APPLICATION OF OUT-OF-STEP PROTECTION SCHEMES FOR GENERATORS

Power System Relaying and Control Committee
Report of Working Group J5
of the
Rotating Machinery Protection Subcommittee

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KEYWORDS

Critical Clearing Angle

Loss of Synchronism

Out-of-Step Tripping

Power Swing Blocking

Pole Slip

Slip Angle Characteristics

Stability Studies

Swing Locus

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1. INTRODUCTION

Out-of-Step (OOS) protection schemes for generators have received much attention after the 1965 Northeast Power failure and other subsequent power system disturbances. In 1970s, the Rotating Machinery Subcommittee formed a working group that prepared a report on the need for and the methods of accomplishing generator OOS protection. OOS protection has attracted further attention since the 2003 Blackout. In 2010, North American Electric Reliability Corporation (NERC) System Protection and Control Subcommittee produced a Technical Reference Document "Power Plant and Transmission System Protection Coordination" which provides guidance on setting the OOS relay.[1][1] The assignment of this working group is to produce a report and summary paper explaining the various schemes and setting guidelines in use for OOS protection for AC synchronous generators.

2. OUT-OF-STEP CHARACTERISTICS

Out-of-Step or Loss of Synchronism is a condition where a generator experiences a large increase in the angular difference of the Electro Motive Force (EMF) with other generators or portions of a system to which it is connected, usually following a major power system disturbance. Depending on the severity of the disturbance, one or more generators may no longer maintain synchronism with the rest of the system. When a generator still connected to but is no longer in synchronism with other generators or with the power system, the condition is referred to as out of step. If the generator EMF angle exceeds the critical level, then the generator loses synchronism with the system. This condition can also be introduced by malfunctions in the Automatic Voltage Regulator (AVR) system. Unstable swings (actual OOS conditions) will require tripping generators or possibly system islanding to minimize the scale of the system disturbance.

The out-of-step condition produces high peak currents, winding stresses, pulsating torques and mechanical resonances within the generator, which usually requires separation of the generator from the system. Usually this separation is accomplished by out-of-step tripping (OOST) relays.

If the disturbance is not so severe, the system remains stable and the load angle of the generator will also oscillate (i.e. the angle will increase and decrease in synchronism with the power system oscillations). Such a "stable" system may or may not be well damped. In the case of stable power swings, it is never desirable to trip.

When generators experience out of step conditions and OOST relays separate them from the system, it is common that nearby generators and transmission system terminals will also experience oscillations similar to those experienced by the OOS generator. Often it is desirable that these other facilities do not trip during the generator OOS event. These facilities may require Power Swing Blocking (PSB) relays in order to avoid undesirable tripping. Some OOST

[1] "Considerations for Power Plant and Transmission System Protection Coordination, Technical Reference Document" Revision 2, NERC System Protection and Control Subcommittee, July 2015.

relay characteristics only provide OOST capability, while other relay characteristics can provide both OOST and PSB capability.

The conventional method to detect the OOS condition is to analyze the locus of the apparent impedance seen from the generator terminals. Transient stability studies can determine if the generator will remain in synchronism for different power system contingencies. During the OOS condition between one generator and another or between one generator and the system, the impedance seen by the generator varies depending on the voltage and the angular difference between the generator and the other generators or the system. When the two systems are in phase with each other i.e. the angular difference between the two systems is zero, the voltage at the terminal of the generator will be at a maximum and the current at a minimum. However, when the two systems are perfectly out of phase with one another (180º apart), the voltage at the terminals of the generator will be at a minimum and the current at a maximum. Appropriate protective devices and the associated logic measure this variation of voltages and currents to determine whether or not an OOS condition exists.

In some cases, a system disturbance or load rejection event may result in operation of turbine control schemes (e.g. Power/Load Unbalance) intended to protect against overspeed. Overspeed should not be confused with OOS. By the time speed becomes significant the machine will have already slipped at least one and perhaps several poles. Also, an over-frequency event in the system will not always result in generator pole slipping, but an undetected OOS condition will result in an overspeed. Therefore, a dedicated out-of-step protection relay is required to detect an OOS condition.

The limit between a stable system response and an unstable "runaway" response to a disturbance is often described by the critical clearing angle, δ_C. This is the angular difference beyond which the interconnected system will not be able to recover. This value is critical to the settings of several OOST relay schemes. A common rule of thumb is that $\delta_C = 120°$. However, stability studies are required to establish the actual δ_C value. Typically these studies model cases with increasing fault clearing times at critical system locations until the system model loses stability. The maximum angle δ in the last stable case identifies the critical clearing angle, δ_C. In addition, these studies identify the swing rates that are important for correct operation of several out-of-step relay characteristics. The critical clearing angle and system swing rates can change with system configuration, so that the necessary studies to obtain conservative results can be fairly extensive.

During power system oscillations, the relays will calculate (measure) an apparent impedance that varies with time. This variation in the measured or calculated apparent impedance can result in mis-operation of the generator impedance protection elements if these are not appropriately set.

The best way to illustrate the variation of the impedance measured or calculated by a protection relay during a power system oscillation is by using a simple equivalent system consisting of two generators with EMF E_S and E_R as shown in Fig. 1. E_R is lagging the sending voltage E_S by an angle δ_S as shown in Fig. 2.

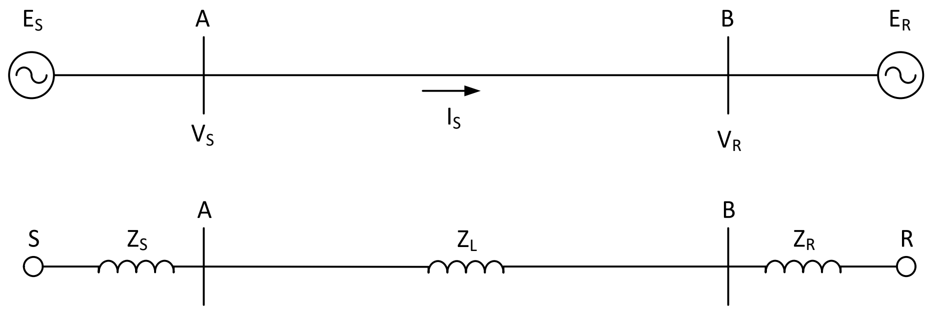

Fig. 1. Equivalent system for analysis of power system oscillations

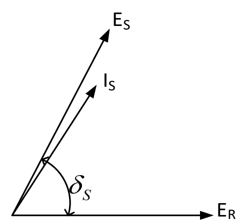

Fig. 2. Relationship of E_S and E_R

The protective relay which is an impedance-sensing element is assumed to be located at the generator terminals whose voltage is V_S and the current is I_S which flows from S towards R.

The voltage V_S seen by a relay at the generator terminals is then given by:

$$V_S = E_S\angle\delta_S - I_S Z_S = I_S Z_L + I_S Z_R + E_R \tag{1}$$

The current I_S seen by the relay is:

$$I_S = \frac{E_S\angle\delta_S - E_R}{Z_S + Z_L + Z_R} \tag{2}$$

The impedance measured by the relay located at A is $Z_{relay} = V_S/I_S$; the expression for this impedance can be obtained using the voltage V_S given above in (1), which feeds the relay:

$$V_S = I_S Z_L + I_S Z_R + E_R \tag{3}$$

$$\frac{V_S}{I_S} = Z_{relay} = Z_L + Z_R + \frac{E_R}{I_S} \tag{4}$$

The current, I_S, causes a voltage drop in the system elements in accordance with the phasor diagram shown in Fig. 3. The value of δ_S, which is the phase difference between E_S and E_R, increases with the load transferred.

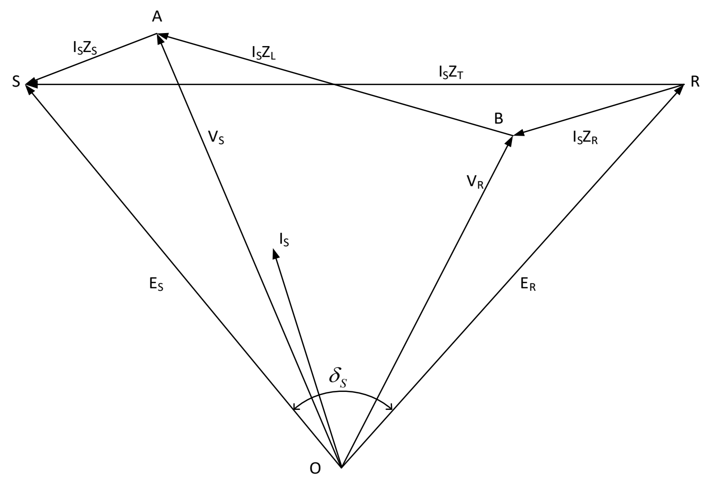

Fig. 3. Voltage phasor diagram for system of Fig. 1

Using Fig. 3 we can easily obtain the respective system impedances and apparent impedance by dividing the voltage drops in Fig. 4 by the current I_S. Z_T is the sum of Z_S, Z_L and Z_R.

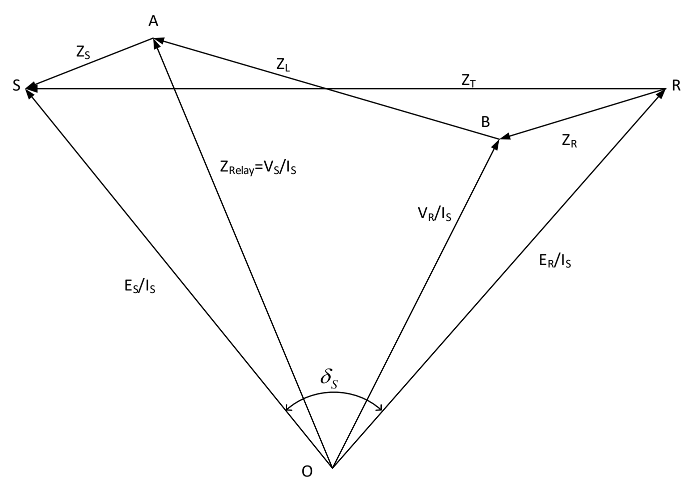

Fig. 4. Impedance diagram for system of Fig. 1

I_S and δ_S are variables and depend on the power transfer. The increment of load transferred brings with it an increase in I_S and δ_S. This results in a reduction in the size of the vector V_S/I_S. If the increment of load is sufficiently large, the impedance seen by the relay (V_S/I_S) can move into the relay operating zones, as shown in Fig. 5.

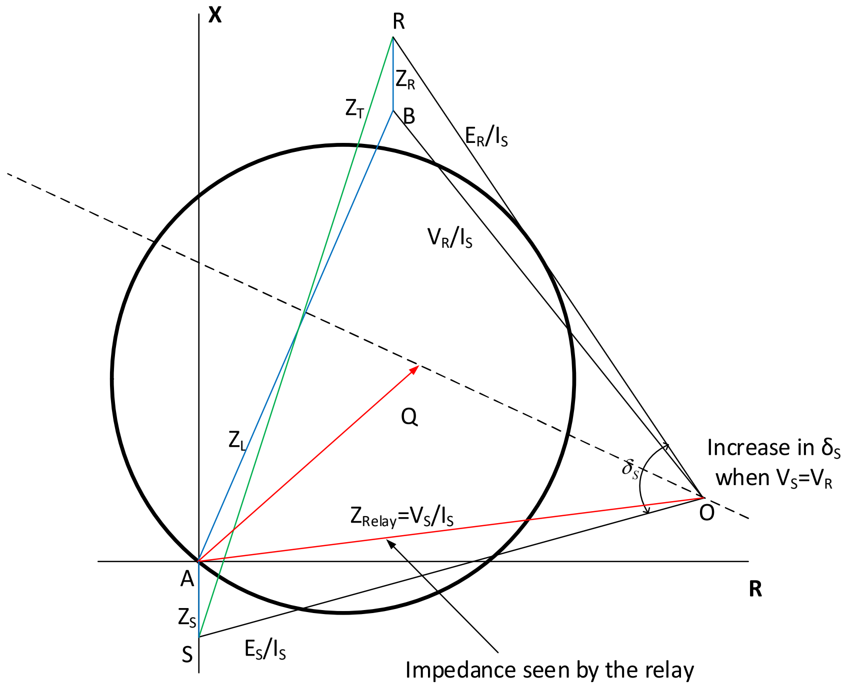

Fig. 5. Impedance seen by the relay during power system swing (In this case a mho characteristics is shown)

The relay at A will measure the value of the impedance represented by AO. If a severe disturbance occurs then the load angle δ_S increases and the impedance measured by the relay may decrease to the value AQ, which will be inside the relay operating characteristic. The locus of the impedance seen by the relay during oscillations is a straight line when $|E_S| = |E_R|$, as shown in Fig. 5. If $|E_S|$ is not equal to $|E_R|$, the locus is a family of circles centered on the SR axis.

From (1) and (2) given above, a more thorough development of the impedance variation can be carried out by substituting the value of the current I_S in the voltage expression V_S. The following expression is then obtained:

$$V_S = E_S\angle\delta_S - \frac{E_S\angle\delta_S - E_R}{Z_S + Z_L + Z_R} Z_S \tag{5}$$

If $n = |E_S|/|E_R|$ and $1\angle\delta_S = \cos\delta_S + j\sin\delta_S$, the generalized equation for the impedance calculated by the relay is:

$$Z_{relay} = \left(Z_S + Z_L + Z_R\right) n \frac{(\mathrm{n} - \cos\delta_S) - j\sin\delta_S}{(\mathrm{n} - \cos\delta_S)^2 + \sin^2\delta_S} - Z_S \tag{6}$$

Where: Z_S, Z_R, Z_L = system impedances, δs = angular separation between E_S and E_R, n = ratio $|E_S|/|E_R|$.

The locus of the impedance when the ratio n = $|E_S|/|E_R|$ = 1 is shown in Fig. 6. This locus is a straight line OO' which is the perpendicular bisector of the total system impedance between S and R. As the angle δ_S increases the impedance moves from O to O'. If the locus reaches the critical clearing angle and goes beyond, the systems will not recover, that is, stability is lost. The critical clearing angle can be determined more precisely with transient stability studies.

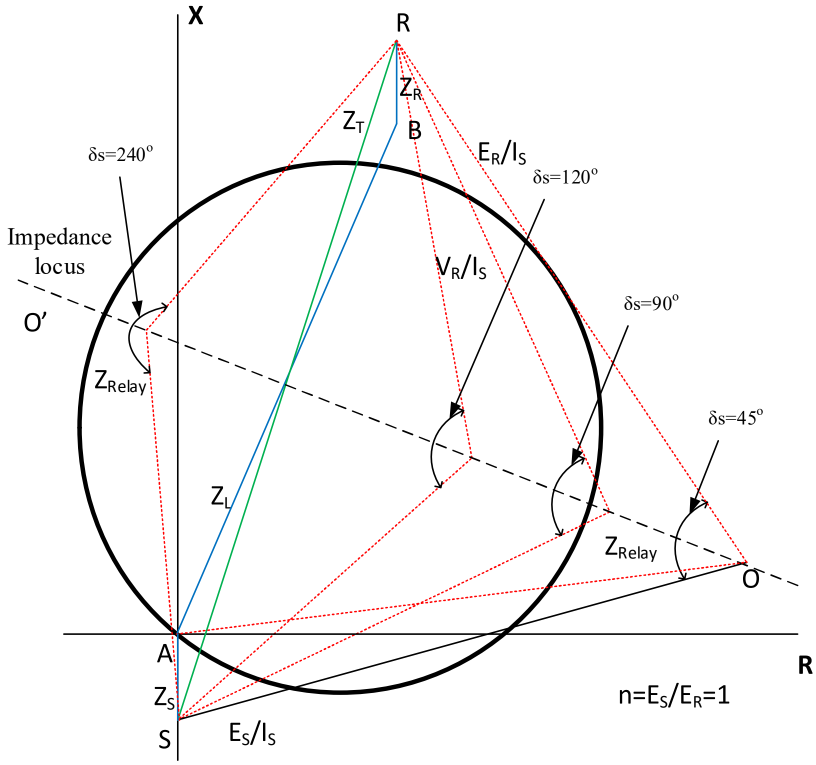

Fig. 6. OOS characteristic for the case n=1

The point where the impedance locus intersects the total impedance line between S and R is called the electrical center of the system. At this point the two generators are 180º out of phase with each other. As the locus keeps moving to the left, the angular separation increases beyond 180º, thereafter the two systems move into phase again. Once the two generators are back into phase again with each other we can say that the generators have completed one slip cycle.

For values of n not equal to 1, the loci of the impedances are circles with the center of the circle on an extension of the total impedance line Z_T. It can be shown that for values of n>1, the loci of the impedance during an OOS condition is above the electrical center of the system (above ½ Z_T). Whereas for values of n<1, the loci of the impedance is below the electrical center. This is shown in Fig. 7. In most relay applications, it is valid to consider the simpler case where n=1 when developing initial settings. However, cases for n>1 and n<1 are also useful to illustrate, at least approximately, the range of the system swing locus in cases of stressed system conditions such as low system (receiving) voltage and system equipment outages, and the generator voltage regulator response to such conditions.

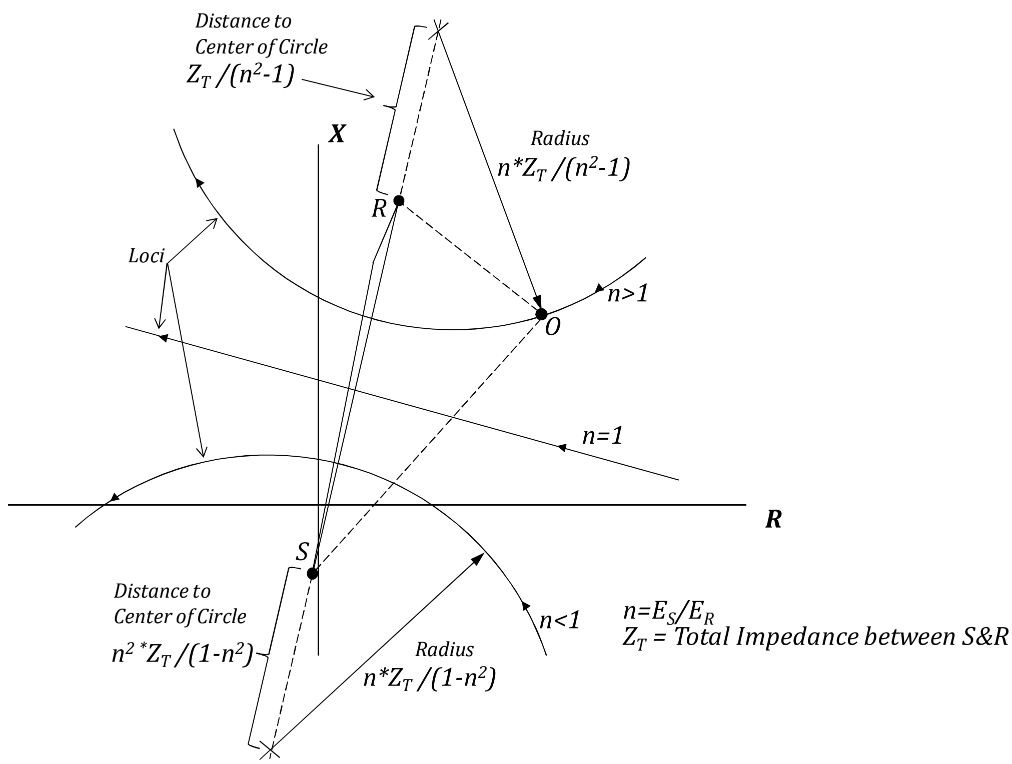

Fig. 7. OOS characteristic for the case n=1, n>1 and n<1

Measuring variations in system impedance helps to detect an Out-of-Step condition and define the schemes for OOS protection. Settings applied to these schemes are critical to system reliability and stability. The schemes must be set to quickly isolate a machine, not only to prevent damage, but also to prevent instability from spreading to other portions of the system.

3. EFFECT ON GENERATORS OPERATING IN OUT-OF-STEP CONDITIONS

A synchronous generator is an alternating-current machine that transforms mechanical power into electrical power at a speed proportional to the frequency of the electrical power system. The synchronous generator is “synchronized” to the power system by closing the generator circuit breaker when the generator voltage and frequency are within accepted close tolerance to the power system voltage and frequency. In normal conditions, equilibrium exists between the prime mover mechanical power, generator electrical power and the power transmitted to loads on the power system. Abnormal conditions, switching or disturbances on the power system, such as faults, line switching or sudden switching of large loads can disrupt the equilibrium among prime mover, generator, and power system.

An OOS condition occurs when the disturbance is so severe that the synchronous generator’s mechanical system cannot respond fast enough to these electrical power system changes, causing loss of electrical synchronism with the power system. The out-of-step condition causes torsional stresses for the mechanical system (turbine-generator shaft) as the prime mover tries to maintain synchronous speed with the electrical power system. This can result in:

- pulsating torques
- winding stresses
- high rotor iron currents

The pulsating torques occur because, as the generator swings towards 180º relative to the system, the torque is negative—trying to decelerate the rotor and prime mover back into synchronism with the power system. As the generator swings past 180º, the torque changes to positive—trying to accelerate the rotor and prime mover to bring it back in phase with the power system.

Winding stresses occur because, as the generator swings through 180º from the power system, two per unit voltage is applied across the system and machine impedance. If the system impedance is smaller than the machine impedance (a common condition), the magnitude of the current can be greater than the three-phase short circuit current. The generator and transformer windings are not braced for currents greater than short circuit levels.

High rotor iron currents occur because the generator rotor slips relative to the power system. Currents similar to the current induced in the squirrel cage of an induction motor are induced in the rotor. Since no squirrel cage is normally present, these currents have to flow in the rotor iron, amortisseur windings (damper windings) as well as in the wedges of the rotor windings.

All of the above things are potentially damaging to the generator. Therefore, it is generally recommended that the generator be separated from the system without delay.[2][2] For hydro generators, the system may have the possibility to get back into synchronism and therefore it is some generator owners' practice to separate their unit only after it experiences a certain number of pole slips.

4. OUT-OF-STEP PROTECTION SCHEMES FOR GENERATORS

Following are the schemes which have been used and are available to relay engineers to detect the generator OOS conditions and to obtain the generator tripping function.

Out-of-step protection schemes include a range of complexity, flexibility, security, and dependability. Relay characteristics, if not properly set, are subject to security failures, i.e. tripping on stable power swings. While safe for the equipment, such operations impose an unnecessary loss of generation on the power system which must be immediately mitigated by other resources. Some relay characteristics are not subject to such security failures, but can only trip after the system has already lost synchronism.

4.1 Loss of Field Relaying

Although Loss of Field (LOF) relaying is applied primarily to protect a machine for a loss of field condition, the conventional impedance based schemes applied at the generator terminals

[2] GEK-75512 Generator Protection, General Electric, 2014

used to detect such a condition may provide a measure of generator OOS protection. The typical setting characteristics of two commonly used relay schemes are shown in Fig. 8 and Fig. 9.

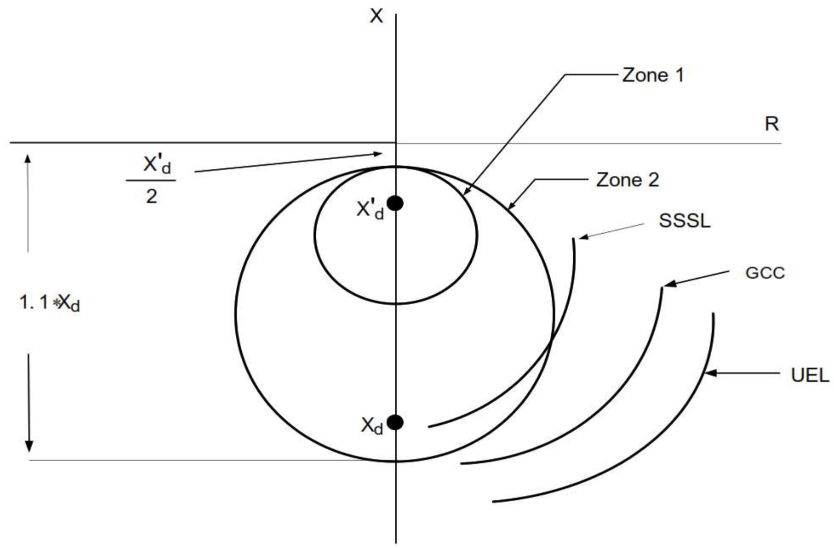

Fig. 8. Generator protection using two loss-of-field relays—Scheme 1

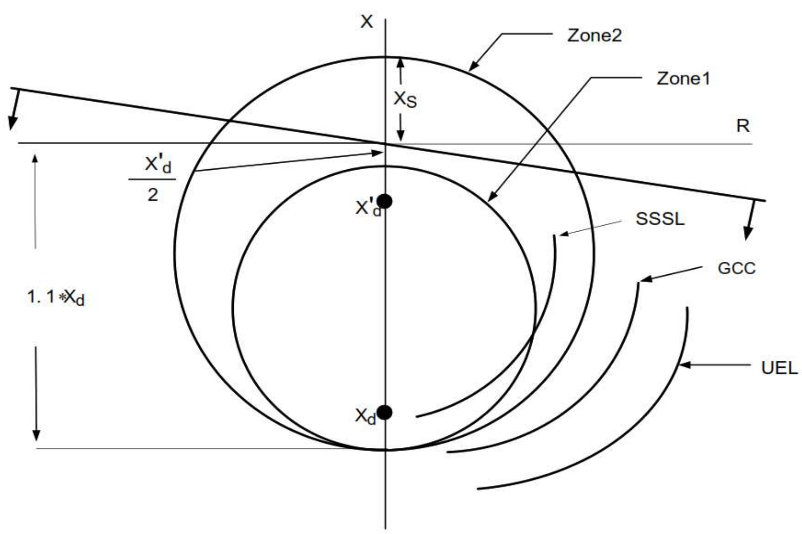

Fig. 9. Generator protection using two loss-of-field relays—Scheme 2

The loss of field characteristics are set with a time delay to ride through stable swings and system transients. Because this scheme measures the impedance looking into the generator, it may not detect swings passing through the GSU. The schemes will operate for impedances that stay within their operating characteristics longer than their set time delay. The offset of LOF relaying in these schemes will also preclude the detection of swings within the generator but close to its terminals. Because of these limitations, this scheme may not be relied upon to provide protection against all OOS conditions.

With the advent and use of new and better schemes, loss of field relaying for OOS protection is considered a legacy scheme.

4.2 Simple Mho Scheme

This scheme uses a simple standard distance relay (with no offset), generally sensing current and voltage at the high side of the GSU and oriented to look into the generator. The relay will immediately trip if the swing impedance characteristic enters the relay characteristic circle. This scheme also provides protection for inadvertent energization and back up protection for multiphase faults in the generator and main transformer HV and LV leads, and for certain transformer faults.

The relay is normally set to see twice the sum of the GSU impedance and the generator subtransient reactance (X''_d). This setting would not detect slow moving swings where the generator synchronous reactance (X_d) would be the appropriate model. On the other hand a setting based on synchronous reactance would operate the scheme below the critical clearing angle and thus result in misoperation on stable swings. Reducing the setting will improve the security but increase the breaker switching angle.

Clearly the Mho and LOF scheme characteristics will often overlap in their protection coverage on the impedance plane. Since the result of operation of either scheme is to trip the generator, it may seem that coordination is less critical. As long as adequate information is collected to be able to distinguish the actual cause of a trip, e.g. generator exciter vs transmission system, so that restoration can be properly accomplished, this is largely true.

Fig. 10 shows a typical Simple Mho scheme.

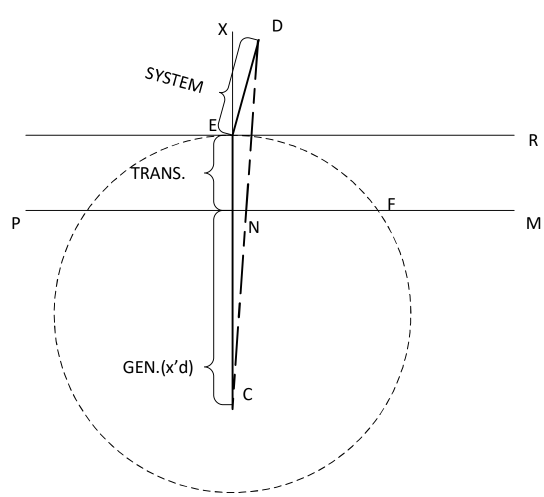

Fig. 10. A typical Simple Mho OOS protection scheme applied at the high side of generator step up transformer

Originally, the swing center would typically go through the transmission system. The transmission was protected by impedance elements such that natural tripping could be counted on to separate an OOST generator. As machines grew and transmission systems got tighter, a hole developed in that the swing center moved into the GSU in many cases. The GSU zone was protected by differential protection which is immune from OOS conditions. The reason for applying a mho looking into the machine was to fix this hole and make sure that if the swing center was inside the GSU, a distance element was there to provide natural tripping with the simple drawback that natural tripping always trips on the way in.

With the advent and use of new and better schemes, Simple Mho scheme is considered a legacy scheme.

4.3 Single Blinder Scheme

Single Blinder Scheme protection is used to detect an out-of-step or pole slip conditions. The operating quantity is typically the measured positive sequence impedance for numerical protection. This particular function uses one pair of blinders along with a supervisory offset mho element as shown in Fig. 11.

The scheme is secure against false out-of-step trips because a trip is only declared after the swing has already passed both blinders A and B, well beyond the critical clearing angle, and the generator has already slipped a pole during an unstable swing.

Some versions of the single blinder include a transit timer between the A and B blinders which makes them sensitive to the system swing rate in differentiate between stable and unstable swings, so that stability modelling is needed to set this timer. A stability study can also determine if the impedance completely exits the blinders following fault clearing. If the impedance does not exit the blinder characteristic on fault clearance, then the scheme will not operate until the second pole slip. Further, following fault clearing, the exciter may be in field forcing mode, which forces the swing center toward the transmission system, potentially outside the supervisory mho circle, which would prevent the OOST operation.

Other versions of the single blinder scheme do not use a transit timer between the blinders, so that stability modelling is less critical to determining characteristic settings.

In either case, the scheme can only trip on the way out, not on the way in and cannot provide power swing blocking.

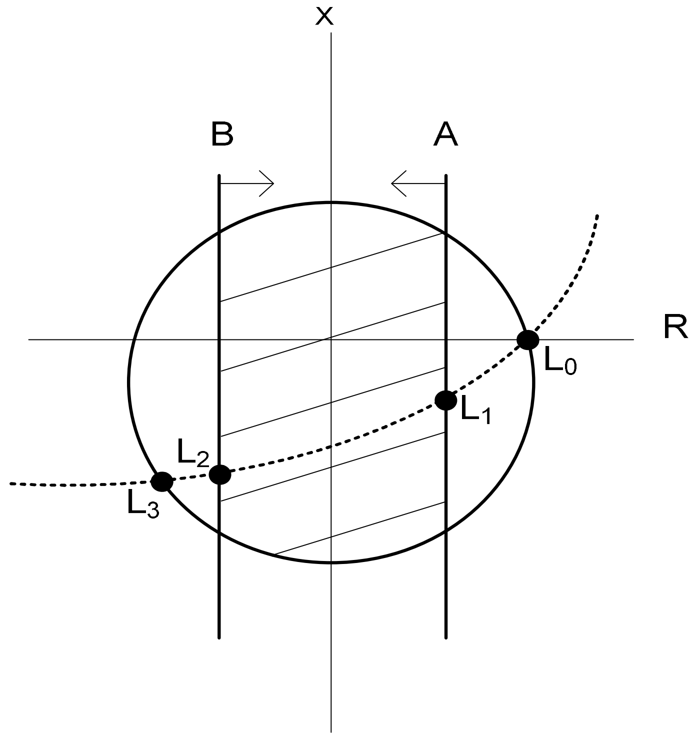

Fig. 11. Single Blinder Out-of-Step Operating Area

Operating Characteristic

The Mho element asserts when the positive sequence impedance moves inside the characteristic. Blinder A asserts when the positive-sequence resistance is less than the resistance of blinder A. Blinder B asserts when the positive sequence resistance is greater than the resistance of blinder B. The operating area is restricted to the region where $R_{BLINDER\_B} < R_{MEASURED} < R_{BLINDER\_A}$ and $Z_{MEASURED} < Z_{MHO}$, the hatched area as shown in Fig. 11. The positive sequence impedance must start outside of both blinders then enter and pass through all three areas of the impedance plane.. Some manufacturers' schemes also include a minimum time that the impedance must remain between the blinders to produce a trip. If these requirements are satisfied, then a trip occurs if a complete transit of the characteristic is confirmed; i.e. the impedance locus must enter on the right side of the characteristic and then exit on the left or vice-versa. A trajectory that swings from left to right represents the machine operating in a motoring condition.

Trip on Mho Exit

There is typically an option in numerical relays referred to as TRIP ON MHO EXIT. If this option is enabled then a trip does not occur until the positive sequence impedance exits the mho characteristic. Note that in this case, the transient recovery voltage (TRV) across the breaker is lower than if it opened close to 180º such as with the simple mho element described in section 4.1 (or at blinder B if the scheme initiates tripping at L_1 or L_2) since the single blinder scheme does not initiate a trip until passing either L_2 or L_3. The TRV is higher than during normal fault clearing if the open circuit angle across the breaker contacts remains between 90º – 270º. The breaker should be rated for 180º (out-of-step) opening regardless of the interrupting medium if tripping is initiated during a high angle across the breaker contacts in order to avoid the possibility of a flashover inside the tank. Use the Trip on Mho Exit time delay (see below) to delay tripping until the angle is within the TRV rating of the breaker.

Typical Settings

Use the following impedances to set the out-of-step protection:

X_T = Transformer Reactance

X_S = System Reactance

X'_d =Transient Reactance of the Generator

NOTE – Use the unsaturated machine reactance since it is higher in magnitude, thus is more conservative.

DIAMETER =	$1.5X_T + 2X'd$	[ohms]
OFFSET =	$-2X'd$	[ohms]
BLINDER =	$(1/2)\bullet(X'd+ X_T + X_S)\bullet \tan(\theta-(\delta/2)$	[ohms]
IMPEDANCE ANGLE =	θ	[degrees]
TIME DELAY ON PICKUP =	3 – 6	[cycles]
TIME DELAY AFTER MHO EXIT =	varies dependent upon rate of swing	[cycles]

Where: θ is the impedance angle (in Fig. 11, $\theta = 90^o$) and δ is the angular separation

Transmission system conditions may vary significantly during transmission equipment outages and due to the effect of the generator automatic voltage regulator (AVR) operation during system disturbances. Equipment outage contingencies usually increase the system impedance, Xs, moving the swing locus in the +X direction. AVR operation typically increases the voltage behind the generator impedance, also moving the swing locus in the +X direction.

The angle of the trajectory corresponding to the reach of the right blinder is typically selected at 120º, the "rule of thumb" critical clearing angle, though this setting is generally not very critical for this scheme. This is illustrated as angle F in Figure 12 in relation to Blinder B and the total system impedance. A similar angle will be modeled (not shown) as the impedance trajectory crosses Blinder A. The difference between these two angles, along with the actual swing rate represents the time delay between blinders. It may be useful to set one blinder shorter than the other if the trajectory exits closer to the reactive axis than the point at which it enters the operating characteristic. The pickup delay must be set shorter than the time taken for the impedance to cross the operating area at the maximum expected slip frequency. For example, for a maximum slip frequency of 5 Hz and 120º between the blinders then the minimum delay setting is $(120^o \cdot 60\ Hz) / (360^o/cycle \cdot 5\ Hz) = 4$ cycles.

If blinder A is set so that it intersects the impedance trajectory at an angle of 120º or more then it is also set where it cannot assert for normal load conditions (typically an angle less than 90º). The mho element only supervises the blinders, so its setting outside the blinders is less critical in terms of relay loadability. However, the scheme is not vulnerable to operation on relay loadability since the scheme cannot initiate a trip until the impedance locus passes both of the blinders.

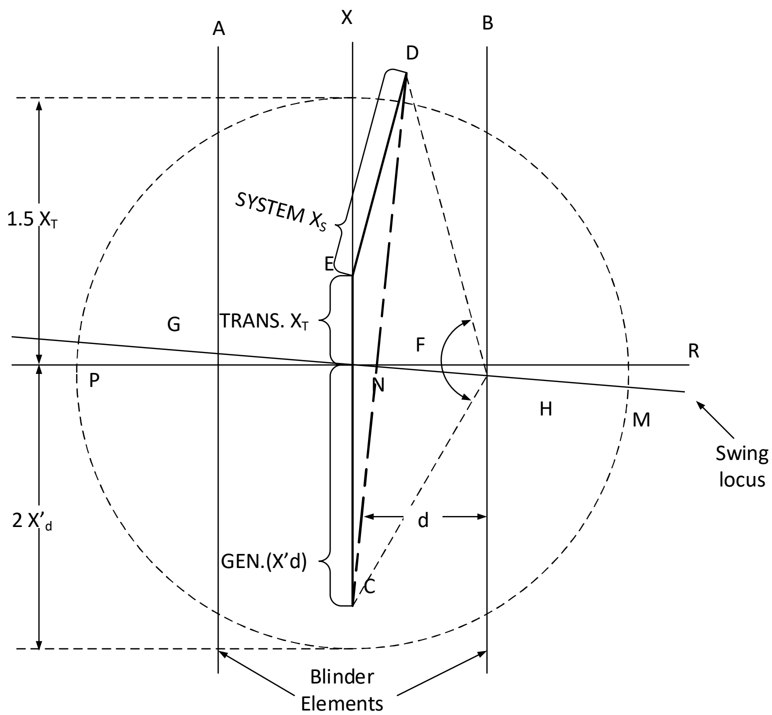

Fig. 12. Single Blinder Out-of-Step Protection Settings

<u>Negative Sequence Current Blocking</u>

Some users prefer to block the Out-of-step tripping (OST) if negative sequence current is detected since that means an unbalanced system condition (fault or single pole trip) is in progress. However, if this supervision is applied, the user should ensure that the element is not disabled during an actual power swing since there may be some unbalance in the current during the swing. For instance, it is possible for a power swing to develop due to an open phase in the power system. Such an occurrence will reduce the generator's power transfer capability (as defined by the power-angle equation). A loss of synchronism could result which would be undetected if negative sequence blocking was applied. The generator would be expected to trip from Unbalanced Current protection (46) however, tripping from the Out-of-step protection would be preferable.

4.4 Double Blinder Scheme

Double Blinder Scheme is among the simplest methods to detect the rate of change of positive sequence impedance for OOS swing detection when the purpose is either PSB or OOST. It compares the actual elapsed time required by the impedance locus to travel between two impedance characteristics with a delay setting. In this case the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically the two blinders on the left half plane are the mirror images of those on the right half plane.

However the scheme simplicity disappears if both PSB and OOST are required because the PSB and OOST requirements for the inner blinder may conflict. .For PSB, the inner blinder must be set outside the tripping element that is intended to be blocked. For OOST, the inner blinder must set inside δ_C to ensure detection of only an unstable swing.

The double blinder scheme design is more complex than the single blinder scheme. The double blinder settings can potentially result in tripping for an otherwise recoverable swing if the inner blinder is set to result in a measured angle smaller than the critical clearing angle or the blinders and timer are set to represent a higher swing rate than expected from stability studies. Therefore more extensive stability modelling to determine critical clearing angle and swing rates are required to assure secure scheme operation However, an assumed higher critical clearing angle, such as 150˚, can make the analysis simpler for OOST applications. If the actual time spent between the outer and inner blinders is shorter than the timer setting, the scheme interprets the event as a fault. Out-of-step protection does not operate for this case. However, if the actual transit time is longer than the setting, the event is considered a swing condition. The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Fig. 13. (Fig. 12 and Fig. 13 uses different system and other parameters; as such different mho circles) The total system impedance is composed of the generator transient, X'd, GSU transformer, X_T, and transmission system, X_S. Usually the mho circle will be set outside both blinders, though in the case of Fig. 13, the mho element is set inside the outer blinder since the mho circle is used as the tripping boundary on the way out of the characteristic.

The OOST scheme logic is initiated when the swing locus crosses the outer blinder, R1, on the right at separation angle α. The scheme only commits to take any action when a swing is detected as the swing locus crosses the inner blinder, R2. So, the setting of the inner blinder is critical to preventing a trip on a stable scheme. At this point the scheme logic makes and seals in the out-of-step trip decision at separation angle β. Tripping usually asserts as the impedance locus leaves the scheme characteristic at separation angle δ. The actual "exit" characteristic depends on the specific manufacturer's scheme, but could use any of the inner or outer blinder, or a separate mho circle. The manufacturer may also include a separate user-set delay timer to further delay the trip after exiting the characteristic. This sequence controls tripping so that the separation angle when opening the breaker does not exceed the breaker's rated capability, which typically is 90° unless the breaker is specifically rated for 180° opening.

When a swing is detected and the swing locus crosses the inner blinder R2, the trip decision is made. The swing may leave both inner and outer blinders in either direction and tripping will take place. Therefore, the inner blinder must be set such that the separation angle, β, is larger than the critical clearing angle, δ_C. Transient stability studies are required to determine an appropriate inner blinder setting. In this respect, the double blinder scheme is quite similar to the double or triple lens schemes and many transmission OOS relay characteristics.

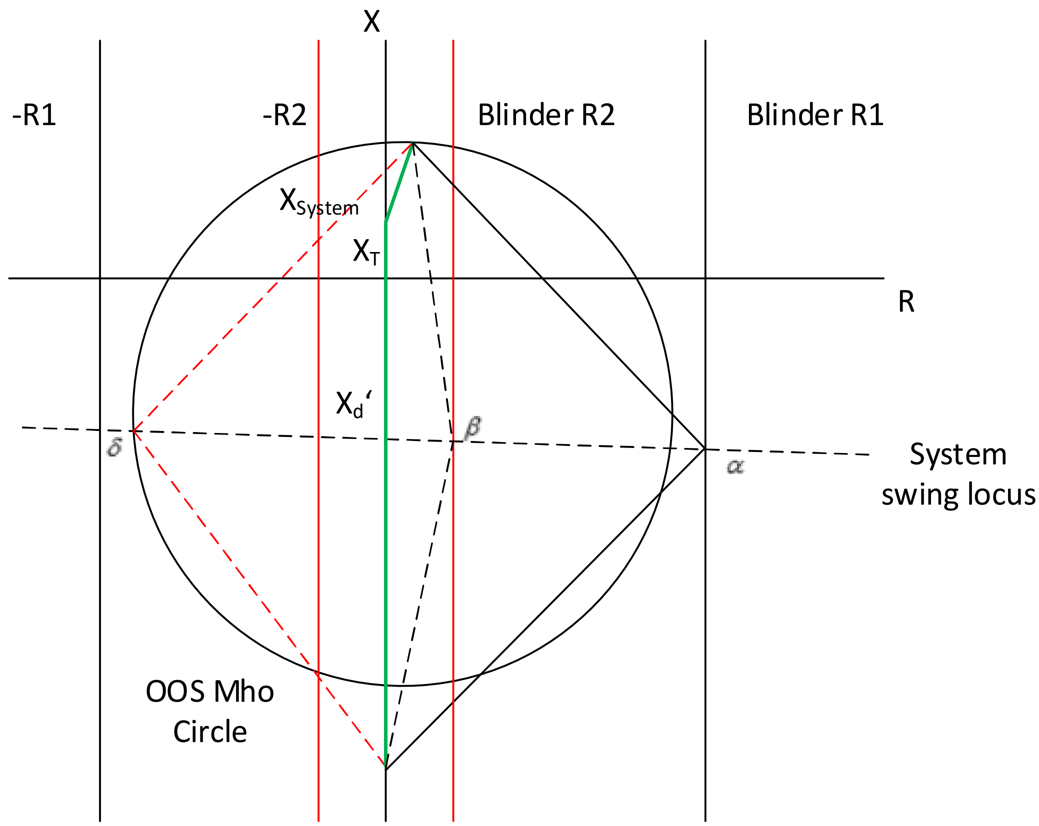

Fig. 13. Double Blinder Scheme applied at the terminals of a generator

4.5 Double Lens Scheme

In a double lens scheme, 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.

The double lens scheme has similar complexity as the double blinder. If both PSB and OOST are required the requirements for the inner lens may conflict. For PSB, the inner lens must be set outside the tripping element that is intended to be blocked. For OOST, the inner lens must set inside δ_C to ensure detection of only an unstable swing.

The double lens scheme design is more complex than the single blinder scheme and similar to the double blinder. The double lens settings can potentially result in tripping for an otherwise recoverable swing if the measured swing rate is faster that modelled by the lens and timer settings. Therefore similar stability modelling to determine critical clearing angle and swing rates is typically required to assure secure operation as for a double blinder scheme. The supervisory mho element may be included in the double lens scheme to obtain security feature. When used, it acts as a starter element, similar to the mho circle in the single or double blinder schemes. Since the shape of the lens characteristic essentially provides a self-supervision function, use of the mho circle is less important than for the double blinder scheme.

Referring to Fig. 14, the outer element operates when the swing impedance enters its characteristics, as at F. If the swing impedance remains between the outer and inner element characteristics for longer than pre-set time, it is recognized as a swing condition in the logic circuitry. When the swing impedance now enters the inner element characteristics, a portion of the logic circuitry is sealed in after a short time delay. Then as the swing impedance leaves the inner element characteristics, its traverse time must exceed a pre-set time before it reaches the outer characteristic. Tripping does not occur until the swing impedance passes out of the outer characteristic. This is to provide for the case where sequential clearing of a fault inadvertently sets up the first two steps of logic in the scheme.

The swing angle DFC (angle formed by points D, F and C in Fig. 14) is controlled by the settings to limit the voltage across the opening poles of the breaker. Once the swing has been detected and the impedance has entered the inner characteristic, the swing can now leave the inner and outer characteristics in either direction and tripping will take place. Therefore, the setting of the inner element must be such that it will respond only to swings from which the system cannot recover. This restriction does not apply to the single blinder scheme because the logic requires that the apparent impedance enter the inner area from one direction and exit toward the opposite direction. The single blinder scheme may, for this reason, be a better choice for the protection of a generator than either the mho scheme, the double blinder scheme, or the concentric circle scheme. However, not all relay manufacturers have a single blinder scheme available.

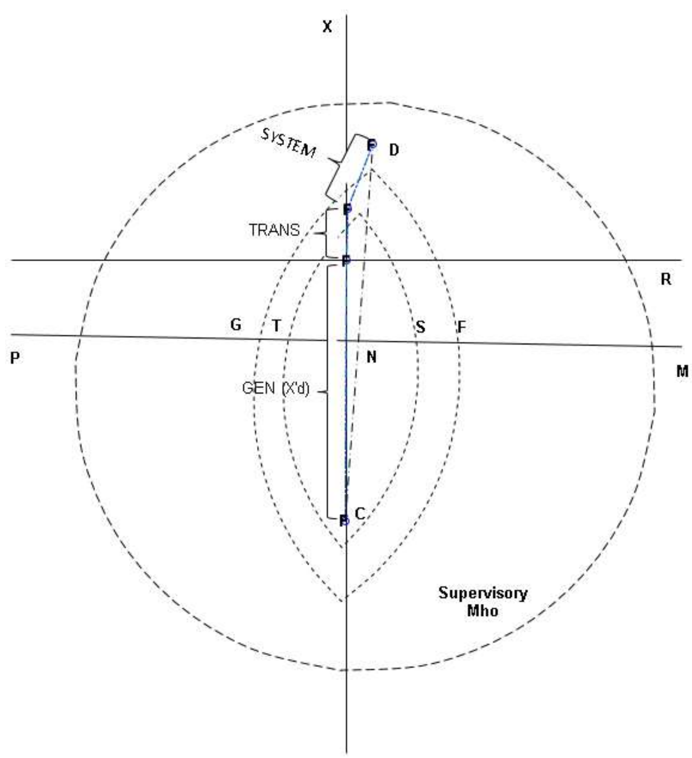

Fig. 14. Double Lens Scheme

4.6 Triple Lens Scheme

The triple lens scheme described here has similar functionality as the double lens scheme, but somewhat increased flexibility and complexity. The triple lens impedance elements are set in conjunction with several timers which represent the separation angle difference between inner, middle, and outer impedance characteristics at the maximum expected swing rate.[3][3] Depending on the setting for each characteristic, the actual shape may be a lens, circle, or tomato. The triple lens scheme tends to be easier to apply than the double lens or blinder schemes when both PSB and OST are required because the middle (PSB) and inner (OOST) lens characteristics provide for separate impedance and timer settings for the two functions.

The triple lens settings can potentially result in tripping for an otherwise recoverable swing if the measured swing rate is faster that modelled by the inner lens and timer settings. Therefore similar stability modelling to determine critical clearing angle and swing rates is required to assure secure operation as for a double blinder or double lens scheme.

The outer element operates when the swing impedance enters the characteristic. If the swing impedance remains between the outer and middle characteristics for longer than Delay 1 time, it is recognized as a swing condition and power swing blocking asserts. As the swing impedance proceeds from the middle to inner characteristics in longer than Delay 2 time (Delay 1 having also expired), then enters the inner characteristic and remains there for at least Delay 3 time, the trip decision is made. If an EARLY trip mode is set, the trip is executed. If a DELAYED trip mode is set, the trip is not executed until the impedance leaves the outer characteristic after having spent at least Delay 4 time between the inner and outer characteristics.

Fig. 15 illustrates the impedance elements for the triple lens OOS scheme. The separation angles α_1, α_2, α_3 and β_1, β_2, β_3 (outer, middle, inner lenses respectively) are similar to the single and double blinder and double lens schemes, except that angles $\alpha_{1\text{-}3}$ in this example is on the left and angles $\beta_{1\text{-}3}$ are on the right. As with other schemes that use multiple impedance characteristics, the separation angle when the swing locus crosses the inner characteristic, α_3 or β_3 is critical to the secure operation of the scheme. If the angle is too small, α_3 or $\beta_3 < 120°$ (large resistive reach), the generator may trip on a recoverable swing. However, with PSB and OOST functions essentially decoupled in the triple lens scheme, it can be possible to improve security by assuming a swing angle much larger than 120˚ (such as 150˚) for the inner lens setting, which can minimize the criticality of swing studies.

[3] G60 Generator Protection System UR Series Instruction Manual, GEK-119519, General Electric, 2013.

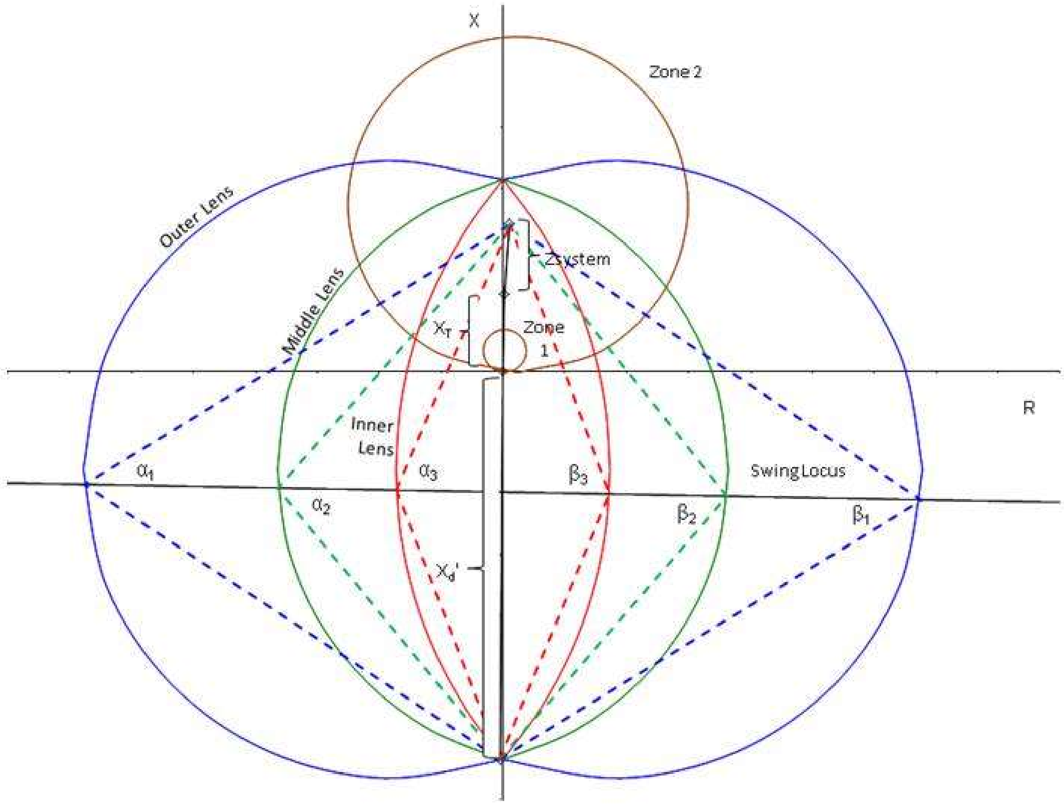

Fig. 15. Triple Lens OOS and Zone distance relay impedance characteristics.

Settings for the impedance characteristics and delay timers are all interrelated. Since this relay uses several timer levels for added security, the setting calculations are the most complex of all scheme characteristics described in this paper. The maximum expected swing rate of the swing locus through the relay characteristic helps to establish values for these parameters.

4.7 Concentric Circle Scheme

The concentric circle OOS scheme is substantially similar to the double blinder and double lens scheme. In this case the two impedance characteristics are circles that are, at least approximately, concentric. The inner circle may either be part of the out-of-step characteristic or (less often for generators) the outer-most distance protection element for the generator protection scheme. The out-of-step timers may either be fixed or settable by the user. The concentric circle scheme is more commonly implemented for electromechanical relay schemes, but occasionally may also be used in electronic or older microprocessor relays. The concentric circle scheme is more commonly used for power swing blocking, but can also be used for out-of-step tripping with additional logic. The concentric circle scheme is illustrated in Fig. 16.

The setting calculations and operation of the concentric circle out-of-step trip scheme is more complex than the single blinder scheme, similar to the double blinder or double lens schemes, but simpler than the triple lens scheme. The concentric circle scheme can potentially trip for stable swing or fail to trip for an unstable swing, Therefore transient stability studies are usually required to determine appropriate settings.and the single blinder scheme, if available, can be a more secure and dependable choice than the concentric circle scheme.

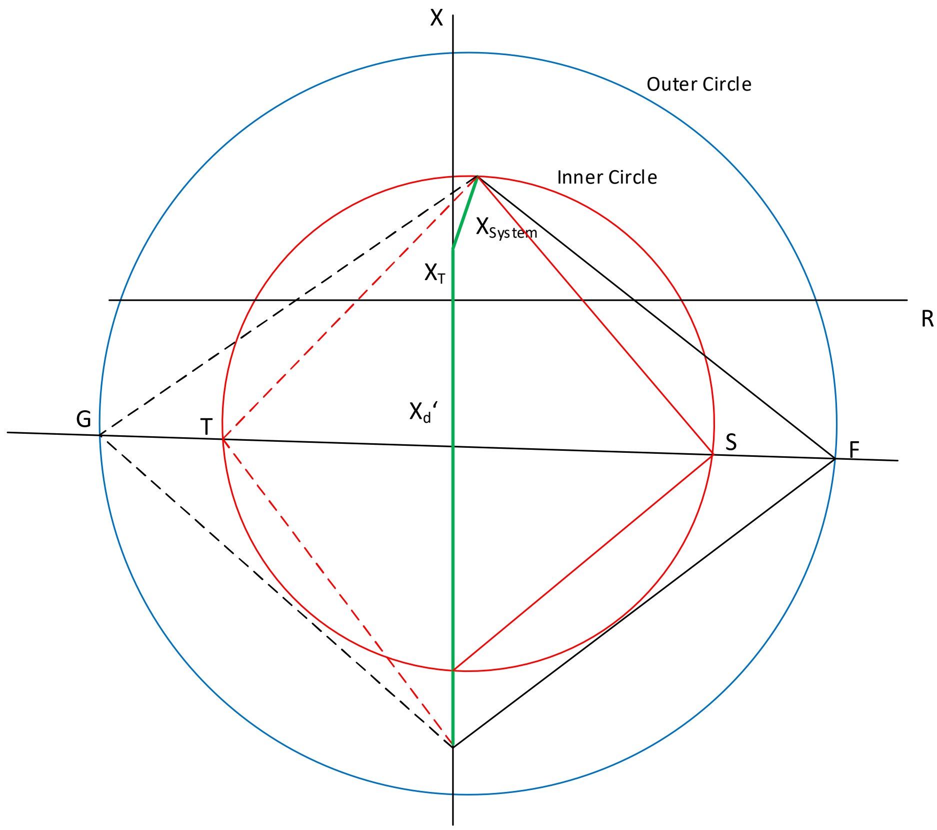

Fig. 16. Concentric Circle Scheme

The diameter of the outer circle is limited by the loadability characteristic of the generator. Since the circle typically has a larger resistive reach than the lens in a double or triple lens scheme, this limitation can be more restrictive than for the lens-based schemes. The diameter of the inner circle must be set to assure that the scheme will not trip for stable swings, such that the separation angle will be greater than the critical clearing angle, δ_C

The first functional requirement is that when the impedance locus enters the outer circle at F, it does not cross the inner circle at S until the first timer expires. If the time spent between the outer and inner circles as the impedance locus enters the characteristic is shorter than this first timer setting, the scheme interprets the event as a fault. Out-of-step functions do not operate for this case.

This OOS tripping scheme requires two additional timers.[4][4] The second timer starts during a detected swing upon entering the inner circle at S. If the second timer expires as the swing locus

[4] Elmore, W. A., "The Fundamentals of OOS Relaying," ABB Silent Sentinels, RPL 79-1C, November 1991.

is within the inner circle before exiting at T, the logic continues. The third timer starts upon exit from the inner circle at T as long as the second timer has expired. The third timer then initiates tripping upon exit from the outer circle at G if the locus spends at least the set time between the circles. This timer logic is substantially similar to the double lens scheme described above.

Electromechanical schemes often use fixed timers, such as T1 = 3 cycles, T2 = 6 cycles and T3 = 3 cycles and may use an inner characteristic that is also used directly for generator backup tripping through a separate timer. Typically, the inner circle is set such that the swing angle at point S is at least the critical clearing angle, then the outer circle is set according to the assumption of a maximum swing rate of 20° per power cycle. T1=3 cycles means the smallest swing angle at the outer circle is 60°. Assume the swing rate is constant when the swing travels through the outer circle, the swing angle changes by 120° when the swing crosses the inner circle, which takes 6 cycles, so T2 is set to 6 cycles. Finally, assume the swing takes the same time traveling from outer to inner or inner to outer circle, thus T3 is set to 3 cycles as well. The fixed settings such as the ones explained above work better when the swing center is close to the center of the circles. When the swing center is moving away from the center of the circles, T2 may not be satisfied. Though the scheme logic can work for any time delays, timers this long (which may be required to reliably operate electromechanical impedance elements) can limit the ability of the scheme to detect higher swing rates. This tends to be a larger problem for the concentric circle scheme than for the double lens scheme because the larger resistive reach of the outer circular characteristic is more likely to encroach on the generator loadability characteristic than for the lens characteristic.

Even when a swing is detected, the impedance remains inside the inner characteristic for the required delay, and the inner and outer characteristics reset with the required delay, the impedance locus can still leave both circles in either direction and tripping will take place. Therefore, the inner circle must be set small enough that the separation angle at point S is large enough that the system will have exceeded the critical clearing angle.In this respect, the concentric circle scheme is quite similar to the double blinder, double lens and triple lens schemes.

4.8 Swing-Center Voltage Method

The swing-center voltage (SCV) out-of-step tripping (OST) function consists of four resistive and four reactance blinders as shown in Fig. 17. The resistive blinders RR6, RR7, RL6, and RL7 are parallel to the positive-sequence line angle setting. The reactance blinders XT6, XT7, XB6, and XB7 are perpendicular to the positive-sequence line angle.

The SCV OST scheme requires eight blinder settings. These eight blinder settings are the Zone 6 and Zone 7 settings in Fig. 17. The resistive blinder settings R1R6, R1R7, R1L6, and R1L7 are set from the origin of the complex R-X plane and are perpendicular to their respective resistive blinders. The reactance blinder settings X1T6, X1T7, X1B6, and X1B7 are set from the origin of the complex R-X plane and are perpendicular to their respective reactance blinders. The SCV

OST element has an option to trip-on-the-way-in (TOWI) or trip-on-the-way-out (TOWO) as shown in Fig. 17 [5] [5].

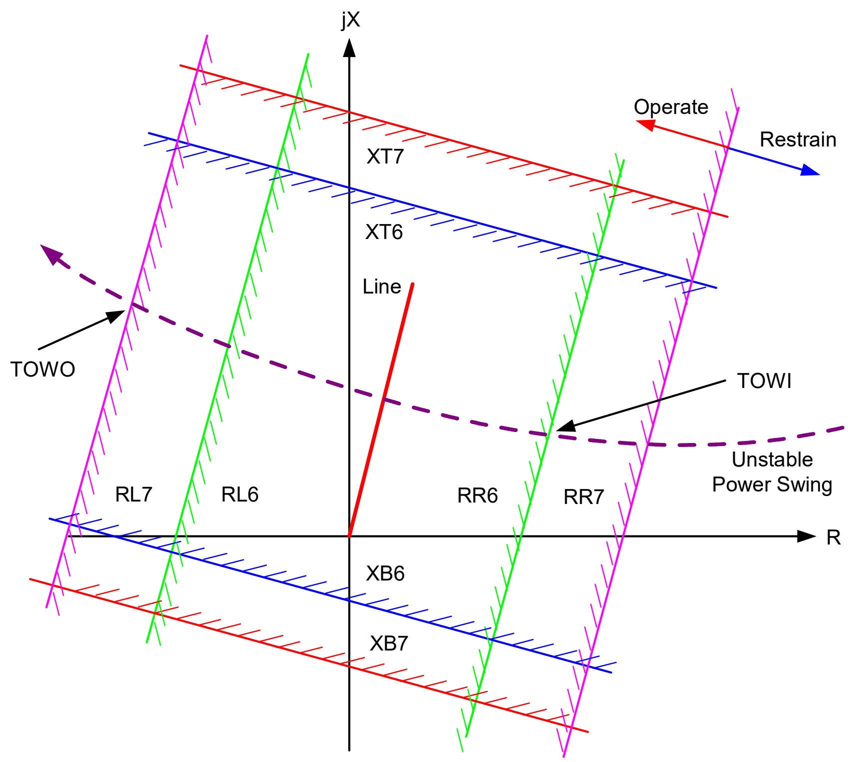

Fig. 17. OST Scheme Blinder Characteristics

The SCV OST function tracks the positive-sequence Z_1 impedance trajectory as it moves in the complex plane and verifies that the measured Z_1 impedance trajectory crosses the complex impedance plane from right-to-left (enters RR7 and exits RL7) or from left-to-right (enters RL7 and exits RR7) and issues a trip at a desired phase-angle difference between sources. Verifying that the Z_1 impedance enters the complex impedance plane from the left or right side and making sure it exits at the opposite side of the complex impedance plane ensures that the function operates only for unstable power swings. On the contrary, double blinder or double lens OST schemes that do not track the Z_1 impedance throughout the complex impedance plane may operate for stable swings, that were not considered during stability studies, if the apparent Z_1 impedance enters their inner OST characteristic.

The SCV OST scheme does not require any OST timer settings, or any settings related to generator maximum load or the rate of power swings. In addition, no stability studies are required for the SCV OST scheme if we trip-on-the-way-out. The settings for the resistive blinders are very easy to calculate. The outermost SCV OST resistive blinders can be placed around 80 to 90 degrees in the complex impedance plane, regardless of whether a stable power

[5] Benmouyal, G., Hou, D., and Tziouvaras D. A., "Zero-setting power-swing blocking protection," in 31st Annual Western Protective Relay Conference, Spokane, WA, October 19–21, 2004.

swing crosses these blinders or whether the load impedance of a heavily loaded generator encroaches upon them. The inner OST resistive blinder can be set anywhere from 120 to 150 degrees.[6][6]

The SCV OST functions offers three tripping options:

1. TOWO during the first slip cycle
2. TOWO after a set number of slip cycles have occurred
3. TOWI before completion of the first slip cycle

Note that, if one desires to TOWI, stability studies are then necessary for setting the innermost resistive blinders to make sure that the apparent Z_1 impedance does not cross these blinders during stable power swings.

The SCV OST scheme is supervised by the output of the robust SCV power-swing blocking (PSB) function that makes certain that the generator is experiencing a power swing and not a fault. Using a reliable bit from the SCV PSB function to supervise the SCV-assisted OST function allows a user to implement OST on-the-way-out without performing any stability studies, which is a major advantage over other OST schemes discussed earlier.

The SCV PSB function that supervises the SCV OST function requires no user settings and is described below to assist the reader to better understand the PSB OST function.

The swing center of a two-source power system is the location where the voltage magnitude equals zero when the angle between the source voltages is 180 degrees. The swing-center voltage (SCV) provides information for power swing detection. Reference [5][5] describes a power-swing blocking (PSB) method that uses the rate of change of the positive-sequence SCV. This method does not require user settings or stability studies for proper application. In addition, the method is independent from the network impedances.

Fig. 18 depicts the positive-sequence voltage phasor diagram of a two-source power system. The angle δ between source voltages E_{1S} and E_{1R} varies with time during the power swing.

[6] Fisher, N., et al, “Tutorial on Power-Swing Blocking and Out-of-Step Tripping,” in 39th Annual Western Protective Relay Conference, Spokane, WA, October 16–18, 2012.

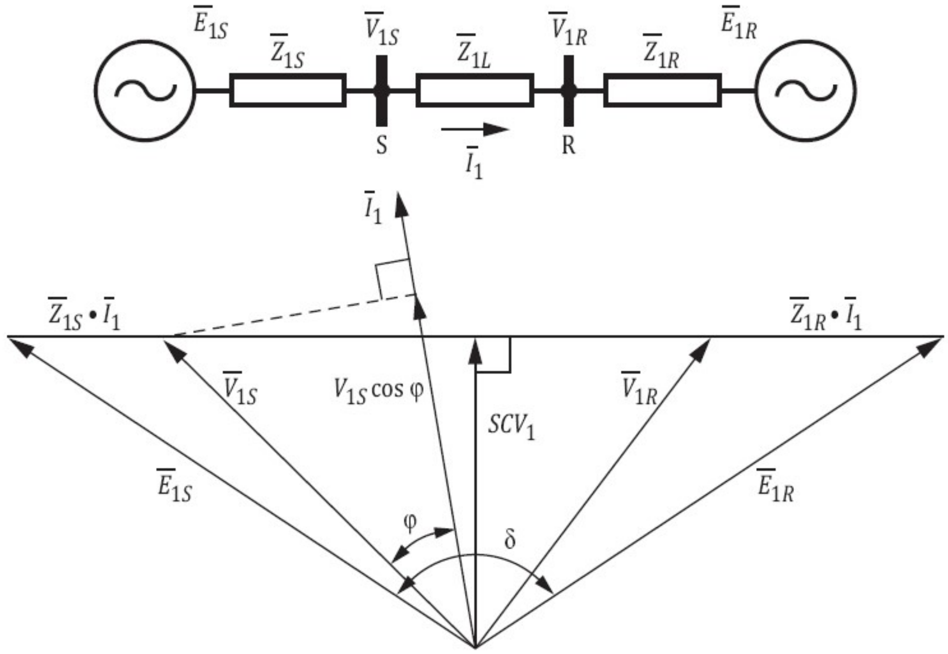

Fig. 18. Voltage Phasor Diagram of a Two-Source System

A relay located at Bus S in Fig. 18 can apply (7) to make an approximate estimation of the SCV, using only locally available quantities.[7][7]

$$SCV_1 \approx V_{1S} \cos\varphi \tag{7}$$

Where V_{1S} is the magnitude of locally measured positive-sequence voltage, and φ is the angle difference between V_{1S} and the local current I_1 as shown in Fig. 18.

Fig. 18 shows that $V_{1S} \cos\varphi$ is a projection of V_{1S} onto the current I_1. The small difference in magnitude between the system SCV and its local estimate have little impact in detecting power swings, because the detection method uses the SCV rate of change.

Assuming $E_{1S} = E_{1R} = E_1$, (8) provides an approximation of the relationship between the estimated SCV and the angle δ.

$$SCV_1 = E_1 \cdot \cos\left(\frac{\delta}{2}\right) \tag{8}$$

The absolute value of SCV_1 is a maximum when $\delta = 0°$, and this value equals zero when $\delta = 180°$. The SCV does not depend on the system source and line impedances. Its magnitude relates

[7] Ilar, F., "Innovations in the Detection of Power Swings in Electrical Networks," Brown Boveri Publication. CH-ES 35-30.10E, 1997.

directly to δ. We obtain the SCV rate of change by taking the derivative of (8) with respect to time, given by (9).

$$\frac{d(SCV_1)}{dt} = -\frac{E_1}{2}\sin\left(\frac{\delta}{2}\right)\frac{d\delta}{dt} \tag{9}$$

Equation (9) provides the relation between the rate of change of the SCV and the two-machine system slip frequency, $d\delta/dt$. 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 180º. When the angle between the two machines is zero, the rate of change of the SCV is also zero. 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.
- 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 120º, assuming equal source magnitudes and a homogeneous system.

The SCV method [5][5] includes a SCV slope detector, a swing signature detector, a three-phase fault detector, and a dependable PSB detector. A starter zone enables the PSB detector.

The SCV slope detector monitors the absolute value of the SCV_1 rate of change and the SCV_1 magnitude. The SCV slope detector asserts a PSB signal when these two magnitudes are between minimum and maximum thresholds and when the SCV_1 rate of change has no significant discontinuities. The SCV slope detector detects the majority of power swing conditions but may fail for some difficult power swings. The swing signature detector and the dependable PSB detector complement the SCV slope detector for these difficult power swings. The starter zone does not require any user settings and it encompasses the largest relay characteristic in use by the out-of-step tripping (OST) logic, when the OST function is enabled.

4.9 Rate of Change of Impedance Scheme

This method determines a power swing condition based on a continuous impedance calculation. Continuous here means, for example, that for each 5ms step an impedance calculation is performed and compared with the impedance calculation at the previous 5ms step. 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 5ms 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.

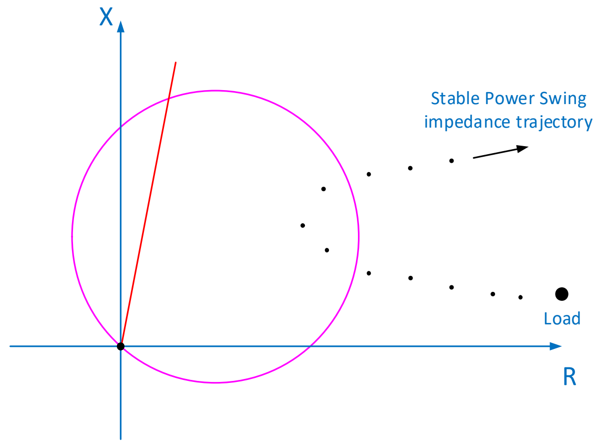

Fig. 19: Power swing detection with continuous impedance calculation

A delta impedance setting is not required because the algorithm automatically considers any delta impedance that is measured between two consecutive calculations and predicts 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.

This scheme is known to be presently applied in a line protection relay to perform Power Swing Blocking, but is not used for Out of Step tripping.

5. STABILITY STUDIES

Settings for out-of-step protection are determined by assessing the possible range of apparent impedance trajectories in the R-X impedance plane and the associated swing rate. Out-of-step protection can be set using either graphical methods or based on transient stability studies.[8][8] While graphical methods offer an expedient and simple approach, transient stability studies can be a useful tool to establish settings or to verify the validity of settings determined using a graphical method. In transient stability studies the dynamic models of the power system elements, specifically of the rotating machines, and of their control systems such as the AVR, turbine governor and Power System Stabilizer (PSS), are considered.

Graphical methods typically are based on an ideal two-source model with an equivalent model of the transmission system. These models are used to represent a system with two coherent groups of generators swinging against each other, or a generating unit or plant swinging against the rest of the system. These models simplify the process of determining settings, but they have limitations given that actual swings are more complex and may exhibit characteristics that cannot be identified through simplified models. In terms of model impedance, the simplified model limitations are less of a concern when establishing settings for generator relays compared to

[8] Kundur, P., Paserba, J., Ajjarapu V., Andersson, G., Bose, A., Canizares, C., Hatziargyriou, N., Hill, D., Stankovic, A., Taylor, C., Cutsem, T. V., and Vittal, V., "Definition and Classification of Power System Stability," IEEE Transactions on Power Systems, vol. 19, No 2, May 2004.

transmission line relays as only the "receiving end" system is simplified. However, the simplified model still lacks certain time varying quantities such as the generator excitation system response which affects the sending end voltage behind the generator impedance.

Transient stability studies require additional time and effort, but offer the ability to model actual system swings which may contain multiple modes, time-varying voltages, and abrupt changes in the apparent impedance trajectory resulting from switching events during the swing. Transient stability studies also provide information on the location of the electrical center of potential swings, i.e., whether swings will pass through the generator or GSU transformer versus a transmission line exiting the generating station. Due to the variability of the apparent impedance locus it is desirable to base out-of-step protection settings on transient stability simulations.

Study Parameters

Stability studies are used to evaluate a variety of operating conditions and contingencies. Studies should address the following:

<u>Generating Unit Models</u>

To accurately represent the generator performance, the generating unit model should include the excitation system, power system stabilizer (if in service), and governor.

<u>System Model</u>

The system model should be accurate for the time period of interest, with consideration to existing and future projects.

<u>Contingencies</u>

Studies typically are based on the critical contingencies identified through planning studies. Depending on the characteristics of the generator and the system to which it is connected, planning studies may not include contingencies for which the generator loses synchronism. In such cases it may still be desirable to provide out-of-step protection, in which case more severe contingencies may be added to the study. For example, contingencies could be simulated with longer clearing times or with additional elements out-of-service, or breaker failure contingencies could be modeled with three-phase faults in place of single-line-to-ground faults.

Planning studies of single and plausible double contingencies may or may not result in system disturbances that result in OOS conditions. More extreme contingency models may be required to produce OOS conditions. Therefore such studies may need to go beyond what is required by standards such as the NERC Transmission Planning (TPL) requirements.

<u>Generator Output</u>

The stability of a generator depends on the magnetic field strength established in the air gap by the excitation system. When a generator operates at a leading power factor (i.e., the generator is under-excited and absorbing reactive power) its stability margin is reduced. Studies should therefore include credible operating conditions with the generator operating at or near its minimum reactive power (maximum absorbing reactive power).

<u>Generator Power Factor</u>

The actual operating power factor of the generator has an effect on the generator stability limits. This may be most easily illustrated using the Equal Area Criteria, where the peak of the maximum power curve is proportional to the generator excitation voltage. A leading power factor results from a low excitation voltage (lower curve peak) and larger power angle to generate the same power level as for a unity or lagging power factor. A higher excitation voltage results in a lagging power factor, produces Vars, a higher curve peak and smaller initial power angle, providing more angular stability margin.

Generally when the Automatic Voltage Regulator (AVR) is in service, system disturbances often result in the AVR increasing the generator excitation as a result of the disturbance. But in any case, the larger initial (pre-disturbance) power angle that results from an initially leading power factor does result in a smaller stability margin.

Study Methods

Transient stability studies may be used to determine out-of-step settings, or to verify the validity of existing settings or settings determined by graphical methods. The out-of-step application and settings should be reviewed when system conditions change.

Determining Settings

The studies needed to determine setting parameters will depend on the type of out-of-step scheme being applied, but typically involve finding a marginally unstable case to determine the critical angle. This can be accomplished by using a planning contingency that results in generator instability and reducing the clearing time until the generator remains stable. The critical angle can then be determined by plotting the rotor angle versus time for the simulation with fault clearing just greater than the critical clearing time. If planning studies have not identified any contingencies for which the generator loses synchronism, then the most severe planning contingency can be simulated with the clearing time increased incrementally until an unstable case is identified. Alternately, a more severe contingency (sometimes referred to as an extreme or beyond criteria contingency) may be simulated with the clearing time increased or decreased as necessary until the marginally unstable case is identified.

An additional setting for some out-of-step schemes relates to timing of the trip output from the relay. Simulations of unstable swings of varying speeds should be used to verify that the circuit breaker is opened at an acceptable angle between the generator and the transmission system. The marginally unstable swing used to identify the critical angle should be the slowest unstable swing resulting in the most severe breaker interrupting conditions. The most severe credible contingency should be used to ensure that circuit breaker opening occurs at an acceptable angle for faster swings. Such calculations are illustrated in Appendix A for the single blinder scheme.

Verifying Settings

Typically the out-of-step settings are determined by calculating initial settings for blinders, time delay, etc. using a graphical approach. The settings are then refined as necessary based on transient stability simulations to ensure dependable tripping for unstable swings and secure non-operation for stable swings. The same approach may be used to verify existing settings when system conditions change due to transmission system topology changes or the addition or retirement of generation.

One method of verifying the settings is to model the out-of-step protection when simulating a series of planning contingencies and confirm the out-of-step protection does not operate for any stable swings, and does operate for unstable swings. However, it is unlikely that any given list of planning contingencies will include the limiting conditions most likely to challenge the out-of-step protection. Thus, it is desirable to also run the same simulations that would be used to determine settings as discussed above. This includes verifying that marginally stable and unstable cases result in secure and dependable operation, timers operate properly for swings with various speeds for a number of unstable cases, and circuit breaker tripping occurs at an acceptable angle.

If these simulations do not result in both secure and dependable operation, the relay characteristic and timer settings should be adjusted to obtain the desired operation. The simulations listed above represent a minimal set of simulations. The degree of confidence in the relay settings is improved by running more simulations which may be based on other contingencies and sensitivity to parameters such as fault type, fault impedance, system load level, and pre-fault generator loading.

System Swing Characteristic Rates

System swing scenarios are normally modeled using transient stability simulations. System stability studies also determine the swing rate (degrees/sec, which is proportional to slip frequency, Hz) that an OOS relay may experience. However, even in the absence of specific transient stability studies, several other plausible swing rate estimates are available.[9][9]

- Local oscillations of a generator against the transmission system usually fall in the range of about 1-2 Hz (360-720°/sec).
- Several other generalized estimates of transmission system swing rates suggest a maximum value of 2.5 Hz (900°/sec) for many system conditions.
- Oscillations between systems (multiple generator plants in each area) seldom exceed 1 Hz (360°/sec) and may be as slow as 0.2 – 0.3 Hz.

The critical swing rate for OOS analysis using graphical models is the maximum expected value for any system conditions, not the actual swing rate for any specific transient stability case. In addition, the swing rate will be the average value calculated when transiting between the two impedance characteristics used for the calculation, rather than an instantaneous value which may be available at any point during the transient stability study. For the graphical analysis, the user should add some margin to the maximum expected swing rate when calculating OOS settings.

Fig. 20 illustrates generator acceleration following separation from the system under full load. The rotor angle reaches 180° (at the first pole slip) when the slip frequency is about 3.6 Hz without governor action (~1300°/sec) essentially independent of the machine inertia (H between 1.5 and 5) and reaches 6.3 Hz (~2300°/sec) at 540°, or the second pole slip. These values are consistent with one of the more widely quoted range of system swing rates[10,13][10,14] of 4-7 Hz (1440-2520°/sec). Of course, OOS relaying conditions no longer apply following generator

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[9] Henneberg, Gene, "Coordinating the NERC PRC-023 Loadability Standard with Out-of-Step Impedance Relaying", Western Protective Relay Conference, Spokane, Washington, 2007.

[10] "Power Swing and Out-of-Step Considerations on Transmission Lines," IEEE Power System Relaying Committee, July 2005.

separation from the system, but this analysis still provides a plausible upper bound to expected swing rates for traditional synchronous generators.

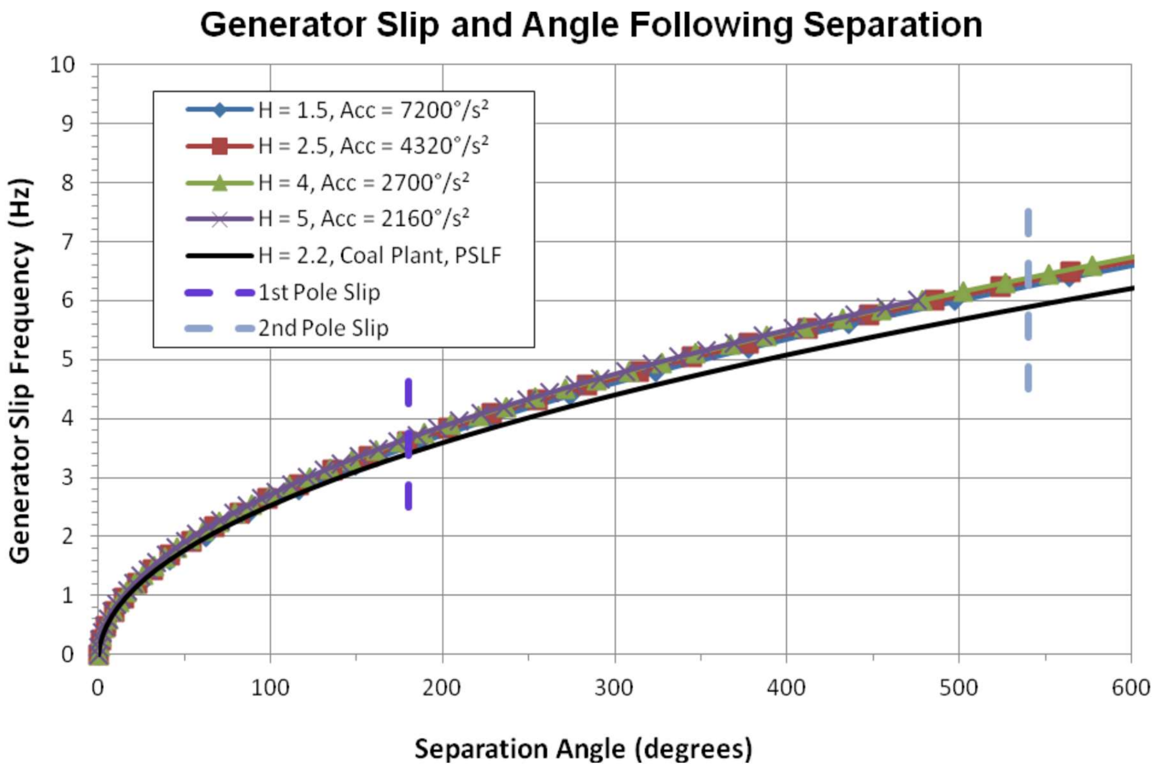

Fig. 20. Generator Slip Frequency vs Separation Angle

Fig. 20 shows slip frequency following separation of a fully loaded generator from the transmission system. Simplified model (without governor action) for inertia, H = 1.5–5.0, full stability model for H = 2.2, Coal Plant, Positive Sequence Load Flow (PSLF). The legend descriptions for the simplified model also identify the (constant) angular acceleration.

System and Relay Impedance Characteristics

As described earlier in this report, the generator and relay OOS characteristics are normally plotted on an R-X impedance diagram. Other impedance-based protection and generator characteristics such as phase distance, loss of field (LOF) and loadability may also be plotted on the same diagram.

The system impedance and generator swing locus are plotted on the positive sequence impedance plane as in Fig. 21 and many other references, including [9][10], [11][11], [12][12].

[11] Kimbark, E.W., Power System Stability, Volume 2, John Wiley and Sons, Inc., New York, 1950.

[12] Tziouvaras, Demetrios and Hou, Daqing, "Out-of-Step Protection Fundamentals and Advancements," 30th Annual Western Protective Relay Conference, October 21-23, 2003, Spokane, Washington.

Variations of the generator swing locus are typically circles on the positive sequence impedance plane, the characteristics of which depend on the ratio of the Thevenin equivalent voltages of the generator and transmission system and the system impedances. When transmission elements are open, e.g. after clearing faulted elements and imposing stress on the system, the system impedance increases, which tends to “push” the swing locus toward the transmission system (+X direction) and curving upward due to a reduced Thevenin equivalent voltage. In addition, for the usual case when the automatic voltage regulator (AVR) is in service, the generator voltage during a disturbance is not initially limited by the excitation limiters, exceeding the transmission system equivalent voltage and also “pushing” the swing locus toward the transmission system.

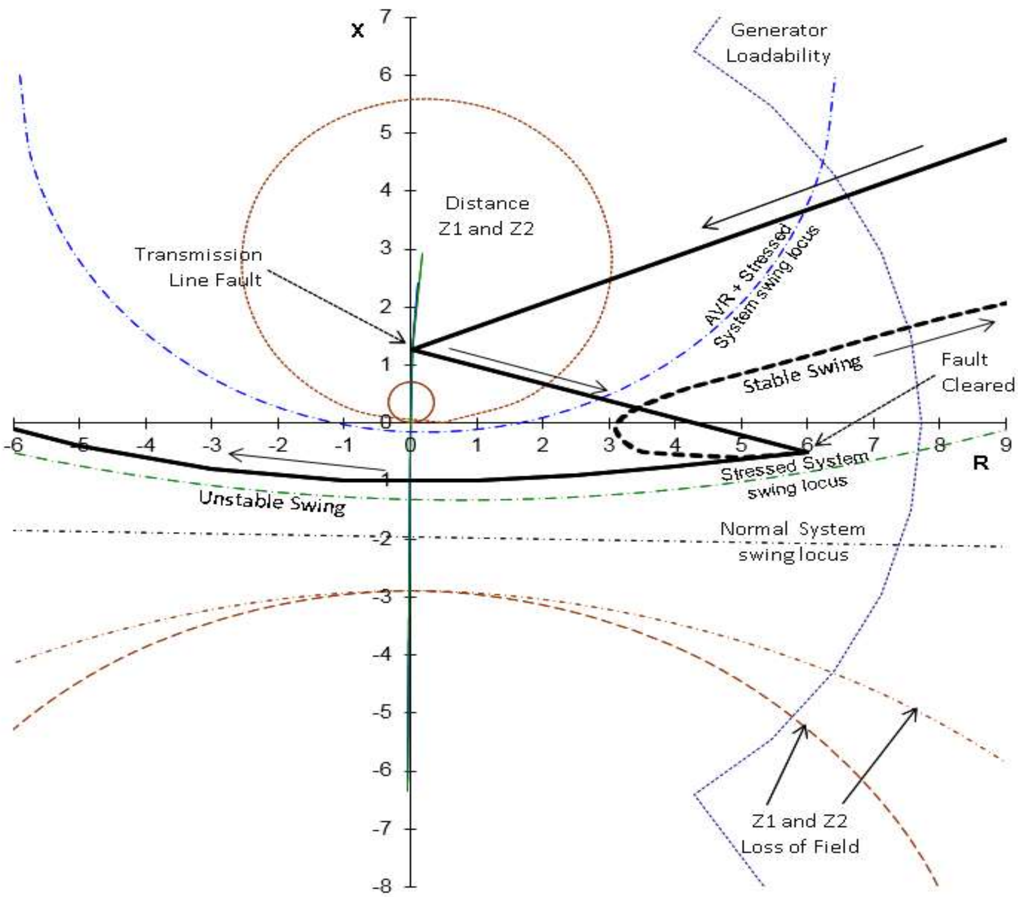

Fig. 21. Generator impedance elements during a stable and unstable swing resulting from a transmission fault near the generator plant (Initial generator loading conditions illustrated with lagging power factor).

The range of the swing locus is generally bounded by the system conditions described above and is illustrated in Fig. 21. The apparent impedance at the generator relay is also impacted by system faults, fault clearing, and other system switching events. A typical sequence for a “fast” swing may proceed as follows:

- Initial generator conditions assumed 1.0 per unit load near the rated lagging power factor.

- A transmission fault close to the power plant results in generator apparent impedance at the GSU transformer HV terminals.
- The generator power angle increases during the fault, based on the fault type, clearing time and turbine-generator inertia.
- As the fault clears, generator apparent impedance jumps to a new value, reflecting the new power angle and power factor, typically near the +R axis (the "real" start of the generator swing locus).
- Generator apparent impedance swings from right to left.
- A stable swing results from clearing the fault in less than the critical clearing time. Apparent impedance will slow, stop, return to the right with damped oscillations around a new stable operating point.
- An unstable swing results from clearing the fault in longer than the critical clearing time. Apparent impedance continues to the left past the X-axis as the generator slips its first pole.

An alternate scenario may occur for faults or other system disturbances originating remote from the generation plant. This scenario may be a result of cascading outages as the generator reacts to the "remote" system event(s). The swing rate may be slower than for events initiated close to the plant. The generator may or may not remain stable, but instability is more commonly the result of increased system equivalent impedance and low transmission system voltage as other transmission elements are lost. The swing locus is bounded by the system conditions described above and illustrated in Fig. 21, but the actual generator apparent impedance is impacted primarily by remote system switching events, loss of other generation, and other transient system conditions.

Graphical Out-of-Step Setting Calculations

A graphical method is probably the most common way to calculate OOS settings for either generators or transmission lines. All the pertinent impedance elements are plotted on the R-X plane for positive sequence impedance. The user manipulates tentative OOS settings until the angles, blinders (lenses, circles), timers and swing rates appear to satisfy all the constraints. These preliminary results are then used in transient stability models to check system performance and further modified as needed.

In general, the critical factors for multiple impedance OOS characteristics are the region where the swing locus will occur, the swing rate between characteristics and, for OOS tripping, the separation angle as the swing locus crosses the inner characteristic where the trip decision is made. The outer characteristic of most multiple-characteristic OOS schemes also needs to avoid encroaching on the generator loadability.

The general method to estimate the range of the swing locus is illustrated in Fig. 21 and Fig. A-3 to A-7 for various schemes. The projected band of the swing locus is affected by the ratio of Thevenin equivalent voltage of the generator and system plus system impedances. To provide some margin for these "swing band" calculations, the voltages and impedances should represent the range of system conditions from normal to a stressed system as may occur during a major system disturbance.

Generally the relay makes the critical trip decision as the swing locus crosses the inner impedance characteristic for schemes that have both inner and outer lenses, blinders, or circles If the separation angle at this point is beyond the critical clearing angle the system will not recover and the event will be an unstable swing. The angle determination is an off-line calculation by the user (not the relay). The separation angle is the angle defined by the total system impedance and the crossing of the swing locus with the relay impedance characteristic, as shown in Fig. 21. The user may choose to use a larger angle for δ_C, e.g. 130°, resulting in a characteristic resistive reach closer to the X-axis, when determining the settings to provide more margin to assure tripping only for unstable swings.

The swing rate is also an off-line user calculation. As the swing locus passes between two impedance characteristics, the difference in the angles (as described above) is divided by the actual transit time. If the transit time is longer than the OOS timer setting, the relay uses its OOS logic to perform the appropriate action. The user should choose a target swing rate as the maximum estimated swing rate the relay is expected to encounter (generally estimated by stability modeling), plus some margin.

The impedance plane figures shown in the appendix were part of a spreadsheet[8][9] developed and revised to perform the appropriate relay setting calculations. The reasoning is described here in enough detail so that the settings are illustrated even without the spreadsheet, but can be more readily calculated using this, or a similar tool.

6. TESTING

Like other protections, it is essential that the Out-of-Step protection function be tested thoroughly prior to placing it in service. If it is part of a multi-function relay it should be tested together with the other protection functions as a complete functional protection system.

A detailed discussion on testing of this protection is out of the scope of this document. At the time of writing this report, IEEE PSRCC Working Group C29 is working on that scope.

7. ADDITIONAL CONSIDERATIONS

Variations in source Impedance:

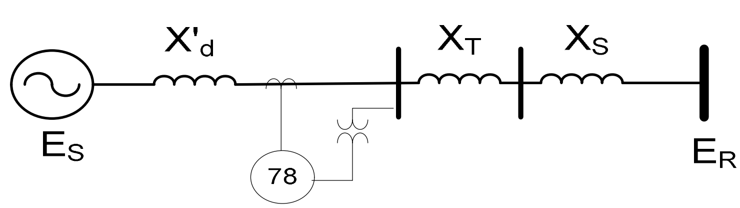

Fig. 22. One machine – infinite bus system model

The simplified model for out of step relay protection is often the one machine infinite bus model as shown above where,

$$P = \frac{|E_S||E_R|\sin(\delta_S)}{X}$$

and:

Es = Internal Generator EMF

E_R = System Equivalent Voltage

X'_d = Generator transient reactance

X_T = Transformer impedance

X_S = Equivalent system impedance

δ_S = Angle between Es and E_R

$X = X'_d + X_T + X_S$

The value of E_S is dependent on generator excitation and is highly variable. The values of X'_d and X_T are solely dependent on equipment design and are considered constant. The value of X_S depends on system contingencies such as lines out of service. Variation in X_S and E_S can affect the dependability of the out of step protection.

When a unit goes out of step the angle between E_S and E_R rotates without stopping. The out of step relay measures the impedance based on the voltage and current at the relay location, at the generator terminals for this illustration. The plot of impedance vs time (locus) for an unstable swing must enter the relay characteristic for the relay to operate properly. When the angle between E_S and E_R is at 180º the impedance locus is at or near the vertical X axis on the R/X impedance plot.

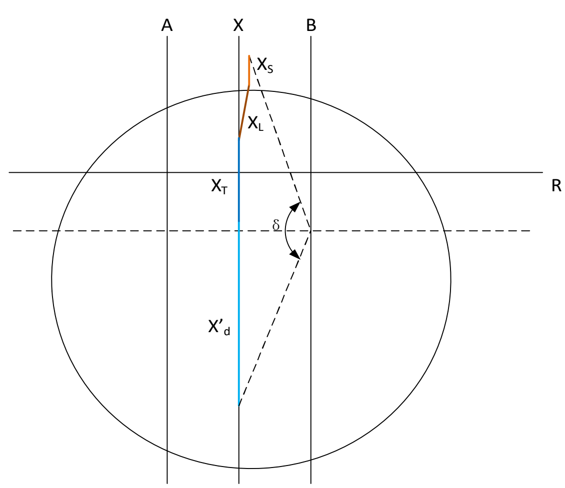

Fig. 23. Single blinder scheme with swing locus

The familiar plot for a single blinder scheme is shown above in Fig. 23 in which the impedance locus, large dashed horizontal line, passes through the X'$_d$ impedance near the generator terminals.

Variations in E_S and X_S can move the locus plot up or down. If the locus moves above the forward reach of the relay mho circle, the out of step relay will not operate.

Teeter Totter Analogy:

The point where the impedance locus crosses the X axis can be visualized using the analogy of the balance point of a playground teeter totter.

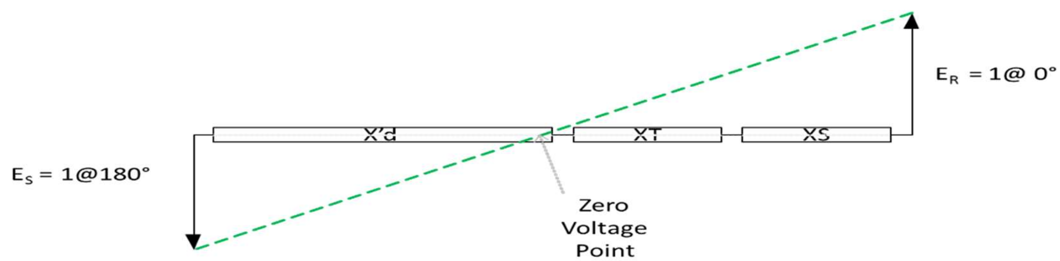

Fig. 24. Teeter totter analogy with the system impedances

Note: The spaces between the impedances do not exist and are shown for purposes of illustration only.

By drawing a line between the arrowheads the 180º point can be determined. This is the point where the system experiences a voltage zero. Variations in X_S can cause this crossing point to move as shown below.

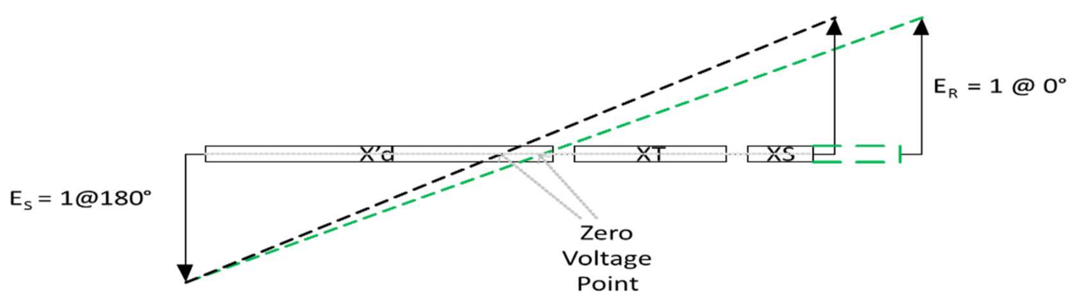

Fig. 25. Teeter totter analogy (Crossing Point would move with a variation in equivalent system impedance)

Variation in the magnitude of E_S can also move the crossing point as shown below:

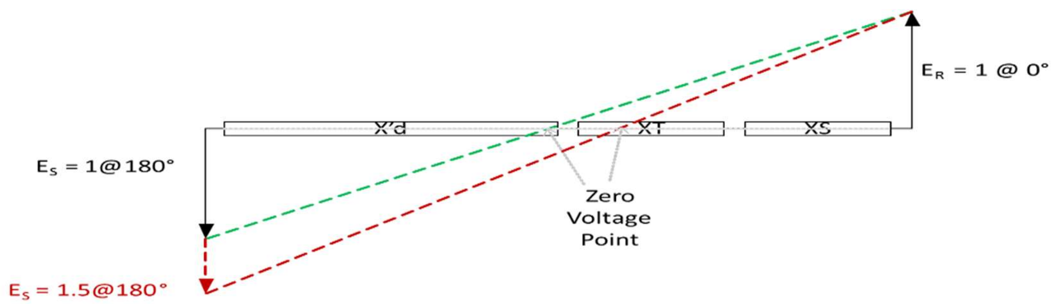

Fig. 26. Teeter totter analogy (movement of the crossing point with different generator voltages)

In extreme cases the locus could shift enough to cause the OST relay to not operate. Recent NERC standards regarding coordination of the generator protection require analysis with highly overexcited generator operating conditions. The effect of these overexcited operating points should be considered when setting the out of step relay.

Effect of Multiple Units at a Station:

When multiple generators are located at a station there is an infeed effect that causes a multiplication of the source impedance as measured by the 78 relay.

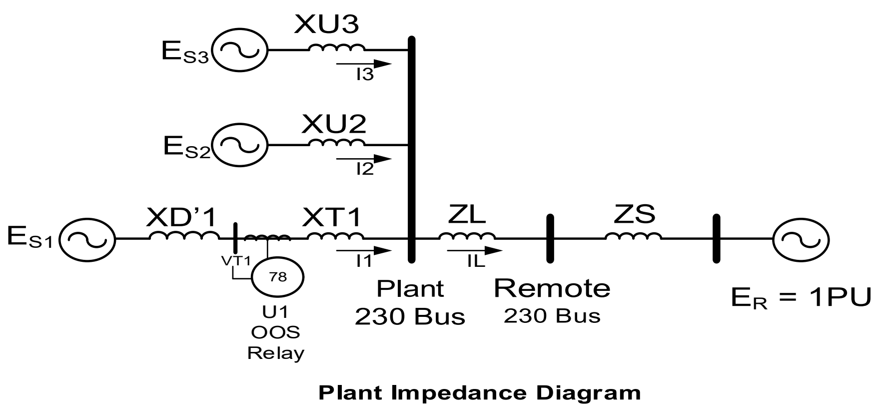

Fig. 27. Plant Impedance Diagram

The OST relay on Unit 1 measures: $Z= V_{T1}/I_1$.

where $\quad V_{T1} = I_1*X_{T1} + (I_1+I_2+I_3)*(Z_L+Z_S) + E_R$

or $\quad Z = X_{T1} + ((I_1+I_2+I_3)/ I_1)*(Z_L+Z_S) + E_R/ I_1$

The magnitude of Z_L and Z_S are multiplied by the infeed ratio $(I_1+I_2+I_3)/I_1$. This also introduces new contingencies such as the number of parallel units operating at a given time. Multiple unit stations are best analyzed using dynamic stability programs that can account for the individual inertia constants and operating conditions of the individual units at the station.

8. NERC TECHNICAL REFERENCE

NERC Technical Reference *Considerations for Power Plant and Transmission*

System Protection Coordination[1] – Revision 2, Chapter 2 provides a description on Purpose of the Generator Function 78 — Loss of Synchronism Protection:

Out-of-step relaying is generally required for larger machines connected to EHV systems. Stability studies may be performed to confirm the need for out-of-step relaying for these applications, or for smaller machines connected at lower voltages.

It is correct that larger machine connected to the EHV system generally require out of step protection. But this statement should not be interpreted that only such machines require that protection. This statement implies that OOST is only required when the swing impedance goes through the GSU and the unit will not be separated by natural tipping of impedance elements on the transmission system. OOST protection should be applied to most machines to ensure that it is separated from the power system after it goes out of step without reliance on sympathetic tripping of other relays.

It also states:

Stability studies must be performed to validate that the out-of-step protection will provide dependable operation for unstable swings and will not trip for stable system conditions and stable swings.

As readers of this report should understand, only some OOST schemes require stability studies. Single blinder schemes are secure even when using the rule-of-thumb assumption that the boundary between stable and unstable swings is 120°.

It also provides settings considerations, issues and a setting example using a single blinder scheme.

NERC has developed standard PRC-026-1 - Relay Performance During Stable Power Swings. This standard has a staged implementation, with effective dates of January 1, 2018 for the requirement applicable to Planning Coordinators, and January 1, 2020 for the requirements applicable to Generator Owners and Transmission Owners. It will apply to Generator Owners that use load responsive protective relays on their generators (and transformers and transmission lines, where applicable), such as phase overcurrent, phase distance, out-of-step tripping, and loss of field elements, that trip with a delay of less than 0.25 second. Planning Coordinator studies that determine a generator is subject to at least one of several specified vulnerabilities, or the Generator Owner becoming aware of a generator trip in response to a stable or unstable power swing due to operation of its relay(s), identifies the load responsive relays applied to the generator as subject to the standard.

Following identification that a generator relay is susceptible to tripping on stable power swings, the owner must mitigate the vulnerability. The standard includes criteria based on static calculations (stability analysis is not required) to evaluate both overcurrent and impedance based relays to estimate susceptibility to tripping on stable power swings. Out-of-step trips on overcurrent elements are outside the scope of this report and the NERC criteria may not provide complete mitigation for impedance-based relays against trips on stable power swings. However, the criteria should provide protection for a significant majority of applications which otherwise may have some susceptibility to trips on stable power swings.

9. CONCLUSION

Out-of-Step protection for generators is important to the generator owner because they want to protect their machines from damage after slipping a pole. The transmission operators want to protect the machine from damage following an OOS event in order restore the system to normal operation as quickly as possible. The transmission operator also wants to trip the minimum number of elements necessary to prevent an expanding system disturbance, so does not want to rely on sympathetic tripping of adjacent transmission elements for this protection. Both generator owners and transmission operators want the OOS scheme to be secure so that it does not remove the generator from service unnecessarily.

There are several schemes available for achieving this protection, each with certain advantages and disadvantages. The ideal scheme should trip the generator in case of unstable swings but should not trip for stable swings. Proper application of the relay scheme (either setting the relay or verifying the setting determined via graphical methods) can be improved by performing stability studies with proper modeling of the system and the machine to determine swing characteristics for different scenarios. Plotting swing characteristics and relay characteristics on the same diagram helps the engineer understand the specific cases. Performing stability studies involves extensive coordination between the Planning Coordinator or Transmission Planner, Transmission Owner, and Generator Owner. The relay characteristics should allow tripping for unstable swings but should not trip for stable swings. It is essential that the Out-of-Step protection function be tested thoroughly prior to placing it in service. If it is part of a multi-function relay it should be tested together with the other protection functions as a complete functional protection system.

The schemes using electromechanical relays often provide minimal useful diagnostic information. A separate Digital Fault Recorder/Sequence of Event Recorder (DFR / SER) may be necessary (and is usually installed on larger units in any case) to determine the event characteristics, which can then be analyzed to determine the actual cause of a trip. Microprocessor relays will normally trigger event reports and SER data to automatically collect the appropriate data as well as provide protection.

APPENDIX A GENERATOR OUT-OF-STEP RELAY SETTING CALCULATIONS

A.1 Simple Mho Scheme

In this scheme an impedance relay, device 21, is used to provide out-of-step protection for the generator. The relay is connected to the GSU Transformer high voltage side current transformers and voltage transformers. An over current relay supervises the operation of the impedance relay. The impedance relay senses three phase currents and voltages, and monitors the impedance looking into both the generator and the main power transformer. If the impedance falls below a preset value and the overcurrent supervision relay operates, the relay will actuate to trip the generator lockout relay. The protective purpose of the relay is multifunctional: Out-of-Step (loss of synchronism) protection, protection for inadvertent energization of the generator from the switchyard while off-line, backup phase fault protection for the HV leads (345kV in example below) and generator bus, and backup loss of excitation protection.

The impedance setpoint for the Out-of-Step relay is calculated by summing the subtransient reactance of the generator (X''_d) and the impedance of the main power transformer (Zmpt), then multiplying the sum by a factor of 2. As written, the equation is: Z(pri) = 2 (X''_d + Zmpt). This impedance setpoint formula ensures coverage for accidental energization of the generator. The subtransient reactance used could be either unsaturated (X''_{di}) or saturated (X''_{dv}); the latter will result in a slightly lower reach. Example below uses X''_{dv}.

The relay's maximum torque angle is determined by plotting the relay characteristics on an R-X diagram that also shows the stable swing points of the generator. The relay characteristic is plotted as a circle with its diameter equal to the impedance calculated by Z(pri) = 2 (X''_{dv} + Zmpt). The relay will actuate (trip) for any point within that impedance circle. Therefore, it is imperative to adjust the angle of the relay so that all stable swing points for the generator lie outside of this circle and all unstable swing points lie inside the circle.

Occasionally it may be necessary to reduce the calculated reach of the impedance relay to ensure that the stable swing points lie outside of this circle.

Example:

1. The impedance of the relay is derived from the following formula: Z(pri) = 2(Zmpt + X''_{dv})

   From Input Data, Zmpt = 0.1267 pu on a 982MVA base, 362.25kVbase

   From Input Data, X"dv = 0.265 pu on a 1068MVA base, 18kV base.

2. Convert Zmpt into actual ohms (refered to the 345kV side) using the formula:

   Zactual = Zpu x Zbase, where Zbase = $(Vb)^2$/Sb. Therefore, Zactual = Zpu x $(Vb)^2$/Sb.

   Vb = 362.25 kV Sb = 982 MVA

   Zmpt actual = Zpu x $(Vb)^2$/Sb = 16.93 ohms.

3. Convert X''_{dv} into actual ohms using the formula:

   Zactual = Zpu x Zbase, where Zbase = $(Vb)^2/Sb$. Therefore, Zactual = Zpu x $(Vb)^2/Sb$.

   Vb = 18 kV Sb = 1068 MVA

   X''_{dv} actual =X''_{dv} pu x Vb^2/Sb = 0.0804 ohms

   Refer X''_{dv} actual to the 345kV side of the transformer using the following formula:

   Z345kV = n^2 x Z18kV, where n is transformer turns ratio of (N1/N2)

   X''_{dv} actual at 345kV = 32.56 ohms

4. Substituting values derived in 2. and 3. back into the formula from 1. yields:

   Z(pri) = 2 x (Zmpt + X"dv) = 99.0 ohms

   This is the desired reach of the device 21 relay in primary ohms.

5. As discussed in the methodology, the maximum torque angle of the relay is determined by plotting the relay's impedance on the same R-X diagram as the generator stable swing points. However, the Z(pri) impedance must first be converted to a per unit value based on the generator swing study MVA and Voltage base.

   Change relay reach impedance into per unit value of the swing study base:

   Zswing study base = $345kV^2$/100MVA = 1190.25 ohms

   Zpu = Z(pri)/1190.25 = 0.0832 per unit (relay reach impedance as per unit value of the swing study base).

   This is the diameter of the relay's impedance circle (desired reach), in per unit and on the same base as the generator stable swing plots shown. The generator stable swing plots will include a plot of the desired reach of the device 21 relay at 90º (dashed), 75º (dotted), 60º (solid) MTAs.

6. Generator stable swing plot BF 1221 BT2-3 UP STABLE has a swing impedance that will traverse into the device 21 desired reach at 60º MTA, which is the minimum MTA setting.

   This will require a revised approach to reduce the desired reach, Z (pri) = 2 x (Zmpt + X''_{dv}), to a value that will not be traversed by the BF 1221 BT2-3 UP STABLE stable swing impedance.

   Revised Z(pri) = 66.1 ohms

   Zpu = Z(pri)/1190.25 = 0.0555 per unit

   The revised Z(pri) is 134% of the calculated Zmpt + X''_{dv}.

Plot BF 1220 BT5-6 UP STABLE shows that the stable swing impedance will not cause a 21T2 trip.

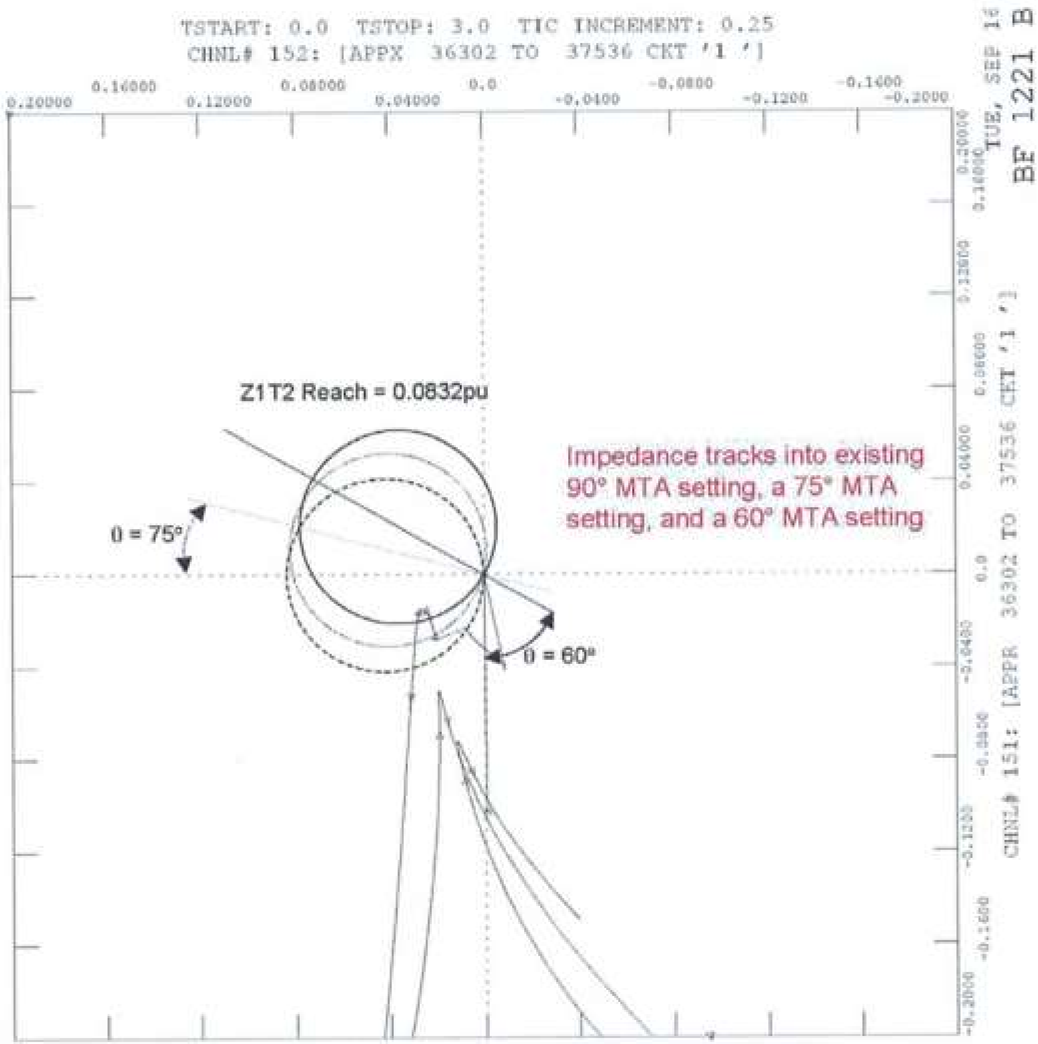

Fig. A-1. Simple Mho Scheme Plot BF 1221 BT2-3 UP STABLE

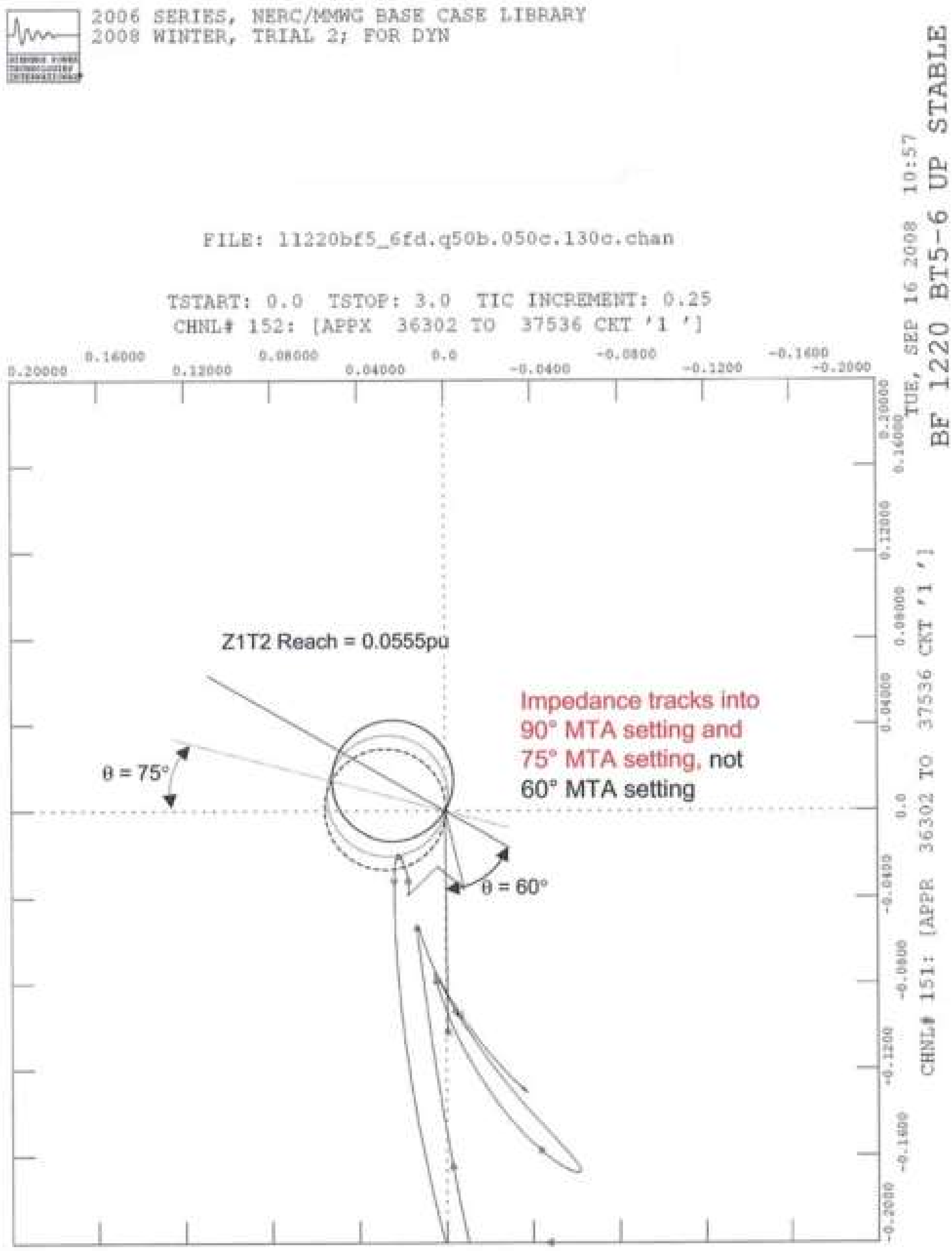

Fig. A-2. Simple Mho Scheme Plot BF 1220 BT5-6 UP STABLE

A.2 Single Blinder Scheme

Generator Model

The calculations for Single Blinder Scheme, Double Blinder Scheme, Double Lens Scheme, Triple Lens Scheme, and Concentric Circle Scheme were performed for a steam turbine generator connected through a generator step up (GSU) transformer to a 345 kV transmission system. This equipment has the following parameters:

TABLE A-1. Generator and GSU Characteristics

Generator Characteristics	Base Quantities	Relay Quantities
Rated MVA, 0.90 pf lag, 0.95 pf lead	308 MVA	
Rated Voltage	22 kV	
CT Ratio	10000:5	
PT Ratio	183.33:1	
Transient reactance, X'd	0.37 pu	6.34 Ω-sec
GSU Transformer	300 MVA	
HV / LV Taps (kV)	336.375 / 21.25	
Transformer Impedance	0.00178 + j 0.0742 pu	0.030 + j 1.262 Ω-sec
Distance Zone 1		0.70 $\angle 88°$ Ω sec
Distance Zone 2		5.60 $\angle 85°$ Ω sec
Loss of Field Zone 1, Offset / Diameter		-2.90 / 17.60 Ω sec
Loss of Field Zone 2, Offset / Diameter		-2.90 / 30.40 Ω sec

The single blinder OOST scheme is the simplest and most secure impedance-based OOS scheme available to ensure that generator OOS trips occur only for unstable swings. The scheme logic also makes it quite dependable. The most potentially significant limitation is that tripping can only occur after the first pole slip "on the way out" of an unstable swing, though this is usually not critical.

The following illustrations provide example calculations for two manufacturers that use different implementations of the single blinder scheme. Relay OOS characteristics monitor the positive sequence apparent impedance using an offset mho circle plus left and right blinders. In order to initiate an OOS trip, the system impedance locus must enter the mho circle, cross the first blinder, then exit the characteristic through the opposite blinder (Section 4, Fig. 11). For a “normal” unstable swing, the apparent impedance begins on the right and exits to the left, though the relay logic works the same in either direction.

In most cases and specifically for these two manufacturer’s relays, the single blinder scheme logic will tolerate a relatively wide deviation in the basic settings (mho circle, blinders, and impedance angle where used) from the manufacturer’s suggested setting calculation methods. Scheme performance can sometimes be adversely impacted for deviations in other settings such as timers and other functions and more care should be taken if settings for these elements are used outside the normal, suggested range.

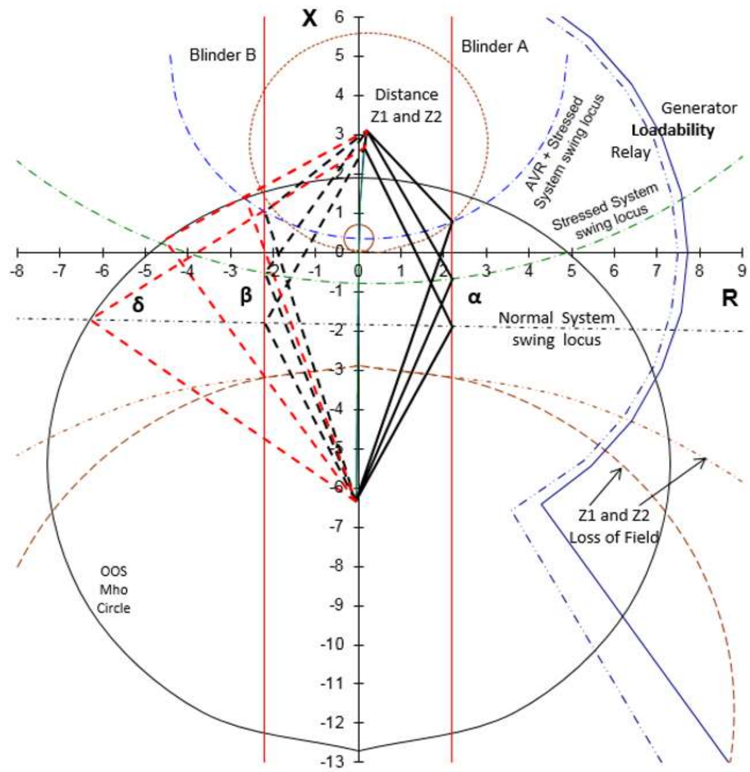

Fig. A-3. Single Blinder OOST and other relay impedance characteristics

Fig. A-3 shows the system and relay impedance elements and their relationship to the band of system swing loci. Three system configurations are illustrated that result in different swing loci. These conditions illustrate transmission line or other system outages and unequal Thevenin equivalent voltages, including low transmission system voltage and the action of the generator automatic voltage regulator (AVR).

- Normal System swing locus, uses maximum generation, transmission system intact and $E_{gen} = E_{system}$ (lower black dashed line, perpendicular bisector of the system impedance),
- Stressed System swing locus (weak transmission system), including minimum generation and plausible system contingencies with $E_{gen} > E_{system}$ (green dashed curve), and
- AVR + Stressed System swing locus including the weak transmission system and $E_{gen} > E_{system}$ resulting from generator AVR action (upper dashed blue curve).

The angles in Fig. A-3 labeled α, β, and δ are the separation angles formed between the generator and system when the swing locus crosses the right (angle α) or left (angle β) blinder and exits the mho circle (angle δ), respectively. Separate angles are illustrated for each of the three swing loci, but only single values of α, β and δ apply for each specific swing locus. The specific geometry and all three sides of each resulting triangle are determined by the total system impedance and the intercepts of the specific swing locus with the blinders and mho circle. Then the angle calculation is performed from the law of cosines. These angles change somewhat as the swing locus changes; largest angles generally occur with the AVR + Stressed System swing locus. The smallest angles generally occur with the Normal System swing locus.

The mho circle is used as a starting element and should be set so that the expected band of the swing locus will always pass through the mho circle. The manufacturers' suggested reach in the –X direction is 2-3 times X'd, generator transient reactance; these example calculations use 2 times X'd. In the case where the generator voltage regulator is on a fixed value (AVR off), the swing locus would be between the Normal System and Stressed System loci. One factor in providing adequate margin in relay settings is if the mho circle overlaps the loss of field characteristic.

Reach in the +X direction is suggested at 1½ - 2 times the GSU transformer reactance, X_T. An alternate method calculates this reach as $X_T + X_{Line}$, using the impedances of the GSU and the longest line at the switching station. Again, the specific reach is critical only in that it should overlap the worst case expected swing locus band, "AVR + Stressed System" in this illustration. These calculations use 2 times X_T.

The manufacturer suggested blinder setting calculation results in a 120° separation angle for the "Normal System" swing locus, measured as the locus crosses the blinder. This suggested blinder setting is conservative, in part because the steady state stability limit cannot exceed 90°. Several references [10][11], [13][13], [14][14] suggest that at 120° separation angle, the generator is unlikely to maintain stability. The typical settings for the single blinder scheme result in an OST angle of at least 240°, well beyond any possibility of recovery from a stable swing (first pole slip at 180°).

The right blinder is usually set inside (closer to the X axis than) the relay loadability characteristic, though even this is not critical for the single blinder scheme. Loadability for the left blinder is seldom of concern because the left half of the impedance plane represents motoring the generator, for which other protection functions will operate. Both manufacturers' relays include relay loadability characteristics that supervise only the phase distance functions. The mho circle acts as a starting or supervisory, not a tripping element, so it is not critical if the mho circle encroaches on the generator loadability characteristic.

[13] SEL-300G Multifunction Generator Relay Instruction Manual, 20121214, Schweitzer Engineering Laboratories, 2012.

[14] Berdy, J., "Out-Of-Step Protection for Generators," General Electric GER-3179.

Single Blinder Scheme - Manufacturer H

Settings used for this generator are listed in Table A-2[15][15]. All quantities are listed in relay level (secondary) units. This relay updates OOS calculations on a 1-cycle interval.

TABLE A-2. Manufacturer H Single Blinder OOS Relay Settings

Relay Element	**Manufacturer's Typical Value**	**Relay Setting**
78 DIAMETER	1.5 X_T + 2 X'd	14.6 Ω-sec
78 OFFSET	2 times X'd	-12.7 Ω-sec
78 BLINDER IMPEDANCE	½ (X'd + X_T + X_{system}) tan(θ- α/2) where typically α ≈ 120° (α is the angle where the right blinder intersects the swing locus)	2.2 Ω-sec
78 IMPEDANCE ANGLE	Typically θ ≈ 90°, or angle of overall Z_d' + Z_T + Z_{system} impedance	90^0
78 DELAY	Based on maximum swing rates from stability studies, typically ≈ 3-6 cycles	3 cycles
78 TRIP ON MHO EXIT	Enable tends to reduce recovery voltage across the breaker contacts	Enable
78 POLE SLIP COUNT	1	1
78 POLE SLIP RESET TIME	Typical 120 cycles	NA

78 DIAMETER, 78 OFFSET and 78 IMPEDANCE ANGLE

The mho circle diameter is the direct measure of that element. The offset is the intercept of the mho circle with the –X axis. The impedance angle is the angle of total system impedance,

$$Z_{total} = r_a + j\,X'd + R_T + j\,X_T + R_{system} + j\,X_{system} = Z_{total}\,\underline{/\,\theta}.$$

Since generators and transformers tend to have quite large X/R ratios, total system impedance generally also has a large X/R ratio and θ is then close to 90°.

78 BLINDER IMPEDANCES

This manufacturer uses a single value for the blinder setting, so that both left and right blinders are the same distance from and on opposite sides of the X axis. The suggested blinder setting calculation (2.2 Ω) results in angles α = β ≈ 120° for the Normal System swing locus. This result

[15] M3425A Generator Protection Instruction Book, 800-3425A-IB-11MC3, Beckwith Electric Company, 2015.

provides significant margin to avoid the generator loadability characteristic. The blinder setting in Fig. A-3 is actually larger (2.9 Ω), but still results in a margin to the generator loadability characteristic of nearly 50% in the leading power factor region.

78 DELAY

This timer setting, in effect, identifies the maximum generator swing rate between the blinders. If the system swing locus passes between the blinders faster that the timer setting, the event is not interpreted as a swing, and the relay OST function does not operate. This is similar to the way many double blinder or multiple lens schemes work for both generator and transmission relays. This application design may provide some additional security against an impedance transient that starts on the right and migrates to the left side of the impedance plane, for example resulting from external switching events.

The upper limit to the timer setting is the difference in the complement of angles α and β on the impedance plane where the swing locus intersects the right and left blinders, divided by the expected swing rate and rounded down to the next relay calculation interval,

$$78\ DELAY = \frac{(180^0 - \beta) + (180^0 - \alpha)}{SwingRate} = \frac{360^0 - (\alpha + \beta)}{SwingRate}$$

In this case, the time delay calculation results from the "AVR + Stressed System" swing locus with $\alpha = 130.3°$ (right Blinder A intercept angle) and $\beta = 126.3°$ (left Blinder B intercept angle). If the 78 DELAY setting is designed to detect a swing rate of up to 4 Hz, then 78 DELAY ~ 0.0718 sec ➔ 4 cycles (maximum recognized swing rate, $\Delta f \sim 4.3$ Hz (1551°/sec).

The minimum timer setting is only a function of the relay characteristics. The maximum time that a microprocessor relay takes to perform impedance calculations is generally a function of the source impedance ratio (SIR) and how close the apparent impedance is to the characteristic setting. These "speed curves" are often documented in relay instruction manuals or other manufacturer literature. The impedance element pickup time can then be described as a maximum swing rate that the relay can still interpret as a system swing, rather than a fault. The OOS impedance calculation time, rounded up to the end of the next OOS calculation interval, is about 2 cycles. In order to assure adequate margin, the minimum setting of the 78 DELAY timer should be at least the next OOS calculation interval longer than the maximum impedance element pickup time, or 3 cycles, representing a maximum swing rate of just under 5.7 Hz (2000°/sec). The relay OST function should operate reliably for 78DELAY setting between 3 and 4 cycles. Generally, the shortest timer value should be used that ensures an adequate margin to detect the anticipated maximum swing rate, so 78 DELAY = 3 cycles.

78 TRIP ON MHO EXIT

If the 78 DELAY timer expires while the system impedance locus is in between the blinders, the event is interpreted as a system swing. The OOS trip (OST) element then asserts either when the impedance locus crosses the left blinder (Disable), or upon leaving the mho circle (Enable).

The limiting design factor is whether the circuit breaker that isolates the generator is rated to withstand the transient recovery voltage as it opens. Some EHV breakers are designed to withstand an opening angle of 180°, but many are not. Without knowing the actual breaker rating, a good static estimate of the safety of opening the breaker is the angle, δ, across the system impedance as the breaker attempts to open, as shown in Fig. A-3[14]. When $\delta > 90°$, there is an increased risk of an internal breaker flashover for breakers not rated for 180° opening.

In this case, the maximum angle on exiting the left Blinder B is $\beta = 126.3°$, or on exiting the mho circle is $\delta = 86.4°$. The safety margin will be adequate if TRIP ON MHO EXIT is "Enabled". If a further improvement in safety margin is desired, if the mho circle diameter, 78 DIAMETER, could be increased to further reduce the exit angle below 90°.

78 POLE SLIP COUNT and 78 POLE SLIP RESET TIME

The user may also specify whether to trip on the first unstable swing or wait to trip on a later swing. This requires a pole slip reset time if the number of poles allowed to slip is more than one. A 78 Pole Slip > 1 is primarily used outside North America. The reset time should be shorter than the inverse of the maximum slip frequency in Hz.

Once a generator slips a pole (loses synchronism with the system), it is practically impossible to reestablish synchronism without first actually separating the generator from the system. Any out-of-step pole slipping imposes significant transient torques on turbine/generators and significant transiently varying voltages and currents on the generator and transmission system. The pole slip count should be set to 1 for thermal generators but might be set larger for hydro units which tend to be more robust. The effects on system currents and voltages are the same regardless of generator type, so tripping even hydro units on the first pole slip also is often preferred.

Single Blinder Scheme - Manufacturer R

The manufacturer R single blinder scheme has several features in common with Manufacturer H's implementation. The mho circle acts as a starter element. Initiating an OOS trip requires the impedance locus to enter the characteristic through mho circle, one blinder and exit through the opposite blinder. The relay updates OOS calculations on a ½-cycle interval, rather than 1 cycle for manufacturer H. Table A-3[12][13] below summarizes the relay settings for this application.

TABLE A-3. Manufacturer R Single Blinder OOS Relay Settings

Relay Elements	Manufacturer's Typical Value	Relay Setting
78REV	1½ - 2 times X_T	1.9 Ω-sec
78FWD	2 - 3 times X'd	12.7 Ω-sec
78R1 Right Blinder 78R2 Left Blinder	½ (X'd+X_T+X_{sys}) tan(θ - α/2) where α ≈ 120°	2.2 Ω-sec -2.2 Ω-sec
78TD	Trip delay timer after mho circle exit	0.5 cycles
78TDURD	Minimum trip duration timer	3.0 cycles
50ABC	Positive sequence current supervision for OOS element	0.25 amp

OOSTC	Torque control for OOS element	1

Fig. A-3 illustrates relay impedance elements for both Manufacturer H and Manufacturer R single blinder schemes and their relationship to the band of system swing loci. The three system swing loci configurations, separation angles α, β and δ, along with the Loss of Field and backup distance impedance elements are the same as described for Manufacturer H.

78FWD, 78REV and 78Z1

Since both relays are used to protect the same generator, these elements are set to yield the same mho circle as for Manufacturer H's relay, but the characteristic is specified differently. The 78FWD element is the mho circle impedance reach in the –X direction and 78REV element is the reach in the +X direction. The mho circle diameter is then the sum of the forward and reverse settings, 78Z1 = 78REV + 78FWD.

78R1 and 78R2 BLINDER IMPEDANCES

This manufacturer uses separate 78R1 and 78R2 elements for the right and left blinders respectively, resulting in potentially different reaches for the blinders. A difference in these settings is unusual, but may be desirable if the actual total system impedance angle is significantly smaller than 90°. If this were the case, the right blinder may be set larger, corresponding to the resistance component of the system impedance. In this example, the blinders are set the same and equal to the settings used for Manufacturer H's relay.

78TD

This relay characteristic is designed to always trip on exiting the mho circle after passing through both blinders. The 78TD timer adds time after exiting the mho circle before issuing the OOS trip. As with Manufacturer H's scheme, the maximum angle δ = 86.4°, so additional delay is not required, but if used would help ensure that the trip only occurs when the breaker opening will be within the circuit breaker rating (δ ≤ 90°). In this case, with the same mho circle, add 0.5 cycle delay after the mho exit.

Then, if the maximum expected slip frequency is up to 4 Hz, the breaker opening angle would be about

$$\delta = 86.4° - 0.00833 \text{ sec X } 1440°/\text{sec} = 74.4°,$$

illustrating that system swing rates faster than the minimum result in additional margin for safe breaker opening. As with Manufacturer H's relay, the same alternate method could be used to reduce the mho exit angle below 90°, i.e. increase the mho circle diameter.

78TDURD

This is the minimum time that an OOS trip is held in once it asserts. Typically this is set larger than the rated interrupting time of the breaker, but shorter than the breaker failure time with some margin. For a 345 kV breaker rated to interrupt fault current in 2 cycles and breaker failure time of 6 cycles, set 78TDURD = 3.0 cycles.

50ABC

This positive sequence current element supervises the OOS characteristic. It should be set based on a minimum generation system under stressed conditions (including contingency outages), in an analogous manner to a fault detector for the longest reaching phase distance element in a line protection scheme. Typically it does no harm to leave this setting at the minimum, 50ABC = 0.25 amp.

OOSTC

OOS torque control may be used to provide other supervision to the scheme. For example, the OOS element operates on positive sequence impedance. All load and fault conditions have a significant positive sequence current, but only unbalanced conditions (L-L-G, L-L or L-G faults) include significant negative sequence current. Fault studies may suggest allowing OOS tripping only when the negative sequence current is below a certain level. In this case, no additional supervision is used, so OOSTC = 1.

A.3 Double Blinder Scheme

The double blinder scheme somewhat resembles the schemes usually used for OOST and PSB functions applied on transmission lines, but is actually simpler because it does not have to consider PSB parameters when setting the blinders. Blinder and concentric impedance elements, such as double blinder and multiple lens schemes are set based on one or more timers which represent the angle difference between inner and outer impedance characteristics (blinders or lenses) at the maximum expected swing rate.

Manufacturer R's relay can be set to use either a single or double blinder scheme. The single blinder application is described above and the double blinder scheme is described here.

The relay makes the trip decision when the swing locus first crosses the inner blinder characteristic. Therefore, the separation angle at this point is critical to the secure operation of the scheme. If the angle is too small (large blinder setting), the generator may trip on a recoverable swing. Transient stability studies are usually required to confirm satisfactory relay settings.

TABLE A-4. Manufacturer R Double Blinder OOS Relay Settings

Relay Elements	Manufacturer's Typical Value	Relay Setting
78REV	1½ - 2 times X_T	2.50 Ω-sec
78FWD	2 - 3 times X'd	5.00 Ω-sec
78R1 Outer Blinder	Outside the mho circle > ½ (78REV + 78FWD)	4.00 Ω-sec
78R2 Inner Blinder	≥ 5% of MAX(78REV, 78FWD) and $\leq \frac{1}{2}(X'd+X_T+X_{sys})\tan(\theta - \alpha/2)$ where $\theta = 90°$ and $\alpha \approx 120°$	0.78 Ω-sec
78D	OOS delay	0.042 sec

78TD	Trip delay timer after mho circle exit	0.042 sec
78TDURD	Minimum trip duration timer	3.0 cycles
50ABC	Positive sequence current supervision for OOS element	0.25 amp
OOSTC	Torque control for OOS element	1

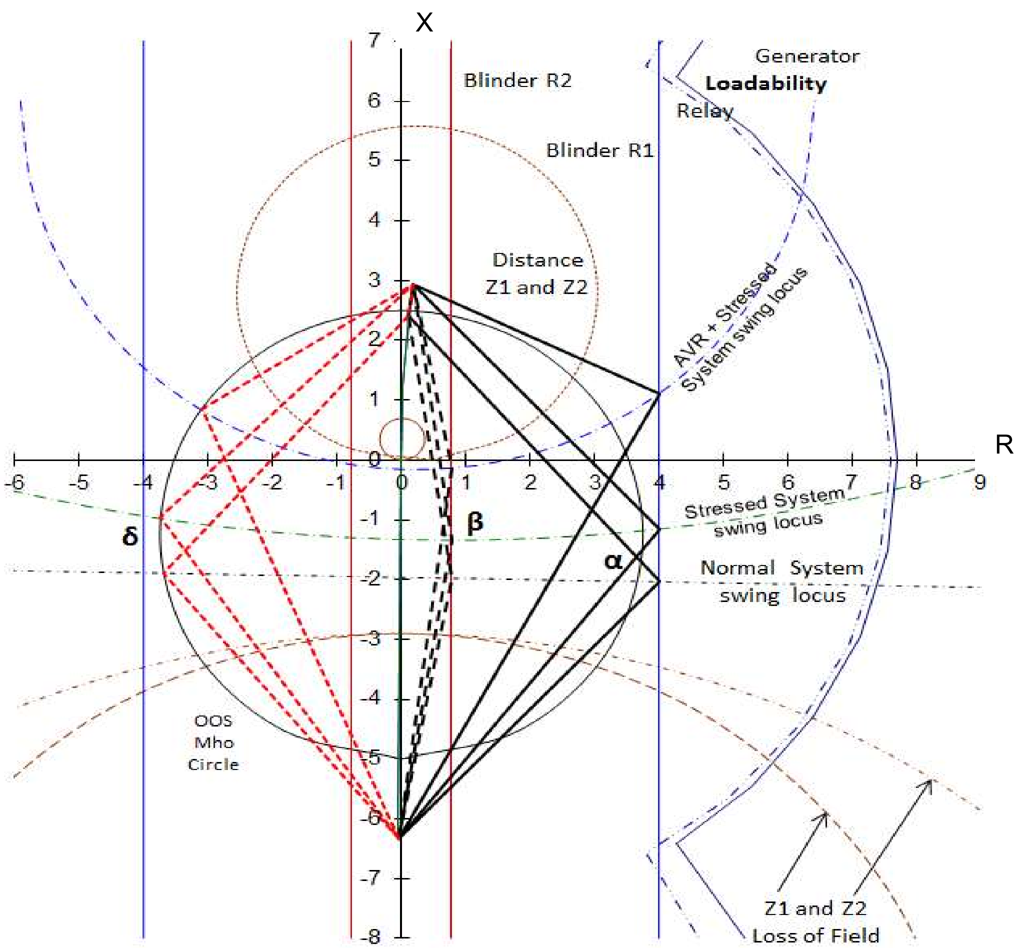

Fig. A-4. Double Blinder OOST and other relay impedance characteristics for Manufacturer R

Fig. A-4 illustrates the impedance elements for manufacturer R's relay when using the double blinder OOS scheme and those elements relationship to the band of system swing loci. The three system swing loci configurations, angle δ, the Loss of Field, backup distance impedance and loadability are the same as described above for the single blinder scheme in Fig. A-3. The separation angles α and β are similar to and calculated in the same way as the single blinder scheme, except that angle α is associated with the outer, R1 blinder and angle β is associated with the inner, R2 blinder.

The double blinder scheme is substantially more complex than the single blinder scheme because the combined timer and blinder settings are critical to determining whether an event is interpreted as a fault or a swing. The engineer must determine a swing rate to interpret as a system swing (slower), versus a fault (faster). This generally requires transient stability modeling, but the discussion under System Swing Characteristic Rates earlier in this paper on stability modeling provides some perspective regarding reasonably expected swing rate values. For this example, the scheme will interpret swing rates up to 4 Hz as system swings, and faster "swings" as faults for which the OOS functions will not operate.

78FWD, 78REV and 78Z1

The mho circle is specified differently than for the single blinder scheme, though using the same setting element names. The scheme logic requires the outer blinder to be outside the mho circle and the inner blinder inside the mho circle. To establish the outer blinder outside of the mho circle, the 78FWD element setting is reduced (compared to the single blinder scheme) to 5.0 Ω-secondary. While this is smaller than suggested by the manufacturer, Fig. A-4 shows that it still provides significant margin below the "Normal System swing locus" curve having significant overlap with the loss of field characteristics, so that no part of the generator impedance characteristic plane is left unprotected.

78R1 and 78R2 Blinder Impedances

This relay uses the 78R1 and 78R2 elements for the outer and inner blinders respectively with the corresponding blinders on the left the mirror images of those on the right. The setting calculation process approximates the requirements for a typical transmission line OOS relay.

The outer blinder should be set with no encroachment on the generator loadability characteristic so that the 78D timer will not start and time out during either normal or emergency loading conditions. In this example generator loadability imposes a maximum setting of about 4.28 Ω-secondary. The minimum outer blinder value should be outside of the mho circle, or at least ½(78REV + 78FWD) = 3.75 Ω-secondary. The outer blinder setting illustrated here is about half way in between at 78R1 = 4.0 Ω-secondary. A relay loadability characteristic is shown, but not used.

The maximum inner blinder should correspond to angle $\beta \approx 120°$ or larger for the most limiting system swing locus, not more than 2.6 Ω-secondary if using the normal system swing locus, the same result as for the single blinder scheme. The minimum blinder setting is 5% of the maximum of the 78FWD or 78REV settings. The actual inner blinder setting may be substantially influenced by the results of stability studies, since the essential requirement is to only trip for unstable swings. The angle $\beta \approx 120°$ is a good rule of thumb to achieve this result, but a blinder setting resulting in a larger angle (78R2 < 2.6 Ω in this case) provides additional margin. In this case a value of 78R2 = 0.78 Ω-secondary is used. At this blinder setting, the minimum $\beta \approx 139.5°$ for the "AVR + Stressed System swing locus" and a stable swing should be virtually impossible. This blinder setting is also substantially influenced by the maximum swing rate corresponding to the 78D timer setting.

78D

This timer setting is calibrated for the generator maximum swing rate as the apparent impedance passes between the outer and inner blinders. If the system swing locus passes between the blinders faster that the timer setting, the event is interpreted as a fault rather than a swing and the relay OST function does not operate. This is similar to the way many concentric characteristic schemes work for both generator and transmission relays.

In addition, a secure timer setting will be longer than the maximum pickup time for the relay to calculate impedance element reach, as described above for the single blinder scheme. For this relay a secure timer setting is at least 78D = 2.5 cycles, which is used here. Then the minimum calculated swing rate is 4.02 Hz (1447°/sec) which meets the swing rate target.

Different blinder settings can substantially affect the calculated angle β and the swing rate and whether these targets are satisfied. For example, if the inner blinder had been set at 1.5 Ω and all other settings were unchanged, then β ≈ 117° for the "AVR + Stressed System" swing locus and the calculated swing rate would have been about 2356 Hz (920°/sec). Stability studies might determine that these settings are acceptable, but the result would still be a lower margin for the scheme to avoid trips on potentially stable swings.

78TD
This relay characteristic is designed to always trip after exiting the mho circle. The 78TD timer adds time after exiting the mho circle before issuing the OOS trip. The maximum angle δ = 100.4° when exiting to the left, so additional delay helps ensure that the trip only occurs when the breaker opening will be within the circuit breaker rating (δ ≤ 90°). In this case, with the same mho circle, add some time after the mho exit based on the minimum expected swing rate of the generator swinging against the system,

78TD = (δ – 90°) / (minimum swing rate)

= (100.4° - 90°) / (360°/sec) = 0.02889 second

= 1.73 cycle (round up to next half cycle, 78TD = 2.0 cycles).

If the scheme were to operate on what would otherwise have been a stable swing, it would initiate the OST as the swing exited the right side of the mho circle, rather than the left. While this would be an undesirable misoperation, it would still be important that the breaker not flash over internally when attempting to open. In this case the maximum angle δ = 102.6° on the right side of the characteristic and

78TD = 2.10 (round up to 2.5 cycles).

Choose the longer of these values, 78TD = 2.5 cycles.

Finally, check the breaker opening angle at maximum swing rate, δ = 102.6° - 0.04167 sec X 1440°/sec = 42°, which adds to the safety margin for the breaker.

78TDURD
This is the same philosophy and calculation as for the single blinder scheme. Set 78TDURD = 3.0 cycles.

50ABC
This is the same philosophy and calculation as for the single blinder scheme. Typically it does no harm to leave this setting at the minimum, 50ABC = 0.25 amp.

OOSTC
This is the same philosophy and calculation as for Manufacturer R's single blinder scheme. In this case, no additional supervision is used, so OOSTC = 1.

A.4 Double Lens Scheme

The double lens scheme setting calculations described here have the same functionality as for the same manufacturer's scheme used for OOS functions applied on transmission lines. The double lens impedance elements are set in conjunction with on one or more timers which represent the separation angle difference between inner and outer impedance characteristics at the maximum expected swing rate.

Manufacturer E's relay can be configured to use either a double or triple lens scheme. The double lens application is described here.[3][3] These calculations are based on the mho circle characteristic shape.

The relay trip decision requires the swing locus to first cross the outer lens, then cross the inner lens at least Delay 1 time after crossing the outer lens, then remain within the inner lens for at least Delay 3 time.

As with other schemes that use multiple impedance characteristics, the separation angle when the swing locus crosses the inner characteristic is critical to the secure operation of the scheme. If the angle is too small (large resistive reach, $\delta < \sim 120°$), the generator may trip on a recoverable swing.

Settings for the impedance characteristics and delay timers are all interrelated. Since this relay uses several timer levels for added security, the setting calculations are relatively complex compared to some other characteristics. The maximum expected swing rate of the swing locus through the relay characteristic helps to establish values for these parameters.

TABLE A-5. Manufacturer E Double Lens OOS Relay Settings

Relay Elements	Manufacturer's Typical Value	Relay Setting
Power Swing Shape	Manufacturer E allows using either Mho circle or Quadrilateral based characteristic shapes. Choose Mho to use the Lens shape	Mho
Power Swing Mode	2 or 3 characteristics	2
Power Swing Supv	Positive sequence current supervision for OOS element	0.25 amp
Power Swing Fwd Reach	Generally $Z > Z_{system} + Z_{GSU}$	4.40 Ω-sec
Power Swing Fwd RCA	Angle of $Z_{system} + Z_{GSU}$	88°
Power Swing Rev Reach	Generally $Z > X'd$	7.60 Ω-sec

Power Swing Rev RCA	Angle of $r_a + j\,X'd$	89°
Power Swing Outer Limit Angle	Defines outer characteristic; > 90° is a lens, = 90° is a circle, < 90° is a tomato shape.	100°
Power Swing Inner Limit Angle	Defines inner characteristic; < 90° is a lens, = 90° is a circle, < 90° is a tomato shape.	140°
Delay 1	Swing detected if locus stays between characteristics ≥ Delay 1	30 msec
Delay 2	Not used for double lens scheme	NA
Delay 3	Trip decision set if locus stays inside inner characteristic ≥ Delay 3	68 msec
Delay 4	Minimum duration required for tripping with locus between inner and out characteristics after leaving the inner characteristic	30 msec
Power Swing Seal-in Delay	Used if trip mode = Early; holds in OS trip following Delay 3	59 msec
Power Swing Trip Mode	Early for instantaneous trip after completing logic sequence. Delayed trip initiates trip when the locus leaves the outer characteristic.	Delayed

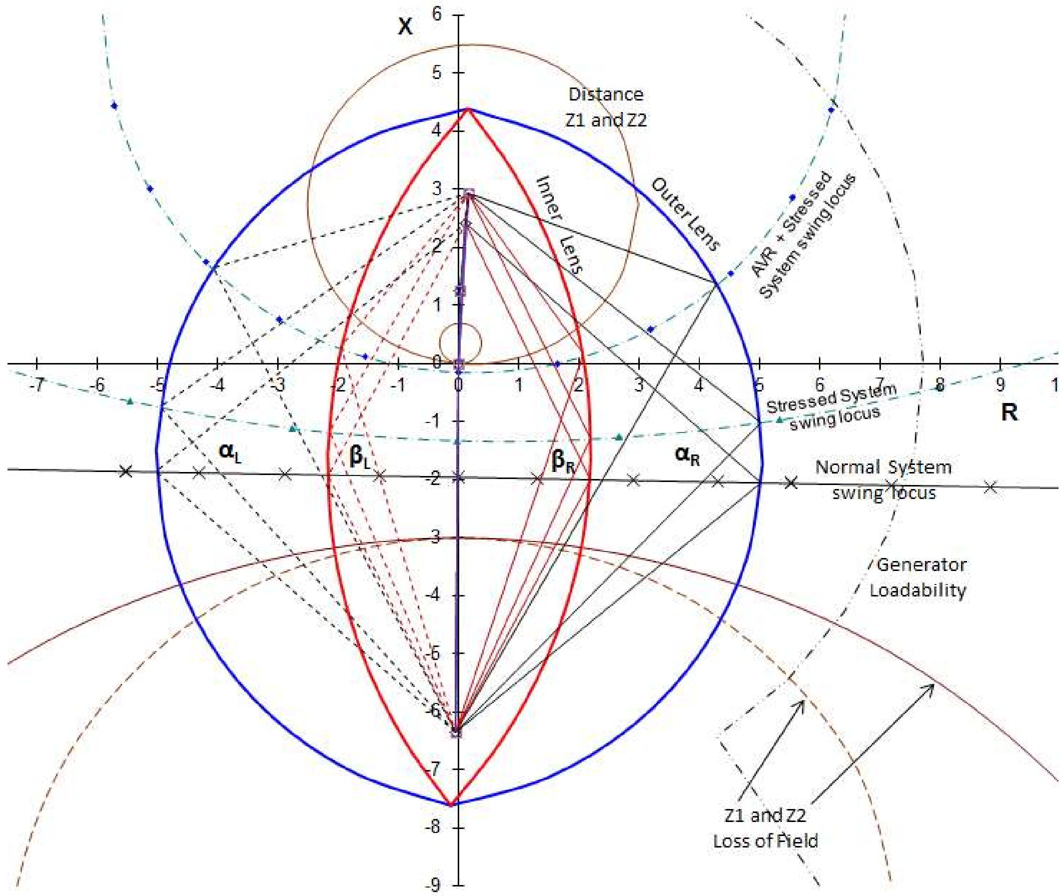

Fig. A-5. Double Lens OOS and other relay impedance characteristics for Manufacturer E

Fig. A-5 illustrates the impedance elements for manufacturer E's relay when using the double lens OOS scheme and those elements relationship to the band of system swing loci. The three system swing loci configurations, the Loss of Field, backup distance impedance and loadability are the same as described above for the single and double blinder schemes in Fig. A-3 and Fig. A-4. The separation angles α and β are similar to and calculated in the same way as the single and double blinder schemes, except that angle α is associated with the outer lens and angle β is associated with the inner lens. Corresponding angles are shown on both the left and right.

The double lens scheme is somewhat more complex than the double blinder scheme. The double lens includes three or four timers in addition to the impedance characteristics. The timers must be set to accommodate the maximum expected swing rate corresponding to each segment of the swing locus between different parts of the lens characteristics.

As with the double blinder, the engineer must determine a swing rate to interpret as a system swing (slower), versus a fault (faster). This generally requires transient stability modeling, but the discussion under System Swing Characteristic Rates above provides some perspective regarding reasonably expected swing rate values. For this example, the scheme will interpret swing rates up to at least 4 Hz as system swings, and faster “swings” as faults for which the OOS functions will not operate.

POWER SWING SHAPE

The MHO shape is specified to select the lens characteristic; the lens is composed of offset segments of mho circle characteristics. The alternate setting is for a Quadrilateral shape, which provides characteristics more similar to the double blinder, but without the Mho circle

POWER SWING MODE

Choose either the Early or Delayed trip for the OST function. An Early trip occurs as the swing locus exits the inner lens. The delayed trip occurs as the swing locus exits the outer lens. This example uses the Delayed trip.

POWER SWING SUPERVISION

This is a positive sequence current that supervises operation of the OOS characteristic. This is the same philosophy and calculation as for manufacturer R’s single or double blinder schemes. Typically it does no harm to leave this setting at the minimum, 0.05 per unit for a 5 amp relay (0.25 amp for a 5 amp relay).

POWER SWING FWD REACH, POWER SWING FWD RCA

These elements specify the length and characteristic angle of the forward reaching impedance. The length should be at least the impedance of the generator step up transformer, but may be larger to ensure coverage for stressed system conditions, including AVR action. The RCA should closely match the system impedance angle at the set length. This example uses a reach (4.4 Ω) of 1.5 times the GSU and system impedance and the RCA rounded off to the nearest whole degree (88°).

POWER SWING REV REACH, POWER SWING REV RCA

These elements specify the length and characteristic angle of the reverse reaching impedance. The length should be approximately the impedances of the generator transient reactance. The RCA should closely match the combined impedance angle of the armature resistance and transient reactance. This example uses a reach (7.6 Ω) or 1.2 times the generator transient reactance and the RCA rounded off to the nearest whole degree (89°).

POWER SWING OUTER LIMIT ANGLE, POWER SWING INNER LIMIT ANGLE

These angles effectively establish the resistive reach of each lens. Angles > 90° result in a lens shape, = 90° is a circle, and < 90° is a tomato shape. They are an approximation of the separation angle for the characteristic. However, use of forward and reverse impedance settings larger than the minimum suggested values will also result in actual separation angles somewhat smaller than the limit angle setting.

The outer angle must be specified to avoid encroachment on the generator loadability characteristic. This example uses 100°.

The inner angle must be specified so that only unstable swings will enter the inner characteristic, generally >=120° for the actual separation angle. In this example, a setting of 140° results in a minimum separation angle of about 125° for the AVR plus stressed System swing locus.

DELAY 1, DELAY 2, DELAY 3, DELAY 4, POWER SWING SEAL-IN DELAY
Secure timer settings will be longer than the maximum pickup time for the relay to calculate impedance element reach, as described above for the single blinder scheme. For this relay a secure timer setting is about 1 cycle, which is suggested as the minimum value for each timer.

The impedance locus must take at least Delay 1 to cross from the outer to the inner lens. Events that take longer than Delay 1 identify the event as a swing and establish OOS blocking. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 1 = 30 msec, resulting in a calculated maximum swing rate of 4.06 Hz (1463°/sec).

Delay 2 is used only for manufacturer E's triple lens scheme.

The impedance locus must take at least Delay 3 after it enters and before it exits the inner lens to continue to be interpreted as a system swing. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 3 = 68 msec, resulting in a calculated maximum swing rate of 1458°/second, or 4.05 Hz. This is the longest delay which will still result in reaching the targeted swing rate of 4 Hz, so that a slightly shorter delay would generally be acceptable. For example a shorter setting of 60 msec would result in a maximum calculated swing rate of 5.89 Hz (1652°/sec).

The impedance locus must take at least Delay 4 after it exits the inner lens and before exiting the outer lens to continue to be interpreted as a system swing. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 4 = 30 msec, resulting in a calculated maximum swing rate of 4.06 Hz (1463°/sec). This is the longest delay which will still result in reaching the targeted swing rate of (4 Hz), so that a slightly shorter delay would generally be acceptable. For example a shorter setting of 25 msec (not less than 1 cycle) would result in a maximum calculated swing rate of 4.88 Hz (1756°/sec).

If the user specifies an Early OOS trip, the trip asserts as the swing locus leaves the inner lens, assuming the scheme logic is satisfied. The Power Swing Seal-in Delay specifies the time that the trip stays asserted following Delay 3. This timer uses a similar philosophy as for the single or double blinder scheme, above. The setting should be about 1.5-2 times the breaker opening time, but shorter than the breaker failure time. Set the seal-in delay to 50 msec (3.0 cycles).

A.5 Triple Lens Scheme

The triple lens scheme setting calculations described here have the same functionality as for the same manufacturer's scheme used for OOS functions applied on transmission lines. The triple lens impedance elements are set in conjunction with four timers which represent the separation angle difference between inner and outer impedance characteristics at the maximum expected swing rate. Manufacturer E's relay can be configured to use either a double or triple lens scheme. The double lens application is described above and the triple lens is described here.[3][3] These calculations are based on the mho circle characteristic shape (blinders are also available).

The relay trip decision requires the swing locus to first cross the outer lens, then cross the middle lens, at least Delay 1 time after crossing the outer lens, remain between the middle and inner lens for at least Delay 2 time, then remain within the inner lens for at least Delay 3 time.

As with other schemes that use multiple impedance characteristics, the separation angle when the swing locus crosses the inner characteristic is critical to the secure operation of the scheme. If the angle is too small (large resistive reach, $\delta < \sim 120°$), the generator may trip on a recoverable swing.

TABLE A-6. Manufacturer E Triple Lens OOS Relay Settings

Relay Elements	**Manufacturer's Typical Value**	**Relay Setting**
Power Swing Shape	Manufacturer E allows using either Mho circle or Quadrilateral based characteristic shapes. Choose Mho to use the Lens shape	Mho
Power Swing Mode	2 or 3 characteristics	3
Power Swing Supv	Positive sequence current supervision for OOS element	0.25 amp
Power Swing Fwd Reach	Generally $Z > Z_{system} + Z_{GSU}$	3.16 Ω-sec
Power Swing Fwd RCA	Angle of $Z_{system} + Z_{GSU}$	88°
Power Swing Rev Reach	Generally Z > X'd	6.34 Ω-sec
Power Swing Rev RCA	Angle of $r_a + j X'd$	89°
Power Swing Outer Limit Angle	Defines outer characteristic; > 90° is a lens, = 90° is a circle, < 90° is a tomato shape.	70°
Power Swing Middle Limit Angle	Defines middle characteristic	105°
Power Swing Inner Limit Angle	Defines inner characteristic	140°
Delay 1	Swing detected if locus stays between characteristics ≥ Delay 1	23 msec
Delay 2	Swing detected if locus stays between outer and middle characteristics ≥ Delay 1 and between middle and inner characteristics ≥ Delay 2	24 msec
Delay 3	Trip decision set if locus stays inside inner characteristic ≥ Delay 3	54 msec
Delay 4	Minimum duration required for tripping with locus between inner and out characteristics after leaving the inner characteristic	48 msec
Power Swing Seal-in	Used if trip mode = Early; holds in OS trip	N/A

Delay	following Delay 3	
Power Swing Trip Mode	Early for instantaneous trip after completing logic sequence. Delayed trip initiates trip when the locus leaves the outer characteristic.	Delayed

Settings for the impedance characteristics and delay timers are all interrelated. Since this relay uses several timer levels for added security and to allow both PSB and OOST functions, the setting calculations are complex compared to some other characteristics. The maximum expected swing rate of the swing locus through the relay characteristic helps to establish values for these parameters.

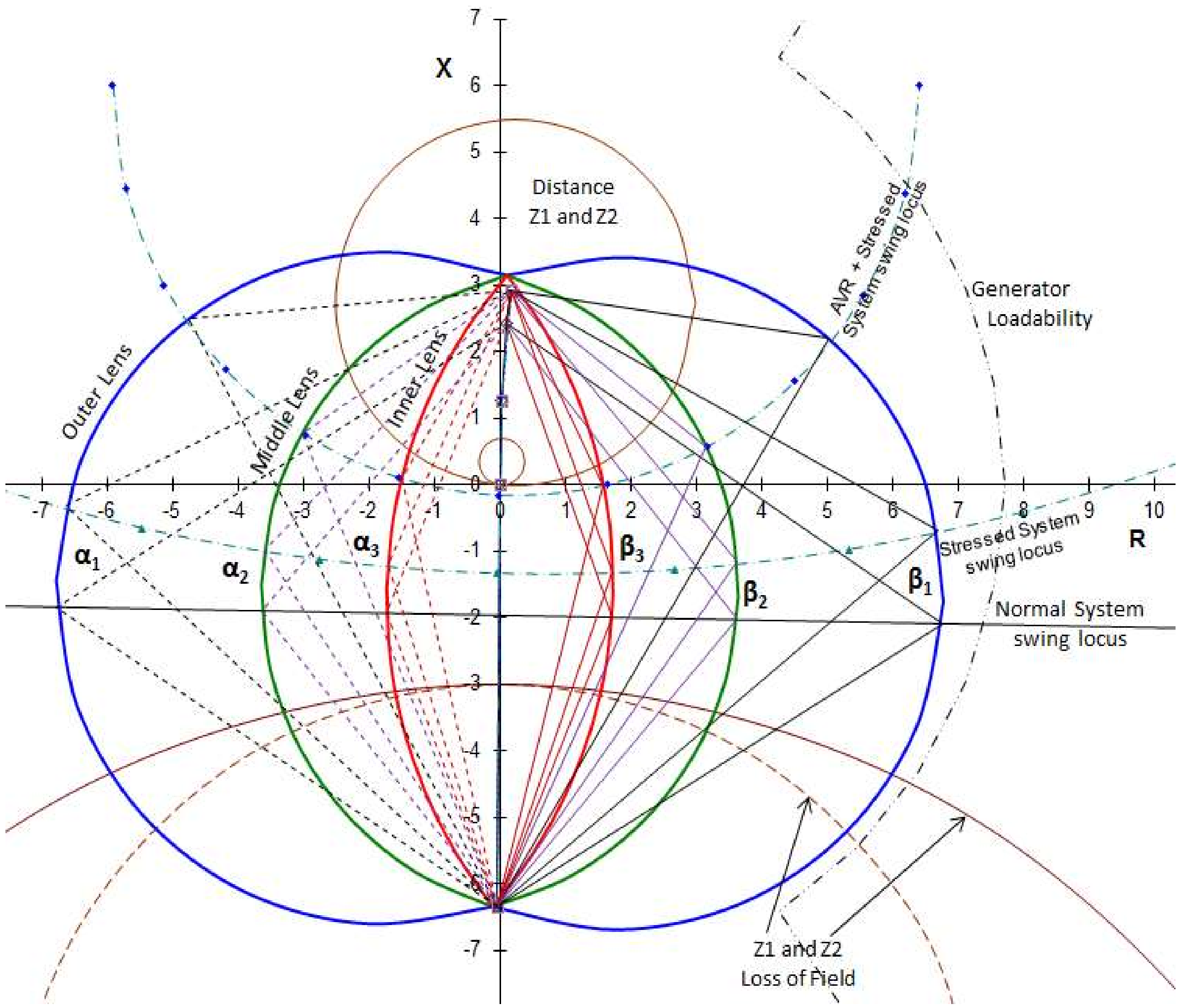

Fig. A-6: Triple Lens OOS and other relay impedance characteristics for Manufacturer E

Fig. A-6 illustrates the impedance elements for manufacturer E's relay when using the triple lens OOS scheme and those elements relationship to the band of system swing loci. The three system swing loci configurations, the Loss of Field, backup distance impedance and loadability are the same as described above for the single and double blinder and double lens schemes in Fig. A-3 – A-5. The separation angles $\alpha_{1\text{-}3}$ and $\beta_{1\text{-}3}$ (outer, middle, inner lenses respectively) are similar to and calculated in the same way as the single and double blinder and double lens schemes, except that angles $\alpha_{1\text{-}3}$ in this example is on the left and angles $\beta_{1\text{-}3}$ are on the right.

The triple lens scheme is the most complex of all the schemes described in this paper. The triple lens uses at least four timers in addition to the impedance characteristics. The timers must be set to accommodate the maximum expected swing rate corresponding to each segment of the swing locus between different parts of the lens characteristics. For this example, the scheme interprets swing rates up to at least 4 Hz (1440°/sec) as system swings, and faster "swings" as faults for which the OOS functions will not operate.

POWER SWING SHAPE
The MHO shape is specified to select the lens characteristic; the lens is composed of offset segments of mho circle characteristics. The alternate setting is for a QUADrilateral shape, which provides rectangular characteristics more similar to blinders.

POWER SWING MODE
Choose either the Early or Delayed trip for the OST function. An Early trip occurs as the swing locus exits the inner lens. The delayed trip occurs as the swing locus exits the outer lens. This example uses the Delayed trip.

POWER SWING SUPERVISION
This is a positive sequence current that supervises operation of the OOS characteristic. This is the same philosophy and calculation as for manufacturer E's double lens scheme.

POWER SWING FWD REACH, POWER SWING FWD RCA
These elements specify the length and characteristic angle of the forward reaching impedance. The length should be at least the impedance of the generator step up transformer, but may be larger to ensure coverage for stressed system conditions, including AVR action. The RCA should generally closely match the system impedance angle at the set length. This example uses a reach (3.16 Ω) of 1.0 times the GSU and system impedance and the RCA rounded off to the nearest whole degree (88°).

POWER SWING REV REACH, POWER SWING REV RCA
These elements specify the length and characteristic angle of the reverse reaching impedance. The length should be approximately the impedances of the generator transient reactance. The RCA should closely match the combined impedance angle of the armature resistance and transient reactance. This example uses a reach (6.34 Ω) equal to the generator transient reactance and the RCA rounded off to the nearest whole degree (89°).

POWER SWING OUTER LIMIT ANGLE, POWER SWING MIDDLE LIMIT ANGLE, POWER SWING INNER LIMIT ANGLE
These angles effectively establish the resistive reach of each lens. Angles > 90° result in a lens shape, = 90° is a circle, and < 90° is a tomato shape. The limit angles are the actual relay

settings. The separation angles are the α and β angles illustrated in Fig. A-6. These separation angles are approximately the same as the limit angles, but vary because the system swing loci change with changing system conditions represented. Use of forward and reverse impedance settings larger than the minimum suggested values will also result in actual separation angles somewhat smaller than the limit angle setting.

The outer angle must be specified to avoid encroachment on the generator loadability characteristic. This eample uses 70°, so that the outer characteristic illustrated in Fig. A-6 does not encroach on the generator loadability characteristic.

The middle angle is specified to provide out-of-step blocking for other relay impedance elements (held in for Power Swing Reset Delay 1 after the impedance exits the outer characteristic). This example uses 105°. This application is not set up for PSB, so the setting was set approximately midway between the inner and outer limit angles.

The inner angle must be specified so that only unstable swings will enter the inner characteristic, with a separation angle greater than the critical clearing angle, δ_C, generally ≥120°. A larger angle will slightly delay an EARLY trip, but also provide added security against tripping during a stable swing. In this example, a setting of 140° results in a minimum separation angle of about 138° for the Normal System swing locus.

DELAY 1, DELAY 2, DELAY 3, DELAY 4, POWER SWING SEAL-IN DELAY

Secure timer settings will be longer than the maximum pickup time for the relay to calculate impedance element reach, as described above for the single blinder scheme. For this relay a secure timer setting is about 1 cycle, which is suggested as the minimum value for each timer.

The impedance locus must take at least Delay 1 to cross from the outer to the inner lens. Events that take longer than Delay 1 identify the event as a swing and establish OOS blocking. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 1 = 23 msec, resulting in a calculated maximum swing rate of 4.14 Hz (1492°/sec). All of the calculated Delay 1 – Delay 4 results are the longest delays which will still result in reaching the targeted swing rate of 4 Hz.

The impedance locus must take at least Delay 2 in between the middle and inner lenses to continue to be interpreted as a system swing. This example uses Delay 2 = 24 msec, resulting in a calculated maximum swing rate of 4.06 Hz (1462°/second).

The impedance locus must take at least Delay 3 after it enters and before it exits the inner lens to continue to be interpreted as a system swing. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 3 = 54 msec, resulting in a calculated maximum swing rate of 4.07 Hz (1466°/second).

The impedance locus must take at least Delay 4 after it exits the inner lens and before exiting the outer lens to continue to be interpreted as a system swing. Shorter events (faster swing rates) are treated as faults and result in the OOS function not operating. This example uses Delay 4 = 48 msec, resulting in a calculated maximum swing rate of 4.02 Hz (1449°/second).

If the user specifies an Early OOS trip, the trip asserts as the swing locus leaves the inner lens, assuming the scheme logic is satisfied. The Power Swing Seal-in Delay specifies the time that the trip stays asserted following Delay 3. This timer uses a similar philosophy as for the double lens scheme, above. The setting, when used, should be longer than the breaker opening time, but shorter than the breaker failure time. If Early OOS Trip is used, set the seal-in delay to 50 msec (3.0 cycles).

A.6 Concentric Circle Scheme

The concentric circle scheme setting calculations described here have similar functionality as for manufacturer E's double lens scheme described above. The concentric circle impedance elements are set in conjunction with three timers which represent the separation angle difference between inner and outer impedance characteristics at the maximum expected swing rate. This description is intended as a generic description for an electromechanical relay scheme, but may also apply to appropriate electronic and older microprocessor relay schemes

The relay trip decision requires the swing locus to first cross the outer circle, then cross the inner circle at least Time 1 time after crossing the outer circle, remain within the inner circle for at least Time 2 time, and finally remain between the circles on the way out of the inner and outer circles for at least Time 3. Though this scheme is named for concentric elements, the centers of the impedance circles are not required to actually coincide. The Concentric Circle characteristics are illustrated in Fig. A-7.

The outer circle maximum reach is limited primarily by the loadability characteristic of the generator.

The inner circle settings are often a compromise between secure and dependable operation. As with other schemes that use multiple impedance characteristics, the separation angle when the swing locus crosses the inner characteristic is critical to the secure operation of the scheme. If the angle is too small ($\delta < \sim 120°$ with a large inner circle diameter), the generator may trip on an otherwise recoverable swing.

An unstable swing is identified when the swing locus crosses the inner circle at least Timer 1 delay after crossing the outer circle. If an unstable swing crosses the outer circle, but then stays between the two circles (beyond the reach of the inner circle), eventually exiting on the opposite side of the outer circle, the out-of-step tripping logic will not operate, since no time was spent inside the inner circle. The OOS tripping desired objective is most readily guaranteed by setting the inner circle to cover the forward and reverse reaches of the total system characteristic impedance. Then even stressed transmission system conditions such as line outages and generator AVR action that "push" the swing locus into or beyond the GSU impedance characteristic still result in an unstable swing locus crossing into the inner circle. However, smaller settings are not unusual to achieve a larger separation angle.

TABLE A-7. Concentric Circle OOS Relay Settings

Relay Elements	**Manufacturer's Typical Value**	**Relay Setting**
Z_{outer} Fwd	Object: $Z > Z_{system} + Z_{GSU} + 2$	6.00 Ω-sec
Z_{outer} Rev	Object $Z > \sim Z_{GEN} + 2$	7.00 Ω-sec

Z_{outer} Angle	Angle of $Z_{system} + Z_{GSU} + Z_{GEN}$	90°
Z_{inner} Fwd	Object: $Z \sim Z_{system} + Z_{GSU}$	1.50 Ω-sec
Z_{inner} Rev	Object; $Z \sim Z_{GEN} \sim X'd$	3.50 Ω-sec
Z_{inner} Angle	Angle of $Z_{system} + Z_{GSU} + Z_{GEN}$	90°
Timer 1	Swing detected if swing locus stays between circles ≥ Time 1	3 cycles
Timer 2	Trip decision enabled if locus stays inside inner circle ≥ Time 2	6 cycles
Timer 3	Minimum duration required to initiate tripping with locus between inner and outer circle after leaving the inner circle	3 cycles

Settings for the impedance circles and delay timers are all interrelated. Since this relay uses essentially the same logic as the double lens, the setting calculation methods are also similar. The maximum expected swing rate of the impedance locus through the relay characteristic helps to establish values for these parameters. The primary differences are that the outer circle generally will have a larger resistive reach than for the lens and the timers often have fixed values. These factors limit the flexibility, and can limit the applicability of this scheme to on generators which experience relatively fast swing rates.

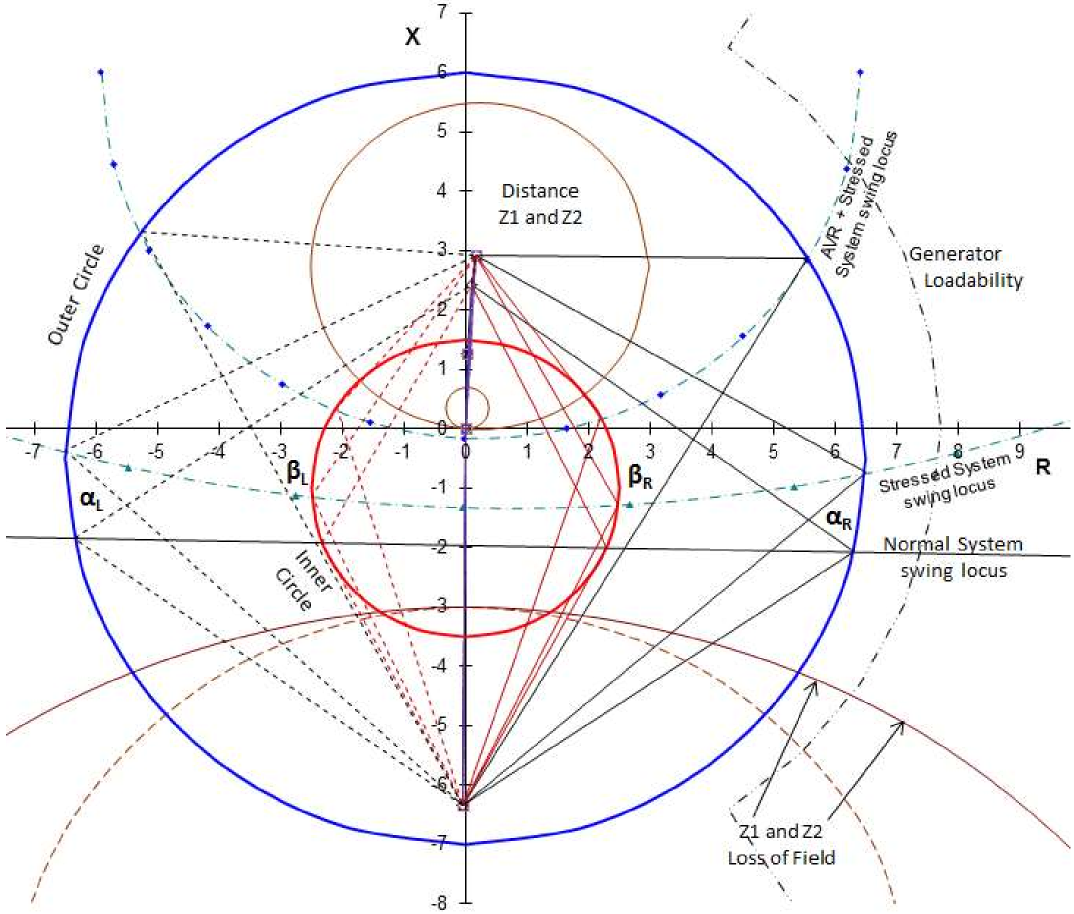

Fig. A-7. Concentric circle OOS and other relay impedance characteristics for a generic electromechanical scheme

Fig. A-7 illustrates the impedance elements for the generic concentric circle relay OOS scheme and those elements relationship to the band of system swing loci. The three system swing loci configurations, the Loss of Field, backup distance impedance and loadability are the same as described above for the other schemes. The separation angles α and β are similar to other schemes using two characteristics, except illustrated here with right (R) and left (L) subscripts.

The concentric circle scheme can be more difficult to obtain acceptable settings than the double lens scheme because the circle characteristics often provide less flexibility in achieving desirable separation angles and fixed timers often provide a smaller range of appropriate swing rates. Otherwise, the double lens and concentric circle schemes use very similar logic.

As with the double lens, the concentric circle timers should be set to accommodate the maximum expected swing rate corresponding to each segment of the swing locus between different parts of the circle characteristics. When fixed delay timers are used, these tend to put a relatively low upper limit on the swing rate that the scheme can reliably detect, and therefore potentially limiting the applicability of the scheme.

As with the double blinder and lens, the engineer must determine a swing rate to interpret as a system swing (slower), versus a fault (faster). In this example, transient stability modeling is perhaps even more critical than for other schemes because the illustrated settings result in a swing rate of just over 2.78 Hz (1000°/sec), the inner circle barely covers the GSU and loss of field impedances, but results in a separation angle of barely 120°.

Z_{outer} Fwd, Z_{outer} Rev, Z_{outer} Angle

These settings specify the forward and reverse reaches and characteristic angle of the outer impedance circle. The setting of each element should be at least 2 Ω larger than the inner circle. The Z_{outer} Angle should closely match the combined impedance angles of the GSU and system impedance. This example uses 90°.

Z_{inner} Fwd, Z_{inner} Rev, Z_{inner} Angle

These elements specify the forward and reverse reaches and characteristic angle of the inner impedance circle. Z_{inner} Fwd should cover the combination of $Z_{system} + Z_{GSU}$. Z_{inner} Rev should cover the generator impedance, approximately X'd. In this case the impedance circle had to be set smaller than these objectives to ensure that the minimum separation angle as the swing locus crosses the inner circle is at least 120° (121.5° on the left and 124.7° on the right).

The Z_{inner} Angle should closely match the combined impedance angles of the GSU and system impedance. This example uses 90°.

Timer 1, Timer 2, Timer 3

These timers for electromechanical schemes are often fixed, e.g. 3, 6, and 3 cycles respectively. The user's capability for adjusting the scheme characteristics is limited to the impedance settings, both to achieve appropriate impedance coverage and swing rates. In this case, the calculated maximum swing rates for each segment over the range of swing loci illustrated in Fig. A-7 are about

$$\text{Swing Rate 1} = (\beta_R - \alpha_R)/\text{Timer 1} = (124.7° – 70.7°)/0.05 \text{ sec} = 1049°/\text{sec}$$

$$\text{Swing Rate 2} = (360° - \beta_L – \beta_R)/\text{Timer 2} = (360° - 125.4° – 125.4°)/0.10 \text{ sec} = 1091°/\text{sec}$$

$$\text{Swing Rate 3} = (\beta_L - \alpha_L)/\text{Timer 3} = (121.5° – 69.1°)/0.05 \text{ sec} = 1049°/\text{sec}$$

These calculated swing rates do not achieve the target swing rates of 4 Hz.

These impedance and swing rate results may still be acceptable, but only if transient stability studies determined both that the actual maximum generator swing rate does not exceed these calculated values and that the impedance circles provide satisfactory coverage of the actual swing locus.

APPENDIX B POSSIBLE FUTURE SCHEMES

B.1 Equal Area Criterion Method

References [16][16], [17][17] describe the Equal Area Criterion (EAC) method for relaying purposes. A detailed description of the EAC method can be found in classical power system literature such as [18][18], [19][19]. Fig. B-1 shows the test system used for the studies. For the purpose of explaining the EAC, the machine is assumed to be of the round rotor type (ie $X_d = Xq$). However, the Alternative Transient Program (ATP) simulations shown later are done for a salient-pole type machine to demonstrate that EAC is applicable for both round rotor and salient-pole type machine.

In Fig. B-1, the power transfer from the generator to the infinite bus is given by the power-angle characteristic below:

$$P = \frac{E' \cdot E_B}{X} \sin \delta$$

where:

X : Total transfer impedance between generator and the infinite bus

δ : Angle between generator rotor and the infinite bus

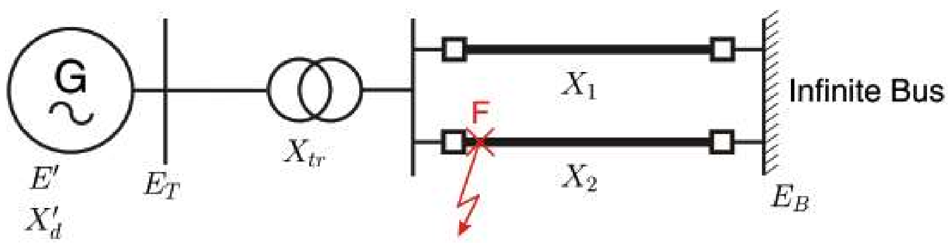

Fig. B-1. Sample system to explain the EAC concept

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[16] Kimbark, E.W., “Power System Stability – Volume I – Elements of Stability Calculations”, Ch. IV, John Wiley & Sons, 1948.

[17] Centeno, V., Phadke, A., Edris, A., Benton, J., Gaudi, M., and Michel, G, “An Adaptive Out-of-Step Relay,” IEEE Transactions on Power Delivery, vol. 12, no. 1,pp. 61 -71, 1997.

[18] Horowitz, S. H., and Phadke, A. G., “Power System Relaying”, 3rd Ed. John Wiley & Sons, New York, 2008.

[19] Grainger, J. J., and Stevenson, W. D. Jr., “Power Systems Analysis”, McGraw-Hill, New York, 1994.

The transfer impedance *X* is not constant and will change in Fig. B-1 depending on the topology of the system. The transfer impedance *X* is also affected during a fault condition. Fig. B-2 shows the resulting power–angle characteristics for these different conditions.

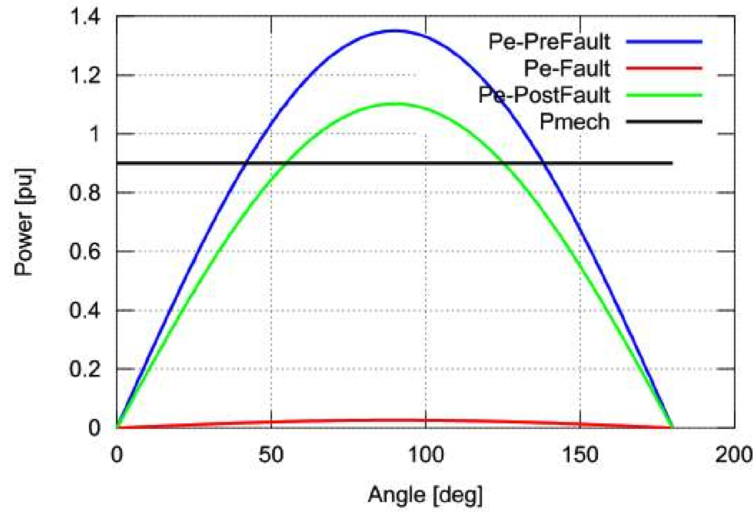

Fig. B-2. Power-angle characteristics before, during and after a fault condition

For a 3-phase fault at point F with duration time equal to the critical clearing time, the generator follows a trajectory in the power-angle plane as shown in Fig. B-3, where the area between the mechanical power P_{mech} and the electrical power P_e-Fault during fault correspond to the acceleration of the generator. The area above the mechanical power P_{mech} and the electrical power P_e-Post Fault correspond to the deceleration of the generator. A small fault resistance (0.0001 ohms) is used in the simulations; as a result, during fault P_e-Fault is not equal to zero. The EAC method states that stability is achieved if the decelerating area is larger or equal to the accelerating area.

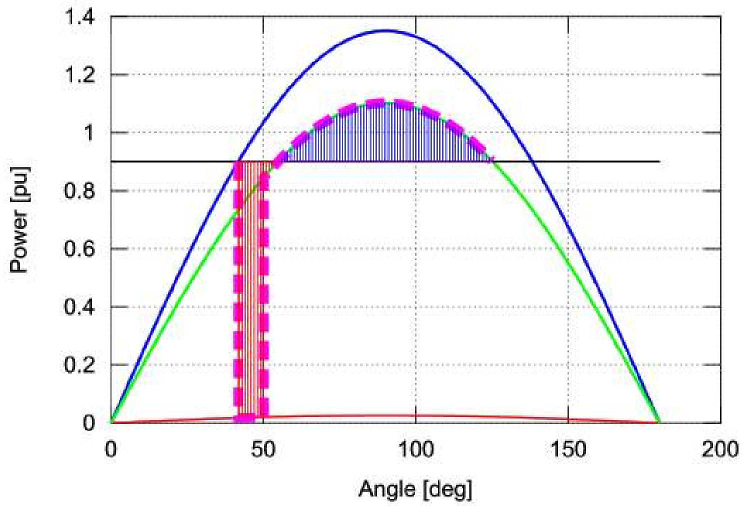

Fig. B-3. Trajectory in power-angle plane for a fault with critical clearing time duration

In case of a fault with duration longer than the critical clearing time the power swing will be unstable. The EAC method will produce in this case an accelerating area bigger than the decelerating area as shown in Fig. B-4.

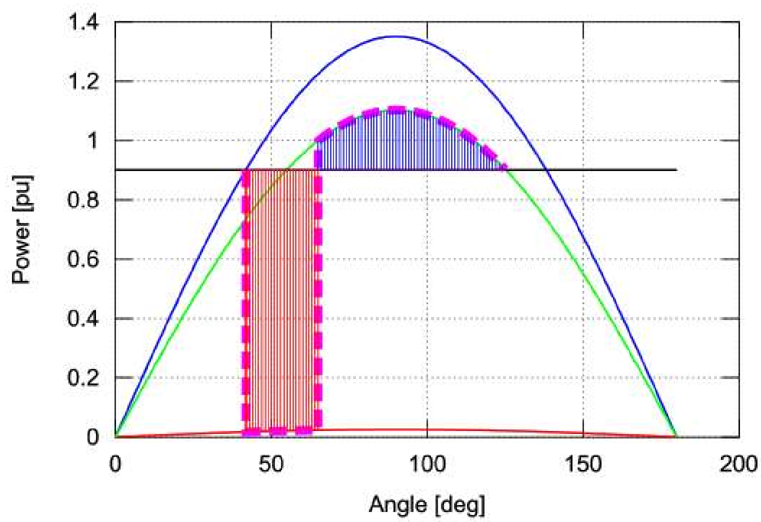

Fig. B-4. Trajectory in the power-angle plane for a fault that causes unstable power swing

B.1.1 EAC Algorithm Implementation

The implementation of the EAC algorithm is based on the integral of the accelerating power in the power-angle plane.

$$\int_{\delta ini}^{\delta max} (P_M - P_E) d\delta$$

The electrical power at the air gap is approximated by adding the electrical power at terminals of the generator P_T plus the losses in the armature resistance P_R.

$$P_E = P_T + P_R$$

The mechanical power P_M could be assumed constant (manual mode) during the first swing and is estimated equal as the prefault electrical power P_E. One of the difficulties in the implementation of the algorithm is the estimation of the angle δ, especially during fault conditions. This is solved here with the help of the integral of accelerating power in the power-time plane.

$$\int_{t0}^{t} \frac{\omega_{m0}}{2H}(P_M - P_E)dt = \Delta\omega_m$$

The differential of the angle $d\delta$ is calculated by the following relationship.

$$\Delta\omega_m dt = d\delta$$

Thus, the EAC algorithm results in the following basic equation:

$$\int_{t0}^{t\delta max} (P_M - P_E)\Delta\omega_m dt$$

Theoretically, this integral should produce zero value in case of a stable power swing. For an unstable power swing the integral will be a positive finite value. Fig. B-5 shows the algorithm implementation.

Also, an important point that needs to be taken into consideration in the classical swing equations (given below) used for the equal area criterion analysis is that the angular momentum (M) coefficient in the left-hand side of the equation is not a constant in the strictest sense[19]. This is because ω_m is not equal to the synchronous speed value during faulted conditions.

$$M = J\omega_m$$

$$M\,\frac{d^2\delta_m}{dt^2} = P_M - P_E$$

In the above equations J is the total moment of inertia, M is the angular momentum and is normally referred to as the "inertia constant" of the generator in the power system stability literature.

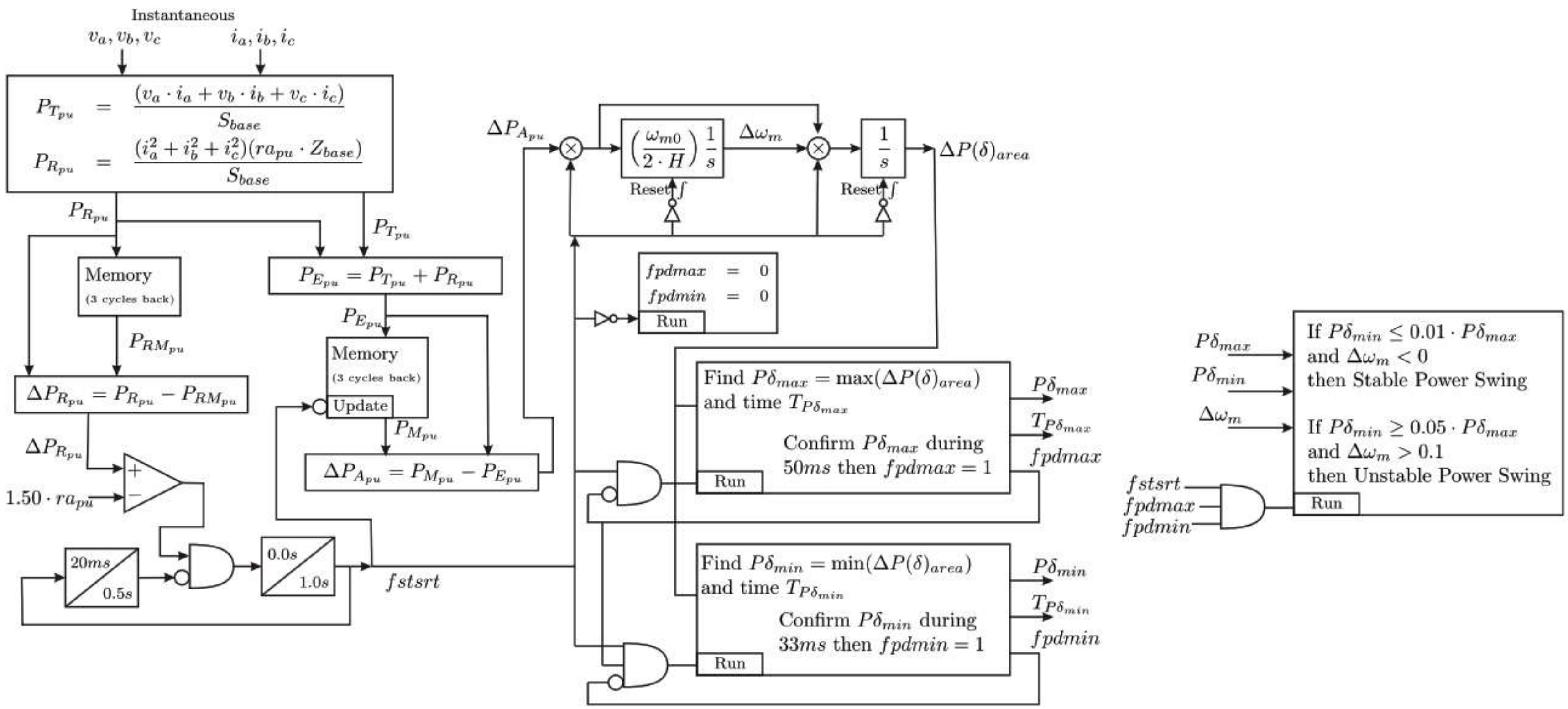

Fig. B-5. Equal Area Criterion Flow Chart (Program Implementation in ATP)

B.1.2 Application Example of EAC Method

The system from example 13.1 from Kundur[20] is used to illustrate the EAC method of power swing detection.

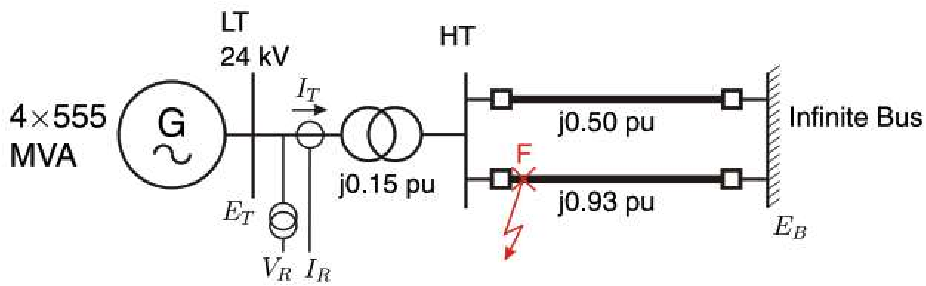

Fig. B-6. Example system for evaluation of EAC power swing detection method

TABLE B-1. Generator Parameters for example system

Generator Parameters		
S = 2220 MVA	X'd = 0.3 pu	T''d0 = 0.03 s
V = 24 kV	X'q = 0.65 pu	T'q0 = 1 s
ra = 0.00125 pu	X''d = 0.23 pu	T''q0 = 0.07 s
Xl = 0.163 pu	X''q = 0.23 pu	H = 3.5 s
Xd = 1.81 pu	T'd0 = 8 s	Freq = 60 Hz
Xq = 1.76 pu		

In Table B-1, the generator parameters correspond to a machine that is not round rotor type, since *Xd* is different from *Xq*. This example will help to illustrate that the EAC concept does not impose a restriction on the type of generator to be used.

<u>Stable Power Swing</u>

Fig. B-7 to B-11 show the results of the simulation for a fault duration equal to the critical clearing time. The results show a stable power swing.

[20] Kundur, P., "Power System Stability and Control", Mc. Graw Hill, 1994.

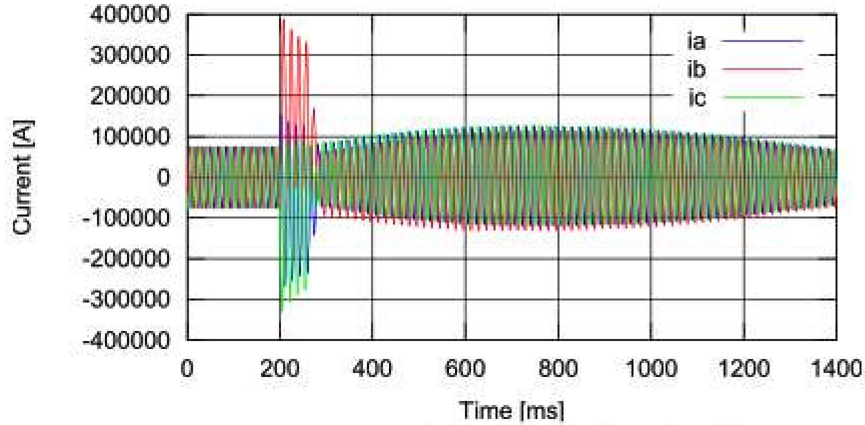

Fig. B-7. Current at generator terminals for a fault and stable power swing

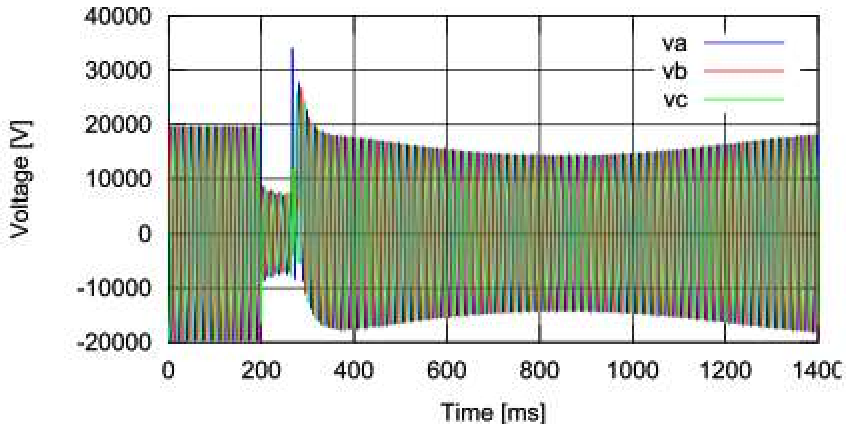

Fig. B-8. Voltage at generator terminals for fault and stable power swing.

In Fig. B-9, the rotor angle shown (calculated by the simulation tool and not based on the generator terminal voltage and current measurements) reaches slightly above 120º in this stable case.

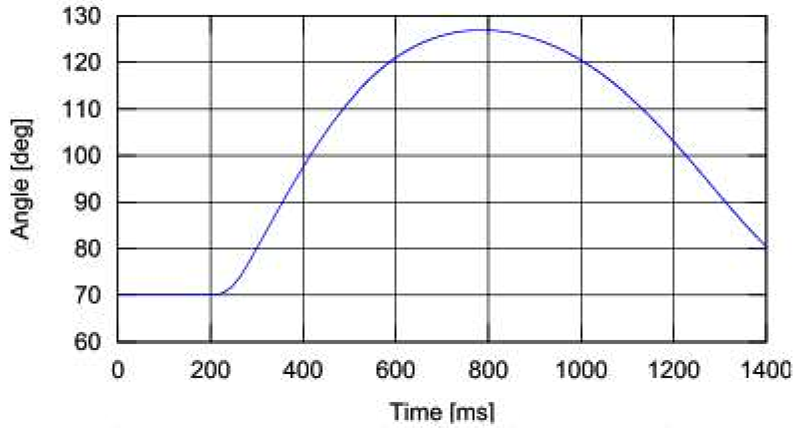

Fig. B-9. Rotor angle for stable power swing

In Fig. B-10, the estimated speed change $\Delta\omega_m$ and the integral of accelerating power in the power-angle plane $P\delta_{area}$ are both calculated based on the measurements from the generator terminal voltage and current as indicated in the algorithm description. Observe that the minimum of the $P\delta_{area}$ variable coincides with the change of sign in the $\Delta\omega_m$ variable. The change of sign of $\Delta\omega_m$ to the negative indicates that the angle δ stopped increasing, i.e., is a maximum. In a stable case the minimum of the $P\delta_{area}$ variable is practically zero as expected.

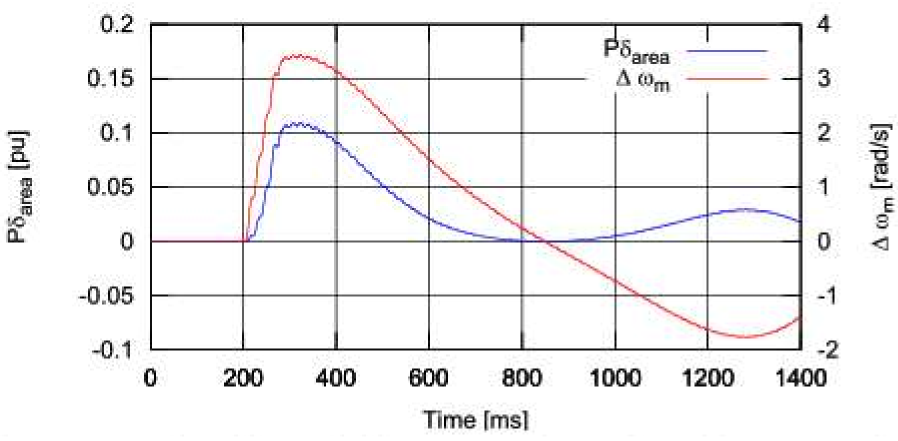

Fig. B-10. Algorithm variables $P\delta_{area}$ and $\Delta\omega_m$ for stable power swing

In Fig. B-11, the output flag takes a value of 1.0 as soon as it confirms it is a stable case.

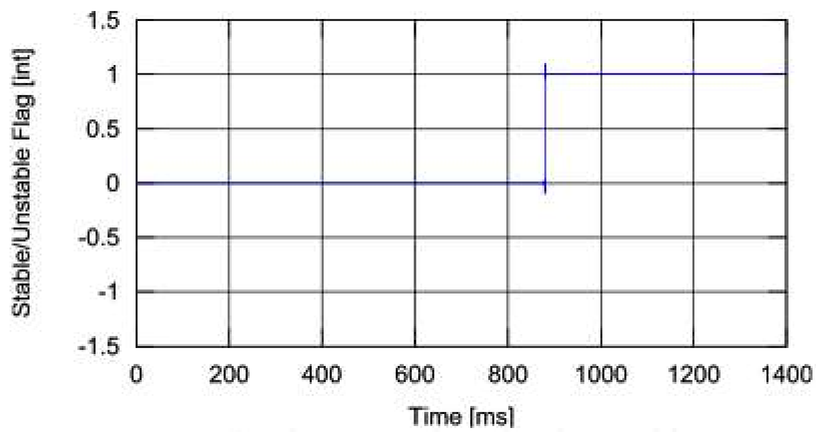

Fig. B-11. Output flag from EAC detection for a stable power swing

Unstable Power Swing

Fig. B-12 to B-16 show the results of the simulation for a fault producing an unstable power swing with a duration longer than the critical clearing time.

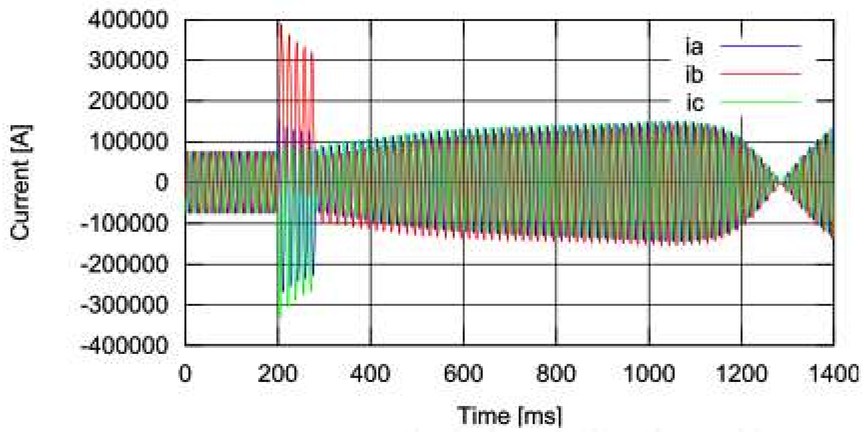

Fig. B-12. Current at generator terminals for a fault and unstable power swing

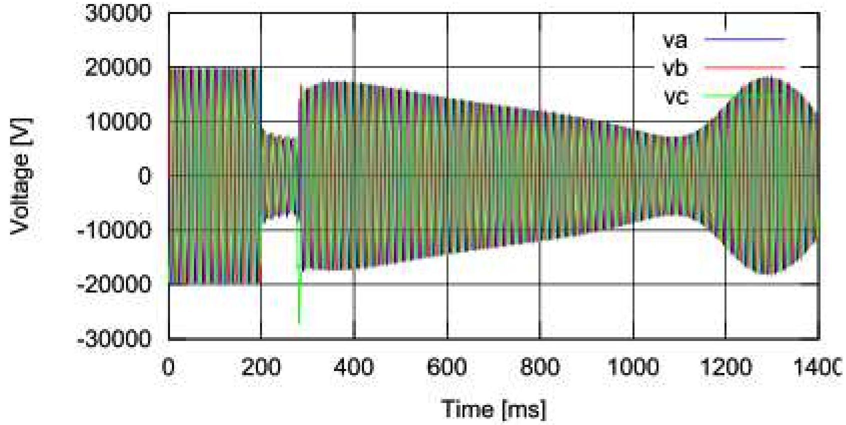

Fig. B-13. Voltage at generator terminals for fault and unstable power swing

In Fig. B-14, the rotor angle shown is calculated by the simulation tool. This angle keeps increasing as expected for an unstable power swing condition.

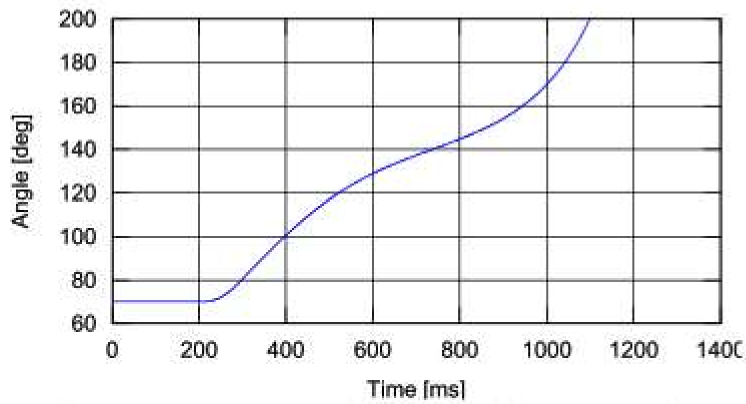

Fig. B-14. Rotor angle for unstable power swing

In Fig. B-15, the estimated speed change $\Delta\omega_m$ does not change sign to the negative indicating that it does not return to the synchronous speed. Also, the integral of accelerating power in the power-angle plane $P\delta_{area}$ also has a maximum and then a minimum similar to that in a stable case. However, the minimum does not reach the zero value since this is an unstable case.

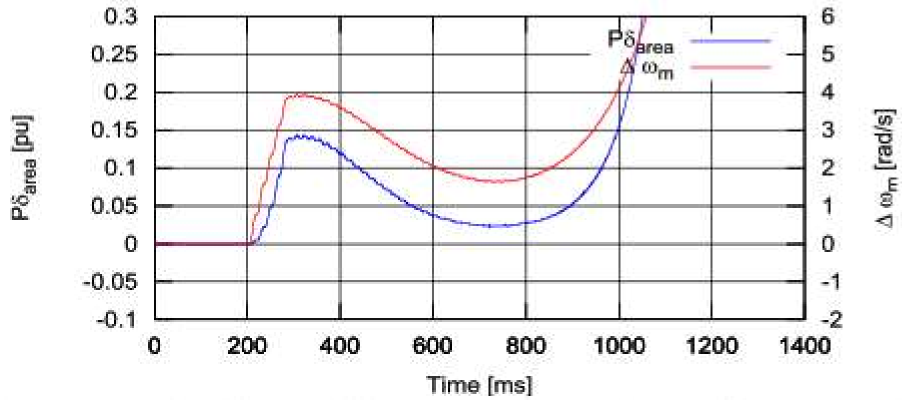

Fig. B-15. Algorithm variables $P\delta_{area}$ and $\Delta\omega_m$ for unstable power swing

The output flag takes a value of -1.0 indicating this is an unstable case almost immediately after detecting the minimum of the $P\delta_{area}$ variable.

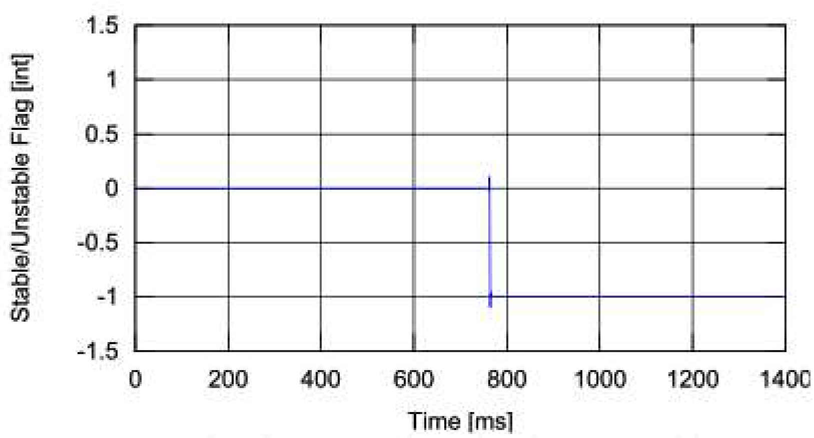

Fig. B-16. Output flag from EAC detection for an unstable power swing

B.2 Power versus Integral of Accelerating Power Method

References [21][21], [22][22] discuss a method based on local measurements of voltage at the generator terminals for detecting out-of-step conditions. A Discrete Fourier Transform

[21] So, K. H., Heo, J. Y., Kim, C. H., Aggarwal, R. K., and Song, K. B., "Out-of-Step Detection Algorithm Using Frequency Deviation of Voltage," IET Generation, Transmission & Distribution, vol. 1, no. 1, pp. 119-126, 2007.

(DFT) or a recursive DFT calculation is performed on the voltage signal to find the frequency. The angular velocity and the rate of change of angular velocity are used to detect the out-of-step condition. The angular velocity is calculated using two successive phase angle values of voltage. The average of ω is then obtained over a data window[22]. The angular acceleration is computed using successive angular velocity values and an average value of acceleration is obtained.

The above method for finding the out of step conditions is simple and does not need network parameter information. The method could be used in simulation studies but may pose practical issues while implementing in a relaying application. Firstly, calculating the speed and acceleration from the terminal voltage angles of the generator is prone to errors due to the derivative terms used in the calculation of speed and acceleration. The derivative terms amplify the power system noise significantly. Secondly, the estimated generator rotor speed from the voltage angle measurements have large errors during the transient period and an appropriate time delay needs to be introduced before an accurate estimate of the speed and acceleration is obtained.

The practical difficulties discussed could be overcome using the electrical power deviation instead of estimating the rotor acceleration (electrical power deviation has direct relationship to rotor acceleration); and the integral of accelerating power instead of directly estimating the rotor speed (integral of accelerating power has a direct relationship to the generator speed deviation). The electrical power changes are straightforward to measure and the values obtained are more stable during transient conditions. The mechanical power deviations could also be included in the analysis to obtain an accurate estimate of the speed and acceleration changes.

Power based and accelerating power based stabilizers have also been reported on by the Excitation Controls Subcommittee of the Energy Development and Power Generation Committee[23,24,25,26][23, 24, 25, 26].

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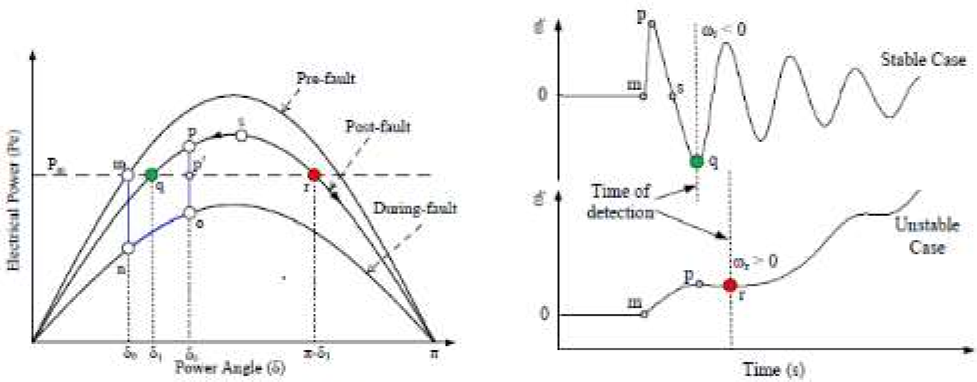
B.2.1 Method Description



(a) Power-angle characteristics (b) Generator relative speed versus time

Fig. B-17. Typical power-angle curves at the terminals of the generator

The power-angle characteristics for a typical pre-fault, during fault and post-fault conditions are shown in Fig. B-17. It can be analyzed from the curve that the generator speed increases during the faulted condition and starts decreasing as the fault is removed. Initially, the machine operates in a steady state condition as shown by point ‘m’. After a fault occurs in the system, the operating point moves to point ‘n’ and the machine starts accelerating until it reaches point ‘o’ where the fault is removed and the operating point moves to point ‘p’. As shown in Fig. B-17(b), the speed of the machine is greater than the synchronous speed at point p and the rotor angle $\boldsymbol{\delta}$ increases as the machine starts to decelerate. The stability of the machine depends on whether it regains synchronous speed before reaching point ‘r’. If the synchronous speed is regained at point ‘s’, then the rotor angle $\boldsymbol{\delta}$ starts to swing backwards. As it swings back, the state changes from deceleration to acceleration at point ‘q’. The relative speed of the generator is negative at point ‘q’ and settles into a new steady state operating point ‘q’ after a few oscillations. If the disturbance is large, then the machine may oscillate beyond point ‘s’ and reach point ‘r’ where the state changes from deceleration to acceleration. The stability of the machine depends on the relative speed at point ‘r’. The machine will be unstable if the relative speed is positive at point ‘r’. The generator relative speed ‘ω_r’ for stable and unstable conditions is shown in Fig. B-17(b).

This method uses online measurement of electrical power and the generator speed as inputs to the relay. The algorithm first determines the equilibrium point at which the relative rotor speed is evaluated to determine stability. The equilibrium point is the point at which P_m - P_e changes from negative to positive assuming P_m to be constant (i.e. governor action is slower and would not change during this short interval).

B.2.2 Results Using Electromagnetic Transient Simulation Studies (PSCAD/EMTDC)

The power system model used in Fig. B-1 was used for the studies. The parameters of the model are given in the Appendix A.

Case I: Stable Power Swing

A sustained three-phase fault is applied at the middle of the transmission line for the duration of 0.2 seconds. At the point where angular acceleration changed its polarity from negative to positive, the angular velocity (ω_v) was found to be less than base velocity (ω_o) and the relay detected it as a stable swing.

In the first plot, the instantaneous values of the terminal voltage phase are measured and a polynomial curve fitting is done on the sampled values of the phase angles. The angular velocities are determined from the curve fitted values to get a stable value. The angular acceleration is determined taking the slope of the instantaneous speed values. Fig. B-18 gives the plot of angular acceleration versus angular velocity determined in this fashion.

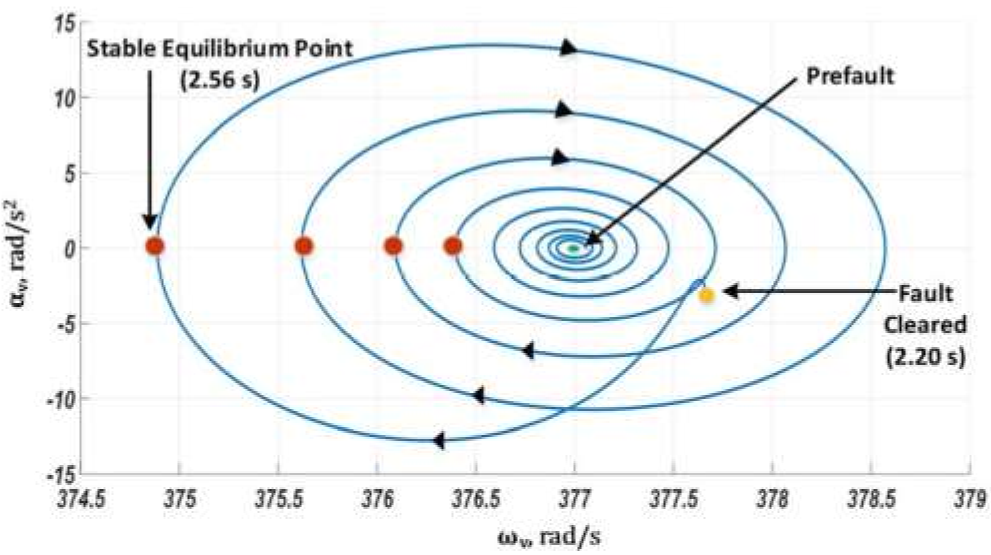


Fig. B-18. Plot of angular acceleration vs. angular velocity for a stable swing with terminal voltage phase angle values

In the second plot, the instantaneous values of the electrical power and the integral of accelerating power are determined. The acceleration and the speed deviation are determined from the power and the integral of accelerating power values, respectively and plotted in Fig. B-19.

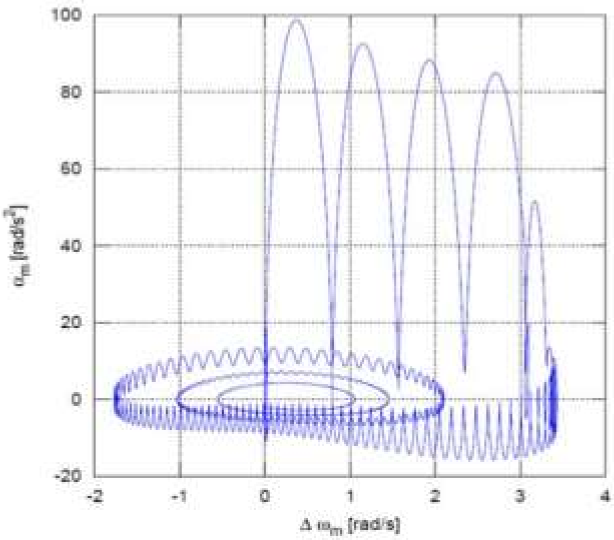


Fig. B-19. Plot of angular acceleration vs. angular velocity for a stable swing scenario with power and integral of accelerating power values

Case II: Unstable Power Swing

At the point where angular acceleration changes its polarity from negative to positive, the angular velocity (ω_v) is found to be greater than base velocity (ω_o) and therefore the relay detects it as an unstable swing.

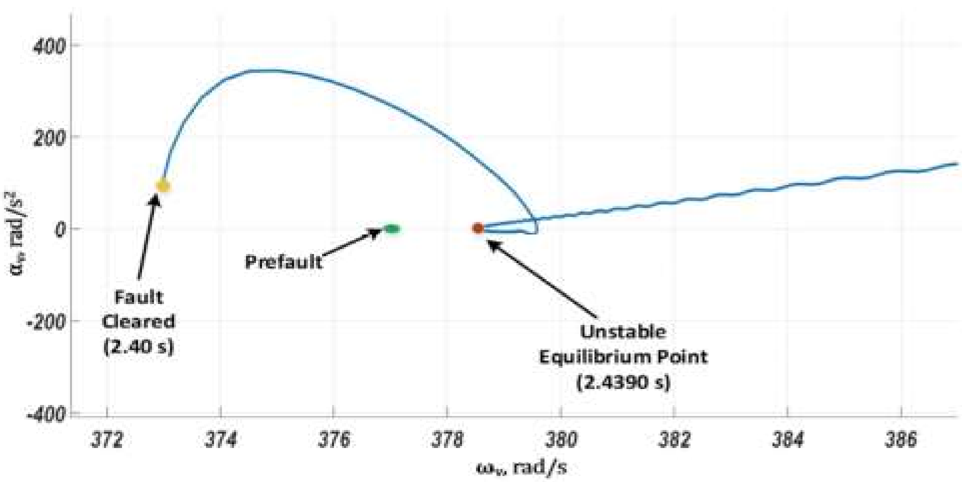


Fig. B-20. Plot of angular acceleration vs. angular velocity for an unstable swing with terminal voltage phase angle values (polynomial curve fitting done on the sampled values of the phase angles)

Fig. B-21 shows the plot of angular acceleration and the speed deviation determined from the power and the integral of accelerating power values.

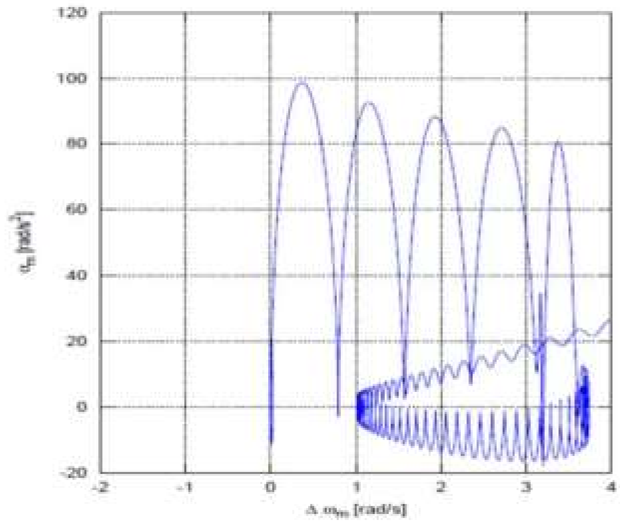


Fig. B-21. Plot of angular acceleration vs. angular velocity for an unstable swing with instantaneous power values

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