POWER SWING AND OUT-OF-STEP CONSIDERATIONS ON TRANSMISSION LINES

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A report to the Power System Relaying Committee Of the IEEE Power Engineering Society

Abstract

The August 14, 2003 blackout in the Northeastern United States and Southeastern Canada has led to substantial scrutiny of many aspects of transmission line protection. One of the more difficult and commonly misunderstood issues being addressed is that of power swing and out-of-step protection applied to transmission lines.

This paper begins with clarifying the proper use of the terms power swing and out-of-step. The paper then provides a brief discussion of these phenomena, how these phenomena affect the protective relaying on transmission lines, and explains many of the methods available that protective relays use to detect power swings and out-of-step conditions.

Problems associated in the application of power swing protection and risks involved in applying, or not applying such protection, are identified and discussed.

The Appendix includes examples of relay calculations and settings, a computer simulation plot of an OOS condition, an example DFR record during a severe power swing condition, and additional informational articles.

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1 INTRODUCTION

Changes in regulations and the opening of the power markets are causing rapid changes in the way the power grid is operated. Large amounts of power are commonly shipped across a transmission system that was not designed for such transactions. Independently owned and operated generating units are being built in locations that may not be optimum for system stability and system needs, often where a natural gas pipeline passes near a transmission line. Power plant systems are being upgraded to get every possible megawatt out. The results of these upgrades often make the generating units more susceptible to instability.

Power systems in the U.S. have experienced a number of large disturbances in the last ten years, including the largest blackout, which occurred on August 14, 2003 in the Northeast U.S. and Southeast Canada impacting 50 million customers and removing 50 GW of power. The July 2, 1996 and August 10, 1996 major system disturbances also impacted several million customers in the Western U.S. All of these disturbances caused considerable loss of generation and loads and had a tremendous impact on customers and the economy in general. Typically, these disturbances happen when the power systems are heavily loaded and a number of multiple outages occur within a short period of time, causing power oscillations between neighboring utility systems, low network voltages, and consequent voltage instability or angular instability.

Power systems under steady-state conditions operate typically close to their nominal frequency. A balance between generated and consumed active and reactive powers exists during steady-state operating conditions and the sending and receiving end voltages are typically within 5%. The system frequency on a large power system will typically vary +/- 0.02 Hz on a 60 Hz power system. Power system faults, line switching, generator disconnection, and the loss or application of large blocks of load result in sudden changes to electrical power, whereas the mechanical power input to generators remains relatively constant. These system disturbances cause oscillations in machine rotor angles and can result in severe power flow swings. Depending on the severity of the disturbance and the actions of power system controls, the system may remain stable and return to a new equilibrium state experiencing what is referred to as a stable power swing. Severe system disturbances, on the other hand, could cause large separation of generator rotor angles, large swings of power flows, large fluctuations of voltages and currents, and eventual loss of synchronism between groups of generators or between neighboring utility systems. Large power swings, stable or unstable, can cause unwanted relay operations at different network locations, which can aggravate further the power-system disturbance and possibly lead to cascading outages and power blackouts.

In light of recent regulation changes and the August 14, 2003 blackout in the Northeastern US and Southeast Canada, it is prudent to raise awareness of the impacts to the power system brought by power swing and out-of-step (OOS) phenomena, and the complexities involved in applying power swing blocking (PSB) and out-of-step tripping (OST) protection. This report makes an attempt to provide the fundamental aspects of power swing protection relaying and to help protection engineers in the proper application of PSB and OST relay functions.

2 DEFINITIONS

Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.

Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.

Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.

Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.

Out-of-Step Condition: Same as an unstable power swing.

Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

3 POWER-SWING PHENOMENA AND THEIR EFFECT ON TRANSMISSION LINE RELAYING

3.1 FUNDAMENTAL POWER-SWING DETECTION PROBLEM

The power grid is a very dynamic network connecting generation to load via transmission lines. Power systems under steady-state conditions operate very close to their nominal frequency and typically maintain absolute voltage differences between busses of 5%. The system frequency on a 60 Hz system normally varies by less than +/- 0.02 Hz. A balance between generated and consumed active and reactive power exists during steady-state operating conditions. Any change in the power generated, load demand or in the transmission line network causes the power flow to change across the system until a new equilibrium is established between generation and load. These changes in power flow occur continuously, are automatically compensated for via control systems, and normally have no detrimental effect on the power grid or its protective systems.

Power system faults, line switching, generator disconnection, and the loss or application of large blocks of load result in sudden changes to electrical power, whereas the mechanical power input to generators remains relatively constant. These system disturbances cause oscillations in machine rotor angles and can result in severe power flow swings. Power swings are variations in power flow that occur when the internal voltages of generators at different locations of the power system slip relative to each other. Large power swings, stable or unstable, can cause unwanted relay operations at different network locations, which can aggravate the power-system disturbance and cause major power outages or power blackouts.

Power swings can, for example, cause the load impedance, which under steady state conditions is not within the relay's operating characteristic, to enter into the relay's operating characteristic. Operation of these relays during a power swing may cause undesired tripping of transmission lines or other power system elements, thereby weakening the system and possibly leading to cascading outages and the shutdown of major portions of the power system. Distance or other relays should not trip unintentionally during dynamic system conditions such as stable or unstable power swings, and allow the power system to return to a stable operating condition. Distance relay elements prone to operate during stable or transient power swings should be temporarily inhibited from operating to prevent system separation from occurring at random or in other than pre-selected locations. A Power Swing Block (PSB) function is available in modern relays to prevent unwanted distance relay element operation during power swings. The main purpose of the PSB function is to differentiate between faults and power swings and block distance or other relay elements from operating during a power swing. However, faults that occur during a power swing must be detected and cleared with a high degree of selectivity and dependability.

Severe system disturbances could cause large separation of the rotor angles between groups of generators and eventual loss of synchronism between groups of generators or between neighboring utility systems. When two areas of a power system, or two interconnected systems, lose synchronism, the areas must be separated from each other quickly and automatically to avoid equipment damage and power blackouts. Ideally, the systems should be separated in predetermined locations to maintain a load-generation balance in each of the separated areas.

System separation may not always achieve the desired load-generation balance. In cases where the separated area load is in excess of local generation, some form of load shedding is necessary to avoid a complete blackout of the area. Uncontrolled tripping of circuit breakers during an Out-of-Step (OOS) condition could cause equipment damage, pose a safety concern for utility personnel, and further contribute to cascading outages and the shutdown of larger areas of the power system. Therefore, controlled tripping of certain power system elements is necessary to prevent equipment damage and widespread power outages and to minimize the effects of the disturbance. The Out-of-Step Trip (OST) function accomplishes this separation. The main purpose of the OST function is to differentiate stable from unstable power swings and initiate system area separation at the predetermined network locations and at the appropriate source-voltage phase-angle difference between systems, in order to maintain power system stability and service continuity.

The difference in the rate of change of the positive-sequence impedance vector has been used traditionally in PSB and OST functions to detect a power swing or an OOS condition and to block (or not block) the operation of one or more of the distance protection elements before the impedance enters the protective relay operating characteristics. This detection method is based on the fact that it takes a certain time for the rotor angle to advance because of system inertias. In other words, the rate of change of the impedance phasor is slow during power swings. It takes a finite time for the generator rotors to change position with respect to each other because of their large inertias. On the contrary, the rate of change of the impedance phasor is very fast during a system fault. Actual implementation of measuring the impedance rate of change is normally performed through the use of two impedance measurement elements together with a timing device. If the measured impedance stays between the settings of the two impedance measurement elements for a predetermined time, the relay declares a power swing condition and issues a blocking signal to block the distance relay element operation. After a predetermined time the relay will trip if the power swing element is not reset. It is not recommended to apply power swing blocking for unstable power swings without some form of OST being applied at some predetermined location.

The required settings for the PSB and OST elements could be difficult to calculate in many applications. For these applications, extensive stability studies with different operating conditions must be performed to determine the fastest rate of possible power swings. This is a costly exercise, and one can never be certain that all possible scenarios and operating conditions were considered.

3.2 EFFECT OF POWER SWINGS ON TRANSMISSION LINE RELAYS AND RELAY SYSTEMS

The loss of synchronism between power systems or a generator and the power system affects transmission line relays and systems in various ways. The required settings for the PSB and OST elements could be difficult to calculate in many applications. For these applications, extensive stability studies with different operating conditions must be performed to determine the fastest rate of possible power swings. In fact, some transmission line relays may operate for stable power swings for which the system should recover and remain stable.

Instantaneous phase overcurrent relays will operate during OOS conditions if the line current during the swing exceeds the pickup setting of the relay. Likewise, directional instantaneous overcurrent relays operate if the swing current exceeds the pickup setting of the relay and the polarizing and operating signals have the proper phase relationship during the swing. Time-overcurrent relays will probably not operate but this will depend on the swing current magnitude and the time delay settings of the relay.

Phase distance relays respond to positive-sequence quantities. The positive-sequence impedance measured at a line terminal during an OOS condition varies as a function of the phase angle separation, δ, between the two equivalent system source voltages. Zone 1 distance relay elements, with no intentional time delay will be the distance relay elements most prone to operate during a power swing. Also very likely to operate during swings are the distance relay elements used in pilot relaying systems, for example blocking or permissive type relay systems. Backup zone step distance relay elements will not typically operate during a swing, depending on their time-delay setting and the time it takes for the swing impedance locus to traverse through the relay characteristic. Figure 1a shows the operation of a Zone 1 distance relay when the swing locus goes through its operating characteristic and Figure 1b shows a directional comparison blocking scheme characteristic and how it may be impacted by the swing locus.

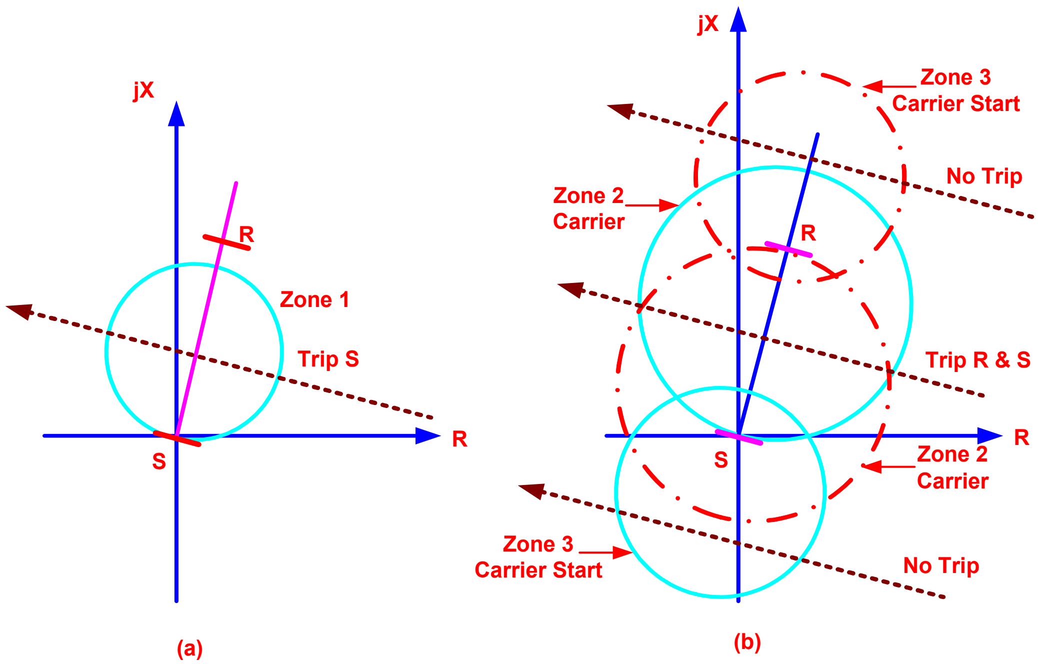

Figure 1 Zone 1 and Directional Comparison Blocking Scheme Characteristics

It is important to recognize the relationship between the distance relay polarizing memory and the measured voltages and currents plays the most critical role in whether a distance relay will operate during a power swing. Another important factor in modern microprocessor-type distance relays is whether the distance relay has a frequency tracking algorithm to track system frequency. Relays without frequency tracking will experience voltage polarization memory rotation with respect to the measured voltages and currents. Furthermore, the relative magnitude of the protected line and the equivalent system source impedances is another important factor in the performance of distance relays during power swings. If the line positive-sequence impedance is large when compared with the system impedances, the distance relay elements may not only operate during unstable swings but may also operate during swings from which the power system may recover and remain stable.

3.3 IMPEDANCE MEASURED BY DISTANCE RELAYS DURING POWER SWINGS

During a system OOS event, a distance relay may detect the OOS as a phase fault if the OOS trajectory enters the operating characteristic of the relay. To demonstrate this, let us look at the impedance that a distance relay measures during an OOS condition for the simple two-source system.

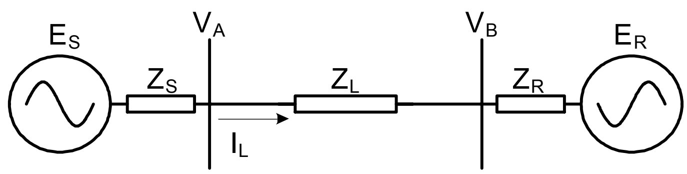

Figure 2 Two Machine System

Considering Figure 2, the current IL at bus A is computed as:

$$IL = \frac{ES - ER}{ZS + ZL + ZR} \tag{1}$$

The direction of current flow will remain the same during the power swing event. Only the voltages change with respect to one another.

The impedance measured at a relay at bus A would then be:

$$Z = \frac{VA}{IL} = \frac{ES - IL \cdot ZS}{IL} = \frac{ES}{IL} - ZS = \frac{ES \cdot (ZS + ZL + ZR)}{ES - ER} - ZS \tag{2}$$

Let us assume that ES has a phase advance of δ over ER and that the ratio of the two source voltage magnitudes $\frac{|ES|}{|ER|}$ is k. We would then have:

$$\frac{ES}{ES - ER} = \frac{k(\cos\delta + j\sin\delta)}{k(\cos\delta + j\sin\delta) - 1} = \frac{k[(k - \cos\delta) - j\sin\delta]}{(k - \cos\delta)^2 + \sin^2\delta} \tag{3}$$

For the particular case where the two sources magnitudes are equal or k is one, equation 3 can be expressed as:

$$\frac{ES}{ES - ER} = \frac{1}{2}(1 - j\cot\frac{\delta}{2}) \tag{4}$$

And finally the impedance measured at the relay will be:

$$Z = \frac{VA}{IL} = \frac{(ZS + ZL + ZR)}{2}(1 - j\cot\frac{\delta}{2}) - ZS \tag{5}$$

Remembering that δ is the phase angle between the sources, there is a geometrical interpretation to equation 5 that is represented in Figure 3a. The trajectory of the measured impedance at the relay during a power swing when the angle between the two source voltages varies, corresponds to the straight line that intersects the segment A to B at its middle point. This point is called the **electrical center** of the swing. The angle between the two segments that connect P to points A and B is equal to the angle δ. When the angle δ reaches the value of 180 degrees, the impedance is precisely at the location of the electrical center. It can be seen that the impedance trajectory during a power swing will cross any relay characteristic that covers the line, provided the electrical center falls inside the line.

In situations where the k, the ratio of the sources magnitudes, would be different from one, it can be demonstrated that the impedance trajectory will correspond to circles. This is shown in Figure 3b. The circle's center and radius values as a function of the k ratio can be found in the reference [1].

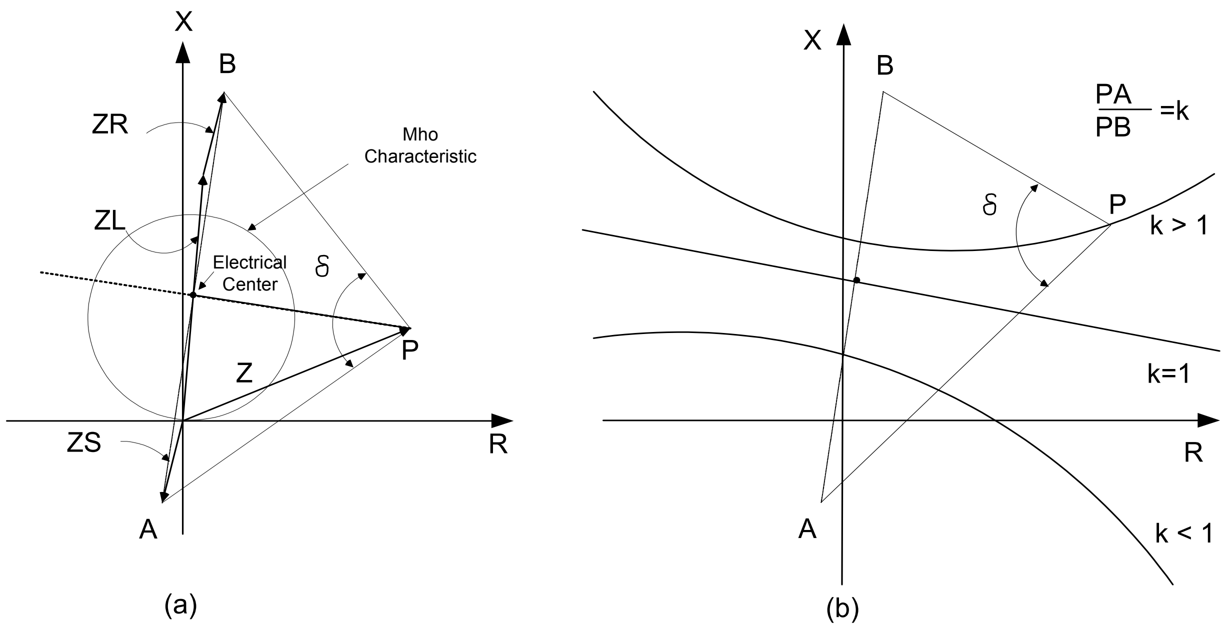

Figure 3 Impedance trajectories at the Relay During a Power Swing for Different k Values

4 POWER-SWING DETECTION METHODS

This section discusses a number of power-swing detection methods used for PSB and OST protection functions. It covers traditional detection methods for PSB and OST based on the rate of change of impedance or resistance and newer methods used in microprocessor-based relays.

4.1 CONVENTIONAL RATE OF CHANGE OF IMPEDANCE PSB AND OST METHODS

Conventional PSB schemes are based mostly on measuring the positive-sequence impedance at a relay location. During normal system operating conditions, the measured impedance is the load impedance, and its locus is away from the distance relay protection characteristics. When a fault occurs, the measured impedance moves immediately from the load impedance location to the location that represents the fault on the impedance plane. During a system fault, the rate of impedance change seen by the relay is determined primarily by the amount of signal filtering in the relay. During a system swing, the measured impedance moves slowly on the impedance plane, and the rate of impedance change is determined by the slip frequency of an equivalent two-source system. Conventional PSB schemes use the difference between impedance rate of change during a fault and during a power swing to differentiate between a fault and a swing. To accomplish this differentiation, one typically places two concentric impedance characteristics, separated by impedance ΔZ, on the impedance plane and uses a timer to time the duration of the impedance locus as it travels between them. If the measured impedance crosses the concentric characteristics before the timer expires, the relay declares the event a system fault. Otherwise, if the timer expires before the impedance crosses both impedance characteristics; the relay classifies the event as a power swing.

4.1.1 Concentric Characteristic Schemes

The simplest method for measuring the rate of change of impedance is to determine the elapsed time required by the impedance vector to pass through a zone limited by two impedance characteristics. The second impedance characteristic is concentric around the first one. This is typically accomplished with either two additional characteristics, which are used specifically for the power swing function, or with an additional outer impedance characteristic that lies concentric to one of the existing distance protection characteristics. Figure 4 shows a concentric distance relay characteristics used for PSB and OST protection.

The advantage of this concentric characteristic is that the detection of the power swing condition is checked before one of the impedance tripping zones is entered allowing the tripping elements to be blocked if desirable. This advantage is realized by setting the inner concentric zone larger than the largest tripping zone that one seeks to control. The major setting effort is limited to a single delta impedance setting and a timer setting. To find the correct settings for these two parameters extensive stability studies are typically required.

A drawback of the concentric circular characteristics is load encroachment. That is, the characteristic will limit the amount of load carried by the transmission line or limit the reach of the higher impedance zones. A limiting requirement for the application of the concentric polygon characteristic concept is that the resistive reach of the outer characteristic cannot reach into the load. This could become a limiting requirement especially on long heavy loaded transmission lines. A smaller delta time setting permits a smaller delta Z setting to detect slip cycles.

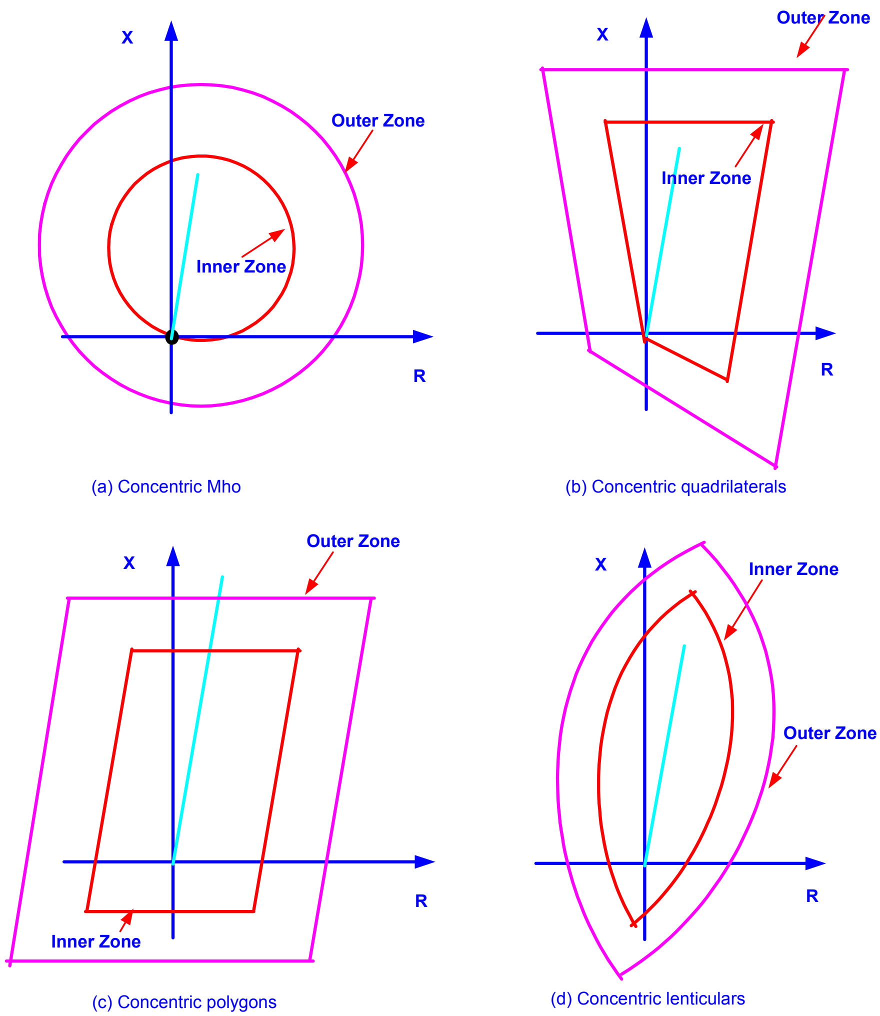

Figure 4 PSB and OST Concentric Distance Relay Characteristics

4.1.2 Blinder Schemes

4.1.2.1 Two-Blinder Scheme

The two-blinder scheme shown in Figure 5 is based on the same principle of measuring the time needed for an impedance vector to travel a certain delta impedance. The time measurement starts when the impedance vector crosses the outer blinder (RRO) and stops when the inner blinder (RRI) is crossed. If the measured time is above the setting for delta time, a power swing situation is detected. If the blinders are set in parallel to the line impedance, then they are optimized for the delta impedance measurement because the power swing impedance vectors will normally enter the protection zones at an angle of nearly 90 degrees to the line angle. Depending on certain network conditions, this may not be always correct but it can be assumed for simplification. One advantage of the blinder scheme for power swing detection applications is that it can be used independent of the distance zone characteristics. In addition, while the impedance vector is in this delta impedance area, the protective relay element can be blocked from tripping as this may be either heavy load or a stable power swing. If an unstable swing is detected, the mho element can be allowed to trip immediately (not recommended) or tripping can be delayed until the swing passes through thereby minimizing over-voltages across the opened breaker. To find the correct settings for the blinders is not always simple and requires a sophisticated grid analysis.

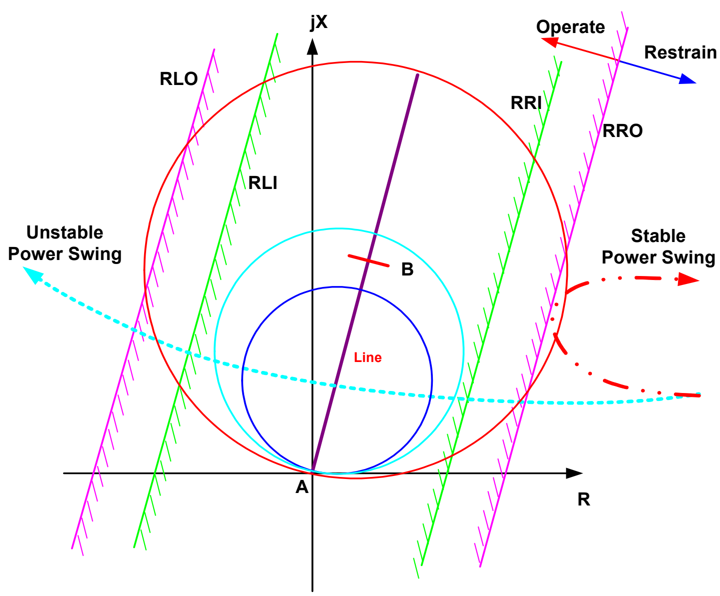

Figure 5 Two-Blinder Scheme

4.1.2.2 Single-Blinder Scheme

A single-blinder scheme uses only one set of blinder characteristics. A single-blinder characteristic plus auxiliary logic can be used for an OST function. It can be used to restrict tripping of the distance relay for loads outside of the blinders. The single-blinder scheme cannot distinguish between a fault and an OOS condition until the fault has passed through the second blinder within a given time. As such, this scheme cannot be used to block phase distance relays from tripping for unstable power swings because the relays will have tripped prior to the scheme declaring an unstable condition. The scheme can be used to prevent automatic reclosing for a detected unstable power swing. In addition, the single-blinder scheme delays OST until the swing is well past the 180 degree position and is returning to an in-phase condition. The basic advantage of the single blinder scheme is its use for load encroachment.

4.1.3 Rdot Scheme

Out-of-step tripping initiation on major EHV interconnections sometimes is required before the voltage at the electrical center reaches a minimum value. This prevents severe voltage dips throughout the power system with possible uncontrolled loss of loads and loss of synchronism within sub-areas of utility network. An OST relay described in references [37, 38] was applied in the US Pacific NW-SW 500 kV AC Intertie for such a purpose. The OST relay was augmented with the rate of change of apparent resistance and it was termed the Rdot scheme. Resistance based control algorithms to describe the OST detection are given by:

1. Conventional OST relay: $Y1 = (R - R1) \leq 0$
2. R-dot relay: $Y2 = (R - R1)) + T1\dfrac{dR}{dt} \leq 0$

Where Y1 and Y2 are control outputs, R is the apparent resistance measured by the relay and R1 and T1 are relay-setting parameters. The above characteristic of the R-dot relay can be best visualized in the R-Rdot phase-plane shown in Figure 6. Y1, and Y2 then become “switching lines” in the phase-plane and the Rdot relay develops an output when the power-swing trajectory crosses a “switching line” in the R-Rdot plane. For a conventional OST relay without rate of change of apparent resistance augmentation is just a vertical line in the R-Rdot plane offset by the R1 relay setting parameter. Switching line Y2 is a straight line having slope T1 in the R-Rdot plane. System separation is initiated when output Y2 becomes negative. For low separation rates (small dR/dt) the performance of the Rdot scheme is similar to the conventional OST relaying schemes. However, higher separation rates dR/dt would cause a larger negative value of Y2 and will initiate tripping much earlier. In the actual implementation, the relay uses a piecewise linear characteristic consisting of two line segments rather than a straight line shown in Figure 7.

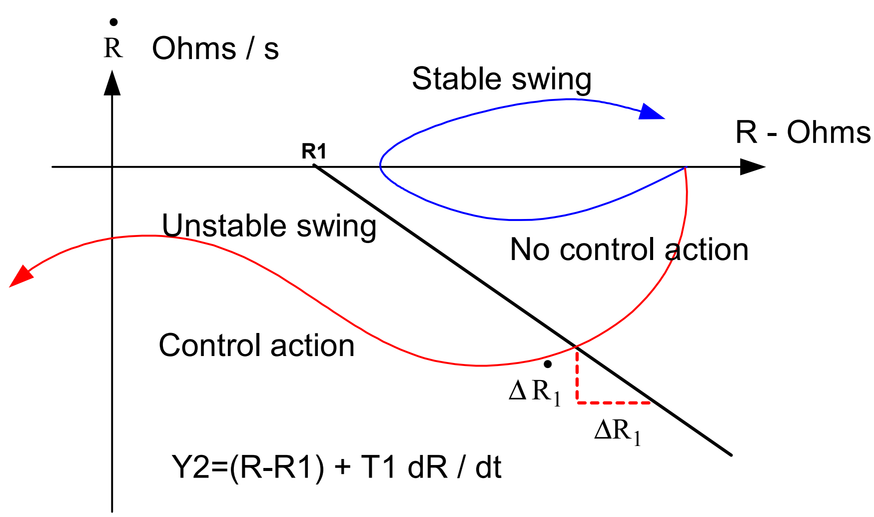

Figure 6 Phase-plane Diagram Illustrating the Concept of R-dot Principle

4.2 Additional Power Swing Detection Methods

4.2.1 Continuous Impedance Calculation

This method determines a power swing condition based on a continuous impedance calculation. Continuous here means, for example, that for each 5 ms step an impedance calculation is performed and compared with the impedance calculation of the previous 5 ms. As soon as there is a deviation, an out-of-step situation is assumed but not proven yet. The next impedance that should be calculated 5 ms later is predicted based on the impedance difference of the previous measured impedances. If the prediction is correct, then it is proven that this is traveling impedance. In this situation a power swing condition is detected. For security reasons additional predictive calculations may be required.

A delta impedance setting is not required anymore, because the algorithm automatically considers any delta impedance that is measured between two consecutive calculations and sets the delta impedance for the next calculation automatically in relation to the previous calculation. This leads to a dynamic calculation of the delta impedance and an automatic adaptation to the change of the power swing impedance. Also the delta time setting is not required anymore because it is determined by the calculation cycles of the algorithm.

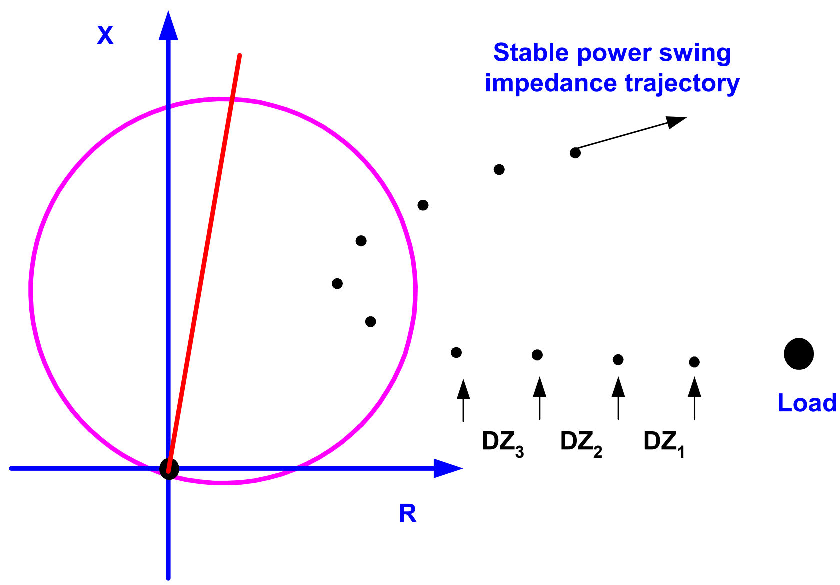

Figure 7 Power swing detection with continuous impedance calculation

As long as the changing impedance vector is not approaching a tripping zone faster than the relay can confirm the out-of-step condition (at least 3 calculations 10 ms) the detection will be successful.

4.2.2 Swing-Center Voltage and its Rate of Change

Swing-center voltage (SCV) is defined as the voltage at the location of a two-source equivalent system where the voltage value is zero when the angles between the two sources are 180 degrees apart. When a two-source system loses stability and goes into an OOS situation after some disturbance, the angle difference of the two sources, $\delta(t)$, will increase as a function of time. Figure 8 illustrates the voltage phasor diagram of a general two-source system, with the SCV shown as the phasor from origin o to the point o'.

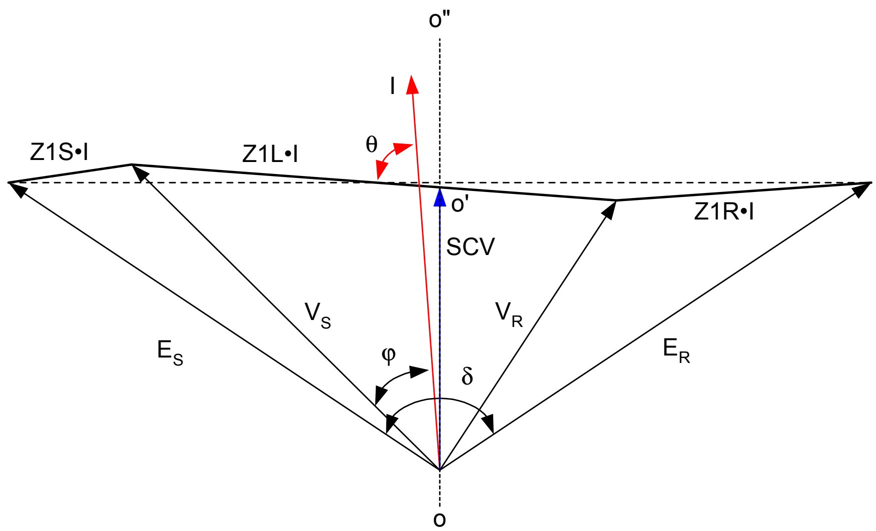

Figure 8 Voltage Phasor Diagram of a Two-Source System

An approximation of the SCV can be obtained through the use of locally available quantities as follows:

$$\mathrm{SCV} \approx |\,V_S\,| \cdot \cos\varphi \tag{6}$$

Where $|V_S|$ is the magnitude of locally measured voltage, and φ is the angle difference between V_S and the local current as shown in Figure 9. In Figure 9, we can see that $V\cos\varphi$ is a projection of V_S onto the axis of the current, I. For a homogeneous system with the system impedance angle, θ, close to 90 degrees, $V\cos\varphi$ approximates well the magnitude of the swing-center voltage. For the purpose of power-swing detection, it is the rate of change of the SCV that provides the main information of system swings. Therefore, some differences in magnitude between the system SCV and its local estimate have little impact in detecting power swings. Ilar [6] first introduced the quantity of $V\cos\varphi$ for power swing detection.

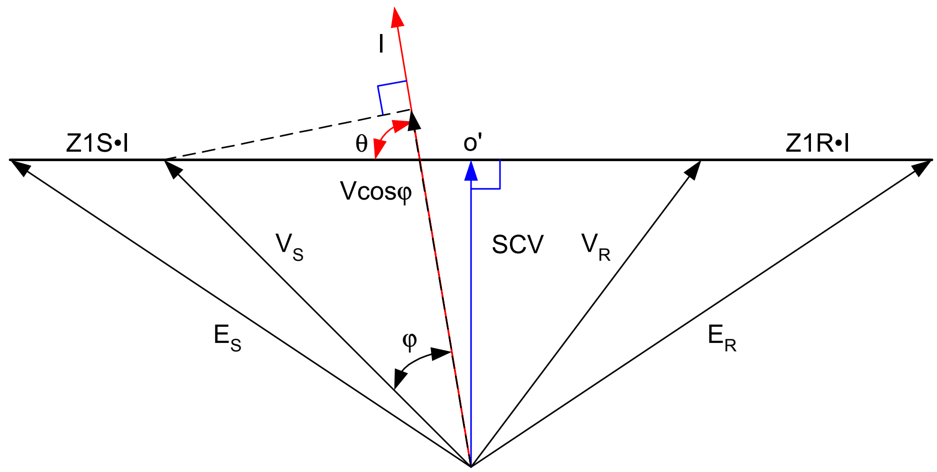

Figure 9 Vcosφ is a Projection of Local Voltage, V_S, Onto Local Current, I

From equation (6) and by keeping in mind that the local SCV estimation is using the magnitude of the local voltage, the relation between the SCV and the phase-angle difference, δ, of two-source voltage phasors can be simplified to the following:

$$\mathrm{SCV1} = \mathrm{E1} \cdot \cos\left(\frac{\delta}{2}\right) \tag{7}$$

In equation (7), E1 is the positive-sequence source magnitude equal to E_S that is assumed to be also equal to E_R. SCV1 represents the positive-sequence swing-center voltage, in the swing-center power-swing detection method, which is characterized by its smooth magnitude during system OOS. The absolute value of the SCV is at its maximum when the angle between the two sources is zero, and this value is at its minimum (or zero) when the angle is 180 degrees. This property has been exploited so one can detect a power swing by looking at the rate of change of the swing-center voltage. The time derivative of SCV1 then becomes the following:

$$\frac{d(\mathrm{SCV1})}{dt} = -\frac{\mathrm{E1}}{2}\sin\left(\frac{\delta}{2}\right)\frac{d\delta}{dt} \tag{8}$$

Equation (8) provides the relation between the rate of change of the SCV and the two-machine system slip frequency, dδ/dt. Note that the derivative of the SCV voltage is independent from the network impedances and that it reaches its maximum when the angle between the two machines is 180 degrees. When the angle between the two machines is zero, the rate of change of the SCV is also zero. The maximum value of the derivative of the SCV occurs when δ is 180 degrees. For the purpose of detecting power system swings, the SCV method has the following advantages:

- The SCV is independent of the system source and line impedances. On the contrary, other quantities, such as the resistance and its rate of change and the real power and its rate of change, depend on the line and system-source impedances and other system parameters.
- The SCV is bounded with a lower limit of zero and an upper limit of one per unit, regardless of system impedance parameters. This is in contrast to other electrical quantities, such as impedance, currents, and active or reactive powers, whose limits depend on a variety of system parameters.

- The magnitude of the SCV relates directly to δ, the angle difference of two sources. For example, if the measured magnitude of swing-center voltage is half of the nominal voltage, then δ is 120 degrees, assuming equal source magnitudes and a homogeneous system.

4.2.3 Synchrophasor-Based Out-Of-Step Relaying

Traditional techniques for detecting out-of-step have been based on the determination of phase-based impedance trajectory in the complex plane. It should be borne in mind however that another basic phenomenon could be taken advantage of to detect an out-of-step situation. When an out-of-step situation develops on a power network, a number of generators start to run at slightly different speeds. When one portion of a network becomes unsynchronized with respect to another, the voltage phase angle at the buses close to the generators causing the disturbance reflects the changes in rotation speed. With the advent of synchronized phase-angle measurement also called synchrophasor [17,19], the measurement of the phase angle of bus voltages at different locations on a network can be accomplished in real time. This measurement of bus voltage phase angle in real time has led to the development of special protection systems for network out-of-step relaying. When a protection system detects instability, remedial action schemes can invoke network separation or load shedding.

Two approaches have been described in the literature to implement synchrophasor-based network out-of-step application [11,13,35,36]:

1. To the extent that a two-machine system equivalent can represent a network, one approach consists of synchronous measurement of the phase angle between the voltages behind the transient reactances of the two machines. When a disturbance occurs, the new phase angle between the two machines is computed and the equal area algorithm is implemented in real time to determine whether the new point of operation is stable [11,36].

2. A second approach consists of measuring the positive sequence phasors at two or more strategically located buses. During a disturbance, the phase angle between the signal pairs is computed in real time, and a predictive algorithm is used to establish whether the disturbance will be stable. One application uses a model of the phase angle time waveform in the form of an exponentially damped sine wave [35]:

$$\delta(t) = \delta_0 + A\, e^{\alpha t} \sin(\omega t + \beta)$$

   where δ_0 is the initial phase difference, α is a damping constant, ω is the angular frequency of the phase difference, and A is the oscillation amplitude. A predictive algorithm is used to identify the phase angle variation parameters and to determine stability or instability conditions.

4.3 Remarks on Power-Swing Detection Methods

4.3.1 Quantities Used for Power-Swing Detection

As we have seen different quantities have been used in the detection of power swings and for the implementation of PSB and OST functions. Most traditional power-swing protection functions use the rate of change of impedance measurement method. Other power system quantities have also been used for power-swing detection such as power and its rate of change, the phase angle difference across a transmission line or path and its rate of change, the swing-center voltage and its first and second derivatives and so on.

Most power-swing functions require relay settings that are difficult to calculate, as we mentioned earlier, and extensive stability studies in most applications. One of the reasons for setting parameters and extensive stability studies stems from the fact that the quantities used in many of the methods depend on system source and line impedances. Power-swing functions with limited or no-setting requirements utilize quantities that are less dependent or independent from system source and line impedances and take advantage of well-regulated power system quantities.

Using Figure 9, we can compute different quantities used in power-swing detection functions and see their dependence on system impedances. Assuming that the total system impedance is XT and ES = ER = E1, the following quantities used for power swing detection are shown:

Power:
$$P = E1 \cdot I \cdot \cos\varphi = \frac{E1^2}{XT} \cdot \sin\delta \qquad (9)$$

Current:
$$I = 2 \cdot \frac{E1}{XT} \cdot \sin(\frac{\delta}{2}) \qquad (10)$$

Impedance:
$$Z = \frac{V}{I} = \frac{XT}{2} \cdot \cot(\frac{\delta}{2}) \qquad (11)$$

Rate of change of Z:
$$\frac{dZ}{dt} = -\frac{XT}{2}\left(\frac{1}{1-\cos\delta}\right)\frac{d\delta}{dt} \qquad (12)$$

SCV:
$$V\cos\varphi = \frac{P}{I} = E1 \cdot \cos(\frac{\delta}{2}) \qquad (13)$$

We can observe that most of them are dependent on the total system impedance XT, a changing and not well-defined quantity.

4.3.2 Setting Issues for Concentric Impedance Elements and Blinder- Based Schemes

There are a number of issues one must address with regards to properly applying and setting the traditional PSB and OST relaying functions. To guarantee that there is enough time to carry out blocking of the distance elements after a power swing is detected, the PSB inner impedance element must be placed outside the largest distance protection characteristic one wants to block. In addition, the PSB outer impedance element must be placed away from the load region to prevent PSB logic operation caused by heavy loads, thus establishing an incorrect blocking of the line mho tripping elements.

The above requirements are difficult to achieve in some applications, depending on the relative line- and source-impedance magnitudes. Figure 10 shows a simplified representation of one line interconnecting two generating sources in the complex plane with a swing locus bisecting the total impedance. Figure 10 (a) depicts a system in which the line impedance is large compared to system impedances, and Figure 10 (b) depicts a system in which the line impedance is much smaller than the system impedances.

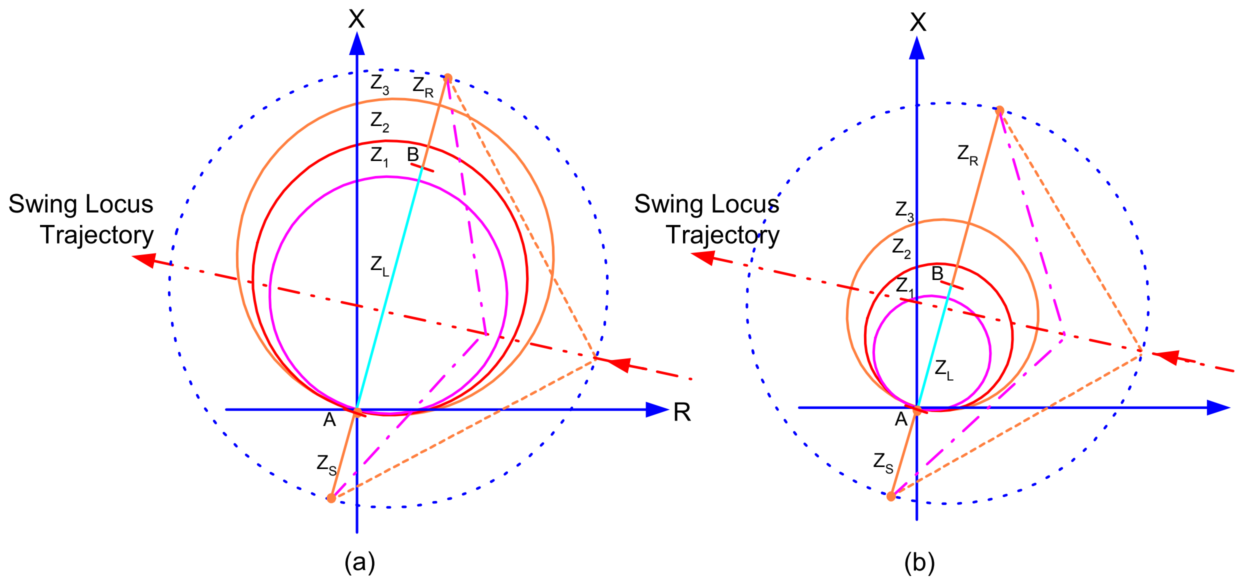

Figure 10 Effects of Source and Line Impedance on the PSB Function

We can observe from Figure 10(a) that the swing locus could enter the Zone 2 and Zone 1 relay characteristics before the phase-angle difference of the source voltages reaches 120 degrees, i.e., even during a stable power swing from which the system could recover. For this particular system, it may be difficult to set the inner and outer PSB impedance elements, especially if the line is heavily loaded, because the necessary PSB settings are so large that the load impedance could establish incorrect blocking. In the past to avoid incorrect blocking resulting from load, lenticular distance relay characteristics, or blinders that restrict the tripping area of the mho elements, would be applied. Modern numerical relays have dedicated 'load encroachment' elements to deal with loading issues. The system shown in Figure 10 (b) becomes unstable before the swing locus enters the Zone 2 and Zone 1 relay characteristics, and it is relatively easier to set the inner and outer PSB impedance elements.

Another difficulty with traditional PSB systems is the separation between the PSB impedance elements and the timer setting that is used to differentiate a fault from a power swing. The above settings are not trivial to calculate and, depending on the system under consideration, it may be necessary to run extensive stability studies to determine the fastest power swing and the proper PSB impedance element settings. The rate of slip between two systems is a function of the accelerating torque and system inertias. In general, a relay cannot determine the slip analytically because of the complexity of the power system. However, by performing system stability studies and analyzing the angular excursions of systems as a function of time, one can estimate an average slip in degrees/sec or cycles/sec. This approach may be appropriate for systems whose slip frequency does not change considerably as the systems go out of step. However, in many systems where the slip frequency increases considerably after the first slip cycle and on subsequent slip cycles, a fixed impedance separation between the PSB impedance elements and a fixed time delay may not be suitable to provide a continuous blocking signal to the mho distance elements.

Below we show a few steps for setting the PSB polygon characteristics. These settings guidelines are applicable to all other blinder schemes shown in Figure 5 and are outlined as follows.

- Set the outer characteristic resistive blinders inside the maximum possible load with some safety margin as illustrated in Figure 5(c).
- Set the inner resistive blinders outside the most overreaching protection zone that is to be blocked when a swing condition occurs. Normally, you want to block the distance elements that issue a trip such as the distance element that is used in a communications-assisted tripping scheme and perhaps the Zone 1 instantaneous tripping element.
- Based on the outer and inner blinders set in the previous steps, the PSB timer value, T1, can be calculated from the following equation with information of the local source impedance, Z1S, the line impedance, Z1L, and the remote source impedance, Z1R. Ang2R and Ang1R are machine angles at the outer and inner blinder reaches, respectively, as illustrated in Figure 11. The maximum slip frequency, Fslip, is also assumed in the calculation. Typical maximum slip frequency is chosen anywhere between 4 to 7 Hz.

$$T1 = \frac{(\text{Ang1R} - \text{Ang2R}) \cdot \text{Fnom(Hz)}}{360 \cdot \text{Fslip(Hz)}} (\text{cycle}) \tag{9}$$

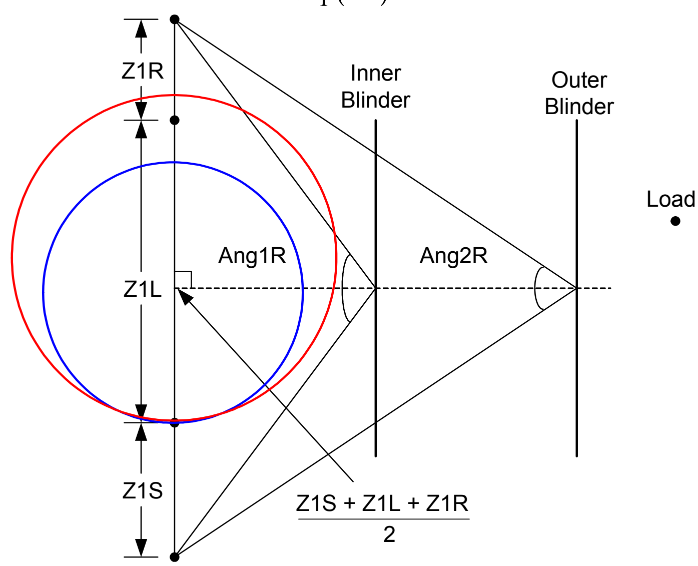

Figure 11 Equivalent Two-Source Machine Angles During OOS

It is very difficult in a complex power system to obtain the proper source impedance values, as shown in Figure 11, that are necessary to establish the blinder and PSB timer settings. The source impedances vary constantly according to network changes, such as, for example, additions of new generation and other system elements. The source impedances could also change drastically during a major disturbance and at a time when the PSB and OST functions are called upon to take the proper actions. Note that the design of the PSB function would have been trivial if the source impedances remained constant and if it were easy to obtain them. Normally, very detailed system stability studies are necessary to consider all contingency conditions in determining the most suitable equivalent source impedance to set the conventional PSB function.

Other than needing careful system studies and detailed source parameters, one may also experience difficulties for a long line with heavy loads, where the load region is close to the distance element that needs to be blocked in a swing condition. In this condition, the spacing between the inner and outer blinders may be small enough to cause a significant timing error for a power swing. If the load region encroaches into the distance element and one wants to block under swings, then it is impossible to place the PSB characteristics between the load and distance regions, and one cannot apply the conventional PSB blocking function. A more modern relaying system with 'load encroachment' capabilities could be required.

5 PSB AND OST PROTECTION PHILOSOPHY

Protective relays that monitor voltages and currents may respond to variations in system voltages and currents and cause tripping of additional equipment, thereby weakening the system and possibly leading to cascading outages and the shutdown of major portions of the power system. In addition to distance relays, other protective relays prone to respond to stable or unstable power swings and cause unwanted tripping of transmission lines or other power system elements include overcurrent, directional overcurrent and undervoltage.

The philosophy of PSB and OST relaying is simple and straightforward: avoid tripping of any power system element during stable swings. Protect the power system during unstable or out-of-step conditions. When two areas of a power system, or two interconnected systems, lose synchronism, the areas must be separated from each other quickly and automatically in order to avoid equipment damage and shutdown of major portions of the power system. Uncontrolled tripping of circuit breakers should be avoided and a controlled well-designed system separation is necessary in order to prevent equipment damage, widespread power outages, and minimize the effects of the disturbance.

5.1 POWER-SWING PROTECTION FUNCTIONS

One of the traditional methods of minimizing the spread of a cascading outage caused by loss of synchronism is the application of power swing protection elements that detect OOS conditions and take appropriate actions to block relay elements that are prone to mis-operate during power swings and to separate affected system areas, minimize the loss of load, and maintain maximum service continuity.

There are basically two functions related to power-swing detection. One is called PSB protection function that discriminates between faults and power swings. The PSB function should block relay elements prone to operate during stable and/or unstable power swings. In addition, the PSB function must allow relay elements to operate during faults or faults that evolve during an OOS condition. The other is the OST protection function that discriminates between stable and unstable power swings and initiates network sectionalizing or islanding during loss of synchronism.

Out-of-step tripping schemes are designed to protect the power system during unstable conditions, isolating generators or larger power system areas from each other with the formation of system islands, in order to maintain stability within each island by balancing the generation resources with the area load. To accomplish this, OST systems must be applied at pre-selected network locations, typically near the network electrical center, and network separation must take place at such points to preserve a close balance between load and generation. As discussed earlier, many relay systems are prone to operate at different locations in the power system during an OOS condition and cause undesired tripping. Therefore, OST systems must be complemented with PSB functions to prevent undesired relay system operations, prevent equipment damage and shutdown of major portions of the power system, and achieve a controlled system separation.

In addition, PSB blocking must be used at other locations in the network to prevent system separation in an indiscriminate manner. Where a load-generation balance cannot be achieved, some means of shedding nonessential load or generation will have to take place to avoid a complete shutdown of the area. Examples are under/over frequency and/or voltage protection. Typically, the location where system islanding should take place during loss of synchronism determines the location of OST functions. However, in some systems it may be necessary to separate the network at a location other than the one where OST is installed. This is accomplished with the application of a transfer tripping type of scheme. One important aspect of the OST function is avoiding line tripping when the angle between systems is near 180 degrees. Tripping during this condition imposes high stresses on the breaker and can cause re-strikes and breaker damage. The other important aspect is to block line reclosing after OST initiation.

Where a power system over time has built higher voltage lines overlying lower voltage lines, e.g. a 345 kV or 500 kV line over lying or shunting a lower voltage 138 kV or 230 kV system, tripping of the higher voltage line may cause a transiently stable swing onto the lower voltage lines. Blocking of the higher impedance zones for these lines is usually required.

5.2 METHOD FOR DETERMINING NEED FOR POWER SWING AND OOS PROTECTION

In this section we present a simplified method to give an indication of where to apply power swing detection, PSB and OST protection in a particular transmission line in the power system. The method is no substitute for detailed system studies to determine the requirements for the application. The method does tell the application engineer the likelihood of requiring this protection and where on the protected system this protection may be required.

A power swing with sufficient accelerating power, once initiated, will traverse 360 degrees and unless interrupted will continue. The impedance seen by an impedance relay at either the sending or receiving ends of the transmission line will look like a three phase short circuit as the impedance trajectory crosses near the electrical center of the system. This apparent three-phase fault will be either in front of or behind the impedance relay applied to the protected line terminal. Assuming a simplified two-source equivalent system with equal sending and receiving end voltages, the impedance trajectory will cross the total system impedance at right angles at half the sum of the protected line plus the sending and receiving end Thévenin impedances. The method consists of determining the system electrical center and the electrical center lies on the line under investigation. The simplified system shown below will be used to illustrate the method. In using this method it is important to note that the current does not change direction, but the voltages go 180 degrees out phase with each other.

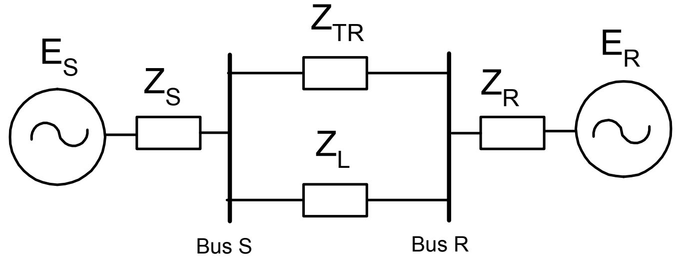

Figure 12 Two-Source System Equivalent

Where,

E_s = Equivalent sending end voltage
Z_s = Equivalent sending end source impedance
Z_L = Line impedance
E_R = Equivalent receiving end voltage
Z_R = Equivalent receiving end source impedance
Z_{TR} = Equivalent impedance of the system interconnecting sending and receiving busses

The problem is to determine if the line, Z_L, requires power swing protection. Appendix A adapted from reference [9] shows the details on how to determine the above parameters using the results from a short circuit study. Basically, after we determine Z_S, Z_R, and Z_{TR}, using the method in Appendix A, we need to first sum Z_S, Z_R, and the parallel combination of Z_L and Z_{TR} and then divide by two to find half of the total equivalent impedance. If this impedance is larger than each of the source impedances then the electrical center falls in the line under consideration. PSB is then necessary at this location if controlled separation, using OST, of the system is desired. OST protection may or may not be applied at this location depending on the power-swing protection philosophy of the utility. One must keep in mind that the system electrical center is not always at the same network location and this is constantly changing depending on network operating conditions and system disturbances. Therefore, the application of PSB protection should be applied at other network locations away from the system electrical center to avoid tripping of transmission lines during stable power swings.

To identify whether a swing is possible, the method should be used with minimum and maximum fault conditions including plausible contingencies. This method is useful in identifying possible swing conditions and will allow the protection engineer to dialogue with the planners who do the necessary studies.

5.3 APPLICATION OF PSB AND OST PROTECTION FUNCTIONS

While the power-swing protection philosophy is simple, it is often difficult to implement it in a large power system because of the complexity of the system and the different operating conditions that must be studied.

5.3.1 PSB and OST Options

There are a number of options one can select in implementing power-swing protection in their system. Below we list a number of possible options, however, the working group recommends that each utility develop and implement a well thought power-swing protection philosophy to avoid cascading blackouts and equipment damage. Designing the power system protection to avoid or preclude cascade tripping is a NERC requirement.

5.3.1.1 No Power Swing Detection

This application does not use any form of power-swing detection and accepts that if a power swing occurs a line trip either by Zone 1 or Zone 2 will occur. There are two problems with a Zone 2 trip. First, the swing may be stable and the system is returning to an equilibrium state. The unnecessary trip may provoke an under/over frequency and/or voltage event resulting in further loss of load or generation. Second, the swing may separate the system at locations where an imbalance of load and generation results in an event similar to that just described. In addition, Zone 1 tripping may occur in the case of an unstable power swing when the swing is near the 180 degree position that could cause breaker damage and an unsafe condition for utility personnel. For lines equipped with auto-reclosing, auto-reclosing may occur after the power swing trip and before the power system stabilizes exacerbating the swing condition.

5.3.1.2 Block All Elements Prone to Operate During Power Swings

This application applies blocking to all relay elements that may operate for any power swing and prevents the relay from issuing a trip signal. The major disadvantage with this application is once an unstable swing starts there are no relaying functions to detect it and eliminate it with potential damage to machines and loads. In addition, transmission lines in adjacent systems may trip due to the swing causing a wide spread loss of load and generation. Assuming the swing is stable, the system will return to a steady state. This application is not recommended.

5.3.1.3 Block Zone 2 and Higher / Trip with Zone 1

This application applies a blocking signal to the higher impedance relay zones and allows Zone 1 to trip if the swing enters its operating characteristic. As stated in Section 5.4, breaker application is a consideration when tripping during a power swing. A subset of this application is to block the Zone 2 and higher impedance zones for a preset time and allow a trip if the detection relays do not reset. The benefits of this application are the relay detects and blocks the transient swing minimizing the equipment removed from service while allowing a trip for a slow swing. Second, if the swing enters Zone 1 a trip is issued and the system is likely to return to a stable condition assuming there would be balanced load and generation on each side of the system electrical center.

5.3.1.4 Block All Zones / Trip with OST Function

This application applies a blocking signal to all impedance relay zones and allows tripping if the power swing is unstable using the OST function available in modern relays. This application is the recommended approach since a controlled separation of the power system can be achieved at pre-selected network locations. Tripping after the swing is well past the 180 degree position is the recommended option. Section 5.4.1 discusses the challenge to circuit breaker interruption process during an unstable power swing.

5.3.2 Placement of OST Systems

The selection of network locations for placement of OST systems can best be obtained through transient stability studies covering many possible operating conditions. The maximum rate of slip is typically estimated from angular change versus time plots from stability studies. With the above information at hand, reasonable settings can be calculated.

The recommended approach for power-swing protection application is summarized below:

1. Perform system transient stability studies to identify system stability constraints based on many operating conditions and stressed system-operating scenarios. The stability studies

will help identify the parts of the power system that impose limits to angular stability, generators that are prone to go OOS during system disturbances and those that remain stable, and groups of generators that tend to behave similarly during a disturbance. The results of stability studies are also used to identify the optimal location of OST and PSB protection relay systems because the apparent impedance measured by OOS relays is a function of the MW and MVAr flows on the transmission lines.

2. Determine the locations of the swing loci during various system conditions and identify the optimal locations to implement the OST protection function. The optimal location for the detection of the OOS condition is near the electrical center of the power system. However, one must determine that the behavior of the impedance locus near the electrical center would facilitate the successful detection of OOS. There are a number of methods to determine the system electrical center, or whether the swing locus would go through a particular transmission line. Some of the methods are discussed in Appendix A.
3. Determine the optimal location for system separation during an OOS condition. This will typically depend on the impedance between islands, the potential to attain a good load/generation balance, and the ability to establish stable operating areas after separation. To limit the amount of generation and load shed in a particular island, it is essential that each island have reasonable generation capacity to balance the load demand. High impedance paths between system areas typically represent appropriate locations for network separation.
4. Establish the maximum rate of slip between systems for OOS timer setting requirements as well as the minimum forward and reverse reach settings required for successful detection of OOS conditions. The swing frequency of a particular power system area or group of generators relative to another power system area or group of generators does not remain constant. The dynamic response of generator control systems, such as automatic voltage regulators, and the dynamic behavior of loads or other power system devices, such as SVS and FACTS, can influence the rate of change of the impedance measured by OOS protection devices.
5. Two factors affect the settings of PSB scheme logic that uses two concentric circles or polygons (an outer zone and an inner zone): 1) the reach of the outermost zone of phase distance element you want to block; and 2) the load impedance the relay measures during the maximum anticipated load. The inner zone must be set to encompass the largest reaching zone of phase distance element you have selected for PSB. The outer zone must be set such that it is inside the minimum anticipated load impedance locus. The PSB time delay is set based on the settings of the inner and outer resistance blinders and the fastest stable swing frequency.
6. For OST schemes set the OST inner zone at a point along the OOS swing trajectory where the power system cannot regain stability. Set the OST outer zone such that the minimum anticipated load impedance locus is outside the outermost zone. The OST time delay is set based on the settings of the inner and outer zone resistance blinders and the fastest OOS swing frequency expected or determined from transient stability studies.
7. Determine whether you will perform OST well before the swing goes through the 180^0 position, called trip-on-the-way-in (TOWI), or trip after the swing is well past the 180^0 position and is returning to an in-phase condition, called trip-on-the-way-out (TOWO). TOWO is the most common application of out-of-step tripping since the breakers will be given a tripping command when the two equivalent voltage sources will be moving to an in-phase condition. In rare occasions, system stability requirements are such that a TOWI is desired. Care should be exercised in such cases since the tripping command to circuit

breakers will be issued when the two equivalent voltage sources will be close to an out-of-phase condition. Therefore, the user needs to verify with the circuit breaker manufacturer that the circuit breakers are capable of tripping for such a system condition to avoid breaker damage and ensure personnel safety.

8. Include mathematical models of the PSB and OST functions and their operation behavior in transient stability studies to verify correct application of the power-swing protection schemes.

5.3.3 Additional Considerations

When the power system is in an OOS condition, the bus voltages and line currents vary in great magnitudes, and power system equipment is stressed to their limits. Although faults during stable power swings and system OOS conditions are events with very small probability, proper operation against these faults is nevertheless extremely important to ensure controlled power system separation and continuous operation of remaining part of the power system.

Ideally, the performance requirements of protective relays under system OOS condition should be identical to those under normal system operations in terms of speed, selectivity, reliability, and sensitivity. However, due to the nature of the distance relay elements under system OOS, it is almost impossible to demand the same performance of the distance elements as those under normal system fault conditions

Selectivity is critical to avoid cascade tripping.

5.3.3.1 Distance Protection Requirements During OOS Conditions

Because of the complexity and the rare occurrence of power system OOS, many utilities do not have clear performance requirements for distance relays during system OOS. The performances of distance elements are routinely exempt from being scrutinized in detail under system OOS conditions.

Speed

A fault occurs instantaneously while a power swing can be characterized as a slow speed event. The PSB function takes advantage of this and relay logic may be used to block the distance element operations. The distance elements can be made operative in case of unbalanced faults, only if the relay logic resets the PSB condition during the fault condition. Traditionally, some time delay is necessary to coordinate with other protective devices in the event that the fault is external to the protected line section.

Selectivity

If a PSB condition is removed due to an unbalanced fault, distance element loops may overreach protection zones simultaneously when the system electrical center falls on the protected line and when the fault occurs at a large machine δ angle. Therefore, it may not always be possible for a distance relay to perform single-pole tripping for SLG faults during system OOS. Distance elements, therefore, may trip three poles for internal SLG faults during system OOS conditions.

Dependability

Distance elements must trip all internal line faults during system OOS conditions. Sometimes it may be difficult to reset the PSB when the fault occurs at a voltage peak and a current minimum during an OOS cycle, especially for three-phase faults that do not produce any negative-sequence currents. Regardless, the distance relay must be able to detect ensuing three-phase faults during OOS conditions even if the operating time is longer.

Security

Distance elements must be secure to external faults during system OOS conditions. Distance elements, however, maybe challenged and trip on external faults if an OOS condition develops during a single-pole open condition. Traditionally, some time delay is necessary to coordinate with other protective devices in the event that the fault is external to the protected line section. A simple time delay does not guarantee the coordination when the system electrical center does not stay in one location on the system, and may not also be applicable on parallel-line systems to restrain the distance relay from tripping for external faults.

5.3.3.2 Power Swing Protection During Single Pole Open Conditions

Power swing conditions could occur after a single pole trip in weak areas of the power system. Detection of a power swing on the protected line is more difficult during the single pole open period since unbalance is present due to load flow through the two unfaulted phases. Distance relays should properly distinguish between a power swing and a fault during the open pole period following a single pole trip. The phase and ground distance elements still in-service should be blocked by the PSB logic if a power swing develops during the open pole period, and trip if a fault occurs in another phase during the power swing. Disabling the PSB function during the single pole open period is not desirable. If PSB function is inhibited due to an open pole, undesired tripping can occur if an ensuing swing enters the operating characteristics of the phase or ground distance elements for the two remaining phases.

During the open pole condition the line impedance effectively doubles and a power swing center behind the line during a three pole condition may move forward onto the protected line during the open pole condition. Protection to detect this event is required.

5.3.3.3 Three-Phase Faults Following Power Swings

Power swings and three-phase faults involve all three-phases of the power system. The distance relay cannot simply use the measured impedance alone to determine whether or not phase distance protection should be inhibited or allowed to trip. A critical distinction between three-phase faults and power swings is the rate of change of the measured impedance. The rate of change is slower for a power swing than a three-phase fault. However, when concentric characteristics are used to detect a power swing the relay may not be able to detect a three-phase fault after PSB asserts; for example, the power swing evolves into a three-phase fault.

When a three-phase fault occurs during a power swing the measured impedance moves to the line angle and remains there until the fault is cleared. One solution is not to block a time-delayed zone; for example, allow tripping on a delayed Zone 2 operation. Manufacturers of numerical distance relays may account for this scenario using other techniques.

5.3.3.4 Effects of Small Generators

Small generators can be transmission line connected as a tap or connected on a distribution feeder.

Transmission Line Connected

For a transmission line connected generator such as the Independent Power Producer (IPP) shown in Figure 13, a determination is made whether existing clearing times on line 2 and line 3 are adequate to assure stability of the generation. In some cases, relaying (for example, an existing stepped impedance scheme) may have to be replaced with a communications assisted scheme to improve the clearing speed and to assure stability. Faults and clearing times on line 1 are of no consequence in terms of impacting the stability of the connected generation, since the generation will be 'lost' anyway once line 1 is tripped.

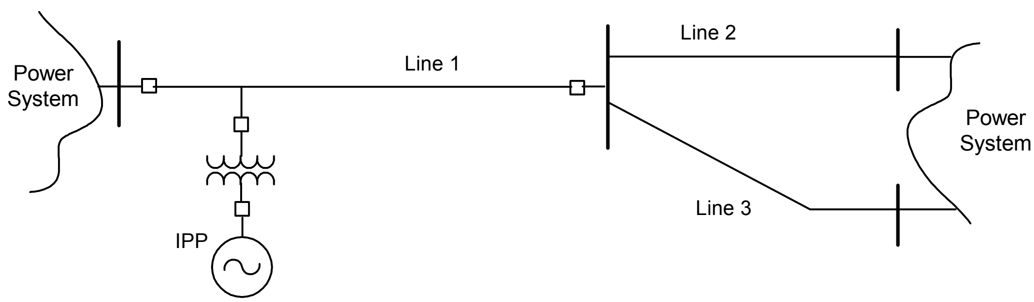

Figure 13 Transmission Line Connected IPP

Distribution Feeder Connected

Distribution feeder connected IPPs, given that they will be typically small relative to the system they connect to, will typically have swing centers in the IPP unit transformer or the IPP generator. As detailed in section 5.2 in this document, it is relatively straight forward to make a first approximation as to where the swing center is located. If the swing center is found to be within the IPP plant, it is the responsibility of the IPP to provide OOS protection to detect for these conditions.

For the situation where the IPP generation is large relative to the connected system, the swing center may move out onto the distribution feeder itself. For this situation two approaches can be taken.

- If a new feeder position is being established for the IPP, a feeder breaker with OOS switching capabilities should be provided
- If an existing feeder and feeder CB provides the connection to the IPP, power-swing protection for the feeder should be provided. TOWO should be implemented to ensure there is an optimal angle across the feeder circuit breaker when it is tripped.

5.4 SYSTEM RISKS DUE TO POWER SWINGS AND OOS CONDITIONS

The electric power system is exposed to a variety of risks when a significant power swing or an out-of-step condition occurs. In order to maintain system security it is necessary to identify and mitigate these risks as appropriate. A few of the risks to be considered are as discussed below:

5.4.1 Transient Recovery Voltage (TRV) causing Breaker Failure

An OOS condition can pose a TRV application challenge to the circuit breaker interruption process. In particular, if the breaker is called upon to trip during a system swing, significant TRV can be produced. The extreme case occurs when the system voltages across the breaker contacts are 180 degrees out-of-phase during interruption. If this out-of-phase switching application is not addressed by some means such as phase angle trip supervision or if the circuit breaker is not otherwise rated for this application, it may fail to interrupt and result in a breaker failure condition.

5.4.2 Isolating Load and Generation

When the transmission system experiences an unstable power swing, protection schemes should act as required to block tripping of breakers or trip and block auto-reclosing of breakers in strategic locations to force the system into separate electrical islands with a favorable balance of load and generation. However, this may not always be feasible. To account for those situations where there is an imbalance between load and generation, some method of shedding load or generation should be provided in an effort to keep generation on line and to avoid a widespread outage.

5.4.3 Equipment Damage

Transmission disturbances of sufficient magnitude may cause pole slipping of a synchronous generator. This phenomenon creates thermal and mechanical stresses on a turbine-generator set, which may result in either immediate physical damage or loss of life to the machine.

5.4.4 Cascading Tripping of Lines

Without an effective power swing protection scheme, it is possible that some relays susceptible to operating for a stable system swing will cause indiscriminate breaker tripping. These unnecessary trips could further challenge the system by causing other relay operations and create additional system stability problems which result in cascaded tripping of lines. NERC Planning Standards do not allow cascade tripping and a power swing protection scheme may be required to comply with the NERC standards.

5.4.5 Unwanted Cascading Tripping of Generating Units

Failure to trip a line during an unstable power swing that will result in pole slipping of a connected generator will most likely result in the loss of that generator. System separation at the point of detecting the unstable power swing may prevent unnecessary loss of generation. NERC Planning Standards do not allow cascade tripping and a power swing protection scheme may be required to comply with the NERC standards.

5.5 METHODS TO IMPROVE TRANSIENT STABILITY

Utilities should take prudent actions in the design of power systems to avoid cascading outages and power system blackouts. Power-swing protection should be the last resort in preserving system transient stability. Methods that can improve the transient stability are briefly discussed in this section and they try to achieve one or more of the following effects:

1. Minimize fault severity and duration.
2. Increase of the restoring synchronizing forces.
3. Reduction of the accelerating torque by:
    a. Control of prime-mover mechanical power.
    b. Application of artificial loads.

5.5.1 High-Speed Fault Clearing

The amount of kinetic energy gained by the generators during a fault is directly proportional to fault duration and the positive sequence voltage at the point of fault. Therefore, application of high-speed relaying systems and high-speed breakers is essential in locations where fast fault clearing is important and stability studies require it.

5.5.2 Local Breaker Failure Protection

Local breaker failure protection improves stability by minimizing the amount of time a fault remains on the system should a breaker fail to clear a fault. It also minimizes the amount of the system that must be isolated thereby keeping as much outlet capacity intact as possible.

5.5.3 Independent-Pole Operation of Circuit Breakers

Independent-pole operating breakers use separate mechanisms for each phase of the circuit breaker allow each phase to open and close independent from the other phases. As a result, failure of one pole does not restrict the operation of the other two poles. Failure of more than one pole at the same time is highly improbable. During multi-phase faults, independent operation of the breaker poles will reduce the fault to a single line-to-ground fault thus significantly reducing the severity of the disturbance.

5.5.4 Single-Pole Tripping

Single-pole tripping uses independent-pole breaker operating mechanisms on each phase and for single-phase-to-ground faults, the relaying system applied is designed to trip only the faulted phase followed by fast reclosing between 0.5 to 1.5 seconds. Single-pole tripping improves power system transient stability by only interrupting the faulted phase rather than opening all three phases. During the open pole period, approximately 50% of the pre-fault power is transferred over the remaining two phases. Since the majority of faults on HV and EHV systems are single line-to-ground faults, opening and reclosing only the faulted phase results in an improvement in transient stability over three-phase tripping and reclosing.

5.5.5 Dynamic Braking

Dynamic braking uses the concept of applying an artificial load near generators during a transient disturbance to consume power output out of the generators to reduce rotor acceleration. Bonneville Power Administration [28] has used such a scheme by switching in shunt resistors for about 0.5 seconds following a fault to reduce the accelerating power of nearby generators and remove the kinetic energy gained during the fault.

5.5.6 Shunt Compensation

Shunt compensation capable of maintaining voltages at selected network locations can improve system stability by increasing the flow of synchronizing power between interconnected generators. Synchronous condensers and static VAr compensators are used for this purpose.

5.5.7 Steam Turbine Fast Valving

The purpose of turbine fast valving is to reduce the generator output without removing the unit from service. This is desirable when the system is stressed, e.g. upon some occurrence which would result in a transient stability problem. By reducing the generator output, the stability is not endangered and the unit can be returned to full output, maintaining system security. Appendix C provides additional information on the topic.

5.5.8 Generator Tripping

Selective tripping of generating units has been used for transient stability improvements. Rejection of generation at appropriate locations reduces the power transmitted over critical transmission paths. Since generating units can be tripped very rapidly, especially hydro units with very little risk of damage to the unit from a sudden trip, this is a very effective means to improve transient stability.

5.5.9 High-Speed Excitation Systems

Fast and temporary increase of generator excitation can provide significant improvement in transient stability. The increase of field generator voltage during a disturbance has the effect of increasing the internal voltage of the machine. This in turn increases the synchronizing power. The effectiveness of this type of control depends on the ability of the excitation system to increase the field voltage to the highest possible value. High-initial-response excitation systems with high-ceiling voltages are the most effective.

5.5.10 Controlled Separation and Load shedding Using Special Protection Systems

Controlled separation is used to prevent a major disturbance in one part of an interconnected power system from propagating into neighboring systems and cause a severe breakup or blackout. The initiating disturbance could be the loss of a major transmission line or corridor carrying a large amount of power or loss of a significant amount of generation. Special protection systems have been designed to monitor the power system and take control actions to mitigate major blackouts.

The Western Electricity Coordinating Council has had systems in operation for many years. The following is a representative list of potential stability control actions the SPS takes in order to preserve stability:

1. Generator dropping.
2. Turbine fast valving.
3. Direct load shedding.
4. Insertion of breaking resistors.
5. Series capacitor insertion.
6. Shunt capacitor insertion.
7. Controlled islanding.

5.5.11 Reduction of Transmission System Reactance

Reduction of reactances of the transmission system elements improves transient stability by increasing the post-fault synchronizing power transfers. One way to achieve this is to reduce the reactances of transmission lines. Series capacitor compensation directly offsets the line series reactance and has been used extensively in many parts of the world in EHV systems. For transient stability applications use of switched series capacitors offers some benefits. Upon fault detection or a power swing, a series capacitor bank is switched in and removed in about 0.5 seconds. These types of series capacitor banks are sometimes installed in a substation to serve a number of transmission lines.

5.5.12 Power System Stabilizers

Power system stabilizers (PSS) are special control systems whose purpose is to dampen power swings seen by the generator by modifying the generator's excitation modulation so that torque changes are provided in phase with speed changes. The PSS provides control of a generator's excitation system supplemental to the normal voltage or VAR regulating control.

The problem of small-signal stability is usually one of insufficient damping of system oscillations. The use of power system stabilizers (PSS) to control the generator excitation is the most cost-effective method to enhance the small-signal stability of power systems.

A fast acting excitation system, while beneficially boosting generator voltage during a fault can act to exacerbate power swings after the fault, by the nature of its fast response to voltage magnitude. By examining the generator's dynamic trends of power and frequency or speed together with knowledge of the characteristics of both the generator and its excitation control system, the PSS compensates for phase lags introduced by the generator and its excitation system. Boosting and bucking the internal voltage of the appropriate generators at the appropriate point in the swing produces a dynamic state that continues to satisfy the power transfer equation but with a reduced angular difference between generators on either side of the system swing center. Limiters within the PSS control system limit the voltage response to within 5-10%.

PSS systems, although applied independently and universally on all sizable generators, if tuned to a similar frequency, will act with a similar response to avert system instability. Application of PSS's will also better dampen stable power swings, reducing the probability that a stable power swing will enter the impedance zone of a distance relay. Large generators, due to their high inertia and potential power and VAr output, are most influential in their effect on damping swings. PSS's generally are not effective in averting first swing instability.

Generally PSS's are tuned to respond to power swings for local modes and/or inter-area modes and can be reasonably effective for both. Tuning to favor the higher local mode can make the machine less effective to inter-area oscillations. Inter-area modes are usually in the 0.2 to 2.0 hertz range whereas local modes are of higher frequency than the inter-area mode. Knowledge of the power system is as important in properly tuning PSS's as it is in properly applying and setting the response of the protection system to power swings. Since most Control Areas will allow operation of both the AVR and PSS in local or manual operation modes, protection settings should not consider the effects of the AVR and PSS in setting of power swing detection.

A PSS is now a requirement for all sizable (typically over 30 MVA) synchronous generators in some U.S. and Canadian jurisdictions. Without knowledge of conditions in the rest of the system and without coordination with the responses in other parts of the system, PSS systems are limited by their ability to respond to local generator measurements.

5.5.13 High-Speed Reclosing

High-speed reclosing as an effective measure to enhance power system stability and power supply reliability, has been widely applied to EHV transmission systems. Statistically, the failure rate of high-speed reclosing is known to be between 20% and 35% [41]. When the high-speed reclosing of a circuit breaker is successful, it will be a valuable means to improve the transient stability of a power system. However, if it fails for some reason such as insufficient recovery of insulation or high switching surge voltage, it can result in severe electrical or mechanical stress on the power system equipment and apparatus such as turbine generator and transformer. In such cases, longer dead time of the reclosing relay may increase the rate of successful reclosing.

The system transient stability is significantly affected by the reclosing time. Generally, it is believed that the faster the line reclosing is, the better the system stability will be for a transient fault. However, faster line reclosing may not improve the transient stability. Some recent studies have shown that there is an optimal reclosure time for different system and fault conditions; reclosure at this time will effectively reduce the system oscillations to a safe level thereby enabling the system to quickly reach a stable state. However, the optimal reclose time is not fixed; it varies with the type of fault, pre-fault operating condition, severity of fault, etc. and therefore traditional fixed-time reclosure cannot meet the requirements of optimal reclosure. The optimal reclosing instant is the time when the transient energy of the post-reclosing system is minimum because the larger transient energy weakens the system stability and increases the oscillation.

After reclose at a fixed time the impact from the fault and the reclose action add together possibly causing an increase in oscillation. However, the impact of the optimal reclose operation mitigates the impact from the fault, increase system damping, reduces the amplitude of system oscillation and expedites its damping. It is clearly evident from some studies that optimal reclosure is effective in enhancing system stability.

If successful reclosing is the only method to maintain stability, for example, on a heavily loaded transmission line or on a single line between two systems, fast reclosing may be needed to keep the system stable. Generally, these situations can be avoided by sound operation and planning practices, so that it is unnecessary to applying fast reclosing. Fast reclosing following fault detection and clearing is a method sometimes used to improve stability. If there is a reasonable probability that the fault is temporary and can be removed by simply opening and immediately reclosing the faulted line, then automatic reclosing can be very effective as a means of improving transient stability. However, the price to be paid by unsuccessful reclosing must always be considered. In many systems that are stability limited, automatic reclosing following fault detection and clearing is not permitted, since the consequences of reclosing onto a permanent fault may lead to widespread outages and possible blackout. Therefore, this option must be studied very carefully before making a decision to employ automatic reclosing for stability enhancement.

The success of reclosing depends a great deal on the speed of tripping. Fast clearing of the fault ensures less damage to lines and equipment, and also limits the ionization of the fault path. Fast fault clearing also improves system stability and limits the shock to the system. Therefore, breaker speed is an important factor in the success of stability. Circuits with very high-speed relays and circuit breakers will have a higher probability of successful reclosure. This is usually the case at the highest transmission levels, where breakers are usually fast and the relaying is high speed pilot relaying. This gives the arcing fault little time to become established and improves the probability of successful deionization and reclosing.

The following examples illustrate how reclosing time interval optimization can have an influence on system stability. Figure 14 shows that the rotor angles change rapidly and almost go asymptotic near the end of the record, indicative of a stability problem.

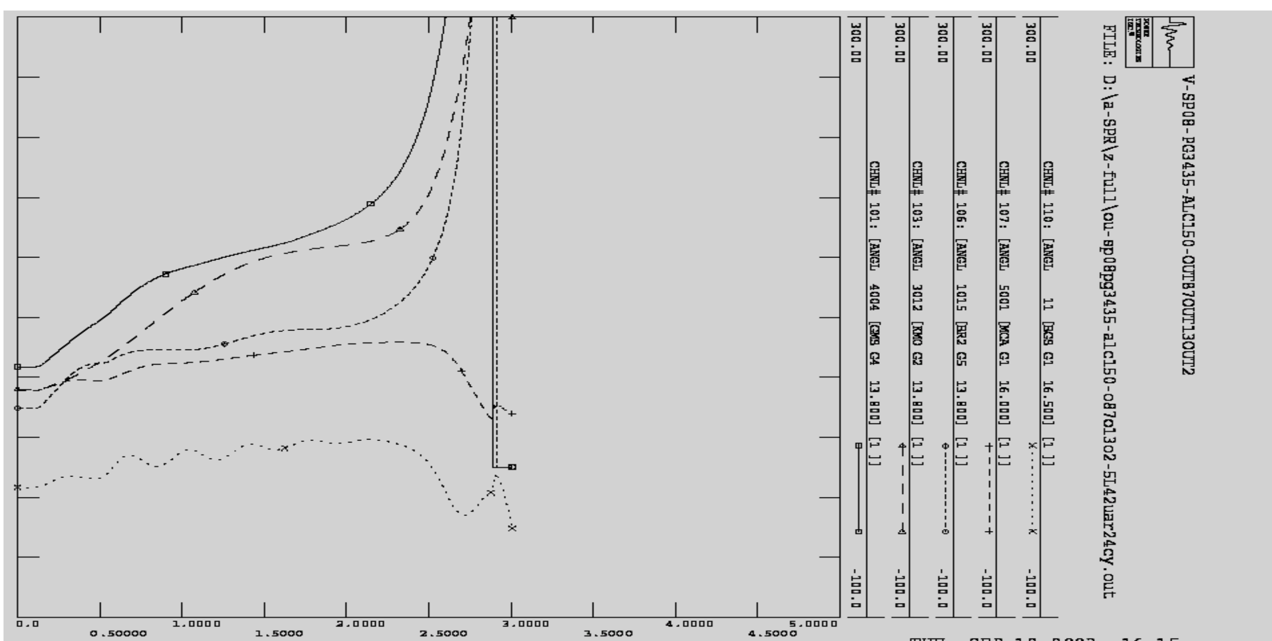

Figure 14 Reclosing at 24 cycles

Figure 15 shows the same case with reclosing at 72 cycles. We can observe that the rotor angles are much better behaving, with rotor angles settling out soon after reclosing. The system is stable.

for this case.

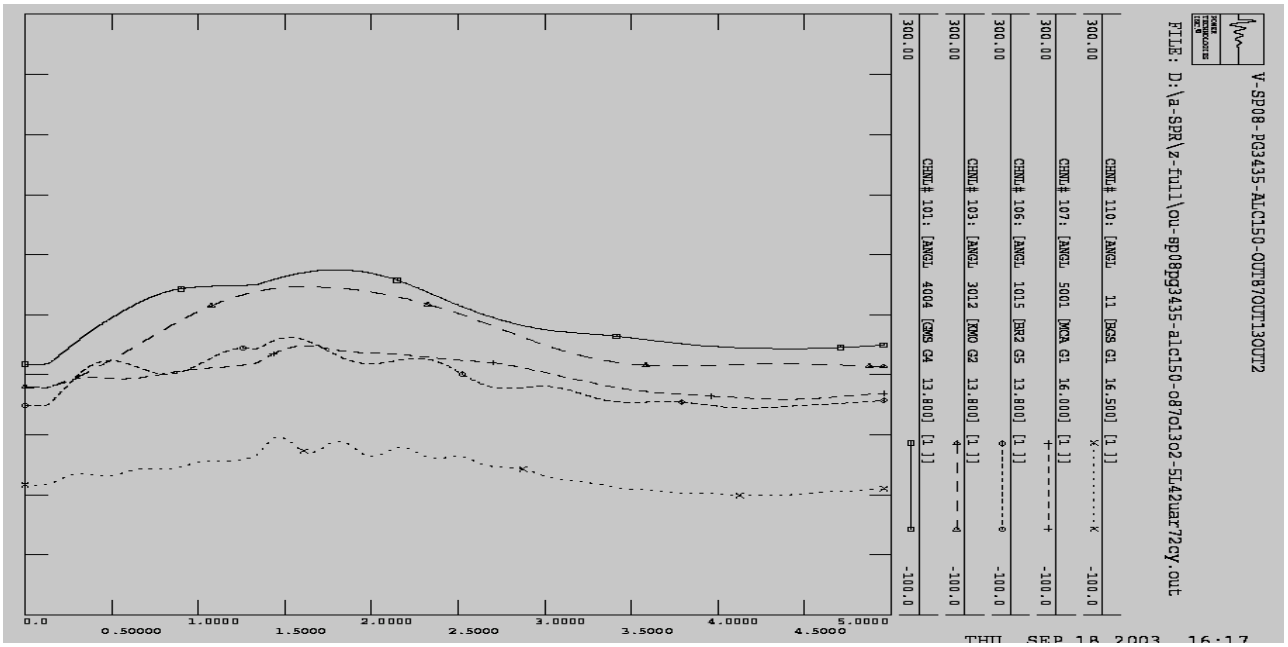

Figure 15 Reclosing at 72 Cycles

5.6 POWER-SWING PROTECTION FUNCTIONAL TESTING

Testing of power-swing protection functions with traditional relay testing equipment can be very difficult if not impossible to perform. The difficulty arises from the inability of older test sets to reproduce the type of waveforms present during power swings. Using older relay test sets and ramping the currents, voltages, and/or frequency is not a recommended approach.

Today's modern test equipment is able to replay COMTRADE waveforms captured during power swings by relays, digital fault recorders, or computer generated by electromagnetic transient programs (EMTP/ATP). The most proper test method to verify the relay behavior for stable power swing and OOS conditions is to generate a number of COMTRADE test cases from transient simulations and play them back into the relay using modern test equipment. Using this methodology, one can verify if the relay will perform satisfactorily during OOS conditions. The user should decide whether to use generic OOS COMTRADE test cases or whether they should model the actual network where they plan to apply the power swing protection relays. The user should be aware that generic OOS test cases do not reflect conditions for his particular application. In addition, test signals generated using transient simulations for a particular application depend on the simulated network and reflect that particular system and selected operating and fault conditions.

The two waveforms shown in Figure 16 are from a simulated multi-machine network. Figure 16 demonstrates how different the waveforms can be on two different lines for the same OOS case. In the first plot the OOS condition resembles that of a two-machine system, while the second one shows how complex the OOS waveforms can be due to multi-machine mode excitation. The second waveform would be impossible to generate using a test set and try to ramp the voltages, currents, and/or frequency.

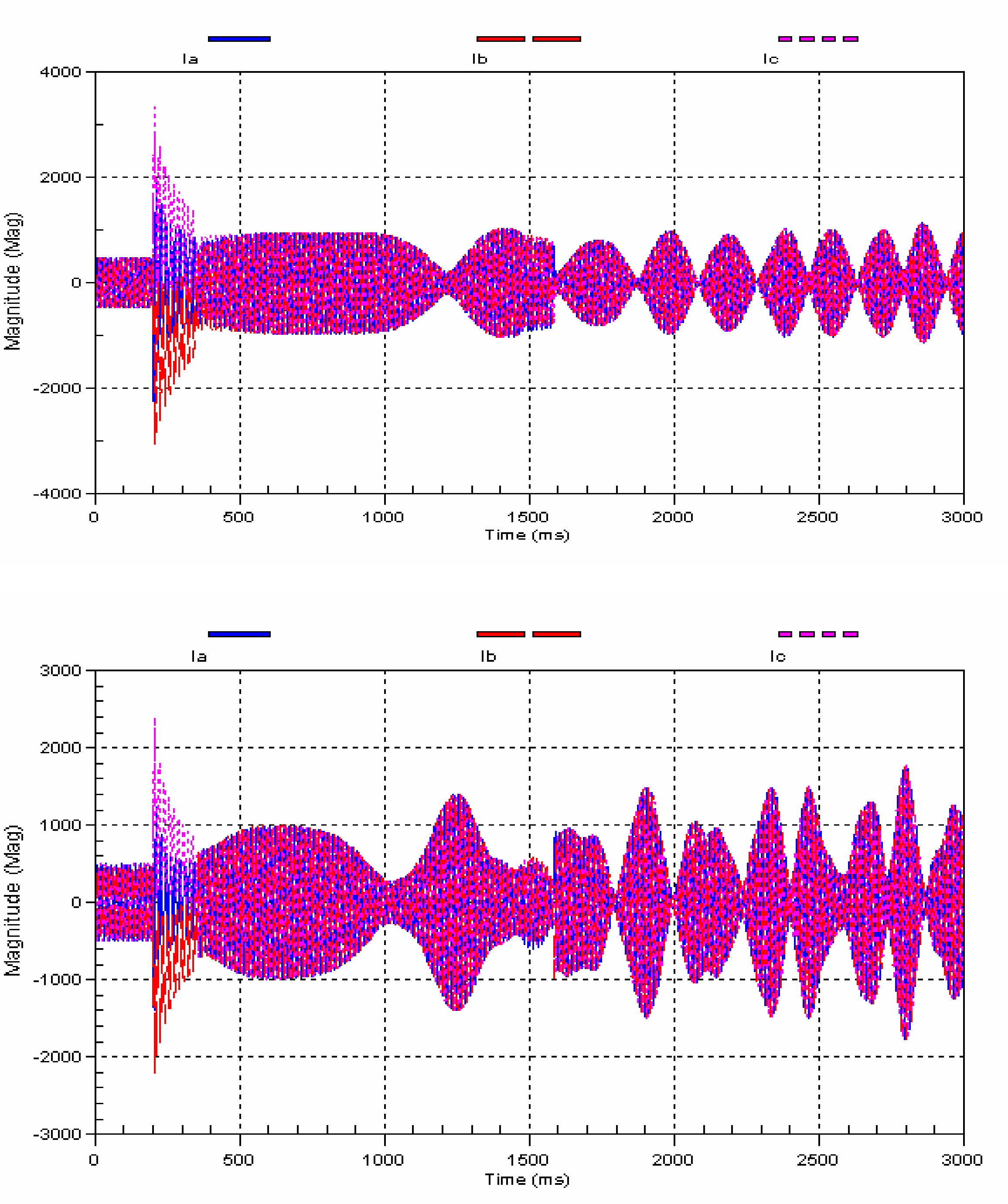

Figure 16 Typical OOS Waveforms from EMTP/ATP Simulations

6 SUMMARY AND CONCLUSIONS

Power swings both stable and unstable can precipitate wide spread outages to power systems with the result that cascade tripping of the power system elements occur. Protection of power systems against the effects of power swings both stable and unstable has been described in this paper. The paper has given an overview of power swings, their causes and detection. Methods of detecting and protecting the power system against power swings have been developed and elaborated.

Detailed system studies both steady state and transient are required to determine the application of power swing protection. Extensive stability studies under different operating conditions must be performed to determine the rate of change of power swings. To assist the protection engineer, shortcut methods for determining the need and application requirements have been detailed. The shortcut methods are steady state in nature and do not address the system dynamics and the effects of transient swings onto lower voltage lines following a high voltage line trip. However, as shown in the paper the short cut methods are no substitute for detailed system studies.

Protective relays use a number of methods to detect the presence of a power swing, the most common being the rate of change of the positive sequence impedance. Other power system quantities have also been used for power-swing detection such as power and its rate of change, the phase angle difference across a transmission line or path and its rate of change, the swing-center voltage and its first and second derivatives.

Four Appendices give details on the shortcut method for identifying a system zero, a detailed application example, fast valving and a review of equal area stability criteria for a two-machine system.

The report draws a number of conclusions.

- There are four options for the application of power swing protection. The recommended option is to apply PSB on transmission lines in conjunction with OST, located at critical network locations, to separate the power system into islands with a balance of generation and load. PSB protection by itself without OST protection is not recommended.
- The location of a system voltage zero is an indicator where system islanding should take place and determines the location for OST and PSB protection. In some systems, it may be necessary to separate the network at locations other than where OST is installed.
- Application of PSB and OST may be required on other power system elements, e.g. a lower voltage line(s) in parallel with higher voltage lines.
- Detailed system studies (both steady state and transient) are required to determine both the application and settings for the PSB and OST elements. Shortcut methods to identify the initial need for power swing detection gives a good starting point for the detailed studies.
- During power swings, voltages across the breakers on either side of the system zero approach 180 degrees and may cause irreparable damage to the breaker. Breaker application needs to be addressed concurrent with the power swing application.
- Where a load/generation balance cannot be achieved, some means of shedding load or generation will have to take place to achieve the load/generation balance and avoid a complete shutdown of the area.
- The relationship between the measured voltages and currents plays the most critical role in

whether a distance relay will operate during a power swing.

- The effects of power swings on other parts and equipment in the power system should be studied.

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APPENDIX A: SWING-CENTER IN A COMPLEX NETWORK

To determine whether the swing locus would traverse a particular transmission line during loss of synchronism we need to reduce the complex power system, excluding the line of interest, to a two-source equivalent system shown in Figure A1. This can be achieved with reasonable accuracy using a number of methods. In this section we discuss two methods, the first one using the output of an equivalent network from a commercial short circuit program and the second using 3-phase short circuit currents from a short circuit program or hand calculations.

First method:

The easiest method for developing this equivalent is to use the output of a commercially available short circuit program. First, we need to delete from the network the transmission line of interest, and request the short circuit program to calculate an equivalent two-port network as seen from the two ends of the line of interest. The short circuit program will compute Z_S, Z_R, and Z_{TR} impedances shown in Figure A1. Reintroduce the line impedance Z_L in parallel with the equivalent transfer impedance Z_{TR}, and calculate the total impedance Z_T given by equation A1.

$$Z_T = Z_S + \left[(Z_{TR} Z_L) / (Z_{TR} + Z_L) \right] + Z_R \qquad \text{(A1)}$$

The swing locus bisects Z_T, given equal source voltage magnitudes as a reasonable initial assumption.

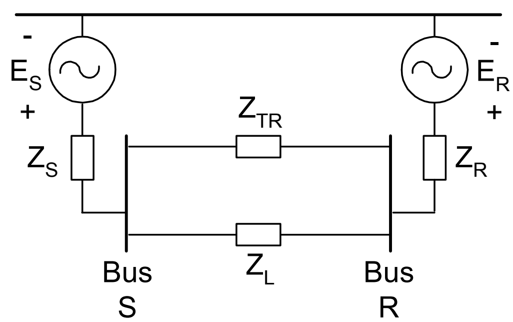


Figure A1 Two-Source System Equivalent

Second method:

The second method to develop a two-source equivalent from a complex power system is based on the knowledge of the total three-phase fault currents at the two ends of the transmission line of interest and the line current flow for each respective fault.

Given the following data:

I_{3Ph-S} = Total fault current for a three-phase fault at Bus S in p.u.
I_{3Ph-R} = Total fault current for a three-phase fault at Bus R in p.u.
I_{3Ph-RS} = Fault current contribution over the line for a three-phase fault at Bus S in p.u.
I_{3Ph-SR} = Fault current contribution over the line for a three-phase fault at Bus R in p.u.

First calculate the following distribution factors:

$$K_S = \frac{I_{3Ph-RS}}{I_{3Ph-S}} \quad \text{(A2)}$$

$$K_R = \frac{I_{3Ph-SR}}{I_{3Ph-R}} \quad \text{(A3)}$$

The wye-system equivalent shown in Figure A2, excluding the transmission line of interest, can be developed using the following formulas:

$$X_1 = \frac{K_S Z_L}{1-(K_S + K_R)} \quad \text{(A4)}$$

$$Q_1 = \frac{K_R Z_L}{1-(K_S + K_R)} \quad \text{(A5)}$$

$$W_1 = Z_{Th-S} - X_1(1 - K_S) \quad \text{(A6)}$$

Where $Z_{Th\text{-}S}$ is the positive-sequence driving point impedance for a fault at Bus S given by:

$$Z_{Th-S} = \frac{1.0}{I_{3Ph-S}} \quad \text{(A7)}$$

This wye system equivalent shown in Figure A2 can be converted to a delta equivalent shown in Figure A1 using the well-known wye-delta conversion formulas.

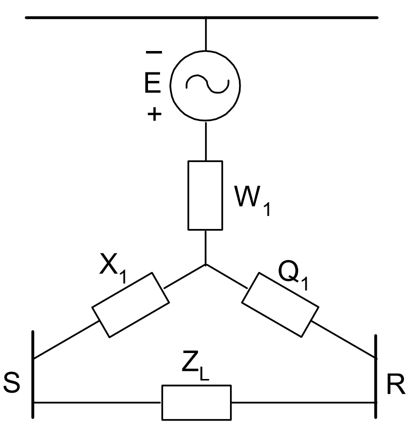


Figure A2 Wye System Equivalent With Line Reintroduced Between Buses S and R

Example Using Method 2:

The following example demonstrates the above procedure for determining a two-port equivalent. Given the system shown in Figure A3, obtain the equivalent as viewed looking into buses 2 and 3, and determine whether the swing locus passes through transmission line c.

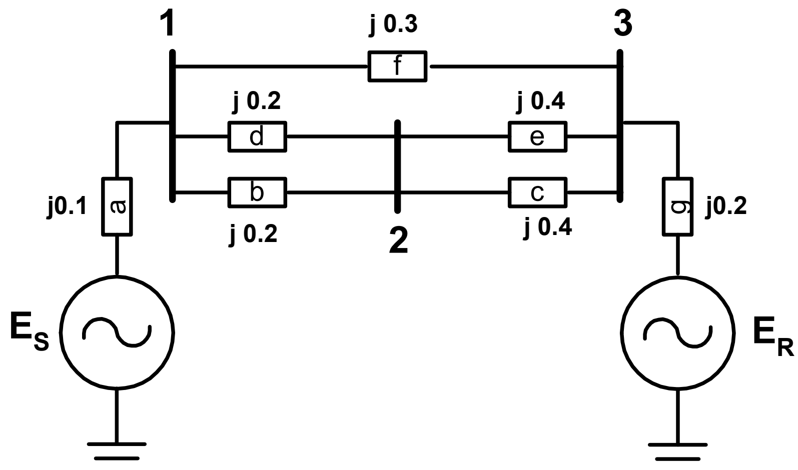


Figure A3 Example Network for Swing Locus Study

First form the bus nodal admittance matrix Y_{BUS} and invert it to calculate the bus impedance matrix Z_{BUS}. For the above network the Z_{BUS} matrix is given by:

$$Z = \begin{pmatrix} 0.08j & 0.07j & 0.04j \\ 0.07j & 0.13j & 0.07j \\ 0.04j & 0.07j & 0.11j \end{pmatrix}$$

Using the driving-point impedances for buses 2 and 3 we can calculate the total three-phase fault currents in p.u. for faults at these two buses. For a fault at Bus 2 the voltage at Bus 3 is 0.5 p.u. Therefore, the fault current flowing through line "c" is –j1.25 p.u. For a fault at Bus 3 the voltage at Bus 2 is 0.4 p.u., and the fault current flowing through line "c" is –j1.0 p.u.

The fault currents are:

I_{3Ph-2} = –j 7.50 p.u. total three-phase fault current for a three-phase fault at Bus 2.
I_{3Ph-3} = –j 9.00 p.u. total three-phase fault current for a three-phase fault at Bus 3
I_{3Ph-32} = –j 1.25 p.u. fault current over line "c" for a three-phase fault at Bus 2.
I_{3Ph-23} = –j 1.00 p.u. fault current over line "c" for a three-phase fault at Bus 3.
Z_L = j 0.40 p.u. transmission line positive-sequence impedance.

Letting Bus S and R to correspond to Buses 2 and 3 respectively and by substituting the above fault currents in equations A2, A3 and A7, we first compute distribution factors K_S and K_R and Z_{Th-S}:

$$K_S = \frac{I_{3Ph-RS}}{I_{3Ph-S}} = \frac{-j1.25}{-j7.5} \qquad \text{(A8)}$$

$$K_R = \frac{I_{3Ph-SR}}{I_{3Ph-R}} = \frac{-j1.0}{-j9.0} \qquad \text{(A9)}$$

This gives:

$K_S = 0.17$, $K_R = 0.11$, and $Z_{Th-S} = -j\ 1.33$ pu.

Now if we substitute K_S and K_R into equations A4, A5, and A6 we get:

$X_1 = j\ 0.09$, $Q_1 = j\ 0.062$, $W_1 = j\ 0.056$

Up to here we have computed the elements of the wye-equivalent network shown in Figure B. In order to determine whether the swing center passes through line "c" we must first convert the wye-equivalent network to a two-source equivalent network represented by Figure A1 using the well known wye-delta conversion formulas. By doing so we calculate the following impedances for the two-source equivalent:

$Z_R = j\ 0.233$, $Z_S = j\ 0.156$, $Z_{TR} = j\ 0.255$

The two-source equivalent is now shown in Figure A4

.

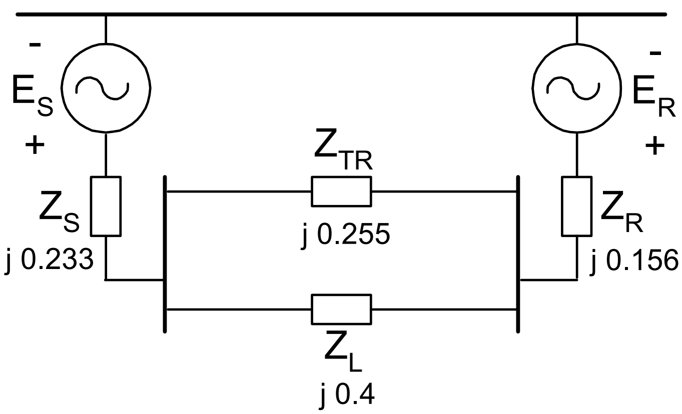


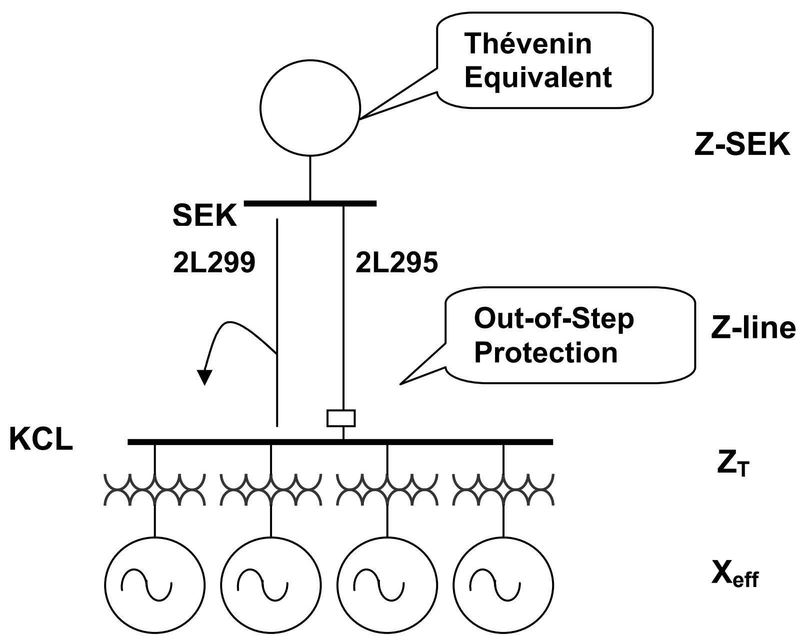
Figure A4 Equivalent Network Between Buses 2 & 3

The total impedance between the two sources is ZT = j 0.54 p.u. and 0.5(ZT) = j 0.27 p.u. By inspection of the equivalent network of Figure A4 we determine that the swing locus will pass through line "c." In a similar manner we can verify that the swing locus does not pass through line "b."

APPENDIX B: PSB AND OST SAMPLE CALCULATIONS FOR AN INTERCONNECTED SYSTEM

This example illustrates the procedure for calculating out-of-step protection settings using study results from dynamic simulations of an interconnected system. Figure B1 shows a simplified single-line diagram of the studied system between Substation A (KCL) generating station and Substation B (SEK) substation. A 230 kV parallel circuit comprising of two lines, 2L295 and 2L299, connects the two stations. KCL has four 147 MVA generators equipped with their own unit transformers and SEK is a major transmission station. Power flow is radial from KCL to SEK. The figure does not show several 500 kV and other 230 kV circuits emanating from SEK for simplicity and thus an ideal source at SEK with Thévenin impedance representing rest of the studied system is shown.

Figure B1 Simplified Single-Line Diagram of KCL-SEK Interconnection.



Dynamic simulations indicated that a three-phase fault close to KCL on one of the two lines in the parallel circuit followed by a loss of the faulted circuit results in stable or unstable power swings, depending upon fault clearing time and pre-fault power flow conditions. Longer clearing time can be due to a stuck breaker. Basically, acceleration of KCL generators during a fault and reduced transfer capability due to loss of one line results in KCL machines swinging against rest of the studied system. The swing center of unstable power swing passes close to KCL terminal or through the unit transformers.

Out-of-step protection functionality was implemented at the KCL terminal in the multifunction relays protecting 2L295 and 2L299. The relay uses two concentric rectangles in the R-X plane to distinguish unstable swings from stable swings and faults. Figure B.2 shows an R-X diagram of KCL and SEK interconnection system with the origin at the 230 kV bus at KCL looking toward SEK. The first quadrant of R-X diagram shows positive sequence impedance of 2L295 and the Thévenin equivalent of the studied system at SEK. The third quadrant shows source impedance behind the KCL bus, which includes unit transformer impedance and its associated machine's effective reactance. Effective machine reactance during power swings is the average of d- and q-axis transient reactance. Mho circle is Zone 1 reach of the line protection scheme for 2L295 at KCL. Two concentric rectangles, (or polygons tilted at line angle) along with a timer within 2L295 protection scheme at KCL are used for distinguishing faults, stable and unstable power swings, as described below. When the positive sequence apparent impedance seen by the line protection at KCL:

- Enters the outer and inner rectangles simultaneously (less than specified timer setting), it is considered a fault.
- Enters the outer rectangle, and stays between the outer and inner rectangles for longer than a specified timer setting before entering into the inner rectangle, it is considered an unstable swing.
- Enters the outer rectangle but does not enter the inner rectangle, it is considered a stable swing.

Source impedance calculations:

All impedance values are in the per unit system with 230 kV as the base voltage and 100 MVA as the base power or 529 ohms as the base impedance.

Impedance	PU value	Calculation Procedure
Z-SEK	$0.014\angle 87.4°$	Thévenin impedance at SEK 230 kV bus. It is obtained using the steady-state short circuit program with 2L295 and 2L299 out-of-service.
Z-line	$0.043\angle 81.7°$	Line impedance generally available from conductor and spacing data.
Z-KCL	$0.340\angle 86.3°$	Unit transformer impedance plus average of associated machine's d- and q-axis transient reactances ($Z_T + X_{eff}$). Out-of-step conditions most likely to occur during heavy power flow from KCL to SEK i.e. when all four machines are connected. However, in these calculations, impedance of a single unit transformer and machine are used incase unstable swing occurs with one machine operating.
Zone 1	$0.034\angle 81.7°$	Zone 1 reach of 2L295. Not important as the line is equipped with a communication-assisted protection scheme. Should impedance swing pass anywhere through the line impedance, communication-assisted line protection will trip the line at a high-speed irrespective of Zone 1 setting.

Several dynamic simulations of the KCL-SEK interconnection were performed using the full study model rather than a simplified system as shown in Figure B1. Results from two cases, stable and unstable, are presented to illustrate the setting procedure of out-of-step relaying. In both cases, pre-fault loading was about 285 MW/per line or load impedance was about 0.35 pu (=100/285). A three-phase fault close to KCL bus on 2L299 was simulated. Fault was applied for the longer duration than the normal clearing time in order to simulate a stuck breaker. Tripping of 2L299 at both ends cleared the fault. However, the line tripping time was slightly shorter (about one cycle) for the stable case than the unstable case. In this manner, the worst case of the stable swing was simulated. Line 2L295 carried all generation (570 MW) from KCL to SEK following 2L299 tripping. Thus, the post-fault load impedance seen by 2L295 at KCL was about 0.175 pu. Study results included trajectory of positive sequence apparent impedance as seen by the line protection at KCL. These impedance trajectories were super-imposed on the R-X diagram for calculating the out-of-step protection settings.

Figure B2 shows trajectory of the apparent impedance for the stable power swing case. Since pre-fault power flow was from KCL to SEK, the load impedance seen by the relay at KCL is on the positive side of the R-axis. However, both pre- and post-fault impedances are out-of-range of the R-axis scale used and thus cannot be seen in the figure. As soon as a three-phase fault close to KCL terminal is applied, apparent impedance jumps immediately very close to the origin from the pre-fault load location on the R-X plane. During a fault, the power flow from KCL to SEK is very limited and the KCL machines begin to accelerate. Acceleration of machines continues until 2L299 trips and clears the fault. Pre-fault loading and 2L299 tripping times affect the extent of acceleration. On tripping of 2L299, the apparent impedance steps to (0.075, -0.02i) p.u. (identified by mark ⊗ in the figure) and starts to travel towards the origin until it reaches (0.04, 0.00i) p.u., where the swing reverses its direction and finally settles down to the post-fault loading location.

Figure B3 shows apparent impedance trajectory for an out-of-step condition or unstable power swing case i.e. when the fault was simulated for slightly longer duration (about one cycle) than the stable case. In this case, the apparent impedance steps to (0.063, -0.014i) p.u. after 2L299 tripping and starts to travel towards the origin. This time passes the unit transformers at about (0.00, -0.002i) or close to the KCL bus. When it crosses the unit transformers, KCL machines have already slipped a pole and gone out-of-step with the rest of the studied system represented at SEK.

Power-Swing Protection Setting Calculations:

Maximum Load MVA: 4×147 or 588 MVA
$Z_{LoadMax}$: 0.182 p.u. (=100/588)

Setting	PU value	Calculation Procedure
RR-Inner	0.02	Right side resistive reach of Inner Rectangle. Select to ensure it does not trip for the most severe stable swings. Figure B2 shows that stable swing begins at (0.075, -0.02i) p.u. after fault removal. It travels up to (0.04, 0.00i) p.u., reverses and finally settles at post-fault load impedance. RR-Inner is set lower than 0.04 p.u. with margin.
LR-Inner	-0.02	Left side resistive reach of Inner rectangle. Set same as negative of RR-Inner.
RR-Outer	0.05	Right side resistive reach of Outer Rectangle. Must be less than $Z_{LoadMax}$.

		Figure B2 shows that stable swing begins at (0.075, -0.02i) p.u. after fault removal, and thus RR-Outer is set lower than 0.075 p.u. with margin.
LR-Outer	-0.05	Left side resistive reach of Outer Rectangle. Set same as negative of RR-Outer.
TX-Inner	0.017	Top reactive reach of Inner Rectangle. Set to overlap with line protection zones along the reactive or X-axis reach. Swing center passing through unit transformer and generator will be detected by out-of-step protection and those passing though the line by the line protection. Set about $0.4Z_L$
BX-Inner	0.02	Bottom reactive reach of Inner Rectangle. It must be set to detect swing center passing anywhere in the unit transformer and generator. Set to one unit transformer impedance plus half of the associated machine's effective reactance ($Z_T + X_{eff}/2$). Since KCL is radially feeding to SEK, a longer setting based on one unit transformer and generator will be cover cases of more than unit without many security concerns.
TX-Outer	0.025	Top reactive reach of Outer Rectangle. Set to more than TX-Inner with margin i.e. about $0.6Z_L$.
BX-Outer	-0.02	Bottom reactive reach of Outer Rectangle. Set to less than BX-Inner with margin i.e. about BX-Inner – 0.02i.

Figures B2 and B3 show that impedance trajectories jump from pre-fault loading to close-to-origin in the R-X plain immediately on fault inception. Figure B3 shows it takes about 0.29s or 17 cycles to travel from 0.05 p.u. (RR-Outer) to 0.02 p.u. (RR-Inner) for out-of-step conditions simulated. OOS-Timer was set 2 cycles to ensure fastest out-of-step conditions are detected. With the settings used, the out-of-step protection at KCL is intended to operate as discussed below. If the positive sequence apparent impedance seen by the line protection at KCL:

- Enters the outer and then enters inner rectangles in less than 2-cycles, the condition is identified as fault. No tripping is initiated. It is assumed as fault to be cleared by other protection function.
- Enters the outer rectangle and then takes 2 cycles or more to enter the inner rectangle, out-of-step tripping is initiated i.e. KCL end of the line opened and no tripping at SEK takes place.
- Does not enter the inner rectangle, no action is initiated.

Trip-On-Way-In or Trip-On-Way-Out:

The applied out-of-step scheme offers a feature, which allows Trip-On-Way-In or Trip-On-Way-Out. TOWI declares an out-of-step condition when swing impedance enters the inner rectangle whereas TOWO holds declaration until after the swing impedance exits the inner rectangle. TOWI allows tripping just before the first pole slipping. However, this scheme imposes higher transient overvoltage across breaker poles, as the voltages on either side of its poles are about 180 degrees apart when poles are just slipping. TOWO allows tripping after the first pole slipping and imposes less transient over-voltages on the breaker poles.

In the application discussed, TOWI was used because the studied breakers at generating stations are rated for out-of-step tripping duty. However, the studied system uses TOWO in the distribution system where a new distributed resource is connected to an existing feeder, whose breaker is not rated for out-of-step duty. In those cases, TOWO allows use of the existing breaker and thereby reduces the new resource inter-connection cost.

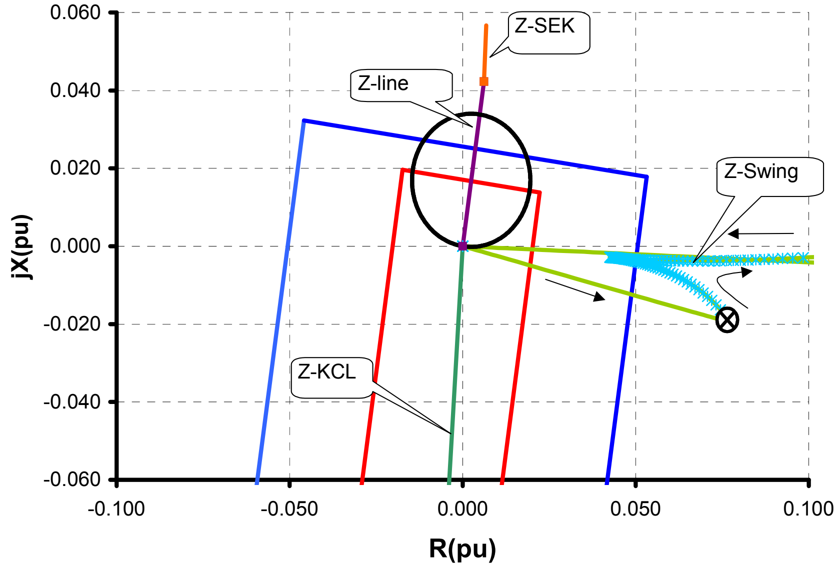


Figure B2 R-X Diagram of KCL-SEK Interconnection with Stable Power Swing Superimposed

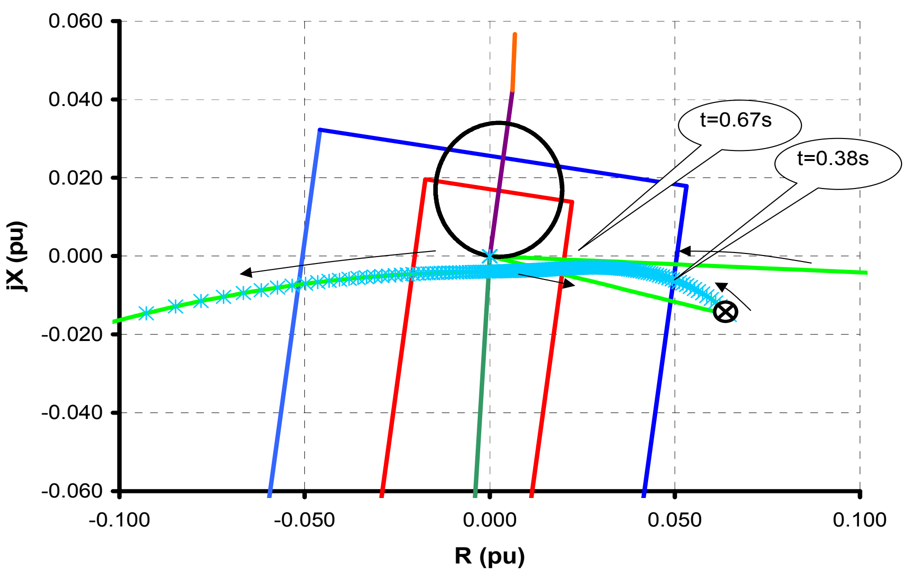


Figure B3 R-X Diagram of KCL-SEK Interconnection with Unstable Power Swing Superimposed

APPENDIX C: TURBINE FAST VALVING

The purpose of turbine fast valving is to reduce the generator output without removing the unit from service. This is desirable when the system is stressed, e.g. upon some occurrence which would result in a transient stability problem. By reducing the generator output, stability is not endangered and the unit can be returned to full output, maintaining system security.

There are two concepts in use. Company A, for example, closes the turbine valves to a predetermined position and stays there until the operator returns the unit to a desired load level. This procedure requires a turbine bypass system to allow the trapped steam to escape until the boiler pressure matches new load level. Company B [32] has opted to use a momentary fast valving (MFTV) scheme, which closes the turbine valves momentarily, and then allows them to return to a predetermined position. The scheme reduces the turbine mechanical power about 50% within one second. The valves then reopen automatically to their original positions, restoring mechanical power to the pre-disturbance level in less than 10 seconds.

The installation of this MFTV at Company B's ABC plant has several advanced protection schemes as well as the special protection scheme. The plant started out as a single 1300MW coal-fired unit connected to the Company B 765kV system through a single line to Station DEF. To prevent loss of the unit for a single-phase-to-ground fault, single phase tripping and reclosing was installed. This is not a new scheme as it is being used in Europe and Canada but it has not been generally used in the U.S. Since its inception it has been invaluable in maintaining vital generation at Company B's westernmost boundary. Subsequently, a second 1300 MW unit was installed, together with a second 765 kV line to the west, a tie to Station STU with a relatively weak interconnection to a neighboring utility.

This system configuration resulted in several unusual stability problems. The most striking was the fact that a three-phase opening of the ABC-DEF line, without any fault, is more severe with respect to plant stability than a three-phase opening resulting from a fault. This is because, in response to a voltage depression due to a nearby fault, the excitation level of the ABC units is boosted via voltage regulator action, which increases the internal generator voltage and, in turn, improves the plant's stability performance.

Another special control was the Quick Reactor Switching (QRS) scheme. For selected disturbances, a 150 MVAr shunt reactor bank at ABC on the ABC-STU line is automatically opened in about 5 cycles and reclosed in about 2.5 minutes. In addition, a Rapid Unit Runback (RUR) is installed on both ABC units. This scheme automatically reduces the output of each unit by about 50 MW within 30 seconds and by 200 MW within 3 minutes following selected disturbances. This maximizes plant production since plant output curtailment is deferred until after a disturbance, rather than prior to anticipated contingencies. Finally, an Emergency Unit Tripping (EUT) scheme for both ABC units provides an intentional turbine trip of one of the units following selected disturbances.

Each of the supplementary controls requires that three input conditions be met in order to operate:

1. Pre-contingency ABC area transmission status.

2. Pre-contingency ABC plant output, and
3. Type of contingency.

The supplementary controls are asymmetric, i.e. the controls act differently in response to events on one line than they do in response to events on the other line. All of the schemes have arming switches for personnel to be able to activate or disable these controls based in system needs. Historically, the MFTV scheme is armed about 99% of the time, the RUR and EUT schemes only 1% of the time. The QRS control is disabled only when the ABC-DEF line is out of service.

APPENDIX D: THE EQUAL-AREA CRITERION

Consider the network of Figure D1 where we have a generator connected to an infinite bus through impedance XT. The generator has a phase angle advance δ (also called the rotor angle) with respect to the infinite bus voltage ER. The results and conclusions of the analysis would remain exactly the same if we were to assume that another generator replaced the infinite bus. It can be demonstrated that the maximum power P_{max} that can be transferred from the generator to the infinite bus will be equal to:

$$P_{\max} = \frac{ES\ ER}{XT} \tag{D1}$$

At any moment, the electrical power P_e supplied by the generator to the infinite bus is a function of the maximum power and the phase angle δ:

$$P_e = P_{\max} \sin \delta = \frac{ES\ ER}{XT} \sin \delta \tag{D2}$$

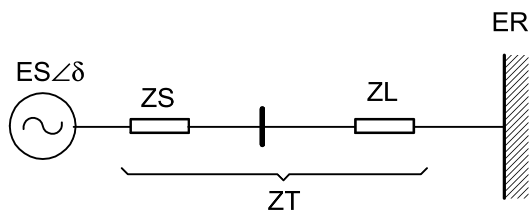


Figure D1 Generator Connected to an Infinite Bus

When a disturbance occurs on the network, the generator rotor angle will move from some point of equilibrium to a new value. The differential equation modeling the motion of the rotor angle as a function of the maximum power is provided by the swing equation:

$$\frac{2H}{\omega_0} \frac{d^2\delta}{dt} = P_m - P_{\max} \sin \delta \tag{D3}$$

In equation D3, we have:

- P_m: mechanical power supplied to the generator
- P_{max}: maximum power supplied through the system
- H: generator inertia constant in MW s/ MVA
- δ: rotor angle in electrical radians
- t: time in s
- ω_0 system frequency in radians.

Let us assume, as shown in figure D2, that the generator is running at an initial equilibrium point with an initial supplied mechanical power P_i and a rotor angle δ_i. The generator is then subjected to a mechanical power step from the initial P_i to the final P_f. We can assume then than the rotor angle will move from the initial position δ_i to the final δ_f. Before the rotor settles to the final angle position δ_f, we can anticipate that it will reach a maximum value δ_u and it will go back to the final position δ_f.

We want to determine if the rotor angle motion will be stable (the rotor will settle to a viable fixed steady-state final value) or unstable (the rotor angle will not settle to a viable fixed final steady-state value). The equal-area criterion described below allows us to determine if the rotor angular motion will be stable or not.

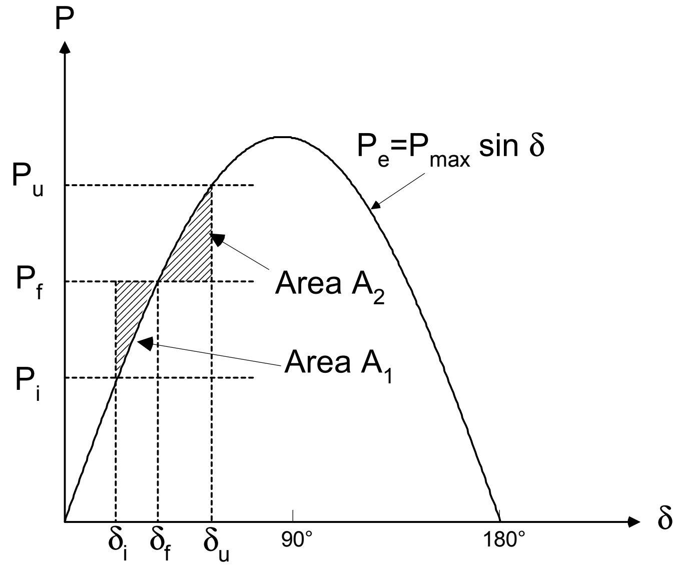


Figure D2 Step Change in the Rotor Angle

By virtue of equation D3, we have:

$$\frac{d^2\delta}{dt} = \frac{\omega_0}{2H}(P_f - P_e) \tag{D4}$$

In equation D4, P_f is the final mechanical power supplied to the generator, P_e is the electrical power supplied by the generator that is a sine function of the angle δ as shown in figure D2. If we multiply, both sides of equation D3 by the derivative of the rotor angle, we get:

$$2\,\frac{d\delta}{dt}\frac{d^2\delta}{dt} = \frac{\omega_0\,(P_f - P_e)}{H}\frac{d\delta}{dt} \tag{D5}$$

The left-hand term in equation D5 can also be expressed as the time derivative of the square of the time derivative of the rotor angle. So that equation D5 can be otherwise expressed as:

$$\frac{d}{dt}\left(\frac{d\delta}{dt}\right)^2 = \frac{\omega_0\,(P_f - P_e)}{H}\frac{d\delta}{dt} \tag{D6}$$

Integrating both sides of equation D6, we then get:

$$\left(\frac{d\delta}{dt}\right)^2 = \int \frac{\omega_0\,(P_f - P_e)}{H}\,d\delta \tag{D7}$$

The left-hand side of D7 is the square of the time derivative of the rotor angle or its speed. Notice that the rotor speed at the point of initial equilibrium δ_i is zero and that the speed will also have to be zero at the point of maximum deviation δ_u before the rotor angle goes back to the final steady-state point δ_f. Based on this observation, the integral in equation D7 can then be equated to zero for the shown boundaries in equation D8:

$$\int_{\delta_i}^{\delta_u} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta = 0 \tag{D8}$$

The integral in equation D8 can be separated in the two integrals shown in equation D9:

$$\int_{\delta_i}^{\delta_f} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta + \int_{\delta_f}^{\delta_u} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta = 0 \tag{D9}$$

So that we finally get:

$$\int_{\delta_i}^{\delta_f} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta = -\int_{\delta_f}^{\delta_u} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta \tag{D10}$$

Notice that the left-hand side integral in D10 is equal to area A1 in figure D2:

$$Area\ A1 = \int_{\delta_i}^{\delta_f} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta \tag{D11}$$

and that the right-hand side integral in D10 is equal to area A2 in figure D2:

$$Area\ A2 = \int_{\delta_f}^{\delta_u} \frac{\omega_0\,(P_f - P_e)}{H}\, d\delta \tag{D12}$$

Equation D11 and D12 express the fact that when a change occurs in the rotor angle, the accelerating energy (mechanical power greater than the electrical power) supplied to the rotor when the angle δ advances must be equal to the decelerating energy supplied by the rotor (electrical power greater than the mechanical power) when the rotor angle goes back to its final value. This condition is tantamount to stating that the area A1 corresponding to the rotor accelerating must be equal to area A2 corresponding to the rotor decelerating. When a rotor angle transient takes place then, if it is possible to find the two equal areas A1 and A2 for the acceleration and the deceleration, then the rotor angle motion will be stable. If it is not possible to find two equal areas, then the rotor angle motion will have to be considered as unstable. This principle is known as the **equal-area criterion** and can be similarly applied in every situation when a change in the basic equilibrium of the rotor angle takes place. In each particular situation the proper mechanical power supplied to the generator and the proper electrical power supplied by the generator will have to be defined depending upon the network conditions.

APPENDIX E: DIGITAL FAULT RECORDING DURING AN OOS CONDITION

The following DFR record depicts an out of step condition on a 230 kV transmission circuit.

The following observations are noted from the oscillograph traces.

- Swing voltages and currents are a three phase phenomena
- Notice for any current/voltage pair the current is high when the voltage is low
- Notice there is no neutral current in the trace, illustrating that an out-of-step condition on a transmission line is a three phase phenomenon and appears like a three phase fault at the swing centre
- Swing phenomena are time varying, with the beating effect as shown: currents and voltages are constantly increasing/decreasing over time. This in turn can be related to r-x swing plots, where the apparent impedance over time passes through the transmission line (i.e.: voltage low and current high) and then as time progresses further, the swing leaves the transmission line on the r-x diagram and renters it some time later.

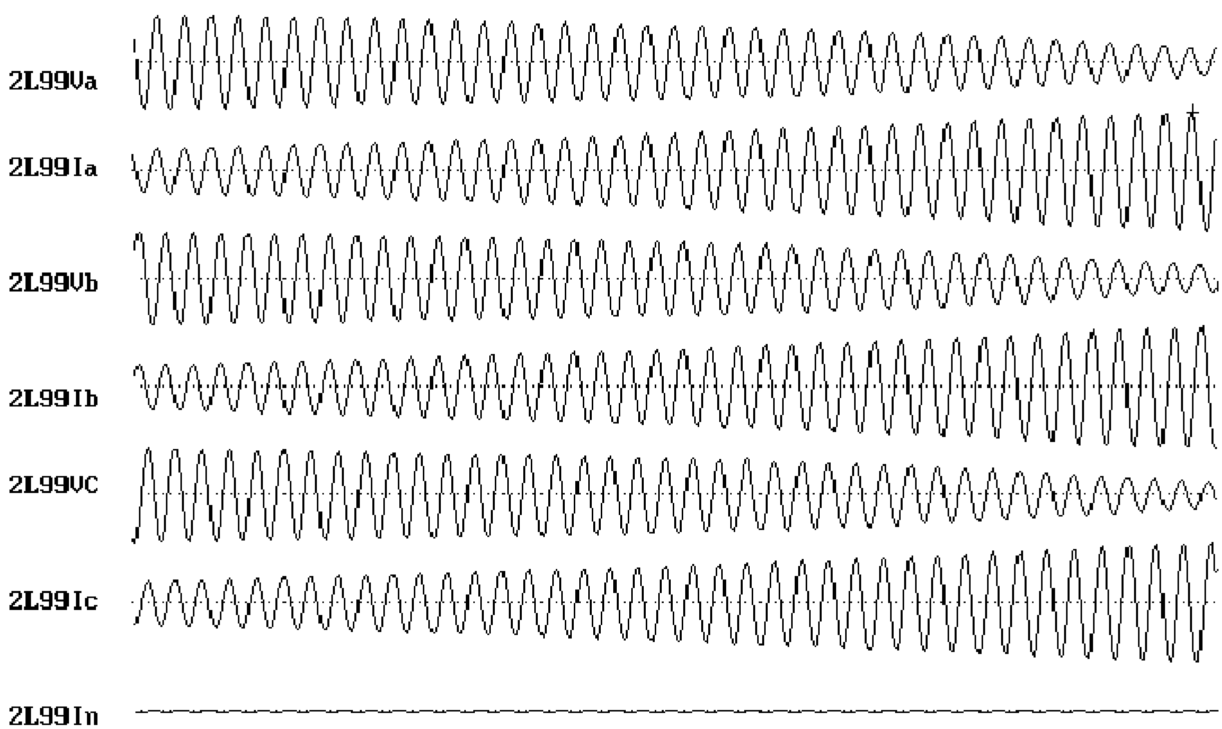


Figure E1 Digital Fault Record of an OOS Condition