PROTECTION AND COMMUNICATION FOR A 230 KV TRANSMISSION LINE USING A PILOT OVERREACHING TRANSFER TRIPPING (POTT) SCHEME

By

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Abstract

New applications are continuously emerging in the ever-changing field of power systems in the United States and throughout the world, consequently causing new pressures on grid performance. Because power system protection is a fundamental aspect of the system, their operation must be addressed when a system is under high stress or when a high demand of energy is required. An extreme example is the transmission protection of a system because it transports large amounts of power. Transmission lines in a power system are frequently exposed to faults and generally protected by distance relays. If a faulted segment of transmission lines is not cleared in a short period of time, the system becomes unstable. The basic function of distance protection is to detect faults in buses, transmission lines, or substations and isolate them based on voltage and current measurements. Power system protection has previously focused on matching automation and control technologies to system performance needs.

This report focuses on project activities that run simulations to determine settings for a protective relay for pilot overreaching transfer tripping and then test the settings using hardware equipment for various scenarios. The first set of scenarios consists of five faults in the system; two faults are in the protected line, and the remaining faults are outside the protective line. The second set of scenarios consists of instrument transformer failures in which the current transformer (CT) of one relay fails to operate while the other relay is fully operational. The second scenario consists of a failure of the voltage transformer (VT) of one relay while the other relay remains fully operational. Finally, the third and fourth scenarios consist of the failure of both CTs and VTs for each relay.

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Chapter 1 - Introduction

The importance of power system protection must be understood in conjunction with operating conditions of a power system. Electrical power technology has steadily advanced and continues to make progress, allowing for the design and construction of economical and reliable power systems. Thus, electric power is instantly available at the correct voltage, frequency and amount needed. The public often perceives the power system to be imperturbable, constant, and infinite in capacity [1]. However, the power system is a victim to constant disturbances attributed to factors such as load changes or faults provoked by natural and artificial causes. Power system stability can be maintained in part by quick preventive and corrective actions taken by the protective relaying equipment. This protective equipment detects irregular power system conditions and initiates corrective actions as quickly as possible in order to return the power system to its normal state. The quickness of response time is measured in milliseconds [3]. In addition, the response must be automatic and with a minimum amount of interruption to the power system.

1.1Power Protection in Transmission Lines

Transmission power systems are the primary electricity highways that transport high amounts of electricity to cities and industrial facilities. Thus, transmission lines are elements of a power system that are primarily exposed to short circuits between phases or from a phase to ground [2]. This is also the main source of deterioration for all other electrical equipment in a power system. Transmission lines are commonly protected by distance relays and their function is to detect faults that appear in the line or substations and isolate those faults. Protection schemes for transmission lines are also set to protect a certain zone of the transmission lines. These zones always overlap to make the protection scheme redundant and ensure the relays operate when a fault occurs. Thus, relays must coordinate to take appropriate action and operate according to configured settings.

1.2 Distance Protection of Transmission Lines Overview

Distance relays protect transmission lines and are suitable under different considerations. Distance protection should be implemented when overcurrent protection relaying is too slow and on transmission lines where high-speed automatic reclosing is not necessary to maintain stability. A balance exists between voltages and current with a ratio which can be expressed in terms of impedance [3]. Thus, distance relays respond to impedance between the relay location and fault location. The former statement means that a distance relay operates when the voltage and current ratio is less than its preset value.

The ability of a distance relay to differentiate between faults and load, particularly when the system is stressed, has become a major concern. North American Electric Reliability Corporation (NERC) requires that this condition be included in relay settings studies.

Contingency analysis typically provides a plan in which one transmission line can be lost on a system. However, a fault should be removed as quickly as possible to prevent instability in the system. When the system is stressed, the loss of another element could be the final step in a cascading failure of the entire network. The use of digital logic and communications allow reordering of protection priorities and require additional inputs before allowing the trip [5].

1.2.1 R-X Diagram

Distance relay characteristics are shown in an R-X diagram, where the resistance R is the independent variable (horizontal axis) and the reactance X is the dependent variable (vertical axis). Typical characteristics on these axes are shown in Figure 1.1. Thus, the origin is the relay location with the operating area generally in the first quadrant [6]. Whenever the ratio of system voltage and current fall within the circles shown, the unit is operational. The circle through the origin is known as an MHO unit and is used for line protection; therefore, it is directional and more sensitive to fault.

The primary protection of a line commonly requires two distance units. Zone 1 unit operates instantaneously and is commonly set to 90% of the total segment of the line. Zone 2 is set to approximately ± 150% of the lines and must have a time delay because it overreaches. Certain applications require implementation of a Zone 3 and are set to look backward. This kind of application can be used for backup or in pilot protection. Figure 1-2 is an example of various zone settings for the two different relays.

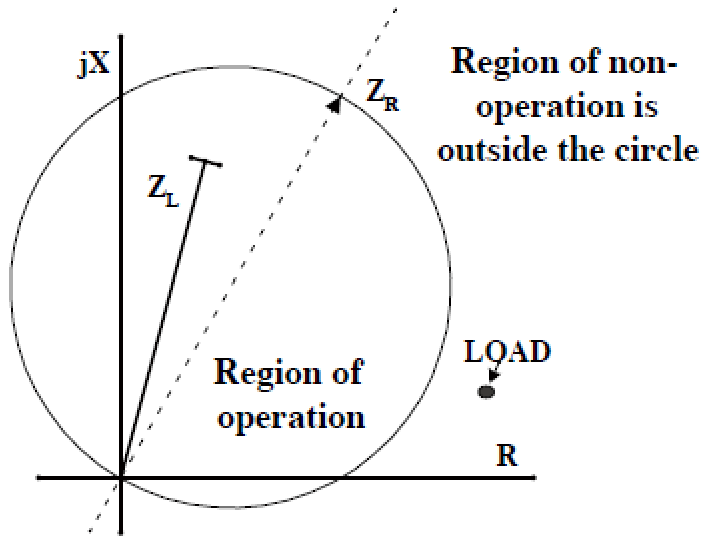


Figure 1-1 MHO Diagram

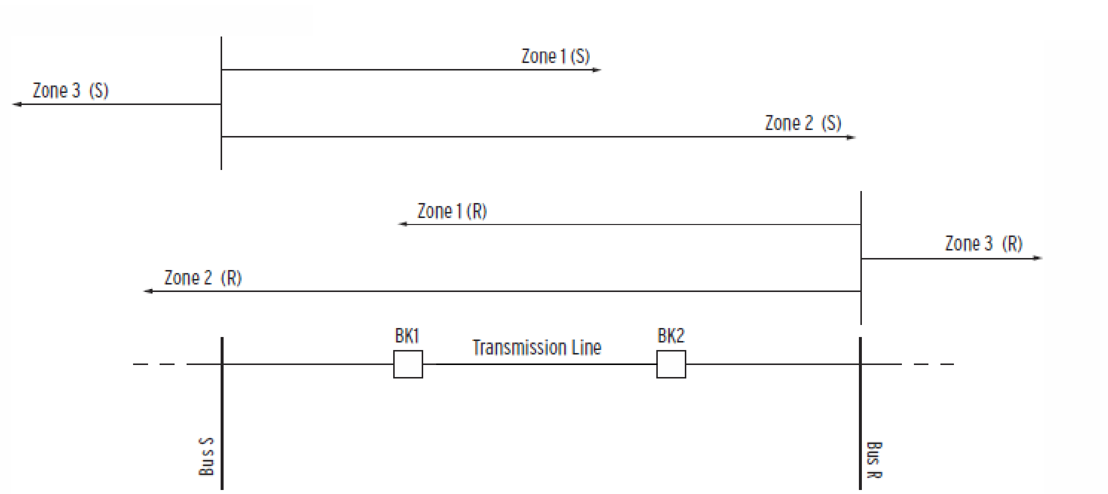


Figure 1-2 Protection Zones

A distance relay trips a faulted line in a very short time as long as the fault is within the distance of the protected segment of the transmission line. For faults at the far end of the line just beyond the threshold, the fault must be cleared by some means. This is accomplished by providing more than one different thresholds with different relaying times. Distance relays, due to their simplicity, are often adequate to ensure high quality protection and rapid response. In some cases, this scheme is not adequate [4]. For example, when the time delay to clear a fault is too large, it is considered unacceptable. Therefore, lines carrying high power transfers can cause severe stability problems. An example of the former statements refers to Figure1-3. To avoid loss of coordination for a fault at F_2, the relays at terminal B trip instantaneously in their first zone and the relays at terminal A use a time delay for second zone or backup tripping [1], resulting in a slow clearing for a fault at $F_{1.}$

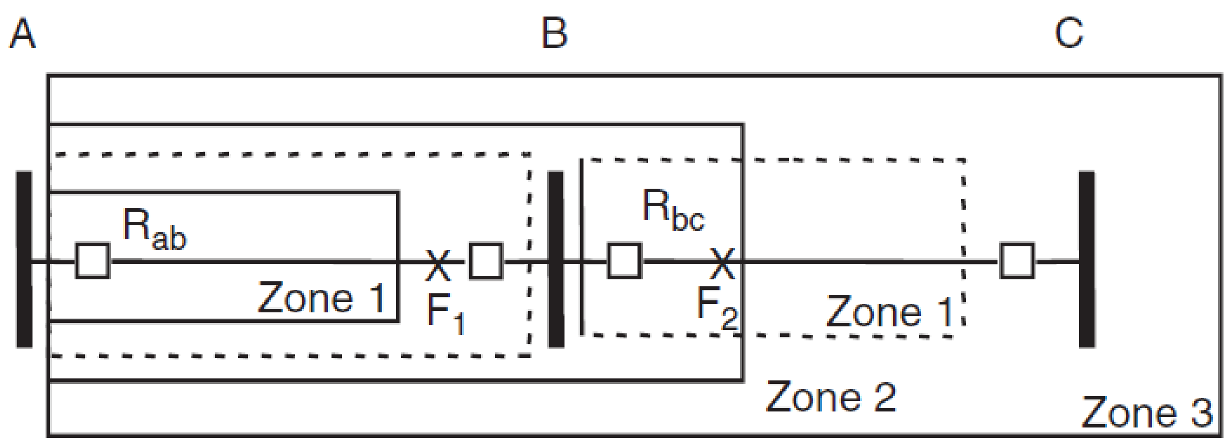


Figure 1-3Zone Coordination

1.3 Pilot Protection Overview

Pilot protection for lines provides possibilities for high speed simultaneous detection of phase and ground faults protection for 100% of the segment being protected from all terminals, which is the ideal primary protection goal. It is a type of protection for which quantities at the terminals are compared by a communication channel rather than by a direct wire interconnection of the relay input devices [6]. The increment in time delays when using distance relays becomes impractical because of the distance between several terminals. Thus, pilot protection does not require any coordination with protection in the adjacent system unless additional backup is included.

Pilot protection conveys three fundamental concepts protective system design: selectivity, reliability and security. This is especially important in extra high voltage (EHV) circuits because of a considerable system disturbance that occurs when a heavy load line is opened. For the protection system, the relaying system must be selective and precautions are taken to ensure no operations are initiated by the relay logic or other means that would cause tripping of important lines or other facilities when not absolutely necessary [4]. Thus, pilot protection is an adaptation of differential relay principles that avoid the use of control cables between terminals. The term ‘pilot’ refers to a communication channel between two or more ends of a transmission line to provide instantaneous clearing over 100% of the line [1]. Communication channels typically used include power line carrier, microwave, fiber optic, and communication cable.

1.3.1 Communications Channels

Communication channels used for protective relaying are [1]:

a) Power Line Carrier (PLC): Operates on radio frequency signals over transmission lines in the 10 to 490 kHz band. PLC systems with power outputs of 10W are reliable up to approximately 100 miles and those with 100W outputs are effective at over 150 miles. Capacitors are used to couple carrier equipment to the high voltage transmission line. They create low impedance paths to the high frequency of the carrier current but otherwise at the 60 Hz power frequency. In conjunction with line tuners and wave traps are used which also present low impedance to the power frequency and high impedance to the radio frequency. The signal is captured between the ends of the line. Typically only one 4 kHz bandwidth channel is provided exclusively for protection. Transmission time is approximately 5 ms. In the United States, the government limits the number of transmit/receive power line frequencies. PLC is subject to high impulse noise associated with lightning, faults, switching, or other arching phenomena. PLC is a versatile communications link that can be applied to directional or phase comparison fault detection schemes to block or trip circuit breakers or with on-off or frequency-shift modes of operation.

b) Microwave: Operates at frequencies between 150 MHz and 20 GHz. This bandwidth can be put at the disposal of protection systems with many 4 kHz channels operating in parallel. Protection, however, is usually a small part of total microwave system use. The large bandwidth allows a variety of information to be sent, such as voice, metering, and alarms. The microwave signal is subject to atmospheric attenuation and distortion. The transmission length is limited to a line-of-sight path between antennas but can be increased through the use of repeaters for increased cost and decreased reliability.

c) Fiber-optic links: The use of optical cable is becoming very popular. Such links have virtually unlimited channel capacity. Single fibers have as many as 8000 available channels, and this can be significantly increased by using multiple fiber cables. Any number of fibers can be in the cable, depending on the application. Each glass fiber is protected by a plastic tube, and all the tubes are protected by an aluminum tube. Additional strength members are used for support, and the entire construction is comprised of galvanized steel. Because the fiber cable is non-conducting, it is immune to interference from electric or magnetic fields and provides excellent transmission quality. Very little signal attenuation is present, but the transmission length can be several hundreds of miles with the use of repeaters. The channel capacity provides as many as 8000-4 kHz channels per fiber. The use of fiber cable, however, is rarely justified only for protection, but because of its large data transmission capacity, it is also used for dispatching and telemetering. Once available, however, it makes an excellent communication channel for relaying. Many utilities are installing fiber optic cable, using advanced computer programs to monitor and reroute signals in the event of a disturbance on any path.

1.4 Report Objectives

The objective of this research is to design a POTT protection scheme for a 230 kV transmission line with distance relay, including the design of its proper communication zones of protection. First, the report discusses principles of distance protection in transmission lines. Operation principles of an impedance relay are presented as well as concepts of pilot protection. Protection in transmission lines has two forward-looking zones and one backward-looking zone. Second, the design and implementation of the POTT protection scheme with five fault cases is presented. Finally, a study of effects of failures on the CT and VT on the protection scheme is conducted.

Chapter 2 - Literature Review of Related Works

The first chapter presented a layout of concepts that constitute pilot protection as well as characteristics of distance protection. The importance of protection in the transmission stage of a power system has also been discussed. Over the past years, extensive research has been performed on protection in transmission lines. New regulations in the U.S. electric grid have revived the attention of researchers. The next chapter discusses the achievements of previous researchers on this topic.

2.1 Power Transmission History and Overview

In the 1890s, the development of high-voltage power transmission lines using alternating current allowed power lines to transmit power over much larger distances in the U.S. than the direct current system preferred by Edison. In 1896, George Westinghouse built an 11,000 volt AC line to connect a hydroelectric generating station from Niagara Falls to Buffalo, New York, 20 miles away. This more capable transmission system motivated the industry to build larger generators to serve increasing loads and populations. Consequently by 1907, Commonwealth Edison had consolidated

20 power companies, and subsequently, by 1913, 43 states had regulatory commissions with oversight over electric utilities.

The growth continued in the post-World War II era. Electric utilities made technological advances by constructing larger generating plants to capture economies of scale. It cost less to generate a kilowatt-hour (kWh) of electricity from a large plant than from a small plant. In 1948, for example, only two power plants exceeding 500 megawatts (MW) existed in the United States. By 1972, 122 such plants were in existence. By 1992, Congress passed the Energy Policy Act (EPACT) which required the well-established competitive generators or any utility to be given access to the transmission grid on rates and terms comparable to those the utility would charge for grid access. Access to the transmission grid became indispensable for the growth of wholesale power makers, whereby power generators could use the transmission system to send power at fair and predictable rates and terms. Since the mid-1990s, the Federal Energy Regulatory Commission (FERC) has issued several orders to carry out the goals of EPACT [7].

2.1.1 Power Transmission Regulation

The FERC has dictated several relevant orders regarding power transmission systems [7]:

- Order 888 detailed how transmission owners should charge for use of their lines and the terms under which they should give others access to their lines. Order 888 also required utilities to functionally unbundle, or separate, their transmission and generation businesses and follow a corporate code of conduct. FERC hoped that this separation would make it impossible for the transmission business to allow preferential transmission line access to its own power plants.
- Order 889 created an on-line system through which transmission owners could post available capacity on their lines and companies that desired to use the system would be aware of available capacity.
- Order 2000 encouraged transmission-owning utilities to form regional transmission organizations (RTOs). FERC did not require utilities to join RTOs; instead, it asked that RTOs meet minimum conditions, such as an independent

board of directors. FERC gave these regional organizations the task of developing regional transmission plans and pricing structures that would promote competition in wholesale power markets, using the transmission system as a highway for that wholesale commerce.

- Order 2003-A was issued in 2004, requiring transmission owners to interconnect new generators larger than 20 megawatts to their grid. Order 2003-A required transmission owners to connect these large generators under a standard set of terms and conditions and to follow a standard process and timeline for interconnecting them. Occasionally, new power plants add new stresses to the power grid, so transmission owners must upgrade the transmission grid when this occurs. Order 2003-A defines who pays for these upgrades.

2.1.2 Modern Transmission System

The current transmission system is an interconnected network of high voltage and transmission lines. As the U.S. becomes an increasingly technology-dependent society, a reliable power system, including the transmission system and generation, is essential. The system has developed into a sophisticated network, involving interconnecting power plants and power lines that operate many different voltages. The network has performed well a majority of the time; however weaknesses appear when the system is stressed due to the growing population of various counties throughout the country. A blackout in the northeastern and midwestern United States on August 14, 2003, is an example of a network breakdown. Recently, electric transmission has received more attention than ever due to the debate on how to successfully combine technology and policy in order to strengthen weak sections of the network. Changes that have occurred in the past decade in the power industry require that the physical network and institutions adapt to these changes. Therefore, the power system will serve the increasing demand of electricity through the implementation of new infrastructure and technology as well as more efficient measures.

2.2 Distance Protection

Distance relays are typically used to protect transmission lines [9].They respond to impedance between the relay location and fault location. Because the impedance per mile is fairly constant, these relays respond to the distance to a fault of a transmission line and hence their name [1]. Also, one of the advantages of distance protection compared to over-current protection is the non-existing coordination of time delays when multiple sources are present in a power system [8].

2.2.1 Distance Protection with Multiple Power Sources

Distance protection is able to discriminate between faults occurring in different parts of the system, depending on the measured impedance. Essentially, this involves comparing the fault current, as seen by the relay, against the voltage at the relay location to determine the impedance down the line to the fault. A distance relay is adjusted based on the positive sequence impedance of the protected line. If a fault occurred downstream, the relay divides the line into two portions. The first portion from the relay location to the fault has an impedance proportional to the distance between the relay location and the fault position. With this information, the fault location can be predicted using the impedance seen at the relay location [10].

For the protection of systems with multiple power sources, a fundamental concept of zones protection is applied to it in which transformers, generators and transmission lines define the protective zone of the system. Protective zones contain overlapping between zones, and circuit breakers are located in the overlap regions [8]. Figure 2-1 illustrates the zone protection concept in which each zone is defined by a dotted line. For example, the generator has its own protection, as well as the transformer and the bus. The zones overlap to provide total system protection. Therefore, if a fault occurs in the zone, action will be taken to isolate the fault and reduce the time the system must be inoperable or operate under unstable conditions.

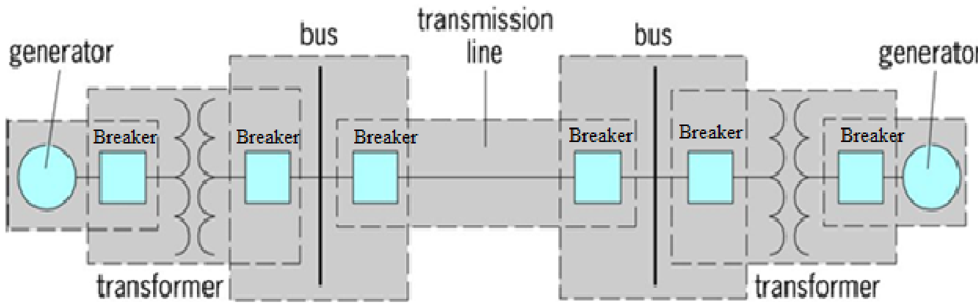


Figure 2-1 Protection Zones

2.2.2 Three-Phase Distance Relays

A three-phase power system contains ten distinct faults described in Table2-1. Equations that govern the relationship between voltages and currents at the relay location vary for each of these faults. Therefore, several distance relays, each energized by a different pair of voltage and current inputs, should be required to correctly measure distance to the fault.

A fundamental principle of distance relaying suggests that, regardless of the fault type, the voltage and current used to energize the appropriate are such that the relay will measure the positive sequence impedance to the fault. Once this is determined, the zone settings of all relays can be based on the total positive sequence impedance of the line, regardless of the fault type. This study considers various types of fault and determines appropriate voltage and current inputs to be used for distance relays responsible for each fault type.

Qty	Types of Fault	Phase Sequence
1	Three Phase	A-B-C
3	Phase-Phase	A-B, B-C, A-C
3	Phase- Ground	A-G,B-G, C-G
3	Double Phase-Ground	AB-G,BC-G, AC-G

Table 2-1Type of Fault for Three-Phase Systems

Figure 2.2 shows the operational graph for a distance relay. If the fault impedance lies in the white area, the relay will trip. However, if a fault occurs outside the white area, the relay will not trip and the system will continue to operate normally. Segment BC represents impedance of the transmission line. When a fault occurs in the white area between A and B, the fault is considered forward-looking, but when a fault occurs in the white area between A and C, it is considered backward-looking.

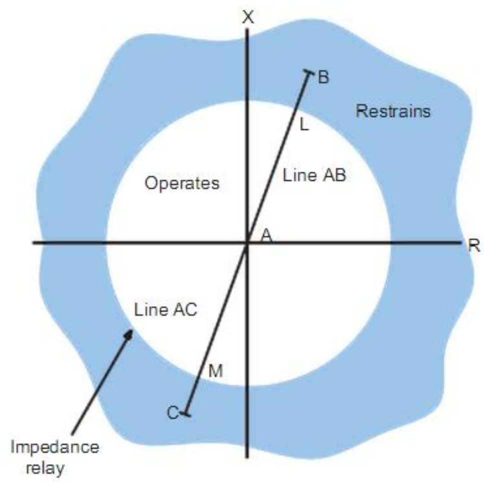


Figure 2-2 Impedance Relay Trip Regions [19]

2.3 Pilot Protection

As mentioned in the previous chapter, due to integration of communications systems that decrease error tripping in the system, pilot protection offers increased certainty when a fault is present in a system. Implementation of pilot protection in transmission systems is widely used because of its adaptability and reliability. The pilot protection scheme used in this report is somewhat based on the applications manual developed by SEL [12]. The reference presents distance protections schemes for a 230 KV line in a multiple source configuration in which some relay settings are applicable to this report. For a better understanding of pilot protection in transmission lines, several applications concerning pilot protection have been done and are presented below. Justification of pilot protection is also addressed. Finally, the specific pilot protection scheme used in this report is explained.

2.3.1 Pilot Protection Applications

The development of modern optical fiber communication technology has become increasingly popularized due to its long-distance, large-capacity, high-speed, and real-time synchronous data transmission. Pilot protections based on fiber communication technology have become one of the primary forms of transmission line pilot protection [13]. Consequently, many of these configurations rely on differential protection, but problems such as low sensitivity or poor reliability because of CT saturation and influence of large charging current because of line distributed capacitance for long transmission lines arise when implementing differential protection. These complications are seriously impairing and threatening to the speed and sensitivity of conventional current differential protection. To reduce CT saturation and line distributed capacitance, reference [13] proposes an Enhanced Transmission Line Pilot Impedance (ETLPI) scheme. ETLPI is defined as the ratio of voltage difference of fault-superimposed components at both terminals of the protected line, which can be calculated from real-time voltages and currents measurements synchronously transmitted from local terminal to remote terminal. When this model is implemented, the amplitude of ETLPI is greater than the amplitude of the positive sequence impedance of the protected segment of the line. ETLPI also effectively avoids distributed capacitances and CT saturation. Therefore, this scheme may suit larger transmission lines.

Fiber optic communication is applied in power protection because the appearance of digital communication technology makes information exchange reliable and fast. Hence, [14] proposes the construction of an intercommunicated protection system. Pilot protection can improve relay reliability with communications between protections schemes. Fiber optic-based communications in pilot protection systems faults can detect faults more rapidly with a low time delay. With the implementation of fiber optics, information exchange is not limited to the digital state value. A variety of information exchange by the same communication channel provides sufficient information. Pilot protection can be implemented with distance relays, which distinguish internal and external fault by comparing fault direction of fault distance on both sides. The information exchange is logical instead of analog quantities. Therefore, in a pilot protection system, protection Intelligent Electronic Device (IED) on each side of a transmission line collects information and calculates fault direction, fault distance, and other parameters based on local information and then sends the results to the IED on the opposite side. The information exchange is voltage and currents values, protection start-up signal, fault direction, and distance information, fault phase selection information, and breaker status. Reference [14] concludes that, besides providing better reliability and rapid communication, the digital communication channel also provides the possibility for various and large amounts of synchronous electrical information exchange. With the aid of an optical digital channel, multiple protection criteria can be executed to improve the operation performance of traditional pilot protection system which can complete various functions such as relaying protection, auto reclosing, measurement of transmission line parameters, and more functions within the unified pilot protection.

2.3.2 Justification of Pilot Protection on Transmission Lines

The protection zone for a transmission line is unique because the zone limits generally extend to geographically separate locations. In addition to their relay sources, elements entirely at one location, can have instantaneous tripping configured. In order to affect high speed tripping for 100% of a transmission line, each terminal of the protected line must communicate with the other terminal(s) in some way [15].

When pilot protection is evaluated for implementation, its goal is to improve system stability while fault clearing in the shortest amount of time. From the perspective of electric utilities, clearing time reduction improves stability, reduces equipment damage, and improves power quality in addition to providing quality service. Reference [15] presents the following technical reasons to consider pilot protection:

- Cascading Issues: Protective relay with protected zones are configured with distance elements, and stepped distance schemes are coordinated in a cascading manner. Therefore, this configuration risks triggering a chain of undesirable events, leading to widespread blackout.
- Limit fault damage due to high current: Fault currents can cause thermal and mechanical damage to conductors and electrical equipment.

- Need for high-speed reclosing: A system in equilibrium with no fault, mechanical power equals electrical power, ignoring losses. When a fault occurs, equilibrium is disturbed and the synchronous machine accelerates. The positive sequence voltage immediately after the fault can be used to estimate the requirement for high-speed tripping. The accelerating power is proportional to the difference between pre-fault and fault positive sequence voltages at the point of fault. Thus, the smaller the positive sequence voltage, the faster the system accelerates and the faster the system needs to isolate the fault. Therefore, high speed reclosing is required.

Protection performance requirements for the line dictate the number of pilots schemes required. The following are considerations to determine the number of required pilot systems:

- Number of systems required: Where high speed clearing is desired for faults anywhere on the line, but time delayed tripping is acceptable under contingencies.
- Different voltage levels: Protection system performance requirements can vary greatly and dictate at what voltage level pilot channels are used. From 230 kV to 345kV, at least one pilot scheme is typically present and, depending on system configuration, two schemes often exist, in addition to direct transfer tripping for the breaker. Above 345kV, at least two pilot schemes and a direct transfer trip for equipment failure are typically applied.
- Regulatory/regional reliability council requirements: Reliability councils sometimes dictate protection system performance requirements, the number and type of pilot systems, and the channel required.

2.3.3 Permissive Overreaching Transfer Tripping Scheme

The previous section presented a general overview of pilot protection. This section discusses a specific pilot scheme, the Permissive Overreaching Transfer Tripping Scheme (POTT). The POTT was implemented for the design of the projected presented in this report. In the POTT scheme, a distance element is set to reach beyond the remote end of the protected line to send a signal to a remote end. However, the received relay contact must be monitored by a directional relay contact to ensure that tripping does not occur unless the fault is within the protected section [16]. In Figure 2-3, the contacts of Zone 2 are arranged to the signal, and the received signal, supervised by Zone 2 operation, is used to energize the trip circuit. The scheme is known as a POTT. Since the signaling channel is keyed by overreaching Zone 2 elements, the scheme requires duplex communication channels.

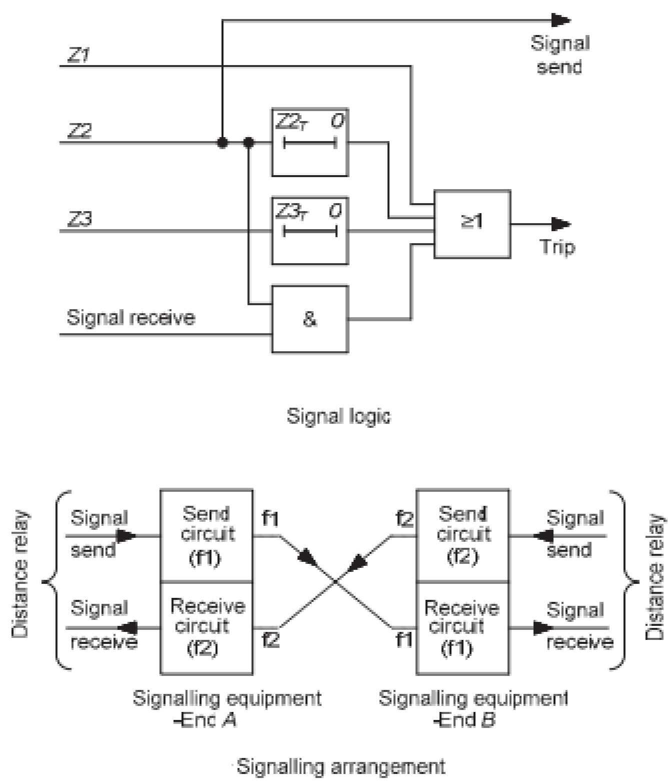


Figure 2-3 Permissive Overreaching Transfer Trip Scheme [16]

To prevent the relay from operating under current reversal conditions in parallel feeder circuit, a current reversal guard timer must be used to restrain tripping of the forward Zone 2 elements. Otherwise, malfunction of the scheme may occur under current reversal conditions. It is necessary only when the Zone 2 reach is set greater than 150% of the protected line impedance.

This chapter presented insights on the importance of transmission systems and challenges utilities and engineers face when designing and implementing reliable protection. Basic principles of distance protection were also presented. A discussion on pilot protection, its benefits, and cases when implementation of this scheme is suitable were also discussed. Finally, a brief discussion of the operation of permissive overreaching transfers tripping was conducted.

Chapter 3 - Design of Pilot Protection for a Transmission Line

As mentioned in previous sections of this report, the inclusion of digital communications in power protection schemes improves the reliability and efficiency of the system. Thus, pilot protection is widely used in the protection of transmission lines because electrical power highways carry large amounts of power and loss of supply would be a costly issue. This chapter discusses the scope and design for the protection line of a 230 kV transmission line with double end sources in each end.

3.1 Transmission Power System

The protection system used for this report consists of two generators, two transformers, three segments of 50 miles with six buses, and four loads. Table 3.1 provides details of the power system [8] and [11]. This system was selected because it is suitable for POTT testing and has the characteristics of a "short transmission line."

Power System	
Line Voltage	230 kV
Total Power	100 MVA
Frequency	60 Hz
Line Length	50 Miles
Transmission Line Zero Sequence (Z_{0L})	$124\ \angle 81.5°$
Transmission Line Positive Sequence (Z_{1L})	$39\ \angle 84°$
Transformers Zero Sequence (Z_{0T})	$5.29\angle 90°$

Transformers Positive Sequence (Z_{1T})	$5.29\angle 90°$
Generator Zero Sequence (Z_{0S})	$50\ \angle 86°$
Generator Positive Sequence (Z_{0T})	$50\ \angle 86°$
Current Transformer (CT)	100
Voltage Transformer (VT)	2000
Phase Rotation	ABC
Max Load Situation	10 MW-1MVAR
Time Delay (DT)	4 cycles (0.067 s)
DT represents the combination of the breaker, arc flash and communication time	

Table 3-1 Transmission Power System [11]

3.2 Short Transmission Line Parameters

For convenience, transmission lines are represented in a two-port network, shown in Figure 3.1, where V_S and I_S are the sending a voltage and current, respectively, and V_R and I_R are the receiving voltage and current [8].

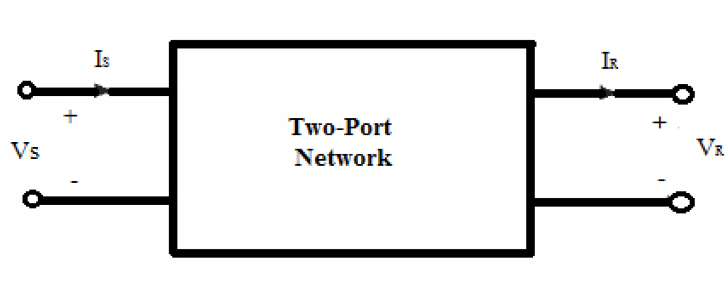


Figure 3-1 Two-Port Network

The relationship between sending and receiving quantities can be represented as:

$$V_S = AV_R + BI_R\ Volts \tag{3.1}$$

$$I_S = CV_R + DI_R\ Amps \tag{3.2}$$

Thus, in matrix form:

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \tag{3.3}$$

Where A,B,C, and D are parameters that depend on transmission line constants R,L,C, and G. The ABCD parameters are, in general, complex numbers. A and D are dimensionless. B has units in ohms, and C has units of Siemens. Network theory [17] shows that ABCD parameters apply to linear, passive, and bilateral two-port networks, with the general relationship:

$$AD - BC = 1 \tag{3.4}$$

The circuit in Figure 3.2 represents a short transmission line, usually applied to overhead AC 60 Hz lines, less than 80 KM (50 mile approx.).

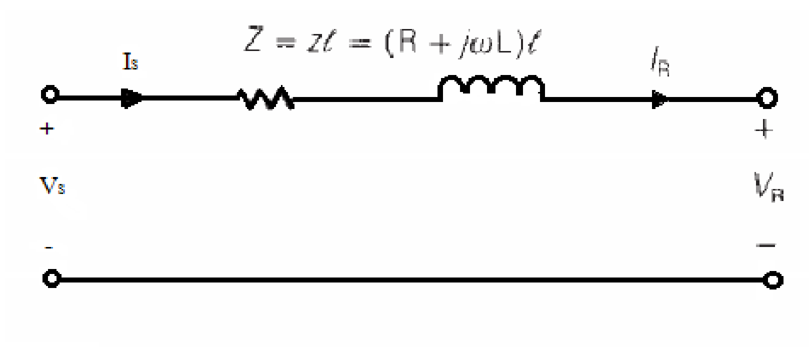


Figure 3-2 Short Transmission Line [19]

Only the series resistance and reactance are included, and shunt admittance is neglected. The circuit applies to single phase or completely transposed three-phase lines operating under balanced conditions. Z is the series impedance, V_S and V_R are positive sequence line to neutral voltages, and I_S and I_R are positive sequence line currents [8]. In order to better understand and avoid confusion between total series impedance and series impedance per unit length, the following notation is used:

$z = R + j\omega L \frac{\Omega}{m}, series\ impedance\ per\ unit\ length$

$y = G + j\omega L \frac{s}{m}, shunt\ admittance\ per\ unit\ length$

$Z = zl\ \Omega, total\ series\ impedance$

$Y = yl\ \Omega, total\ shunt\ admittance$

$l = line\ length, m$

The shunt conductance G is usually neglected for overhead transmission. When applying KVL and KCL, ABCD parameters for a short line are easily obtained in the equation:

$$V_S = V_R + ZI_R \tag{3.4}$$

$$I_S = I_R \tag{3.5}$$

Thus, the matrix form is represented by:

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} 1 & Z \\ 0 & 1 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \tag{3.6}$$

The segment in which the protection system is applied has a length of 50 miles, so it is considered a short length line. Thus, the line has ABCD parameters of short line approximations.

3.3 Per Unit Quantities

Power system quantities, such as voltage, current, power, and impedance, are often expressed in per unit or percent of specified values. For example, if a base voltage of 20kV is specified, then the voltage of 18 kV is (18/20) = 0.9 per unit or 90%. Calculations in this report are made with per-unit quantities rather than actual quantities. One advantage of the per-unit system is that, by specifying base quantities, the equivalent circuit can be simplified. Thus, quantities expressed in per unit do not change when they are referred. This can be a significant advantage in a power system of moderate size. The per-unit system allows the possibility of making a calculation error when referring quantities of the power system. Another advantage of the per-unit system is that the per-unit impedances of similar electrical lie within very closely numerical range when equipment ratings are used as base values. Therefore, per-unit impedance data can be rapidly checked for errors by being familiar with per-unit quantities.

Manufacturers also typically specify the impedance of machines and transformers in per-unit or percent of nameplate rating [8].

Per-unit quantities are calculated as:

$$per - unit\ quantity = \frac{Actual\ Quantity}{Base\ Vale\ Quantity} \tag{3.7}$$

Where the actual quantity is the value of the quantity in actual units. The base value has the same unit as the actual quantity, making the per-unit quantity dimensionless. In addition, the base value is always a real number; therefore, the angle of the actual quantity is identical to the angle of the actual quantity.

Two independent base values can be arbitrarily selected at one point in a power system. Usually the base voltage VbaseLN and base complex power Sbase1f are selected for a single-phase circuit or for one phase of a three-phase circuit. Then, in order for electrical laws to be valid in the per-unit system, the following relations must be used for other base values:

$P_{base\ 1\ \phi} = Q_{base\ 1\ \phi} = S_{base\ 1\ \phi}$	(3.8)
$Z_{base} = R_{base} = X_{base} = \frac{V_{base\ LN}}{I_{base}} = \frac{V^2_{base\ LN}}{S_{base\ 1\phi}}$	(3.9)
$I_{base} = \frac{S_{base1\phi}}{V_{base\ LN}}$	(3.10)
$Y_{base} = G_{base} = B_{base} = \frac{1}{Z_{base}}$	(3.11)

From (3.7) to (3.11) and information of the power system from Table 3.1, the following values were computed and used for simulation of the power system shown in Figure 3.3. Per-unit values are shown in Table 3-2. These values are used in project activities, including simulation and relay settings work.

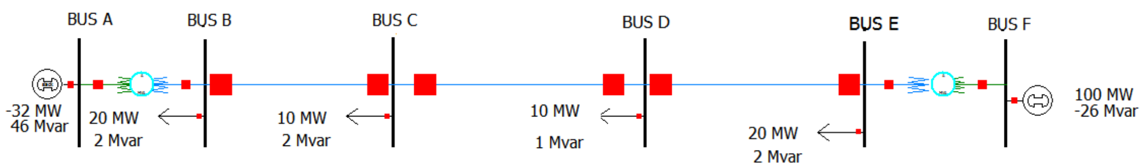


Figure 3-3 One-Line Diagram Power System

Base Values					
V_{Base}		S_{Base}		Z_{Base}	
230 kV		100 MVA		529	
Transmission Line Per-Unit Impedance					
Positive Sequence		Negative Sequence		Zero Sequence	
$RL1_{pu}$	$XL1_{pu}$	$RL2_{pu}$	$XL2_{pu}$	$RL0_{pu}$	$XL0_{pu}$
0.0077	0.0773	0.0077	0.0773	0.0346	0.2318
Generator Per-Unit Impedance					
Positive Sequence		Negative Sequence		Zero Sequence	
$RT1_{pu}$	$XT1_{pu}$	$RT2_{pu}$	$XT2_{pu}$	$RT0_{pu}$	$XT0_{pu}$
0.0066	0.0942	0.0066	0.0942	0.0066	0.0942
Transformer Per-Unit Impedance					
Positive Sequence		Negative Sequence		Zero Sequence	
$RT1_{pu}$	$XT1_{pu}$	$RT2_{pu}$	$XT2_{pu}$	$RT0_{pu}$	$XT0_{pu}$
0	0.01	0	0.01	0	0.01

Table 3-2 Per-Unit Quantities

3.4 Fault Current Information

For development of this project, a majority of data was gathered from simulation software PowerWorld. This section generally discusses symmetrical components and three-phase faults. Finally, data gathered from the simulation is presented.

3.4.1 Symmetrical Components

The method of symmetrical components provides a means of extending per phase analysis with a system of unbalanced faults. This is possible because of the property of unbalanced phasors discovered by Fortescue. He observed that a system with three unbalance phasors can be broken down into two sets of balance phasors plus an additional set of single phase-phasors.
If the voltage and current are represented in this way, a per phase representation is adequate for each component, and desired simplification has been achieved [18].

Assume that a set of three-phase voltage designated, V_a, V_b, and V_c, is given. These phase voltages are resolved into three sets of sequence components:

1. *Zero Sequence Components:* Consisting of three phasors with equal magnitude and zero phase displacement [8].
2. *Positive Sequence Components:* Components, consisting of three phasors with equal magnitude ±120º phase displacement, positive sequence [9].
3. *Negative Sequence Components:* Consisting of three phasors with equal magnitudes ±120º phase displacement, and negative sequence [10].

Thus, the sequence components are defined by the following transformation:

$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} \tag{3.12}$$

Where:

$$a = 1\angle 120° = \frac{-1}{2} + j\frac{\sqrt{3}}{2} \tag{3.13}$$

Equation (3.13) can be rewritten more compactly using matrix notation. Defining the following vectors V_p and V_s, and matrix A:

$$V_p = \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \tag{3.14}$$

$$V_s = \begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} \tag{3.15}$$

$$A = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \tag{3.16}$$

V_p is the column vector of phase voltages, V_s is the column vector of sequence voltages, and A is a 3 X 3 transformation matrix. Therefore, the following expressions are obtained:

$$V_p = AV_s \tag{3.17}$$

Solving V_s from (3.17):

$$V_s = A^{-1}V_p \tag{3.18}$$

Expanding (3.18) in matrix form:

$$\begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \tag{3.19}$$

Equation 3.19 demonstrates that no zero-sequence voltage is present in a balance three-phase system because the sum of three balanced phasors is zero. In an unbalanced three-phase system, line-neutral voltages may have zero-sequence components. However, line-line voltages never have a zero-sequence component since, by KVL, their sum is always zero. Symmetrical component transformation can also be applied to currents as:

$$I_p = AI_s \tag{3.20}$$

$$I_p = \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \tag{3.21}$$

$$I_s = \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{3.22}$$

$$I_s = A^{-1} I_p \tag{3.23}$$

$$I_a = I_0 + I_1 + I_2 \tag{3.24}$$

$$I_b = I_0 + a^2 I_1 + a I_2 \tag{3.25}$$

$$I_c = I_0 + a I_1 + a^2 I_2 \tag{3.26}$$

And the sequence currents are:

$$\mathbf{I_0} = \frac{\mathbf{1}}{\mathbf{3}}(\mathbf{I_a} + \mathbf{I_b} + \mathbf{I_C}) \tag{3.27}$$

$$I_1 = \frac{1}{3}(I_a + aI_b + a^2 I_c) \tag{3.28}$$

$$I_2 = \frac{1}{3}(I_a + a^2 I_b + aI_c) \tag{3.29}$$

$$\mathbf{I_n} = \mathbf{I_a} + \mathbf{I_b} + \mathbf{I_c} \tag{3.30}$$

In a three-phase Y-connected system, the neutral current I_n is the sum of the line currents. Comparing (3.27) and (3.30)

$$\boldsymbol{I_n} = \mathbf{3}\boldsymbol{I_0} \tag{3.31}$$

The neutral current equals three times the zero sequence current. In a balanced Y-connected system, line current has no zero-sequence component, since the neutral current is zero. Also, in any three phase system with no neutral path, such as a delta connected system or a three wire Y-connected system with an ungrounded neutral, line currents have no zero sequence components.

3.4.2 Three Phase Balanced Faults

The three-phase fault, although not unbalanced, is analyzed in this section. This fault is important because it is often the most severe type, consequently requiring verification that circuit breakers have adequate interrupting rating. Second, the three-phase fault is important because it is the simplest fault to determine analytically and, therefore, is the only one calculated in some cases when the system has incomplete information. Finally, the assumption is often made that the other types of faults, if not cleared promptly, develop into three-phase faults. Therefore, the three-phase fault must be computed in addition to other types [18]. Figure 3-4 shows a representation of a three-phase fault.

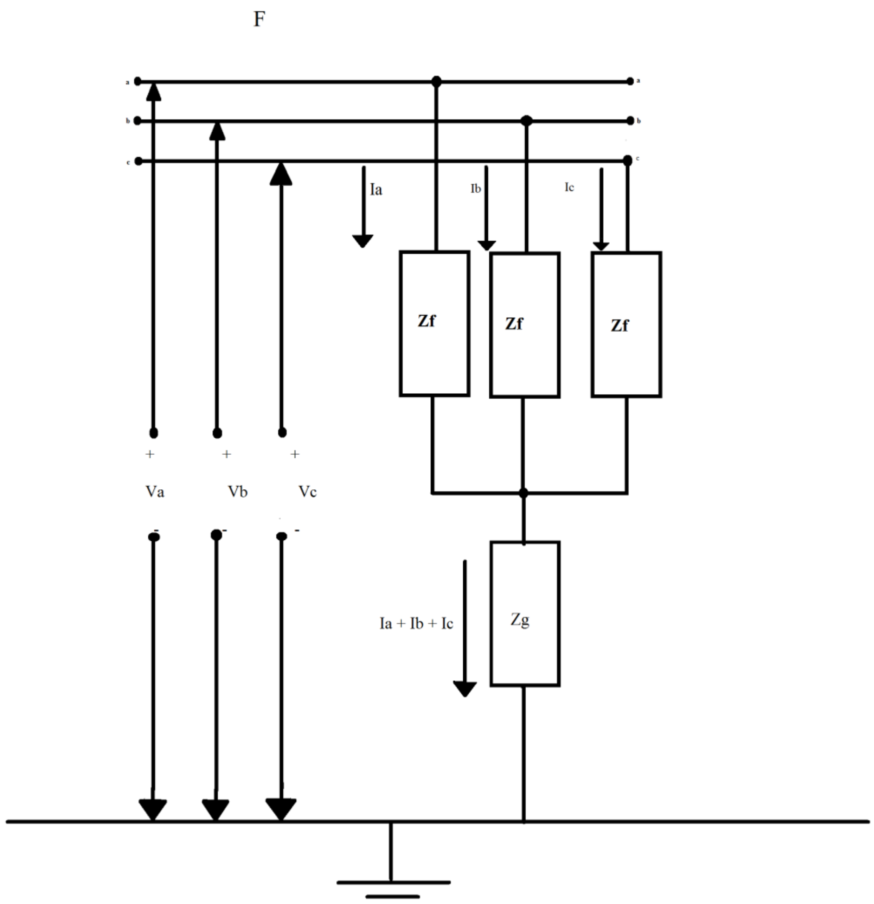


Figure 3-4 Diagram of Three-Phase Fault at F

For a three-phase fault, the zero sequence current I_0 and negative-sequence current I_2 are both zero. Therefore, the fault currents in each phase, from (3.20):

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} 0 \\ I_2 \\ 0 \end{bmatrix} \tag{3.32}$$

As shown in Figure 3.4, sequence components of line-to-ground voltages at the fault terminals are:

$$\begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} = \begin{bmatrix} 0 \\ V_F \\ 0 \end{bmatrix} - \begin{bmatrix} Z_0 & 0 & 0 \\ 0 & Z_1 & 0 \\ 0 & 0 & Z_2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{3.33}$$

During a bolted three-phase fault, sequence fault currents are $I_0=I_2=0$ and $I_1=V_F/Z_1$. Thus, the sequence voltage are $V_0=V_1=V_2=0$, which must be true since $V_{ag}=V_{bg}=V_{cg}=0$.

3.4.3 Fault Values

In order to implement the POTT scheme, five fault scenarios were developed in the power system, as shown in Figure 3.5, and specifications of the scenarios are shown in Table 3.3. However, values shown in the table are primary currents and voltages. Thus, these values will be reduced in order to implement the protection relay and its VT and CT quantities.

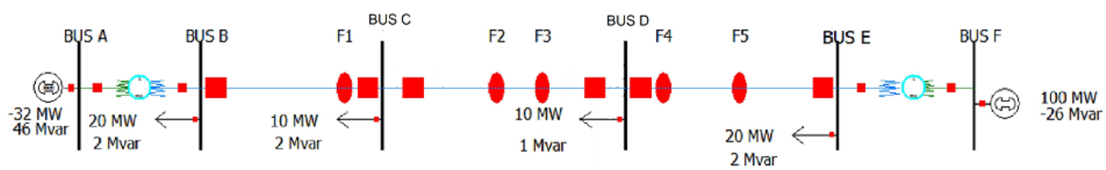


Figure 3-5 Fault Scenarios Power System

Table 3.3 shows the fault scenarios and are distances are shown done to respective of BUS C. For example fault F1 say it is at -10% of Bus C, meaning that the fault is at 10% of the total distance from BUS C and BUS B. Fault F2 is located at 50% of the distance between BUS C and BUS D, and so on for the rest of the fault scenarios.

For this report, the segment of transmission system that is protected is between BUS C and BUS D.

Fault	Distance From BUS C
F1	-10%
F2	50%
F3	90%
F4	110%
F5	150%

Table 3-3 Fault Locations

Once fault locations have been determined, the values of fault voltages and currents must be extracted. Table 3.4 shows the value of three-phase fault currents with respective phase angles. The faults are also calculated for each breaker of the power system using PowerWorld; one for BUS C and the other one for BUS D.

Three Phase Fault Location	SEL Relay Location	Distance From Bus C	Fault Currents (Amps ∠°)			
			Mag (Amps)	I_A (∠°)	I_B(∠°)	I_C(∠°)
F1	BUS C	-10%	979.14	108.99	-11.01	-131.01
F2		50%	1179.25	-88.07	151.93	31.93
F3		90%	1036.24	-88.10	151.90	31.90
F4		110%	977	-88.11	151.89	31.89
F5		150%	876.84	-88.10	151.90	31.90
F1	BUS D	-10	979.36	109.03	-10.97	-130.97
F2		50	1181.79	-70.93	169.07	49.07
F3		90	1370.67	-70.88	169.12	49.12
F4		110	976.86	-88.15	151.85	31.85
F5		150	876.17	-88.31	151.69	31.69

Table 3-4 Primary Fault Currents

Computation of the fault voltage for each scenario requires converting line-line voltage to line-ground. The protection relay reads line-ground voltages. Therefore, quantities given from the software must be converted from per-unit line-line value to real magnitude. Also, the phase angle must be included because they will be used for system testing. Table 3.5 shows the fault voltage for each case.

The voltage was converted to line-ground using the expression:

$$V_{LN} = \frac{p.u * 230kV}{\sqrt{3}} \tag{3.34}$$

p.u.= Per unit value of the fault voltage

Three Phase Fault Location	SEL Relay Location	Distance From Bus C	Fault Voltages (V ∠°)			
			Mag (V)	V_A (∠°)	V_B(∠°)	V_C(∠°)
F1	BUS C	-10%	3784.53	12.99	-107.01	132.99
F2		50%	22988.70	-4.06	-124.06	115.94
F3		90%	36362.04	-4.09	-124.09	115.91
F4		110%	41900.73	-4.11	-124.11	115.89
F5		150%	51267.78	-4.17	-124.17	115.83
F1	BUS D	-10	42001.65	13.03	-106.97	133.03
F2		50	23037.83	13.08	-106.92	133.08
F3		90	5343.49	13.12	-106.88	133.12
F4		110	3808.433	-4.15	-124.15	115.85
F5		150	17080.85	-4.31	-124.31	115.69

Table 3-5 Primary Fault Voltages

For system testing, values for which the system typically operates must be gathered. Hence, Table 3.5 provides the maximum load situation of the system under normal operation or as a “pre-faults” state with its current and voltage. Also, the voltage must be converted from line-line to line-neutral, so they are divided by 1.74 and subtracted 30 degrees. To compute values under maximum load situation, the following expression must be used:

$$V_A = \frac{|V_{AB}|}{\sqrt{3}} \angle V_{AB}° - 30° \tag{3.35}$$

$$P = \sqrt{3} V_{LL} I \cos(\delta - \beta) \tag{3.36}$$

Thus,

$$\beta = \delta - \cos^{-1}\left(\frac{P}{\sqrt{3} V_{LL} I}\right) \tag{3.37}$$

Where:

$P = Real\ Power\ flowing\ along\ the\ line$ in kW.

$I = Line\ current\ in\ Amps$

$V_{LL} = Line - Line\ Voltage\ in\ kV$

$\delta = Line - Line\ voltage\ angle\ in\ degrees$

$\beta = Line\ current\ angle\ in\ degrees$

$P, I\ and\ V_{LL}\ are\ provided\ by\ the\ power\ flow\ analysis$

Loads	Mag (Amps)	I_A (∠°)	I_B(∠°)	I_C(∠°)	Mag (V)	V_A(∠°)	V_B(∠°)	V_C(∠°)
Max load situation Bus C	176	-7.27	-127.27	112.73	130811.98	-25.74	-145.74	-265.74
Max load situation Bus D	176	-4.26	-124.26	115.76	130723.65	-22.74	-142.74	-262.74

Table 3-6 Prefault States

Settings for different zones on the relays can be determined for the POTT scheme parameters with normal values as well as faulted values for various scenarios.

3.5 POTT Scheme Settings and Parameters

This section presents the parameters, settings, and zones of the POTT scheme and computations to define various protection zones. Figure 3.6 shows one line diagram simplified and its different zones of protection. In this case, three zones of protection are evident, two of which are forward looking and the remaining one is backward looking. This scheme is also used as a reference for design of the protection scheme presented in this report.

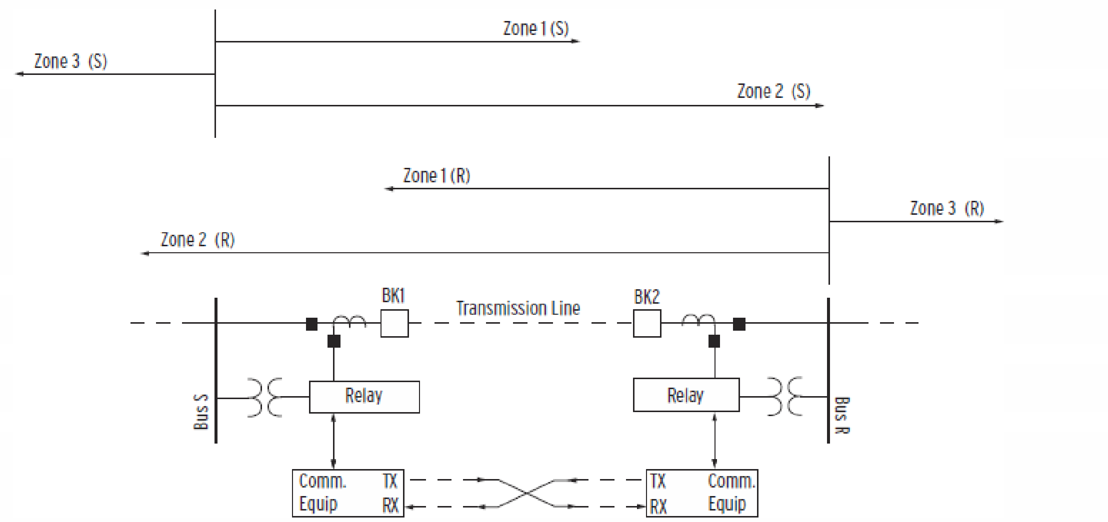


Figure 3-6 Three-Zone POTT Scheme [20]

In the projected implemented three protection zones, the first zone is instantaneous protection and is set at 85% percent of the total length of the transmission line. The second zone is set at 120% percent of the total length of the transmission line, overreaching the bus, and the third zone is set to protect 20% of the transmission line backward looking. Table 3-7 outlines protection zones for the POTT scheme.

Zone 1	Forward Looking	85 % Of the line Instantaneous Protection
Zone 2	Forward Looking	120% Of the line comm assisted with Time Delay
Zone 3	Backward Looking	20% Of the line with Time Delay

Table 3-7 Protection Zones

When the scheme from Figure 3.6 is adapted to the power system shown in Figure 3.5, the protection zones for each bus can be defined. For this case, the protection zones are defined for BUS C and BUS D. Hence, Figure 3.7 is obtained by adapting the configuration from Figure 3.6.

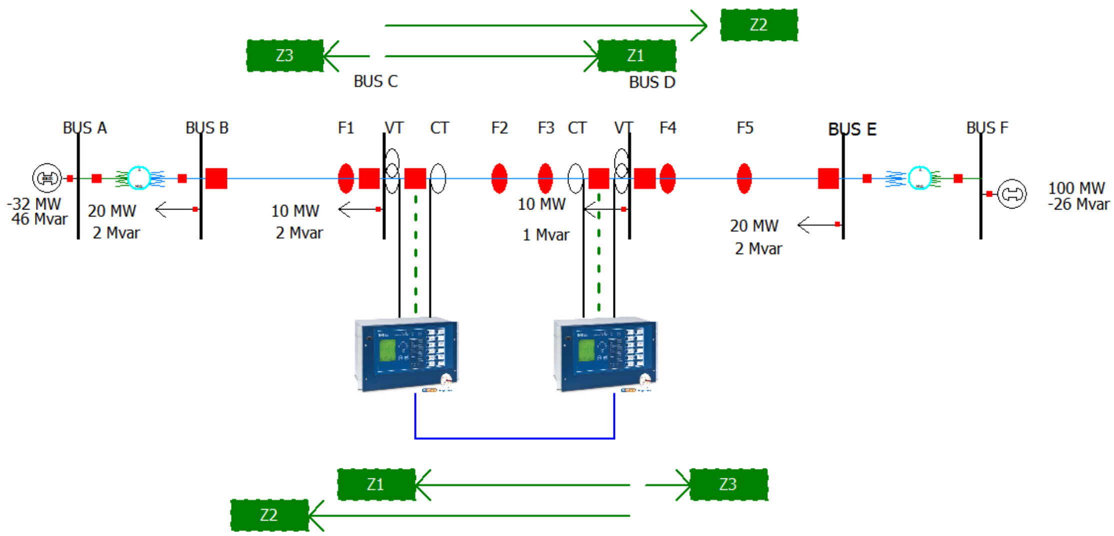


Figure 3-7 Protection Zones for Six Bus System

Once protection zones are defined, secondary impedances must be computed. Section 3.1 discussed quantities of the two instrument transformers, CT and VT. The following relation is used to compute secondary impedances:

$$Z_n Psecondary = \frac{L\%}{100} * \frac{CT}{VT} * Z_{IL} \tag{3.38}$$

L%= Percentage of the line being protected

CT=Secondary Current Transformer Value

VT=Secondary Voltage Transformer Value

Z_{1L}=Positive Sequence of Transmission Line

Table 3.8 shows values of secondary impedances for each protection zone.

Zone 1	$Z_{85\%}P_{secondary}$	$1.66\angle 84°$
Zone 2	$Z_{120\%}P_{secondary}$	$2.34\angle 84°$
Zone 3	$Z_{-20\%}P_{secondary}$	$0.39\angle 264°$

Table 3-8 Secondary Protection Impedances

The POTT communicates when a fault occurs over the reaching of the total zone of the transmission line. Because this system uses communication protocols between the two relays, some digital logic must be applied for the relay to operate under POTT characteristics. Figure 3.8 displays a simplified logic block diagram of the scheme used for this application.

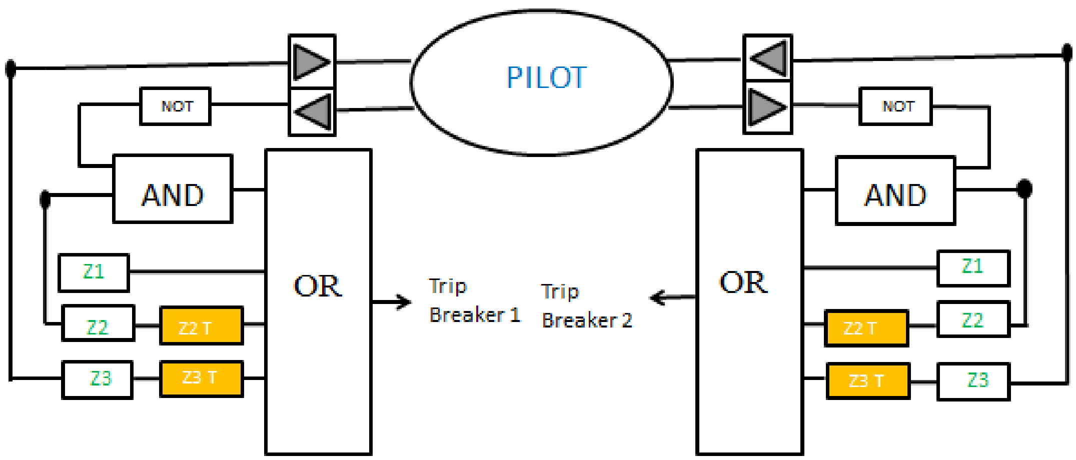


Figure 3-8 Simplified Block Logic Diagram

The predicted outcome of the system can be obtained from Figure 3.8 by using a true/false table. Table 3.9 displays the logic table, and the results are verified in the results and testing section of this report. In Table 3-9, a 1 means a trip and a 0 means no trip.

Faults	Inputs						Breaker 1								Breaker 2							
	Zones BK1			Zones BK2			AND			OR					AND			OR				
	Z1	Z2	Z3	Z1	Z2	Z3	i	i	o	i	i	i	i	o	i	i	o	i	i	i	i	o
1	0	0	1	0	1	0	0	1	0	0	0	1	0	1	1	0	0	0	0	0	0	0
2	1	0	0	1	0	0	0	1	0	1	0	0	0	1	1	0	0	1	0	0	0	1
3	0	1	0	1	0	0	1	1	1	0	1	0	1	1	0	1	0	1	0	0	0	1
4	0	1	0	0	0	1	1	0	0	0	0	0	0	0	0	1	0	1	0	0	0	1
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 3-9True Table from Figure 3.8

3.6 Hardware Settings

SEL relays must be set up under specific parameters in order to work as an MHO relay. Therefore, in this section, specifications of the relays, such as part number, communications, and other computations relevant to this application are presented. In addition, pre-fault, fault, and post fault voltages and currents are supplied by the Relay Test System (SEL RTS) and requires its own group of specific settings in order to function and be applicable to the transmission system.

3.6.1 Relay Settings

Relay settings are defined by the protection type, the length of the line and its characteristics, and CT and VT specifications. Therefore, some settings were computed using the following expressions:

Secondary Impedance

$$Z_{1Lsecondary} = \frac{CTR}{VTR} * Z_{LPrimary} \tag{3.39}$$

Source –to-line Impedance Ratio
The relay detects CVT (capacitor voltage transformer) transients. The relay adapts automatically to different system. Thus, this setting is not entered (3.40)

$$SIR = \frac{|Z_{1S}|}{Z1_{Reach}\% * |Z_{1L}|}$$

If SIR< 5 Setting ECVT:= N Transient Detection (Y,N)

Zero Compensation Factor helps to keep the phase and ground distance elements at the same reach if you set the reach equal per zone.

$$k01 = \frac{Z_{0L} - Z_{1L}}{3Z_{1L}} = k0M1\angle k0A_1° \tag{3.41}$$

From (3.39) to (3.41) and Table 3-1, the values in Table 3-10 are the settings of both relays for BUS C and BUS D.

Global General Settings Group	
BUS C	
SID Station Identifier	BUS C
RID Relay Identifier	Relay 1
NUMBK Numbers of Breakers in Scheme	1
BID1 Breaker Identifier	Breaker 1
NFREQ Nominal System Frequency	60
PHROT System Phase Rotation	ABC
FAULT Condition Equation (SELogic)	Z2P OR Z2G OR Z3P OR Z3G
EGAVDS Enable Advance Global Setting	N
BUS D	
SID Station Identifier	BUS D
RID Relay Identifier	Relay 2
NUMBK Numbers of Breakers in Scheme	1
BID1 Breaker Identifier	Breaker 2
NFREQ Nominal System Frequency	60
PHROT System Phase Rotation	ABC
FAULT Condition Equation (SELogic)	Z2P OR Z2G OR Z3P OR Z3G
EGAVDS Enable Advance Global Setting	N
All settings after this point are the same for relay on BUS C and BUS D	
Control Inputs Group	
EICIS Enable Independent Control Input Settings	N

Breaker 1	
EB1MON Breaker Monitoring	N
Breaker 1 Configuration	
BK1TYP BK1 Trip Type (3 phase pole =3)	3
Breaker 1 Inputs	
52AA1 N/0 Contact Input-BK1 (SELogic)	IN201
Line Configuration Group	
CTRW Current Transformer Ratio- Input W	100
PTRY Potential Transformer Ratio- Input Y	2000
VNOMY PT Nominal Voltage (L-L)-Input Y	115
Z1MAG Positive Sequence Line Impedance Magnitude (ohms,sec)	1.95
Z1ANG Positive Sequence Line Impedance Angle (deg)	84.00
Z0MAG Zero-Sequence Line Impedance Magnitude	6.2
Z0ANG Zero-Sequence Line Impedance Angle (deg)	81.50
EFLOC Fault Location	Y
Relay Configuration Enables	
E21MP Mho Phase Distance Zones	3
E21MG Mho Ground Distance Zones	3
ECOMM Communication Scheme	POTT
Mho Phase Distance Element Reach	
Z1MP Zone 1 Reach (ohms, sec)	1.66
Z2MP Zone 2 Reach (ohms, sec)	2.34
Z3MP Zone 3 Reach (ohms, sec)	0.39
Phase Distance Element Time Delay	
Z1PD Zone 1 Time Delay (cyc)	0.000
Z2PD Zone 2 Time Delay (cyc)	20.000
Z3PD Zone 3 Time Delay (cyc)	60.000
Mho Ground Distance Element Reach	Same as Mho Phase Distance Element Reach
Ground Distance Time Delay	Same as Mho Phase Distance Element Time Delay

Zero Sequence Compensation Factor	
K0M1 Zone 1 ZSC Factor Magnitude	0.727
K0A1 Zone 1 ZSC Factor Angle (deg)	-3.65
Zone/Level Direction	
DIR Zone/Level 3 Directional Control	R
Trip Logic	
TR Trip (SELogic)	Z1P OR Z1G OR Z2PT OR Z2GT OR Z3P OR Z3G
TRCOMM Communications-Assisted Trip (SELogic)	(Z2P OR Z2G OR Z3P OR Z3G) AND PLT02
TRSOTF Switch-Onto Fault Trip (SELogic)	50P1 OR Z2P OR Z2G
DTA Direct Transfer Trip A-phase (SELogic)	NA
DTA Direct Transfer Trip B-phase (SELogic)	NA
DTA Direct Transfer Trip C-phase (SELogic)	NA
E51DTT Enable 51 Element Direct Transfer Trip	N
BK1MTR Breaker 1 Manual Trip –BK1 (SELogic)	OC1 OR PB8_PUL
ULTR Unlatch Trip (SELogic)	TRGTR
ULMTR1 Unlatch Manual Trip –BK1 (SELogic)	NOT(52AA1 AND 52AB1 AND 52AC1)
TOPD Trip During Open Pole Time Delay (cyc)	2.000
TULO Trip Unlatch Option	3
Z2GSTP Zone 2 Ground Distance Time Delay	N
67QGSP Zone 2 Directional Negative Sequence	N
TDUR1D SPT Minimum Trip Duration Time Delay	12.000
E3PT Three-Pole Trip Enable (SELogic)	1
E3PT1 Breaker 1 Three Pole Trip Enable (SELogic)	1
ER Event Report Trigger Equation (SELogic)	
R_TRIG Z2P OR R_TRIG Z2G OR R_TRIG 51S01 OR R_TRIG Z3P OR R_TRIGZ3G	

Fault Locator	
Z1RTMAG Positive Sequence Line Impedance Magnitude From Relay Point to T(ohms, sec)	7.80
Z1RTANG Positive Sequence Line Impedance angle from Relay point to T (deg)	84.00
Z0RTMAG Zero Sequence Line Impedance magnitude from Relay point to T (ohms,sec)	24.80
Z0RTANG Zero Sequence Line Impedance angle from Relay point to T (deg)	81.50
LLR Line Length	50

Table 3-10 Relay Settings

3.6.2 AMS Settings And Secondary Voltages and Currents

The SEL-AMS adaptive multichannel source and the SEL-5401 Test System software are tools that represent power sources for the transmission system. The SEL-5401 test software can simulate different states in the power system. For this application, only three states are utilized: pre-fault, fault, and post-fault state.

Some features of the SEL-AMS Adaptive Multichannel Source are [21]:

- Twelve analog output channels (+/- volts peak)
- Replay of downloaded waveforms or generation of sinusoids with 16-bit precision
- Six sense inputs for monitoring relay contacts
- Ten contact outputs for driving relay logic inputs
- 50VA source of 24, 48, 125, 250 Vdc
- Buffered outputs for monitoring analog and digital signals

The SEL-5401 and SEL test software contains the following features [21]:

- Multistate capability supports simulating power system changes
- Amplitude ramping allows relay element threshold tests
- Programmable inputs and outputs simulate circuit breakers, communications
- System frequency ramping

Figure 3.9 displays SEL-5401 windows software for one state. Table 3-11 shows the secondary currents and voltages computed by stepping down the maximum load of power system quantities with values of the CT and VT. Tables 3-12 and 3-13 show secondary voltage and current in different fault scenarios. Because the SEL AMS does not have a built-in model for the SEL 411L relay, the configuration and setting for the SEL 421 settings are used.

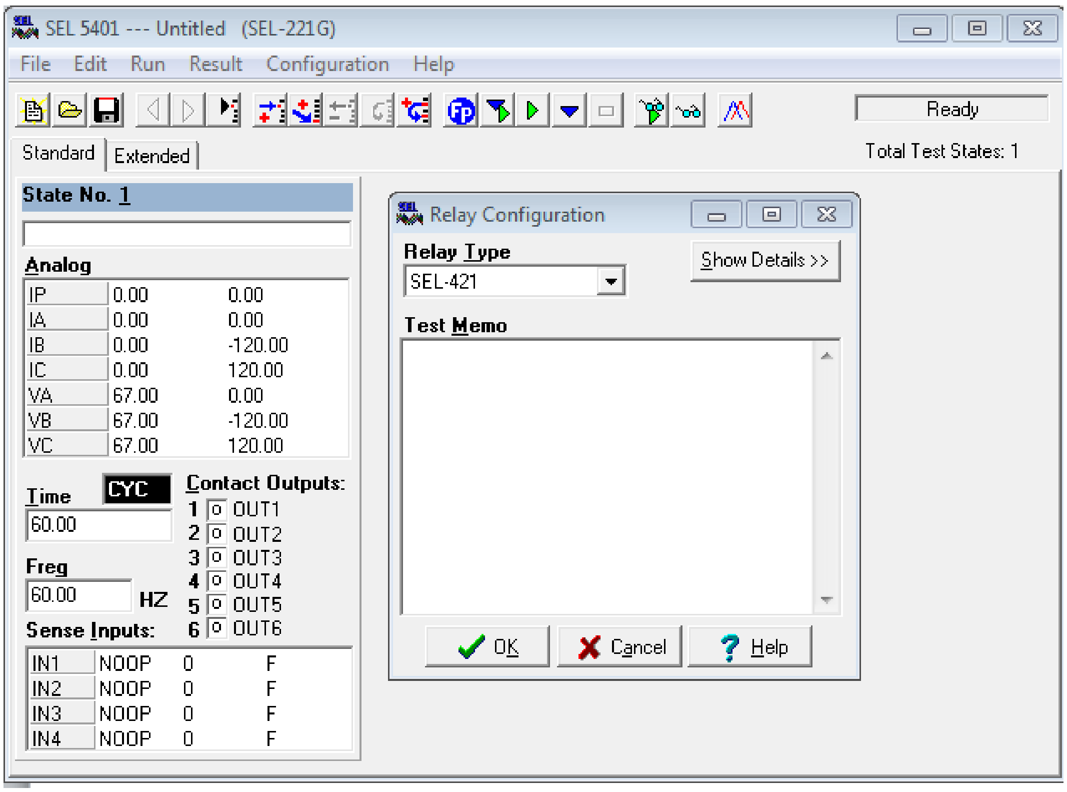


Figure 3-9 SEL-5401 State Window

Maximum secondary currents for the SEL-421 of 75 analog voltages and 159 amps RMS. And a $V_{PEAK\text{-}max\ (+/-)}$=3.3 V

Loads	Mag (Amps)	I_A (∠°)	I_B(∠°)	I_C(∠°)	Mag (V)	V_A(∠°)	V_B(∠°)	V_C(∠°)
Max load situation Bus C	176	-7.27	-127.27	112.73	130811.98	-25.74	-145.74	-265.74
Max load situation Bus D	176	-4.26	-124.26	115.76	130723.65	-22.74	-142.74	-262.74

Table 3-11 Secondary Currents for Prefault State

CTR=100			VTR=2000			
Three Phase Fault Location	SEL Relay Location	Distance From Bus C	Fault Currents (Amps ∠°)			
			Mag (Amps)	I_A (∠°)	I_B(∠°)	I_C(∠°)
F1	BUS C	-10%	7.88.	114.26	-5.74	-124.74
F2		50%	9.10	-87.71	152.29	32.29
F3		90%	8.23	-87.87	152.13	32.13
F4		110%	7.85	-87.94	152.06	32.06
F5		150%	7.19	-88.04	151.96	31.96
F1	BUS D	-10	7.89	-65.7	174.3	54.3
F2		50	9.15	-65.46	174.54	54.54
F3		90	10.24	-65.26	174.74	54.74
F4		110	7.84	92.02	-27.98	-147.98
F5		150	7.18	91.74	-28.26	148.26

Table 3-12 Secondary Fault Currents

Three Phase Fault Location	SEL Relay Location	Distance From Bus C	Fault Voltages (V ∠°)			
			Mag (V)	V_A (∠°)	V_B(∠°)	V_C(∠°)
F1	BUS C	-10%	1.537	18.26	-101.74	138.26
F2		50%	8.878	-3.71	-123.71	116.29
F3		90%	14.44	-3.87	-123.87	116.13
F4		110%	16.83	-3.94	-123.94	116.06
F5		150%	21.01	-4.11	-124.11	115.89
F1	BUS D	-10	16.91	18.3	-101.7	138.3
F2		50	8.92	18.54	-101.46	138.54
F3		90	3.46	18.74	-101.26	138.74
F4		110	1.53	-3.98	-123.98	116.02
F5		150	7.00	-4.25	-124.25	115.75

Table 3-13 Secondary Fault Voltages

3.6.3 Communications Protocols

The MBA protocol is used for communication between both relays, which is the SEL Mirrored Bit Communication. This protocol is advantageous because the relays can directly exchange information quickly, securely, and with minimal cost [11]. For communication between the relays, the EIA-232 Port 2 is connected to each other. Figure 3-10 shows the physical location of port 3 in the rear of the SEL-411L relay.

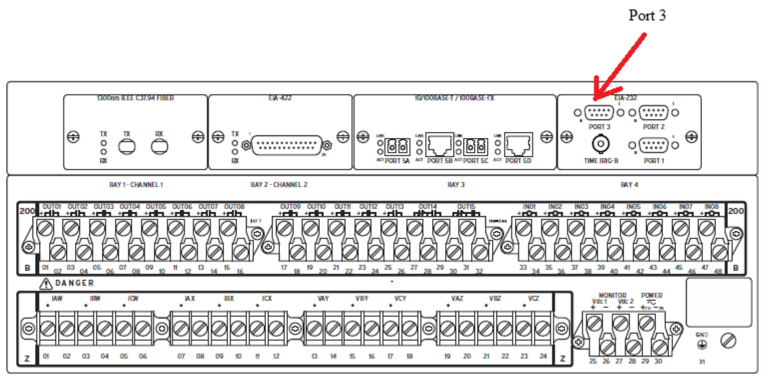


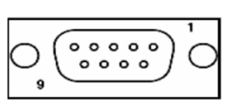
Figure 3-10 Port 3 Location on Rear Panel

The relays can communicate only if the port is properly configured. Therefore, the relays must be configured to receive and transmit information. Table 3-14 shows the relay settings and communication parameters for Port 3.

Relay Bus C		Relay Bus D	
RXID Mirrored Bits Received	2	RXID Mirrored Bits Received	3
TXID Mirrored Bits Transmit	3	TXID Mirrored Bits Transmit	2

Table 3-14 Relays Communication Parameters

EIA-232 ports allow bidirectional communication between relays. Figure 3-11 presents the nomenclature and functions of each pin in the connector [22].



Pin	Port 2
1	N/C or +5 Vdc[a]
2	RXD
3	TXD
4	+IRIG-B
5, 9	GND
6	–IRIG-B
7	RTS
8	CTS

Figure 3-11 EIA-232 Port 3 Connector

With these activities, the relay settings and other values have been determined. The next step is to program the relays with these values. Also the proper connections of the hardware have been. One AMS connected to the relay corresponding to BUS C and the other AMS connected to the corresponding to BUS D.

Chapter 4 - Results and Summary

This chapter discusses results obtained for five faults scenarios and system results once the CT or VT fails during a fault state. The R-X diagram for MHO parameters computed in previous sections is also shown. Finally, a summary of all results obtained is presented.

4.1 MHO R-X Diagram

In the previous chapter, a relay model with three zones of protection was defined and presented; two of the zones were forward looking and the remaining zone was backward looking. However, these values were based on the secondary of the VT and CT, so the values were stepped down so the relay could sense them. Figure 4-1 shows the R-X diagram for a transmission system in which the largest circle represents Zone 2 on the overreaching zone and the circle enclosed in the bigger one is Zone 1 which is the instantaneous protection. The smallest circle, which appears to be tending to the third quadrant, is the Zone 3 backward looking protection zone.

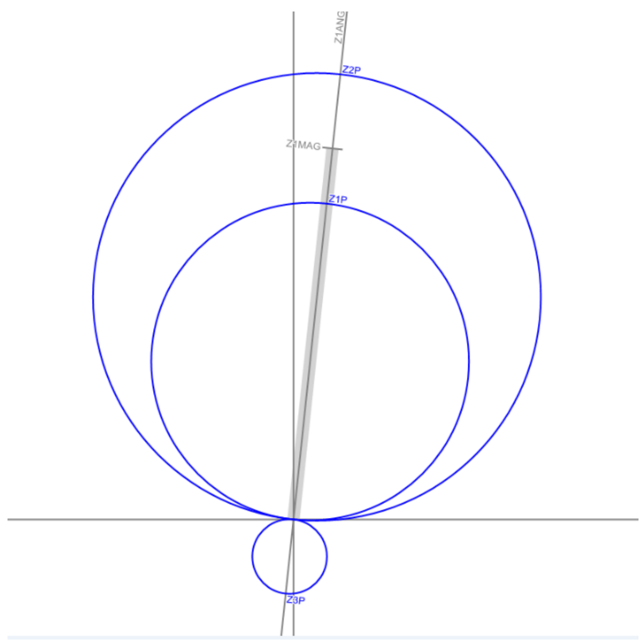


Figure 4-1 R-X MHO Diagram

4.2 Results for Faulted Zones

Results for the faulted zones are presented from -10% of BUS C to 150% of BUS C. Figures from the front panel of each relay display which protection zone detected the fault. Data from the SEL –AMS is presented in different stages.

For the faulted scenario at -10% of BUS C, Figures 4-2 and 4-3 show three stages from the AMS that serve as the system power source.

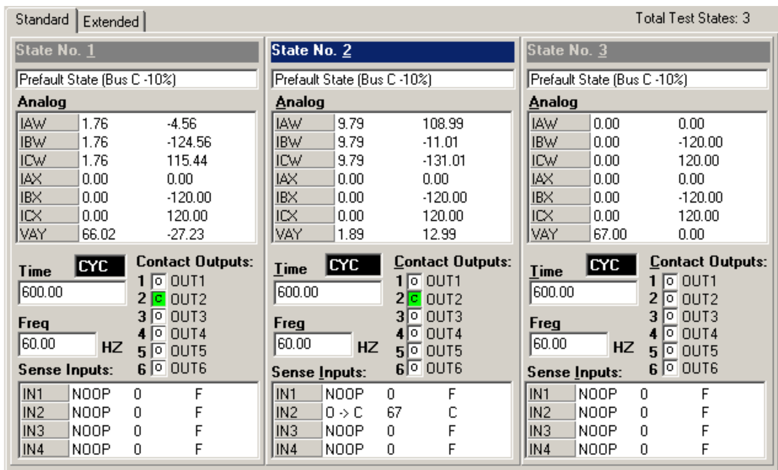


Figure 4-2 AMS Power Source for Bus C Side for Fault F1

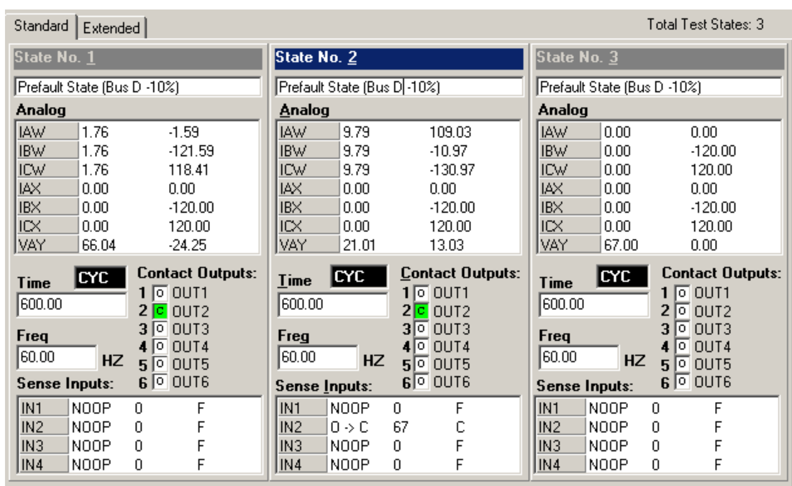


Figure 4-3 AMS Power Source for Bus D Side for Fault F1

For this scenario, the fault must be detected by Zone 3 in BUS C while Zone 2 in BUS D will not trip.

Thus, Figure 4-4 a) and b) displays the front panel of the relay and the zones where the fault was detected and proven to be satisfactory.

a) BUS C Relay

b) BUS D Relay

Figure 4-4 Front Panel of the Relays for Fault F1

For the faulted scenario at 50% of BUS C, Figures 4-5 and 4-6 show three stages from the AMS that serve as the system power source.

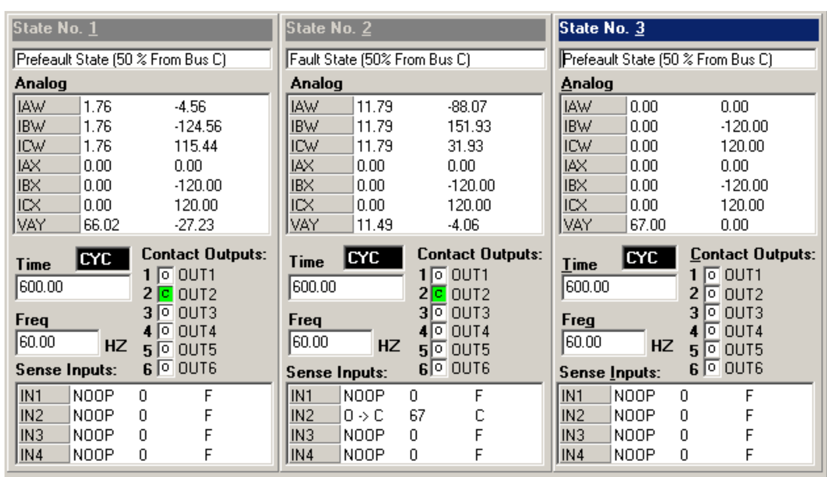


Figure 4-5 AMS Power Source for BUS C Side for Fault F2

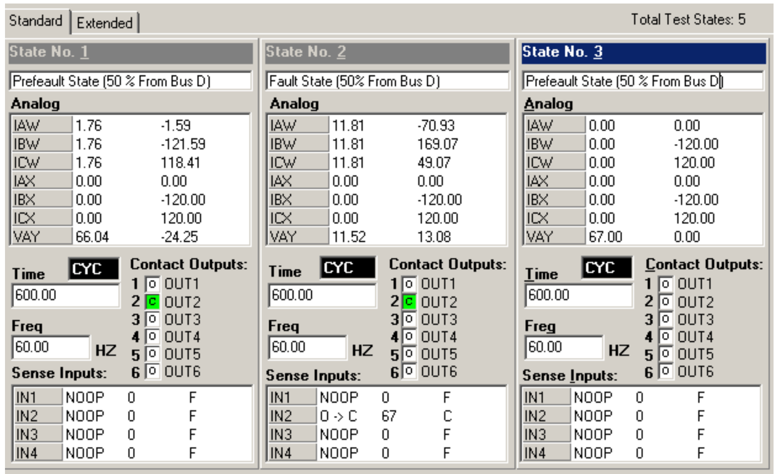
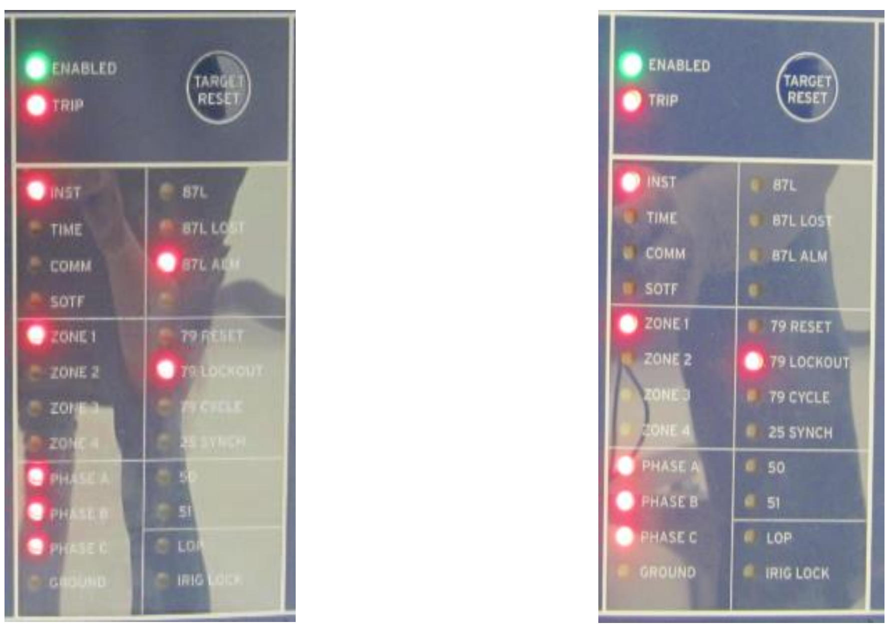


Figure 4-6 AMS Power Source for BUS D Side for Fault F2

For this scenario, the fault must be detected by Zone 1 in BUS C and Zone 1 in BUS D. Thus, Figure 4-7 a) and b) displays the front panel of the relay and the zones where the fault was detected and proven to be satisfactory.



a) BUS C Relay b) BUS D Relay

Figure 4-7 Front Panel of the Relays for Fault F2

For the faulted scenario at 90% of BUS C, Figures 4-8 and 4-9 show three stages from the AMS that serve as the system power source.

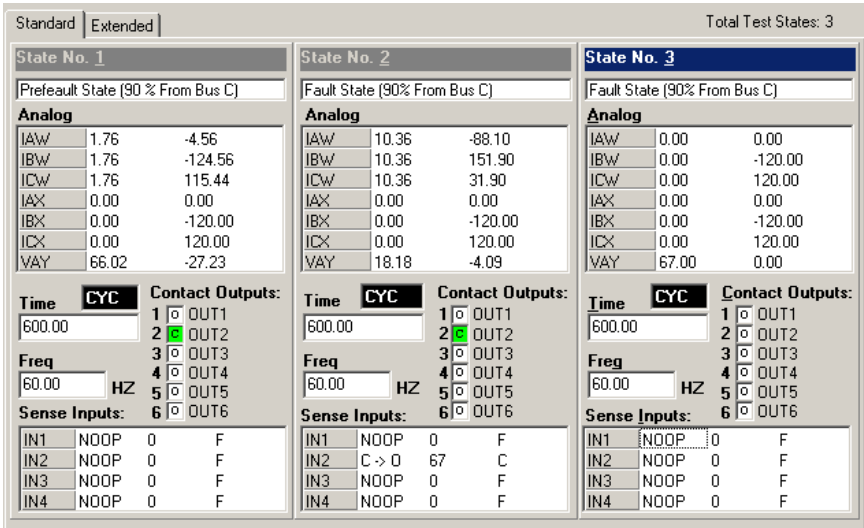


Figure 4-8 AMS Power Source for BUS C Side for Fault F3

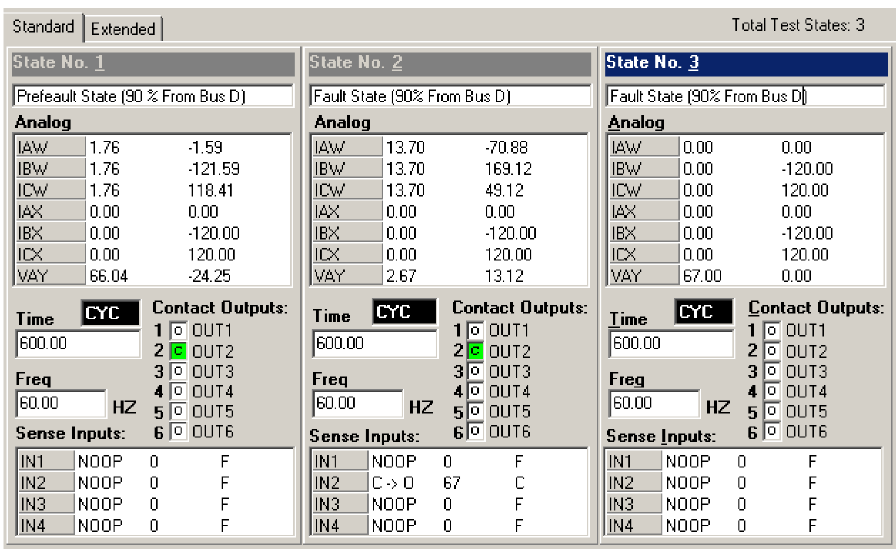
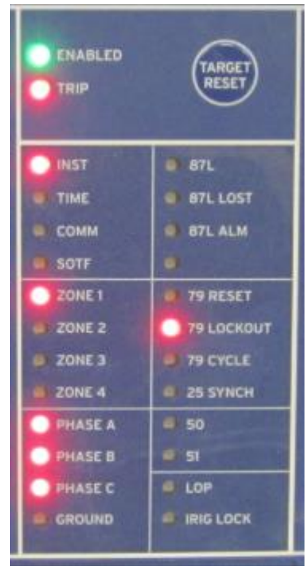


Figure 4-9 AMS Power Source for BUS D Side for Fault F3

For this scenario, the relay in BUS C is expected to send a communication signal to BUS D and BUS C must detect the fault in Zone 2 while BUS D detects the fault in Zone 1. Thus, Figure 4-10 a) and b) displays the front panel of the relay and the zones where the fault was detected and proven to be satisfactory.

a) BUS C Relay



b) BUS D Relay

Figure 4-10 Front Panel of the Relays for Fault F3

For the faulted scenario at 110% of BUS C, Figures 4-11 and 4-12 show three stages from the AMS that serve as the system power source

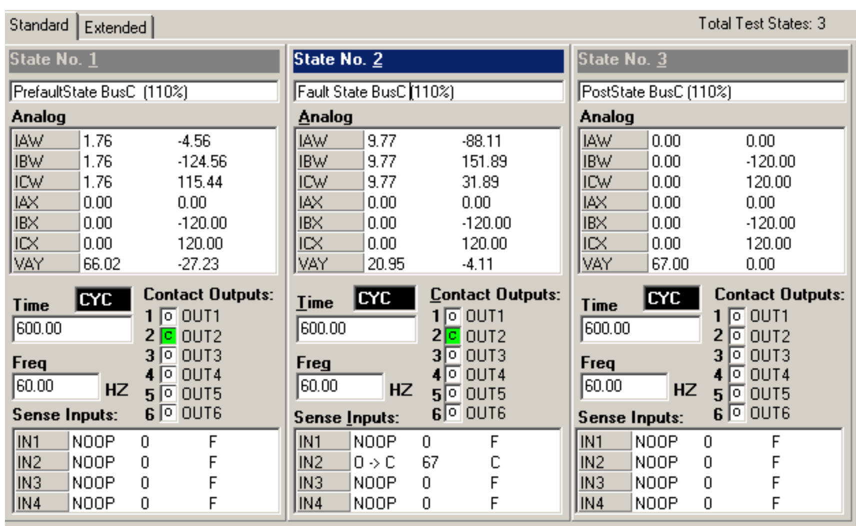


Figure 4-11 AMS Power Source for BUS C Side for Fault F4

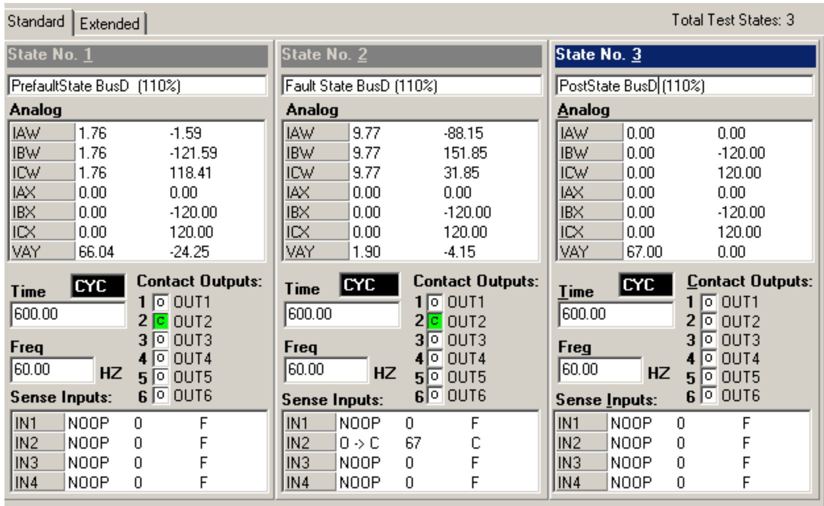


Figure 4-12 4 11AMS Power Source for BUS D Side for Fault F4

In the fourth scenario, Zone 2 of BUS C must not detect the fault and does not trip the relay, while Zone 3 of BUS D detects the fault and trips. Figure 4-13 a) and b) displays the front panel of the relay and the zones where the fault was detected and proven to be satisfactory.

a) BUS C Relay

b) BUS D Relay

Figure 4-13 Front Panel of the Relays for Fault F4

For the faulted scenario at 150% of BUS C, Figures 4-14 and 4-15 show three stages from the AMS that serve as the system power source.

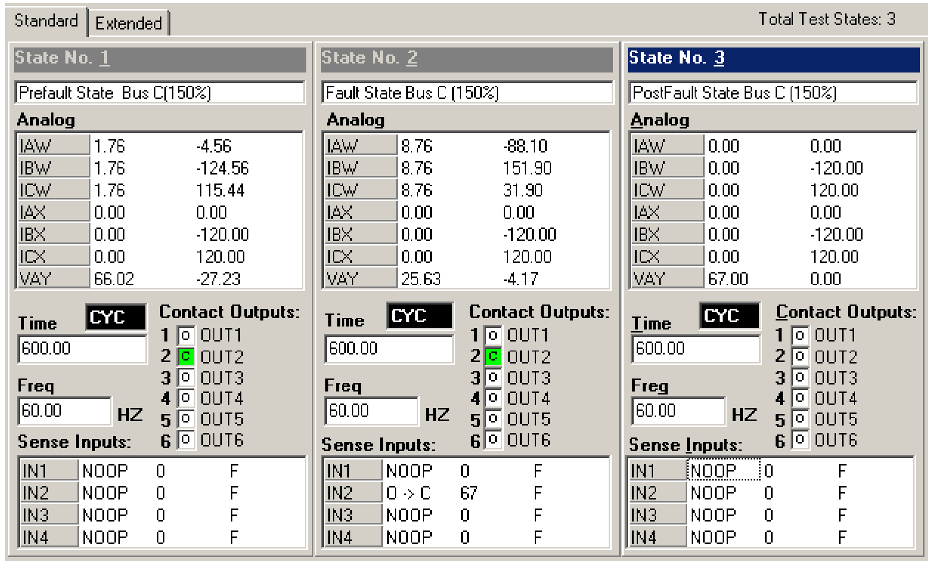


Figure 4-14 AMS Power Source for BUS D Side for Fault F4

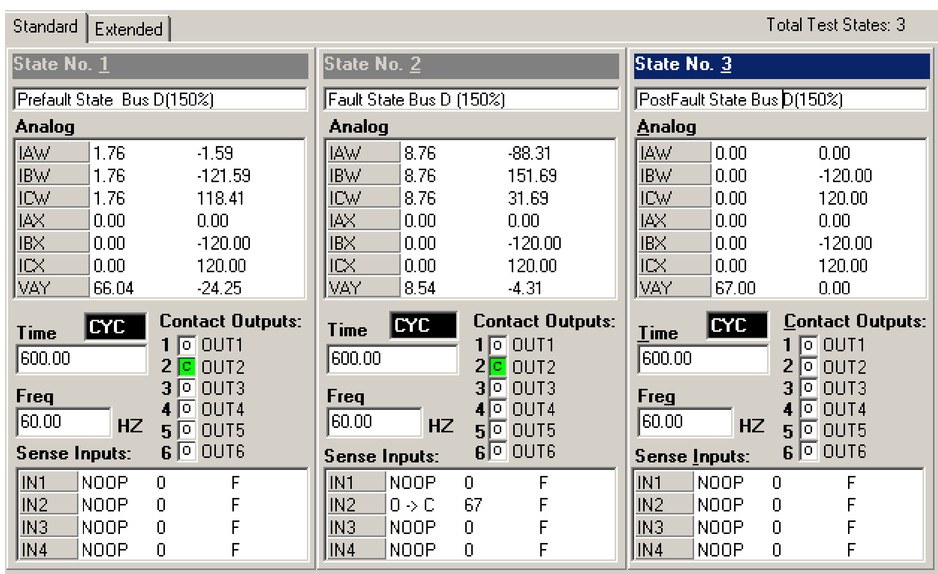
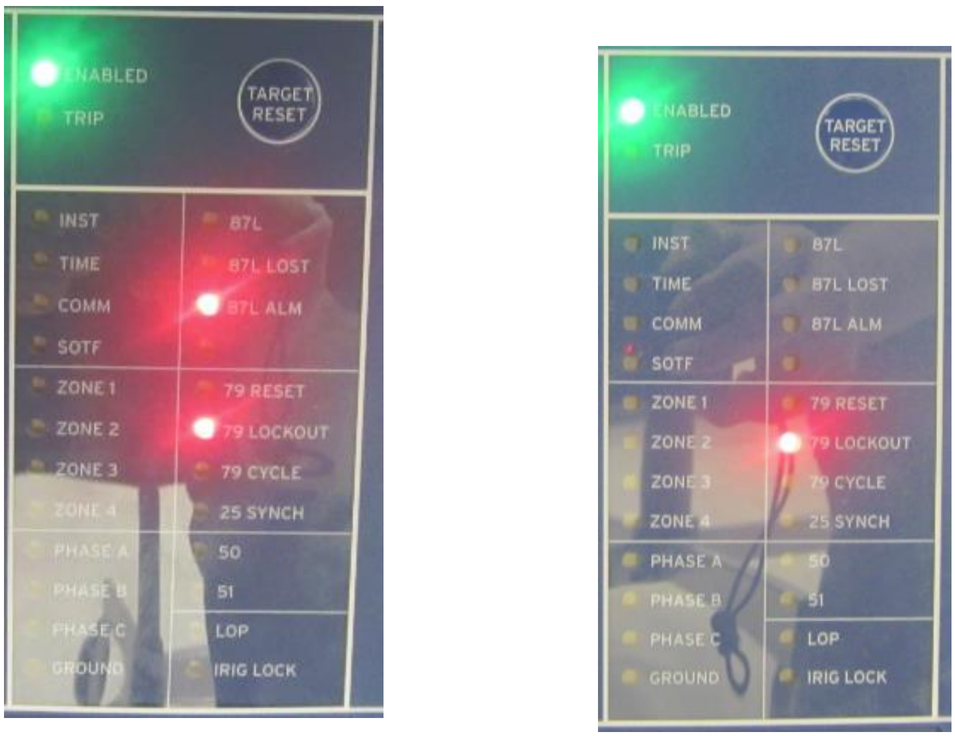


Figure 4-15 AMS Power Source for BUS D Side for Fault F5

For the final scenario, both relays should not trip since they are outside the zone of protection. Figure 4-16 a) and b) summarizes results of five fault scenarios on both buses and proven to be satisfactory.



a) BUS C Relay

b) BUS D Relay

Figure 4-16 Front Panel of the Relays for Fault F5

Tables 4-11 and 4-12 summarize results of five fault scenarios on both buses. If Zone 1, Zone 2, and Zone 3 LEDs were lit then it meant that the fault occurred in that respective zone. While Phase A, Phase B, and Phase C were lit, it meant that the fault occurred in those phases. Because three-phase faults are the most severe in the systems and are studied in this research, all LEDs lit up where faults were present.

Cases	Location	Relay 1 (BK1)-Bus C					
		Front-Panel Target LED's [Yes/No]					
		ABC Fault	Zone1	Zone2	Zone3	Trip	Comm
1	-10%	Yes	No	No	Yes	Yes	No
2	50&	Yes	Yes	No	No	Yes	No
3	90%	Yes	No	Yes	No	Yes	Yes
4	110%	No	No	No	No	No	No
5	150%	No	No	No	No	No	No

Table 4-1 Bus Summary of Relay Tripping

Cases	Location	Relay 1 (BK1)-Bus D					
		Front-Panel Target LED's [Yes/No]					
		ABC Fault	Zone1	Zone2	Zone3	Trip	Comm
1	-10%	No	No	No	No	No	No
2	50&	Yes	Yes	No	No	Yes	No
3	90%	Yes	Yes	No	No	Yes	No
4	110%	Yes	No	No	Yes	Yes	No
5	150%	No	No	No	No	No	No

Table 4-2 BUS D Summary of Relay Tripping

4.3 Results for CT and VT failures

In order to further expand on capabilities of distance protection, four additional failures were induced in the system involving CT and VT malfunction. The objective of this testing was to observe if the relays communicate when the VT or CT fails to operate. Thus, the testing was done under the fault F3(90%), which was the only condition in which the relay communicated to the other relay. Results for these conditions are presented in the following sections.

The first analyzed scenario is a situation in which both CTs failed to operate. Figure 4-17 a) and b) shows the instantaneous protection trip on both relays for BUS C and BUS D, with no communication between them. Even though the CT failed to operate, the relay primary functions were achieved, thereby protecting the transmission line against faults.

a) BUS C Relay

b) BUS D Relay

Figure 4-17 Relay Status When Both CTs Fail To Operate

The second analyzed scenario analyzed is a situation in which both VTs failed to operate. Figure 4-18 a) and b) shows results for both relays and, similar to the first case, the instantaneous protection tripped the relays for BUS C and BUS D, with no communication between them. The transmission line remained protected against faults.

a) BUS C Relay

b) BUS D Relay

Figure 4-18 Relay Status When Both VTs Fail To Operate

The third analyzed scenario is one in which one CT fails on the BUS C relay and the BUS D is fully functional. Figure 4-19 a) and b) demonstrates how the relays operated under this condition. For this case, only the relay for BUS D tripped and cleared the fault, while the relay from BUS C did not detect the fault. The relay did not send a communication signal. However, the Zone 2 of BUS D tripped.

a)BUS C Relay

b)BUS D Relay

Figure 4-19 Relay Status When One CT Fails To Operate

The final case to analyze is a situation in which a VT fails to operate for one relay and the remaining relay operates under normal conditions. Figure 4-20 a) and b) shows the status for relays on BUS C and BUS D, respectively. For this scenario, both relays tripped with instantaneous protection. Even though the VT of the relay of BUS C failed to operate, the CT still sensed the fault and tripped the relay.

a) BUS C Relay

a) BUS D Relay

Figure 4-20 Relay Status When One VT Fails To Operate

4.4 Summary

This section provided simulation results of pilot overreaching transfer tripping distance protection with three zones of protection for a 230 kV short transmission line. Implementation of a protection scheme aims to protect the power system from possible faults and contingencies and to prevent costly damages from system instability. To implement the transmission scheme, characteristics of the system, such as system length, per-unit quantities, and fault quantities, must first be recognized. To obtain the fault quantities, the system must be run in a power flow software tool and fault values that will damage the system must be gathered. For this application, the three-phase fault was the most significant fault from which the system had to be protected. For proper operation of the protective equipment, the gathered quantities must be converted to line-ground quantities. Next, the reach and number of protection zones must be defined. In this case, three zones were present; two of which were forward looking and one of which was backward looking. The first forward looking zone was assigned as the instantaneous protection and covered only 85% percent of the total line. However, the second protection zone covered 120 % of the transmission. The third zone was defined to protect 20% of backward looking of the transmission line. Once the protection zones were defined, the next step was to define the pilot protection. Several pilot protection schemes exist, but this report focuses only on the POTT scheme. This application used digital communication, and a simplified logic scheme from [16] was implemented into the inside logic of the relay. Once the necessary values were gathered, the obtained primary values were converted from the power flow software and to secondary. Thus, the system can be simulated. The final step was to simulate the system under various conditions. Each faulted condition was run ten times in the relays in order to see the proper operation of it. Once the testing was complete, the obtained values were matched the values predicted.

Chapter 5 - Conclusion and Future Work

Pilot distance protection in transmission system is currently used today because of the increasing energy demands from traditional and renewable sources. The primary objectives of this report were to implement a pilot protection scheme in a 230 kV line with two power sources at each end of the system. Implementation of the pilot protection scheme conveys implementation of digital logic in the relay in order to trip under POTT scheme conditions. In addition, familiarization with the SEL-411L protection relay, SEL AMS, and their respective software is essential in order set the system settings.

Many challenges from gathering were encountered in the development of this report. One challenge included the gathering of fault currents and voltages to set up the adaptive multichannel source which served as the power sources of the system. This was a challenge because the current directions must be considered so it can be forward looking and vice-versa. Another challenge was that, in setting the relay, the desired parameters must be specified. The tester must know which parameters are automatically defined and also to define the proper protection scheme as the relay has the capabilities to be configure in different protection schemes and one must also be able to become familiar of the internal logic operators of the relay (SELogic). In regards to system hardware, some rearrangement was required with the relays and power sources in order to achieve proper connection.

The theoretical background on distance protection and its design parameters are discussed in detail in this report in addition to various applications that were mentioned regardless of pilot protection. Obtained results match predicted results. However, when implementing protection, the entire system must be protected. A possible extension of this report could be a protection scheme which protects the source side, including details as to how it coordinates with the protected system discussed in this report.

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