“Myths” of Protecting the Distributed Resource To Electric Power System Interconnection

by

Gerald Dalke, Basler Electric Company

Introduction

The word *myth* has the definition, “A fiction or half-truth, especially one that forms part of an ideology” (Ref. 1). For the ideology of power system protection, the “myths” described in this paper are better described as “conditional” truths rather than half-truths. As you read about the “myths” in this paper, be alert for the assumed or not so obvious conditions that can cause one to feel there is adequate system protection when, actually, there is not.

Myth 1: “Distribution circuit load will always be sufficient to keep synchronous generation from back feeding single line to ground faults on the transmission or distribution system.”

Situation: A single line to ground fault F1 on a 138 kV system (Figure 1) continued to be energized by Distributed Resources, DR, at Substation C by way of Substation A, as an ungrounded system after 138 kV breakers opened at Substations D and E. The ungrounded condition continued for about 57 cycles until the voltage from the DR, as detected at Substation D, dropped low enough to permit an undervoltage relay to initiate reclosing of breaker 112 for a hot bus dead line condition. Fortunately, the DR did not sustain any damage to its generators even though they were out of phase with the 138 kV system when breaker 112 reclosed automatically.

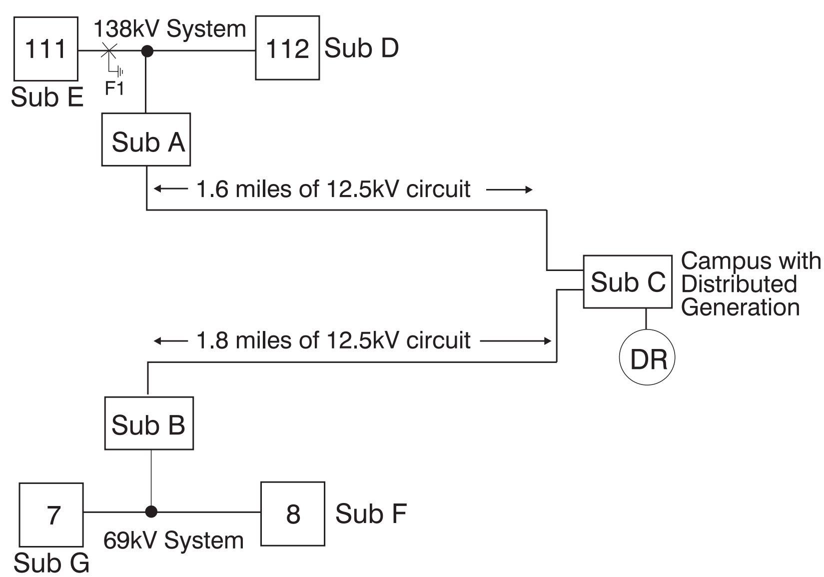

Figure 1: System One-line Diagram

The DR is in a campus type setting, Substation C (Figure 2), with five 1000 kW, 2.4 kV generators connected through individual step-up transformers to a 12.5 kV load bus. A single point of interconnect at the DR can be switched to connect to either of two utility

12.5 kV distribution circuits. The preferred distribution circuit ends at Substation A (Figure 3), approximately 1.6 miles away, which has a 138 to 12.5 kV delta wye transformer feeding only the one circuit. The alternate 12.5 kV circuit terminates about 1.8 miles away at Substation B (Figure 4) which has two 69 to 12.5 kV delta wye transformers with two 12.5 kV circuits per transformer. When connected to Substation B, the DR can back feed load and faults on two 12.5 kV circuits.

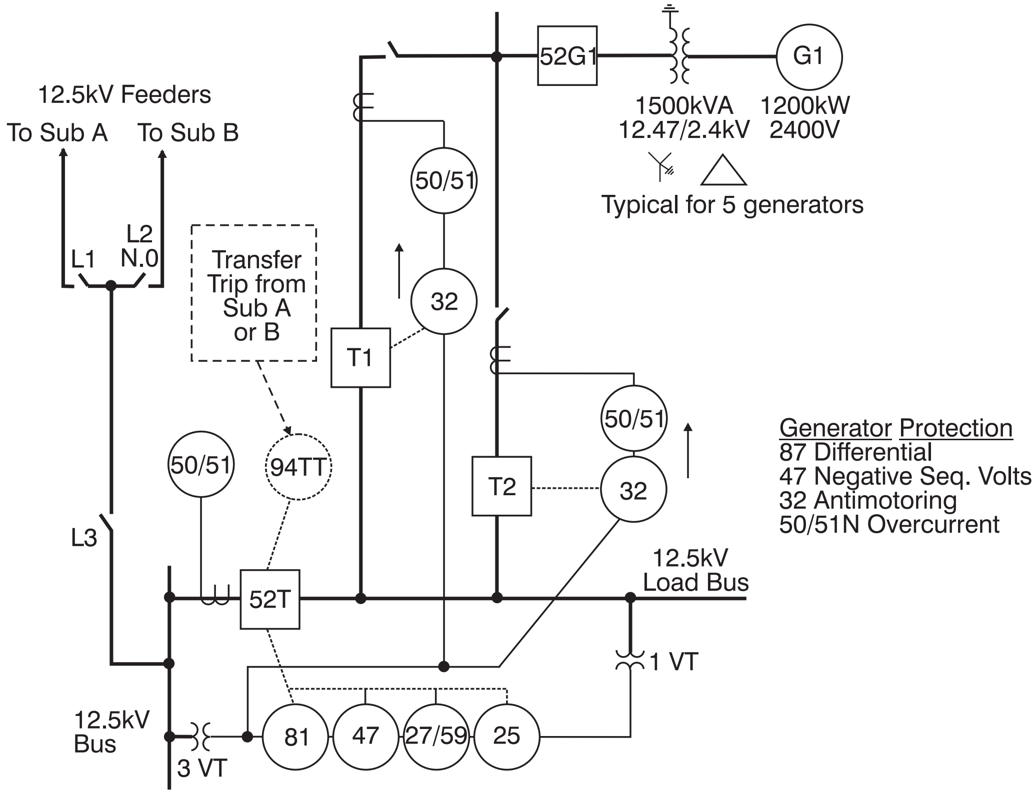

Figure 2: Substation C with Distributed Resource Generators

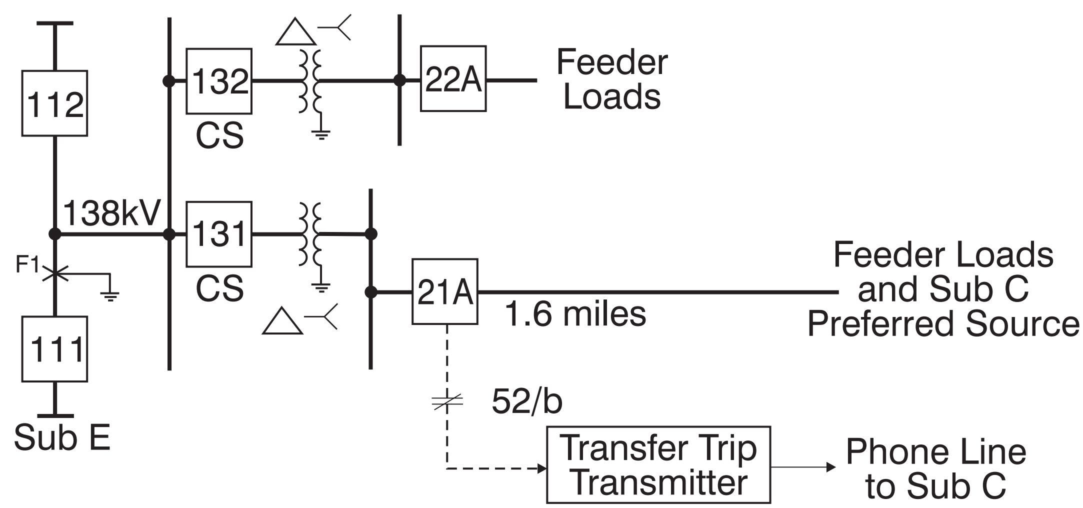

Figure 3: Substation A

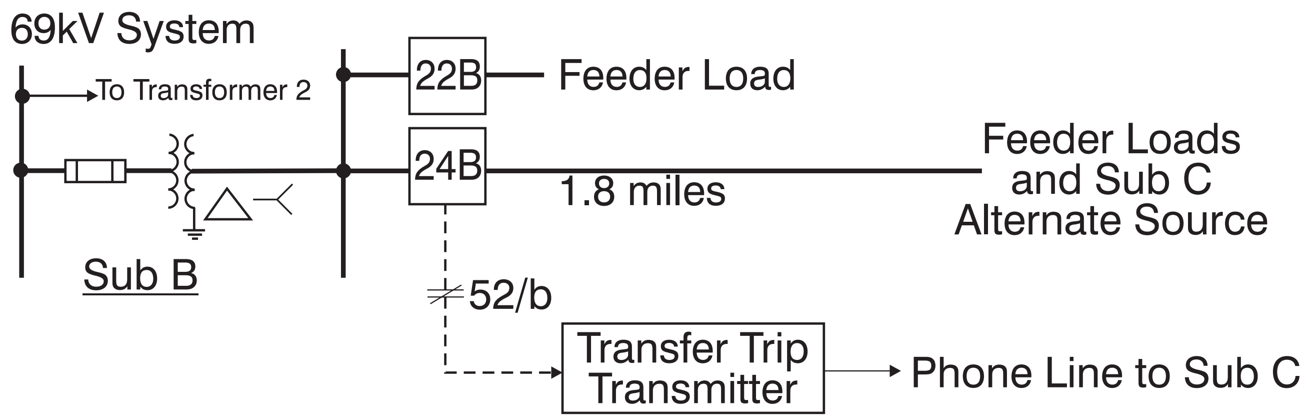

Figure 4: Substation B

Each of the utility substations has dual transfer trip keyed by its feeder breaker 52/b auxiliary contact that will trip the DR interconnect breaker, 52T, any time a utility feeder breaker is opened by overcurrent protective relays or manually in the supplying substation, either A or B.

Protection at Substation C interconnect breaker 52T as shown in Figure 2 consists of devices 50/51 phase overcurrent, 81 under frequency, 47 negative sequence voltage and 27/59 under/over voltage relays. Two reverse power relays, device 32, are located away from the interconnect breaker and are directionalized to monitor power flow into the generator bus and not for power back into the utility. For the preceding fault condition, the interconnect undervoltage relay time delay setting was not fast enough to isolate the campus generation before the transmission system closed back into the fault. This undervoltage relay had successfully operated previously, from low voltage due to circuit load being greater than the DR generation capacity during distribution circuit faults, and opened the interconnect breaker.

Solution: At Substation A, three potential transformers were added to the 138 kV bus (Figure 5) to serve as a zero sequence voltage filter. The secondaries of these VTs are connected in broken delta with a device 59N electromechanical inverse time delay undervoltage relay installed that will detect any zero sequence voltage present for single line to ground faults on the 138 kV system. The overvoltage relay keys the transfer trip transmitter and trips the interconnect breaker 52T at the DR Substation C.

Characteristics of single line to ground faults are a collapse of the faulted phase voltage and an increase in the corresponding phase current for grounded systems. In our situation, the zero sequence current is blocked by the delta winding of the power transformer and cannot flow to the transmission system fault, thus no 12.5kV overcurrent relay sees the fault. The phase to neutral voltages of the two unfaulted phases remain unchanged, thus the vector sum of the three phase to ground voltages yields a voltage 3Vo, approaching rated unfaulted secondary voltage due to the unbalance of the voltages (Figure 6). This is the voltage seen by the 59N voltage detector. Under normal unfaulted conditions, the vector sum of the three phase to neutral voltages is essentially zero volts (Figure 7). A small 3Vo voltage may be present due to untransposed transmission lines or load imbalances.

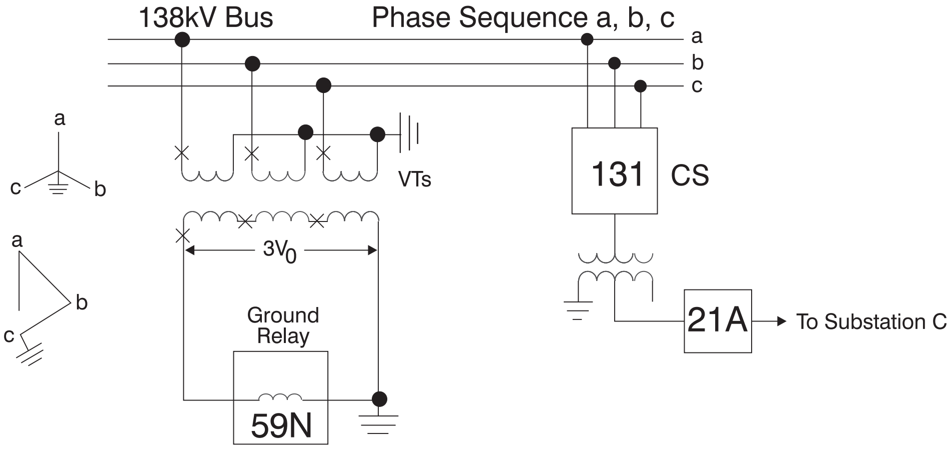

Figure 5: Substation A, 138kV Zero Sequence Voltage Detector

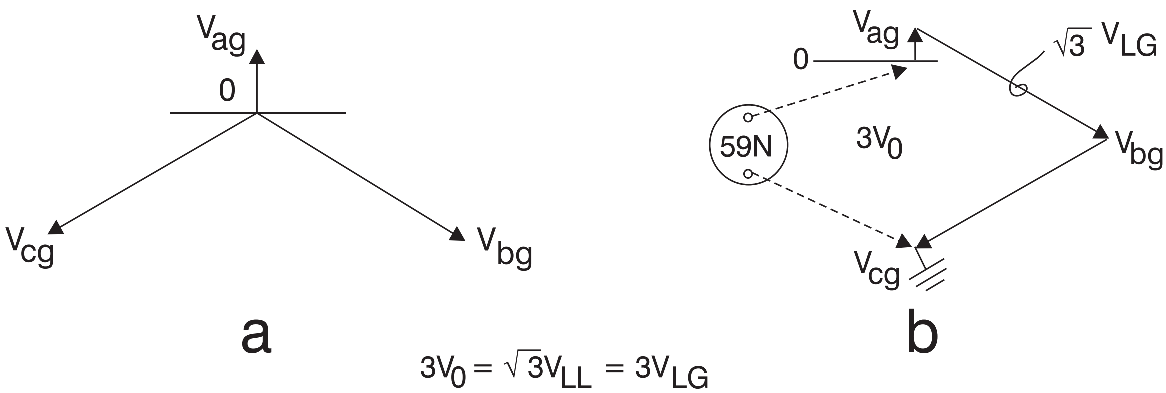

Figure 6: 138kV Single Line-to-Ground Fault Voltages at Bus A

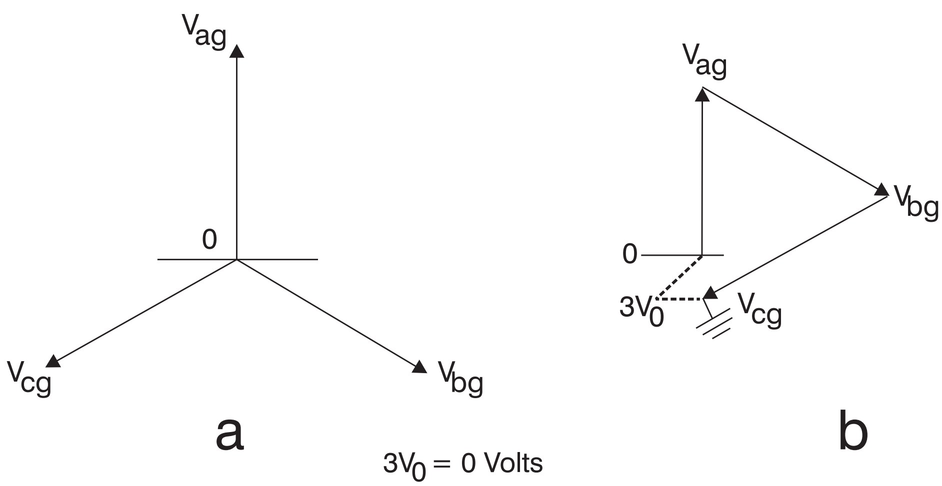

Figure 7: 138kV Normal Balanced Voltages at Bus A

A more economical way to detect ungrounded system voltages is to install a single potential transformer connected phase to neutral and to install a 27/59 under/over voltage relay to detect the ground (Ref. 2). The 27 element will operate for grounds on the connected phase, and the 59 element will operate for line to ground faults on either of the other two phases. A caution here is that, due to heavy circuit loading, the 59 overvoltage element may not see enough high voltage from the ground fault to reach its set point and operate. Also, this single phase scheme is prone to go into ferroresonance unless a loading resistor is connected in parallel with the relay.

The hazard of an energized but grounded power line was removed with the installation of the zero sequence voltage detector. Perhaps the load on the distribution circuit would have been enough to operate a directional power relay if one had been installed on the interconnect breaker monitoring power flow back into the utility system. However, the zero sequence voltage detector at Substation A is a much more reliable method to detect single line to ground faults on the transmission system connected to the delta side of the transformer.

Myth 2: "Transformer excitation current will be sufficient to prevent any back feed through wye delta transformers for single line to ground faults on the transmission system."

Situation: An industrial plant is being served by two delta wye 138 to 13.8 kV, 40 MVA power transformers operating in parallel through the main bus of the plant (Figure 8). Two 138 kV transmission lines supply utility power to the substation, and a 138 kV bus tie breaker permits continuous operation of each transformer when a 138 kV supply line is open. Each transmission line has impedance relays and voltage polarized ground directional overcurrent relays to detect line faults. To prevent feed back through the normally closed 13.8 kV plant bus for abnormal or fault conditions on the transmission system, two directional power relays, each one sensitive enough to operate on excitation current of one power transformer, were installed on the utility 13.8 kV transformer main breakers. These power relays are directionalized to operate on watts flowing out of the industrial plant bus into the 13.8 kV winding of each transformer (Ref. 3). A single line to ground fault on the 138 kV system could be backfed through one of the power transformers, creating an ungrounded system, because the power transformer delta connection would isolate any ground source and block zero sequence current flow to the fault. Therefore, the sensitive three phase directional power relays were used to open the appropriate transformer 13.8 kV main breaker and eliminate ungrounded transmission system conditions.

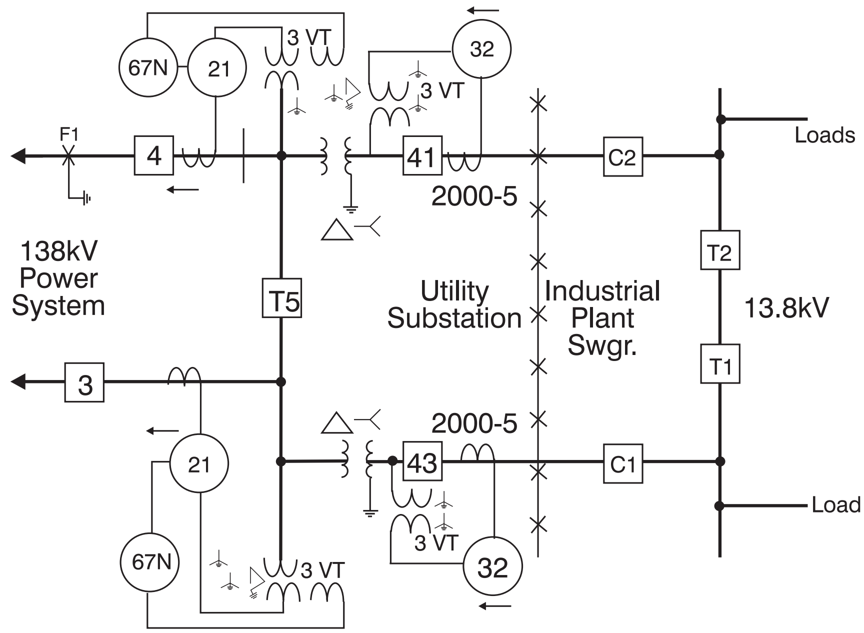

Figure 8: Directional Power Detection for Ungrounded 138kV System

A single line to ground fault F1 occurred on one of the 138 kV lines when the bus tie breaker T5 was open for maintenance. The 67N did not trip, because there was no zero sequence current flow through the delta-wye transformer. The directional power relay failed to operate on transformer excitation current, thus the other transmission line was back feeding the faulted transmission line through the 13.8 kV bus as an ungrounded source. Circuit breaker 4 was opened manually to isolate the fault.

The power relay was extremely sensitive at its minimum setting of .008 amperes at 208 volts or 76 primary kilowatts. From the transformer Certified Test Report that was obtained after the incorrect operation, No Load Loss in Kilowatts is 33.8kW at rated transformer voltage. The power relay's current transformer ratio of 2000:5 amperes provided only .0035 amperes to the relay or about half the requirement for operating the relay. The ct ratio had been sized above load current of 1673 amperes for 40MVA at 13.8kV, which resulted in a ratio of 2000:5 amperes being selected. To provide adequate sensitivity for transformer excitation current, the ct ratio should have been 600:5 amperes, which would have provided .012 amperes to the power relay, which gives a 50% margin of operation.

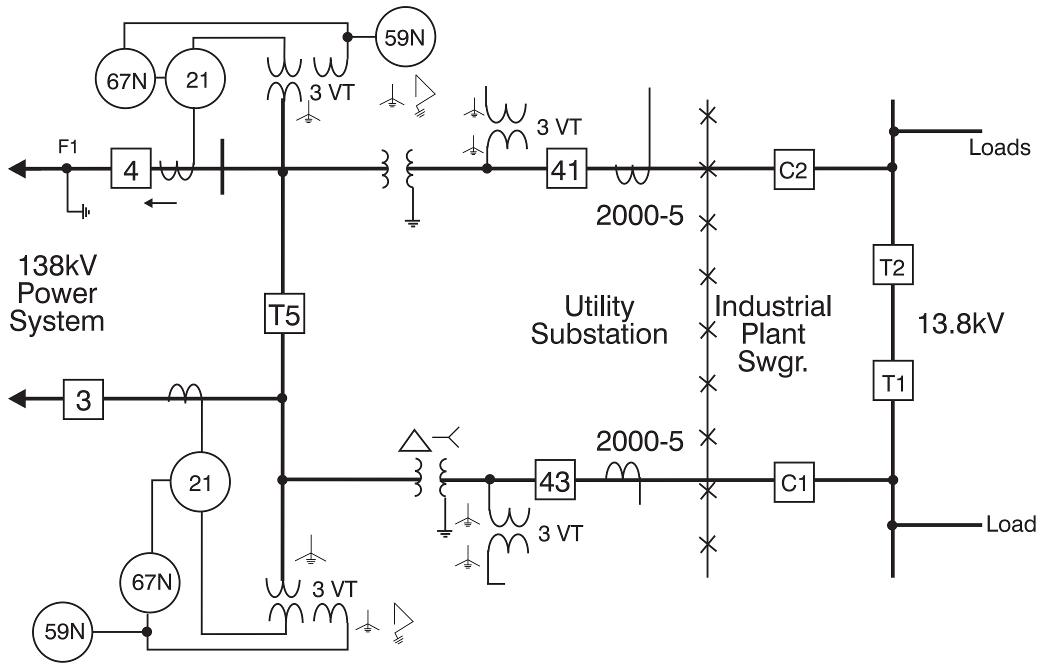

Figure 9: Zero Sequence Voltage 59N Detection

Solution: One solution was to install 5-15 ampere auxiliary ct's to provide an overall ct ratio of 666-5 amperes, which would supply .011 amperes to the power relays, giving a 133% operating margin. Since zero sequence voltage detectors were already available on each 138 kV bus for transmission line protection, it was decided to remove the directional power relays and install electromechanical inverse time overvoltage zero sequence voltage detector relays, 59N, (Figure 9) that function as explained previously in Myth 1. Anytime the 138 kV tie breaker is opened, 13.8 kV circuit breaker 43 is also opened to eliminate current flow from one 138 kV line to the other by way of the plant 13.8 kV bus.

An outside factor influencing the decision to remove the power relays was improper operation of similar directional power relays in a location where the paralleled transformers did not have equal impedances, thus unequal excitation currents and voltage drop which causes circulating currents. Circulating current from the lowest impedance transformer would operate the directional power relay looking back through the higher impedance transformer. The 59N relays at the utility substation were not installed to detect circulating current but only to operate as zero sequence voltage detectors on an ungrounded 138kV transmission system.

Today, numerical transmission line multifunction relays with sequence voltage detectors could provide the same functionality as the discrete electromechanical 59N relay. Also, external inputs to internal logic could be programmed to place the overvoltage element in service only when the tie breaker is open for maintenance.

Myth 3: "Reverse Power protection is all I need to protect for back feed into the Electric Power System for power system faults".

Situation: A paper mill wanted an inter-connection to the local utility at 13.2 kV for standby power and to operate its 20 MVA of generation in parallel with the utility. Figure 10 shows the protection at Substation C that was a transformer differential relay and overcurrent protection on the feeder breaker 16. The differential would trip motor operated switch 31 and breaker 16 by way of a lockout relay device 86. The plant wanted the utility to add only a 32 directional power relay looking toward the 69-13.2 kV transformer and, through it, to all the 69 kV system of the utility until additional protection could be purchased and installed. In addition to loads on the 69 kV line, a 21.4 MVAR 69 kV capacitor bank is connected on the line at the remote Substation B, which could further complicate system protection at Substation C.

In Figure 10 there are two single line to ground faults indicated, F1 on the 13.2kV bus and F2 on the 69kV system. The following discussion will focus on methods of detecting these faults.

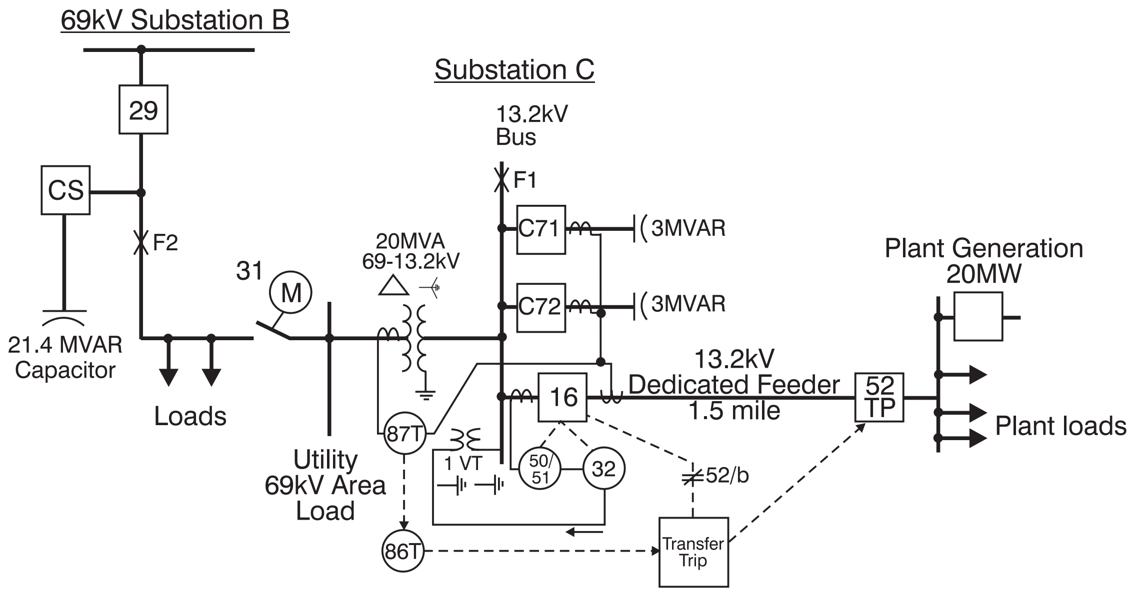

Figure 10: Single phase directional power protection

As discussed in Myths 1 and 2, reverse power relays do not always operate as desired. Basic operation of directional power relays is accomplished by voltage and current phasors that are approximately in phase with each other and of constant magnitude, assuming balanced load and unity power factor conditions (Figure 11). (Ref. 4) A single phase power relay will not see a line to ground fault, F1 in Figure 10, on the phases to which it is not connected, thus, three single phase directional power relays would be needed to detect faults on either of the three phases. Sensitivity of power relays is expressed in watts at rated voltage, so their ability to operate during suppressed voltages that occur during fault conditions would have to be determined. Because faults are inductive loads where the current lags the voltage by about ninety degrees, there is very little power or watts in the fault current, thus a fault may not have enough watts to be detected by a power directional relay. Also, there may be limits to their accuracy during high fault currents, because power relays typically are not required to operate instantaneously but usually after a time delay of seconds rather than cycles. So, their current sensing elements may be prone to saturate for extremely high fault currents.

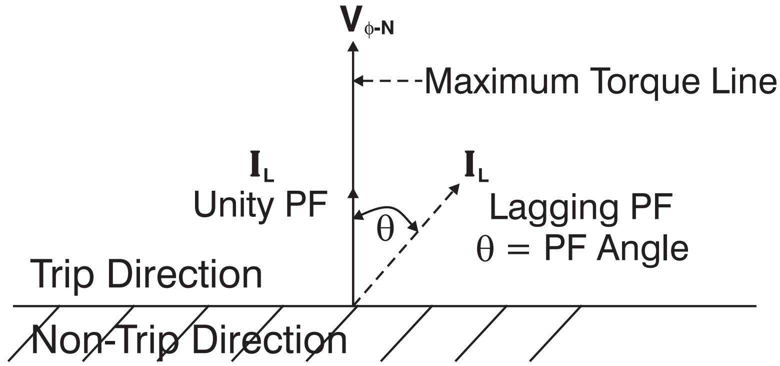

Figure 11: Single Phase directional power relay characteristic

Fault directional relays, on the other hand, must operate during collapsed voltage and high current levels (Ref. 5) Quadrature polarization (as opposed to sequence polarization) where the balanced phase load current at unity power factor leads its polarizing voltage by 90 degrees (Figure 12) is widely used for fault directional relays. The polarizing voltages are selected so that they usually do not include the voltage associated with the phase current so a stable polarizing voltage is available during the fault. Their range of operation, as determined by the angle of maximum torque, will be for currents in the first, second and fourth quadrants, which is different than in the directional power relay that operates for current in the first and second quadrants only, as shown in Figure 11.

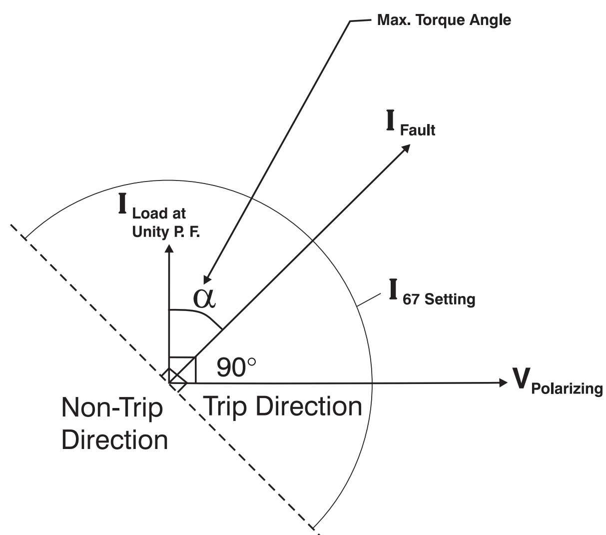

Figure 12: Fault directional relay characteristics

The current flow seen by any type of directional relay in our situation for phase faults at F2 will cover a wide range of conditions from current lagging A phase to neutral voltage by 90 degrees for transformer excitation conditions only, to leading by about 90 degrees for either local 13.8 kV or remote 69 kV capacitors being energized. Somewhere in between these extremes, 69kV load current will also be a factor in detection (Figure 13). Ground faults at F2 will not be seen by overcurrent relays on the 13.2kV side of the transformer, because the transformer delta connection blocks zero sequence current flow to the fault as explained in Myths 1 and 2. For "normal" conditions without the presence of the capacitors or transformer, the current seen by a directional phase overcurrent element for phase faults will approach the construction angle of the protected line depending on factors such as arc resistance or power factor if heavy line load, thus the angle of maximum torque of the element is selected as close to this line angle as possible in order to obtain directional element operation with the least amount of current. If the maximum torque angle is not able to be selected close to the line angle, as may be the case in electromechanical relays, then more current will be required to operate the element by the cosine of the angular difference between the line angle and fault current angle. Electromechanical relays typically have only one angle of maximum torque, while electronic or numeric relays may have three or four angle selections or can be continuously adjusted over a wide range from zero to ninety degrees (Figure 14).

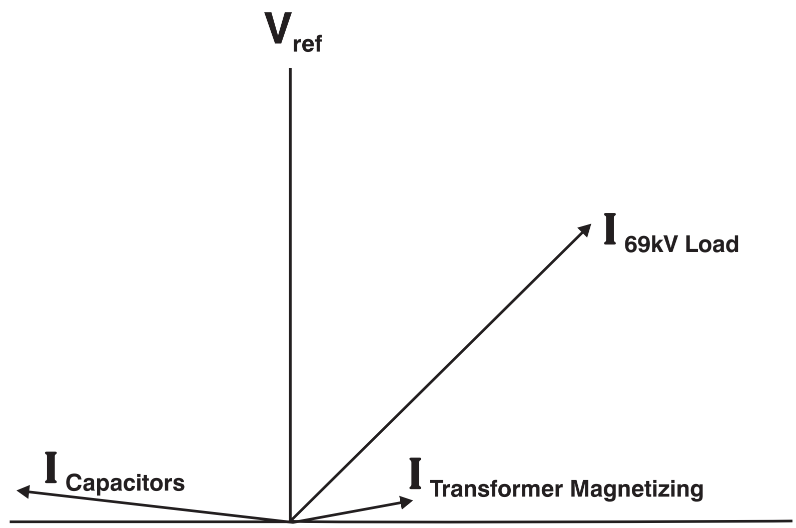

Figure 13: Steady state phase currents

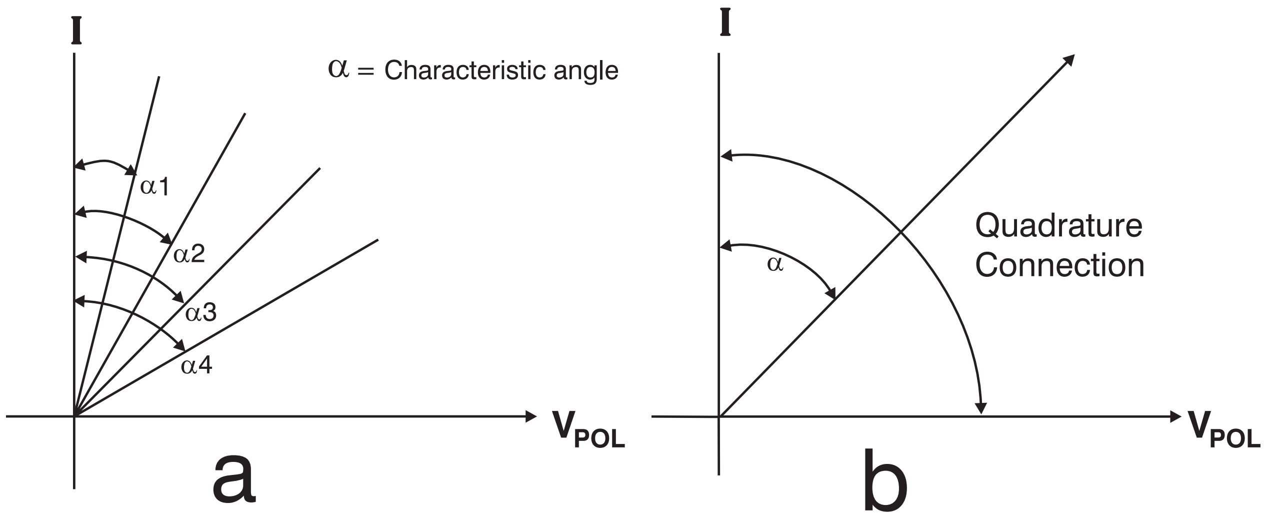

Figure 14: Fault directional relay, maximum torque angle selectivity

Because of the presence of capacitor banks in the area of operation, if phase fault directional overcurrent relays, device 67 (Figure 15), were installed instead of a directional power relay to detect 69kV faults, they possibly could become confused by low voltage at the plant and operate for the combined capacitive and load current in the non-trip direction (Figure 16). One way out of this predicament is using a directional overcurrent relay that can be adjusted to restrict its region of operation (Ref. 6) to less than ± 90 degrees (Figure 17). Another method is to use compensator type impedance relays (Ref. 7). The line drop compensator technique, when used for three phase fault detection, uses positive sequence rotation (ABC) of the applied voltages to develop restraint and negative sequence rotation (ACB) to provide operation. An added bonus of using the compensator type is if the relay is using current and potential transformers installed on the wye low voltage side of the transformer (Figure 18) in the interest of economy, the relay will detect all phase fault conditions such as at F2 on the delta side of the transformer, even if the system becomes ungrounded. Single line to ground faults on the delta side of the transformer still must be detected through other methods.

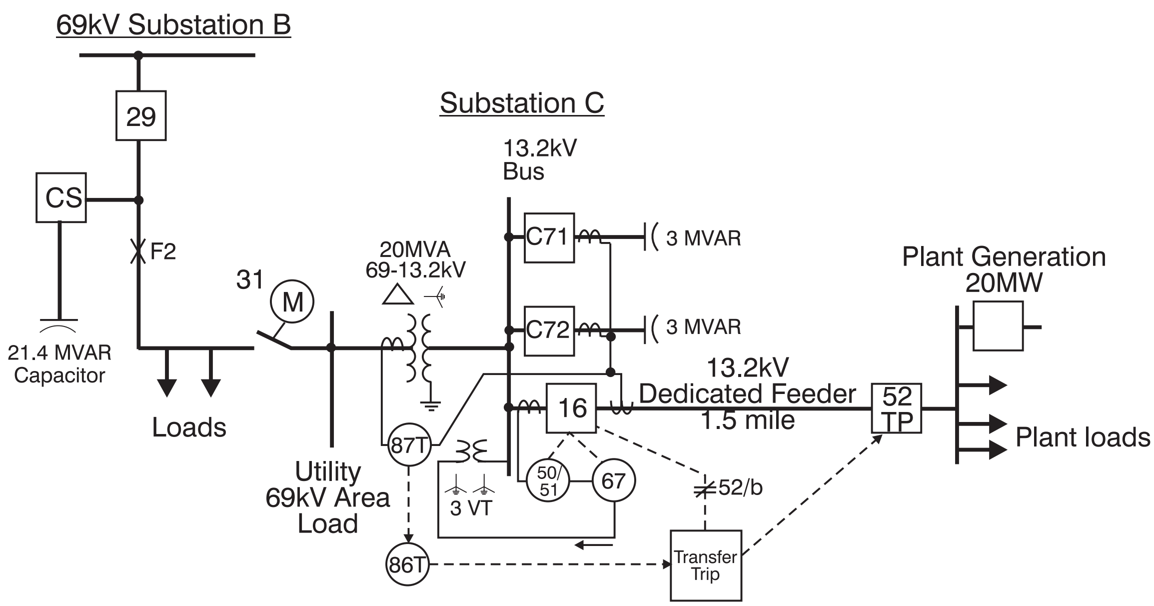

Figure 15: Directional overcurrent possibility

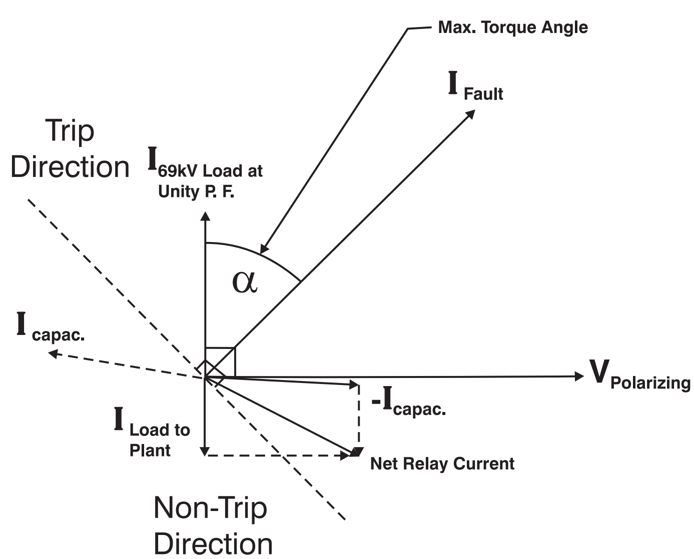

Figure 16: Confused fault directional element

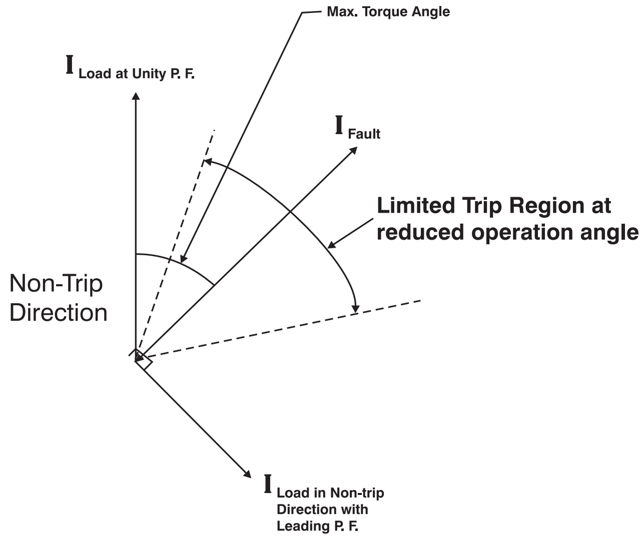

Figure 17: Limited region of operation

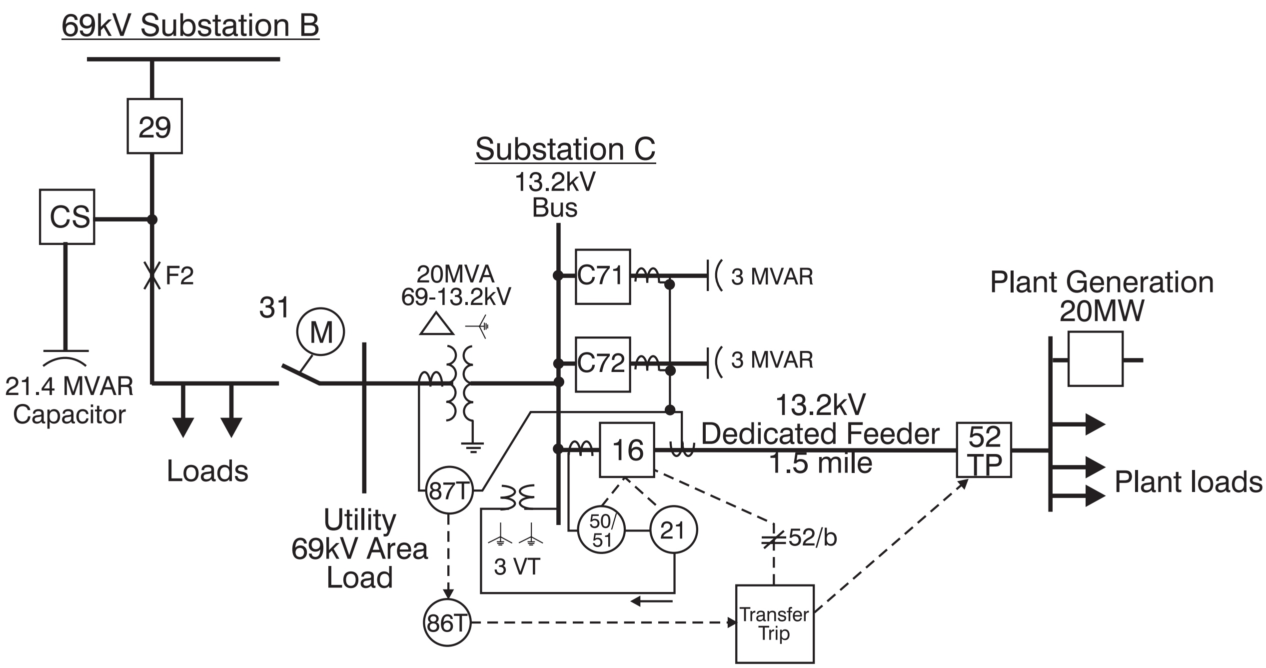

Figure 18: Impedance protection through power transformer

Solution: As in Myths 1 and 2, a zero sequence voltage detector with an electromechanical overvoltage relay was installed to detect any backfeed to the 69 kV system if it becomes ungrounded (Figure 19). This time, the other windings of the 69 kV potential transformers at Substation C were used for impedance relays in a step distance scheme to sense phase faults on the 69 kV system. The current supply for the impedance relay comes from ct's on the 69 kV bushings of the transformer. Circuit breaker 24 was installed to replace the Motor Operated Switch 31. The directional power relay, device 32, was turned to look in the opposite direction from that indicated in Figure 10 and is used only to alarm when load above contract requirements is being sent to the paper mill complex.

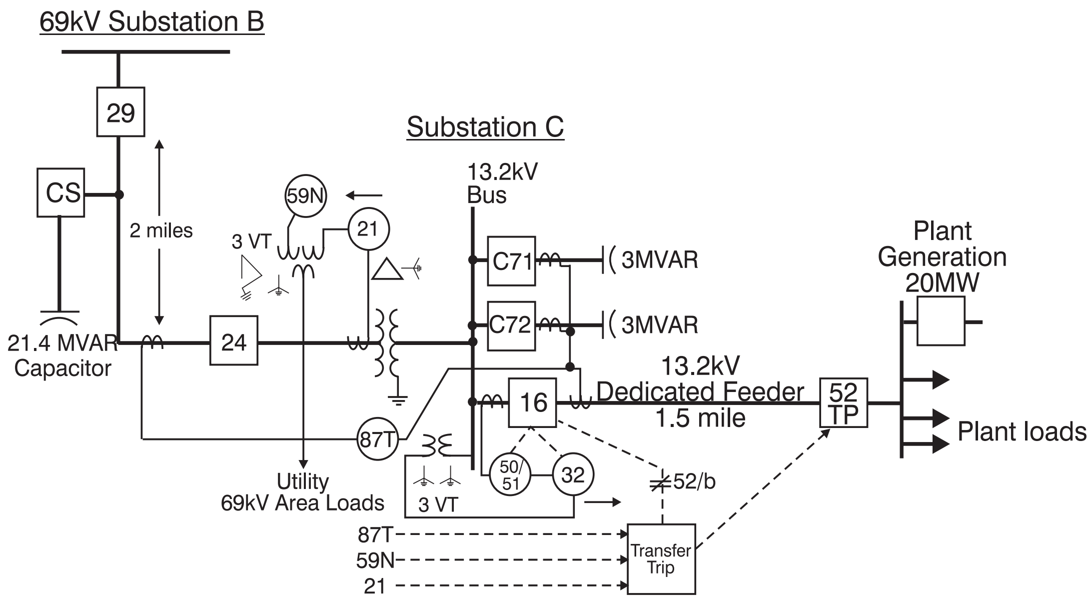

Figure 19: Impedance protection at 69kV

This Myth 3 situation occurred about 10 years ago. Today, technology in the multifunction protective relays provides a variety of polarizing choices and characteristics such as phase comparators, quadrilaterals, positive sequence memory action, negative and zero sequence polarizing, lens, tomatoes, directional overcurrent elements and load encroachment blinders. All these features allow one box to provide interconnect circuit protection all in one package. The only mystery is knowing when and how to apply only the features required for a particular unique situation on the power system.

Conclusion

Through the situations in this paper I have attempted to dispel the myths by showing that

1. Relying on load conditions is not <u>always</u> a dependable or fast method of separating Distributed Resources at the Point of Common Connection to the power grid.
2. All facts relating to setting the protection must be known, such as certified test data of transformers, properly sized current and voltage transformer ratios, and line impedances, <u>before</u> settings are calculated and protection is placed in service.
3. One single phase directional power relay is not a reliable means of detecting fault conditions on the power system because it will not operate for single phase to ground faults on phases not connected to the relay. Three phase directional power relays should be used only in situations in which a guaranteed amount of load is always available to operate the relay, such as in an industrial facility operating around the clock, or 24/7.

These myths are conditional truths because, in some of the situations described, <u>people</u> did not recognize all details of the design scheme until trouble developed on the power system. As relay technicians and engineers, we must verify, through the use of our training and experience, every detail of the protection scheme before commissioning the system.

By doing so, we may have to delay energization of power lines and interconnects to Distributed Resources, but in the end we, the relay geeks, will be the “mystics” who make the “mythology” of power system protection dependable and reliable.

References

1. American Heritage College Dictionary, Third Edition, Houghton Mifflin Company 1993.
2. IEEE Guide for Protective Relaying of Utility-Consumer Interconnections, C37.95-1989, pages 34-35.
3. Kenneth Winick, Power Relays Application Guide GER-2309A, General Electric Company, 1980.
4. J. Lewis Blackburn, Protective Relaying Principles and Applications, 2nd Edition, 1998.
5. Stanley H. Horowitz and Arun G. Phadke, Power System Relaying, 1992.
6. Phase Directional Overcurrent Relay Model BE1-67 Instruction Manual Revision F, Basler Electric Company.
7. Walter Elmore, Protective Relaying Theory and Applications, ABB Power T & D Company, 1994.

Biography

Gerald Dalke received the A.D. in Electrical Technology from Oklahoma State University in 1960. He served more than 33 years with Oklahoma Gas and Electric Company in system protection until retirement in July of 1994. He is a Registered Professional Engineer in the State of Oklahoma. Since June 1994 he has been a Regional Application Engineer for Basler. He is a member of the IEEE Industrial Application Society Medium Voltage Protection Subcommittee and Texas A&M Protective Relay Conference Planning Committee. Gerald has presented papers at the Texas A&M Protective Relay Conference, MVEA Engineering Conference and Iowa State, Washington State, and University of Texas at Arlington “Hands On” relay schools.

Basler Electric®
www.basler.com

Highland, Illinois USA
Tel: +1 618.654.2341
Fax: +1 618.654.2351
email: info@basler.com

Suzhou, P.R. China
Tel: +86 512.8227.2888
Fax: +86 512.8227.2887
email: chinainfo@basler.com