

Deterministic High-Impedance Fault Detection and Phase Selection on Ungrounded Distribution Systems

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Abstract— Downed conductors, tree branches touching conductors, and failing insulators often cause high-impedance faults in overhead distribution systems. The fault currents of these faults are much smaller than detection thresholds of traditional ground fault detection devices, so reliable detection of these high-impedance faults is challenging. Although fault currents can be much smaller in ungrounded systems than fault currents in multigrounded systems given similar fault conditions, fault detection for ungrounded systems is nevertheless easier. This paper contrasts the differences between high-impedance fault detections for ungrounded and multigrounded systems. The paper explains fault detection of ungrounded distribution systems and the issue of fault detection sensitivity. The paper also introduces a recent advance in faulted phase selection on these ungrounded systems and demonstrates this advance through a staged fault test example from a utility.

I. INTRODUCTION

High-impedance faults (HIF) are short-circuit faults with fault currents smaller than what a traditional overcurrent protective relay can detect. HIFs are the main concern for medium-voltage overhead distribution systems with voltage levels less than 35 kV. On power transmission systems where voltage levels are 64 kV and greater, the systems are commonly grounded and a ground fault normally generates large enough currents to operate protection devices even if large fault impedance is involved.

The main causes of HIFs are tree branches touching a phase conductor, failing or dirty insulators that cause flashovers between a phase conductor and the ground or downed conductors. Almost all HIFs involve the ground directly or indirectly.

Staged downed-conductor fault tests in North America indicate that downed-conductor HIFs generate quite small fault currents. For ungrounded systems, fault current magnitude depends on the type of ground surfaces and system stray capacitance. The ground fault current of ungrounded systems is normally in a range of milliamperes to several amperes. The HIF current of multigrounded systems depends highly on the surface types upon which a conductor falls, and the fault current varies from zero to less than 100 amperes.

Because of small fault currents, HIFs generally do not affect distribution system operations. HIFs cause minor, localized damage to utility equipment. Utilities incur only small direct cost associated with repairing a damaged line. The cost of improved HIF detection is highly unlikely to be justified by

a conventional cost/benefit analysis. The primary motivation for detecting and clearing HIFs is to improve public safety.

System grounding methods heavily influence ground fault detection [1]. Although the high-impedance ground fault current of ungrounded systems can be much smaller than that of multigrounded systems, the high-impedance fault detection of ungrounded systems can be more reliable and deterministic than the fault detection of grounded systems. In this paper, we first review ground fault detection for ungrounded and multigrounded distribution systems. The review should help in providing an understanding of why different systems need dramatically different high-impedance fault detection techniques and how these techniques affect fault detection reliability.

We then concentrate on high-impedance fault detection of ungrounded systems. We review sensitive directional overcurrent protection and discuss ways to improve fault detection sensitivities. We introduce a new faulted phase selection method that works reliably under very high fault impedance. Finally, we provide an example of staged fault tests from one utility that demonstrates fault detection and faulted phase selection results.

II. DETECTING HIGH-IMPEDANCE GROUND FAULTS OF UNGROUNDED SYSTEMS VERSUS MULTIGROUNDED SYSTEMS

Because no intentional neutral groundings exist in ungrounded systems; the ground fault current of such systems is quite small. There is a misconception that it is more difficult to detect high-impedance faults on ungrounded systems than on multigrounded systems. This section compares the structures of ungrounded and multigrounded systems, introduces general ground fault detection methodologies for each system, and concludes that high-impedance fault detection for ungrounded systems can be more deterministic and reliable than for multigrounded systems.

Fig. 1 shows a typical ungrounded distribution feeder. This feeder has the benefit of not having a neutral conductor running throughout the system. Fig. 1 shows phase-to-phase and phase-to-ground distributed capacitances that primarily determine ground fault current magnitude and unbalance residual current under normal system operations. All loads are connected phase-to-phase, and the load unbalance induces no residual current. The normal residual unbalance in the system results mainly from the uneven distribution of capacitance. This so-called standing residual unbalance is normally quite small.

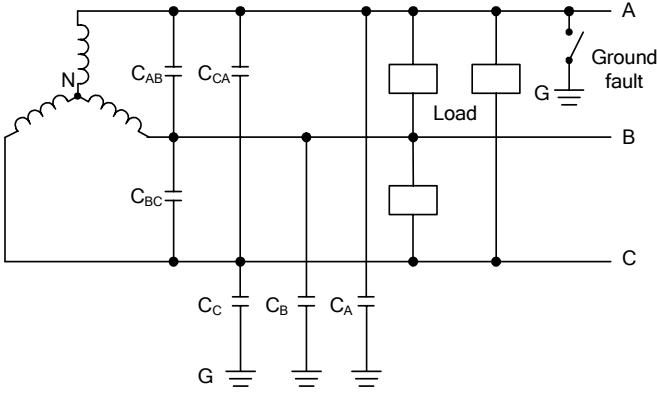


Fig. 1. Ungrounded power system

The large capacitive impedance of ungrounded systems limits ground fault current and has virtually no effect on the phase-to-neutral voltage of the faulted phase. The major well-known benefits of ungrounded systems, such as low thermal stress, better personnel safety, and more reliable load service, come from this limited ground fault current. Fig. 2 shows the phase-to-phase and phase-to-ground voltages for a ground fault condition. The uncollapsed voltage triangle during a ground fault means that the system can operate normally in the presence of a single line-to-ground fault. Nevertheless, it is desirable to detect the ground fault as quickly as possible because the increased voltage level on the unfaulted phases makes it easy for the fault to evolve into a multiphase fault.

Because single line-to-ground faults make up approximately 80 percent of all faults on a power system, we can see that power interruptions because of faults seldom occur. This characteristic of ungrounded systems makes these systems popular in industrial systems and some regions of the world. On the other hand, limited ground fault current can cause difficulties with ground fault protection on these systems.

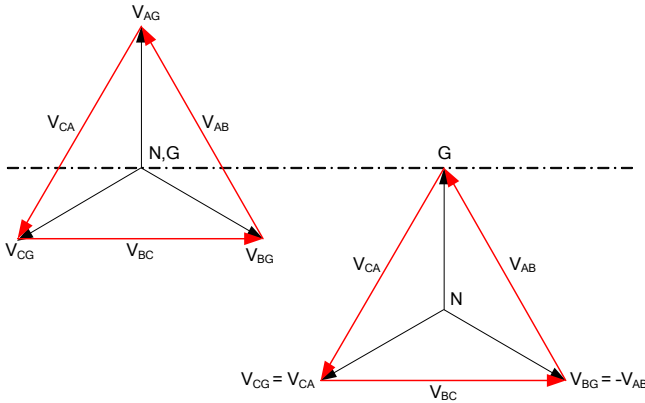


Fig. 2. Voltage triangle of a normal ungrounded system and one with a ground fault

When relay current measurement sensitivity is low, traditional ground fault protection uses zero-sequence overvoltage. However, because the voltage condition does not pinpoint which feeder is faulted, the system operator has to manually open each feeder on a bus sequentially to find the faulted feeder. Modern microprocessor relays are more sensitive than traditional electromechanical relays. The sensitive current channels in modern microprocessor relays can measure a cur-

rent as small as several milliamps secondary. An available sensitive directional overcurrent protection, which we discuss in more detail in the next section, uses the fundamental frequency component of the residual current and benefits from the fact that phase-to-phase connected loads do not introduce residual current and the standing residual current from system stray capacitance is small. Microprocessor relays have satisfactorily detected downed-conductor high-impedance faults on such unfavorable ground surfaces as soil and concrete.

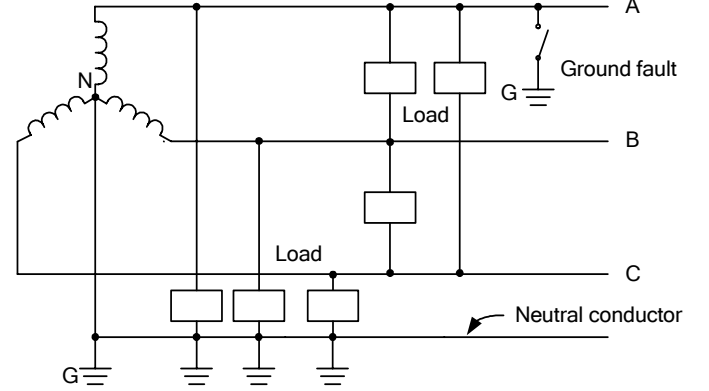


Fig. 3. Multigrounded system

Fig. 3 shows a typical four-wire multigrounded distribution feeder. The neutral wire is typically grounded at each distribution transformer point to eliminate potential rise on this wire. Service loads can be more flexibly connected as either phase-to-phase or phase-to-neutral. The system standing residual current comes from load unbalance. When a solid-ground fault occurs, residual current that relays measure at the substation contains both load unbalance and fault current.

Grounded distribution systems are possibly unbalanced because a majority of the loads for these systems are of a single-phase nature. Even worse, the amount of load unbalance is dynamic and changes according to time of day and variations in system operation conditions. As a consequence, utility engineers must consider the worst system load unbalance when they set pickup values for a ground relay. This worst load unbalance, together with concerns about cold load pickup, transformer inrushes, and coordination with downstream ground relays, makes ground relays unsuitable for high-impedance fault protection. Many utilities have eliminated the use of all ground relays because of unpredictable load unbalances. For those utilities that do use ground relays, a survey [2] indicates that engineers most often set the pickups of ground relays as a percentage of phase relay pickups. The protection functions of these ground relays for high-impedance faults are therefore diminished.

To detect high-impedance faults combined with unbalanced loads, power system personnel routinely use current components other than fundamental frequency to look for arcing signatures normally involved with these faults. Many new techniques, including expert systems, neural networks, wavelet decomposition, and hypothesis testing, are in use. We measure successes in detecting high-impedance faults through use of some of these techniques in the statistical sense.

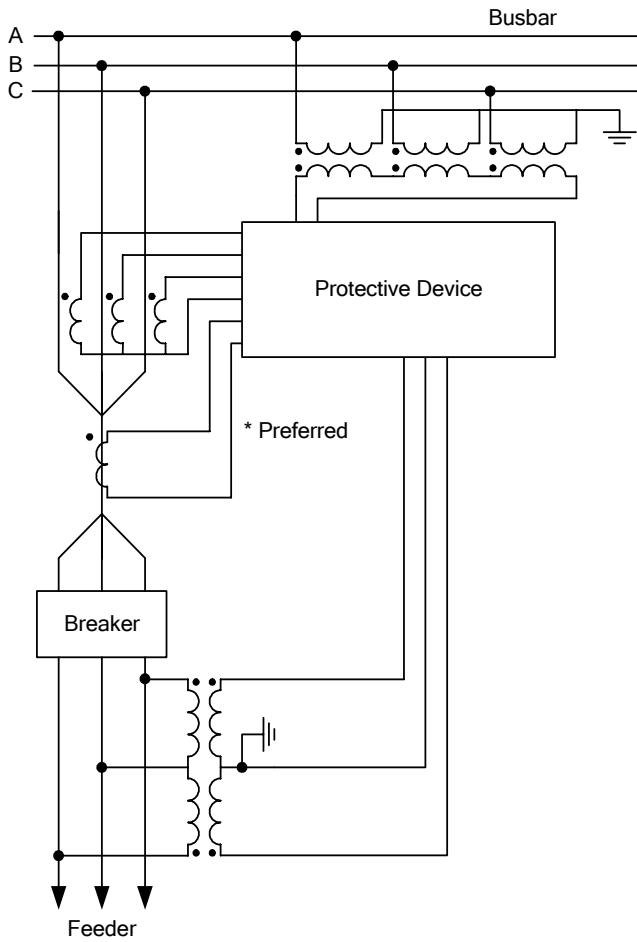


Fig. 5. Typical instrument transformer connections to a protective device for an ungrounded power system

A. Identifying the Faulted Feeder

If we now go back and analyze the single line-to-ground fault represented in Fig. 4, we would typically start with the voltage profile of the system. Fig. 2 shows the prefault voltage phasor diagram of the power system. Note we assume the system has no standing unbalance; usually protection systems

have a standing unbalance because of power line asymmetry. Fig. 2 also shows the voltage phasor diagram for the same power system during a solid A-phase-to-ground fault. We can observe the angular relationship between the residual voltage and current by superimposing the fault current phasor diagram on top of the fault voltage phasor diagram, as in Fig. 6.

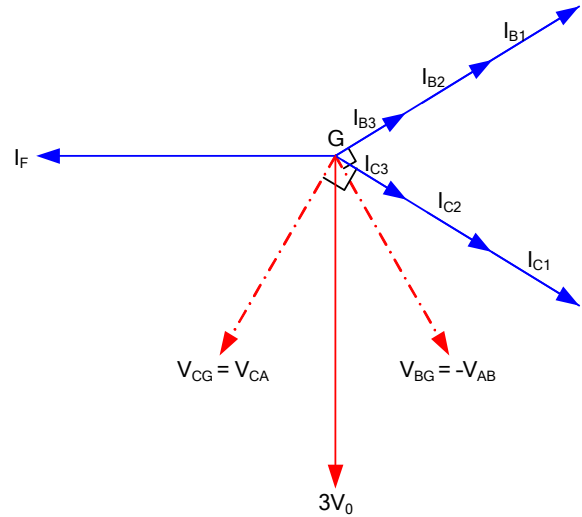


Fig. 6. Angular relationship between the residual voltage and current for an A-phase-to-ground fault

From Fig. 6, we can see that the fault current (I_F) lags the residual voltage ($3V_0$) by 90 degrees. However, because it is not possible to determine the fault current (I_F) from a single protective device and this information alone will not indicate the faulted feeder, let us break up the fault current as seen by each individual feeder and then compare that current to the residual voltage. Fig. 7 shows the fault current flowing through each individual feeder referenced to the residual voltage of the system.

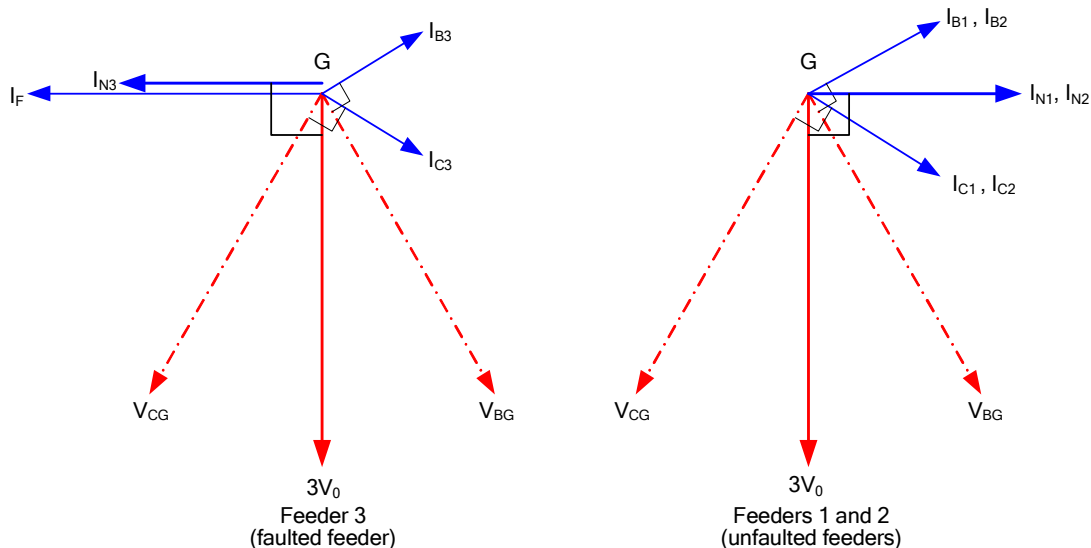


Fig. 7. Residual current flowing through the faulted and unfaulted feeders as compared to the residual voltage

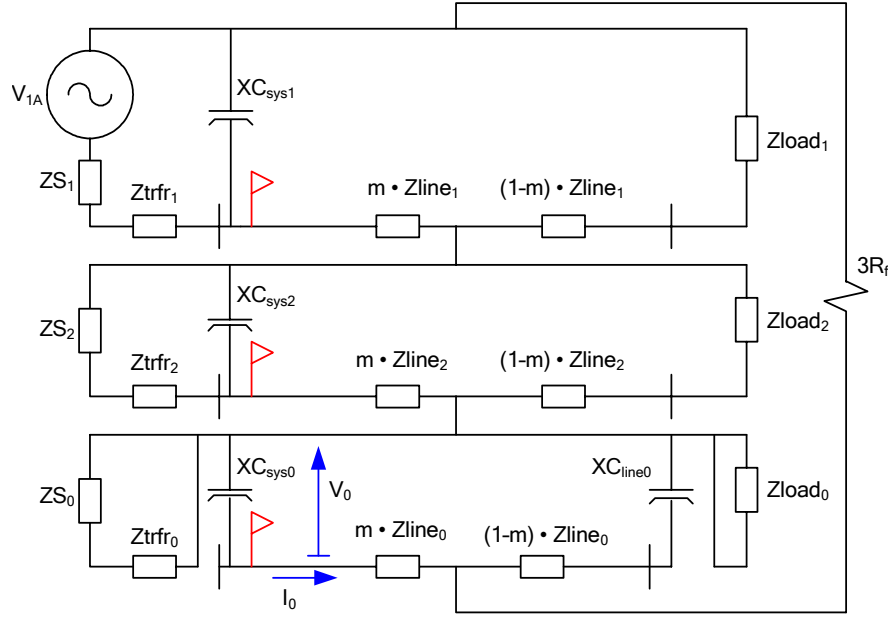


Fig. 8. Equivalent sequence diagram for an A-phase-to-ground fault on an ungrounded system

In analyzing the faulted feeder phasor diagram in Fig. 7, we can say that, for the faulted feeder case, the neutral or residual current (I_{N3}) lags the residual voltage ($3V_0$) by 90 degrees. In reality, the lag will be less than 90 degrees because of the conductance (G) of the feeder. However, the effect of the conductance is relatively small and can be ignored for all practical purposes. In analyzing the phasor diagram of the unfaulted feeders, one can see that the residual currents (I_{N1} , I_{N2}) lead the residual voltage ($3V_0$) by 90 degrees. From this observation, one can say that the fault is in front of the relay measuring point if the residual current lags the residual voltage by 90 degrees and the fault is behind the relay measuring point if the residual current leads the residual voltage by 90 degrees. To examine this relationship when fault resistance is introduced as in high-impedance fault situations, let us examine a sequence diagram for a single-line-to-ground fault on an ungrounded power system. Fig. 8 shows the exact equivalent sequence diagram, excluding the system conductance (G).

If we examine the zero-sequence circuit more closely, we observe that the source impedance primarily consists of the zero-sequence capacitance of the power system. Therefore, for forward faults, the angular relationship between current and voltage will always remain constant regardless of fault resistance. This means that for a forward fault the residual current will always lag the residual voltage by 90 degrees. The influence of the fault resistance is that it will reduce the magnitude of the residual current and voltage.

For a reverse fault, the protective device would measure the impedance in front of the relay. This impedance is the sum of the zero-sequence impedance and the zero-sequence capacitance of the line/feeder, but the line impedance when compared to the zero-sequence capacitance is negligible. Therefore, once again the fault resistance has no influence on the angular relationship between residual voltage and current. Residual current will always lead residual voltage by an angle that is very close to 90 degrees for a reverse fault.

By simply comparing residual voltage to residual current, one can identify the faulted feeder. If residual current leads residual voltage, the fault is behind the relay measuring point. If residual current lags residual voltage, the fault is in front of the relay measuring point.

B. Identifying the Faulted Phase

Once the faulted feeder in the power system has been identified, it is desirable to identify the faulted phase. To achieve this purpose, let us re-examine the sequence diagram for a single line-to-ground fault on an ungrounded power system shown in Fig. 8. We can simplify this sequence diagram by considering the following:

The impedance of XC_{sys1} is much greater (on the order of 100 times) than the sum of ZS_1 and $Ztrfr_1$ [$XC_{sys1} \gg ZS_1 + Ztrfr_1$]; this means one can ignore the effect of XC_{sys1} .

The impedance of XC_{sys2} is much greater than the sum of ZS_2 and $Ztrfr_2$; this means one can ignore the effect of XC_{sys2} .

The impedance XC_{sys0} is much greater than the sum of ZS_1 , ZS_2 , $Ztrfr_1$ and $Ztrfr_2$, [$XC_{sys0} \gg ZS_1 + ZS_2 + Ztrfr_1 + Ztrfr_2$].

From the above considerations, we can neglect positive- and negative-sequence impedance and reduce the sequence diagram of Fig. 8 to that of Fig. 9.

If we now examine Fig. 9 carefully, we will see that for a forward fault the residual current (I_0) leads the positive sequence voltage (V_{1A}) by 90 degrees, but the above diagram is for an A-phase-to-ground fault with the A-phase as a reference in calculating the value of the positive-sequence voltage V_1 . To modify Fig. 9 so that it can apply to a B-phase-to-ground and a C-phase-to-ground fault while maintaining the A-phase used as the reference quantity in the positive-sequence voltage calculation, we need to phase shift the zero-sequence voltage by the appropriate ($1 \angle 120^\circ$) factor. If we now redraw the reduced sequence diagram shown in Fig. 9, we obtain a sequence diagram that addresses the question of how to modify

Fig. 9. Fig. 10 illustrates sequence diagrams for the different single-phase-to-ground faults.

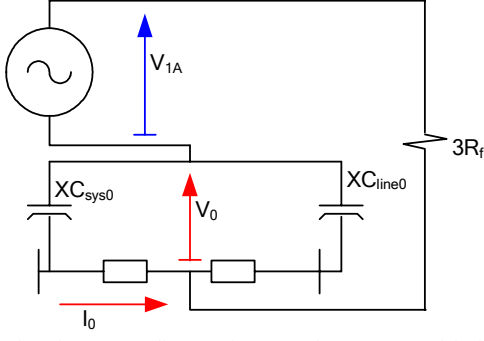


Fig. 9. Reduced sequence diagram for an A-phase-to-ground fault on an ungrounded system

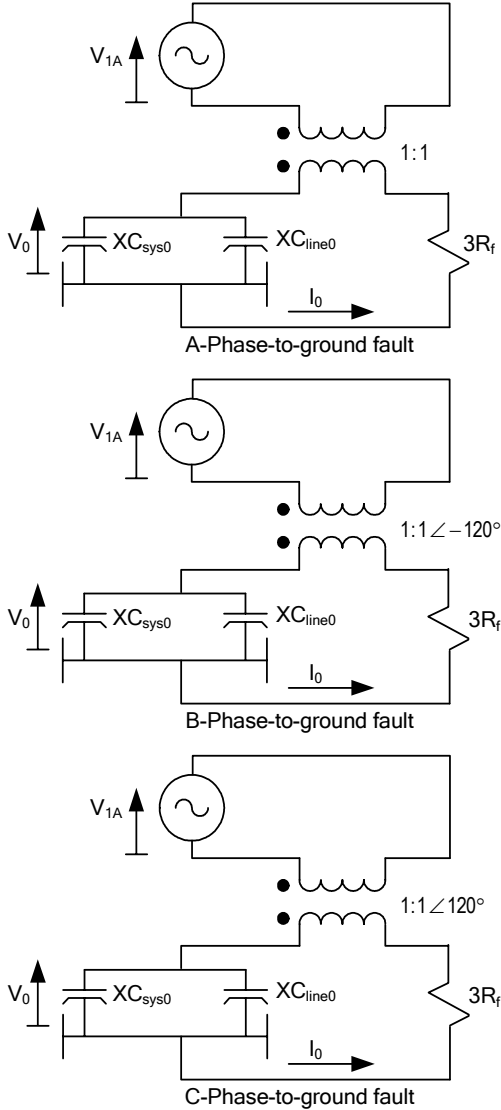


Fig. 10. Reduced sequence diagrams for single-line-to-ground faults on ungrounded systems

If we now analyze the sequence diagrams in Fig. 10, we can state the following with regard to single-line-to-ground faults in front of the relay measuring point:

A-phase-to-ground fault, I_0 , leads V_{1A} by 90 degrees.

B-phase-to-ground fault, I_0 , lags V_{1A} by 30 degrees.

C-phase-to-ground fault, I_0 , lags V_{1A} by 150 degrees.

By analyzing the same sequence diagram again, this time for a single-line-to-ground fault behind the relay measuring point, we can state the following:

A-phase-to-ground fault, I_0 , lags V_{1A} by 90 degrees.

B-phase-to-ground fault, I_0 , leads V_{1A} by 150 degrees.

C-phase-to-ground fault, I_0 , leads V_{1A} by 30 degrees.

If we now draw a phasor diagram of the previous statements, we obtain the phasor diagrams shown in Fig. 11.

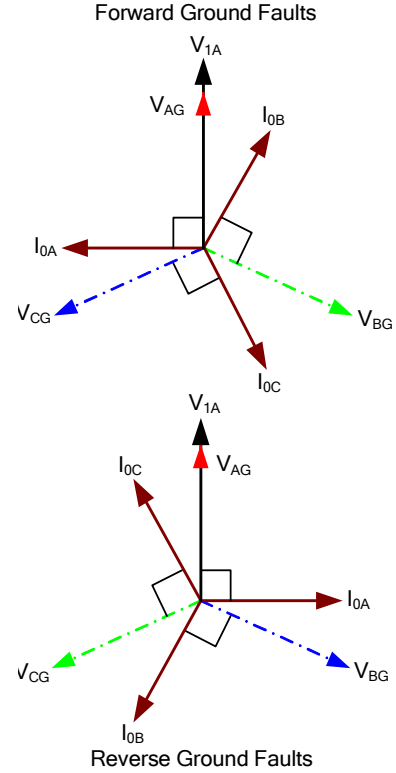


Fig. 11. Phasor diagram for solid single-line-to-ground faults for fault in front of the relay measuring point and behind the relay measuring point, referenced to the positive-sequence voltage (V_{1A})

To examine how the above-described relationship behaves when fault resistance increases, let us again analyze the reduced sequence diagram shown in Fig. 9 and increase the fault resistance for an A-phase single-line-to-ground fault in front of the relay measuring point. Fig. 12 represents the phasor relationship between the positive-sequence voltage (V_{1A}), the residual current (I_0) and the residual voltage (V_0) for three different fault resistances, namely:

$$R_f \ll X_{C\Sigma 0}$$

$$R_f = 1/3 X_{C\Sigma 0}$$

$$R_f \gg X_{C\Sigma 0}$$

Where $X_{C\Sigma 0}$ is the total zero-sequence capacitive impedance.

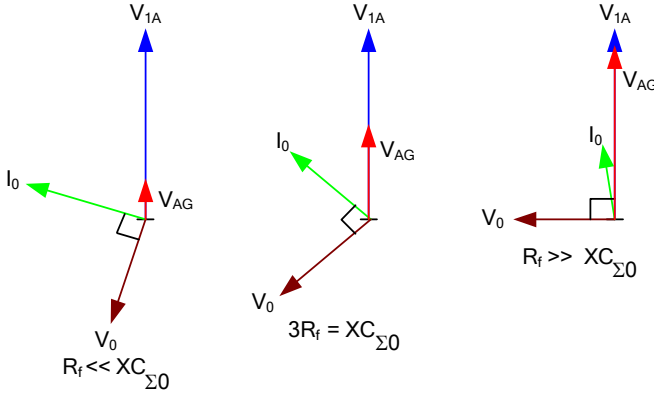


Fig. 12. The relationship between the positive-sequence voltage and residual current and voltage for varying values of fault resistance

From the phasor diagrams of Fig. 12, we see that increasing fault resistance decreases the angle between the residual current (I_0) and the positive-sequence voltage (V_{1A}). A few further minor observations include the following:

1. The magnitude of the residual current (I_0) and residual voltage (V_0) decrease, but their relative angular relationship remains fixed (as expected).
2. The faulted phase voltage (V_{AG}) increases.

By applying our observations from Fig. 12 and applying them to the B- and C-phase-to-ground faults, we can create the phasor diagram shown in Fig. 13.

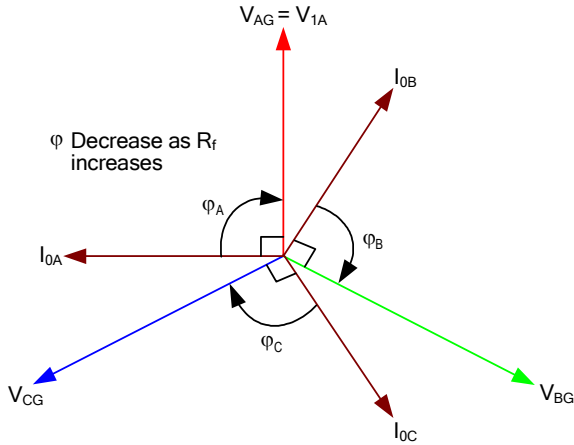


Fig. 13. Relationship between the positive-sequence voltage and residual current for single-line-to-ground faults as fault resistance increases

If we now combine information from Fig. 12 and Fig. 13, we can generate a phase-to-ground fault diagram for faults in front of the relay measuring point and faults behind the relay measuring point, as shown in Fig. 14.

If we know the direction of the fault and note the angular difference between the residual current (I_0) and the positive-sequence voltage (V_{1A}), we can determine the faulted phase.

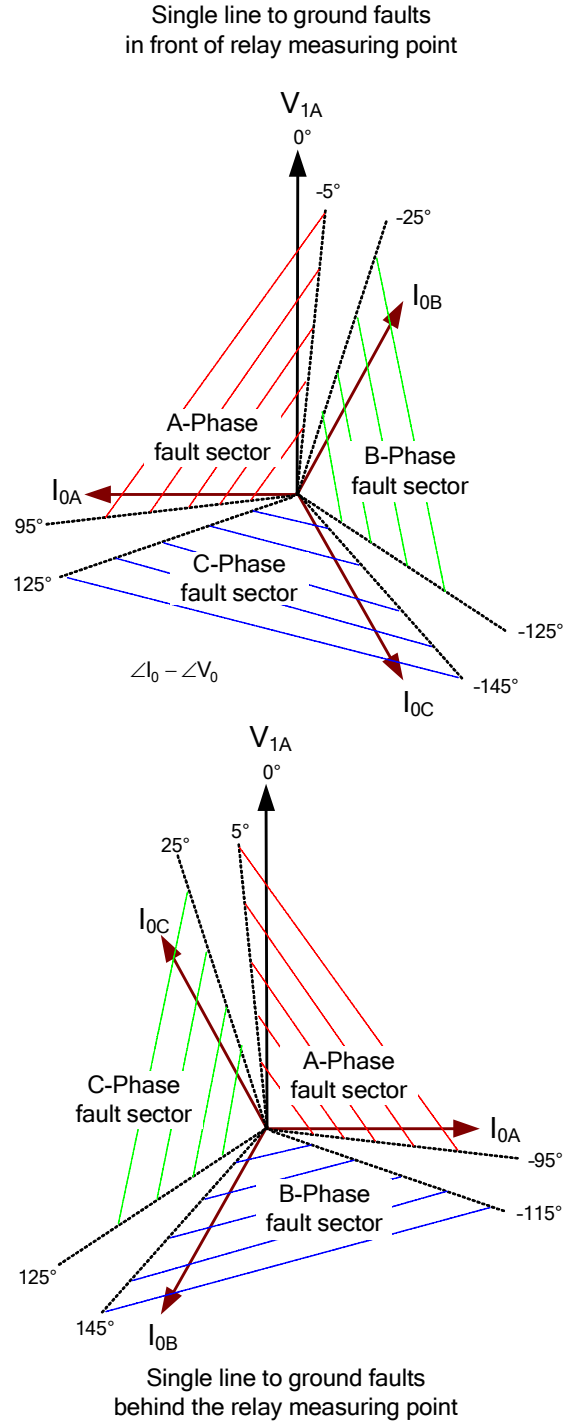


Fig. 14. Fault sector used to identify the faulted phase in an ungrounded power system

C. Fault Detection Sensitivity

The standing unbalance of the power system is one of the determining factors governing fault detection sensitivity. The standing unbalance occurs because line-to-ground capacitance per phase is not identical. This lack of identical capacitance applies not only to the power line, but also to the equipment connected to the grid. The standing unbalance on a power system changes as system load dynamics change. This relationship exists because of differences in phase-to-ground capacitance of windings in power transformers or large motors.

Therefore, the maximum unbalance resulting from the power line plus that resulting from the maximum load condition govern sensitivity of the fault detection element. The overcurrent detection threshold setting value must be greater than the worst case standing unbalance.

The current transformer ratio in use for measuring/calculating residual current (I_0) also impacts the sensitivity of the fault detection element. The higher the current transformer ratio, the lower the fault detection sensitivity and vice versa. The reason for this is that current transformers have the least error when they operate in their linear region. A high-resistance fault could result in a current transformer operating in the ankle region, where fault current could be just slightly greater than magnetizing current. A further problem associated with a high current transformer ratio is that the reduced secondary current input to a relay will be comparable in magnitude to A/D quantization noise and, therefore, not easily detectable. Therefore, the lower the current transformer ratio the better.

If residual current calculation or measurement occurs in the fourth wire of the three-current-transformer connection, sensitivity is decreased when compared to the residual current obtained by means of a toroidal current transformer. The reason for this decreased sensitivity when one uses three current transformers to obtain residual current is that the three current transformers are not identical; their magnitude and angle errors result in a fictitious residual current. The same is not true for a toroidal current transformer. System loads also determine the phase transformer ratio when you use the three CT approach, and this ratio cannot be lowered to increase fault detection sensitivity. When you use three separate phase current transformers to obtain residual current, you must desensitize fault detection. With use of a toroidal current transformer, the

toroidal current transformer ratio can be sized according to a much smaller neutral fault current level.

D. Performance in Actual Field Tests

Staged high-impedance fault tests on a 4.6 kV ungrounded distribution system have verified the performance of the fault detection and phase selection we discussed in the previous section. The bus section feeder on which we tested the relay contains four radial feeders; each is about two to four miles long. Two Wye/Delta transformers supply the 4.6 kV bus. Dropping one phase of a feeder to the ground creates high-impedance faults. We used several ground surfaces, including topsoil, grass, and concrete, and we used the same relay on all feeders. The relay on the test feeder detects the fault in its forward direction, and the remaining relays detect the fault in its reverse direction.

Fig. 15 shows prefault feeder load voltages and currents. From the figure, you can see that the loads among the three phases are quite unbalanced, as in typical distribution loads. The load currents also involve large harmonics from served industrial plants.

Fig. 16 shows the neutral current and voltage from an open-delta potential transformer (PT) for a 30-second high-impedance fault on topsoil. Notice that the prefault standing neutral current is very small (less than 5 mA). The maximum neutral current for the fault is about 0.8 A primary. Also notice the close correlation between the neutral current and residual voltage. Note that the fault current decreases as the fault progresses. We suspect that it is because the ground is burning drier.

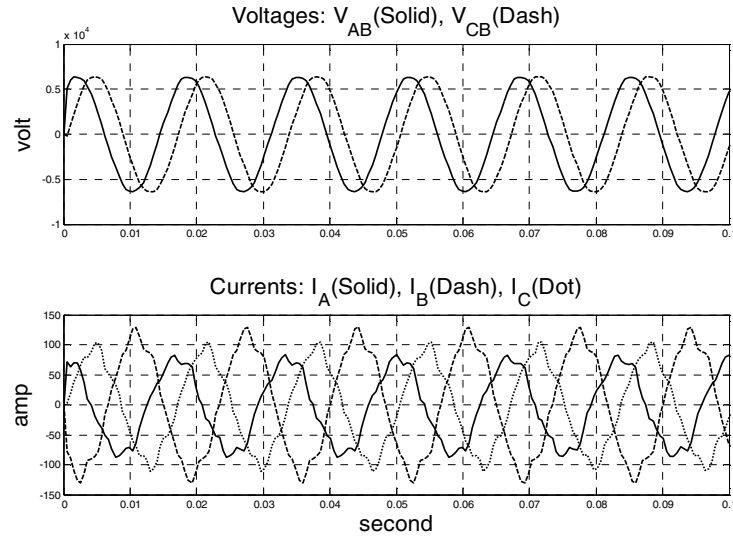


Fig. 15. Phase-phase voltages and three-phase currents on the test feeder

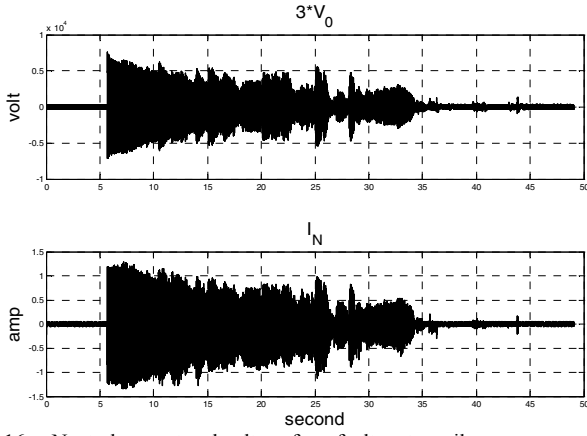


Fig. 16. Neutral current and voltage for a fault on topsoil

Fig. 17 shows the activities of the relay protection elements for the high-impedance fault shown in Fig. 16. One can see that the forward directional element, 32NF, and the C-phase fault selection element, NSC, picked up just a little longer than a half cycle after the fault occurred. The directional neutral overcurrent 67N1 picked up within two cycles following pickup of the directional and phase selection elements. The relay issued a trip, TRIP, when a two-cycle definite-time delayed directional neutral overcurrent, 67N1T, picked up. The relay under test was in the monitoring mode; its trip output was not connected to the breaker trip coil so the relay did not interrupt the fault test shown in Fig. 16.

IV. CONCLUSIONS

In conclusion, the detection of high-impedance ground faults on an ungrounded power system is less complex than detection of the same fault condition in a multigrounded power system. This paper shows a method that uses the system fundamental frequency component of residual current and

voltage. The method reliably detects the faulted feeder and faulted phase in an ungrounded power system in the presence of a high-impedance fault. The factors that influence fault detection sensitivity are system standing unbalance, the type of current transformers used to determine residual current, and the current transformer ratio.

This paper shows that the discussed method of fault detection operates favorably for actual fault conditions in the field.

V. REFERENCES

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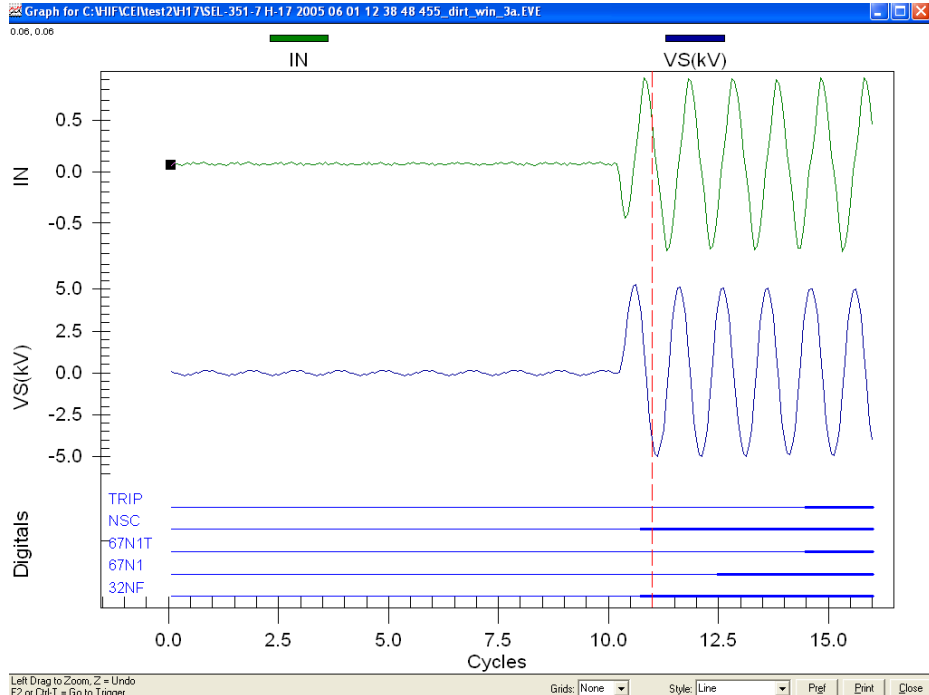


Fig. 17. Relay directional overcurrent and phase selection elements performance

VI. BIOGRAPHIES

Daqing Hou received B.S. and M.S. degrees in Electrical Engineering at the Northeast University, China, in 1981 and 1984, respectively. He received his Ph.D. in Electrical and Computer Engineering at Washington State University in 1991. Since 1990, he has been with Schweitzer Engineering Laboratories, Inc., Pullman, Washington, USA, where he has held numerous positions including development engineer, application engineer, and R&D manager. He is currently a principal research engineer. His work includes system modeling, simulation, and signal processing for power systems and digital protective relays. His research interests include multivariable linear systems, system

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Normann Fischer joined Eskom as a Protection Technician in 1984. He received a Higher Diploma in Technology, with honors, from the Witwatersrand Technikon, Johannesburg, in 1988, a B.Sc. in Electrical Engineering, with honors, from the University of Cape Town in 1993, and an M.S.E.E. from the University of Idaho in 2005. He was a Senior Design Engineer in Eskom's Protection Design Department for three years, then joined IST Energy as a Senior Design Engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories as a Power Engineer in the Research and Development Division. He was a registered professional engineer in South Africa and a member of the South Africa Institute of Electrical Engineers.