotor angle with shaft torque. With the machine operating as a motor (when rotor angle and torque are positive), torque increases with rotor angle until δ_R reaches 90 electrical degrees. Beyond 90°, torque decreases with increasing rotor angle. As a result, if the required torque output of a synchronous motor is increased beyond the level corresponding to 90° rotor angle, it will *slip a pole*. Unless the load torque is reduced below the 90° level (the pullout torque), the motor will continue slipping poles indefinitely and is said to have lost synchronism with the supply system (and become unstable).

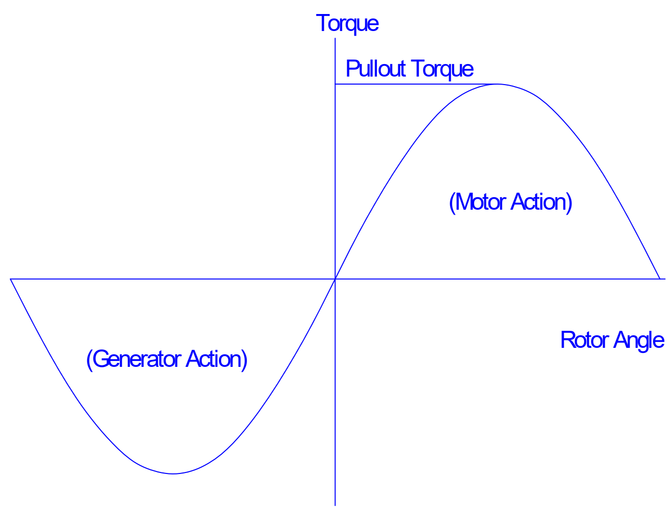

Figure 3—Torque vs. rotor angle relationship for synchronous machines in steady state

A generator operates similarly. Increasing torque input until the rotor angle exceeds 90° results in pole slipping and loss of synchronism with the power system, assuming constant electrical load.

Similar relations apply to the other parameters of the torque equation. For example, air-gap flux φ_{SR} is a function of voltage at the machine. Thus, if the other factors remain constant, a change in system voltage will cause a change in rotor angle. Likewise, changing the field excitation will cause a change in rotor angle if constant torque and voltage are maintained.

The preceding discussion refers to rather gradual changes in the conditions affecting the torque angle, so that approximate steady-state conditions always exist. The coupling between the stator and rotor fields of a synchronous machine, however, is somewhat elastic. This means that if an abrupt rather than a gradual change occurs in one or more of the parameters of the torque equation, the rotor angle will tend to overshoot the final value determined by the changed conditions. This disturbance can be severe enough to carry the ultimate steady-state rotor angle past 90° or the transient swing rotor angle past 180°. Either event results in the slipping of a pole. If the conditions that caused the original disturbance are not corrected, the machine will then continue to slip poles; in short, pulling out of step or loosing synchronism with the power system to which it is connected.

Of course, if the transient overshoot of the rotor angle does not exceed 180°, or if the disturbance causing the rotor swing is promptly removed, the machine may remain in synchronism with the system. The rotor angle then oscillates in decreasing swings until it settles to its final value (less than 90°). The oscillations are damped by electrical load and mechanical and electrical losses in the machine and system, especially in the damper windings of the machine.

A change in rotor angle of a machine requires a change in speed of the rotor. For example, if we assume that the stator field frequency is constant, it is necessary to at least momentarily slow down the rotor of a synchronous motor to permit the rotor field to fall farther behind the stator field and thus increases δ_R. The rate at which rotor speed can change is determined by the moment of inertia of the rotor plus whatever is mechanically coupled to it (prime mover, load, reduction gears, etc.).With all other variables equal, this means a machine with high inertia is less likely to become unstable given a disturbance of brief duration than a low-inertia machine.

Traditionally, transient stability is determined by considering only the inherent mechanical and electromagnetic characteristics of the synchronous machines and the impedance of the circuits connecting them. The responses of the excitation or governor systems to the changes in generator speed or electrical output induced by a system disturbance are neglected. On the other hand, *dynamic* stability takes automatic voltage regulator and governor system responses into account.

The traditional definition of transient stability is closely tied to the ability of a system to remain in synchronism for a disturbance. Transient stability studies are usually conducted under the assumptions that excitation and governor-prime mover time constants are much longer than the duration of the instability-inducing disturbance.

However, technological advances have rendered the assumption underlying these conventional concepts of transient stability obsolete in most cases. These include the advent of fast electronic excitation systems and governors, the recognition of the value of stability analysis for investigating conditions of widely varying severity and duration, and the virtual elimination of computational power as a constraint on system modelling complexity. Most transient stability studies performed today consider at least the generator excitation system, and are therefore actually dynamic studies under the conventional conceptual definition.

Two-machine systems

The previous discussion of transient behaviour of synchronous machines is based on a single machine connected to a good approximation of an infinite bus. An example is the typical industrial situation where a synchronous motor of at most a few thousand horsepower is connected to a utility company system with a capacity of thousands of megawatts. Under these conditions, we can safely neglect the effect of the machine on the power system.

A system consisting of only two machines of comparable size connected through a transmission link, however, becomes more complicated because the two machines can affect each other's performance. The medium through which this occurs is the air-gap flux. This is a function of machine terminal voltage, which is affected by the characteristics of the transmission system, the amount of power being transmitted, the power factor, etc.

In the steady state, the rotor angles of the two machines are determined by the simultaneous solution of their respective torque equations. Under a transient disturbance, as in the single-machine system, the rotor angles move toward values corresponding to the changed system conditions. Even if these new values are within the steady-state stability limits of the system, an overshoot can result in loss of synchronism. If the system can recover from the disturbance, both rotors will undergo a damped oscillation and ultimately settle to their new steady-state values.

An important concept here is synchronizing power. The higher the real power transfer capability over the transmission link between the two machines, the more likely they are to remain in synchronism in the face of a transient disturbance. Synchronous machines separated by sufficiently low impedance behave as one composite machine, since they tend to remain in step with one another regardless of external disturbances.

Multi-machine systems

At first glance, it appears that a power system incorporating many synchronous machines would be extremely complex to analyse. This is true if a detailed, precise analysis is needed; a sophisticated program is required for a complete stability study of a multi-machine system. However, many of the multi-machine systems encountered in industrial practice contain only synchronous motors that are similar in characteristics, closely coupled electrically, and connected to a high-capacity utility system. Under most type of disturbances, motors will remain in synchronism with each other, although they can all loose synchronism with the utility. Thus, the problem most often encountered in industrial systems is similar to a single synchronous motor connected through impedance to an infinite bus. The simplification should be apparent. Stability analysis of more complex systems where machines are of comparable sizes and are separated by substantial impedance will usually require a full-scale computer stability study.

Problems caused by instability

The most immediate hazards of asynchronous operation of a power system are the high transient mechanical torque and currents that usually occur. To prevent these transients from causing mechanical and thermal damage, synchronous motors and generators are almost universally equipped with pull-out protection. For motors of small to moderate sizes, this protection is usually provided by a damper protection of pull-out relay that operates on the low power factor occurring during asynchronous operation. The same function is usually provided for large motors, generators, and synchronous condensers by loss-of-field relaying. In any case, the pull-out relay trips the machine breaker or contactor. Whatever load is being served by the machine is naturally interrupted. Consequently, the primary disadvantage of a system that tends to be unstable is the probability of frequent process interruptions.

Out of step operation also causes large oscillatory flows of real and reactive power over the circuits connecting the out-of-step machines. Impedance or distance-type relaying that protects these lines can falsely interpret power surges as a line fault, tripping the line breakers and breaking up the system. Although this is primarily a utility problem, large industrial systems or those where local generation operates in parallel with the utility can be susceptible.

In any of these cases, an industrial system can be separated from the utility system. If the industrial system does not have sufficient on-site generation, a proper load shedding procedure is necessary to prevent total loss of electrical power. Once separated from the strength of the utility, the industrial system becomes a rather weakly connected island and is likely to encounter additional stability problems. With the continuance of problems, protection systems designed to prevent equipment damage will likely operate, thus producing the total blackout.

System disturbances that can cause instability

The most common disturbances that produce instability in industrial power systems are (not necessarily in order of probability):

- Short circuits
- Loss of a tie circuit to a public utility
- Loss of a portion of on-site generation

- Starting a motor that is large relative to a system generating capacity
- Switching operations
- Impact loading on motors
- Abrupt decrease in electrical load on generators

The effect of each of these disturbances should be apparent from the previous discussion of stability fundamentals.

Solutions to stability problems

Generally speaking, changing power flow patterns and decreasing the severity or duration of a transient disturbance will make the power system less likely to become unstable under that disturbance. In addition, increasing the moment of inertia per rated kVA of the synchronous machines in the system will raise stability limits by resisting changes in rotor speeds required to change rotor angles.

System design

System design primarily affects the amount of synchronizing power that can be transferred between machines. Two machines connected by a low impedance circuit, such as a short cable or bus run, will probably stay synchronized with each other under all conditions except a fault on the connecting circuit, a loss of field excitation, or an overload. The greater the impedance between machines, the less severe a disturbance will be required to drive them out of step. For some systems, the dynamic stability problems could be resolved by the construction of new connecting circuits. This means that from the standpoint of maximum stability, all synchronous machines should be closely connected to a common bus. Limitations on short-circuit duties, economics, and the requirements of physical plant layout usually combine to render this radical solution impractical.

Design and selection of rotating equipment

Design and selection of rotating equipment and control parameters can be a major contributor to improving system stability. Most obviously, use of induction instead of synchronous motors eliminates the potential stability problems associated with the latter. (Under rare circumstances, an induction motor/synchronous generator system can experience instability, in the sense that undamped rotor oscillations occur in both machines, but the possibility is too remote to be of serious concern.) However, economic considerations often preclude this solution.

Where synchronous machines are used, stability can be enhanced by increasing the inertia of the mechanical system. Since the H constant (stored energy per rated kVA) is proportional to the square of the speed, fairly small increases in synchronous speed can pay significant dividends in higher inertia. If carried too far, this can become self-defeating because higher speed machines have smaller diameter rotors. Kinetic energy varies with the square of the rotor radius, so the increase in H due to a higher speed may be offset by a decrease due to the lower kinetic energy of a smaller diameter rotor. Of course, specifications of machine size and speed are dependent on the mechanical nature of the application and these concerns may limit the specification flexibility with regard to stability issues.

A further possibility is to use synchronous machines with low transient reactance that permit the maximum flow of synchronizing power. Applicability of this solution is limited mostly by short-circuit considerations, starting current limitations, and machine design problems.

Voltage regulator and exciter characteristics

Voltage regulator and exciter characteristics affect stability because, all other things being equal, higher field excitation requires a smaller rotor angle. Consequently, stability is enhanced by a properly applied regulator and exciter that respond rapidly to transient effects and furnish a high degree of field forcing. In this respect, modern solid-state voltage regulators and static exciters can contribute markedly to improved stability. However, a mismatch in exciter and regulator characteristics can make an existing stability problem even worse.

Application of power system stabilizers (PSSs)

The PSS installation has been widely used in the power industry to improve the system damping. The basic function of a PSS is to extend stability limits by modulating generator excitation to provide damping to the oscillation of a synchronous machine rotor. To provide damping, the PSS must produce a component of electrical torque on the rotor that is in phase with speed variations. The implementation details differ, depending upon the stabilizer input signal employed. However, for any input signal, the transfer function of the stabilizer must compensate for the gain and phase characteristics of the excitation system, the generator, and the power system, which collectively determine the transfer function from the stabilizer output to the component of electrical torque, which can be modulated via excitation control. To install the PSS in the power system to solve the dynamic stability problem, one has to determine the installation site and the settings of PSS parameters. This job can be realized through frequency domain analysis.

System protection

System protection often offers the best prospects for improving the stability of a power system. The most severe disturbance that an industrial power system is likely to experience is a short circuit. To prevent loss of synchronism, as well as to limit personnel hazards and equipment damage, short circuits should be isolated as rapidly as possible. A system that tends to be unstable should be equipped with instantaneous overcurrent protection on all of its primary feeders, which are the most exposed section of the primary system. As a general rule, instantaneous relaying should be used throughout the system wherever selectivity permits.

System stability analysis

Stability studies, as much or more than any other type or power system study described in this text, have benefited from the advent of the computer. This is primarily due to the fact that stability analysis requires a tremendous number of iterative calculations and the manipulation of a large amount of time and frequency-variant data.

Time- and frequency-domain analysis

Time and frequency-domain (eigenvalue analysis) techniques are, by far, the most common analytical methods used by power system stability programs. Time-domain analysis utilizes the angular displacement of the rotors of the machines being studied, often with respect to a common reference, to determine stability conditions. The differences between these rotor angles are small for stable systems. The rotor angles of machines in unstable systems drift apart with time. Thus, time-domain analysis can be used to determine the overall system response to potentially instability-inducing conditions, but it is limited when one is attempting to identify oscillation modes.

Frequency-domain analysis, on the other hand, can be used to identify each potential oscillation frequency and its corresponding damping factor. Therefore, the powerful frequency-domain techniques are particularly suited for dynamic stability applications whereas time-domain techniques are more useful in transient stability analysis. Fortunately, dynamic stability can also be evaluated by the shapes of the swing curves of synchronous machine rotor angles as they vary with time. Therefore, time-domain analysis can be used for dynamic stability as well.

How stability programs work

Mathematical methods of stability analysts depend on a repeated solution of the swing equation for each machine:

$$P_a = \frac{(MVA)H}{180f}\frac{d^2\delta_R}{dt^2}$$

where

P_a is the accelerating power (input power minus output power) (MW)

MVA is the rated MVA of machine

H is the inertia constant of machine (MW·seconds/MVA)

f is the system frequency (Hz)

δ_R is the rotor angle (degrees)

t is the time (seconds)

The program begins with the results of a load flow study to establish initial power and voltage levels in all machines and interconnecting circuits. The specified disturbance is applied at a time defined as zero, and the resulting changes in power levels are calculated by a load flow routine. Using the calculated accelerating power values, the swing equation is solved for a new value of δ_R for each machine at an incremental time (the incremental time should be less than one-tenth of the smallest machine time constant to limit numerical errors) after the disturbance. Voltage and power levels corresponding to the new angular positions of the synchronous machines are then used as base information for next iteration. In this way, performance of the system is calculated for every interval out to as much as 15 s.

Simulation of the system

A modern transient stability computer program can simulate virtually any set of power system components in sufficient detail to give accurate results. Simulation of rotating machines and related equipment is of special importance in stability studies. The simplest possible representation for a synchronous motor or generator involves only a constant internal voltage, a constant transient reactance, and the rotating inertia (H) constant. This approximation neglects saturation of core iron, voltage regulator action, the influence of construction of the machine on transient reactance for the direct and quadrature axes, and most of the characteristics of the prime mover or load. Nevertheless, this classical representation is often accurate enough to give reliable results, especially when the time period being studied is rather short. (Limiting the study to a short period—say, 1/2 s or less, means that neither the voltage regulator nor the governor, if any, has time to exert a significant effect.) The classical representation is generally used for the smaller and less influential machines in a system, or where the more detailed information required for better simulations is not available.

As additional data on the machines becomes available, better approximations can be used. This permits more accurate results that remain reliable for longer time periods. Modern large-scale stability programs can simulate all of the following characteristics of a rotating machine:

Induction motors can also be simulated in detail, together with speed-torque characteristics of their connected loads. In addition to rotating equipment, the stability program can include in its simulation practically any other major system component, including transmission lines, transformers, capacitor banks, and voltage-regulating transformers and dc transmission links in some cases.

Simulation of disturbances

The versatility of the modern stability study is apparent in the range of system disturbances that can be represented. The most severe disturbance that can occur on a power system is usually a three-phase bolted short circuit. Consequently, this type of fault is most often used to test system stability. Stability programs can simulate a three-phase fault at any location, with provisions for clearing the fault by opening breakers either after a specified time delay, or by the action of overcurrent, under-frequency, overpower, or impedance relays. This feature permits the adequacy of proposed protective relaying to be evaluated from the stability standpoint.

- Voltage regulator and exciter
- Steam system or other prime mover, including governor
- Mechanical load
- Damper windings
- Salient poles

- Saturation

Short circuits other than the bolted three-phase fault cause less disturbance to the power system. Although most stability programs cannot directly simulate line-to-line or ground faults, the effects of these faults on synchronizing power flow can be duplicated by applying a three-phase fault with properly chosen fault impedance. This means the effect of any type of fault on stability can be studied.

In addition to faults, stability programs can simulate switching of lines and generators. This is particularly valuable in the load-shedding type of study, which will be covered in a following section. Finally, the starting of large motors on relatively weak power systems and impact loading of running machines can be analysed.

Data requirements for stability studies

The data required to perform a transient stability study and the recommended format for organizing and presenting the information for most convenient use are covered in detail in the application guides for particular stability programs. The following is a summary of the generic classes of data needed. Note that some of the more esoteric information is not essential; omitting it merely limits the accuracy of the results, especially at times exceeding five times the duration of the disturbance being studied.

- System data
- Impedance (R + jX) of all significant transmission lines, cables, reactors, and other series components
- For all significant transformers and autotransformers
- kVA rating
- Impedance
- Voltage ratio
- Winding connection
- Available taps and tap in use
- For regulators and load tap-changing transformers: regulation range, tap

step size, type of tap changer control

- Short-circuit capacity (steady-state basis) of utility supply, if any
- kvar of all significant capacitor banks
- Description of normal and alternate switching arrangements
- Load data: real and reactive electrical loads on all significant load buses in the system
- Rotating machine data
- For major synchronous machines (or groups of identical machines on a common bus)
- Mechanical and/or electrical power ratings (kVA, hp, kW, etc.)
- Inertia constant H or inertia Wk^2 of rotating machine and connected load or prime mover
- Speed
- Real and reactive loading, if base-loaded generator
- Speed torque curve or other description of load torque, if motor
- Direct-axis subtransient, transient, and synchronous reactances
- Quadrature-axis subtransient, transient, and synchronous reactance
- Direct-axis and quadrature-axis subtransient and transient time constants
- Saturation information
- Potier reactance
- Damping data
- Excitation system type, time constants, and limits
- Governor and steam system or other prime mover type, time constants, and limits
- For minor synchronous machines (or groups of machines)
- Mechanical and/or electrical power ratings
- Inertia
- Speed
- Direct-axis synchronous reactance
- For major induction machines or groups of machines
- Mechanical and/or electrical power ratings

- Inertia
- Speed
- Positive-sequence equivalent circuit data (e.g., $R1$, $X1$, X_M)
- Load speed-torque curve
- Negative-sequence equivalent circuit data (e.g., R_2, X_2)
- Description of reduced-voltage or other starting arrangements
- For small induction machines: detailed dynamic representation not needed, represent as a static load
- Disturbance data
- General description of disturbance to be studied, including (as applicable) initial switching status; fault type, location, and duration; switching operations and timing; manufacturer, type, and setting of protective relays; and clearing time of associated breakers
- Limits on acceptable voltage, current, or power swings
- Study parameters
- Duration of study
- Integrating interval
- Output printing interval
- Data output required

Stability program output

Most stability programs give the user a wide choice of results to be printed out. The program can calculate and print any of the following information as a function of time under time domain analysis:

- Rotor angles, torques, and speeds of synchronous machines
- Real and reactive power flows throughout the system
- Voltages and voltage angles at all buses
- Bus frequencies
- Torques and slips of all induction machines

The combination of these results selected by the user can be printed out for each printing interval (also user selected) during the course of the study period.

The value of the study is strongly affected by the selection of the proper printing interval and the total duration of the simulation. Normally, a printing interval of 0.01 or 0.02 s is used; longer intervals reduce the solution time slightly, but increase the risk of missing fast swings of rotor angle. The time required to obtain a solution is proportional to the length or the period being studied, so this parameter should be closely controlled for the sake of economy.

Avoiding long study periods is especially important if the system and machines have been represented approximately or incompletely because the errors will accumulate and render the results meaningless after some point. A time limit of five times the duration of the major disturbance being studied is generally long enough to show whether the system is stable (in the transient stability sense) or not, while keeping solution time requirements to reasonable levels.

Frequency domain analysis will calculate the eigenvalues to determine the stability characteristics of the system. For a large utility system, most programs can only provide dominant eigenvalue(s) of the system. This information is sufficient for most stability studies except multi-dominant eigenvalues situations.

Interpreting results

The results of a computer stability study are fairly easy to understand once the user learns the basic principles underlying stability problems. The most direct way to determine from study results whether a system is stable is to look at a set of swing curves for the machines in the system. Swing curves are simply plots of rotor angles or machine frequencies (rotor speeds) versus time; if the curves of all the machines involved are plotted on common axes, we can easily see whether they diverge (indicating instability) or settle to new steady-state values. Even if the system is stable, a poor damping situation is not acceptable from the security operation point of view. As previously mentioned, most utility engineers expect that any oscillations should be damped to an acceptable value within 6 s. The system responses, as shown in both Figure 1 and Figure 5, have good damping factors, and the system returns to normal within a reasonable time frame. However, the situation depicted in Figure 2 is considered marginal, even though the system is still stable by definition (oscillations are clearly bounded). In a frequency domain analysis of this same system, one can expect that all the eigenvalues of the system should lie in the left-half of the s-plane, and most utility engineers consider that the real part of the dominant eigenvalues should be less than –0.2 to –0.3 (time constant is between 3.33 to 5 s) for a normal power system. The time domain responses for various root locations in the frequency domain are shown in Figure 6.

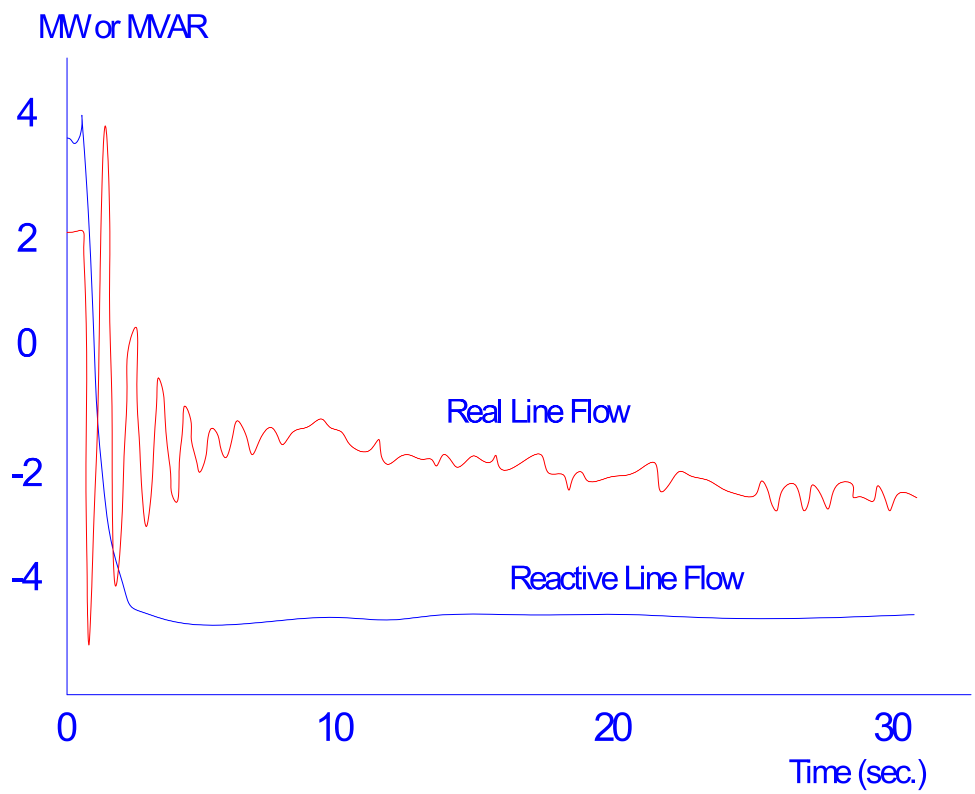

Figure 5—Oscillation record of the tie line between co-gen and utility

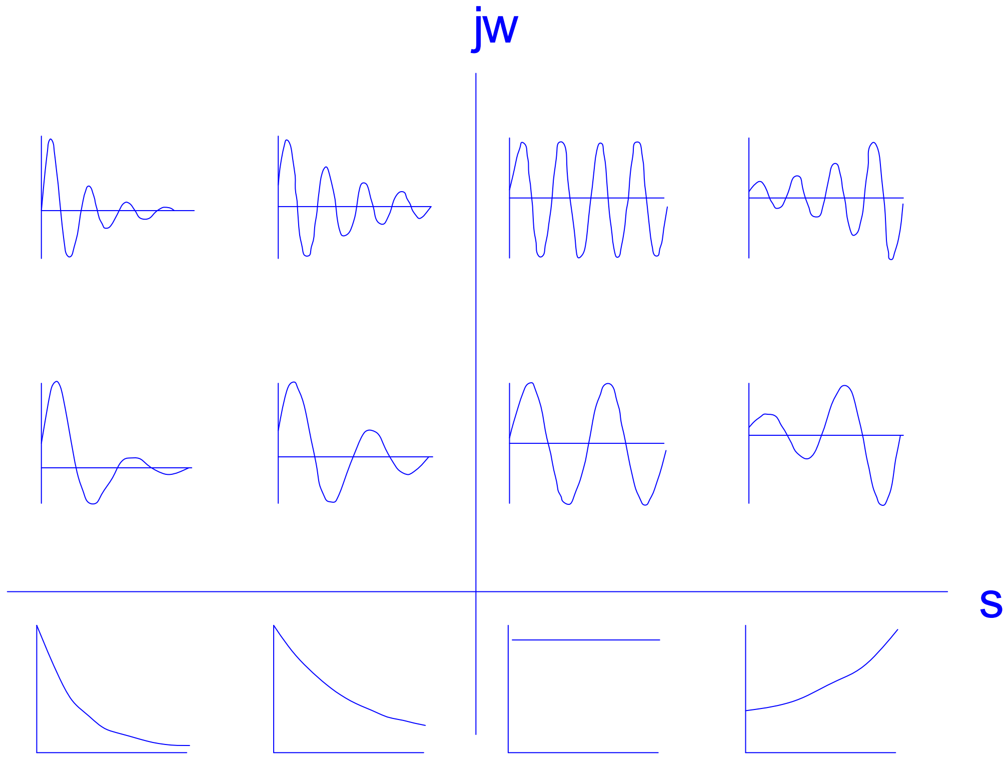

Figure 6—The response for various root locations in the frequency domain

Stability studies of industrial power systems

The requirement of stability studies depends on the operating conditions of the industrial power systems. This sub clause is intended to summarize the so-called "things to look for" under different operating conditions and disturbance scenarios.

A co-gen plant with excess generation

Consider the situation where a co-gen plant is exporting power to the connected utility company when a severe disturbance occurs. If the tie line(s) between co-gen and utility company are tripped, the co-gen facility becomes islanded. Because the plant has enough generation to support its own operation, stability problems within the facility are less likely to happen. However, the following should be checked to ensure secure operation.

- Transient stability problem. Generally speaking, the inertia of the co-gen units is smaller than the utility generators. They tend to respond faster to a system disturbance. If the fault happens in the vicinity of the plant and is not cleared before the critical clearing time, the speed of the units inside the plant may increase rapidly and the units may lose synchronism. Figure 7 illustrates this phenomenon. A faster circuit breaker can be used to avoid this problem.

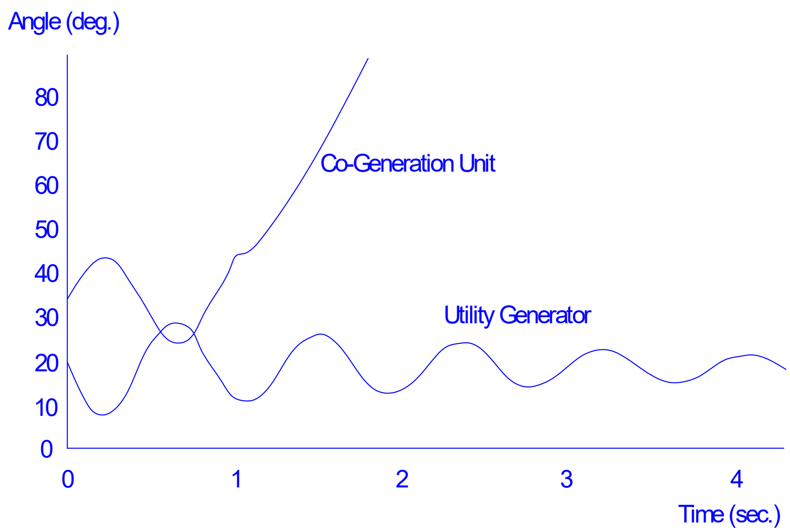

Figure 7—Out of step phenomenon of co-gen unit(s) under severe disturbance

- Potential over-frequency. Because the plant has excess power before islanding occurs, the frequency within the co-gen plant will rise after the interruption. The exact extent of the frequency deviation depends on the level of excess power and the response of the machine governors.
- Voltage problems. If the co-gen facility exports reactive power before the disturbance, the system may experience overvoltage phenomena following the separation. On the contrary, if the co-gen facility is importing reactive power, then an under-voltage problem may arise. The ability to overcome the voltage problems depends on the response of the automatic voltage regulators (AVRs) within the plant.
- In-plant oscillations. For some co-gen plants, a series reactor is inserted in the line to limit the fault currents. This may cause the generators to be loosely coupled from the electrical standpoint, even though are physically located within a plant. During the

disturbance, two generators within the plant may experience oscillations often called hunting. Figure 8 shows a typical hunting oscillation of two generators. One can see that the output of the generators is basically out-of-phase.

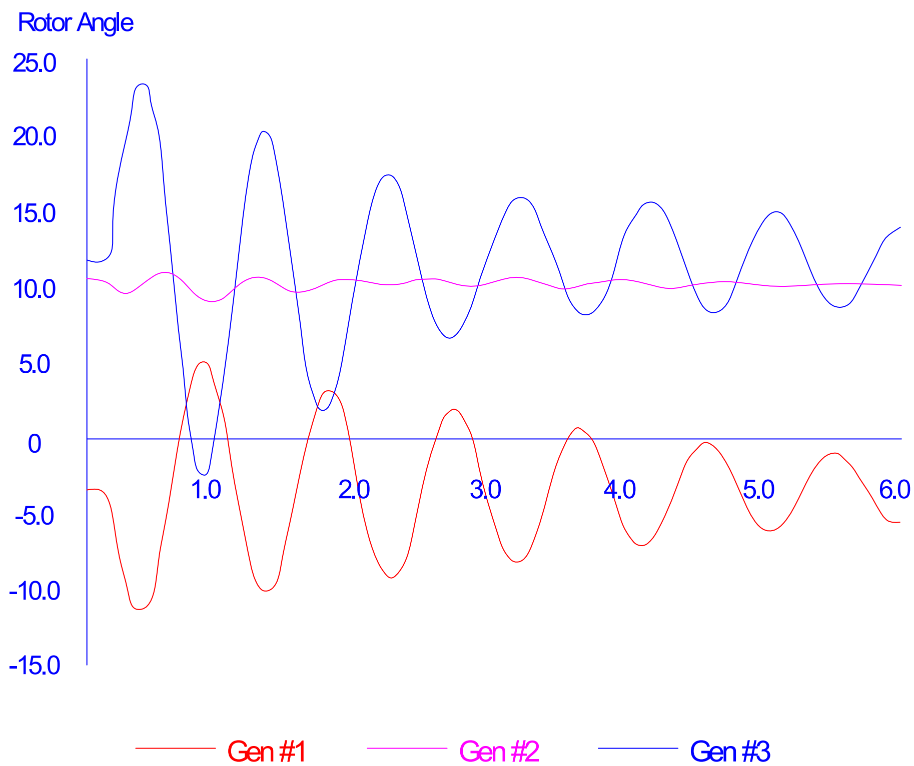

Figure 8—Hunting phenomena of two generator units

Co-gen plant that imports power from local utility

A co-gen plant relies on the supply from the local utility under normal operating conditions and the tie line(s) between the plant and the utility company are interrupted due to a system fault. Because the plant does not have enough generation to support its own operation, stability problems may happen. In order to protect the system from total blackout, an appropriate load shedding procedure has to be in place for safe operation. The following problems may happen under this scenario.

- Potential under-frequency. Because the co-gen plant has to import power before islanding, the frequency within the co-gen plant will decline after the interruption. The exact extent of the frequency deviation depends on the level of the power deficiency and the response of the machine governors. A proper load-shedding procedure may be needed to maintain continuing operation of critical loads.

- Voltage problems. When the load-shedding procedure is activated, a certain percentage of the real and reactive power is interrupted. The plant may face potential over-voltage problems. The situation may be compounded if the plant is exporting reactive power before islanding.

Oscillations between industrial power plant and utility system

The causes of low-frequency oscillation phenomena in a power system are complex. If the capacity of the industrial power plant is small compared to the connected utility system, the likelihood of having oscillations between industrial plant and utility system is generally very small. However, if the size of the industrial power plant is comparable to the capacity of the local utility, a detailed simulation including both the industrial power plant and the local utility has to be performed to ensure secure operation of the system. The system structure, operation conditions, and excitation systems frequently play important roles in low-frequency oscillation. It is necessary to distinguish the causes and the reasons before trying to solve the problem. In time domain analysis, the mode of oscillation cannot be identified exactly, but the potential oscillation phenomena can be investigated. The following steps can be considered as standard procedure to identify the possible causes of the low-frequency oscillation.

Response of the system before connection

The first step is to identify whether the dynamic stability problem is a pre-existing problem. If the problem exists before the connection, it is the responsibility of the utility to solve the problem. However, the plant still needs to provide information for detailed system analysis including specifics regarding on-site generation.

Different line flow between utility and co-gen plant

As a rule of thumb, the stability limit is the upper bound of the transfer capability of the interconnecting line(s) and transformer(s). The system is going to have stability problems if the transfer limits exceed this value. Therefore, the least-cost step is to investigate the possible solution(s) for low-frequency oscillation by adjusting the power flow of the interconnecting equipment.

Reduced impedance of the interconnected transmission

A system is less likely to have stability problems if the generators are electrically close together. Sometimes the stability problem will go away after the construction of a new transmission line, the reconfiguration of the utility supply, or some other system change. Lowering system impedances will reduce the electrical distance of the generation units and establish a stronger tie between co-gen and utility systems. The effectiveness of reducing impedances to increase system stability can be determined easily using modern computer programs.

Reduce fault clearing time

The longer a disturbance is on the system, the larger the frequency deviation and the phase angle separation can be. Therefore, fault duration may affect the recovery capability of the system after a severe disturbance. With today's technology, high-speed relays and breakers are available to clear the fault within a few cycles. This is an effective method of dealing with many transient stability problems.

System separation

Though this is not the most favourable solution, it is an effective measure to mitigate the problem if it appeared after the connection of both systems. However, if the utility imports power from the co-gen plant before the disturbance, system separation means loss of generation capacity. This may compound the problem on the utility side and should therefore be studied carefully.

Installation of a power system stabilizer (PSS)

The PSS installation has been widely used in the power industry to improve the system damping. To install the PSS in the power system to solve the dynamic stability problem, one has to determine the installation site and the setting of PSS parameters. This job can be realized through frequency domain analysis. The basic function of a PSS is to extend stability limits by modulating generator excitation to provide damping to the oscillation of a synchronous machine rotor. Since site selection and setting of a PSS are very sensitive to the system parameters, accuracy of the system information is vital in this type of study.

Summary and conclusions

Power systems are highly nonlinear and the dynamic characteristic of a power system varies if the system loading, generation schedule, network interconnection, and/or type of system protection are changed. When a co-gen plant is connected to the utility grid, it changes the system configuration and power flow pattern in the utility. This may result in some unwanted system stability problems from low-frequency oscillations. The evaluation of potential problems and solution methods prior to the connection of the co-gen plant becomes a challenging task for the power engineer.

From the industrial power plant point of view, stability problems appear as over/under voltages and frequencies and may lead to the operation of protection equipment and the initiation of load-shedding schemes. While there is no single way to design a system that will always remain stable, the use of low-impedance interconnections (where possible considering fault duties) and fast-acting control systems are definite options to consider when designing for maximum stability. It is important to consider problems that could originate in either the utility or industrial system, or both, and the impact of subsequent disturbances that are associated with protective device operation and load-shedding initiated by the original event.