Back to Table of Contents

Directional Overcurrent Relaying in the Distributed Generation Environment

John Horak, Basler Electric Company

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John Horak, Basler Electric Company

Directional overcurrent relaying (device 67) can add to the protection schemes that are used in the distributed generation (DG, also referred to as a Distributed Resource, DR) market. This paper reviews the basics of the theory of directional overcurrent relaying as applied in modern numeric relays, and then discusses several applications of the directional overcurrent relaying in the DG environment.

Symmetrical Component Impedances for Directional Analysis

Modern microprocessor relays, for the large majority of cases, use the angular relationships of symmetrical component currents and voltages and the resultant angular nature of Z_1, Z_2 and Z_0 as can be calculated from V_n/I_n, to determine direction to fault. There are variations among manufacturers on of how one senses the angular relationships and, in many cases, the complete magnitude and angle of Z is not actually calculated, but there is a common concept involved. In faulted conditions there is, in at least the common basic systems, an approximate 180^0 difference of calculated Z_1, Z_2 and Z_0 for faults in the two directions from the relay location. This high variation in phase angle is a reliable indication of direction to fault.

As described in detail in [1], the three phase voltage drop equation for a system that can be represented by voltages at two defined locations, (V_{Sys} and V_{Fault} in this example) is:

$$\begin{bmatrix} V_{A,Sys} \\ V_{B,Sys} \\ V_{C,Sys} \end{bmatrix} - \begin{bmatrix} V_{A,Fault} \\ V_{B,Fault} \\ V_{C,Fault} \end{bmatrix} = \begin{bmatrix} Z_{AA} & Z_{AB} & Z_{AC} \\ Z_{BA} & Z_{BB} & Z_{BC} \\ Z_{CA} & Z_{CB} & Z_{CC} \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{1}$$

Again, as discussed in [1], when the impedances are highly balanced (i.e., the diagonal self impedance elements Z_{AA}, Z_{BB}, and Z_{CC} are all one value, and all off diagonal mutual impedance elements are another value), equation (1) can be restated in symmetrical component quantities by the equation:

$$\begin{bmatrix} V_{0,Sys} \\ V_{1,Sys} \\ V_{2,Sys} \end{bmatrix} - \begin{bmatrix} V_{0,Fault} \\ V_{1,Fault} \\ V_{2,Fault} \end{bmatrix} = \begin{bmatrix} Z_0 & 0 & 0 \\ 0 & Z_1 & 0 \\ 0 & 0 & Z_2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{2}$$

In the typical power system, we can usually assume that, at the system, voltage has negligible V_0 and V_2, and V_1 is 1.0, or at least very close to 1.0. At the other end, the fault location, every

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type of fault will have differing values of V_0, V_1, and V_2 and will need to be calculated via means that will not be covered here (see [1]), but we know that some value exists. Hence, (2) reduces to:

$$\begin{bmatrix} 0 \\ V_{1,System} \\ 0 \end{bmatrix} - \begin{bmatrix} V_{0,Fault} \\ V_{1,Fault} \\ V_{2,Fault} \end{bmatrix} = \begin{bmatrix} Z_0 & 0 & 0 \\ 0 & Z_1 & 0 \\ 0 & 0 & Z_2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{3}$$

If Z_0, Z_1, and Z_2 are divided into two impedances as seen from the relay location (line impedance and source impedance), the net system has the appearance of figure 1.

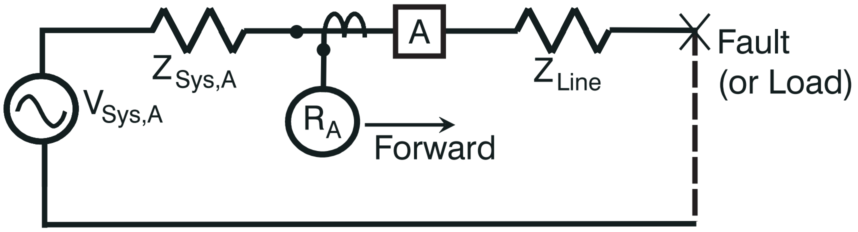


Figure 1 - Single Source System with Relay

In this application, (3) becomes:

$$\begin{bmatrix} 0 \\ V_{1,Sys} \\ 0 \end{bmatrix} - \begin{bmatrix} V_{0,Fault} \\ V_{1,Fault} \\ V_{2,Fault} \end{bmatrix} = \left(\begin{bmatrix} Z_{0,Sys} & 0 & 0 \\ 0 & Z_{1,Sys} & 0 \\ 0 & 0 & Z_{2,Sys} \end{bmatrix} + \begin{bmatrix} Z_{0,Line} & 0 & 0 \\ 0 & Z_{1,Line} & 0 \\ 0 & 0 & Z_{2,Line} \end{bmatrix} \right) \begin{bmatrix} I_{0,Relay} \\ I_{1,Relay} \\ I_{2,Relay} \end{bmatrix} \tag{4}$$

We can calculate the voltage at the relay by starting at the fault location and work back to the system or at the system and work toward the fault. Since we do not know the fault voltages, we need to take the latter approach, so we can calculate relay voltage from:

$$\begin{bmatrix} V_{0,Relay} \\ V_{1,Relay} \\ V_{2,Relay} \end{bmatrix} = \begin{bmatrix} 0 \\ V_{1,Sys} \\ 0 \end{bmatrix} - \begin{bmatrix} Z_{0,Sys} & 0 & 0 \\ 0 & Z_{1,Sys} & 0 \\ 0 & 0 & Z_{2,Sys} \end{bmatrix} \begin{bmatrix} I_{0,Relay} \\ I_{1,Relay} \\ I_{2,Relay} \end{bmatrix} \tag{5}$$

If we solve for the impedances, since $V_{2,Sys} = 0$ and $V_{0,Sys} = 0$, then:

$$Z_{0,Relay} = \frac{V_{0,Relay}}{I_{0,Relay}} = -Z_{0,Sys} \tag{6}$$

$$Z_{2,Relay} = \frac{V_{2,Relay}}{I_{2,Relay}} = -Z_{2,Sys} \tag{7}$$

For $Z_{0,Relay}$ and $Z_{2,Relay}$, the impedance seen by the relay for the fault indicated will be dependent solely upon the source impedance. (The dependency on source impedance might be counter-intuitive to engineers accustomed to setting impedance relays in terms of line impedances.) The angle of $Z_{0,Relay}$ and $Z_{2,Relay}$ is the source of determining the direction to a fault. For instance, in figure 1, a CT polarity orientation can cause the apparent Z_0 and Z_2 at the relay to either match the source impedance angle or to be inverted by 180^0. The current polarity would be the signature of a fault that is either forward or reverse from the relay's location.

The apparent Z_1 at the relay will be dependent on the fault type. First, we need to define the impedance between the relay and the fault location:

$$Z_{1,Line,Flt} = Z_1 \text{ from relay location to fault location on the line} \tag{8}$$

Three phase fault:

$$Z_{1,Relay} = \frac{V_{1,Relay}}{I_{1,Relay}} = \frac{V_{1,Sys} - Z_{1,Sys} I_{1,Relay}}{\dfrac{V_{1,Sys}}{Z_{1,Sys} + Z_{1,Line,Flt}}} = \frac{V_{1,Sys} - Z_{1,Sys}\left(\dfrac{V_{1,Sys}}{Z_{1,Sys} + Z_{1,Line,Flt}}\right)}{\dfrac{V_{1,Sys}}{Z_{1,Sys} + Z_{1,Line,Flt}}} = Z_{1,Line,Flt} \tag{9}$$

Phase to ground fault (similar derivation to (9)):

$$Z_{1,Relay} = Z_{0,Sys} + Z_{0,Line,Flt} + Z_{1,Line,F} + Z_{2,Sys} + Z_{2,Line,Flt} \tag{10}$$

Phase to phase:

$$Z_{1,Relay} = Z_{2,Sys} + Z_{1,Line,Flt} + Z_{2,Line,Flt} \tag{11}$$

Hence, the Z_1 measurement as seen at the relay is a mix of the various system and line impedances, but it tends to be a measure of forward looking line impedance more than source impedance, most clearly seen in (9). The impedance angle of the various components of $Z_{1,Relay}$ tend to be similar, in the area of 50^0 - 85^0. Hence, independent of the fault type, the angle of $Z_{1,Relay}$ as sensed by the relay falls in a narrow band. This allows the impedance angle as sensed at the relay to continue to act as a strong indication of the direction to the fault. The CT polarity orientation relative to the fault location will still cause the calculated $Z_{1,Relay}$ angle either to be the approximate net system impedance phase angle, or to be reversed by 180^0, which again is the signature of a fault that is either forward or reverse.

If a relay uses $Z_{1,Relay}$ for sensing direction to fault, the $Z_{1,Relay}$ measurement will see balanced load flow as an indication of the direction to fault and, hence, to turn on overcurrent elements (67/51) that are set to look in the direction of present load flow. The Z_1 that is sensed during balanced load flow conditions is a minor modification of (8):

$$Z_{1,Relay} = Z_{1,LIne} + Z_{1,Load} \tag{12}$$

Typically, relays that use $Z_{1,Relay}$ for direction to fault measurement will give priority to $Z_{2,Relay}$ and $Z_{0,Relay}$ for determining direction to fault and, hence, the negative sequence impedance detection will be the determining factor for direction to fault for phase to phase and phase to ground faults. The $Z_{1,Relay}$ measurement will usually only become part of the analysis for three phase faults and load flow conditions.

Directional overcurrent relaying would not be useful in a system with only one source. A system with two sources is shown in figure 2. We can apply the same concepts as above to analyze the circuit. i.e.: We have a fault location where there is a calculable level of sequence voltages, and a system and line impedance in two directions, looking back toward the system source voltage. The same approach as in (1) to (7) can be applied to find the impedance seen by the relays at either end of the line.

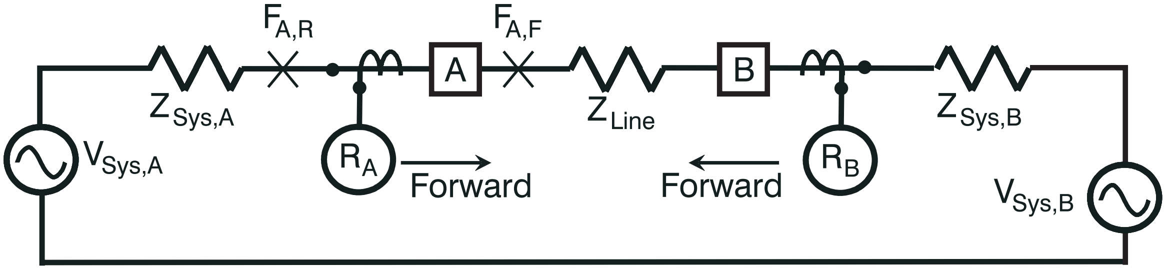


Figure 2 - Two Source System

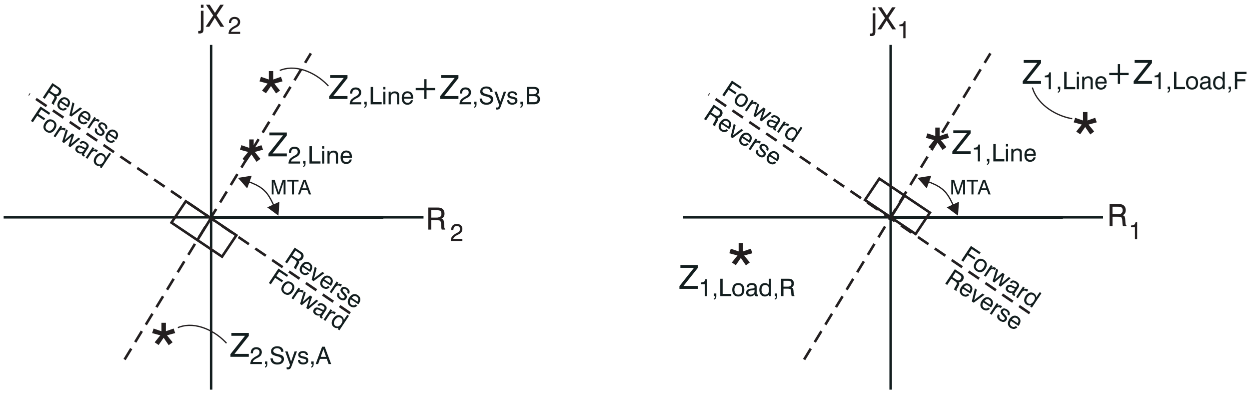
The impedance as seen by relay A will vary according to the direction to the fault. For faults on the two different sides of the breaker, the relay will sense two completely different impedances. For fault $F_{A,F}$ and $F_{A,R}$ the impedance seen by relay R_A will be:

$$\begin{aligned} Z_{0,Relay,Fault\ A,For} &= -Z_{0,Sys,A} \\ Z_{0,Relay,Fault\ A,Rev} &= 1\angle 180^0 \cdot \left(-Z_{0,Sys,B} - Z_{0,Line}\right) = \left(Z_{0,Sys,B} + Z_{0,Line}\right) \\ Z_{2,Relay,Fault\ A,For} &= -Z_{2,Sys,A} \\ Z_{2,Relay,Fault\ A,Rev} &= 1\angle 180^0 \cdot \left(-Z_{2,Sys,B} - Z_{2,Line}\right) = \left(Z_{2,Sys,B} + Z_{2,Line}\right) \end{aligned} \tag{13}$$

In (13), $Z_{\#,Line}$ refers to the entire line impedance. The $1\angle 180^0$ factor in (13) accounts for the effective change in CT polarity for faults in the reverse direction. The positive sequence impedance does not lend itself to simple equations such as (13), but for 3 phase faults and unfaulted load flow conditions:

$$\begin{aligned} Z_{1,Relay,Forward,Faulted} &= Z_{1,Line,Flt} \\ Z_{1,Relay,Reverse,Faulted} &= -Z_{1,Sys,A,to\ Fault} \\ Z_{1,Relay,Forward,Unfaulted} &= Z_{1,Line} + Z_{1,Load,B} \\ Z_{1,Relay,Reverse,Unfaulted} &= -Z_{1,Sys,A} - Z_{1,Load,A} \end{aligned} \tag{14}$$

A graphical representation of the forward and reverse zones of protection can be seen in figure 3. The “Maximum Torque Angle” (MTA), a concept that is a holdover from electromechanical relays, is a user setting that effectively defines forward and reverse phase angles. Sensed impedance angles that are +/- 90^0 from the MTA would fall into either the forward or reverse zone, depending on relay setup and CT connections.



Z_2 Directionality
(Z_0 similar)

Z_1 Directionality
(3 Phase Faults
and Load Flow)

Figure 3 - Forward and Reverse Impedance Angles

As previously mentioned, the various relay manufacturers have differing ways of sensing angular relationships. The most obvious process is to measure the impedance angle and compare it to a window of the MTA +/-90^0 as forward or reverse. There are alternate processes in use. For instance, equation (11) above has led one manufacturer to configure their $Z_{2,Relay}$ and $Z_{0.Relay}$ directional elements to subtract the MTA from the calculated impedance, and then find the real portion of this resultant impedance, Z_{Real}. Then, Z_{Real} is compared to a user setting for the dividing point between forward and reverse. For the great majority of cases this gives the same result as the phase angle window, though a large variation between actual line angle and MTA on a short line might give a small window for undesirable results.

Variations of Zero Sequence Directionality

Zero sequence directionality has several variations. The V_0 and I_0 used in a Z_0 measurement each can be obtained from various inputs:

- V_0 as calculated from the 3 phase VT inputs.
- V_0 as seen on a 4th auxiliary VT input on the relay (V_X below). This V_X input can be connected to a variety of sources, such as:
    - a broken delta VT, or
    - the neutral of an impedance grounded generator.

- I_0 as calculated from the 3 phase CT inputs.
- I_0 as seen on a 4th CT input on the relay (I_G below). This auxiliary CT input can be connected to a variety of sources, such as:
    - a window CT that wraps all 3 phases, or wraps all 3 phases as well as a power carrying neutral conductor,
    - the neutral of a transformer, or
    - the neutral of a generator.

The result is that there are 5 different combinations of currents and voltages that can be used to create a directional 67_{ZERO}.

67_{ZERO} Type	Quantity 1	Quantity 2
V_0I_0	Calculated Vo from phase VTs	Calculated Io from phase CTs
V_0I_G	Calculated Vo from phase VTs	Current on 4th CT input
V_XI_0	Voltage on 4th VT input	Calculated Io from phase CTs
V_XI_G	Voltage on 4th VT input	Current on 4th CT input
I_0I_G	Calculated Io from phase CTs	Current on 4th CT input

The last item in the list uses only current for the directional decision and is sometimes referred to as zero sequence current polarization. The MTA is always 0^0. If the two currents are in phase (+/-90^0), the fault is forward.

Other Issues

There is a number of subtleties involved in the forward/reverse direction decision and element operation that will not be covered here. One should refer to the various relay manufacturers' instruction manuals for details on their relays' algorithms. Two issues that need to be understood: 1) It is counter-intuitive to some users to have negative angles as forward and positive angles as reverse, so some manufacturers effectively invert the Z_2 and Z_0 forward impedance angle. Effective, a "-1" factor is entered into the relay's impedance angle calculations. 2) The relay has limits to its sensitivity. There must be sufficient quantities of current and voltage for a directional decision. Typically, the relay will default to a "neither forward nor reverse" status if either currents or voltages are very low.

Overcurrent and Directional Element Names and Control

One needs to understand which directional decision controls which overcurrent element. There is no standard way to name all of the overcurrent elements that are involved. Assume for the discussion that there are 67/51P (phase), 67/51G (ground), and 67/51Q (negative sequence) elements and similar 67/50 elements, and that each has a forward or reverse looking mode with different settings for each direction. There are three directional elements called the 67_{POS} (positive sequence), 67_{NEG} (negative sequence), and 67_{ZERO} (zero sequence) that control the 67/51 and 67/50 elements. The protective elements and their directional controls are:

67/51 elements	67/50 elements	Directionally Controlled by (typically)
67/51P - Forward	67/50P - Forward	67_{POS} (3ph) and 67_{NEG} (Ph-Ph)
67/51P - Reverse	67/50P - Reverse	67_{POS} (3ph) and 67_{NEG} (Ph-Ph)
67/51G - Forward	67/50G - Forward	67_{ZERO} and 67_{NEG}
67/51G - Reverse	67/50G - Reverse	67_{ZERO} and 67_{NEG}
67/51Q - Forward	67/50Q - Forward	67_{NEG}
67/51Q - Reverse	67/50Q - Reverse	67_{NEG}

A given relay may have more than one copy, or no copy, of the indicated element.

DG Application Note 1

Applications Needing Different Forward and Reverse Fault Response and Sensitivity at the PCC

A load-only facility, of course, has no need for directional current sensing. However, when generation is added to the facility, that facility, now a DG, can backfeed the utility lines. The fault current that is seen at the Point of Common Coupling (PCC) can vary hugely for faults in the DG facility that are fed by the utility and for faults in the utility that are fed by the DG. The differing current levels may require two 67 relays, or two 67 functions in one relay, each designed to respond to the appropriate fault in the two directions, each with differing overcurrent pickup and time dial settings. Further, two relays or relay functions can be used to determine appropriate response to the fault. For faults in the facility, the response should be to trip the PCC breaker, but for faults in the utility, the response might be either to trip the generation rather than the PCC breaker, or to trip the PCC and implement some immediate remedial action scheme to help generation survive any major difference between present generator output and facility loading.

In many DG applications, the generator is intended to be used for peak shaving purposes, not as a base load unit. Since generation may be off during times of high facility loading, the overcurrent relaying at the Point of Common Coupling (PCC) must be able to carry the peak loading of the facility, so its overcurrent setting is, for the purpose of discussion, 1.25 per unit, where 1 per unit is the peak loading of the facility. The minimum loading of the facility is as low as 0.1pu. Assume a generator is obtained that is 1.0 per unit in capability, though it is common for a DG to be sized much smaller than the local load. The unit size relative to local load means that, during facility light loading times, the generator could easily carry the entire facility and the plant could even export power. However, suppose the generation is designed as a peak shaving "no reverse power flow allowed" facility; therefore, there has to be a control package for the generator that monitors the voltage, power, and VARs at the facility PCC and takes appropriate action to turn down prime mover power whenever the facility approaches the point of power export. The control system is not a protective relay, so typical engineers and utility personnel will not allow it to be relied upon to prevent an island condition. Compared to facilities where generation is always less than local load, this DG has an increased risk of supporting an island or supporting the fault condition for an extended period.

To mitigate the risk of the DG supporting an island and being slow to trip for a utility fault, the utility might ask that the DG install overcurrent relaying that can sense all faults on the line to which the DG is connected. The basic solution is to provide two back-to-back directional overcurrent relays, one looking into the DG facility (forward) and a second looking into the utility lines (reverse). However, several things may cause a determination that the reverse looking overcurrent relay will need to be set fairly sensitively. 1) The utility distribution line continues many miles farther after the DG tap, so the DG sees substantial impedance to the fault location. 2) The utility does not allow for "sequential tripping" (i.e., the generator must see the utility line fault even when the utility is still connected and supporting the fault). 3) The utility discounts the use of generator sub-transient reactance (X_D") and requests the use of generator steady state reactance (X_D) with no allowance for excitation boosting, so the generator fault contribution is weak on a steady state basis. These considerations, or others, result in a need to set the phase overcurrent element that looks toward the utility to below the pickup of the facility's full load current. A possible scenario is shown in figure 4 where the DG is asked to trip at 0.25 pu for reverse phase-phase faults, which is much less than load current into the facility.

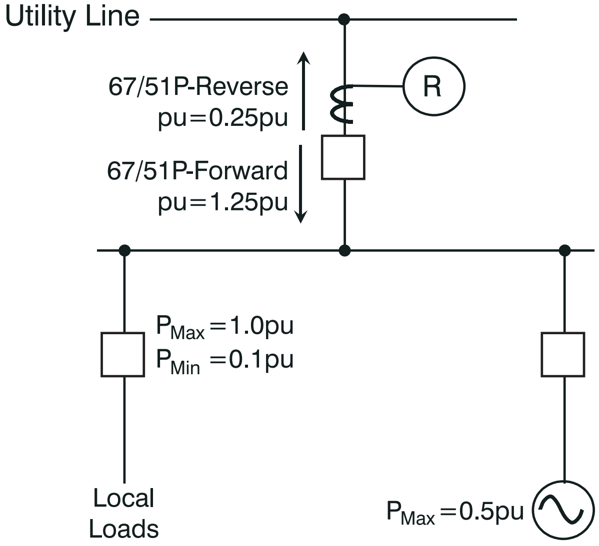
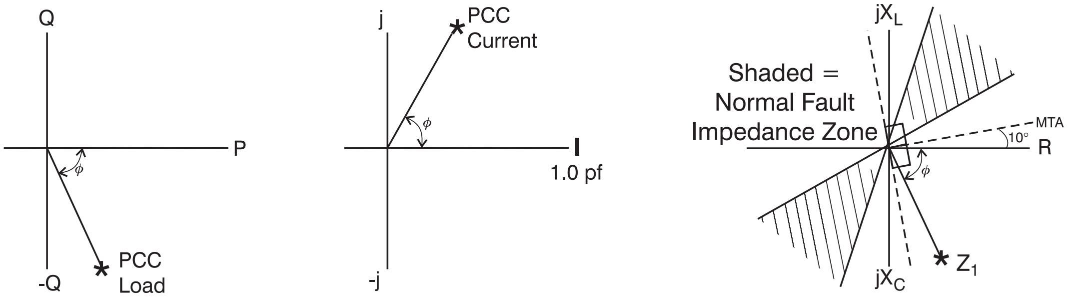


Figure 4 - Example DG One-Line

One concern that can be seen in this arrangement is whether forward load current might ever be seen as a reverse condition by the 67_{POS} element and lead to a subsequent trip. The generation in the facility might cause load current to be virtually any power factor. Suppose the generation output is set a little below present facility load levels, so that net power into the facility is low, and since the facility is absorbing at least some power, there is a verification to the utility that the generator is not supporting an island. Also suppose that the generator is running in an over-excited mode and shipping VARs to the utility. In this mode the facility is seen by the utility as a leading power factor load. While this would not be a normal excitation level for the generator, such a condition cannot be excluded from occurring. It might occur during loss of an inductive load in the facility. Figure 5 shows the condition. A positive sequence directional element, 67_{POS}, is at risk of seeing current in the reverse direction for this condition. One approach to addressing the issue is to set the MTA used by the 67_{POS} element to about 10^0. This will skew the forward direction for faults to include this load flow pattern as a forward condition, and since the angle of maximum torque covers the zone of $+/-90^0$, the relay still will be able to correctly distinguish forward and reverse fault conditions.



$S = VI^*$

$I = (P/V)^*$

$Z_1 = V_1/I_1$

Figure 5 - DG S, V, Z_1 at PCC for Leading PF Condition

Application Note 2

Use of the 67/51 as a Loss of Synchronism Detection

In the recent few years there was considerable attention and promotion given to requiring distributed generation to include the loss of synchronism function (alternatively referred to as an “Out of Step” relay or as “Device number 78”) in their protective relaying packages. To most engineers the ideal 78 function should be done with the classical impedance functions that monitor for relatively slow moving 3 phase faults on an R-X plane. The cost of the required relay, the cost of the engineering required to properly set the function, and various arguments that the function was not necessary, eventually led to the function being left as a suggested or “if needed” function in most regulatory and utility standards. However, if a generator does pull out of step, it is not a good situation, so it is good engineering practice to address the concern if possible, given the restraint of the ideal 78 function is not available in the relaying packages being used at one’s facility. Let us see if the commonly available and easily set 27, 50, and 67/50 element can be configured to respond to a loss of sync condition.

For a 27, 50, and 67/50 element to sense loss of synchronism, we have to assume the event actually occurs; we cannot predict it is about to occur, as might be possible with impedance elements. To sense the condition, we want to configure these elements to look for the low voltages, high currents, and high currents in an abnormal direction that might occur when the generator goes 180^0 out of phase with the system. There are notable issues, as we will see below, with using a 27 or non directional 50 element. A 67/50 element may be most capable.

Voltage during Loss of Synchronism

Let us assume the simple system shown in figure 6. We will assume that the generator slips a pole and analyze the circuit to determine the voltages and currents at the PCC.

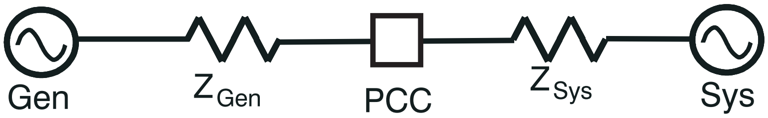


Figure 6 - Simple System for Loss of Sync Analysis

We are ignoring load in this figure. To analyze the circuit under the presence of load, see reference [2], which analyzes figure 6 in detail and also includes facility loads.

Let us use V_{Sys} as the fixed voltage and rotate the generator voltage phasor around by 360^0. The voltage at the PCC will be:

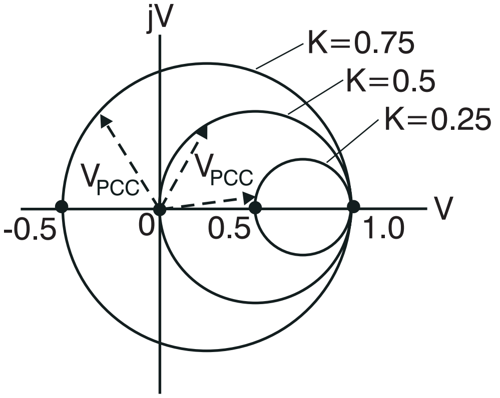
$$\begin{aligned} V_{PCC} &= V_{Sys} - Z_{Sys} I_{Sys} = V_{Sys} - Z_{Sys}\left(\frac{V_{Sys} - V_{Gen}}{Z_{Sys} + Z_{Gen}}\right) \\ &= V_{Sys} - k\left(V_{Sys} - V_{Gen}\right) \end{aligned} \qquad (15)$$

where

$$k = \left(\frac{Z_{Sys}}{Z_{Sys} + Z_{Gen}}\right)$$

A k value of 0.5 will indicate the PCC is at the electrical impedance center. If 0.5<k<1 then the generator impedance is smaller than the system impedance, and if 0<k<0.5 the generator impedance is larger than the system impedance.

A graphical picture that helps give a feel for the significance of this equation is seen in figure 7. Note in figure 7 that if the PCC is near the electrical impedance center, then a very low voltage will be seen at the PCC for each slip cycle, but if the PCC is remote from the electrical impedance center, the voltage drop seen at the PCC might be difficult to sense.



$V_{Sys} = V_{Gen} = 1.0$

$$K = \frac{Z_{Sys}}{Z_{Sys} + Z_{Gen}}$$

V_{PCC}= Origin to K circle as generator slip advances

Figure 7 - V_{PCC} for Varying k as Generator Slips Pole

There is some difficulty in stating the apparent impedance of a generator during a pole slip event. This paper takes the generally accepted view (which is in agreement with generator simulation tests performed at the Basler factory) that the transient reactance, X_D', is a reasonable representation of the generator impedance during a pole slip event, falling in the 0.3pu range. During a slow pole slip, when a slip cycle exceeds twice the X_D' time constant (typically about 0.3 second time frame), it would be anticipated that the apparent generator impedance will start to increase somewhat.

Let us look at our sample system in figure 6. The generator was rated at half the system load, so its effective impedance at the base of 1.0 PU will be $X_D' = 0.6$pu. A power system that is capable of delivering 1pu current with good voltage regulation likely has a fault duty on the order of 10 times the load current level, so we might assume X_{Sys} of around 0.1pu, which is reasonable considering a 5% impedance facility transformer and a long line to the facility. In any case, the generator impedance is notably higher than the system impedance and k has a value of about 0.14 in this case. If a generator is used that could support the full facility load, k would have been about 0.25. Per figure 7, k=0.25 indicates only a 50% voltage dip at the PCC.

Let us call the undervoltage element that we want to sense the out of step condition a 27T-3/3 (T indicates the 27 is a definite time delay element, and 3/3 indicates all 3 phases must be low for a trip). Some issues that need consideration when setting the 27T-3/3 are:

1. The minimum voltage that will be seen at the PCC during a pole slip needs to be determined. See (15) and Ref. [2] as a starting point. The PU setting for 27T-3/3 element needs to be less than the worst case voltage drop that will occur during load inrush at the facility. Load inrush should not cause more than 20% voltage drop in most facilities, so a setting of 75% of nominal may be appropriate. Hence, the voltage during a loss of sync

condition might be insufficiently low to reliably differentiate from low voltage due to normal events. This issue may prevent the ability of the 27 to detect loss of synchronism.
2. The low voltage at the PCC for a pole slip will be seen on all 3 phases, so to help differentiate the pole slip from a temporary fault, the element should monitor for all phases going low.
3. The 27T-3/3 should be time delayed only a matter of cycles. If the PCC is at the electrical impedance center where k=0.5, V_{PCC} will be below 0.5pu for about 1/3 of the slip cycle. Assuming the slip is 1 pole slip per second, this gives a low voltage for around 20 cycles. If the PCC is not at the electrical center, the minimum low voltage will be higher than 0V and the low voltage condition will last a shorter time. If the slip was faster, there would be even less time for the relay to respond. Time delay may need to be as low as 5 cycles, if the voltage dip can be sensed at all.
4. The 27-3/3 could be fooled by external events that deliberately remove power at the PCC, so an input to the relay to block operation for such conditions may be necessary.
5. If the breaker is opened at the moment of lowest PCC voltage, then the breaker will try to interrupt current with the generator and system 180^0 out of phase and with twice the system voltage across the breaker once current is interrupted. It may be advisable to delay tripping until the 27-3/3 element drops out.

Current during Loss of Synchronism

The current that will flow in the circuit in figure 6 during an out of step condition can be approximated by the equation:

$$\begin{aligned} I_{PCC} &= \left(\frac{V_{Sys} - V_{Gen}}{Z_{Sys} + Z_{Gen}} \right) \\ I_{PCC,\,Peak} &\approx \frac{2}{Z_{Sys} + Z_{Gen}} \end{aligned} \qquad (16)$$

This current does not reflect the load flow that will be superimposed on top of these currents. Again, see [2] for a more detailed analysis, and see earlier discussion on the use of X_D'. From the previous discussion, let us assume Z_{Sys} = 0.1pu and Z_{Gen} = X_D' = 0.6pu after converting to our common base. This gives a peak current of around 2.9pu. If a generator had been used that could have supported the entire facility, X_{Gen} = 0.3, then the peak current would be around 5pu. Let us call an overcurrent element that we want to sense the out of step condition a 50T-3/3 (T indicates the 50 is a definite time delay element, and 3/3 indicates all 3 phases must be high for a trip). Some issues that need consideration when setting the 50T-3/3 are:

1. The peak current for an out of step condition needs to be determined, and the peak load and/or transformer inrush as seen at the relay location needs to be determined. The pickup setting for 50T-3/3 element needs to be about 75% or less of the peak out of step current (= 2.1pu for our small generator case and 3.75A for our large generator case). We also need the pickup to be at least 125% or more of the worst case load/transformer inrush at the facility (maybe 2pu in this example). For the small generator case, we have a marginal condition. On a case-by-case basis, these to settings requirements may very well conflict with one another. If the conflict arises, either i) external logic must be used to block the relay element for load inrush conditions, or ii) the relay should be put at the generator terminals and should be set based upon peak load inrush as seen at the generator, rather than at the PCC.

2. Pole slip currents can be seen better at the generator terminals rather than at the PCC. In facilities with smaller generators, the load current flow at the PCC may mask the pole slip condition.
3. The high current for a pole slip will be seen on all 3 phases, so to help differentiate a pole slip from a fault, the element should monitor for all phases going high. A positive sequence overcurrent current element, 50-I_1, would not be appropriate since phase to phase and phase to ground faults can cause high I_1.
4. The 50T-3/3 should operate in a matter of cycles. The current level will oscillate from 0 to $I_{PCC,Peak}$ and back to 0 in one slip cycle and will be above about 2/3 of $I_{PCC,Peak}$ for only about 1/3 of the slip cycle. For a 1 second slip rate, a pickup of 2pu current, and a peak current of 2.9pu, the relay will be picked up for less than 20 cycles. If the slip was faster, there would be proportionately less time for the relay to respond. A delay of 5-10 cycles may be appropriate.
5. If the breaker is opened at the moment of highest current, the breaker will try to interrupt current with the generator and system 180^0 out of phase and with twice the system voltage across the breaker once current is interrupted. It may be advisable to delay tripping until the 50T-3/3 element drops out.

The 67_{POS} during Loss of Synchronism

The above equations for current and voltage at the PCC can be combined to create equations for the apparent impedance during the loss of synchronism

$$\begin{aligned} Z_{PCC} &= \frac{V_{PCC}}{I_{PCC}} = \frac{V_{Sys} - Z_{Sys}\left(\dfrac{V_{Sys} - V_{Gen}}{Z_{Sys} + Z_{Gen}}\right)}{\left(\dfrac{V_{Sys} - V_{Gen}}{Z_{Sys} + Z_{Gen}}\right)} \\ &= \frac{V_{Sys} Z_{Gen} + V_{Gen} Z_{Sys}}{V_{Sys} - V_{Gen}} \end{aligned} \qquad (17)$$

The apparent ZPCC will be lowest when VGen is 180^0 out of phase with VGen. The impedance takes a path shown in figure 8, seen in many resources. Figure 8 includes the forward and reverse zones for the 67POS element. At the point where the 67POS sees reverse current, the generator voltage will be just past 1800 out of phase, so current will still be high. If this is a facility that should not be sending large amounts of current to the utility, then we have a signature for out of step that we can monitor with what we will call a 67/50T-3/3. Some issues that need consideration when setting the 67/50T-3/3 are:

1. The peak current for an out of step condition needs to be determined, and the peak current that the facility will ever send out to the utility needs to be determined. Similar to the 50T-3/3, the 67/50T-3/3 pickup setting for 50T-3/3 element needs to be about 75% or less of the peak out of step current but, in this case, it only needs to be about 125% or more of the worst case “outrush” from the facility to the utility. Because the 67/50T-3/3 element is not turned on by the 67_{POS} until the pole slip is just past its peak, a more sensitive pickup of 50% of peak current might be good, if possible.
2. Pole slip currents can be seen better at the generator terminals rather than at the PCC. In facilities with smaller generators, the load current flow at the PCC may mask the pole slip condition.

3. The high current for a pole slip will be seen on all 3 phases, so to help differentiate a pole slip from a fault, the element should monitor for all phases going high. A positive sequence overcurrent current element, 50-I_1, would not be appropriate since phase to phase and phase to ground faults can cause high I_1.
4. The 50T-3/3 should operate in a matter of cycles. Because the element is not turned on by the 67_{POS} until the pole slip is just past its peak, high speed operation is more important. At the turn-on point of the 67/5--3/3, and given a 1 second slip cycle, the current may decay to below pickup in less than 10 cycles, and there would be even less time if the slip rate were higher. A 3-5 cycle delay would be appropriate. Of course, the faster one makes the relay, the more chance of some unrealized transient causing a misoperation of the element.
5. If the breaker is opened at the moment of highest current, the breaker will try to interrupt current with the generator and system 180^0 out of phase and with twice the system voltage across the breaker once current is interrupted. It may be advisable to delay tripping until the 67/50T-3/3 element drops out.

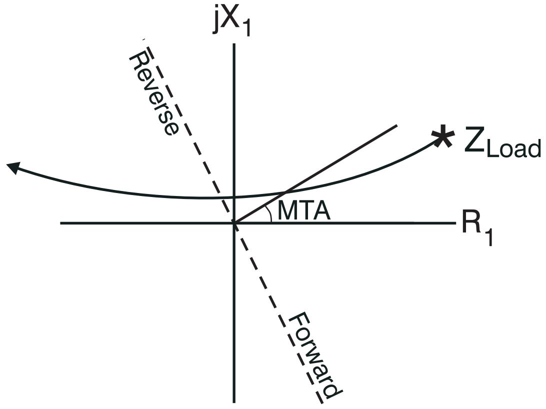


Figure 8 - Z_{PCC} during Pole Slip Event

Application Note 3

Sensitive Generator Ground Fault Detection

For the smaller generators found in the DG environment that lack a current differential (87G) element, figure 9 shows a fairly fast and sensitive means of sensing a ground fault in a generator. In this logic, the 50TN and 150TN are set non-directional. Again, the T indicates that these are definite time elements. The elements start to operate on any ground current, but they are supervised by a directional element that picks up whenever there is ground current flowing out of the generator. The 50TN (the element on the phase CTs) needs to be time delayed enough to ride through false residual current that arises due to transient phase CT saturation that might be caused by high DC offset in phase currents during normal load energization or external faults. Both elements need to be delayed long enough for the 67_{ZERO} to make a correct directional decision (which also might be affected by transient CT error). The 67_{ZERO} needs to be any method that will sense out-of-generator faults and needs to be sensitive enough to correctly see the same faults as the 50TN and 150TN elements.

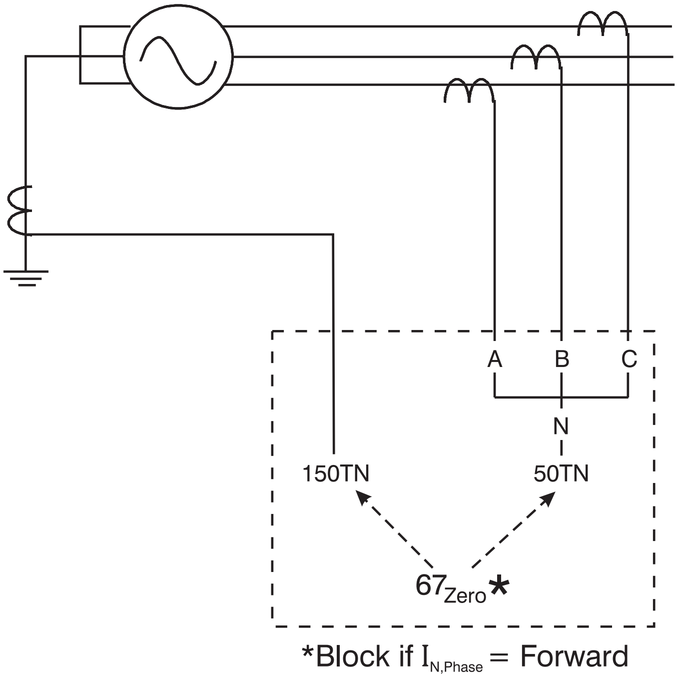


Figure 9 - Ground Fault Sensing Schematic

Application Note 4

Direction to Fault on High Impedance Grounded Systems

Some DG systems are run in an ungrounded or high impedance grounded mode behind a transformer that isolates the plant from the utility ground grid. In system with a high impedance ground, the existence of a ground somewhere in the system is indicated by a high Vo voltage, sensed by appropriate relaying, typically called a 59N relay. Once the fault is detected, the faulted phase will be indicated by a low V_{LG} on the faulted phase. However, when multiple feeders or generators are connected to the bus, the specific faulted feeder or generator is unknown.

Though small, there will be some capacitive ground current flow in the system through the fault. In figure 10, if feeder 3 has a ground fault, phase to ground capacitance on the unfaulted phases of feeders 1 and 2 will result in current flow into the ground fault. If enough capacitance is involved, the current may be detectable. For the current level to be detectable, it will likely be necessary that the relay monitor a window CT that wraps all phases, that the CT ratio be low, and the ground input (Ig) of the relay be configured as a 1A input, rather than the more typical 5A input (U.S. market). A basic approach to determining which feeder is faulted is to simply look at the magnitude of the current involved on each feeder, and the one with the most current will be the faulted phase. This approach requires that at least three feeders be on the faulted bus. With only two feeders, the faulted feeder will see about the same current as the unfaulted feeder.

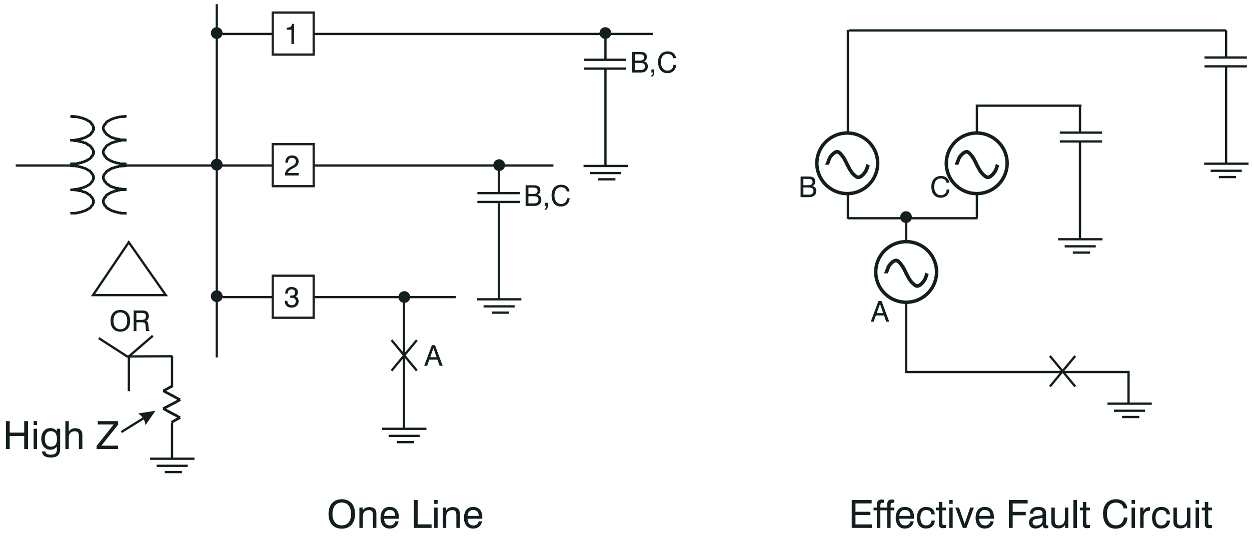


Figure 10 - Line to Ground Fault on High Z_G System.

A smarter method to sense the faulted feeder is the 67/50G with the 67_{ZERO} in the V_0I_G mode. By comparing the phase relationship between the calculated V_0 and the measured I_0, the relay can determine if there is a ground fault forward and hence on the feeder, or reverse and hence on another feeder.

This approach to sensing direction to the fault has its issues. In a high impedance grounded system, there can be some level standing offset in Vo due to system unbalance Z_{LG}; e.g., if phase A is always strung closer to ground than phase B and C, then $X_{Cap,LG}$ is lower on phase A. This will add a confusion factor to the unfaulted condition: “Is this measured V_0 due to a fault or is this due to the normal offset in my system?” If such a problem shows up, one should attempt to find the source of the standing unbalance and remove it, or one might mask it with a small ground bank. A VT connected in a broken delta arrangement with a resistor in the broken delta can act as a very small ground bank. One should calculate the ground bank impedance required before trying to use a broken delta VT so one does not find the effect too small.

Another issue is that if the phase to ground capacitance of the system is small (X_C large), there just may not be enough current for the relay to work with. One should study the relay manufacturer’s instruction manuals for the minimum currents and voltages that are required for the 51/67G and 67_{ZERO} elements to operate.

A last issue that some may be concerned about is ground fault detection when the fault impedance itself is very high; possibly on the order of thousands of ohms of resistance. The fault resistance will make the V_0 neutral shift small and make the ground fault hard to sense, especially if there is any standing V_0 in the system due to unbalanced Z_{LG} in the system. The fault resistance also will turn capacitive current flow into a capacitive/resistive flow, so that instead of I_0 leading V_0 by 90^0, it will lead by, for instance, 30^0, and reduce a small current into an even smaller current. If one is concerned about that eventuality, then the zero sequence MTA can be adjusted from 90^0 leading to some value closer to 30^0 leading, but outside of this option, one will need to look for specialized ground fault sensing relays or equipment.

Application Note 5

Detecting Hidden Phase Loss

Examine figure 11. In this case one phase feeding the DG has been lost, but due to generation on site, the matter is not easily detected simply from a voltage standpoint. It is likely that a fault occurred that caused this situation to arise, but somehow the fault has cleared and the DG is left back feeding an unfaulted phase. One might make the argument that this situation would not likely occur, but that will not dissuade the concerned utility engineer that it is still possible and should be protected against.

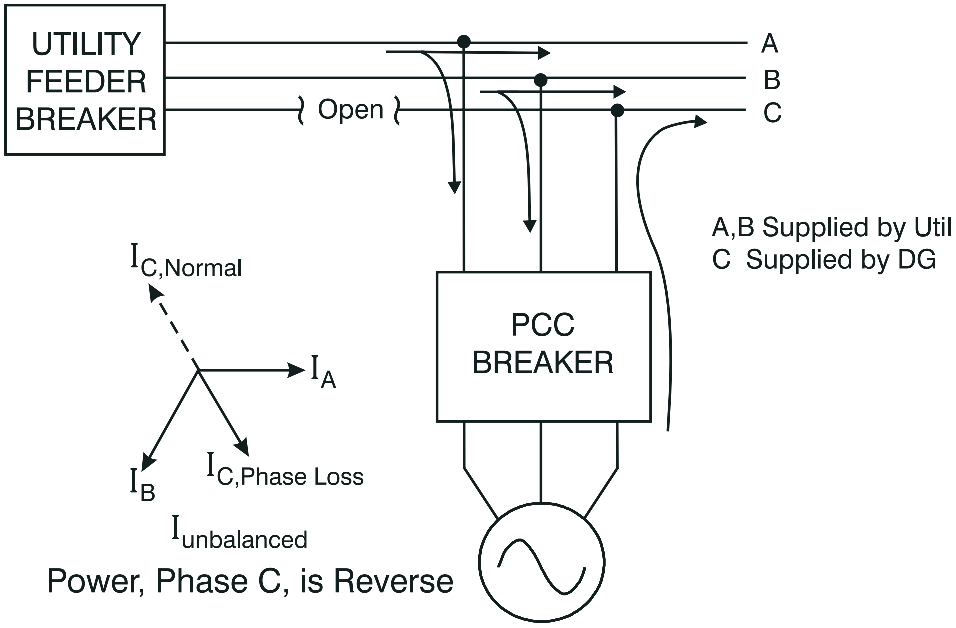


Figure 11 - Phase Loss Condition with Generator on Line

The negative sequence directional element at the PCC in this case will see high current unbalance. The load current will appear as a reverse phase to ground fault. The voltage unbalance may bee enough for the 67_{NEG} or 67_{ZERO} to enable sensitive reverse looking overcurrent elements. Another element that will see the situation is a reverse looking 32 element. A 32 element set to monitor on a three phase basis will not see the situation, but a 32 element that is set to monitor power flow one phase at a time will sense the problem.

Application Note 6

Unbalanced Load Conditions Cause Pickup of Directional Element.

In an industrial facility, there is a possibility of unbalanced loading that could result in sufficient negative or zero sequence current flow for the 67_{NEG} or 67_{ZERO} directional element bit to set. If forward is into the facility as in figure 4, the 67_{NEG} or 67_{ZERO} will be set as forward and this will turn on the forward version of the appropriate 67/51 elements. It would be anticipated that the 67/51P-Forward and 67/51G-Forward element pickup will be set above highest expected forward current conditions, so only turning on the forward direction bit set should not be a problem. Further, in such current conditions the 67_{POS} element is already set to forward due to high facility load current, and hence the 67/51P forward looking element is already enabled, so setting the negative sequence directional has not affected the matter. Therefore, the effect of the unbalanced load on the directional elements can be ignored in this case. One should think through this issue for one’s facility.

References

1. John Horak, ”A Derivation of Symmetrical Component Theory and Symmetrical Component Networks,” Western Protective Relay Conference, October 2004. Available at www.basler.com.
2. “PoleSlip_R0.xls” Spreadsheet to model voltages, currents, and power flow during a pole slip event. Available at www.basler.com.

Back to Table of Contents