Protection Application Issues Near Strong Grounding Paths

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Abstract

This paper goes through the event analysis of a recent undesired trip of a line-distance relay applied near a large 522 MVA wye-grounded/delta generator step-up transformer. The generator was off-line setting up a large remote ground source (without positive or negative sequence currents) that undesirably affected the relay operation. This paper utilizes the recorded fault data and symmetrical component sequence networks to analyze the fault. Detailed lists of observations of the relays' analog (currents and voltages) and digital logic signals are developed from which a cause and solution are quickly determined. In addition other possible relay application problems are identified.

Introduction

The single line diagram below shows the general arrangement of the system in the Sturgis, Mississippi area. The Red Hills generating plant is connected to the TVA system through two 161kV lines from Sturgis. One of the lines is tapped in the middle with two autotransformers at Ackerman. Also, there is no interconnection to generation (positive sequence source) from Ackerman 69 kV. There are, however, motors at Ackerman 69 kV that have a small transient contribution to faults on the 161 kV system.

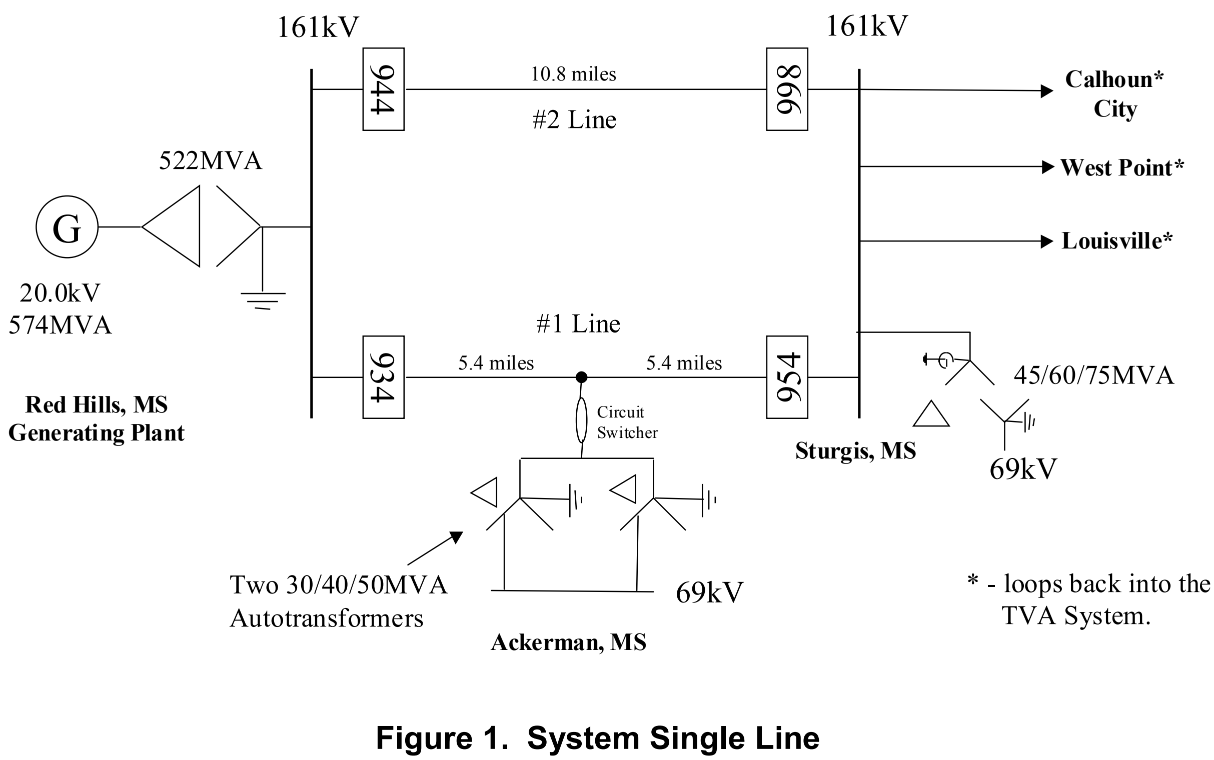


Figure 1. System Single Line

With the generation off-line at Red Hills and the 522 MVA step-up transformer still tied to the Red Hills bus, the only current that can flow from Red Hills in the two lines to the Sturgis bus is zero sequence. Due to the size of the solid grounded delta-wye transformer at Red Hills and the autotransformers at Ackerman considerable ground current is available to flow into ground faults around Sturgis. This system configuration sets up a number of protection application issues that have resulted in incorrect operations.

Figure 2 is the symmetrical component sequence network connection model for the system of Figure 1 with a reverse two phase-to-ground fault connection. It also shows the single phase-to-ground connection. It is provided to better understand the system. The gray area is the part of the circuit where no positive or negative sequence current flows because of the generator (positive sequence source) being disconnected from the system through the open switch SW. As can be clearly seen the positive sequence system source at Sturgis has a [ground] path through the Ackerman (Z_{0A}) and Red Hills (Z_T) transformers that allows zero sequence current to flow in the Red Hills to Sturgis lines

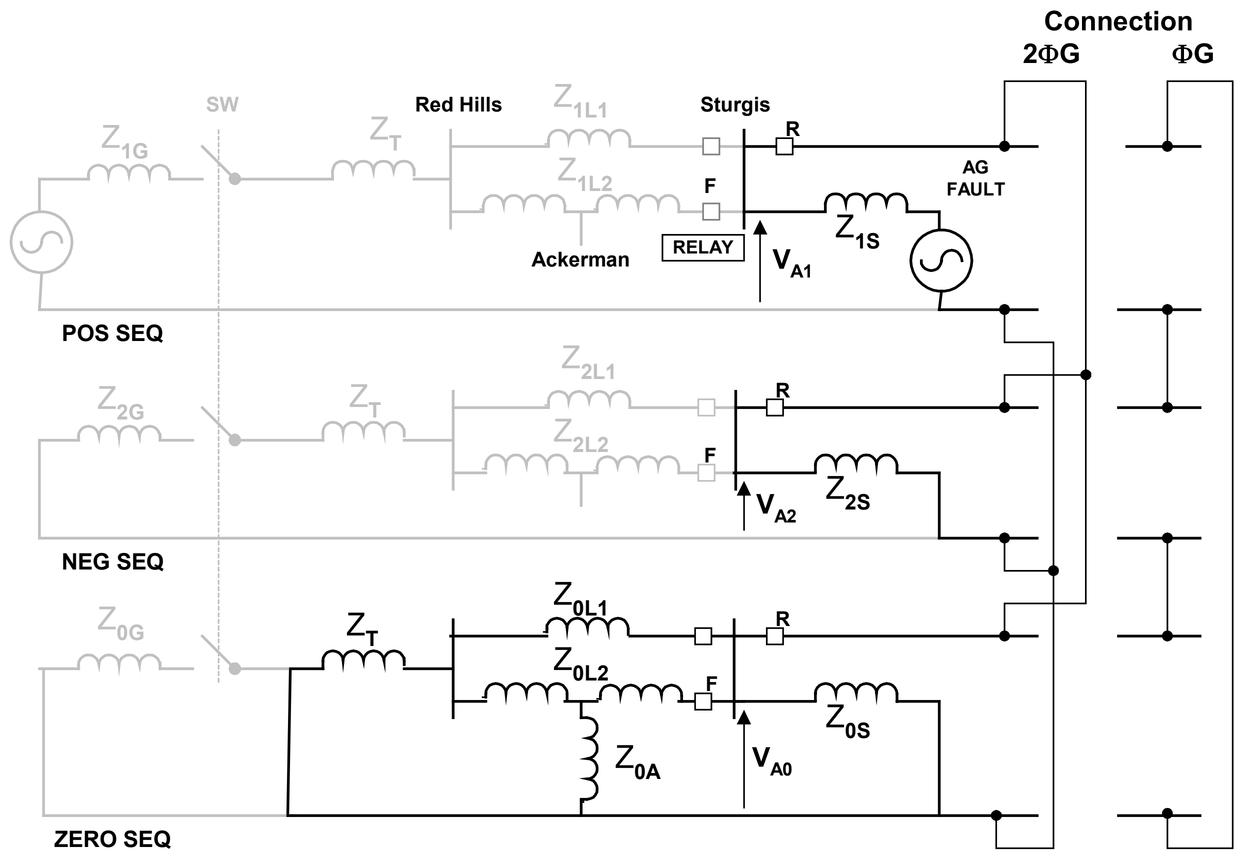


Figure 2. System Sequence Network Connection for Single and Two Phase-to-ground Faults

Also, there are two POTT (Permissive Overreaching Transfer Trip) pilot protection schemes of different manufacturers associated with each line, A-set and B-set.

Incident 1 (2/16/2001 at 11:08)

This event was precipitated by a double-phase-to-ground fault on one of the adjacent lines out of Sturgis as shown in figure 3. When this fault occurred, the Red Hills generator was off-line so that only zero sequence current could flow from the Red Hills lines into the Sturgis bus. A-set protection for both lines incorrectly tripped. B-set correctly restrained from operation. Digital fault records were collected from both sets of protection and analyzed. Analog and digital quantities recorded by both relays are shown in Figures 4 to 8.

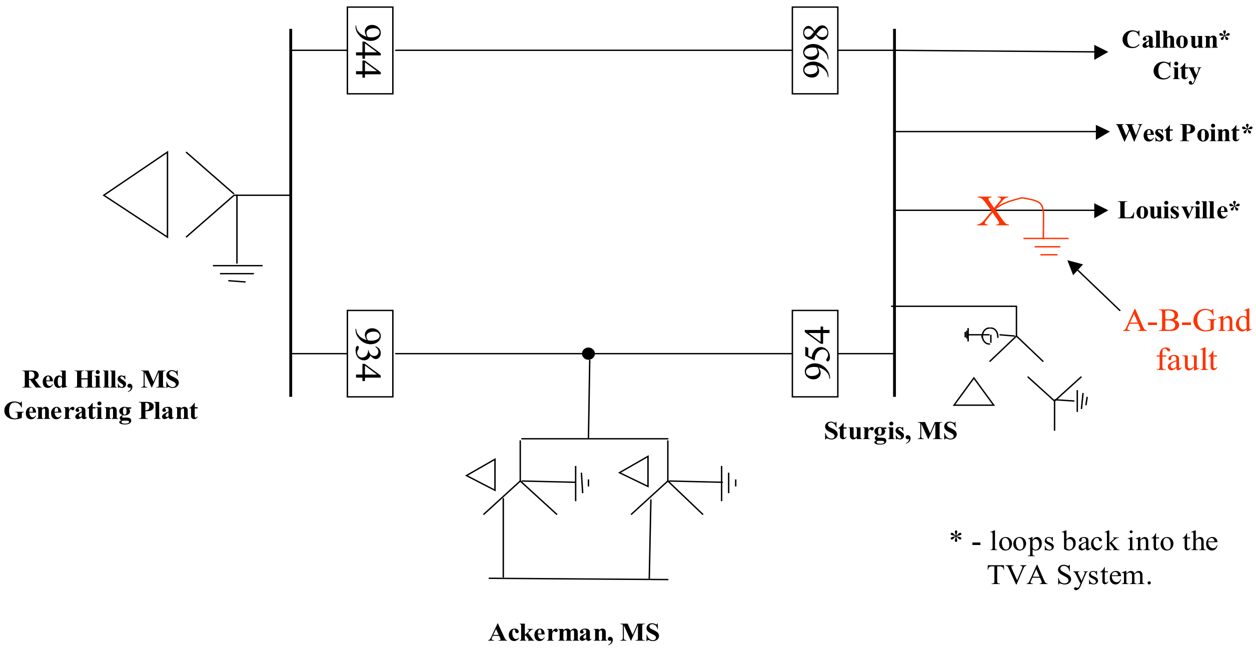


Figure 3. System Configuration with A-B-Ground Fault.

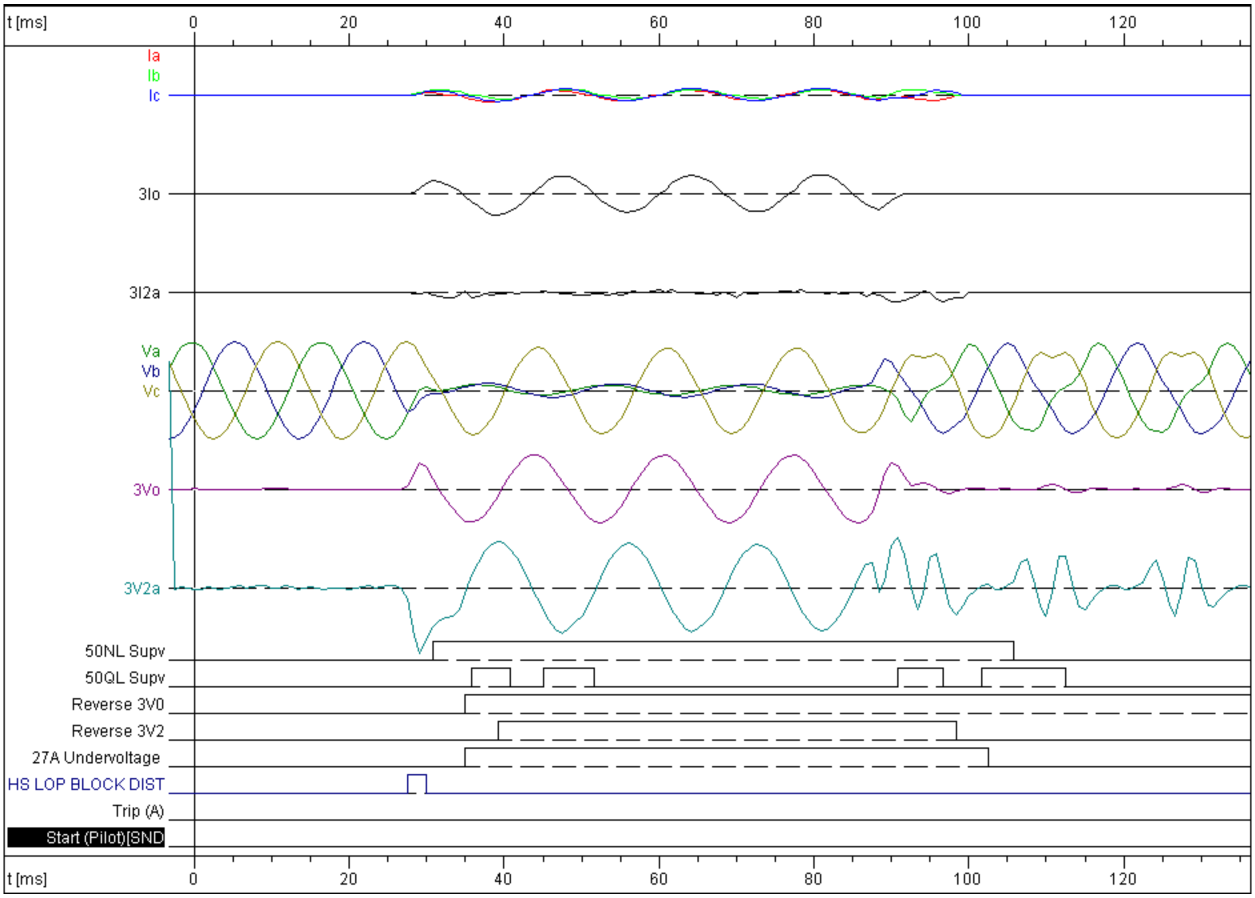


Figure 4. Current, Voltage and Digital Quantities in 998 B-set Relays During Incident 1.

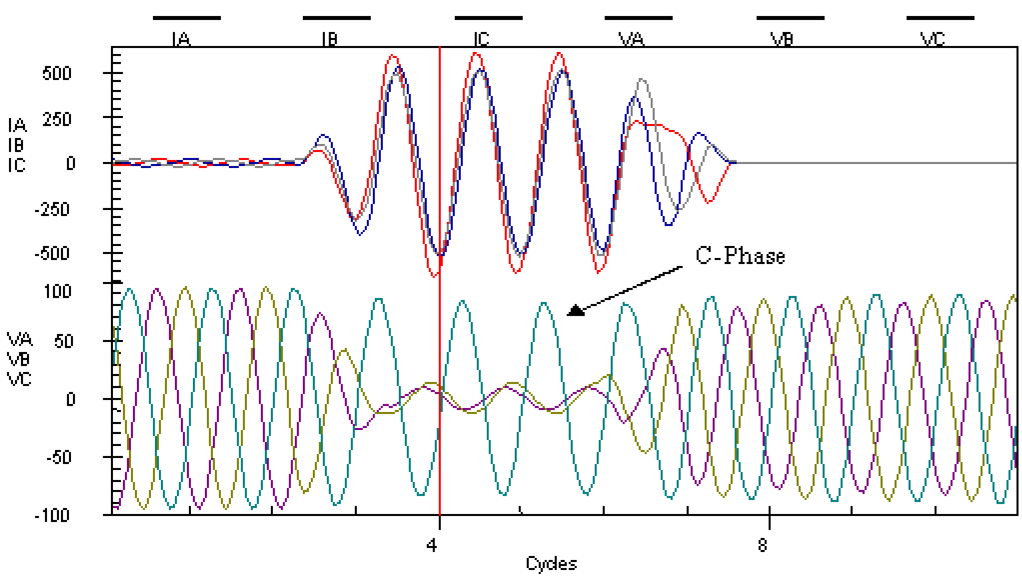
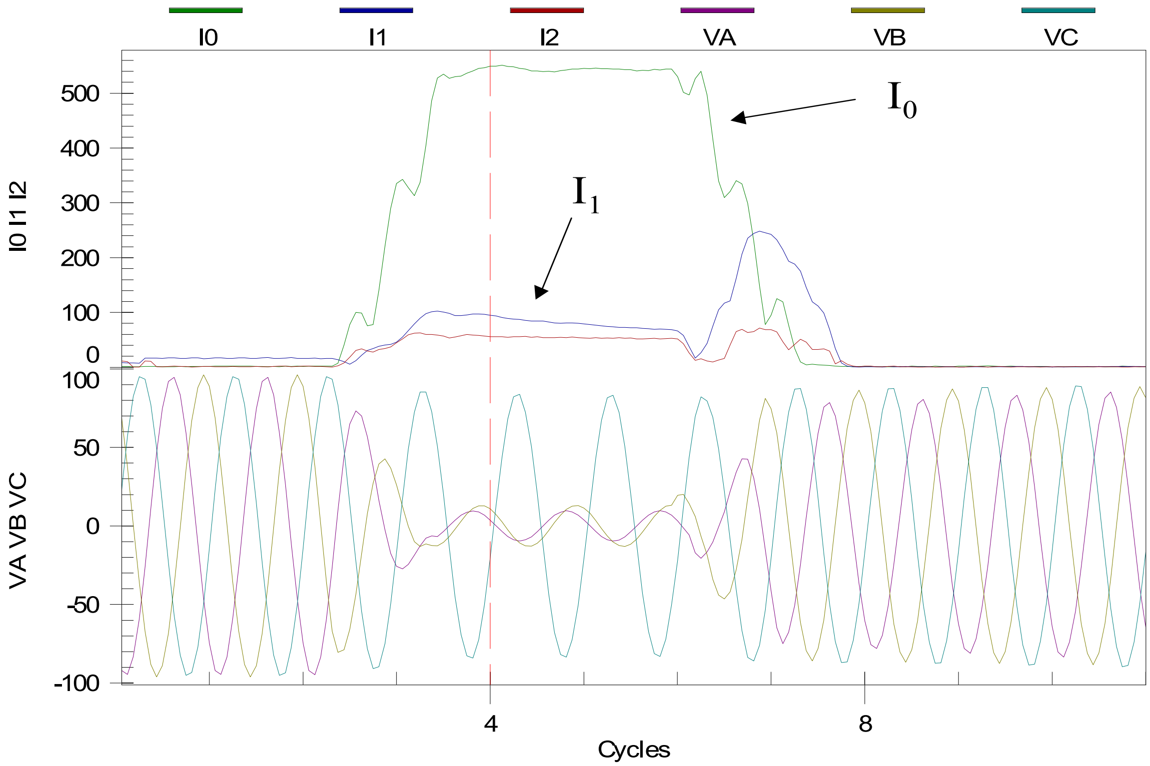
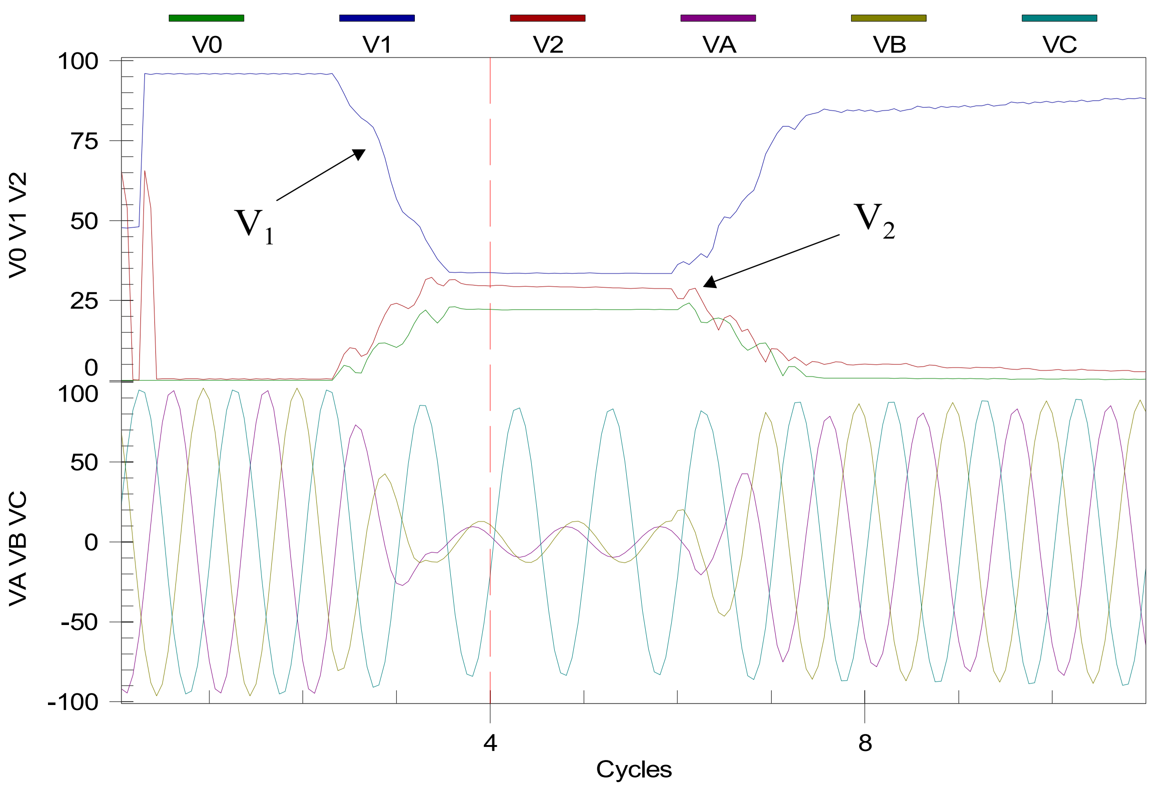


Figure 5. Phase Currents and Voltages in 998 A-set Relays During Incident 1.



Note: I_1 and I_0 are plots of the rms quantities computed over the previous cycle of sample data.

Figure 6. Sequence Currents in 998 A-set Relays During Incident 1.



Note: V_1 and V_2 are plots of the rms quantities computed over the previous cycle of sample data. The irregular waveform at the beginning of these traces is due to the fact that the sequence quantities are calculated in the oscillograph display program and at the beginning of the shot they have incomplete data to be computed until a full cycle of data is available.

Figure 7. Sequence Voltages at 998 A-set Relay During Incident 1.

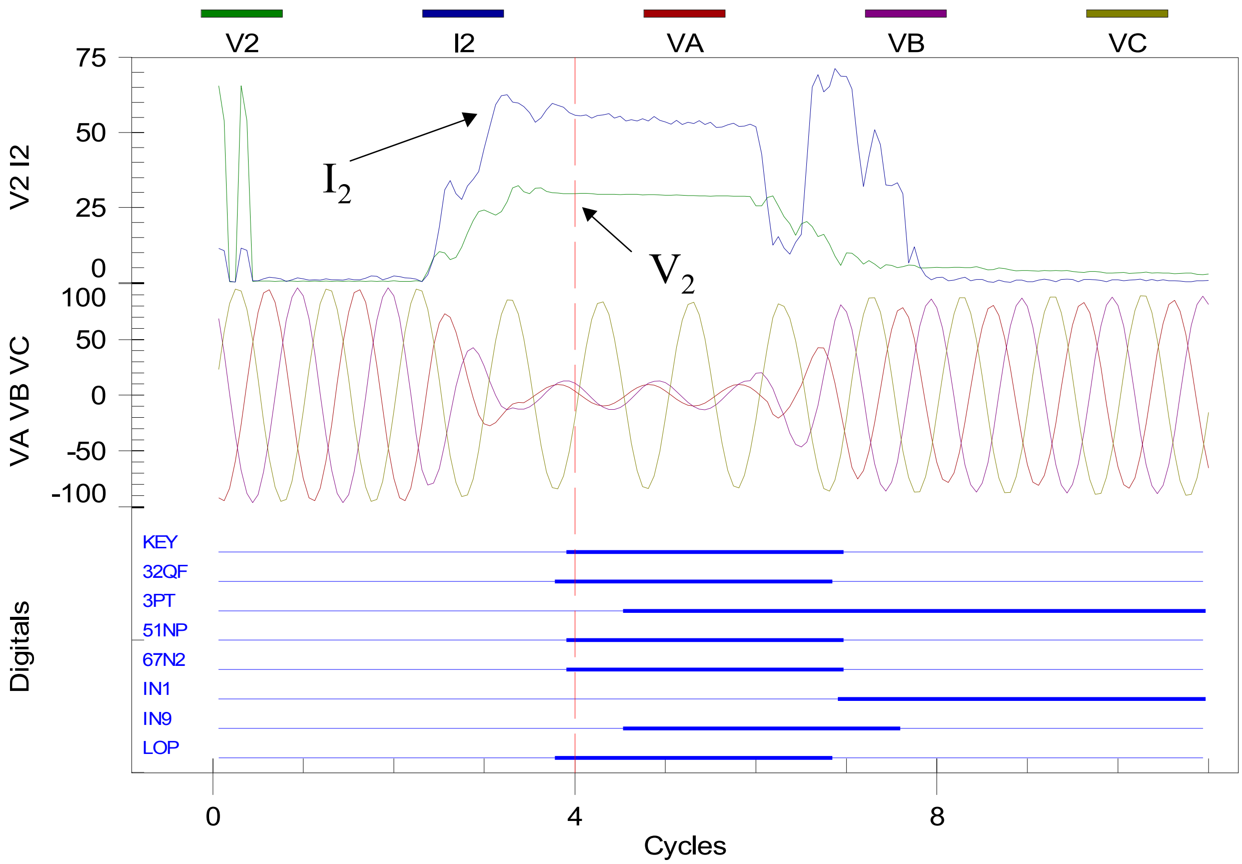


Figure 8. V2 and I2 Magnitudes in 998 and digital traces during Incident 1.

Review of the Analog Data

Figures 4 and 5 show the analog quantities for B-set and A-set relays, respectively. Different formats are used because different analysis programs are required for the different relay manufacturers. As expected the phase analog data is nearly identical. Figures 5 and 6 show the primary rms values of the sequence currents and voltages for A-set relays. Some observations with respect to the analog data are:

1. The data of Figures 4 and 5 show that the currents Ia, Ib and Ic are in phase. From this it can be inferred that the forward (looking into line # 1 from Sturgis) system zero sequence equivalent impedance is much smaller than the forward positive and negative equivalent impedance. The sequence network of Figure 2 shows the grounding effect of the large wye-delta generator step-up transformer and supports these results.
2. The data of Figures 4 and 8 show no appreciable negative sequence current (Figure 4 . . . 3I2a, Figure 8 . . . I_2) flowing to the fault through the relay. Note that this is consistent with observation #1. The sequence network also readily reveals this. With the switch SW open to show that the generator is out of service, it is observed that there is no positive or negative sequence current source to the relay. The small amount of measured negative sequence current may possibly be explained as motor contribution from Ackerman or possibly some small impedance unbalance or mutual on the parallel lines from Red Hills. It is, however, inconsequential. There is

negative sequence voltage (Figure 4 . . . 3V2a, Figures 7 and 8). This indicates that negative sequence current is flowing to the fault, but not through the relay.

3. The decision to trip was made in about 2 ½ cycles followed with breaker F clearing in about 2 to 3 cycles. This indicates high-speed clearing.

Most of these observations will have some bearing on defining and solving the problem. Some may not, but they should be listed and rationalized with the symmetrical component sequence network as a matter of habit. This will help hone the intuitive skills required for fault analysis.

Review of Digital Data

Figures 4 and 8 show some of the digital (status) signals that operated for B-set and A-set relays. These signals include the appropriate measuring unit and key logic signal operations. Some observations are:

1. The reverse directional zero sequence and negative sequence units of B-set relay (Figure 4 - Reverse 3V0 and Reverse 3V2) operated agreeing with the correct fault direction.
2. The forward directional negative sequence unit of A-set relay (Figure 8 – 32QF) operated for the reverse fault.
3. On the B-set relay (Figure 4) the low-set ground (3I0) instantaneous overcurrent unit (50NL) operated while the low-set negative sequence (3I2) instantaneous unit (50QL) operated on and off indicating it is very close to pickup (200 A primary). This is in agreement with the analog data where I_2 rises above and falls below 67 A.
4. On the B-set relay (Figure 4) there is also a low phase voltage (27 A Undervoltage). The loss-of-potential block function (HS LOP BLOCK DIST) momentarily operates, but does not sustain. The event ends without tripping.
5. On the A-set relay the loss-of potential function (LOP) operated simultaneously with the 32QF. This was followed closely by the simultaneous pickup of the ground time overcurrent element (51NP), the overreaching [forward] directional ground overcurrent (67N2) element, and the pilot KEY signal. One-half cycle later a pilot permissive signal is received on input IN9 and the relay trips.

Knowing the direction to the fault is reverse, which is also indicated by the B-set relay performance, the key issue is why the A-set relay saw the fault in the forward direction, which resulted in the pilot trip. The other key piece of information is the A-set relay loss-of-potential operation, which also disagrees with the B-set relay and is an incorrect decision.

LOP Logic

The above results indicate that a look at the Loss-of-potential (LOP) and directional (32QF) logic is probably the first step to resolve the issue. LOP logic is used to detect when one or more of the potentials on the relay are missing. Losing one or more potentials results in an inability of voltage polarized directional elements to work correctly. The relay has to detect this LOP condition so that voltage-directional supervised elements can be disabled or made non-directional.

The A-set microprocessor relays on these four breakers used an older version of the manufacturer's LOP logic. The older logic declares a LOP condition when it sees the presence of negative sequence voltage without accompanying negative sequence current (there is additional logic to detect loss of all three potentials). The idea being that negative sequence voltage would not be present without negative sequence current unless one or two potential fuses were blown. Figure 9 is a simplified logic diagram showing this concept:

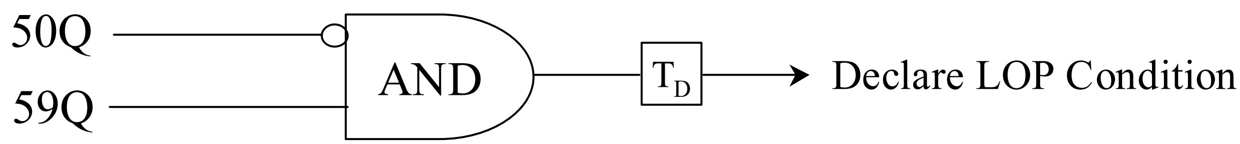


Figure 9. Simplified Piece of LOP Logic

When the negative sequence voltage measured at the relay exceeds the 59Q setting without the negative sequence current exceeding the 50Q setting the logic is satisfied and after a short delay (T_D) an LOP condition is declared.

The user chooses whether or not to block the distance elements and force the directional elements to a forward decision when a LOP condition occurs. The relays under investigation in this paper were set with a T_D of 1 cycle (minimum) and were set to block distance element operation and force directional elements to a forward decision.

The B-set microprocessor relays used a similar logic except it looks for zero sequence voltage without zero sequence or negative sequence current.

Resolution

The cause of the operation is now quickly resolved based on what we have learned in our analysis of the event reports and review of LOP logic. Figure 8 above shows the magnitude of negative sequence current being over 50A primary and that of negative sequence voltage being around 30kV. This value of current would be zero except for the possible motor contribution or unbalance line impedance effects as discussed on page 7. In the logic diagram of Figure 9 the LOP logic looked for negative sequence voltage (59Q) in the absence of negative sequence current (50Q). The 50Q element had a pickup of 67A (actual pickup was 200A as this element operates on $3I_2$, but for purposes of comparison with Figure 8 the pickup will be shown in I_2 amps). The 59Q element had a pickup of 15kV, and it operates on V_2. From Figure 8 it can be seen that the V2 present is well above the 59Q setting and the I_2 present is below the 50Q setting. In this case LOP was asserted. See Appendix A for background discussion on these settings.

The following sequence is noted from our previous observations of the digital signals. LOP asserts and simultaneously forces the overcurrent directional supervising element 32QF to forward. The 51NP (ground time overcurrent) element then begins timing, the 67N2 (overreaching directional ground overcurrent) asserts which in turn keys permission via the POTT logic. A short time later (½ cycle) permission from the remote end is received (IN9) as it made an incorrect LOP declaration as well and a POTT trip occurs (3PT indicates three-pole trip). The breaker is open less than three cycles later (IN1 is a b-finger). In summary, we pilot cleared this line due to the large ground current and insecure LOP logic.

Incident 2 (2/16/2001 at 13:19)

This incident is similar to the one previously described except that the fault is an A-Ground fault this time and the zero sequence current from Red Hills is less. The system configuration is shown in Figure 10 and the related fault recordings are shown in Figures 11 and 12.

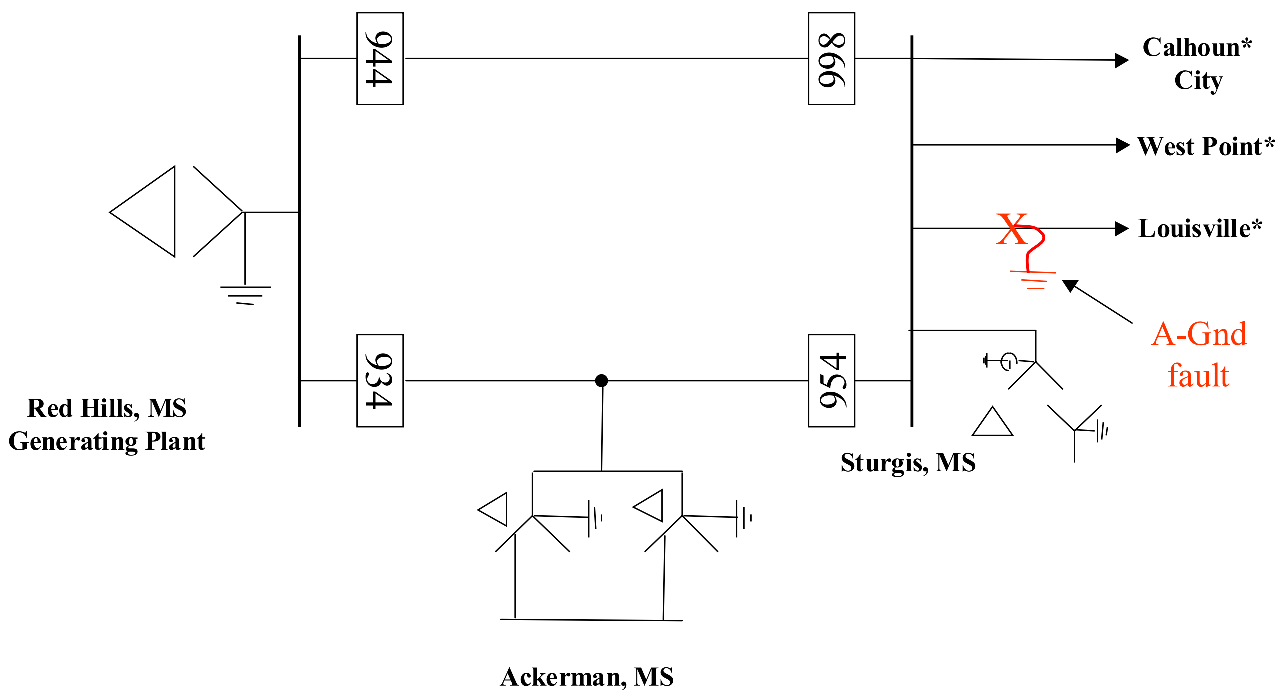


Figure 10. System Configuration with A-Ground Fault.

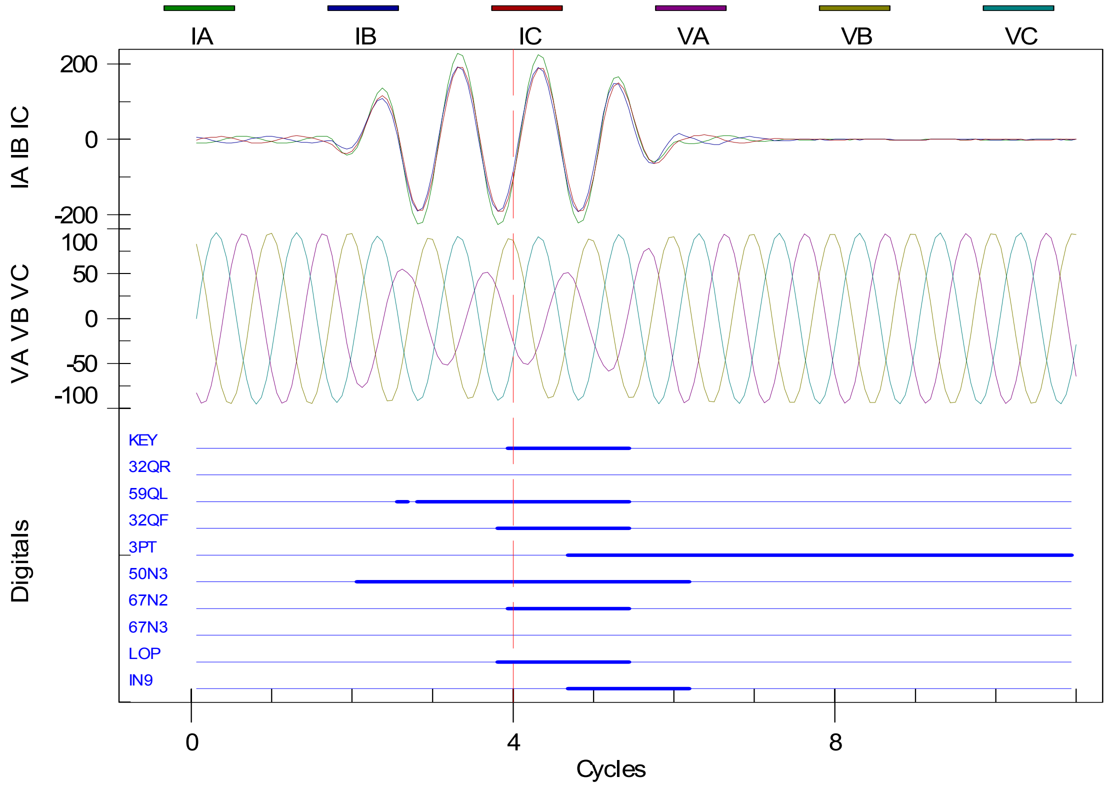


Figure 11. Phase Currents and Voltages with Digital Traces in 998 A-set Relay

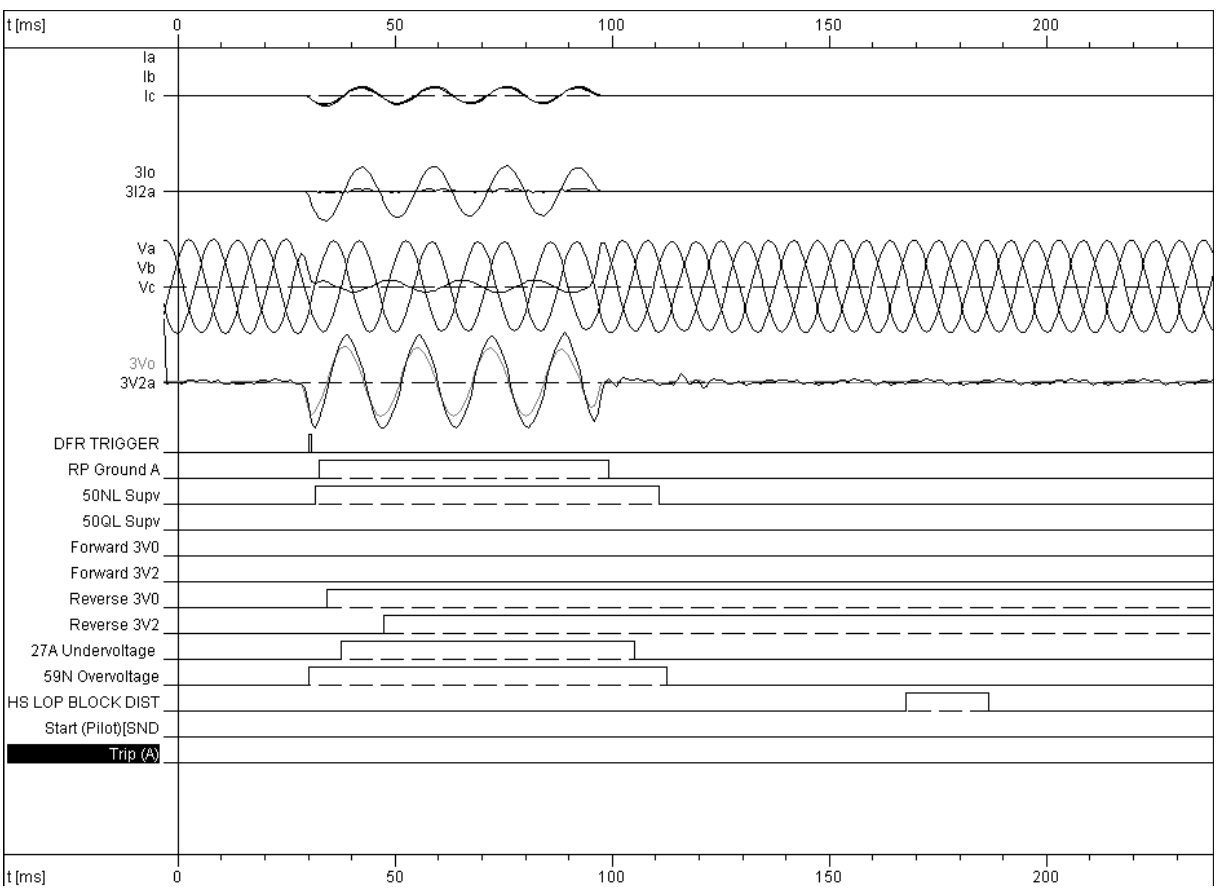


Figure 12. Phase Currents and Voltages with Digital Traces in 998 B-set Relay

For the A-set relay note that when the LOP logic asserts the relay forces directional elements forward as before. In this case, with a POTT scheme, this allowed a pilot trip to occur because the reverse looking residual overcurrent (67N3, that blocks the sending of permission) could not assert even though the residual current present exceeded its 50N3 pickup. It could not assert because its directional supervisor (32QR) is a reverse directional and LOP has forced all directional decisions forward.

The B-set relays at Sturgis correctly restrained from tripping and also provided useful fault data for this case. Analog and digital data are provided in Figure 12.

Resolution

The correct logic is similar to that of Figure 3 except it utilizes zero sequence, 50N and 59N. Until the relays could be upgraded to a newer version of firmware with adequate LOP logic the relay was set so a LOP condition would not block distance element operation or force overcurrent directional decisions forward. The logic behind this was that ground faults out of Sturgis were much more likely than a blown fuse.

With the LOP logic corrected we are still left with a lingering application decision to make as to what we allow to occur during a LOP condition.

1. Set LOP and have a pilot trip for any unbalanced fault within the sensitivity of the remote 67N2.
2. Block all tripping and rely on remote backup.
3. Do not use LOP and risk incorrect impedance or voltage directional element operation.

This issue is probably worthy of a different discussion specific to loss of potential operations and the application, and is not further addressed here.

Other Issues

Directional Supervision

Since Sturgis has individual breaker failure relays and a local backup ground relay (in 161 kV transformer neutral), it is not a requirement for the relays at Red Hills (looking into line 1 & 2) to backup for stuck breakers at Sturgis. However, in the absence of adequate Sturgis backup protection, it would be desirable for the relays at Red Hills to operate and remove the large ground source of the Red Hills GSU. This would allow the other positive sequence source lines into Red Hills to see a large increase in ground current from their end to backup clear a ground fault with a stuck breaker at Sturgis. Since the negative sequence directionally supervised relays cannot operate without a negative sequence source behind them, they could not provide backup protection for the above scenario. A backup ground time-overcurrent relay is located on the neutral of the GSU transformer but it is set slow to ensure it coordinates with the line relays. It will eventually trip but much slower than the line relays could.

Using zero sequence polarization may be the more practical solution provided the zero sequence mutual coupling problems with the parallel lines can be handled. The use of non-directional time-delayed overcurrent may also be considered.

Ground Impedance Reach Settings

The tapped ground path at Ackerman will affect the measured ground impedance reaches at breakers 934 and 954 (see figure 1). This should be considered when setting under and overreaching impedance units. This will be particularly important if a transformer is removed from service and affects the ground path impedance.

Summary

Modern microprocessor relays provide valuable data that help in understanding the performance of the power system and assist in analyzing relay operations for system disturbances. In this case we had data from two relays that let us see clearly the effect of the large ground path when the Red Hills generator was removed from service. Noting the analog values and digital targets that were recorded for the event by both relays, and observing differences pointed directly to the cause of the misoperation.

To aid in the analysis, there is no substitute for a relay engineer well grounded in symmetrical component analysis. A good symmetrical component understanding of how the system will behave under various configurations and faults is invaluable for setting protective relays and analyzing their operations. This coupled with the wealth of information provided by most microprocessor relays makes difficult analysis relatively simple.

Biographical Sketch

Russell W. Patterson is Manager of System Protection & Analysis for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. He is accountable for the application of all protective relays in the TVA transmission system and at Hydro, Fossil and Nuclear generating plants. He is responsible for ensuring that TVA's protective relays maximize the reliability and security of the transmission system. This includes setting and ensuring the proper application of protection philosophy for the TVA. He also reviews and makes protective relaying recommendations on new construction (including IPPs) and retrofit projects for the generation and transmission system. Prior to his position as Manager Russell was a Project Specialist in System Protection & Analysis and was TVA's Power Quality Manager responsible for field and customer support on PQ related issues and disturbances. Russell has performed transient simulations using EMTP for breaker Transient Recovery Voltage (TRV) studies including recommending mitigation techniques. Mr. Patterson earned the B.S.E.E. from the Mississippi State University in 1991 and has completed all coursework toward the M.S.E.E. at Mississippi State University. Russell is a registered professional engineer in the state of Tennessee. Russell can be e-mailed at rwpatterson@tva.gov.

Elmo Price received his BSEE degree from Lamar University in 1970 and MSEE degree in Power Systems from the University of Pittsburgh in 1978. He began his career with Westinghouse in 1970 and worked in several engineering positions that included assignments at the Small Power Transformer Division in South Boston, VA, the Gas Turbine Systems Division in Philadelphia, and T&D Systems Engineering in Pittsburgh. He also worked as a District Engineer and an Advanced Technology Specialist located in New Orleans and supporting the South-central U.S. With the consolidation of Westinghouse into ABB in 1988 Elmo assumed regional responsibility for product application for the Protective Relay Division. From 1992 to 2002 he has worked at both the Coral Springs and Allentown Divisions in various technical management positions responsible for product management, application support and relay schools. Elmo is currently Regional Technical Manager for ABB in Alpharetta Georgia supporting product sales in the southeast.

Elmo is a registered professional engineer and a member of the IEEE and the PSRC Line Protection Subcommittee. Elmo can be e-mailed at elmo.price@us.abb.com

Appendix A – 50Q and 59Q Setting Calculations

The 50Q elements were set on minimum = 0.5A secondary = 200A primary $3I_2$. This setting need only be above normal expected unbalance to avoid forcing a forward directional decision in the absence of an unbalanced fault.

The 59QL setting is used to detect the resulting negative sequence voltage (V_2) due to the loss of 1 or 2 fuses. It should be set above the normal expected system unbalance voltage.

$V_2 = 1/3 \times [V_a + a^2V_b + aV_c]$; where a = 1@120° unit operator.

For one blown fuse (assuming 66.0V phase-neutral on relay),

$V_2 = 1/3 \times [V_a + a^2V_b + 0]$
$V_2 = 1/3 \times [66.0@0° + (1@240°)*(66.0@-120°) + 0]$
$V_2 = 22.0@60°$ Volts phase-neutral
$V_2 = 22.0$V secondary

Set 59QL = 22V/2 = 11V secondary = 15.4kV primary

For two blown fuses,

$V_2 = 1/3 \times [V_a + 0 + 0]$
$V_2 = 1/3 \times [66@0° + 0 + 0]$
$V_2 = 22.0$V secondary (same as for 1 blown fuse)

Note: In both cases the result was 0.333V per unit.