Application of Out-of-Step Relaying for Small Generators in Distributed Generation

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***Abstract**: The recent popularity of distributed generation (DG) has caused an increasing number of small generators (rated between 100 kVA – 12.5 MVA) to be connected to the power system at the distribution level (480 V - 12.47 kV). Some utilities require that out-of-step relays be installed by the generation owner at the point of common coupling (PCC). This paper will examine out-of-step relaying practices as they apply to small generation protection. It will consider the value, purpose, and applicability and provide guidelines for setting of this type of relay, when employed.*

I. INTRODUCTION

In an effort to accommodate the connection of DG on their systems, some utilities have adopted simplified interconnection requirements for these generators (often limited to 5 MVA or less). These requirements are implemented to protect the system by automatically disconnecting the generator in the event of a system fault or unusual generator operating conditions that may cause voltage or current disturbances on the system. Safeguards are also required to disconnect the generator in the event the utility de-energizes the distribution line being fed by the generator. In addition, protective relaying is also installed to protect the generator from damage due to system-originated disturbances and faults.

Included in these protection requirements is the need to automatically disconnect the generator from the power system if the generator loses synchronism, or goes out-of-step, with the system. Some utilities have interpreted this requirement by including an out-of-step relay (ANSI / IEEE Device No. 78) in the interconnection protection package.

This requirement when applied can present a challenge for the protection engineer trying to set this relay correctly. The traditional use of the No. 78 relay was to block inadvertent generator tripping. It is undesirable to allow a large generator to be tripped for a system disturbance that would not cause the generator to fall out-of-step or to trip and damage equipment not rated to trip in an out-of-step condition. An out-of-step relay can be employed to block the action of other relays to allow a large generator to ride-through disturbances that do not cause the generator to fall out-of-step, but which might cause other relaying to trip the generator. This relay is also used to block the tripping of breakers when conditions due to an out-of-step condition are too severe to allow the breaker to open until the machine swing has progressed to the point where safe interruption is possible.

Proper setting of an out-of-step relay requires a detailed transient stability study of the power system. This is a perfectly valid reason to perform the transient stability studies for large generators (say 500 MVA and larger). On a small generation project, however, sufficient funds are seldom available to pay for such a study, nor is there any real need to perform such a study.

Methods for calculating "preliminary" settings are available from most relay manufacturers and other sources [1]. Since sufficient system information to properly set this relay is seldom available on a small generation project, the engineer may have to rely on these "preliminary" settings, even though the lack of system information makes it impossible for the engineer to determine how closely these settings are to the optimum values or if the "preliminary" settings actually accomplish the desired result. Also, the practice of allowing the out-of-step relay to trip the generator, instead of block tripping, may be discovered to be undesirable if a complete transient stability study were performed.

Recently published IEEE Std.-1547-2003 [13], however, doesn't require the "Loss-of-Synchronism" protection for such generators. ANSI/IEEE Standard 242 (Buff Book) suggests the following protective relays for use on generators of the sizes indicated [10].

Small Generators (500kVA) on Medium Voltage Systems

Device 51V	Voltage Controlled or Restrained Over current

Device 51G	Ground Time-Over current
Device 32	Reverse Power
Device 40	Loss of Field
Device 87	Differential

Medium Size Generators (Up To 12.5 MW)

Device 51V	Voltage Controlled or Restrained Over current
Device 51G	Ground Time-Over current
Device 32	Reverse Power
Device 40	Loss of Field
Device 87	Differential
Device 46	Negative Sequence Over current

Large Generators (12.5MW to 50MW)

Device 51V	Voltage Controlled or Restrained Over current
Device 51G	Ground Time-Over current
Device 32	Reverse Power
Device 40	Loss of Field
Device 87	Differential
Device 46	Negative Sequence Over current
Device 87G	Ground Differential
Device 49	Stator Temperature Protection
Device 64F	Field Ground Relay (if applicable)
Device 60	Voltage Balance

If electromechanical relays are used, each of these functions is typically provided by a separate relay. With modern microprocessor based relays, however, one "box" may be installed to perform all of these functions and offer other functions including out-of-step.

It is up to the protection engineer to decide which of the many offered functions are valuable in protecting the generator and the system. Care must be exercised in deciding which functions to employ. The easy availability of many functions at no additional hardware cost may tempt the protection engineer into using functions that add little, if any, value to system or generator protection. Keep in mind that more does not necessarily mean better. Keep it simple.

II. SYSTEM STABILITY

The purpose of an out-of-step relay is to detect when a generator is going out-of-synchronism with the system. To understand the basic principles, a very simplified system model for a generator (lossless, unsaturated, constant excitation, constant power, and cylindrical rotor) connected to the system is studied. The "classical" model, as it is called, is shown in Figure 1.

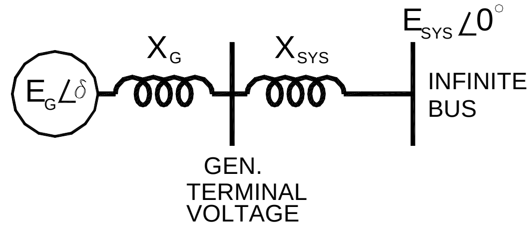


Figure 1: Classical System Model

E_G = Generator Internal (Induced) Voltage
X_G = Generator Reactance (= x_d' transient reactance for stability calculations)
X_{SYS} = Equivalent System Reactance
E_{SYS} = Equivalent System (Infinite Bus) Voltage (reference)

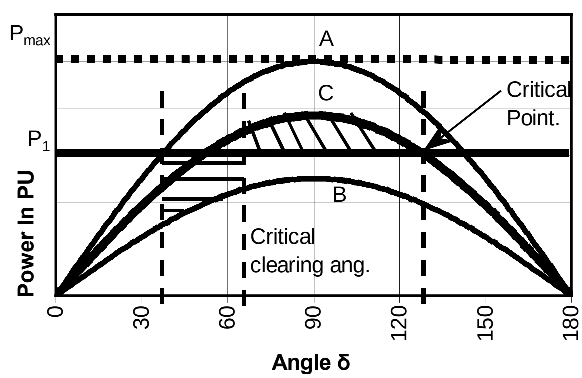
The power transferred from the generator to the connected power system may be calculated using equation (1) [2].

$$P = \frac{|E_G||E_{SYS}|}{X}\sin\,\delta \qquad (1)$$

X = Total reactance between E_G and E_{SYS}
δ = Angle by which E_G leads E_{SYS} (called Power Angle or Torque Angle)
P = Power transferred from the generator to the power system

Assuming the voltages and reactance values are constant, the power output (P) against the power angle (δ) results in the "Curve A" in Figure 2.

The theoretical maximum power (P_{max}) at steady state that may be transferred will occur when the generator internal voltage (E_G) leads the system voltage (E_{SYS}) by 90°. This is also shown in the diagram.



A-Pre fault; B-During Fault; C-Post Fault

Figure 2: Power Angle Diagram

Under normal rated steady-state operating conditions (electrical power output "P" = mechanical power input "P_1"), the power angle δ of a generator is typically between 30^o – 40^o as shown in the diagram.

There are four conditions in power system operation that may cause a generator to pull out-of-step.

1. Operating in an Under-Excited Condition

2. System Switching

3. Sudden System Load Variations, and

4. Faults.

The fourth condition (faults) is the most common occurrence and will be discussed here at length.

If a fault were to occur on the electric power distribution system (Figure 1), the generator would deliver less electrical power to the system. Power angle diagram "Curve A" of Figure 2 would then become "Curve B" during fault. Assuming the input from the prime mover (mechanical power input) did not change (still at the level of P_1), and since the output power to the system is reduced, the excess (difference) energy must be stored in the mass of the spinning rotor. This will cause the generator to speed up; the rotor to swing, and the rotor (power) angle δ will increase from its initial value.

From Figure 2 it is seen that the input power P_1 always exceeds the output power of "Curve B". This would cause the generator to continue to speed up and eventually lose synchronism with the system, if the faulted condition were to continue. If the fault clears before the machine goes out-of-synchronism, then the power-angle diagram "Curve C" in Figure 2 will result due to the new system impedance that results from the disconnecting of the faulted section of the system.

During the rotor swing, the energy that has been stored in the spinning rotor must be transferred to the system if the rotor is allowed to slow down and return to the new operating condition which would be at the point where line P_1 intersects "Curve C" (the point where the mechanical and electrical power once again become equal). If the rotor angle is greater than the angle where line P_1 crosses "Curve C" then the electrical power output of the system would be greater than the mechanical power input, the rotor would slow down, and the power angle would decrease. Under this condition the rotor would oscillate about it's new operating point, but would not pull out-of-step with the system.

If the inertia of the rotor were to carry the rotor beyond the critical point, the mechanical power input from the prime mover will once again exceed the electrical power output of the generator resulting in continued acceleration of the rotor. Under this condition the generator will not return to a stable operating condition and will fall out-of-step with the system. If the fault can be cleared fast enough so the rotor angle never exceeds the critical point, then the machine will not fall out of synchronism but will return to a stable operating condition.

If fault clearing is too slow, the rotor angle will exceed the critical point and the machine will fall out-of-step. The maximum angle at which the fault can be cleared and not allow the rotor to swing past the critical point is known as the "critical clearing angle." Fast breaker operating times result in a reduced likelihood that the generator will fall out-of-step.

In Figure 2, the shaded area between Curve B and line P_1 is representative of the energy that will be stored in the rotor during the fault. This energy will cause the rotor to speed up. The shaded area between Curve C and line P_1 represents the energy that is returned to the system during the new system configuration after the fault clears. If these two areas are equal, the rotor swing will not proceed beyond the critical point and the generator will not fall out of step. This is know as the "Equal Area Criteria".

The purpose of out-of-step relaying as used in most DG interconnection guidelines is to detect this condition and disconnect the generator from the system. The location where the utility decides to separate the system during a power swing will become a more important factor, as distributed generation becomes a larger percentage of a utility's total generation.

During an out-of-step swing the generator sees high currents and depressed system voltages. The job of the No. 78 relay is to differentiate between a rotor swing that will cause the generator to fall out-of-synchronism and one that is stable, trip for the first condition and ignore the second.

III. SYSTEM CONDITIONS DURING A SWING

Figure 3 shows the simplified reactance diagram of an actual generator installation (connected to 12.47 kV system). The system reactances are calculated from the fault current values supplied by the utility (I_{3PH} = 5261A; I_{LG} = 3215A). This "Classical Model" will be used in this paper to illustrate the conditions that a generator protection relay will see during an unstable swing.

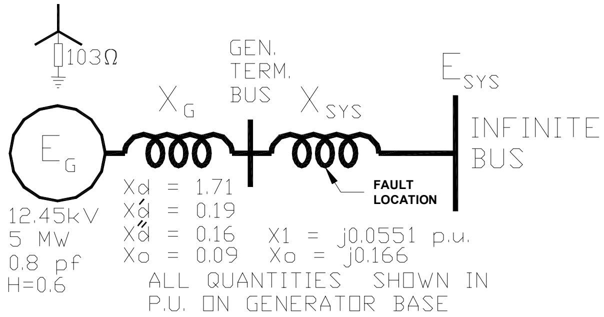


Figure 3: System Model: Case Study

For simplicity, it will be assumed for these calculations that the magnitude of E_G (the voltage behind the transient reactance x_d') will remain constant during the swing (i.e., no automatic voltage regulator "AVR" action) and the generator transient reactance should be used for calculations during the swing. A fault will be placed midpoint in the system equivalent reactance (as shown in Figure 3) for this example. The type of fault usually used for transient calculations is a line-to-line-to-ground fault (phases B to C to Ground)[3].

If the generator in Figure 3 is delivering full-load at rated power factor at the terminals, the calculated value for E_G is 1.15 p.u. with an angle of 9.8° (infinite bus voltage as reference). This is the initial condition of the generator before fault occurs.

Figure 4 shows the sequence networks interconnection for the line-to-line-to-ground fault as indicated in the diagram, including the generator's grounding resistor [4]. This network will be used to calculate the voltage and current seen at the generator terminals during an out-of-step swing caused by the fault assuming that the fault does clear during this swing. This network can be reduced using a wye-to-delta transformation to give a value of j0.556 p.u. for the overall reactance X between the generator and the system used in equation (1) and to be used in drawing the power angle diagram for the period during the fault [3].

It will be assumed in this problem that the system impedance increased 10% when this fault is cleared. So the three impedances (at machine base) we will use in drawing the power angle diagrams are:

1. Pre Fault X = j0.245 pu
2. During the fault X = j0.556 pu
3. Post fault X = j0.2505 pu

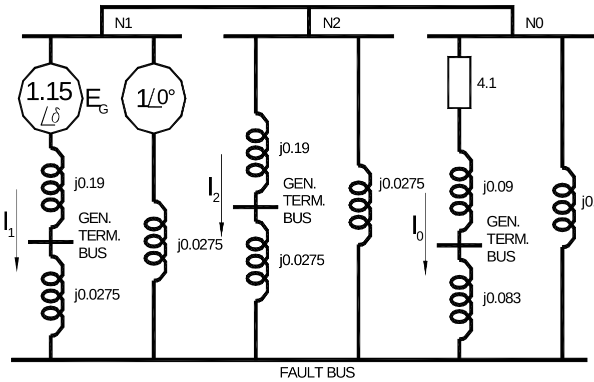


Figure 4: Equivalent Network Connections During Line-to-Line-to-Ground Fault

The power angle diagrams for these three impedances (pre, during, and post fault conditions) are shown in Figure 5.

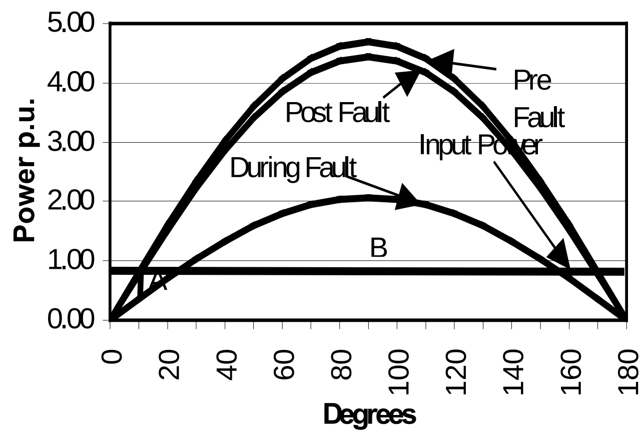


Figure 5: Power Angle Diagrams: Case Study

In Figure 5 above, the area "A" represents the energy that will accelerate the rotor since during this period the input power exceeds the output power. The area labeled "B" represents the decelerating energy since the output power of the generator exceeds the mechanical input power. Since area "B:" is larger than area "A" during the fault this machine will never fall out of step even if the fault never clears.

Using the step-by-step tabular method [2][3], the swing angles the rotor goes through may be calculated along with all other important quantities like power, voltage, current, etc. Figure 6 shows the rotor angles through the first cycle. It can be seen that the rotor angle never exceeds 36° and oscillates with a period of approximately 0.26 seconds. It will oscillate until it once again reaches equilibrium at the new rotor angle of 25°.

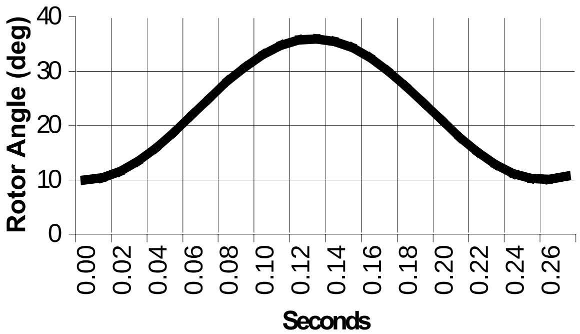


Figure 6: Rotor Angle 1st Cycle

If the line-to-line-to-ground fault is moved to the terminals of the generator it will still stay in synchronism and the maximum swing angle will still not exceed 36°.

Figure 7 shows the magnitude of the currents for each phase measured at the generator terminals during the rotor swing for line-to-line-to-ground fault located as shown in Figure 3.

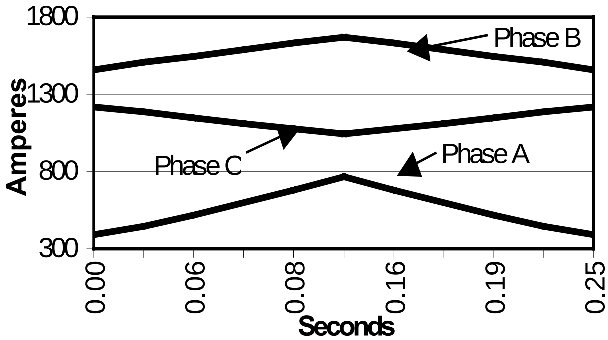


Figure 7: Generator Phase Currents During L-L-G Fault

The corresponding line-to-neutral voltages measured at the generator terminals during the swing are shown in Figure 8.

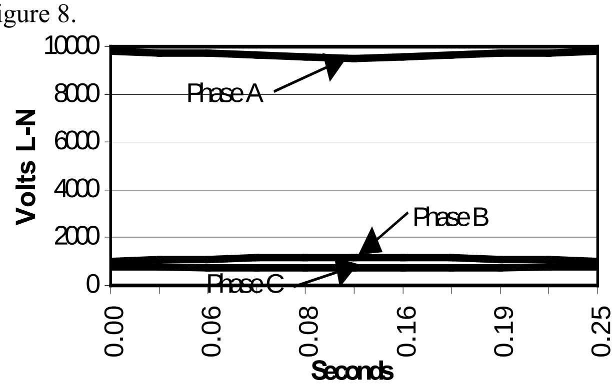


Figure 8: Generator Terminal Phase Voltages During L-L-G Fault

A line-to-line-to-ground fault will not cause this machine to lose synchronism with the system. If a bolted three-phase fault occurs at the center of the system as depicted in Figure 3, the generator will be unable to supply any power to the system and if the fault is not cleared soon enough the machine will fall out-of-step. This is depicted in Figure 9, which shows the power angle diagram for a three-phase fault.

The critical clearing angle is 118°. If the fault were to clear when the rotor was less than 118° "area B" in Figure 9 would exceed "area A" and the decelerating energy would exceed the accelerating energy and the machine would not fall out-of-step.

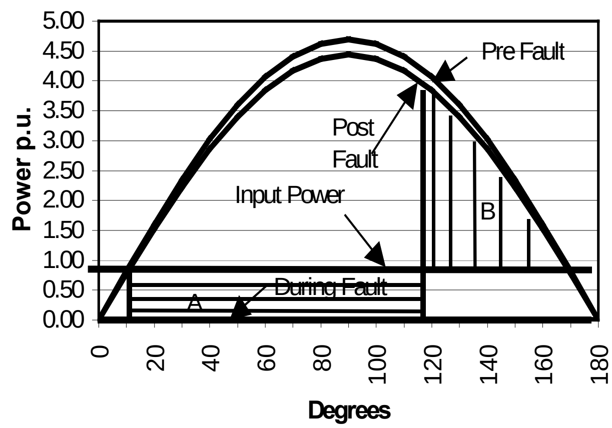


Figure 9: Power Angle Diagram for a Bolted 3-Phase Fault

The rotor angle during a three-phase fault at the generator terminals when the fault is not cleared is shown in Figure 10.

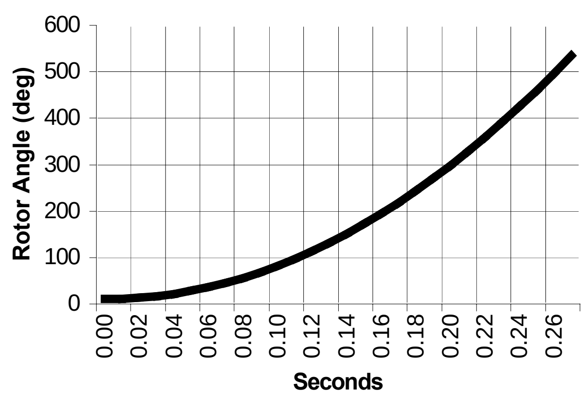


Figure 10: Rotor Angle for Three-Phase Bolted Fault at Generator Terminals

If the fault clears after the rotor reaches 118° the swing will continue and the machine will lose synchronism with the system. The rotor swing calculation shows that the fault must clear in 0.11 seconds (6.6 cycles) or less to prevent a swing exceeding the angle 118°. If the three-phase fault occurred at the center of the system (splitting the reactance in half) the current magnitude from the generator would be 1.2 kA and the voltage magnitude at the generator terminals would be 991 V and the current angle during the machine swing would lag the voltage by 90°

If the fault cleared in 6.5 cycles the voltage angle would have reached 90°. The swing would continue to an angle of 108° and eventually settle around the new voltage angle of 10.1°. Ignoring the sub-transient effects, the current during fault and after the fault is cleared is shown in Figure 11 and the corresponding voltage is shown in Figure 12.

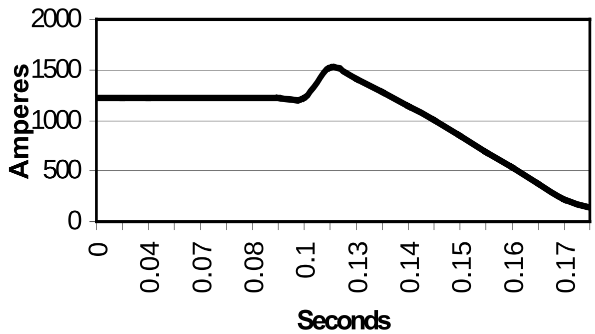


Figure 11: Generator Current for a Bolted 3-Phase Fault

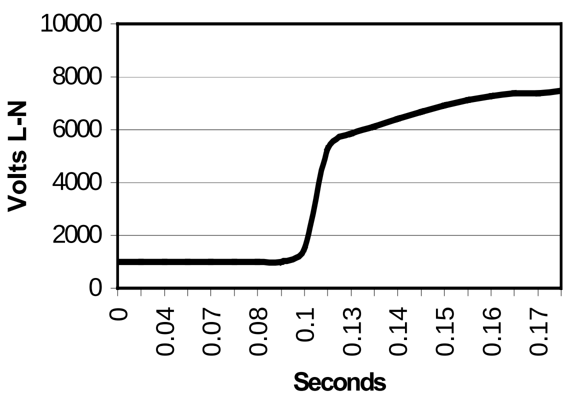


Figure 12: Generator Terminal Phase Voltage for a Bolted 3-Phase Fault

IV. OUT-OF-STEP RELAY OPERATION

There are several methods by which out-of-step relays attempt to detect a swing condition. They all utilize positive sequence impedance measuring elements. One common type uses the "two-blinder method" that will be discussed here.

Three impedances are defined in this relay, a mho circle and two blinder impedances. The impedances calculated by the "preliminary" method recommended by one relay manufacturer for the example of Figure 3 result in the diagram shown in Figure 13. These are secondary values where (CT Ratio)/(PT Ratio) = 4.

The relay measures the impedance at its point of application. If the impedance crosses into the mho circle, crosses one of the blinders, remains between the blinders for a preset time, then crosses the other blinder, the relay determines that an out-of-step condition has occurred and initiates a trip. If all of these criteria are not met the relay determines that a stable swing has occurred and does not trip.

The swing trajectories for the faults already considered plus a three-phase fault that was not cleared in time to prevent an out-of-step swing are shown in Figure 14.

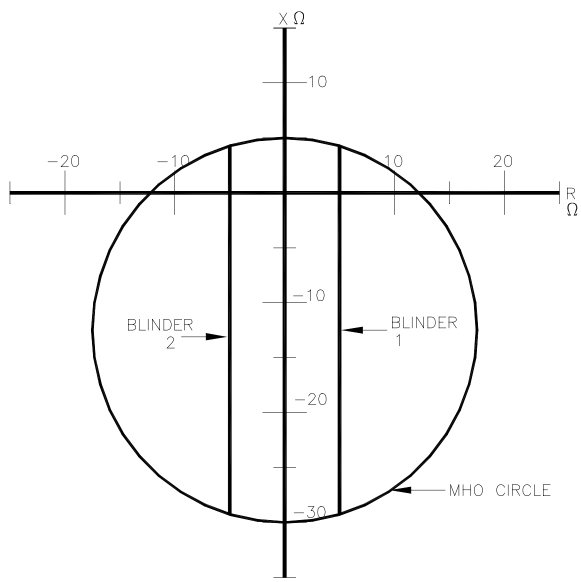


Figure 13: Relay Settings Recommended by One Relay Manufacturer

The line-to-line-to-ground fault and 3-phase fault cleared at a rotor angle 90° did not cause an unstable swing. Figure 14 shows that these trajectories do enter the mho circle, however, they do not cross any of the blinders, so the relay will not trip. The three-phase fault cleared at 130° does cause an unstable swing. The trajectory of this fault does cross both blinders. The calculated time the impedance remains between the two blinders was 0.08 seconds (or 4.8 cycles). If the time delay on the relay was set at less than 0.08 seconds, the relay should trip for this swing.

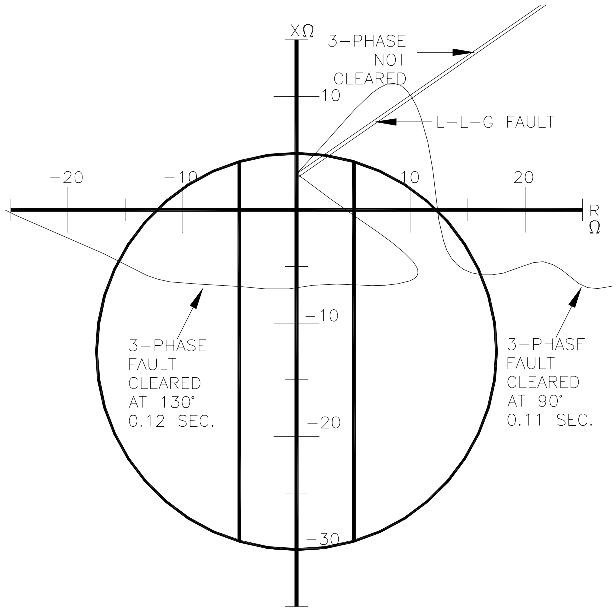


Figure 14: Impedance Trajectories

V. RELAY CORDINATION

Figure 15 is a simplified relaying single-line diagram for the system described.

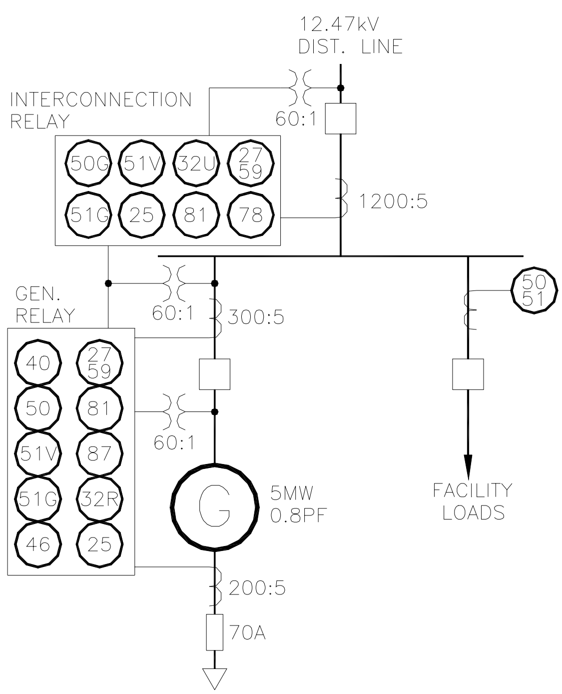


Figure 15: Simplified Relaying One-Line Diagram

Typical settings for the relays in Figure 15 are given in the Appendix.

For each of the faults examined here, the first relay to pick up a trip signal would be the generator instantaneous over-current (50) relay. This relay had a setting of 1,000A primary and as shown in Figures 7 and 11 would have tripped for any of the faults, regardless of whether the generator underwent an unstable swing.

The next relay to pick up would be the interconnection under-voltage relay (27) that had settings of 10 cycles and 0.5 pu volts. This relay would have tripped for all of the faults considered here.

In the case of the line-to-line-to-ground fault the third relay to trip would be the generator voltage restrained over-current relay (51V), which would pick up and time out for this voltage and current level in 0.2 sec. This relay would also trip for a three-phase fault that was not cleared by another source.

The out-of-step (78) relay would have no opportunity to trip unless these three elements failed to operate. This would be true regardless of whether the generator actually lost synchronism with the system or not. In the case where the swing was stable, the Device No. 78 would properly not trip since the machine will not lose synchronism. However, this is irrelevant since other relays would have already tripped the generator off.

If the out-of-step relay is to have any meaningful place in protection of the generator or the system several coordination issues must be faced. The instantaneous over-current relay must be eliminated or set above the maximum current that could be expected at the generator due to any swing that was expected to occur. The under-voltage relay must be delayed beyond the time the voltage is expected to be depressed by the slowest swing, either stable or unstable, that could happen on the system. The voltage restrained over-current relay must have settings that will prevent it from tripping for the depressed voltage and elevated current conditions expected during both stable and unstable swings.

As an alternative, the out-of-step element could be used to block other relay elements from tripping until the generator actually went out-of-synchronism with the system. When it sensed that the generator was out-of-step it could initiate tripping or allow one of the other relays to trip. If this alternative were chosen, other relay settings would have to be examined to insure that all other relays that could trip faster than the out-of-step swing occurred, were blocked. The time this blocking action would be required would be difficult to determine without the results of a transient stability study to determine the slowest swing that might be expected on each individual system. Consideration should also be given to the damage that might result to the generator during this delayed period of time. Any condition that would result in damage to the generator must be removed as quickly as possible.

VI. CIRCUIT BREAKER CONSIDERATIONS

If the over-current or under-voltage relays are allowed to open the breaker at the time when the generator is out-of-step with the system the circuit breaker will be subjected to severe conditions. If the interruption occurs when the generator is exactly 180° out of phase with the system, the breaker contacts may have a voltage across them equal to twice the peak line-to-neutral voltage of the system. The circuit breaker may not be capable of interrupting the current available at these elevated voltage levels.

The out-of-step relay has the advantage that the blinders can be set to insure that the trip is not initiated until the swing angle has proceeded beyond a certain point. An angle of 120° is often used for this setting. Some manufacturers voluntarily test their breakers under this condition and label their breakers as being capable of interrupting 25% of their interrupting rating under this condition. A breaker which meets the IEEE standard C37.013-1997, Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis, and has an out-of-phase current switching rating, must be capable of interrupting 50% of its maximum interrupting rating during an out-of-step condition where the voltage angle difference is 90°, at its rated voltage. If the breaker is expected to interrupt under out-of-synchronism conditions the breaker manufacturer should be consulted to determine the capability of the breaker under these conditions.

The protective relaying must trip the generators before a true out-of-synchronism condition occurs to prevent over-stressing the interrupting device. Alternatively, the out-of-step relay may be used to block tripping of the breaker until the swing has progressed to a point where the breaker is not required to interrupt under elevated voltage conditions. The 78 relay may be employed to block the tripping of other relay elements instead of being used to trip.

If a generator is connected to an existing distribution system there may be fuses present on the system. If generator protection is blocked or delayed these fuses may interrupt before the generator relaying operates under conditions when the generator is out-of-step. This will place high voltages across the fuses as they try to interrupt. It is possible that the fuse is unable to interrupt and completely extinguish the arc under these conditions resulting in further damage until other relaying on the circuit operates. Coordination is necessary to determine which fuses on the system may interrupt under these conditions and whether they are capable of interruption during an out-of-step condition. If fuses are present, delaying or blocking generator protection may not be an option.

VII. CONCLUSION

This paper has only examined a few of the myriad of possible faults that might occur on a distribution system to which a generator is to be connected. If an out-of-step relay is used an in-depth transient stability study is required. This study will require detailed information about the distribution system including an accurate system model and settings and types of relays and fuses used throughout the system. Only by examining the various system conditions that may cause an out-of-synchronism swing can the optimum settings for the 78 relay be calculated.

Relay manufacturers usually suggest a method for making preliminary settings. These preliminary settings cannot be relied upon without checking them using the results of the stability study [1]. Only in this way can it be determined if these settings need to be modified to achieve the results necessary for a particular system or if the out-of-step settings and the settings of other relays are properly coordinated. It is quite possible, as shown in the example considered in this paper, that the other relaying in the system would render the 78 relay irrelevant to system protection.

In generator connections such as the one in Figure 15 where the 78 relay is applied at the interconnection point instead of at the generator, false tripping has been witnessed due to inrush currents when the facility loads are energized without the generation being on-line. It may be necessary to alter the preliminary settings so this relay does not over-trip. The size of the mho circle and the settings of the blinders should be adjusted to be as small as possible while still allowing the relay to trip for all out-of-step events. Sometimes a delay is introduced to try to eliminate the possibility of false tripping. If this is done the information from the stability study is essential in determining how long a swing can be expected to keep the impedance between the two blinders so the delay is not set too long to prevent a trip from occurring for an out-of-step swing. Arbitrarily adding a time delay without understanding its result may totally defeat the ability of the relay to respond to an out-of-step condition.

An in-depth transient stability study can be an expensive undertaking on a large system. In a small generation project sufficient information and funds are often not available to perform a meaningful study. If a transient stability study is not undertaken then the 78 relay should not be used in the system since it cannot be predicted what, if any, effect it will have. This is also consistent with the IEEE Standard 242 recommendations. Other relaying is capable of sensing and disconnecting the generator from the system during an out-of-step condition if the breakers are capable of withstanding the stress of an out-of-step interruption.

If other relaying is depended upon to interrupt for an out-of-step condition, it should operate as fast as possible to allow circuit breakers to clear before a true out-of step condition occurs that would increase the voltage stress on the interrupting device.

One disadvantage in depending upon other types of relays is that they cannot discriminate between a stable and an unstable swing, and will cause a trip for both conditions. For a small distributed generator tripping for any swing, stable or unstable, may be satisfactory. On a small or medium size generator installation the following conclusions may be reached:

1. An ANSI No. 78 device should not be set unless sufficient information is available and an in-depth transient stability study is performed.

2. Relay manufacturer's preliminary setting methods for out-of-step relays are a starting point only, and are not sufficient to properly set this relay without the information provided by a transient stability study.

3. Other relays will likely disconnect the generator for an out-of-step condition due to the high currents and depressed voltages inherent in such an event. The following may be used:

   a) An instantaneous phase over current relay (Device 50).

   b) A voltage restrained phase over current relay (Device 51V) may be set with the smallest possible time dial which will still coordinate with other relaying on the system.

   c) A voltage-controlled phase over current relay (Device 51V) may be set. The control voltage may be set at 50% of the nominal voltage, and the current pickup should be set at or slightly above the generator full load current and an extremely fast time dial, or a short definite time setting (less than 5 cycles) should be used. This should rapidly disconnect the generator from the system for a developing out-of-step condition.

   d) An under-voltage relay (Device 27) may be set at approximately 50% of the nominal voltage with a short time delay (5 cycles).

Any of the above devices may be used to disconnect the generator for an out-of-step condition when insufficient information is available to set a device No. 78. However, these other relays will not discriminate between a stable and an unstable generator swing. If the out-of-step relay is set to block other relaying, a transient stability study is essential, as well as an understanding of the effect this will have on the generator and other protective devices in the system.

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APPENDIX

Typical Relay Settings (Figure 15)			
Interconnection Relay (Settings Required by the Utility)		**Generator Relay**	
Function	Settings	Function	Setting
50G (residual)	PU=5 Amps	50	PU=16.6 Amps
51V	PU = 1.8 Amps TD = 4.0 Voltage Restrained Very Inverse	51V	PU = 1.05 pu. Voltage Restrained TD = 2.0 Very Inverse
32U	PU = -0.012 W Time Delay = 120 cycles	40	#1 Diameter = 75 Ohm Offset = 13 Ohm Time Delay = 5 sec.
27	Level 1 PU = 106 V Delay -= 120 cyc. Level 2 PU = 60V Delay = 10 cyc.	51G	PU = 0.5A Definite Time Time Delay = 1 sec.
59	Level 1 PU = 132 V Delay = 30 cyc. Level 2 PU = 165 V Delay = 6 cyc.	46	PU = 10% TD = 3
51G	PU = 1.25A TD = 4.0 Very Inv.	27	PU = 96V Delay = 10 sec.
25	Phase Angle = 10° Voltage Difference Limit = 12V Maximum Slip Freq. = 0.2 Hz Live Line Dead Bus Enabled	59	PU = 132V Time Delay = 1 sec.
81	Level 1 PU = 60.5 Hz Delay = 10 cyc. Level 2 PU = 59.3 Hz Delay = 10 cyc. Level 3 PU = 59.0 Hz Delay = 5 cyc.	81	Level 1 PU = 59.5 Hz Delay = 60 cyc. Level 2 PU = 58 Hz Delay -= 30 cyc. Level 3 PU = 60.5Hz Delay = 60 cyc. Level 4 PU = 62 Hz Delay = 30 cyc.
78	Diameter = 35 Ohms Offset = -30 Ohms Angle = 90° Time Delay = 1 cycle Blinder = 5 Ohms	87	Slope = 20% Time Delay = 1 cycle
		32R	PU = -0.05 pu. Delay = 5 sec.
		25	Phase Angle = 10° Voltage Difference Limit = 12V Maximum Slip Freq. = 0.2 Hz

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