Hidden Failures in Protection Systems and its Impact on Power System Wide-area Disturbances

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(ABSTRACT)

This document explores Hidden Failures in protection systems, which have been identified as key contributors in the degradation of Power System wide-area disturbances. The Hidden Failure Modes in which the protection systems may fail to operate correctly and their consequences are identified in a theoretical approach. This theoretical side has its practical counterpart since a number of Hidden Failure Modes are found in real wide-area disturbances.

The original definition of Hidden Failure, which is a failure that remains undetected and is uncovered by another system event, is included as well as developments on Hidden Failure sequence of events and a methodology for Hidden Failure identification. This method is based on Protection Element Functionality Defects (PEFD), which are applicable to all the elements included in the protective chain. PEFD are classified in two main groups.

Primary and Back-up protection schemes applied for Generators, Buses, Transformers and Transmission Lines are analyzed. The abnormal Power System conditions that each Power System element may have are enumerated. A catalogue of the relays or relay systems, in charge of detecting and stopping the continuous presence of the abnormal conditions is developed. Relay families organize this catalogue. The relaying schemes for five Special Protection Systems are described. Thirty-three Hidden Failures Modes are included based on the relaying implementation for Primary protection, Back-up protection and Special Protection

Systems. These Hidden Failures Modes are based on PEFD-A. Hidden Failures related to PEFD-B are included in a general fashion.

Wide-area disturbances based on NERC reports are analyzed and Hidden Failures are identified employing the developed methodology. The mechanisms in the disturbances are summarized and are applicable to Primary protection, Back-up protection and Special Protection Systems.

Regions of Vulnerability and Areas of Consequence definitions are included and are identified for a Power System wide-area disturbance. For some protection schemes the term Condition of Vulnerability was developed. Regions of Vulnerability and Areas of Consequence will bring the initial steps towards the problem solution. Further research directions are oriented towards the development of a computer-based tool to track the regions of vulnerability in real time.

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To my Lord, because the first part of my dream is now a reality.

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1. Chapter 1 Introduction

Catastrophic failures are catalogued as Power System wide-area disturbances that cause abnormal conditions in the interconnected network parameters such as frequency, voltages, power angles, power flows, among others, in such magnitudes, that the Power System can not be controlled as a whole any more. Under these circumstances, the advantages of the interconnected network must be ignored, the system splits apart and normally part of the electric service is interrupted in order to acquire stability. The big control problem becomes a set of smaller problems. During this scenario, several monitoring, protection and control systems are employed.

The role of the protection systems within the behavior of the wide-area disturbances is critically important. Several disturbances have started with a single contingency, caused by natural forces out of the human being control, and have finished with considerable electric service interruptions and system separation. Miss-operations of the protection systems have been found as key players in the disturbance sequence of events, and a number of these protection system miss-operations have been catalogued as main contributors of the disturbance degradation. A number of examples of these events will be described in detail. The protection system miss-operations that will be of our interest are failure to operate and unwanted operation. Clearly, the first category is the case when the system does not operate when it should have done so, where as the latter one is referred to as a case when the system operates when not required.

The purpose of this document is to identify the modes in which the protection systems may fail to operate correctly and the consequences of these failure modes. An important part of the objective is to identify the failure modes in the real wide-area disturbances, a connection between the philosophical ideas and the real protection system miss-operations.

Not all-possible failure modes will be of our interest, and we will pay special attention on Hidden Failures, which are failures that remain undetected and are uncovered by the occurrence of another event in the Power System. This special kind of failure and their characteristics will be described in Chapter 2.

There is no way to find the failure modes if the protective systems' operational characteristics are unknown, therefore a description and explanation of the protective systems is included along Chapters 3, 4, and 5. The protection systems to be analyzed will be classified as Primary protection, Back-up protection and Special Protection Systems. Primary and Back-up protection are Power System element oriented schemes. Primary and Back-up protection systems for generators, transformers, buses and transmission lines have been included. Special Protection Systems have a system focus and they are responsible for the wellbeing of the system from a global perspective. Five SPS are described and analyzed for Hidden Failures in Chapter 5.

The relays employed for the above mentioned protection systems implementations are grouped per relay families. A hybrid approach was taken for this task, which combines the industry as well as the academician point of views. The term Hidden Failure Mode will be specifically used for a Hidden Failure in a protection system, and roman numbers are employed for the Hidden Failure Modes list.

Hidden Failure definition, philosophies and sequence of events constitute a theoretical approach to the problem. Chapters 3, 4, and 5 describe how the protection systems may have Hidden Failures, under what conditions they may be triggered, and what would be their consequences. Chapter 6 presents a practical counterpart to the theoretical problem, adding to it importance and strength, since a number of the specific Hidden Failure Modes defined in previous Chapters are identified in real wide-area disturbances analysis performed over the NERC disturbance reports. The mechanisms of the analyzed wide-area disturbances were developed.

Regions of Vulnerability and Areas of Consequence definitions are included in Chapter 7. Regions of Vulnerability are identified as Power System physical areas in which the occurrence of an event will uncover a Hidden Failure of a nearby protection system. Areas of Consequence represent the overall observation of the disturbance degradation, from the initial contingency until the last actions made in order to control the Power System. Regions of Vulnerability and Areas of Consequence were identified for a NERC disturbance. Chapter 7 represents the initial approach towards the problem solution.

2. Chapter 2 Hidden Failure Definition, Philosophies and Sequence of Events

2.1. Hidden Failure Origins

The work done by Mr. Surachet Tamronglak [1] describes the Hidden Failures origins and initial definitions. Hidden Failures have been present in Power Systems since the very beginning of protection systems. References [1] and [2] present the Hidden Failures introduction to the protection engineering community.

Tamronglak states: "A Hidden Failure is defined to be a permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove a circuit element(s) as a direct consequence of another switching event." This definition will be the starting point of the work developed in this document; further Hidden Failures classifications and mechanisms have been defined and will be shown later in this section.

Hidden Failures analysis developed in [1] and [2] is based on permanent defects in the form of hardware failures of protective relays. The logic diagram associated with the most common transmission lines protective schemes was critical in the Hidden Failure analysis. As mentioned before, this analysis is based on relay functionality problems under the operational point of view and regarding to their expected behavior.

Some of the relays examined constitute the transmission lines protective schemes, such as fault detectors, operating distance relays, receivers, transmitters, timers, among others. Typical functionality assumed problems were relays with their output contact always closed or opened, regardless the level of the input quantity which makes a healthy relay to operate. Another functionality problem was the one related with timers, which did not comply with the pre-set time delay.

This section briefly described part of the work done in [1] and [2]. Further developments based on this original work are included next.

2.2. Hidden Failure Characteristics and Classifications

Before refining the Hidden Failure definition it should be noted that this special kind of failure is applicable to all protective system elements, such as potential transformers (PT), current transformers (CT), cables, lugs and connectors, all kind of relays, communication channels, etc. So, a Hidden Failure is a defect from which any of the protection system elements may suffer. The fundamental difference is that these defects, by themselves, will not produce an immediate action in the system, but they will remain undetected. Hidden Failures are normally triggered by other events in the system, such as faults or changes in the Power System conditions.

Hidden Failures are not frequent problems, but the risk associated with their effects in Power Systems may be catastrophic considering that the product of probability times consequence is a measure of risk [3]. The most peculiar and dangerous characteristic of a Hidden Failure is the fact that their effects appear when the system is under stressed conditions, such as during faults, under-voltages, overloads, or as a consequence of another switching event.

The local effect characteristic of Hidden Failures is also an important factor to take in account, since a single contingency (caused by random natural forces or agents out of the human being control) may result in a multiple contingency in the same local area of the network. Taking a look in the Power System as a whole, the circuits tripped by Hidden Failures have an intense local effect since generally the double contingency is electrically within the first contingency surroundings. Additionally, the second contingency may have further effects, such as the triggering of remedial action schemes or transmission lines transfer trips, worsening the overall local post-fault system condition.

2.2.1. Hidden Failures Modes, Mechanisms and Sequence of Events

The philosophy involved with the identification of Hidden Failures classifies Hidden Failure Modes for each protection scheme, which could be a relay or relay system used to protect transmission lines, generators, buses, transformers, etc.

Since the Hidden Failure definition has been already mentioned it is convenient to make some clarifications and define Hidden Failure Mode as well. The term Hidden Failure is related to the general concept of a failure, this complies with the definition included in section 2.1. A Hidden Failure Mode is particularly associated to the relay or relays systems used to protect a specific Power System element. When the term Hidden Failure Mode is used, a specific relay or relay system is implicitly included.

The philosophy utilized in this analysis is strictly concerned with the identification of Hidden Failure Modes and its effect, regardless of the Hidden Failure Mode causes.

The first event in a Hidden Failure mechanism is a Protection Element Functionality Defect (PEFD), but having a PEFD does not guarantee that a Hidden Failure will occur. In general a PEFD takes place when the protection devices are unable to perform their designed and expected actions. This defect can be present on any of the protection system elements, and may take the form of hardware failures, outdated settings and human negligence or errors.

Examples of PEFD can be a relay's contact that is always open or closed, a timer that operates regardless of its pre-assigned time delay, an outdated setting in a relay, a human error in relays coordination, etc. For convenience a PEFD related to hardware failures is referred to as PEFD-A, and a PEFD related to relay settings, human errors or negligence is called PEFD-B.

The logic involved with the PEFD will determine if this first event will result in a Hidden Failure. It is important to note that the determining factor for an undetected

PEFD is the logic sequence of events required for a switching action in a Power System, such as a line or generator trip. Hidden Failures Modes are defined depending on the logic associated with the specific protection scheme being analyzed.

An example of these ideas and philosophies is described in Figure 1, which shows a distance relay basic logic schematic for its three zones of operation, used for non-pilot transmission line protection. A PEFD-A, which takes place on the T3 contacts, will result in a Hidden Failure Mode and a PEFD-A on Z1 will not result in a Hidden Failure Mode.

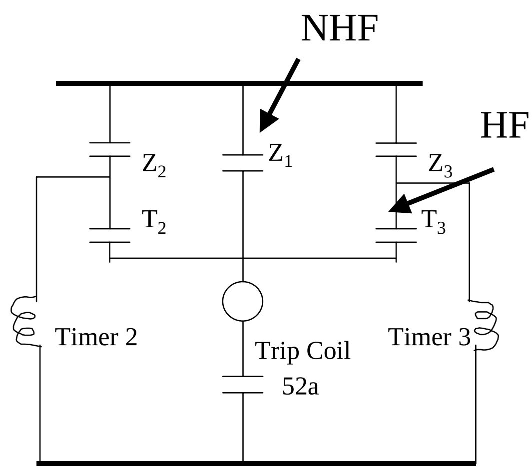

Figure 1: Hidden Failure Modes, a beginning.

A PEFD-A, which takes place in the Z1 contact closing it permanently, will not cause a Hidden Failure Mode since the logic involved with Z1 PEFD-A does not allow the failure to remain undetected. At the instant when Z1 fails closed, Zone 1 distance relay will trip the line circuit breaker. This indeed is a relay miss-operation, but not a Hidden Failure.

If the PEFD-A takes place in T3 closing the contact permanently, the logic will allow this PEFD-A to remain undetected. At the instant when T3 closes its contacts nothing will happen in terms of line trips, because both Z3 & T3 are required to close before tripping the line. This PEFD-A will remain Hidden until some abnormal system conditions occur. This condition will result in a Hidden Failure Mode; this kind of analysis will be performed in the following chapters.

In accordance with the Hidden Failure definition included in section 2.1, it is important to make clear what kind of protection system failures are going to be considered Hidden Failures. In general, and in agreement with what was established in [1], a "failure to trip" will not be considered Hidden Failure. In other words, if there is a PEFD on any of the protective system elements, with the consequence of not clearing the fault, this protection system failure will not be a Hidden Failure. This is a "failure to trip" event, and is not considered a Hidden Failure due to the fact that some other protection systems will react and finally clear the fault. Power systems are biased towards dependability, and, sooner or later, all faults will be cleared by the protection systems.

2.2.2. Hardware Related Hidden Failures

Hardware related Hidden Failures are the ones analyzed in [1] and [2]. These Hidden Failures result from a PEFD-A. Typical PEFD-A are relay contacts that are always closed or always open, regardless of the amount of operating quantity which makes the relays activated or stay "on the shelf" status.

2.2.3. Relay settings, Human error and negligence related Hidden Failures

The coordination of the different protective schemes on the Power System is one of the most critical tasks for the protective engineer. Part of the art of protective relaying is based on the engineering judgement of the relaying community. Relay settings are the result of multiple Power System simulations and reflect the expected harmony of the Power System reactions for all possible contingencies.

Human errors may occur during this process, resulting in protective relay miss-coordination. This type of failure is considered a Hidden Failure since its behavior falls under the Hidden Failure definition and sequence of events. A PEFD, such as miss-coordination, remains undetected until something happens. A typical example would be a generator excitation limiter protection, which was, mistakenly, set to trip the generator unit for a value under its overall capacity. This failure will be hidden until an increment on the Power System reactive power requirement produces an unwanted trip of the generator. The effects of this Hidden Failure may be serious, and the final result will depend on the system strength and the operation conditions.

Human negligence also will fit under this category, where the initial settings used to have a good functionality behavior in terms of coordination, but due to changes in system conditions or topologies they become obsolete, inadequate or even wrong. A human negligence related Hidden Failure was one of the initial events registered in the famous New York 1965 blackout [4].

In the present document, Hidden Failures analysis has been expanded, since it takes in consideration relays and relay systems to protect generators, buses, transformers and transmission lines. Hidden Failure Modes are listed as will be seen in chapters 3, 4 and 5. Hidden Failures related to relay settings, human errors or negligence will be discussed in Chapter 8.

3. Chapter 3 Primary Protection, Schemes and Hidden Failure Modes

3.1. Primary Protection

A modern Power System is overlaid with several layers of monitoring, control and protection systems [3]. The reaction of the Power System to all imaginable disturbances, ranging from natural events to human negligence and errors depends mainly on the proper performance and coordination of these layers. Monitoring, control and protection systems are key elements in the important and critical task of maintaining the Power System stable under all contingencies.

The interaction of the above mentioned systems must be coordinated and hierarchically these systems may be classified in terms of their time of response and areas of action.

Primary protection takes first place in the hierarchy; the objective of this protection is to respond to system faults and remove the least number of elements in the fastest time. Time response periods are in the order of milliseconds. Usually Primary protection actions are not supervised from a higher control level center.

The application of Primary protection for generators, buses, transformers and transmission lines will be described in this chapter. Each Power System element is defined in terms of its role in the system. Abnormal Power System conditions, which each Power System element may have, are enumerated. Relays or relay systems, in charge of detecting and stopping the continuous presence of the abnormal conditions are included.

The relation between the abnormal condition and the protective relay is called "the abnormal condition-protective relaying interface". It is important to note that for a specific abnormal condition on a certain element there may be more than one protective-relaying interface. This means that there is more than one way to protect Power System elements. Furthermore, a specific abnormal condition-relaying interface, i.e. Directional Comparison Blocking for transmission lines, may be implemented with different relay types.

In "the abnormal condition-protective relaying interface" section, all relays applied in the Primary protection for the specific Power System element, are analyzed for Hidden Failures. Hidden Failure Modes are enumerated using roman numbers.

3.2. Primary Protection for Generators

Generators are Power System elements in charge of the energy supply, i.e.; they inject the power in the system. In terms of protection and control, a wide range of devices is normally applied to generators varying from mechanical, electrical, and thermal elements.

The abnormal conditions to be considered are:

a) Stator short-circuits. These are the faults between phases, which do not involve the ground.
b) Stator ground faults. These are faults involving ground.
c) Negative sequence. Unbalanced stator currents induce double frequency rotor currents, which produce over heating in the rotor iron [5]. This condition may be present during ground faults or unbalanced load operation.
d) Over-speed. This situation can occur only when the unit is disconnected from the Power System since the system would hold the unit to synchronous speed [6].
e) Over excitation. During start-up conditions the frequency is low and the voltage must be limited to keep a certain voltage/frequency ratio, in order to avoid saturation, over-fluxing and heating [7].
f) Loss of excitation. When the unit is not connected to the system, the excitation of a synchronous generator will determine the voltage at the generator terminals, which then becomes a concern of the volts/Hz as discussed above. When the unit is connected to the system, the excitation determines the stability of the unit. Reduced excitation will endanger the unit.

g) Field ground protection. Since the field systems are operated ungrounded, a single ground will not affect the generator behavior. A second ground will distort the magnetic field and result in excessive vibration. This condition must be detected and eliminated because it may have further undesirable consequences [5].

h) Inadvertent energization. When the generators are taken out from the Power System, during maintenance for instance, there is a risk that the machine would be energized while being off-line and on turning gear [8]. A dedicated protection system is utilized in order to avoid damage to the generation equipment.

3.2.1. Relays Applied in Primary Protection for Generators

Generator protection against the above mentioned abnormal circumstances using relays will be described. Relay families organize this section, and all abnormal conditions involving the same relay family will be grouped.

3.2.1.1. Over-current Relays

Over-current relays react to the current magnitude. They may acquire different characteristics such as inverse timing, instantaneous, or a combination of these. The family of over-current relays is applied to protect the generator against the following abnormal conditions:

a) Stator phase faults

Reference [6] states: "Differential comparison is one of the most sensitive and effective methods of providing protection." Generators are protected against stator phase faults by the application of the concept of differential relaying.

Figure 2 shows the application of the differential principle with over-current relays for stator phase faults. The relay is connected in such a way that for external faults or load conditions, the difference of the input current (I_1) minus the output current (I_2) is essentially zero. For internal faults, this difference results in a current big enough to operate the over-current relay. Current transformer saturation may affect the security of this protection, and a false trip may occur if one of the current transformers is unable to reproduce the primary current appropriately. This scheme presents some limitations related to settings and coordination with other relays in the system.

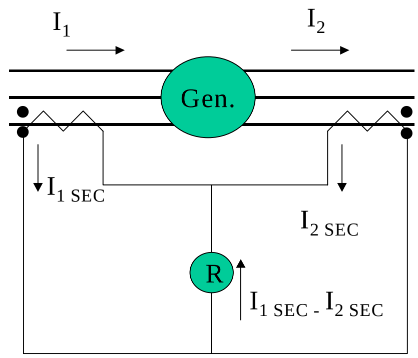

Figure 2: Generator protection against stator phase-faults using over-current relays.

After a Figure 3 analysis, it is determined that no Hidden Failure Modes may result. If a PEFD-A takes place on the over-current relay contacts, and they are always closed, the generator will be tripped just at the time the PEFD-A appears. The logic schematic does not allow this PEFD-A to remain hidden.

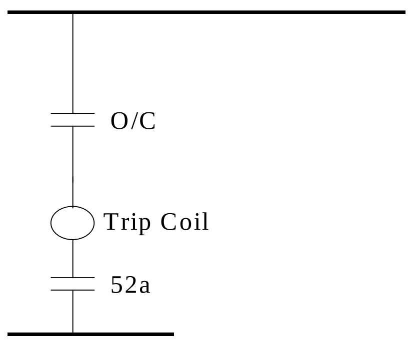

Figure 3: Logic schematic for generator protection against stator phase-faults using over-current relays.

Nomenclature and Protection Scheme Elements

Element	Description	Function
O/C	Over-current relay	Detects a certain current value
52a	CB auxiliary contact	Monitor breaker status

b) Stator ground faults

Ground faults are detected by connecting an over-current relay along with the grounding impedance, see Figure 4.

The value of the grounding impedance will decrease the stator ground fault current and will reduce the relay capacity to differentiate a fault current from steady state harmonics [9].

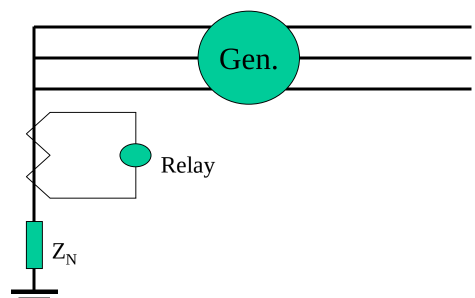

Figure 4: Generator protection against stator ground-faults using over-current relays.

After a Figure 5 analysis, it is determined that no Hidden Failure Modes may result. If a PEFD-A takes place on the over-current relay contacts, and they are always closed, the generator will be tripped just at the time the PEFD-A appears. The logic schematic does not allow this PEFD-A to remain hidden.

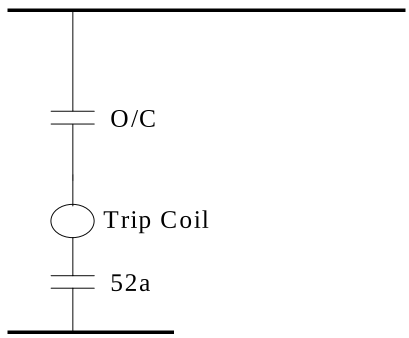

Figure 5: Logic schematic for generator protection against stator ground-faults using over-current relays.

Nomenclature and Protection Scheme Elements

Element	Description	Function
O/C	Over-current relay	Detects a certain current value
52a	CB auxiliary contact	Monitor breaker status

3.2.1.2. Percentage Differential Relays

Generators are also protected against stator phase faults by percentage differential relays. These relays are constituted of restraint and operating windings, which are the essential components [9]. Figure 6 shows the connections of a percentage differential relay. It can be seen that this diagram is similar to the one shown in Figure 2. In fact the same differential principle is used, but now a percentage differential relay is applied instead of the over-current relay.

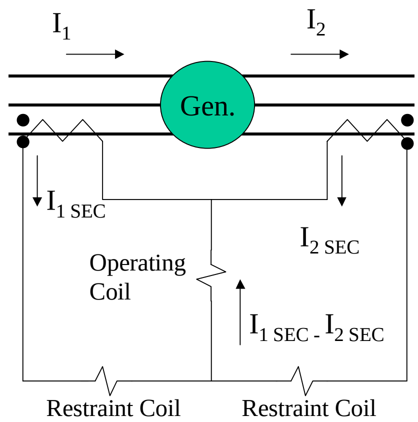

Figure 6: Generator protection against stator phase-faults using percentage differential relay.

The principle of operation is based on the fact that there are more restraint coils than operating coils adding security to the relay operation. The errors coming from the current transformers, until a certain limit, may be tolerated using the variable percentage setting.

Hidden Failure Modes for this relay are shown next.

I. Restraint coils shorted

PEFD-A	Consequence
I	Unwanted trip may occur depending on the load current, since the restraint torque will be diminished.

3.2.1.3. Over-excitation Relays

Over-excitation relays take a sample of the system voltage and system frequency and constantly monitor the volts/hertz ratio. When this ratio exceeds a pre-set value, an alarm will be activated. If this condition last more than a pre-established time, the generator circuit breaker will trip the unit from the Power System. There is not Hidden Failure Mode for this scheme, since the logic schematic is similar to the one shown in Figure 5, but instead of having an over-current unit, a volts per hertz unit is connected.

3.2.1.4. Frequency Relays

Frequency relays may be applied to measure the unit speed and take appropriate actions when the speed has reached a certain value. Figure 7 shows the logic schematic for the generator over-speed protection.

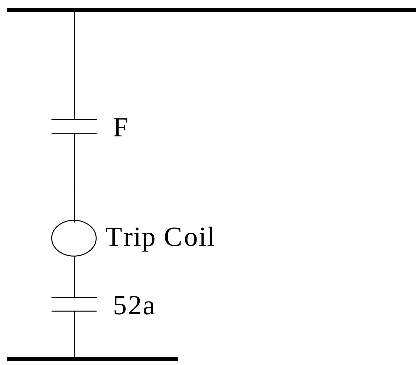

Figure 7: Logic schematic for generator over-speeds.

Nomenclature and Protection Scheme Elements

Element	Description	Function
F	Over-frequency relay	Monitors the frequency value
52a	CB auxiliary contact	Monitor breaker status

After a Figure 7 analysis, it is determined that no Hidden Failure Modes may result. If a PEFD-A takes place on the frequency relay contacts, and they are always closed, the generator will be tripped just at the time the PEFD-A appears. The logic schematic does not allow this PEFD-A to remain hidden.

3.2.1.5. Negative Sequence Relays

Negative sequence relays monitor the presence of this current component at all times. Normally a negative sequence current filter produces an output that is proportional to this current, and if this output exceeds a pre-determined value, the generator circuit breaker is tripped. There is not Hidden Failure Mode for this scheme, since the logic schematic is similar to the one shown in Figure 7. Instead of having an over-frequency unit, a negative sequence unit is connected.

3.2.1.6. Loss of Field Relays

Loss of field relays operation may range from an alarm to the trip of the unit from the Power System. The construction of these relays is conformed basically by an impedance unit, a directional unit, and a voltage unit. The first two units normally operate an alarm, and the last one will trip the generator circuit breaker, if a dangerous under-voltage has been present.

Figure 8 shows the logic schematic for a loss of field relay, specifically the KLF relay from Westinghouse.

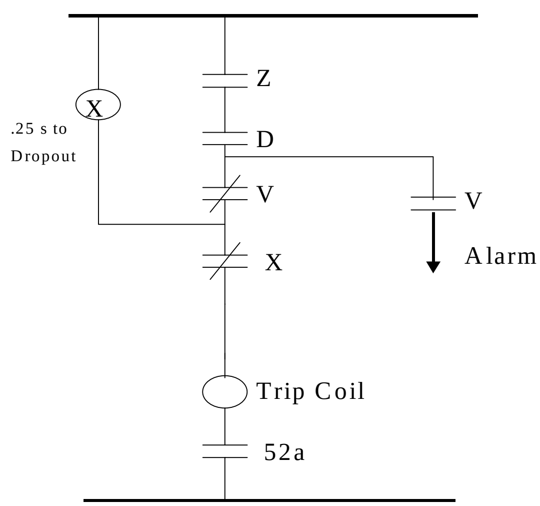

Figure 8: Logic schematic for loss of field relay.

Nomenclature and Protection Scheme Elements

Element	Description	Function
Z	Impedance relay	Monitors the generator impedance as viewed from its terminals
D	Directional relay	Detects reactive power flows in the generator
V	Under-voltage relay	Detects an under-voltage condition at the generator terminals
X	Timer coil	Change X contact status, after time delay
52a	CB auxiliary contact	Monitor breaker status

The operations of the Z and D units, from Figure 8 have some links, since Z would operate as a result of a reduction of the generation excitation. In the case of a reduction in the machine excitation, the first relay reaction is to alarm the operator. If a PEFD-A as shown below takes place a Hidden Failure Mode will result where the alarm is activated and after this action the unit is tripped with a .25 sec time delay. It should be clear that the normally closed contacts of the under-voltage relay are independent of the normally open contacts.

Hidden Failure Modes for this relay are shown next.

II. V normally closed contacts can not picked-up

PEFD-A	Consequence
II	Unwanted trip, the generator is taken out from the Power System, with a .25 seconds delay. The voltage at the machine terminals was not in a dangerous value. PEFD-A remained hidden until a reduced field condition takes place and the unwanted trip took place.

3.2.1.7. Field Ground Detection

The main function of this relay is to monitor the field circuit, and activate an alarm if a ground is present. There are no Hidden Failure Modes for this relay, since its output is limited to an operator warning.

3.2.1.8. Inadvertent Energization Protection

Reference [8] describes a detailed and comprehensive list of protection schemes for generators inadvertent energization. In this section we will analyze the frequency supervised over-current scheme, shown in Figure 9.

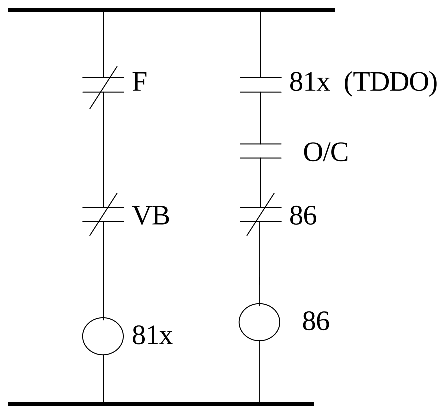

Figure 9: Logic schematic for inadvertent energization.

Nomenclature and Protection Scheme Elements

Element	Description	Function
F	Frequency relay	Monitors the frequency of the generated voltage.
VB	Voltage Balance relay	Monitors the voltage condition.
81x	Timer	Change 81x status. Time delay drop out (TDDO).
O/C	Over-current relay	Monitors the current magnitude
86	Lockout relay	Trips and blocks the generator breakers

The response of these systems, as the one shown in Figure 9 is to trip the generator high-voltage, field and auxiliary breakers if the generator is inadvertently energized [8]. When the generator is off-line the frequency goes down, and F closes back its contacts. During normal and voltage balanced conditions, VB is closed, and 81x is energized. This last action puts the inadvertent energization protection scheme operation dependent on the O/C relay energization. Under this scenario, if the generator is energized by mistake, the O/C relays detect the current flow, close its contacts, and all previously mentioned breakers are tripped.

Hidden Failure Modes for this relay are shown next.

III. O/C relay contacts are always closed

PEFD-A	Consequence
III	Unwanted trip, all previously mentioned generator breakers are opened even when the unit was not inadvertently energized. The frequency relay operation triggers the protection system. Since the unit was already off-line, there will not be consequences in the Power System.

3.3. Primary Protection for Buses

Power system buses are responsible for the distribution of power among the transmission lines that are connected to them. A bus is an element that may connect several transmission lines and in the case of a bus fault all bus circuit breakers must be opened to clear the electrical fault. Of course, this will interrupt the energy supply from this bus to the respective transmission lines. Electrical faults on buses are less common than transmission line faults, due to the decreased exposure.

Buses abnormal conditions to consider are:

a) Internal phase or ground faults. Any kind of phase-phase, phase-ground, phase-phase-ground, or three-phase faults.

3.3.1. Relays Applied in Primary Protection for Buses

Internal phase or ground faults are detected using the differential relaying concept. Bus arrangements, such as single breaker, double breaker, or breaker-and-a-half would define the connections among relays and the logic involved with trips.

3.3.1.1. Over-current Relays

The family of over-current relays is applied to protect buses against the following abnormal conditions:

a) Internal phase or ground faults.

Figure 10 shows the arrangement for bus protection against internal phase or ground faults using over-current relays. Current transformer saturation may affect the security of this protection, and a false trip may occur. There is not Hidden Failure

Mode for this scheme, since the logic schematic is similar to the one shown in Figure 3, now applied to buses.

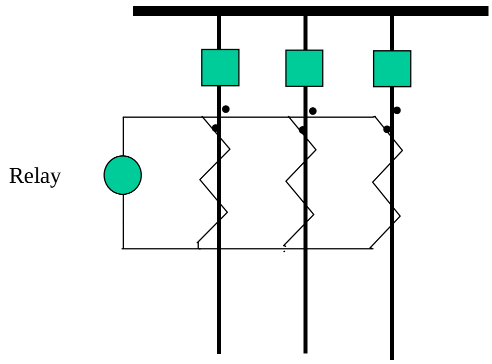

Figure 10: Bus protection against internal phase or ground faults using over-current relays.

3.3.1.2. Percentage Differential Relays

Buses are also protected against internal phase or ground faults by percentage differential relays. These relays were described already in section 3.2.1.2. Figure 11 shows the connections of a bus percentage differential relay.

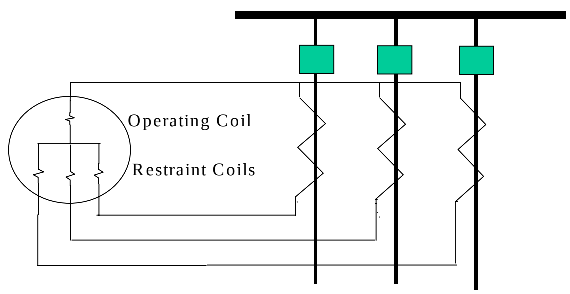

Figure 11: Bus protection against internal phase or ground faults using differential percentage relays.

Hidden Failure Modes for this relay are shown next.

IV. Restraint coils shorted

PEFD-A	Consequence
IV	Unwanted trip may occur depending on the load current, since the restraint torque will be diminished.

3.4. Primary Protection for Transformers

Transformers are Power System elements in charge of providing an adequate voltage level for a specific application. Generation, transmission and distribution networks use transformers in order to obtain the required voltage level in the Power System.

There are several abnormal conditions that a transformer may suffer during its life cycle, such as oil temperature raising, dielectric strength weakening, among many others. Transformers abnormal conditions to be considered are:

a) Internal phase or ground faults*
b) Phase over-current*
c) Over excitation*

* All of these previously defined.

3.4.1. Relays Applied in Primary Protection for Transformers.

Internal phase or ground faults are detected using the differential relaying concept. Power transformers may be protected against internal faults using over-current relays, but this is only normally done for small units, rated 10 MVA and below. For power transformers with capacity of 10 MVA and bigger, differential protection is applied [9]. Over-excitation was already analyzed.

3.4.1.1. Over-current Relays

The family of over-current relays is applied to protect transformers against the following abnormal conditions:

a) Internal phase or ground faults

Figure 12 shows the arrangement for transformer protection against internal phase or ground faults using the differential relaying concept with over-current relays.

Typical problems associated with internal faults for transformer protection are errors and ratio mismatches in current transformers and the effect of the un-load tap changer [6]. As mentioned with buses and generators, this scheme may present false trips. There is not Hidden Failure Mode for this scheme, since the logic schematic is similar to the one shown in Figure 3, now applied to transformers.

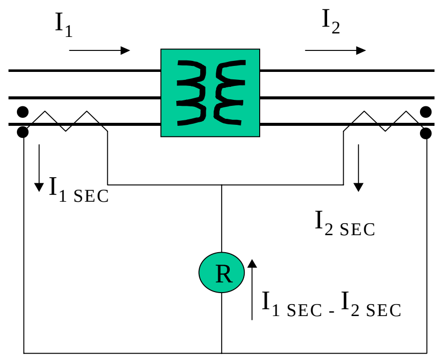

Figure 12: Transformer protection against internal phase or ground faults using over-current relays.

b) Phase over-current is accomplished by the use of over-current relays. There is not Hidden Failure Mode for this scheme, since the logic schematic is similar to the one shown in Figure 3, applied to transformers

3.4.1.2. Percentage Differential Relay

As buses, transformers are also protected against internal phase or ground faults by percentage differential relays. These relays applied in transformers may incorporate some other functions, such as a second harmonic filter, to avoid the relay from tripping due to inrush currents when the unit is energized. The percentage characteristic of the relays may be adjusted in order to overcome the problems mentioned in section 3.4.1.1.

Figure 13 shows the arrangement for transformer protection against internal phase or ground faults using the differential relaying concept with differential percentage relays.

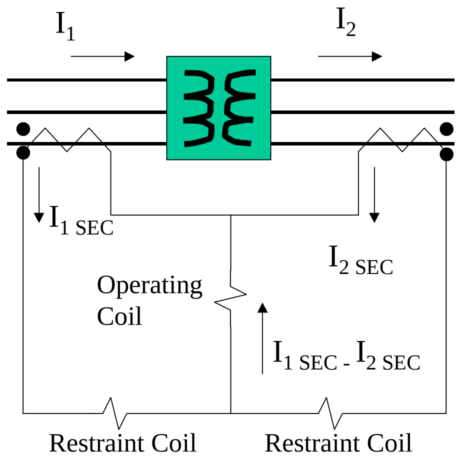

Figure 13: Transformer protection against internal phase/ground faults using percentage differential relays.

Hidden Failure Modes for this relay are shown next.

V. Restraint coils shorted

PEFD-A	Consequence
V	Unwanted trip may occur depending on the load current, since the restraint torque will be diminished.

3.5. Primary Protection for Transmission Lines

Transmission lines are the Power System veins. They carry the power from the generation stations to the consumer centers. The interconnected characteristic of Power Systems provides the availability of transmission lines to transport the bulk power through the network, and continue to do so even during contingencies.

Transmission lines abnormal conditions to be considered, as mentioned in section 3.3 a).

3.5.1. Relays Applied in Primary Protection for Transmission Lines

Primary protection for transmission lines is accomplished by applying the differential relaying concept. The length of the transmission line however, does not permit connecting the protective relays directly through control cable. A way to communicate the information from a relay at one end to the other one is required. “Tele-protection” or ”pilot relaying” is the name given to this transmission line protection based on communication between relays [6].

Primary protection for transmission lines, specifically pilot relaying, is more complicated when compared with previously seen schemes. This protection consists of a set of relays in which each relay plays a role, and the appropriate operation of the Primary protection depends on the correct operation of all of them. The relays are fully coordinated and this coordination depends on the transmission line protective scheme. These schemes are specifically designed to provide Primary protection for transmission lines under different arrangements and philosophies, as will be seen in section 3.5.2.

The specific relays associated with pilot relaying, which constitute a specific transmission line protection scheme, are called pilot relays. Pilot relays may take different functions in the scheme, and under this understanding, they are classified as follows.

a) Directional relay
b) Fault Detector
c) Receiver relay
d) Transmitter relay
e) Timer relay

All of these relays are used in a relay system to protect the transmission line against all internal faults as mentioned previously. These relays, classified by their families will be described next.

3.5.1.1. *Distance Relays*

Voltage and current transducers feed distance relays, which are normally used to protect transmission lines [6]. The principle of operation is based on the Power System voltage and current ratio, called the apparent impedance, Z=V/I.

Their zone of operation shape may classify distance type relays. Among the most common types are the impedance, admittance or mho, offset mho, double binder, reactance and quadrilateral. The resistance-reactance diagram (R-X) provides a very useful tool for distance relays analyses, the impedance of the protected line can be drawn in this diagram. Figure 14 shows the R-X diagram for an impedance type relay.

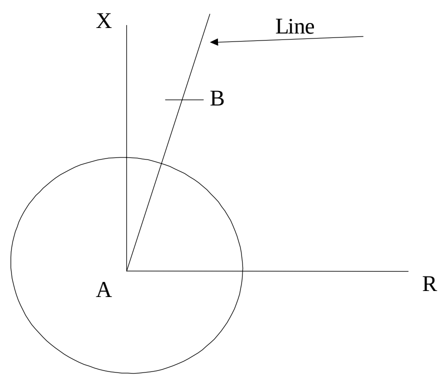

Figure 14: R-X diagram for an impedance relay.

Figure 15 shows the R-X diagram for a mho relay. The protected line is shown as well as the zone-1 (Z1) and zone-2 (Z2) protection zones.

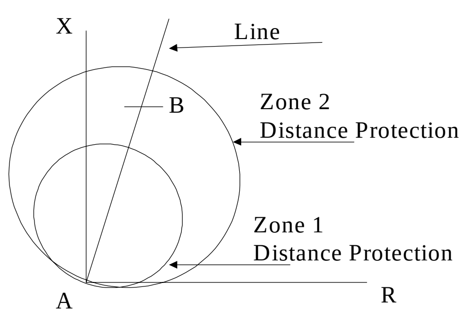

Figure 15: Z1 and Z2, mho distance relay.

Using appropriate design and connections, for any kind of faults the apparent impedance seen by the relay will map in the protected transmission line, and for any external faults or load conditions, the apparent impedance will map outside the protected transmission line, and out of the relay operating zone.

Distance relays are applied within the transmission lines protective schemes. Pilot relays, which may implemented with the distance relay family, are shown next.

a) Directional relay

This relay is set to detect abnormal conditions or faults in a pre-established direction only, and under a certain reach.

b) Fault detector relay

This relay is normally smaller than the previously described, and may be directional or not. It is set to detect faults in some line's zones and to be coordinated with the directional relay.

3.5.1.2. Over-Current Relays

This relay family has been seen and analyzed already. The fault detector relay may be implemented with this family.

3.5.1.3. Directional Over-Current Relays

Directional over-current relays are designed with the capability of distinguishing the direction of a fault and initiating a trip in such direction. These types of relays are mainly conformed by two units, the magnitude unit and the directional unit, as shown in Figure 16. The magnitude unit is responsible for detecting the level of current in which the relay must be activated, i.e., a simple over-current unit. It may acquire different characteristics such as inverse timing, instantaneous, or a combination of these.

The directional unit is responsible of reacting to a pre-established current direction only. Different ways such as voltage, current, positive sequence, and negative sequence polarization may be implemented in order to obtain the directional characteristic. A combination of the above is also allowed.

The general arrangement of these relays is to connect the magnitude and directionality blocks in series as shown in Figure 16. By doing this a relay operation is allowed only if the current is bigger than the pre-established setting and in the required direction.

Directional over-current relays are applied, within the transmission lines protective schemes, to protect the lines to all kind of internal faults. Pilot relays, which may be implemented with the directional over-current relay family, may be used as:

a) Directional relay
b) Fault detector relay

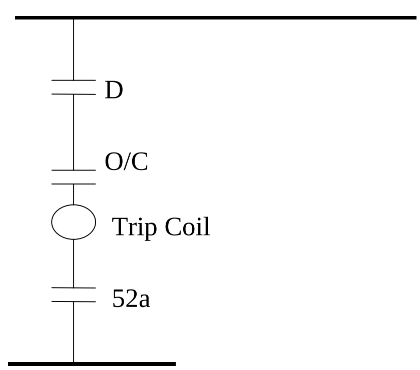

Figure 16: Logic schematic for directional over-current relay.

Nomenclature and Protection Scheme Elements

Element	Description	Function
D	Directional relay	Detects the direction of the current
O/C	Over-current relay	Detects the magnitude of the current
52a	CB auxiliary contact	Monitor breaker status

Hidden Failure Modes for this relay are shown next.

VI. Directional unit contacts always closed

VII. Over-current unit contacts always closed

PEFD-A	Consequence
VI	Unwanted trip, the relay becomes no directional and may trip for fault current in the wrong direction.
VII	Unwanted trip, the relay loose the sensitivity for the fault current magnitude and reacts to the fault direction only.

Additional Hidden Failures on these relays would depend on the specific protective scheme where the relay is applied, as will be seen in Section 3.5.2.

3.5.1.4. Communication Channels and Auxiliary Relays

Communication channels are critical elements in pilot relaying, since, as it was mentioned before, this relaying scheme implementation is based on communication between relays. Relays can communicate among each other by different media; a brief description of the different technologies is presented next.

Power Line Carrier.

This communication link consists of interposing a high frequency signal in the same power line, i.e., the power cables will be carrying the 60 Hz frequency load current, and a high frequency signal which will be injected and received by the communication equipment. Line traps and coupling capacitors are the devices used in the power line-communication equipment interface.

It should be clear that this technology incorporates the same power line cables for the signal transmission. A failure on these power cables will also affect the communication signal; this peculiarity makes this communication appropriate for blocking systems, in which an absence of a signal will trip the line circuit breakers.

Microwave.

This communication link uses the air as media. Antennas and repeaters (if needed) are installed along the transmission line stations. The communication media is independent of the power line itself, but may suffer from noise coming from the environment. A failure on the power cables will not affect the communication signal; this peculiarity makes this communication appropriate for transfer trip systems, in which the signal presence will allow the circuit breaker to trip.

Fiber Optic.

Fiber optic cables may also be used as a communication media. These fiber optic cables are normally installed along the transmission line paths. Several arrangements with underground or overhead cables are possible. Depending on the fiber optic installation mode, it can be employed for either blocking or transfer trip systems.

The remaining pilot relays are receivers, transmitters, and timers, which will be described next.

Receiver relays, as their name indicates, are used to receive a communication signal from the local or remote site. There are several types of receivers depending on the communication media (carrier, tone, fiber optic, etc.), and the transmission line protection scheme.

Transmitter relays are in charge of sending the remote or local communication signal. There are several types of transmitters depending on the communication media, such as power line carrier, audio tones, etc.

Timers are used in order to obtain coordination between the different protection relays in a Power System. There are several kinds of relays such as general propose timers, timers for zone distance scheme, etc.

3.5.1.5. Hidden Failure Modes for Pilot Relays

According to the terms and definitions included in Chapter 2, a Hidden Failure analysis will be performed for pilot relaying schemes. All pilot relays are subject to PEFD, and the fact that this PEFD will result in Hidden Failures will depend on the transmission line protection scheme. PEFD taking place on directional relays, fault detectors, receivers, transmitters or timers resulting in Hidden Failures Modes will be discussed in the following section.

3.5.2. Transmission Line Protection Schemes

Most commonly used pilot relaying schemes may be classified by communication channel as blocking systems and transfer trip systems. Another classification is to catalogue the schemes by fault detection principle, as directional comparison and phase comparison.

3.5.2.1. Directional Comparison Pilot Relay Systems

Directional comparison pilot relay systems are based on the directionality of the fault current, the most used schemes are directional comparison blocking, directional comparison un-blocking, permissive overreaching transfer trip and permissive under-reaching transfer trip [9].

a) Directional Comparison Blocking, DCB

This scheme is normally used with Power Line Carrier (PLC) communication channel under the on-off mode; i.e., the communication signal is transmitted only when a fault is detected by the relays. Since the transmitter sends a blocking signal, a line trip is allowed only if there is no blocking signal. The one-line diagram and logic schematics for directional comparison blocking scheme are shown in Figure 17 and Figure 18 respectively.

The blocking signal is started by a fault detector relay (FD), which may belong to the distance relay family, such as a reversed mho type, and it is set to detect external faults only. The blocking signal is stopped by a directional relay (D), usually another distance relay, admittance type, which sees internal and external faults in a given direction. Using this logic, a blocking signal will only be available for all external faults and no trip will occur. Internal faults are going to be seen by (D) and not by FD, so there is no blocking signal, and both end breakers will trip.

When no directional fault detectors are used, there is some coordination time between the relays, to avoid tripping the line by D activation alone (R must open before D closes, see Figure 18). The receiver will operate with any blocking signal either local or remote.

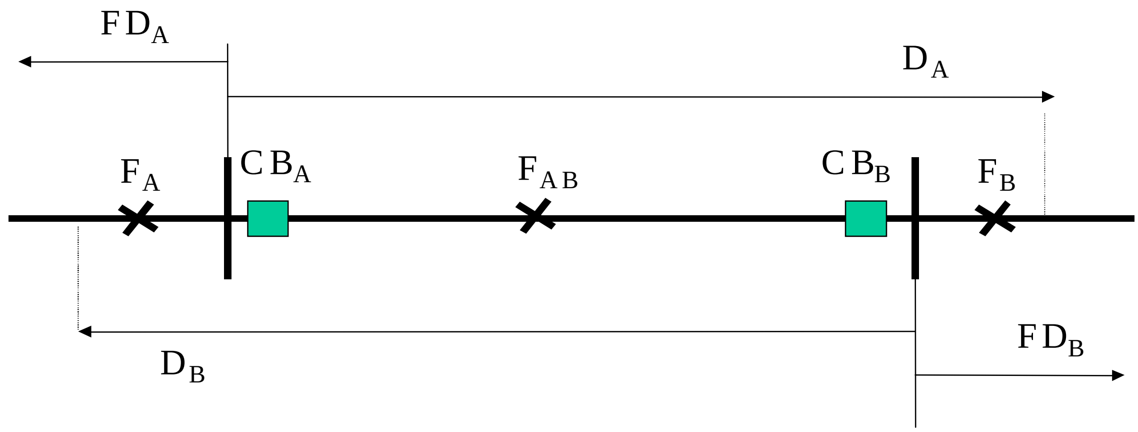

Figure 17: DCB one-line diagram.

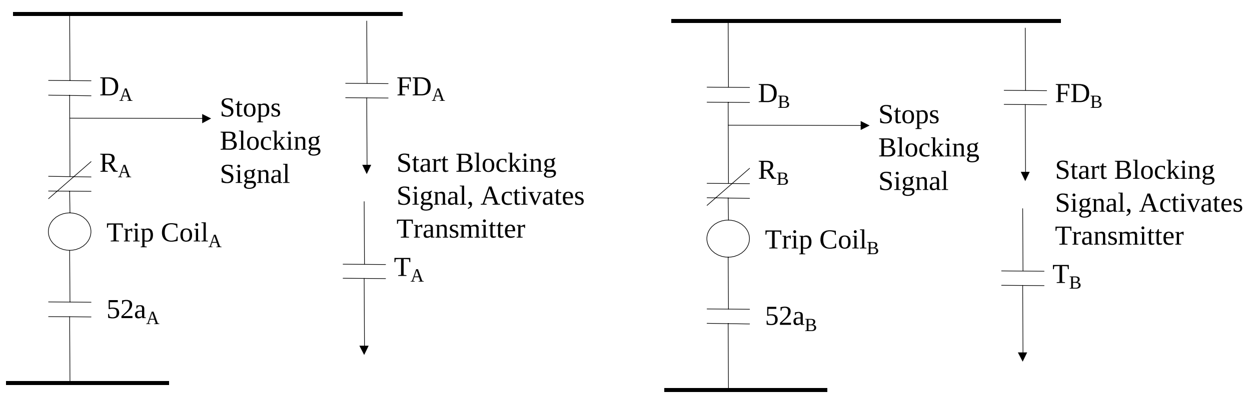

Figure 18: DCB logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
FD_A	Fault detector	Detect external faults and start transmitter
D_A	Directional relay	Stops transmitter
R_A	Receiver	Receives remote/local signal
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A, under D_B reach	
F_B	Fault behind bus B, under D_A reach	
F_{AB}	Fault between A and B	* The same elements apply also for line side B.

DCB logic schematic behavior for internal and external faults

In this section we will review the directional comparison blocking logic schematic at both line ends. We will prove that this transmission line protection scheme does not trip any breaker for external faults and, as expected, for internal faults both breakers are tripped. All three faults presented in Figure 17 are analyzed.

The Methodology, which is going to be used for the next table is shown as follows.

1) Which relays will operate for this fault?
2) What are the consequences of the relay operations at each line side?
3) Final Result; does the breaker trips at A/B side?

Please see Figure 18, along with this table

Case for F_A			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_A	FD_A contact closes, activates T_A to send blocking signal, $BS_{A,}$ remote and locally. R_A opens its contacts.	R_B receives $BS_{A,}$ and open it's normally closed contacts.	
D_B		D_B closes its contacts.	No trip at A, since D_A never closed it's contacts, and BS_A was received. No trip at B side, since BS_A was received.

Case for F_B			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_B	R_A receives $BS_{B,}$ and open it's normally closed contacts	FD_B contact closes, activates T_B to send blocking signal, $BS_{B,}$ remote and locally. R_B opens its contacts.	
D_A	D_A closes its contacts.		No trip at A side, since BS_B was received. No trip at B, since D_B never closed it's contacts, and BS_B was received.

Case for F_{AB}			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A closes its contacts, there is no $BS_{A,}$ so R_A remains closed.	Since there is no BS_A , R_B remains closed	
D_B	Since there is no BS_B , R_A remains closed.	D_B closes its contacts, there is no $BS_{B,}$ so R_B remains closed.	Trip at A side, since R_A remains closed and D_A operated. Trip at B side, since R_B remains closed and D_B operated.

The next table describes Hidden Failure Modes for DCB. The organization of the table is based on the electrical fault location ($F_{A,}$ F_B) that is involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

VIII. FD_A is unable to pickup

IX. T_A is unable to transmit

X. R_A is unable to pickup

Please see Figure 18, along with this table

Case for F_A PEFD-A VIII, FD_A is unable to pickup			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_A	FD_A can not close, T_A is not activated, no $BS_{A.}$ R_A remains closed.	No $BS_{A,}$ so R_B remains closed.	
D_B		D_B closes its contacts.	Unwanted trip at B side, since BS_A was not received, R_B remained closed and D_B was activated.

Case for F_A PEFD-A IX, T_A is unable to transmit			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_A	FD_A contact closes,T_A can not send $BS_{A,}$ R_A remains closed.	No $BS_{A,}$ so R_B remains closed.	
D_B		D_B closes its contacts.	Unwanted trip at B side, since BS_A was not received, R_B remained closed and D_B was activated.

Case for F_B PEFD-A X, R_A is unable to pickup			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_B	R_A receives BS_B, but is unable to pick up, and remain closed	FD_B contact closes, activates T_B to send blocking signal, BS_B, remote and locally. R_B opens its contacts.	
D_A	D_A closes its contacts.		Unwanted trip at A side, since R_A remained closed and D_A was activated.

b) Directional Comparison Unblocking, DCU

This scheme incorporates the use of the Power Line Carrier monitoring capabilities and a continuous blocking signal is always being sent through separate communication channels. The one-line diagram and logic schematics for a directional comparison-unblocking scheme are shown in Figure 19 and Figure 20 respectively.

Two directional relays, which may belong to the distance relay family, mho type, are employed in the scheme. The relays respond to any phase or ground faults and are in charge of shifting the signal from blocking to unblocking when they detect an internal fault. Only for internal faults both relays D_A and D_B will operate, tripping the line.

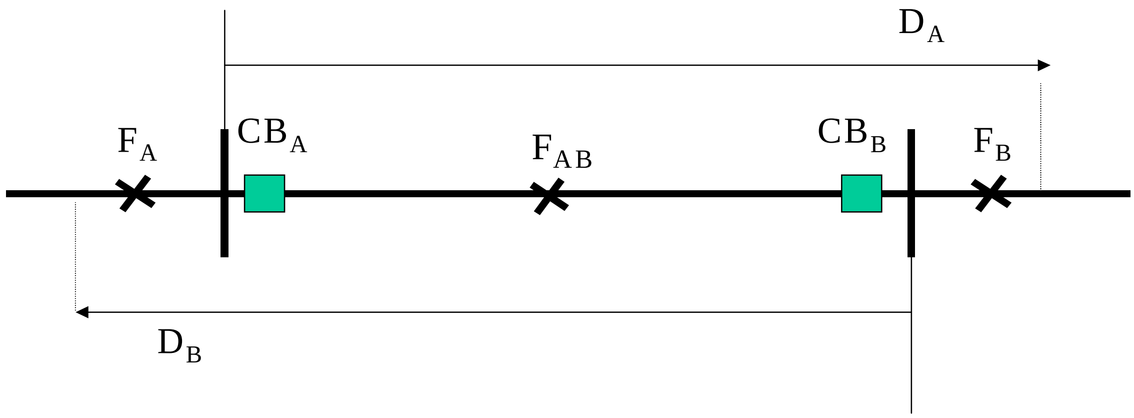

Figure 19: DCU one-line diagram.

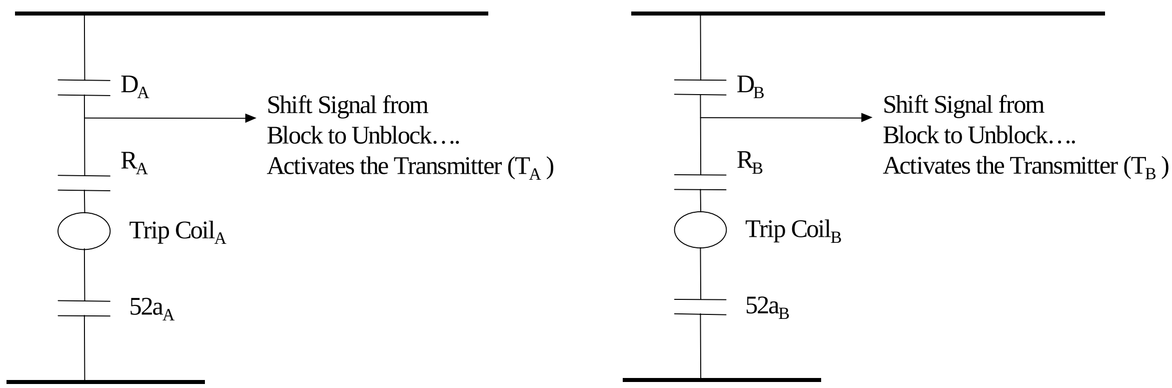

Figure 20: DCU logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
D_A	Directional relay	Shifts transmitter signal to unblocking
R_A	Receiver	Receives remote signal
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A, under D_B reach	
F_B	Fault behind bus B, under D_A reach	
F_{AB}	Fault between A and B	

* The same elements apply also for line side B.

DCU logic schematic behavior for internal and external faults

In this section we will review the directional comparison unblocking logic schematic at both line ends. We will prove that this transmission line protection scheme does not trip any breaker for external faults and, as expected, for internal faults both breakers are tripped. All three faults presented in Figure 19 are analyzed.

The Methodology used before also applies.

Please see Figure 20, along with this table

Case for F_A			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_B	R_A receives UBS_B and closes it's normally open contacts	D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B	No trip at A, D_A never closed it's contacts. No trip at B, R_B remained open, no UBS_A

Case for F_B			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A	R_B receives UBS_A and closes it's normally open contacts	No trip at A, R_A remained open, no UBS_B No trip at B, D_B never closed it's contacts.

Case for F_{AB}			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A	R_B receives UBS_A and closes it's normally open contacts	
D_B	R_A receives UBS_B and closes it's normally open contacts	D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B	Trip at A, D_A and R_A operated Trip at B, D_B and R_B operated

The next table describes Hidden Failure Modes for DCU. The organization of the table is based on the electrical fault location ($F_{A,}$ F_B) that is involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XI. D_A is always picked up

XII. R_A is always picked up

Please see Figure 20, along with this table

Case for $F_{A,}$ PEFD-A XI, D_A is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_B	D_A contacts are always closed, they activate T_A to shift frequency to unblocking signal, $UBS_{A.}$ R_A receives UBS_B and closes it's normally open contacts.	R_B receives UBS_A and closes it's normally open contacts. D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B	Unwanted trip at A, since D_A was always closed and R_A closed its contacts. Unwanted trip at B, since D_B was activated and R_B closed its contacts.

Case for F_B PEFD-A XII, R_A is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	R_A contacts are always closed. D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A	R_B receives UBS_A and closes it's normally open contacts	Unwanted trip at A, since R_A was always closed and D_A was activated.

c) Permissive Overreaching Transfer Trip Scheme, POTT

Transfer trip schemes are used when the communication channel is independent from the power line, such as microwave or fiber optics. This scheme is very similar to (DCU), but instead of shifting the frequency from blocking to unblocking, in this scheme a trip is allowed when the signal is shifted to a tripping mode. In order to avoid confusions, blocking and unblocking terms will be used. The one-line diagram and logic schematics for permissive overreaching transfer trip scheme are shown in Figure 21 and Figure 22 respectively. The shifting action is normally done by changing the signal frequency from low to high frequency. The line will trip only if the relay operates and have received a tripping signal from the remote end.

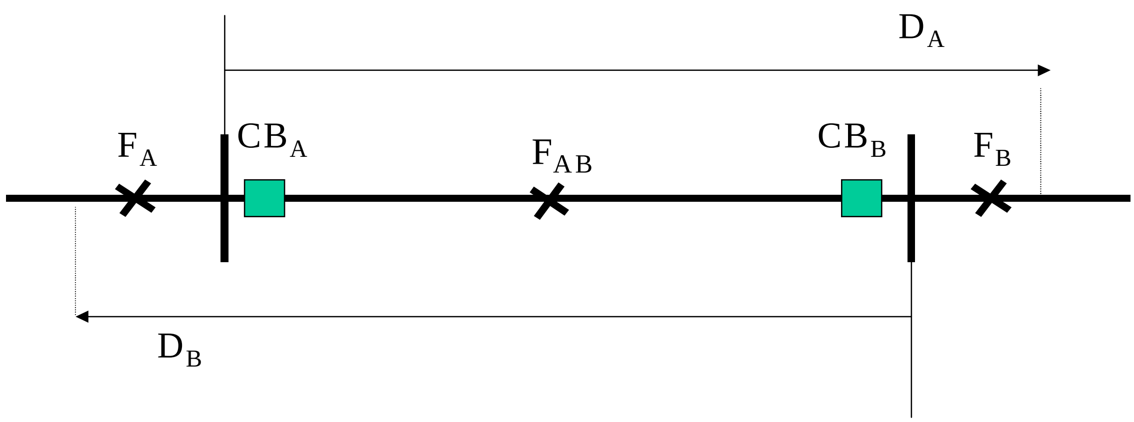

Figure 21: POTT one-line diagram.

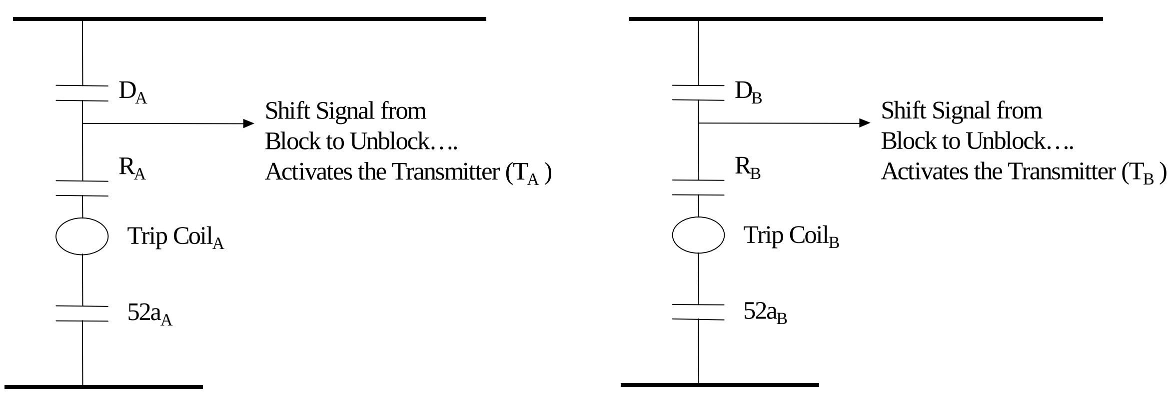

Figure 22: POTT logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
D_A	Directional relay	Shifts transmitter signal to unblocking
R_A	Receiver	Receives remote signal
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A, under D_B reach	
F_B	Fault behind bus B, under D_A reach	
F_{AB}	Fault between A and B	

* The same elements apply also for line side B.

POTT logic schematic behavior for internal and external faults

In this section we will review the permissive overreaching transfer trip logic schematic at both line ends. We will prove that this transmission line protection scheme does not trip any breaker for external faults and, as expected, for internal faults both breakers are tripped. All three faults presented in Figure 21 are analyzed.

The Methodology used before also applies.

Please see Figure 22, along with this table

Case for F_A			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_B	R_A receives UBS_B and closes it's normally open contacts	D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B	No trip at A, D_A never closed it's contacts. No trip at B, R_B remained open, no UBS_A

Case for F_B			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A	R_B receives UBS_A and closes it's normally open contacts	No trip at A, R_A remained open, no UBS_B No trip at B, D_B never closed it's contacts.

Case for F_{AB}			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A	R_B receives UBS_A and closes it's normally open contacts	
D_B	R_A receives UBS_B and closes it's normally open contacts	D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B	Trip at A, D_A and R_A operated Trip at B, D_B and R_B operated

The next table describes Hidden Failure Modes for POTT. The organization of the table is based on the electrical fault location ($F_{A,}$ F_B) that is involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XIII. D_A is always picked up

XIV. R_A is always picked up

Please see Figure 22, along with this table

<table>
<tr><td colspan="4">Case for $F_{A,}$
PEFD-A XIII, D_A is always picked up</td></tr>
<tr><td>Operated Relays</td><td>Consequences at side A logic diagram</td><td>Consequences at side B logic diagram</td><td>Final Result</td></tr>
<tr><td>D_B</td><td>D_A contacts are always closed, they activate T_A to shift frequency to unblocking signal, $UBS_{A.}$

R_A receives UBS_B and closes it's normally open contacts.</td><td>R_B receives UBS_A and closes it's normally open contacts.

D_B contact closes, activates T_B to shift frequency to unblocking signal, UBS_B</td><td>Unwanted trip at A, since D_A was always closed and R_A closed its contacts.

Unwanted trip at B, since D_B was activated and R_B closed its contacts.</td></tr>
</table>

<table>
<tr><td colspan="4">Case for F_B
PEFD-A XIV, R_A is always picked up</td></tr>
<tr><td>Operated Relays</td><td>Consequences at side A logic diagram</td><td>Consequences at side B logic diagram</td><td>Final Result</td></tr>
<tr><td>D_A</td><td>R_A contacts are always closed.

D_A contact closes, activates T_A to shift frequency to unblocking signal, UBS_A</td><td>R_B receives UBS_A and closes it's normally open contacts</td><td>Unwanted trip at A, since R_A was always closed and D_A was activated.</td></tr>
</table>

d) Permissive Under-reaching Transfer Trip Scheme, PUTT

This scheme is also used when the communication channel is independent from the power line, such as microwave or fiber optics. The one-line diagram and logic schematics for permissive under-reaching transfer trip scheme are shown in Figure 23 and Figure 24 respectively.

Directional relays are set–up to under-reach the protected line, and if a fault is located under their reach they instantaneously trip its associated circuit breaker. If the fault is located in such a way that only one directional relay can react to it (close to one circuit breaker), fault detectors arm the remote circuit, and the remote end trips when it receives a tripping signal. For external faults, no breaker will trip; since they have to receive a tripping signal form the remote end.

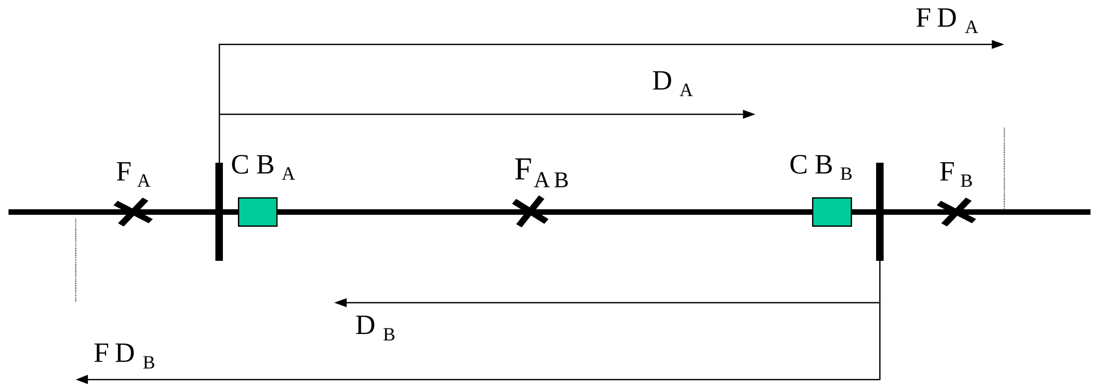

Figure 23: PUTT one-line diagram.

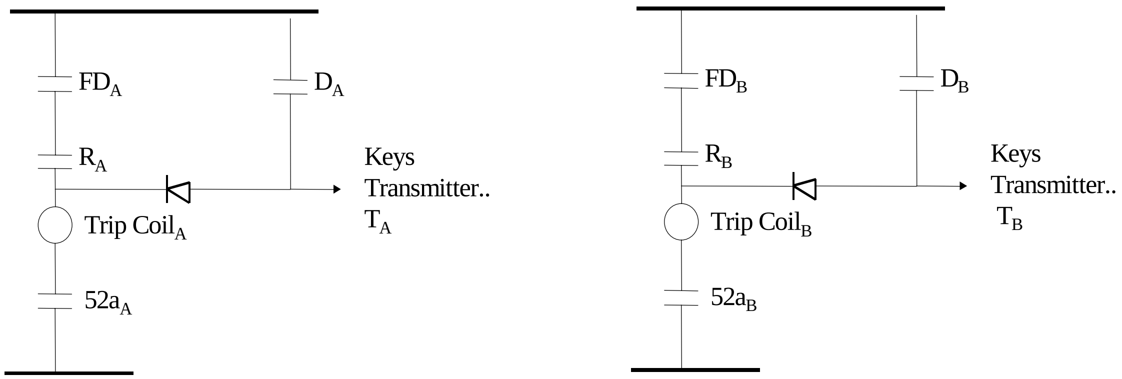

Figure 24: PUTT logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
FD_A	Fault detector	Detect faults
D_A	Directional relay	Shifts transmitter signal to tripping mode
R_A	Receiver	Receives remote signal
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A, under FD_B reach	
F_B	Fault behind bus B, under FD_A reach	
F_{AB}	Fault between A and B	

* The same elements apply also for line side B.

PUTT logic schematic behavior for internal and external faults

In this section we will review the permissive under-reaching transfer trip logic schematic at both line ends. We will prove that this transmission line protection scheme does not trip any breaker for external faults and, as expected, for internal faults both breakers are tripped. All three faults presented in Figure 23 are analyzed. The Methodology used before also applies.

Please see Figure 24, along with this table

Case for F_A			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_B	None	FD_B contact closes.	No trip at A (nothing happen at A side). No trip at B, R_B remained open, no tripping signal.

Case for F_B			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_A	FD_A contact closes.	None	No trip at A, R_A remained open, no tripping signal. No trip at B (nothing happen at B side).

Case for F_{AB}			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
D_A	D_A contact closes, activates T_A to send tripping signal TS_A	R_B receives TS_A and closes it's normally open contacts	Trip at A, D_A closed it's contacts.
D_B	R_A receives TS_B and closes it's normally open contacts	D_B contact closes, activates T_B to send tripping signal TS_B	Trip at B, D_B closed it's contacts
Note: As mentioned before any internal fault close to one of the circuit breakers will be tripped when the fault detectors see the fault and the tripping signal is received.			

The next table describes Hidden Failure Modes for PUTT. The organization of the table is based on the electrical fault location ($F_{A,}$ F_B) that is involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XV. T_A is always picked up

XVI. R_A is always picked up

Case for F_A PEFD-A XV, T_A is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_B	T_A is always picked up, transmits a TS_A	R_B receives TS_A and closes it's normally open contacts FD_B contact closes.	Unwanted trip at B, R_B and FD_B closed.

Case for F_B PEFD-A XVI, R_A is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
FD_A	R_A is always picked up. FD_A contact closes.	None	Unwanted trip at A, R_A and FD_A closed.

3.5.2.2. Phase Comparison Pilot Relay Systems

Phase comparison pilot relay systems utilize the phase of the fault current. One-phase comparison blocking and dual-phase comparison blocking are the schemes to be described.

a) Single Phase Comparison Blocking, SPCB

Phase comparison schemes are based on the fact that the polarity of the currents will differ for internal than for external faults. Single-phase schemes use only a half part of the sine wave, which is converted to a square waveform before being transmitted.

The one-line diagram and logic schematics for single-phase comparison blocking scheme are shown in Figure 25 and Figure 26 respectively.

The comparison is performed on each line side, where the local signal is compared with the remote one. If the relays are connected with positive polarity at one side and negative polarity at the other side, internal faults will have the positive or negative half-wave in phase, where as for external faults, 180° out phase will be seen. If the comparison finds out that the signals are out of phase, an external fault will be declared, and no trip will occur. Two fault detectors are used; low-level fault detectors indicate a fault presence and keys on/off the transmitter and high-level fault detectors arm the circuit for trip, depending of the comparison result.

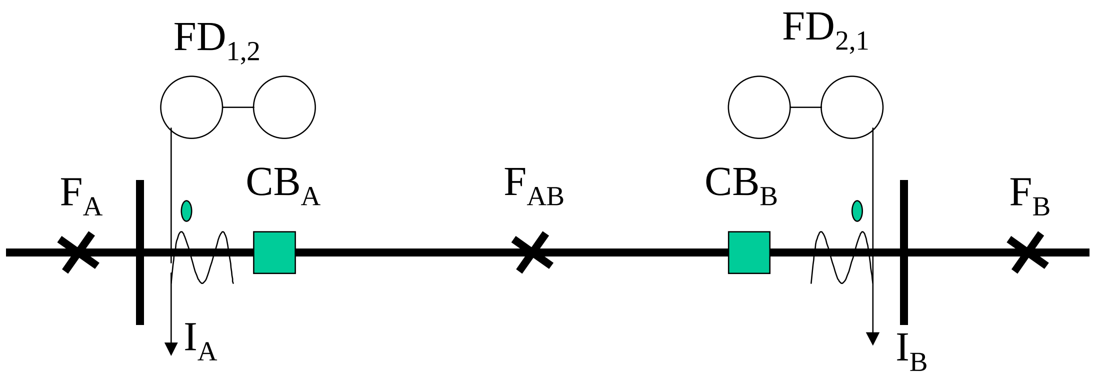

Figure 25: SPCB one-line diagram.

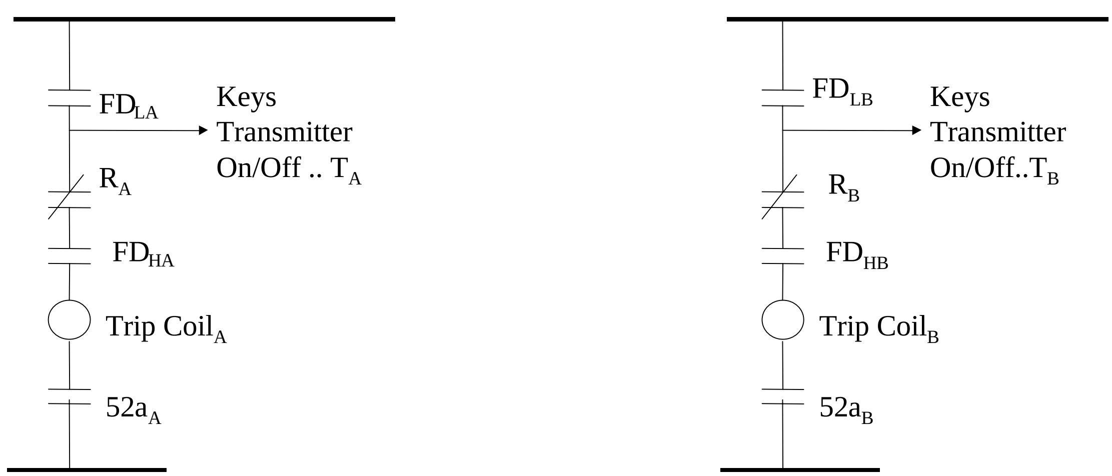

Figure 26: SPCB logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
FD_{HA}	High-level Fault detector	Arms the circuit for tripping
FD_{LA}	Low-level Fault detector	Keys on/off transmitter
R_A	Receiver	Receives remote signal for comparison
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A.	
F_B	Fault behind bus B.	
F_{AB}	Fault between A and B, I_A and I_B are out of phase	

* The same elements apply also for line side B.

SPCB logic schematic behavior for internal and external faults

In this section we will review the single-phase comparison blocking logic schematic at both line ends. We will prove that this transmission line protection scheme does not trip any breaker for external faults and, as expected, for internal faults both breakers are tripped.

Since no directional relays are used, the methodology will take the form of a sequence of events. F_A and F_B are grouped as external faults and $F_{AB,}$ as defined previously, is an internal fault. The magnitude of the faulted current would decide if the fault detectors would operate. Since FD_{LA} is set more sensitive than $FD_{HA,}$ and the first one key the transmitter, the comparison is made after the signal has been received.

Please see Figure 26.

Internal and external faults:

- The first event is a fault, which makes FD_{LA} to operate, and keys the transmitter, the square waveform is sent to the local and the remote receivers.
- On each line side, the receiver compares the remote and local square waveforms. There is a time delay in order to take in account the remote waveform transmission time. On each line side the receiver, based on the comparison, would do the following:

If the local and remote square waveforms are "practically" in phase, an internal fault is detected, and it would keep closed its normally closed contacts.

If the local and remote square waveforms are "practically" 180 electrical degrees out of phase, an external fault is detected, and it would open its normally closed contacts.

- The operation of FD_{HA} would close the dc tripping circuit for internal faults only, since the receiver contacts were kept closed. For external faults, even when FD_{HA} has operated, no tripping would occur since the receiver has opened its contacts.

The next table describes Hidden Failure Modes for SPCB. The organization of the table is based on external faults that are involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XVII. Loss of signal

XVIII. FD_{LA} is always picked up

XIX. FD_{LA} can not pick up

Case for external fault PEFD-A XVII, Loss of signal			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} and FD_{HA} become non-directional over-current relays	FD_{LB} and FD_{HB} become non-directional over-current relays	An unwanted trip would result if current magnitude were above $FD_{HA/B}$ setting. Receiver would keep closed its contacts.

Case for external fault PEFD-A XVIII, FD_{LA} is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} always send a local signal to receiver. No remote signal is present. FD_{HA} becomes non-directional over-current relay.	R_B always receives a remote signal.	An unwanted trip would result if current magnitude were above FD_{HA} setting. Receiver would keep closed its contacts.
Case for external fault PEFD-A XIX, FD_{LA} can not pick up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} can not activate transmitter.	R_B does not receive a remote signal. FD_{HB} becomes non-directional over-current relay	An unwanted trip would result if current magnitude were above FD_{HB} setting. Receiver would keep closed its contacts.

b) Dual Phase Comparison Blocking, DPCB

Double-phase schemes use both, the positive and the negative half of the sine wave. Two different frequencies are used, a high frequency for the positive half of the square wave and a low frequency for the negative half. The one-line diagram and logic schematics for dual phase comparison blocking scheme are shown in Figure 27 and Figure 28 respectively.

The comparison is performed on each line side, where the local signal is compared with the remote one. The relays are connected as in SPCB since internal faults will have the positive half wave in phase with the negative half-wave, the frequency will be the same, and a trip will be initiated. If the comparison finds out that the signals are out of phase (different frequencies), an external fault will be declared, and no trip is allowed. Two fault detectors are used, low-level fault detectors indicate a fault presence and shift the frequency signal; and high-level fault detectors supervise the trip, depending of the comparison result.

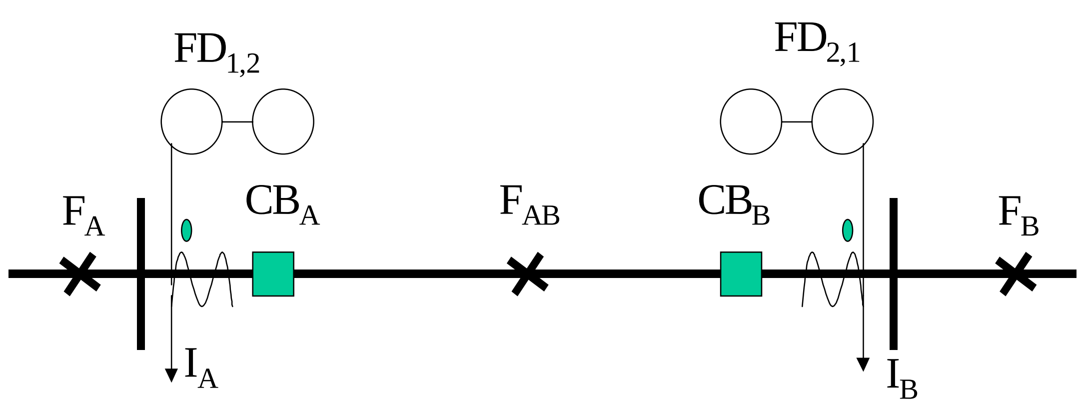

Figure 27: DPCB one-line diagram.

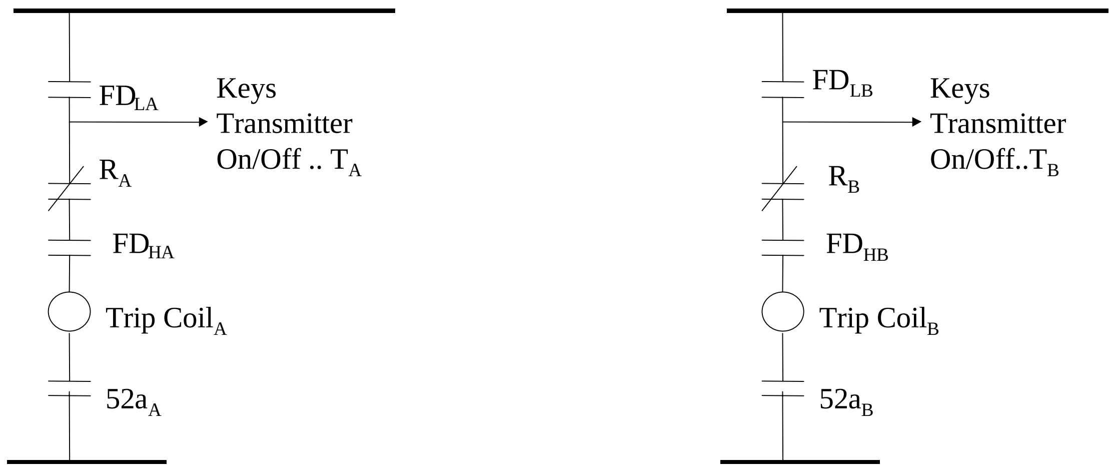

Figure 28: DPCB logic schematic, for A and B line sides.

Nomenclature and Protection Scheme Elements*

Element	Description	Function
FD_{HA}	High-level Fault detector	Arms the circuit for tripping
FD_{LA}	Low-level Fault detector	Keys on/off transmitter
R_A	Receiver	Receives remote signal for comparison
T_A	Transmitter	Transmits communication signal
CB_A	Circuit Breaker	Disconnect one line side
$52a_A$	CB auxiliary contact	Monitor breaker status
F_A	Fault behind bus A.	
F_B	Fault behind bus B.	
F_{AB}	Fault between A and B, I_A and I_B are out of phase	

* The same elements apply also for line side B.

Internal and external faults:

- The first event is a fault, which makes FD_{LA} to operate, and key the transmitter. The square waveform is sent to the local and remote receivers.
- On each line side, the receiver compares the remote and local square waveforms. There is a time delay in order to take in account the remote waveform transmission time. On each line side the receiver, based on the comparison, would do the following:

If the local and remote square waveforms are "practically" in phase, an internal fault is detected, and it would keep closed its normally closed contacts.

If the local and remote square waveforms are "practically" 180 electrical degrees out of phase, an external fault is detected, and it would open its normally closed contacts.

- The operation of FD_{HA} would close the dc tripping circuit for internal faults only, since the receiver contacts were kept closed. For external faults, even when FD_{HA} has operated, no tripping would occur since the receiver has opened its contacts.

The next table describes Hidden Failure Modes for DPCB. The organization of the table is based on external faults that are involved with the circuit breaker miss-operation. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XX. Loss of signal

XXI. FD_{LA} is always picked up

XXII. FD_{LA} can not pick up

Case for external fault PEFD-A XX, Loss of signal			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} and FD_{HA} become non-directional over-current relays	FD_{LB} and FD_{HB} become non-directional over-current relays	An unwanted trip would result if current magnitude were above $FD_{HA/B}$ setting. Receiver would keep closed its contacts.

Case for external fault PEFD-A XXI, FD_{LA} is always picked up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} always send a local signal to receiver. No remote signal is present. FD_{HA} becomes non-directional over-current relay.	R_B always receives a remote signal.	An unwanted trip would result if current magnitude were above FD_{HA} setting. Receiver would keep closed its contacts.
Case for external fault PEFD-A XXII, FD_{LA} can not pick up			
Operated Relays	Consequences at side A logic diagram	Consequences at side B logic diagram	Final Result
Fault Current Dependent	FD_{LA} can not activate transmitter T_A.	R_B does not receive a remote signal. FD_{HB} becomes non-directional over-current relay	An unwanted trip would result if current magnitude were above FD_{HB} setting. Receiver would keep closed its contacts.

4. Chapter 4 Back-up Protection, Schemes and Hidden Failure Modes

4.1. Back up Protection

Section 3.1 defined Primary protection, which has the highest priority in terms of reaction to abnormal Power System conditions. In the case of Primary protection failure or, if this protection is out of service, Power Systems are provided with another protection system, which may take the form of a duplicate Primary and a Back-up system. Duplicate Primary systems operate in the same time as the original Primary system and remove the same system elements. Back-up systems are slower and may remove more of the system than is necessary to clear the fault.

The redundancy of these Back-up protection systems needs to be considered. By definition, a duplicate Primary or Back-up protection must operate independently of the original Primary protection [9]. As mentioned before, the protection elements includes relays, current transformers, potential transformers, cables, dc supply, circuit breakers, etc. Ideally, all elements of the Primary protection would be duplicated for duplicate Primary or Back-up protection. In reality this is done only to some extent. The scope of protection system element duplication varies depending on the voltage class of the protected equipment, its importance to the system and the cost involved relative to the protection being provided. Duplicate circuit breakers in series are not used but, depending on the bus arrangement (i.e. single bus, breaker and a half, etc.) there may be circuit breaker redundancy to allow circuit breaker maintenance. Duplicate and Back-up protection systems are integrated using different current transformer, potential transformer winding, relays, dc supplies, and leads.

4.1.1. Local Back-up

Local Back-up protection systems, as the term implies, are applied in the same substation, i.e., locally. These systems normally share at least one of the protection system elements, such as the breaker, battery and/or potential transformer.

Breaker failure relays (BFR) are a subset of local Back-up relaying that is provided specifically to cover a failure of the circuit breaker. This can be accomplished in a variety of ways. The most common, and simplest, consists of a separate timer that is energized whenever the breaker trip coil is energized and is de-energized when the fault current disappears. If the fault current persists for longer than the timer setting a trip signal is sent to all breakers necessary to clear the fault. Occasionally a separate set of relays are used to provide this breaker failure protection, in which case it uses independent transducers, possibly a second battery or a separate dc circuit.

A typical sequence of events is shown in Table 4.1. The total clearing time, when breaker failure relays are used, is 180 ms [10]

Event Number	Description	Time (ms)
1	Operating time for line protection	20
2	Opening time for circuit breaker	60
3	Set time for BFR plus aux. relays	05
4	Measuring time of breaker failure relay	05
5	Trip relays	10
6	Opening time for adjacent circuit breakers	60

Table 4.1: Sequence of events for a Breaker Failure Relay.

4.1.2. Remote Back-up

Remote Back-up is another and, presently, a less common form of Back-up protection. It is totally independent of all local station protective system elements, providing all of the backup protection from a remote station. It’s main disadvantage is the fact that as systems matured it became more difficult for remote relays to see all faults and tripping the remote station de-energizing tapped loads

Some arguments against the use of remote Back-up relays have been published within the Power System engineering journals [11], mainly because of Hidden Failures related to these relays. This issue will be discussed in detail in chapter 6.

4.2. Back-up Protection for Generators

Back-up protection for generators normally duplicates the Primary protection and it is designed to trip the same circuit breakers [9]. If the failure occurs in the circuit breaker itself, conventional breaker failure relaying is used as was previously discussed. These last sentences lead us to confine the Hidden Failure analysis of Back-up relays for generators within the Primary protection, previously discussed in section 3.2.

4.3. Back-up Protection for Buses

Bus differential protection is universal and is rarely backed up by a local relaying scheme. If the bus protection fails, remote relays will see the fault and trip the remote circuit breakers. As in the case of generators, Hidden Failure analysis was included in Primary protection, in section 3.3.

4.4. Back-up Protection for Transformers

Back-up protection for internal faults on transformers incorporates the use of over-current relays, directional or non-directional depending on the system configuration [12].

As it was seen previously, logic schematics with over-current relays only do not have Hidden Failures. Figure 29 shows again the logic schematic for the directional over-current relay.

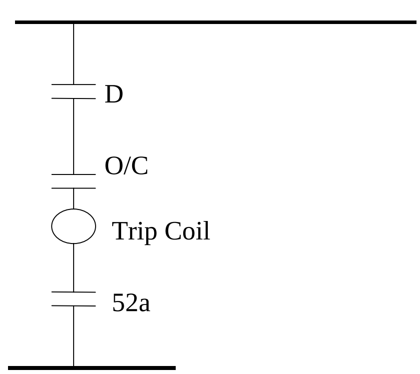

Figure 29: Logic schematic for directional over-current relay.

Hidden Failure Modes for this relay are shown next.

XXIII. Directional unit contacts always closed

XXIV. Over-current unit contacts always closed

PEFD-A	*Consequence*
XXIII	Unwanted trip, the relay becomes no- directional and may trip the transformer even having no internal fault.
XXIV	Unwanted trip, the relay loose the sensitivity for the fault current magnitude and reacts to the fault direction only.

4.5. Back-up Protection for Transmission Lines

Back-up protection for transmission lines that utilize pilot relaying would depend on the Primary protection scheme. Phase comparison relaying systems do not provide inherent Back-up protection; it must be incorporated using another set of relays [5]. Directional comparison and transfer trip systems can provide inherent features such as zone 1 and 2 elements as Back-up protection within the pilot scheme or can utilize separate relays to perform this same function [6]. This section will perform Hidden Failure analysis for Back-up protection using second and third zones of distance relays and directional over-current relays. Breaker failure relays will also be included.

4.5.1. Second and third zone distance relays (Z2/Z3)

Second and third zones of distance relays are used in remote Back-up protection and are coordinated with time delays to allow the Primary protection to operate. After the pre-set time has elapsed, timers' contacts will close tripping the circuit breakers.

Figure 30 shows the one-line diagram for distance relays' zone 2 and zone 3. It is clear to note that CB_{AB} will provide remote Back-up protection to breakers CB_{BC} and $CB_{CD.}$

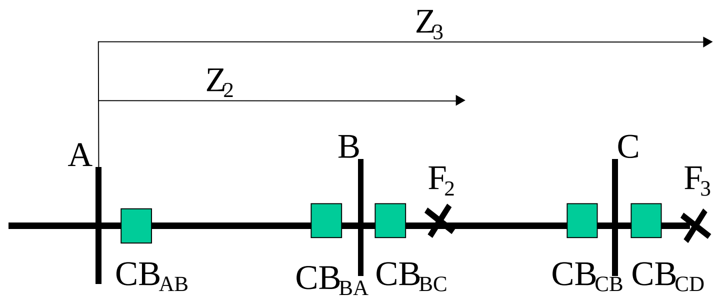

Figure 30: Remote Back-up, Z2 & Z3 one-line diagram.

Figure 31 shows the logic schematic located at station A, to trip CB_{AB} by the implementation of zone 2 and zone 3 distance relays.

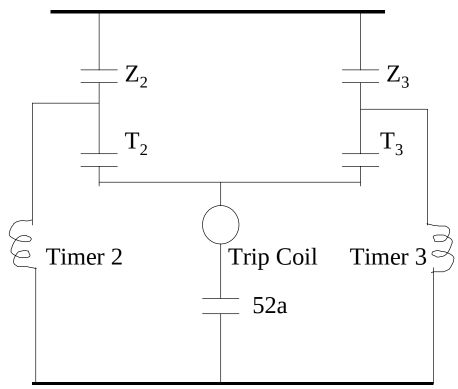

Figure 31: Remote Back-up Z2 and Z3 logic schematic.

Nomenclature and Protection Scheme Elements

Element	Description	Function
Z_2	Fault detector for zone 2	Detects faults
Z_3	Fault detector for zone 3	Detects faults
T_2	Timer 2 contacts	Sets time delay
T_3	Timer 3 contacts	Sets time delay
CB_{AB}	Circuit breaker	Disconnect one line side
52a	CB auxiliary contact	Monitor breaker status
F_2	Fault between bus B and bus C, under Z_2 reach	
F_3	Fault between bus C and bus D, under Z_3 reach	

The sequence of events based on Figure 30 and Figure 31 is described as follows:

- The first event is a fault, such as $F_{2,}$ which makes Z_2 and Z_3 to operate, and energize the timers T_2 and $T_{3.}$
- As soon as T_2/T_3 are energized, the time countdown allowed for the Primary protection operation is started.
- T_2/T_3 will trip CB_{AB} as soon as its contacts are closed. T_3 delay is bigger than $T_{2.}$

The next table describes Hidden Failure Modes for zone 2 and zone 3 distance relays. The organization of the table is based on faults that are involved with CB_{AB} unwanted trips. It should be clear that these trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XXV. T_2 contacts are always closed.

XXVI. T_3 contacts are always closed.

Case for F_2 PEFD-A XXV, T_2 contacts are always closed				
Operated Relays	Consequences at station A	Consequences at station B	Consequences at station C	Final Result
Primary protection of line B-C Back-up protection, Z_2 distance unit of relay associated to CB_{AB}	Back-up protection, Z_2 distance unit of relay associated to CB_{AB} is operated instantly.	Primary protection operated, internal fault	Primary protection operated, internal fault	An unwanted trip, CB_{AB} will open for $F_{2.}$ CB_{BC} and CB_{CB} are opened as expected since they have seen an internal fault.

Case for F_2 PEFD-A XXVI, T_3 contacts are always closed				
Operated Relays	Consequences at station A	Consequences at station B	Consequences at station C	Final Result
Primary protection of line B-C Back-up protection, Z_3 distance unit of relay associated to CB_{AB}	Back-up protection, Z_3 distance unit of relay associated to CB_{AB} is operated instantly.	Primary protection operated, internal fault	Primary protection operated, internal fault	An unwanted trip, CB_{AB} will open for $F_{2.}$ CB_{BC} and CB_{CB} are opened as expected since they have seen an internal fault.

Case for F_3 PEFD-A XXVI, T_3 contacts are always closed				
Operated Relays	Consequences at station A	Consequences at station C	Consequences at station D	Final Result
Primary protection of line C-D Back-up protection, Z_3 distance unit of relay associated to CB_{AB}	Back-up protection, Z_3 distance unit of relay associated to CB_{AB} is operated instantly.	Primary protection operated, internal fault	Primary protection operated, internal fault	An unwanted trip, CB_{AB} will open for F_3. CB_{CD} and CB_{DC} are opened as expected since they have seen an internal fault.

Chapter 7 will define Regions of Vulnerability and will show the differences between the Hidden Failures related to PEFD-A XXV and XXVI.

4.5.2. Directional over-current relays

These relays can also be used for remote backup protection of transmission lines, and Figure 32 shows its application on a one-line diagram. Figure 33 shows again this relay logic schematic.

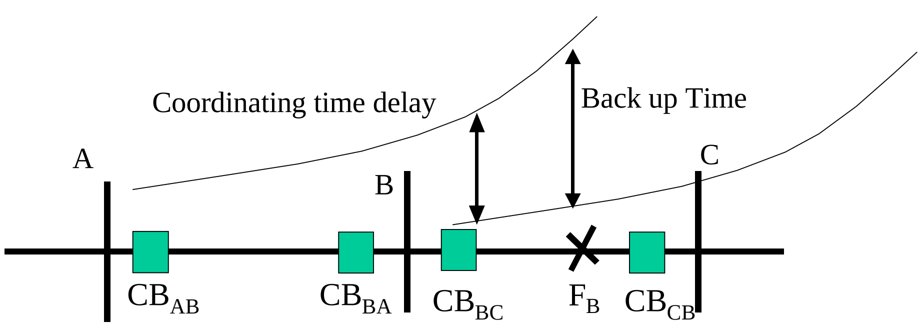

Figure 32: Remote Back-up, directional over-current relays one-line diagram.

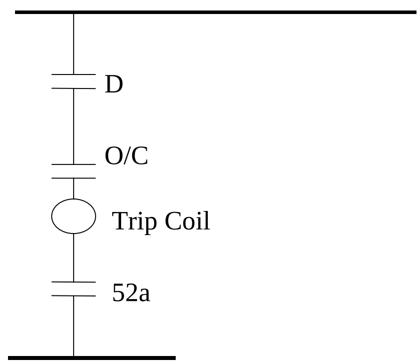

Figure 33: Logic schematic for directional over-current relay.

The next table describes Hidden Failure Modes for directional over-current relays used to provide Back-up protection for transmission lines. The organization of the table is based on faults that are involved with CB_{AB} unwanted trips. It should be clear that these trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at side A of the transmission line. The same methodology applies for relays located at side B.

XXVII. Directional unit contacts always closed.

XXVIII. Over-current unit contacts always closed.

PEFD-A	Consequence
XXVII	Unwanted trip, CB_{AB} may trip for a fault in the wrong direction.
XXVIII	Unwanted trip, CB_{AB} may trip for F_B without the Back-up time delay. Relays coordination is lost.

4.5.3. Breaker Failure Relays

Breaker failure relays, as mentioned before, are a subset of local Back-up protection and they are specifically for cases where the circuit breaker has failed. The logic schematic is shown in Figure 34.

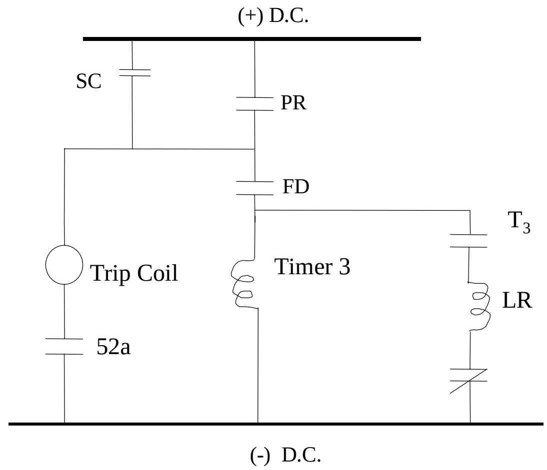

Figure 34: Logic schematic for a breaker failure relay.

Logic schematic elements

Element	Description	Function
SC	Seal in contact	By-pass the relay closing contact
PR	Protective relays	Close the CB tripping circuit
FD	Fault detector	Monitors the presence of fault current
LR	Lockout relays	Trips other circuit breakers
Timer 3	Timer coil	Close timer contact after a preset delay
T_3	Timer 3 contact	Sets time delay
52a	CB auxiliary contact	Monitor breaker status

The sequence of events based on Figure 34 is described as follows:

- The first event is a fault, which is detected by the protective relays PR, closing the tripping circuit to the circuit breaker.
- The fault current presence makes the fault detector to operate and energize the timer 3 coil. It is important to note that timer 3 coil will be de-energized with the absence of fault current, which means that the circuit breaker has operated successfully.
- A time countdown was started by timer 3 coil when fault detector was picked up.

If timer 3 coil is energized long enough and this time countdown goes to zero; the circuit breaker has failed to clear the fault. This condition makes T_3 contacts to close with the consequence of tripping all required circuit breakers to clear the fault.

The next table describes Hidden Failure Modes for breaker failure relays. The organization of the table is based on faults (F_A) that should be cleared by the circuit breaker whose trip coil is shown in Figure 34.

It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below, these unwanted trips are all circuit breaker trips required to remove the fault, clearly different from the failed circuit breaker. This set of breakers required to clear the fault is called "other breakers". The severity of the unwanted trips would depend on the location of the failed circuit breaker; it may be located on buses, transmission lines, generators, etc.

The relay(s) analyzed are the ones located at one specific station A for instance, and the same methodology applies for relays located at another station.

XXIX. T_3 contacts are always closed.

Case for F_A PEFD-A XXIX, T_3 contacts are always closed			
Operated Relays	Consequences at station A	Consequences at others stations	Final Result
PR FD Timer 3	PR activation sends trip signal to circuit breaker T_3 contacts are always closed	T_3 contacts are always closed, so "other breakers" are opened instantly	An unwanted trip, "other breakers" were opened regardless of the initial breaker operation result.

5. Chapter 5 Special Protection Systems, Schemes and Hidden Failure Modes

5.1. Special Protection Systems

Special Protection Systems (SPS) actions affect a wide-area of the network. The operation of these protection systems involves much more than an equipment disconnection from the Power System due to malfunction or a risky operation. The Power System integrity relies on these schemes, whom gather data coming from several parts of the network, analyze it, and detect system phenomena that is not recognizable by Primary protection or Back-up protection systems [3].

Special Protection Systems are defined in [13] as: "A protection scheme that is designed to detect a particular system condition that is known to cause unusual stress to the Power System, and to take some type of predetermined action to counteract the observed condition in a controlled manner."

From the previous definition, it can be said that these Special Protection Systems are activated as a "remedy" for contingencies that would jeopardize the Power System integrity and reliability. Remedial Action Schemes and Special Protection Systems are terms that can be used interchangeably.

There are critical differences between SPS and Primary or Back-up protection. The first difference is the protection approach or focus. SPS are designed to protect the Power System itself, where as Primary or Back-up protection are applied to the Power System elements, such as transmission lines, buses, etc. Another difference is the fact that SPS are tailor made designs. This means that SPS are perfectly fitted to a condition, preference, or purpose; they are made as if made to order. The specific requirements of the system, the Power System itself and the system conditions are some of the several considerations involved in the design of SPS.

There are not "standard" designs for SPS; however, there are guidelines and minimum requirements, which have to be included in the SPS planning stage [14].

For Special Protection Systems, and regarding to the statement mentioned in section 2.2.1, a "failure to trip" event will be considered Hidden Failure. The argument, in which we justified that a "failure to trip" will not be considered a Hidden Failure is not applicable for Special Protection Systems, because of these systems configurations and characteristics. So, once again, when we are talking about an incorrect operation of an SPS an unwanted trip or "failure to trip" event will be considered Hidden Failure. Clearly, the definition and sequence of events mentioned in Chapter 2 will be taken in account in order to determine if the event is catalogued as Hidden Failure.

The variety of Special Protection Systems is quite considerable. A joint effort between IEEE and CIGRE finished in the publication of a survey on Special Protection Systems in 1992 [13]. This paper mentioned that 111 different kind of Special Protection Systems were presented by utilities worldwide. We will study five SPS: Out of Step Relaying, Under-Frequency Load Shedding, Under-Voltage Load Shedding, Generation Rejection and Load Rejection. Four of these five schemes represent, according to [13], 43.3% of the total Special Protection Systems in use.

5.2. Out of Step Relaying

Out of Step Relaying is the first SPS to be described. Its "market share" is up to 2.7% according to [13].

An Out of Step condition may be the first symptom for a loose of the Power System synchronization; therefore these Power System conditions must be identified as soon as possible in order to avoid wide-area outages and equipment stress. The Out of Step conditions, according to [15], result from the system instability which may be caused by large faults, stressed Power System operating conditions, a sequence of contingencies, etc.

The loose of synchronism may take diverse forms and depends on each system, the operation conditions, and the type and disturbance characteristics. Normally, the Power System instability starts a two-frequency Out of Step condition, in which one of the areas gains acceleration while the other one is decelerating [15]. This situation may occur during a fault near a generation station, where this station gets accelerated and the rest of the system is decelerated as a result of the generation deficit.

As it was mentioned previously, the zones in which an Out of Step condition may occur depends on several issues. The Out of Step areas may be a generator against the rest of the system, or one Power System area versus another one, etc. These areas may include several Power System elements, such as transmission lines, generators, buses, etc. This agrees with our note in which we stated that SPS have a system-oriented protection philosophy.

Power swings and Out of Step conditions bring with them large excursions of the Power System parameters, such as voltage, current and power [16]. Protective relays utilize these system parameters and may react inappropriately disconnecting system elements as a consequence of this voltage, current and power oscillations. The next section will show how this fact is considered.

5.2.1. Out of Step Protection implementation using protective relays

The implementation of Out of Step protection is achieved by the use of Out of Step relays (OSR), which are design to detect abnormal system conditions, classify them, and take appropriate actions depending on this abnormal condition classification.

Figure 35 shows a block diagram that may help to better understand Out of Step relay actions.

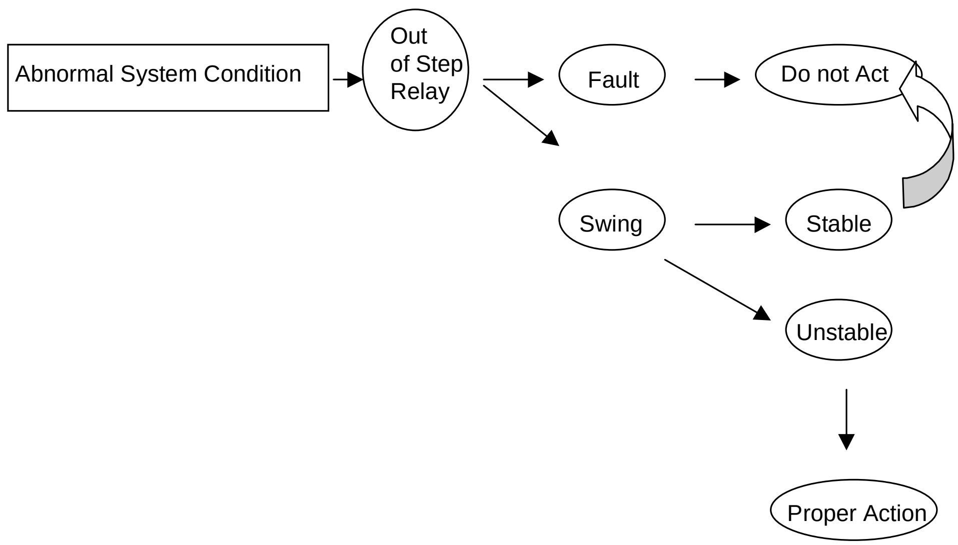

Figure 35: Out of Step Relay Actions.

From Figure 35 it can be implied that an Out of Step relay must be able to distinguish between a fault and a swing. If the abnormal system condition is a fault, Out of Step relays must be inoperative, leaving to the responsibility of clearing the "event" to the protective relays. On the other hand, if a swing is detected, Out of Step relays must be capable to classify stable from unstable swings. Stable swings are classified as oscillations small enough that the Power System itself is able to absorb and attenuate, so for stable swings OSR must be inoperative. For the latter case, unstable swings, the Out of Step relays must initiate "proper action".

"Proper action" is referred to the fact that OSR must perform actions like tripping lines, blocking lines, blocking re-closures, etc. All of these pre-design modes of operation come to the principal objective of Out of Step Relaying; to separate the system in such a way that generation and load on each side of the split are reasonably balanced [9].

The Out of Step protection logic regarding to the lines to be tripped, the lines to be blocked, and so on, comes from a detailed study of the system and on the expected system topology. Contingencies are simulated on an electromagnetic transient program and the Power System response is observed. Several cases must be ran and the result of these simulations represents, to some extent, the actual Power System behavior. Based on the simulation outputs and results, the locations for the Out of Step blocking and Out of Step tripping relays are determined. The physical location of the Out of Step tripping relays will be the separating points of the system, where the Out of Step relay operation will trip the lines. Out of Step blocking relays will be placed at the locations where the system must remain connected during the Out of Step condition, in which an Out of Step relay operation will block the line from tripping. The specific Out of Step relay settings are also applied based on the simulated system response, providing them with the ability to differentiate and classify events. These settings are specifically suitable for the Power System being analyzed, assumed system topology, operational conditions, etc. Out of Step protection is an SPS, and its design and implementation is tailor made, i.e., user and system specific.

Before a decision is made on the requirement and implementation of an Out of Step protection scheme, a Power System study should be performed in order to determine the existence of constrains related to rotor angle stability [16]. The utopia in Power Systems is the network that does not goes unstable, the perfect one, which has a lot of redundant paths, is immune to all credible contingencies and is always able to recuperate from all kind of disturbances. Real Power Systems differ from the perfect network, and Out of Step protection schemes are employed.

The classic Out of Step concentric circle scheme using distance relays will be presented next [9]. Figure 36 shows this scheme which consists of an inner and outer protective elements, which are normally two distance relays. The inner circle, 21-2 $_{3F}$, is an overreaching element for the protected line. The outer device is a blocking relay, ZOS.

Time is used in order to classify the events as swings or faults. This time consideration is based on the fact that during swings the apparent impedance; i.e., the voltage/current ratio will change accordingly with the inertia of the system and the magnitude of the power oscillations. In case of electrical faults, the apparent impedance coming from steady state to the faulted condition will also change, but much faster than in the swing case. Electrical faults will result in an "almost" instantaneous operation of relays ZOS and 21-2 $_{3F}$. For swings, ZOS will always operate first, and later on, 21-2 $_{3F}$ may or not operate depending on the swing intensity and characteristics.

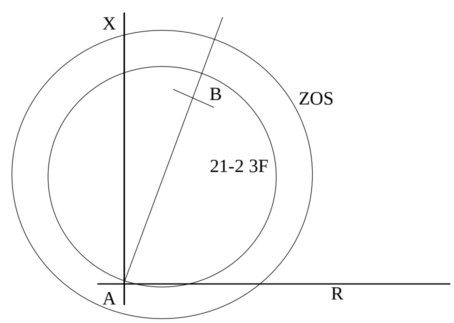

Figure 36: Concentric Circle Scheme for O.S. Relaying.

Figure 37 shows a relay logic schematic used for Out of Step blocking, under the concentric circle scheme. This relay is a KS Westinghouse. It should be important to note that the output of this relay is to block the line tripping if and only if a swing is detected. Due to the specific characteristics of this relay, the stable and unstable swings will have the same result, to block the line from tripping, so this scheme does not have to differentiate unstable from stable swings. Swings will be detected by counting the time between the ZOS to 21-2 $_{3F}$ operations. If 60 milliseconds, which is the OS timer delay, or more have passed between these events, a swing is detected and the relay will block the line trip. For faults this OSR is inoperative and allows the Primary protection to trip the line.

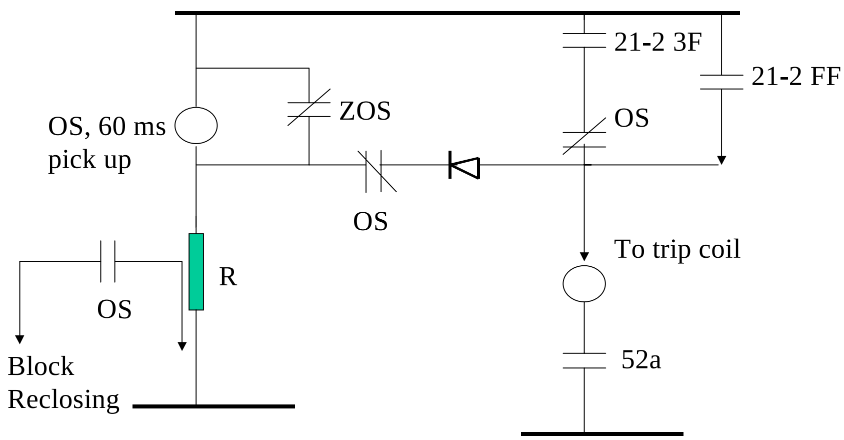

Figure 37: Logic schematic for the OS Blocking relay, KS (68).

Logic schematic elements

Element	Description	Function
ZOS	Outer distance relay	Detects faults or swings firstly
OS	Timer coil	Change OS contact status, after time delay
21-2 $_{3F}$	Inner distance relay	Detects faults or swings secondly
21-2 $_{FF}$	Distance relay	Detects phase-phase faults
52a	CB auxiliary contact	Monitor breaker status

The sequence of events based on Figure 37 will be described next. The events will be classified for faults and for swings.

A typical sequence of events for a fault is:

- The fault is detected by ZOS and 21-2 $_{3F}$ and they operate almost instantaneously. ZOS operation has energized the OS timer, and this started a time countdown.
- Since ZOS and 21-2 $_{3F}$ have operated almost instantaneously, there is not time for OS time countdown to go to zero and operate. So, OS contacts can not change the status, and the line is tripped because 21-2 $_{3F}$ operated and OS contacts remained closed.

For unbalanced faults, 21-2 $_{1F}$ trips the line directly.

A typical sequence of events for a swing is:

- The fault is detected by ZOS firstly.
- Timer OS started a time countdown when ZOS operated.
- If the time countdown has finished and 21-2 $_{3F}$ have not picked –up, a swing is identified and OS contacts change the status.
- No trip may occur because OS contacts are now open. So the Out of Step relay has operated, blocking the line from tripping.

The next table describes Hidden Failure Modes for this Out of Step relay. The organization of the table is based on a swing (S_A), for which the OSR must operate, blocking the line trip. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at one specific station A for instance, and the same methodology applies for relays located at another station.

XXX. OS contacts can not pick-up.

Case for S_A PEFD-A XXX, OS contacts can not pick-up		
Operated Relays	Consequences at station A	Final Result
ZOS OS 21-2 $_{3F}$	ZOS is picked up, OS coil is energized, and time countdown has finished, but due to PEFD-A on OS, the normally closed contacts remained closed, and when 21-2 $_{3F}$ operates…	An unwanted trip, the line should not had been disconnected. Out of Step blocking relay made a miss-operation, since it did not block the line trip.

An Out of Step tripping relay will be presented next, which is also based on the previously mentioned concentric circle scheme. This concentric circle scheme is shown again in Figure 38.

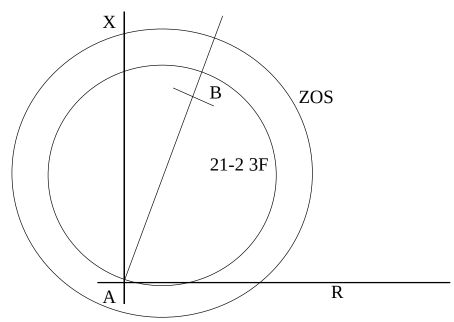

Figure 38: Concentric Circle Scheme for O.S. Relaying.

Figure 40 shows the relay used for Out of Step tripping under the concentric circle scheme. This relay is a KST Westinghouse. It should be important to note that the output of this relay is to trip the line. This relay will detect an Out of Step condition and will trip the line in order to split the Power System in two or more regions with a reasonable balance of load and generation. The relay will operate and trip the line if and only if an unstable swing is detected. Due to the specific characteristics of this relay, the stable and unstable swings will have a different result; therefore, this relay has to differentiate unstable from stable swings. By counting the time the relay 21-2$_{3F}$ remains operated stable and unstable swings are identified. A swing that energizes 21-2$_{3F}$ during 100 ms or more is considered unstable. For faults this OSR is inoperative.

Figure 39 shows a sketch of different swings. Swing 1 is very small and has no consequences in the concentric scheme since ZOS does not operate. Swing 2 would be stable if its trajectory inside 21-2 $_{3F}$ would last a certain period of time. Swing 3 would be unstable if its trajectory inside 21-2 $_{3F}$ would last more than a certain period of time.

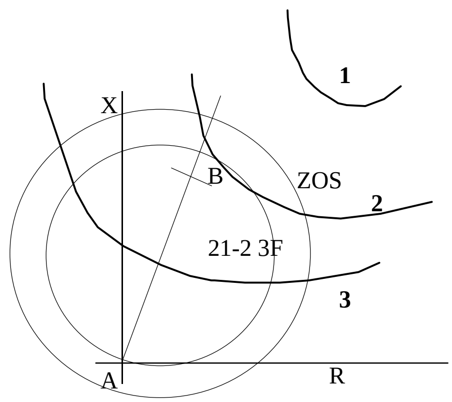

Figure 39: Stable and Unstable Swings.

This KST relay uses the same logic applied in the KS relay in order to differentiate swings from faults. Some other requisites are applied for the tripping logic, as will be seen in the sequence of events.

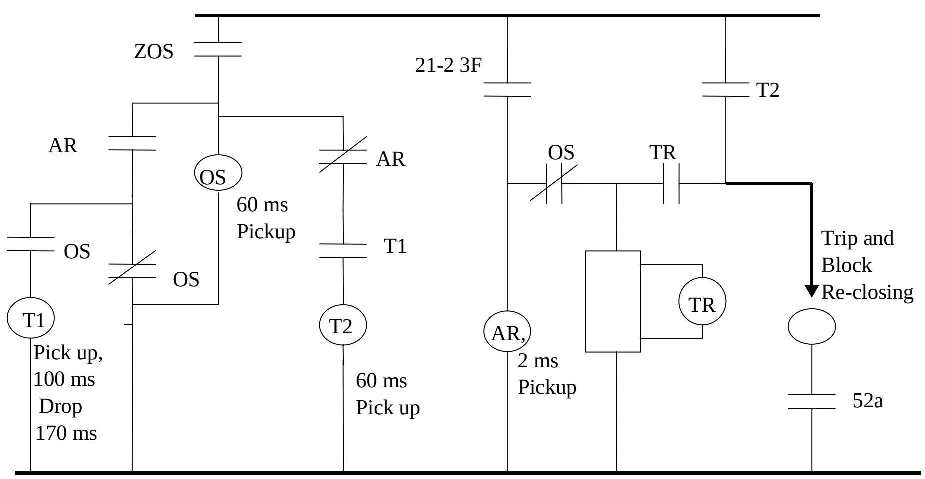

Figure 40: Logic schematic for the OS Tripping relay, KST (68).

Logic schematic elements

Element	Description	Function
ZOS	Outer distance relay	Detects faults or swings firstly
OS	Timer coil	Change OS contact status, after time delay
21-2 $_{3F}$	Inner distance relay	Detects faults or swings secondly
21-2 $_{1F}$	Distance relay	Detects phase-phase faults
52a	CB auxiliary contact	Monitor breaker status
A_R	Timer coil	Change AR contact status, after time delay
T_1	Timer coil	Change T_1 contact status, after time delay
T_2	Timer coil	Change T_2 contact status, after time delay
T_R	Timer coil	Change T_R contact status, after time delay

The sequence of events based on Figure 40 will be described next. The events will be classified for faults, stable swings and unstable swings.

A typical sequence of events for a fault is:

- The fault is detected by ZOS and 21-2 $_{3F}$ and they operate almost instantaneously.
- AR shorts OS timer and T_R is energized by 21-2$_{3F}$ operation.
- T_R closes its contacts, tripping the line. Since ZOS and 21-2 $_{3F}$ have operated almost instantaneously, OS timer is not energized. So, OS contacts can not change the status, and the line is tripped because 21-2 $_{3F}$ operated and OS contacts remained closed.

A typical sequence of events for a stable swing is:

- The fault is detected by ZOS firstly.
- Timer OS started a time countdown when ZOS operated.
- If 21-2 $_{3F}$ has not operated after 60 ms, a swing is detected, the time countdown is terminated and OS contacts change the status.
- As the swings moves in the origin, 21-2 $_{3F}$ operates, energizing timer $A_{R.}$ T_1 is

energized.

- Since 21-2 $_{3F}$ remain operated for less than 100 ms, a stable swing is detected, and T_1 coil does not operates.
- If T_1 does not operate, T_2 will not operate, and the Out of Step relay does not operates.

A typical sequence of events for an unstable swing is:

- The fault is detected by ZOS firstly.
- Timer OS started a time countdown when ZOS operated.
- If 21-2 $_{3F}$ has not operated after 60 ms, a swing is detected, the time countdown is terminated and OS contacts change the status.
- As the swings moves in the origin, 21-2 $_{3F}$ operates, energizing timer $A_{R.}$ T_1 is energized.
- If both ZOS and 21-2 $_{3F}$ remain operated for 100 ms, an unstable swing is detected, and T_1 coil operates.
- As the swing moves out, the first reset comes from 21-2 $_{3F,}$ and A_R is de-energized. T_2 coil is energized as long as ZOS remains picked-up.
- If ZOS remains closed for 50 ms, T_2 is operated. T_2 contacts change its status, and the Out of Step relay is operated, tripping the line.

The next table describes Hidden Failure Modes for this Out of Step relay. The organization of the table is based on a stable swing (S_A), for which the OSR must not operate. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at one specific station A for instance, and the same methodology applies for relays located at another station.

XXXI. T_1 contacts are always closed.

Case for S_A PEFD-A XXXI, T_1 contacts are always closed.		
Operated Relays	Consequences at station A	Final Result
ZOS OS T_1 T_2	ZOS is picked up, OS coil is energized and due to PEFD-A on T_1, T_2 is incorrectly energized. Time countdown has finished and 21-2 $_{3F}$ had not operated, so OS contacts change and at the same timeT_2 operates. T_2 contacts are now closed and…	An unwanted trip, the line should not had been disconnected. Out of Step tripping relay made a miss-operation, since the swing was stable and it should not have operated.

5.3. Under-Frequency Load Shedding

According to the 1992 survey [13], 8.2 % of the total SPS in use are Under-Frequency Load Shedding programs (UFLS). NERC planning standards [14], requires for each reliability council a coordinated and automatic Under-Frequency Load Shedding program in order to minimize the risk of a wide-area disturbance, generating equipment damage, among others.

The main objective of an Under-Frequency Load Shedding program is to identify a lack of generation in the system and perform actions (shed load) in order to bring the generation / load ratio to a safe value. Since the Power System generators operate in synchronism, any mismatch between the load and generation will be reflected in a frequency change. This frequency change is uniform over a wide-area on the Power

System [17]. During a sudden mismatch between load and generation, governors may be incapable to provide support within the time requirements, and rapid load shedding, applied at distribution feeders has to be implemented in order to bring the frequency back to a normal value [18].

The phenomena of frequency instability, i.e., when the Power System frequency moves above or below from the nominal value, may be caused by a number of contingencies, where the post fault condition leaves the system with an important mismatch of generation and load. The characteristics of the specific contingency or combination of contingencies and the integration of the Power System in terms of local generation versus local consumption, among other issues, will determine the occurrence of a frequency instability condition. Contingencies may take the form of removal of generators, transmission lines, and transformers, among others.

5.3.1. UFLS implementation using protective relays

The implementation of UFLS programs is a very serious task, since opportunity costs are associated with them and customer complaints may arise as a consequence of service interruptions [18].

As it was mentioned in section 5.2, before a decision is made on the requirement and the implementation of an UFLS program, Power System simulations should be performed in order to determine if there is a frequency instability condition for any contingency or set of contingencies.

From the Power System simulation outputs and results, the Power System zones where there is a lack of generation will start to present an under-frequency condition. Based on this, under-frequency relays may be used in order to shed load, and compensate the generation deficit.

The specific under-frequency relay settings are applied based on the simulated system response. The decision on the under-frequency relay settings is related to the system being analyzed and depends on factors like the rate of frequency change, the load-frequency change, the system inertia, among others. The frequency levels that may create a risky condition to the equipment or the system are selected. The load should be shed at those frequency values. UFLS is an SPS and its design and implementation is tailor made, i.e., user and system specific.

The basic steps in a UFLS program are as follows [19]:

- Determine the amount of load to be shed
- Select the load to be disconnected from the system
- Determine the time steps of load shedding
- Determine the frequency level(s) in which load shedding will start

Figure 41 shows a typical logic schematic for an UFLS program. This Figure represents the relaying implementation to be applied on the distribution feeder on a specific substation. The scheme to be analyzed is the classical UFLS program, and does not incorporates neither communication channels or remote information. It receives local information and acts locally.

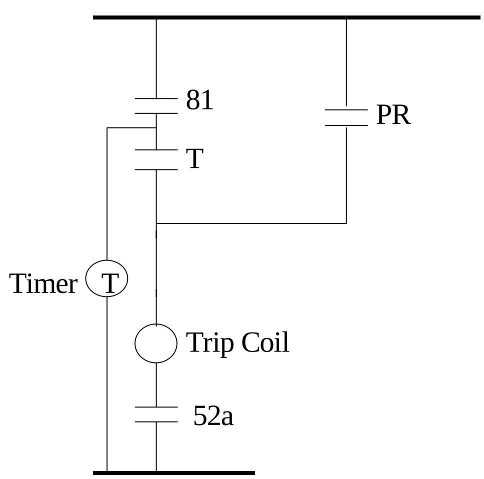

Figure 41: Under-Frequency Load Shedding logic schematic.

Logic schematic elements

Element	Description	Function
PR	Protective relays	Detects electrical faults
T	Timer coil	Change T contact status, after time delay
81	Under-frequency relay	Detects an under-frequency condition
52a	CB auxiliary contact	Monitor breaker status

From Figure 41, it is important to note that this UFLS logic schematic incorporates the protective relays, which are responsible of clearing electrical faults, as well as the under-frequency relays, which are in charge of tripping the circuit breaker when the frequency level has reached a risky value. This UFLS program is automatic, i.e., it does not depend on the Power System operator actions, and the load is shed when a risky condition is present. The operation of the under-frequency relay will not trip the circuit breaker until the T contacts have closed its normally open contacts. This time delay is used to add security to the UFLS program or to coordinate the different load blocks to shed for the different substations.

The next table describes Hidden Failure Modes for this UFLS program. The organization of the table is based on a frequency excursion (FE_A), for which the UFLS program should not trip the circuit breaker. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at one specific station A for instance, and the same methodology applies for relays located at another station.

XXXII. T contacts are always closed

Case for FE_A PEFD-A XXXII, T contacts are always closed		
Operated Relays	Consequences at station A	Final Result
81 T	The operation of the under-frequency relay puts the tripping trajectory dependent on the T contacts status, since T contacts are always closed…	An unwanted trip, the UFLS program should not have operated. Time coordination was lost.

5.4. Under Voltage Load Shedding

NERC planning standards [14] requires, for each reliability council, an Under-Voltage Load Shedding program, which automatically shed load as a result of under-voltage conditions that may jeopardize the Power System integrity.

Voltage stability is defined in [20] as the ability of a certain system to maintain the voltage level so that when the load admittance is increased, load power will increase, and so that both voltage and power are controllable. This same reference defines voltage collapse as the process by which voltage instability leads to a very low voltage profile in a significant part of the system.

The phenomena of voltage instability may be caused by a number of contingencies, where the post fault condition leaves the system with an important lack of reactive power. The characteristics of the specific contingency or combination of contingencies and the Power System conditions, among other issues, will determine the occurrence of a voltage instability condition. Contingencies may be the removal of generators, transmission lines, transformers, changes in load demands, slow clearance of faults, among others [19]. It is important to note that some contingencies may have severe consequences with respect to voltage instability, such as the removal of a generator reactive support, or a transmission line reactive power injection.

According to [17] voltage collapse main symptoms are low-voltage profiles, heavy reactive power flows, inadequate reactive support and heavily loaded systems. Heavily loaded systems may be a vulnerable condition in terms of voltage collapse, and the called domino effect may worsen the situation. It should be clear that the amount of reactive power that the transmission system needs depends on the system conditions. A transmission line reactance absorbs reactive power; where as the capacitance of the line produces reactive power. At peak hours, when the transmission system is at the maximum capacity, the transmission line absorbs the maximum amount of reactive power. In these cases, there is a lack of reactive power and shunt capacitors (reactive power producers) are installed in order to increase the system voltage to the nominal value. On the other hand, during off-peak power transfers, the transmission lines reactance absorbs much less reactive power, where as the capacitance of the lines, roughly produces the same amount of reactive power. Under these conditions, there is excess in reactive power, and shunt reactors are connected in order to absorb this excess and decrease the system voltage to a nominal value.

For heavily loaded systems, and during peak hours, transmission lines consume big amounts of reactive power, and the reactive power production is basically the same. If there is a lack of reactive support coming from the reactive power sources, the voltage profiles may start to decline, and as a result the production of reactive power from transmission lines will decrease, since its proportional to the square of the voltage. In the worst case, this condition may result in voltage instability or voltage collapse.

5.4.1. UVLS implementation using protective relays

There are several actions and recommendations in order to prevent a voltage instability condition; reference [17] presents these issues in detail. The objective of this section is to describe the last and final remedial action, which avoids a voltage collapse condition: Under Voltage Load Shedding. The load curtailment will drop the reactive power demand bringing the voltage levels back to nominal values. The load shedding is the ultimate alternative since it brings opportunity costs and, as mentioned earlier, may arise customer complaints due to the electric service interruptions [17].

As it was mentioned in section 5.3, before a decision is made on the requirement and the implementation of an UVLS program, Power System simulations should be performed in order to determine if there is a voltage instability condition for any contingency or set of contingencies.

From the Power System simulation outputs and results, the Power System zones that turned out to be voltage vulnerable are identified. During contingencies, those zones will present a low voltage profile. Based on this, under-voltage relays may be used in order to shed load, and bring the voltage level back to a safe value. During voltage instability conditions, the voltage levels are not spread evenly and their magnitudes are different over a wide-area. [17]

The specific under-voltage relay settings are applied based on the simulated system response. The decision on the under-voltage relay settings is related to the system being analyzed and the system voltage profile. The voltage levels that may create the risk of voltage instability are selected. The load should be shed at those voltage values. UVLS is an SPS and its design and implementation is tailor made, i.e., user and system specific.

The basic steps in a UVLS program are as follows [19]:

- Determine the amount of load to be shed
- Select the load to be disconnected from the system
- Determine the time steps of load shedding
- Determine the voltage level(s) in which load shedding will start

An UVLS program may take several configurations depending on the system where it is going to be applied. Generally, it may be classified as distributed or concentrated [19]. A distributed UVLS program is implemented in specific Power System locations and incorporates actions based on local data. Basically its function is to shed load when a risky local under-voltage condition is present. The concentrated program has a broader area of action; it collects information from several system points, and takes a decision after the collected data is analyzed. In the concentrated UVLS programs, communication channels are key elements employed in order to get the data from remote locations. These communication paths may be part of the Energy

Management System or they may be designed and used for the concentrated UVLS program only.

Concentrated UVLS programs are extremely system oriented. These programs may utilize some other elements different than under-voltage relays [19]. The remote equipment status and generators reactive outputs may be part of the information that is taken in account in concentrated UVLS programs.

A typical distributed UVLS logic schematic is shown in Figure 42.

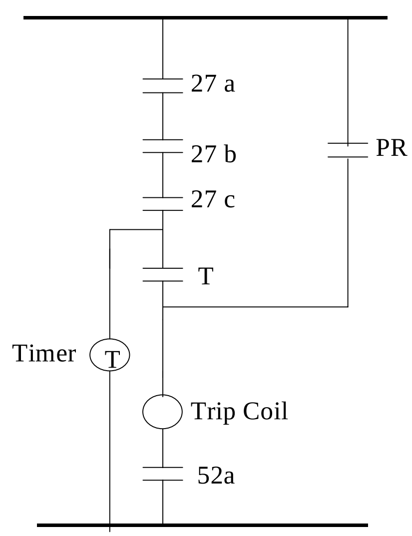

Figure 42: Distributed Under-Voltage Load Shedding logic schematic.

Logic schematic elements

Element	Description	Function
PR	Protective relays	Detects electrical faults
T	Timer coil	Change T contact status, after time delay
27 a	Under-voltage relay	Detects an under-voltage condition for phase a
27 b	Under-voltage relay	Detects an under-voltage condition for phase b

27 c	Under-voltage relay	Detects an under-voltage condition for phase c
52a	CB auxiliary contact	Monitor breaker status

From Figure 42, it is important to note that this distributed UVLS logic schematic incorporates the protective relays, which are responsible of clearing electrical faults, as well as the under-voltage relays, which are in charge of tripping the circuit breaker when the voltage level has reached a risky value. This UVLS program is automatic, i.e., it does not depend on the Power System operator actions, and the load is shed when a risky condition is present. Under-voltage relays should not operate for transient voltage depressions caused by electrical faults, and this is accomplished by a time delay. The operation of the under-voltage relays will not trip the circuit breaker until the T contacts have closed its normally open contacts. This time delay should be short enough to avoid a voltage collapse and long enough to prevent a false trip, caused by the above mentioned transient voltage depressions [19].

Distributed UVLS programs should respond to balanced under-voltage conditions, and one form to achieve this is to connect each single-phase under-voltage relay contacts in series [21]. Figure 42 shows this arrangement, which add security to the UVLS program.

The next table describes Hidden Failure Modes for this distributed UVLS logic schematic. The organization of the table is based on a voltage depression (VD_A), for which the UVLS program should not trip the circuit breaker. It should be clear that unwanted trips would result if any of the relays suffer a PEFD-A assumed as it is indicated below. The relay(s) analyzed are the ones located at one specific station A for instance, and the same methodology applies for relays located at another station.

XXXIII. T contacts are always closed

Case for VD_A PEFD-A XXXIII, T contacts are always closed		
Operated Relays	Consequences at station A	Final Result
27-a 27-b 27-c T	The operation of all single-phase under-voltage relays puts the tripping trajectory dependent on the T contacts status, since T contacts are always closed…	An unwanted trip, the UVLS program should not have operated. Time coordination was lost and the circuit breaker operated for a transient condition.

5.5. Generation Rejection and Load Rejection

Generation Rejection and Load Rejection are the most used Special Protection Systems, with participation of 21.6 % and 10.8 % respectively according to [13].

A Generation Rejection scheme is an SPS in which, for a certain contingency or set of contingencies, a part of the generation is disconnected from the system in order to keep the Power System integrity. Load Rejection, in an analogous way, is referred to the actions that shed load for a specific contingency or set of contingencies.

Even though, Load Rejection and Under-Frequency Load Shedding schemes have the same final result, the latter scheme monitors the system frequency and their operations are allowed only if this parameter is under a pre-established value. Load Rejection shed the load in an automatic and premeditated way; the triggering issue is the occurrence of a contingency or a set of contingencies.

As it has been stated on the previously mentioned SPS, Power System simulations are key ingredients for the design of these systems. All combinations of contingencies are analyzed and the ones resulting in a risky Power System operation are set aside. The risky operation may take several forms such as angular instability, frequency instability, voltage problems, overloads, etc. The contingencies that the Power System can not withstand without violating a certain pre-defined criteria are selected and the occurrence of these events will trigger the Generation Rejection or Load Rejection schemes, according to a pre-designed logic.

Several reasons support the existence of a Generator Rejection or Load Rejection schemes and these are related to the specific requirements and conditions of the Power System being analyzed. It is difficult to generalize the benefits of the applications of these SPS; nevertheless they usually bring improvements under the technical as well as under the economical point of view.

A number of Generation Rejection and Load Rejection applications are going to be described next, these schemes are implemented by utilities in USA and Canada.

a) The Bruce Generation and Load Rejection Scheme, Ontario Hydro, Canada.

Reasons of the SPS implementation.

Delays on the transmission lines construction project motivated the staff of Ontario Hydro in developing a Generation and Load Rejection scheme to maximize the use of the available transmission system. Additionally, North Power Reliability Council required double contingency criteria when the Power System condition was considered “normal”. This criterion could not be obtained without the application of the Bruce Load and Generation scheme [22]. This scheme is a combination of Generation and Load Rejection, since for special contingencies the amount of generation disconnected from the Power System is so high that a certain amount of load must be shed at the same time in order to compensate for the lack of generation.

Benefits of the SPS implementation.

Generation and Load Rejection SPS basically allows the Power System transmission lines to transport more power. This fact is shown in reference [23], which defines two terms: a transmission capacity limit without Generation Rejection and transmission capacity limit with Generation Rejection. Clearly the last one is bigger, since more power will be carried by the transmission lines, and in the occurrence of a certain contingency or a set of contingencies, some generation will be dropped from the system, in order to balance the temporary lack of the power transmission corridor. The implementation of the scheme was a very good alternative since new transmission lines projects were deferred for several years [24].

b) Fast Acting Load Shedding (FALS), Florida Power and Light Company, USA.

Reasons of the SPS implementation.

The main objective of this SPS is to increase the Power System security. Florida's system main risk is the occurrence of a double contingency on big generation stations. Under this scenario the post contingency condition requires a system separation and this last issue interrupts the considerable amounts of power imports. The conditions of the Florida peninsula were studied and the FALS was design to shed load under the detection of a system wide disturbance preventing the possibility of a blackout [25].

Benefits of the SPS implementation.

The implementation of this SPS incremented the Power System security, and has allowed to the Florida Peninsula to continue with its power imports. FALS co-exists with other protection systems such as UFLS programs and Out of Step relaying [25].

c) Generation Shedding scheme for the Jim Bridger Steam Electric Plant.

Reasons of the SPS implementation.

Figure 43 shows the physical arrangement of the Jim Bridger Generation station. All six lines are important for the system stable operation, any loss of these lines blocks the power flow from the generation station to the transmission system, creating an excess of generation at Jim Bridger. These contingencies may result in system instability, depending on the generation being produced at the contingency time [26]. This SPS was developed to shed generation by disconnecting one or more units from the Power System, depending on the number of lines that are out of the transmission system and the total generation at Jim Bridger.

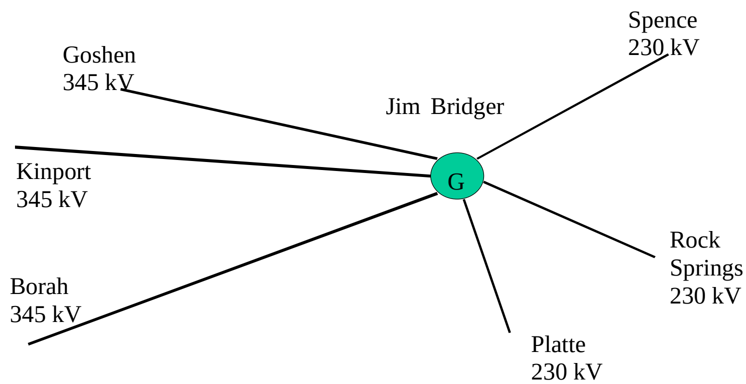

Figure 43: Physical arrangement of the Jim Bridger Generation Station.

Benefits of the SPS implementation.

Directly from [26], the benefits of this SPS are the higher generation and transmission transfer levels, an enhancement in the amount of power that can be generated and delivered through the transmission system.

5.5.1. Generation and Load Rejection implementation using protective relays

The implementation of Generation and Load Rejection schemes normally employs additionally to the protective relays, control equipment such as Programmable Logic Controllers. Since these schemes reactions affects a wide-area of the system, remote information is required and it is obtained by communication channels, that may be incorporated within the Energy Management System, or special dedicated leased lines.

The amount of information required for the correct operation of these schemes is extensive, and a Hidden Failure Modes examination would require detailed information of the logic behind each scheme. As it has been pointed out in this Chapter, these systems are tailored made and there is some "natural" reluctance from the utilities to share detailed information of their Generation and Load Rejection schemes. Nevertheless, the general schematics and logic behind the Jim Bridger

Generation shedding scheme has been obtained and will be briefly discussed next. Based on the information obtained in [26], possible Hidden Failure Modes will be included.

5.5.1.1. Jim Bridger SPS, possible Hidden Failure Modes.

The primary functions of this scheme are to determine if the disconnection of one or more units is required, and then make a selection of the appropriate units to shed [26]. The scheme is configured by two independent systems; the first one is called RAS-A, is microprocessor-based, and operates as the main scheme. RAS-B is electromechanical and works as a duplicate Back-up, it has the responsibility of protecting the Power System if RAS-A has failed or is out of service.

Some logic characteristics and the relays employed are described next.

a) Watt transducers and power level detectors are employed. By doing this, the information regarding to the actual generator output and the power flow in the transmission lines is obtained.
b) The critical part in the logic of the scheme is the section in which the information regarding to each unit power output, the status of the transmission lines, i.e., relayed or open, the neighbor system status, and some other parameters are gathered. The total amount of generation being produced and the status of the lines determine the number of units to be disconnected from the system.
c) Several conditions have to be met before sending a control signal to disconnect a generation unit. An interesting issue is the fact that if one of the lines has relayed, the scheme differentiates what kind of fault did occur. The tripping logic requirements are different for a transmission line phase-ground fault than for a phase-phase fault. This is based on the fact that phase-ground faults leave 2 healthy phases, which still represents a possible power corridor. For phase-phase faults, this power corridor is narrower and more generation must be shed. This logic is such that for an specific generation power level, a transmission line phase-phase fault would require to disconnect a unit from the system, where as

for a phase-ground fault would not.

The possible Hidden Failures Modes analysis will be performed to the RAS-B, the electromechanical scheme for which reference [26] shows some logic schematics.

Possible Hidden Failures

A possible Hidden Failure Mode would be the case where the transmission lines fault indicator relay contacts have a Protection Element Functionality Defect and are permanently closed. From Figure 44, this condition would remain undetected until the power flow relays close their contacts, at a certain power value. The consequence of this Hidden Failure Mode would be an unwanted trip, since the system would loose a generator unit with all transmission lines on service. In an analogous way, if a PEFD-A takes place on the power flow relay, closing its contacts permanently, regardless to the power flow value, would be a Hidden Failure Mode. A fault occurring at low power flow conditions would create an unwanted generation trip.

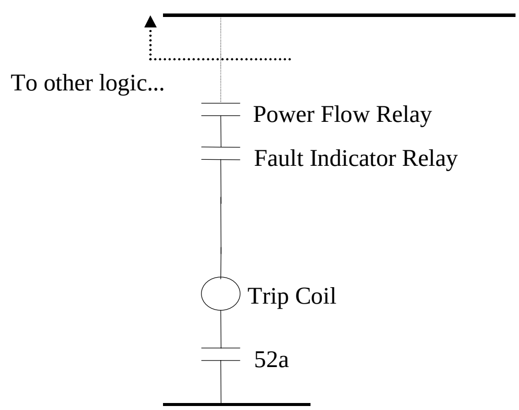

Figure 44: Possible Hidden Failures Modes for the Jim Bridger Generation Station.

Another issue is related to the detection and differentiation of phase-phase faults from phase-ground faults. A Hidden Failure Mode would occur when the relays loose that property and all kinds of faults produces the same output in the scheme logic. This Hidden Failure Mode would also result in an unwanted trip since the generator unit would be disconnected when not required. A transmission line phase-ground fault that produces a phase-phase fault logic output would be an example for this Hidden Failure Mode.

These three cases are built under a “philosophical” approach. They reflect how a Hidden Failure Modes analysis is also applicable to complicated SPS such as Generator and Load Rejection schemes. A different format was used, since these cases are possible Hidden Failure Modes.

6. Chapter 6 Disturbance Analysis

6.1. Introduction

This Chapter describes a detailed disturbance analysis based on the reports published by NERC [27]. One of the objectives of this analysis is to find the practical side of the Hidden Failures definitions and philosophies included in Chapter 2, in other words, to prove the Hidden Failures existence in real Power System disturbances.

Hidden Failures identification will be performed mainly for disturbances occurred in USA and CANADA systems. Hidden Failures happening on Primary protection, Back-up protection or Special Protection Systems will be cataloged. Chapter 2 definitions and classifications are going to be applied as well, and whenever possible, the specific PEFD-A enumerated with roman numbers along Chapters 3, 4, and 5 are going to be referred on the disturbance analysis. This last issue will conclude that the theoretical definitions have found a practical and real counterpart.

6.1.1. Disturbance Analysis

The analysis for each disturbance will follow a certain format, and for each disturbance analyzed the date and reliability council where the event took place will be indicated. The format is as follows:

-Description of the sequence of events related to the identified Hidden Failures. Identified Hidden Failures will be enumerated as HF1, HF2, etc.
-Identification of the Hidden Failure protective scheme, i.e., Primary, Back-up or Special Protection System.
-Identification of the PEFD related to each Hidden Failure, i.e., PEFD-A or PEFD-B.

The disturbances will be presented sorted by their importance, regardless of the disturbance date.

a) **07/02/96, WSCC**

July 2, 1996 was not a very good day for the WSCC. A single phase to ground fault at the Jim Bridger-Kinport 345-kV line ultimately resulted in system separation and electric service interruption to more than 2 million customers. This event is one of the system-wide disturbances suffered by the WSCC [28].

The whole story of this disturbance is quite large, but since the Hidden Failures did occur at the very beginning, a detailed explanation of the initial events is included. The first event took place at 1424:37.180 MAST, when one of the conductors of the Jim Bridger-Kinport 345-kV line sagged too close to a tree, causing a phase to ground fault. The line was tripped and the fault was cleared in 3 cycles.

Twenty milliseconds after the Bridger-Kinport 345-kV line trip, the Bridger side of the Bridger-Goshen 345-kV line was also tripped due to a Hidden Failure. This event will be catalogued as HF1. Figure 45 shows the first fault on the Bridger-Kinport 345-kV line (see number 1 on Figure), and the circuit breaker unwanted trip caused by a HF1, see number 2 on Figure.

Figure 45: WSCC System, HF1 Scenario.

The relay involved with the Bridger-Goshen 345-kV line unwanted trip was identified as a Westinghouse SPCU, segregated phase comparison, solid state relay. The relay had a PEFD-A. A faulty ground element, local delay timer had its contacts always closed. Technical staff of the Pacific Corp utility was contacted, and they agreed in the fact that Jim Bridger-Goshen relay miss-operation follows a Hidden Failure sequence of events.

The mechanisms inside the SPCU relay are sketched in Figure 46. The element with a PEFD-A is “connected” through an AND gate to a fault detector and both are required to trip the circuit breaker. Figure 46 inputs are the local and remote square waves, where the comparison is performed in order to determine if the fault is internal or external. A PEFD-A took place in the timer (shown in bold format in Figure 46), closing its contacts, and it remained hidden until the fault at Bridger-Kinport line forced a current high enough to satisfy the condition for the fault detector relay to close. Since the channel security checks were verified, the relay system (SPCU) sent a trip signal to the circuit breaker. This is a Hidden Failure occurring over a Primary protection system.

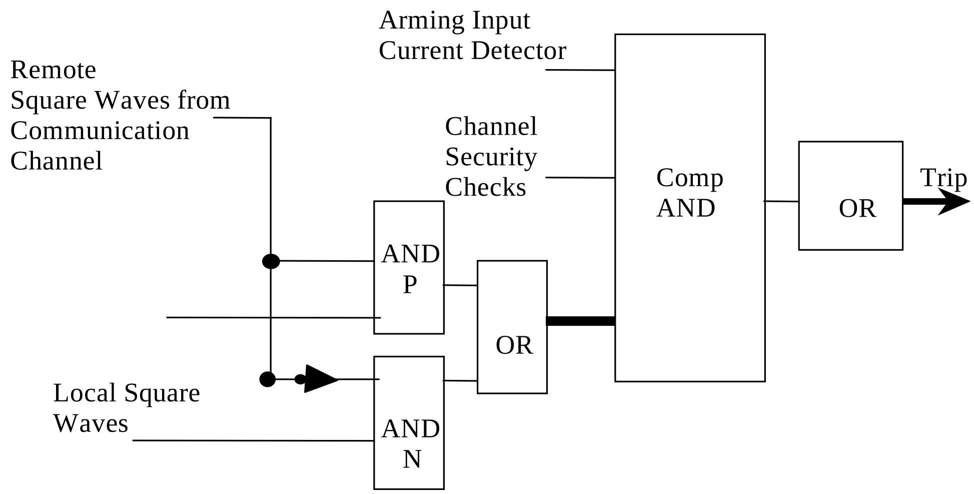

Figure 46: SPCU relay internal logic schematic.

The Jim Bridger SPS (discussed in section 5.5.1) was immediately started, due to the fact that Jim-Bridger plant had lost 2 transmission lines. This SPS operation was appropriate and did work as designed, disconnecting 2 units from the Jim-Bridger plant (1040 MW total), bypassing series capacitors in Burns and segment 3 of the Borah, and inserting the 175 MVAR Kinport shunt capacitor.

Generators from the entire WSCC interconnection did respond to the frequency deviation, 59.9 Hz. Almost 2 seconds after the first event, another relay-unwanted trip disconnected the Round Up-LaGrande 230 kV transmission line. This was a Hidden Failure, and will be catalogued as HF2

A text fragment from [28] is included, in order to identify HF2 from this reference own words. This sentence is written in different format, as follows.

"The next recorded event (1424:38.995) was the tripping of the Round Up-LaGrande 230-kV line due to miss-operation of a KD11 zone 3 relay at Round Up. Voltage at the LaGrande 230-kV bus dropped from 220-kV following the Bridger unit trips to 210-kV after the LaGrande line tripped. Investigation by BPA personnel revealed a faulty phase-to-phase impedance element. Careful investigation discovered corrosion under the crimp-on lug to the phase-to-phase voltage restraint element. This effectively resulted in an open restraint circuit, which caused the phase to phase impedance element to close. The relay is supervised by a fault detector, so the failure was not apparent until a disturbance occurred that created enough current to operate the fault detector and lasted long enough for the relay to time out. The relay has been replaced. This relay was last tested and calibrated on March 9 of 1996. Corrosion of crimp-on lugs is not a common problem and is not one that would be detected by routine maintenance".

The defective relay was identified as KD-11, a Westinghouse electro-mechanical distance relay. This relay belongs to the K-Dar compensator distance-relaying group.

Figure 47 describes HF2 sequence of events. This operation can be justified using the beam concept for distance relays, where there is a voltage restraint force, coming from the potential transformers, and a current operating force, coming from the current transformers [9]. For distance relays, the voltage restraint force supercedes the current operating force during not extremely severe load conditions and for faults out of the relay setting, under these circumstances the relay does not operate. Corrosion under the voltage restraint crimp-on lug did produce a poor connection, reducing the restraint force. Corrosion was accumulated as the time went through until the point that the voltage restraint force was practically eliminated and the KD-11 relay operated, closing its contacts.

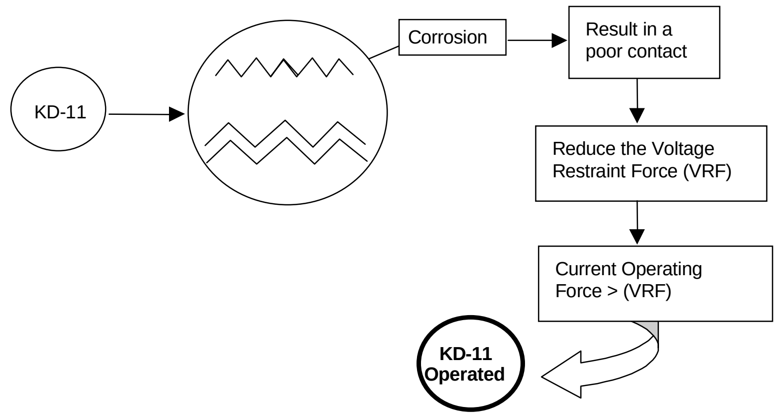

Figure 47: HF2, Sequence of Events.

The exact moment when the corrosion caused the KD-11 relay to operate is unknown. This relay operation remained undetected due to the fact that some others conditions are required before sending a tripping signal to the circuit breaker, i.e., the relay is supervised by a fault detector. The exact text coming from reference [28] by itself, states that the failure was not apparent, so was hidden, until another event uncovered it.

From the time when the KD-11 relay was incorrectly operated (corrosion) until the time the Round Up–LaGrande 230 kV line was tripped, the system conditions must had been “normal”. Hidden Failures are triggered or uncovered by some another “event” which could be a fault, overload, under-voltage, etc. On July 2, 1996 the system did not have normal conditions since two lines were tripped, initiating a SPS, dropping 1040 MW of generation. So HF2 was triggered by the July 2, 96 abnormal conditions. Round Up – LaGrande 230 kV line tripped because KD-11 was operated (corrosion) and the fault detector did close its contacts due to the current increment, following the SPS operation. This Hidden Failure event agrees with the definition that PEFD-A are applicable to all the protective elements, and in this case it is related to the relay connectors and lugs.

A fragment from [11] states “Jim Bridger Remedial Action Scheme should have ensured stability and prevented further outages. Several near simultaneous switching events, however, had some detrimental effects: A 230 kV line relayed in Eastern Oregon”. This 230 kV line is the Round Up – LaGrande, which was trip due to HF2.

July 2, 1996 disturbance problem was related to voltage instability [28]. Since Round Up–LaGrande 230 kV line trip caused the voltages to decline, it can be concluded that HF2 had detrimental effects on the overall sequence and behavior of the disturbance events. This is a Hidden Failure occurring over a Primary protection system. Figure 48 shows the physical location of Round Up-LaGrande 230 kV transmission line.

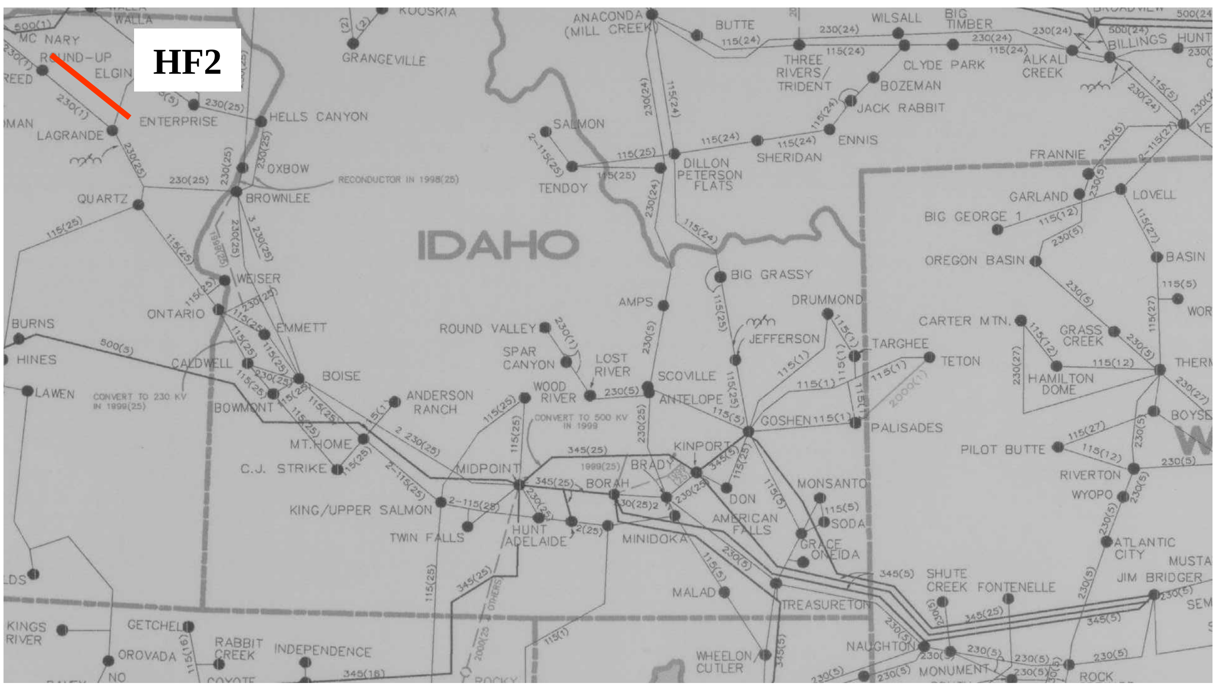

Figure 48: WSCC System, HF2 Scenario.

HF3 will be described next, which is related to the MillCreek-Antelope 230 kV transmission line, where the MillCreek station breaker had an unwanted trip. This is a Hidden Failure occurring over a Back-up protection system; in fact it can be catalogued as an unwanted operation of a Back-up relay. A fragment from [11] states: “relays installed to detect short circuits must not operate for mild overload and mild voltage depression". The relay did not do anything wrong, it tripped because the Power System conditions changed and the apparent impedance encroached under the SEL 221 F, zone 3 distance relay' operating zone. The relay reacted to the apparent impedance resulted from the mild under-voltage and mild overload system conditions.

The PEFD associated to HF3 is a PEFD-B. This Hidden Failure is related to human negligence and relay settings, in the sense that these Power System conditions presented on the July 2, 96 disturbance were not previously considered in the contingency analysis studies. This line trip and the 300 MW interruption caused power swings leading to rapid overload /voltage collapse and angular instability [11].

b) **09/12/91, WSCC**

The first event was the Jim Bridger-Kinport 345 kV line trip due to a phase-ground fault, which was cleared by the protective relays and the associated circuit breakers. The power coming from the Jim-Bridger generation station at that time was 2060 MW in the west direction.

The Jim Bridger Remedial Action Scheme should have operated since one line had a fault but it failed to operate due to loss of calibration. This is a PEFD-B related to the relay settings and human negligence. This HF4 occurred over a Special Protection System.

Twenty cycles after the first event the Goshen terminal of the Goshen-Kinport 345 kV line relayed open, due to HF5, which occurred over a Primary protection system. HF5 did occur because the SLYP[1] relay at the Goshen terminal of the Goshen-Kinport 345 kV line had a card failure that caused a relay element to fail in the closed position. This is the PEFD-A, which remained hidden inside the relaying logic. This relay is supervised by a current level detection element; when the RAS failed the

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[1] SLYP is a relay manufactured by General Electric.

power flows on the Goshen-Kinport 345 kV line increased, enough current was seen by this fault detector, and closed its contacts. Since SLYP contacts were always closed (because of the PEFD-A) the tripping path was only dependent on the fault detector operation, and the circuit breaker was tripped. Figure 49 shows HF5 scenario.

Figure 49: WSCC System, HF5 scenario.

c) **08/28/92, WSCC**

Fire fighters were extinguishing two fired palm trees located over Toluca-Atwater 230 kV line's right of way. Water spray did create a phase-ground fault on this 230 kV line.

HF6 and HF7 took place and caused the miss-operation of two breaker failure relays. This fact disconnected tie lines in the city of Burbank, leaving a lack of generation condition. The automatic UFLS program was initiated, but was not enough to bring the frequency back to normal and the total load lost in this event was 739 MW. The maintenance crew inspected the relays and found that the time delays were set at 1.5 cycles (25 ms) instead of 10 cycles (167 ms). The breaker failure relay delay of 1.5 cycles did not allow the Primary protection, line relays, to operate. This failure is related to human error, a PEFD-B on the settings, acting on local Back-up protection, breaker failure relays.

The PEFD-B on HF6 and HF7, in which the relays settings were wrong have a theoretical counterpart from Chapter 4, specifically PEFD-A XXIX. In this case, 1.5 cycles of time delay are "practically" the same than the condition of having the timer contacts always closed (PEFD-A XXIX). The final results are the same, since the "other breakers" were opened regardless of the initial breaker operation result. The assumed PEFD-A XXIX from Chapter 4 was found in a real disturbance.

d) **04/18/88, NPCC**

Severe snow and freezing rain caused short circuits on insulators of Aranud station, and Churchill Falls generation station (3200 MW) was removed from the Hydro Quebec system. As it is designed in Churchill Falls Special Protection Scheme, this lack of generation requires the operation of the Load Rejection scheme, see Figure 50.

HF8 occurred when a faulty contact in the control center did not allow the load shedding signal (coming from the Special Protection System) to be received by the load shedding computers, starting the remedial action. The PEFD-A took place on the receiver, since it could not recognize the tripping command.

The consequence of this Hidden Failure was a system-wide blackout, with a total loss of load of 18,500 MW. HF8 acted over a Special Protection System, Load Rejection. This is an SPS failure to trip event, which brought severe consequences in the Power System.

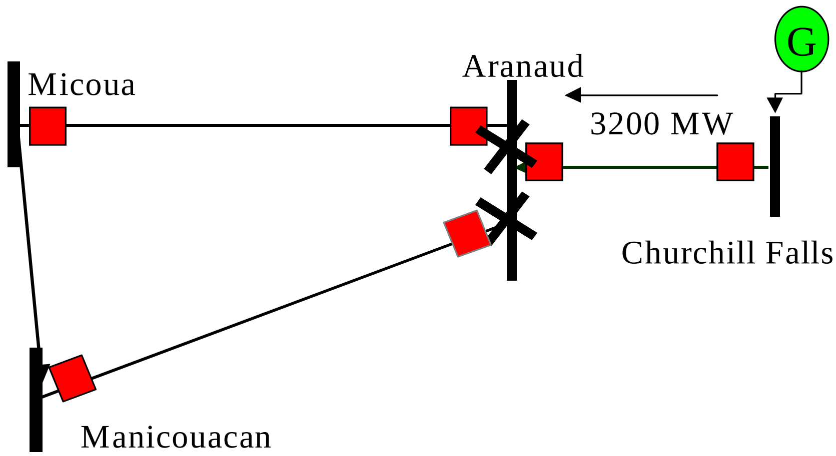

Figure 50: NPCC System, HF8 Scenario.

e) **10/21/95, WSCC**

Three disturbances happened on the same transmission lines during the year; the one occurred on October 21 is described next. A single phase-ground fault did occur on Springerville-Luna 345 kV line and at the same time the Hidalgo side of Hidalgo-Luna 345 kV line opened due to HF9. See Figure 51.

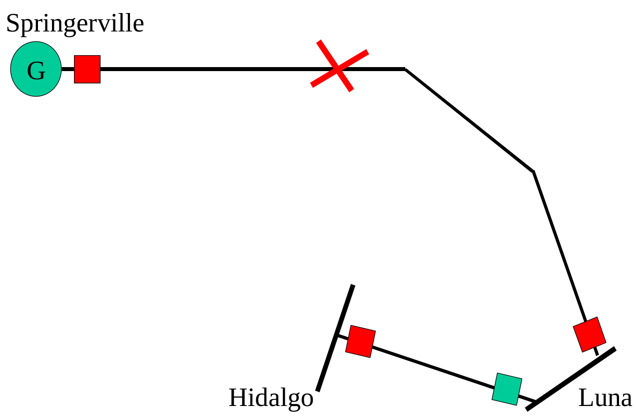

Figure 51: WSCC System, HF9 scenario.

The reason was a relay communication channel that had not been turned on, causing the absence of a blocking signal at Hidalgo's end when this end detected the fault. This is a PEFD-B, human error. This resulted in a simultaneous double contingency and, after other switching actions, cascading outages took place. HF9 acted on Primary protection, and the total load lost in the event was 637 MW.

f) **12/14/94, WSCC**

Figure 52 shows the physical arrangement for the three terminal lines, Midpoint-Borah-Adelaide No.1 and Midpoint-Borah-Adelaide No. 2.

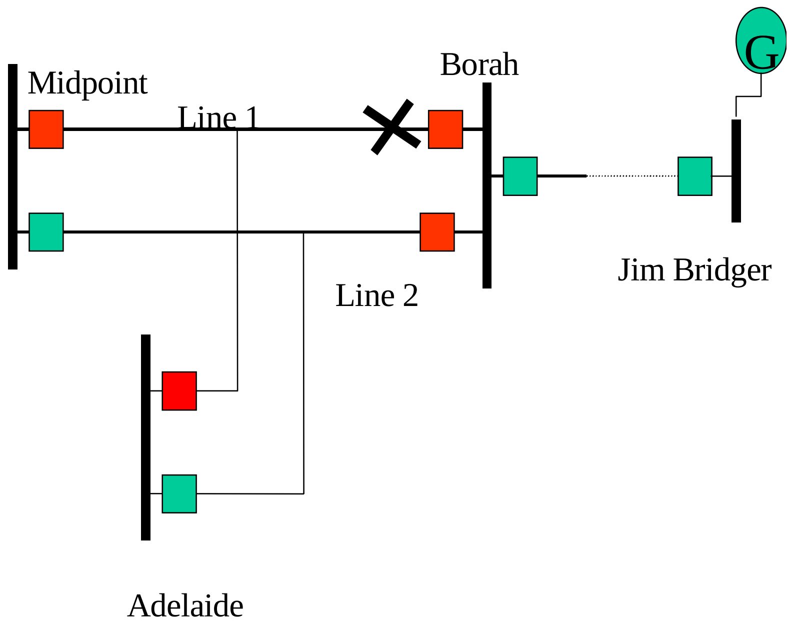

Figure 52: WSCC System, HF10 scenario.

The first event was a line to ground fault on line Midpoint-Borah-Adelaide No. 1, all three terminal circuit breakers were tripped and the fault was cleared. HF10 took place, opening the Borah breaker only of the Midpoint-Borah-Adelaide No.2. HF10 acted in a Primary protection system and was caused by a pilot ground relay, having a PEFD-A.

Because of the bus configuration in Borah, a transfer trip was sent to trip the Jim Bridger end of the Borah-Jim Bridger 345 kV line. Nine seconds after the initial event, the Brandy-American Falls 138 kV line tripped on overload, and some others lines operated for the same reason. Cascading took place, producing 200 MW peak-peak power oscillations, and the system was separated in 5 islands.

7. Chapter 7 Regions of Vulnerability and Areas of Consequence

7.1. Introduction

So far, we have analyzed Primary protection, Back-up protection and a number of Special Protection Systems, and Hidden Failure Modes have been identified. Chapter 6 presented some real disturbances that suffered from the Protection Elements Functionality Defects (PEFD) and Hidden Failure Modes mentioned along the document.

This analysis, however, still looks incomplete; there is something missing which must be taken in account before thinking on the problem solution. If the problem is not well defined yet, all solution attempts are worthless.

Chapters 3, 4 and 5 have shown that a number of Hidden Failure Modes are based on an assumed PEFD-A on a certain protection system element in such a way that a Hidden Failure will result if "another condition" is present. This “another condition” may take the form of an electrical fault, a Power System parameter change, etc. It is important to further analyze this "another condition" as the triggering issue for the Hidden Failure Mode. A number of the Hidden Failure Modes that have been identified have in their logic schematic a section in which two relay contacts are connected in series. Figure 53 shows this arrangement. Usually the sequence of events starts with a PEFD-A on one relay, R2 for instance. Under this scenario, the operation of relay R1 contacts would trigger a control action, which in this case closes the dc path to the circuit breaker trip coil, see Figure 53.

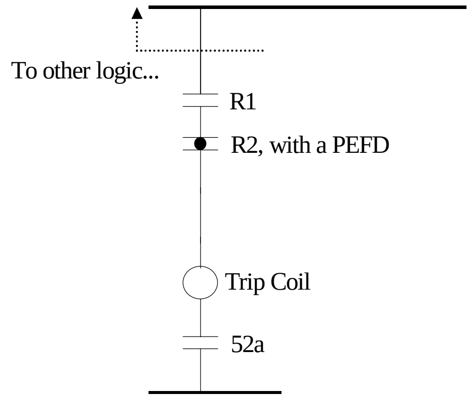

Figure 53: A logic schematic section, two relays is series.

Figure 53 deserves to be analyzed in a deeper fashion. Generally, the conditions required to be present for R1 operation are different from the ones needed for R2 operation. The problems arise after R2 have a PEFD-A, since the conditions required for R1 operation are not the same that have to be present for tripping the circuit breaker, clearly those conditions are the R1 plus R2 requirements. Figure 54 shows the required conditions for a correct trip in a graphical and philosophical fashion. Additionally, there is the need to identify all conditions for which R1 will close its contacts, since these represent the triggering issue for the Hidden Failure.

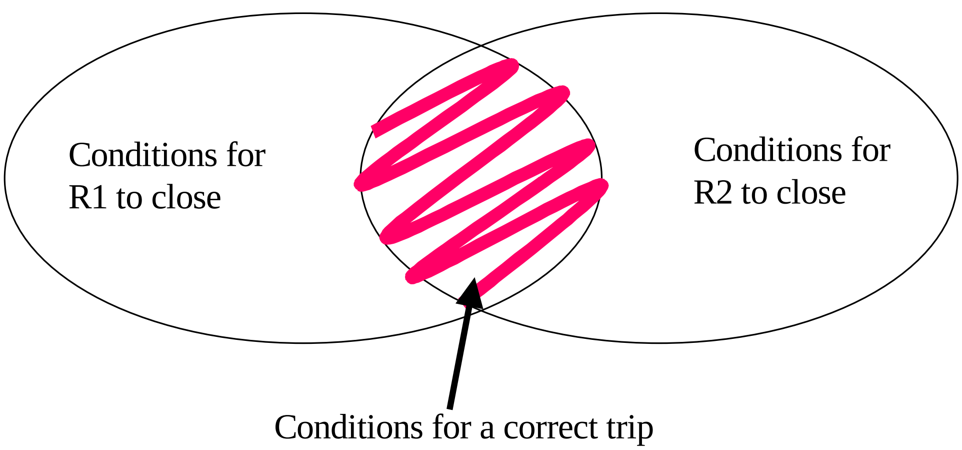

Figure 54: Conditions for a correct trip, two contacts in series.

From Figure 53, the identification of all conditions causing the operation of relay R1 would depend on several factors. The first one is the relay type, which would provide with the nature of inputs the relay will receive, current, voltage, frequency, etc., to be compared and then decide whether to change its contacts status or not. Another issue is to consider other relays from which R1 depends. R1 may be a simple over-current relay depending on the system current magnitude only, or R1 may take the form of a receiver relay, which depends from a transmitter and some other relays.

In order to find all conditions that cause R1 to operate, the protection system relative to the logic schematic should also be considered. The role of R1 in the protection system must be identified regarding to what kind of events will be "observable" to the relay. These two diagrams are combined in a joint analysis, which involves the Hidden Failures Modes.

Mr. Surachet Tamronglak [1] developed the Region of Vulnerability (RV) concept, which comes to the point discussed in the previous paragraphs. A first analysis in the name Region of Vulnerability gives us the idea of a Power System physical location. The Region of Vulnerability in a philosophical approach would be referred as a zone in which the Hidden Failure triggering issues are located. However, in reality we can not talk about a Region of Vulnerability in a general form. Furthermore, the concept of Region of Vulnerability acquires a particular shape depending on the Hidden Failure Modes of the protection system being analyzed.

As it was mentioned previously with the Figure 53 example, an important factor in the Region of Vulnerability is the identification of the relay types that constitute a certain logic schematic, and their input parameters. The parameter associated to the Region of Vulnerability of a UFLS program is a certain frequency level, where as the parameter associated to a transmission line protective scheme is a certain current magnitude. As can be seen, the term "certain" was highlighted in the last paragraph, this was done in order to emphasize that the relay settings, those “certain” levels, are key ingredients in the Region of Vulnerability shape and extension in the Power System.

7.2. Regions of Vulnerability (RV)

Reference [1] defined the Region of Vulnerability for a number of Hidden Failure Modes. Since the Regions of Vulnerability associated with the Hidden Failure Modes described along the document is extensive a few illustrative examples will be included, in order to describe the concept.

Figure 55 shows again the logic schematic of remote Back-up protection for transmission lines using distance relays. For this logic schematic, Regions of Vulnerability will be defined for each PEFD-A shown in section 4.5.1.

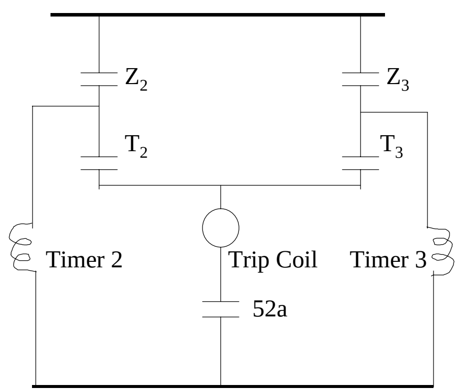

Figure 55: Remote Back-up Z2 and Z3 logic schematic.

7.2.1. Region of Vulnerability for Back-up protection for Transmission Lines.

Analyzing again Figure 55, we should remember that this logic schematic has a PEFD-A XXV, T_2 contacts are always closed. Then the Region of Vulnerability is defined as a Power System zone where the occurrence of an "event" will meet the required condition for the Z_2 relay contacts to close, becoming the Hidden Failure triggering issue. Since Z_2 is a distance unit element, and it reacts to the apparent impedance viewed from the relay terminals, the "event" in question may be an electrical fault or a load condition.

Figure 56 shows this Region of Vulnerability, for which the physical size is totally dependent on the Z_2 relays setting. If we assumed that the setting for Z_2 distance unit is 120% of the A-B line impedance, then the shadow area of Figure 56 will delimit this RV. The RV along different lines will be different depending on the line length, in this case the size of the RV is an electrical distance of 20% the A-B line impedance, applied along B-C line, as it is shown in the Figure 56.

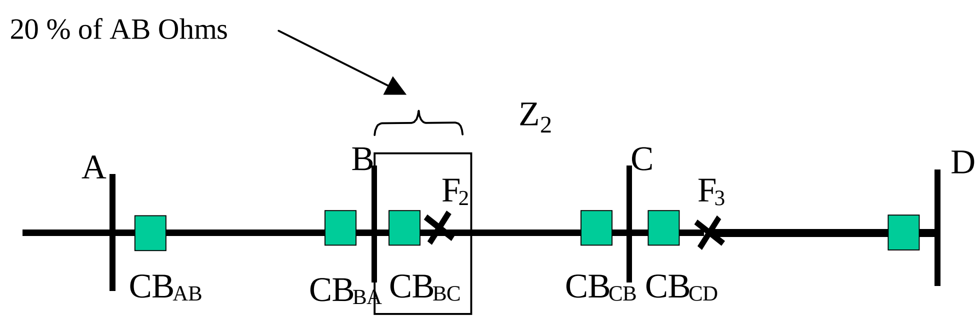

Figure 56: Region of Vulnerability for Back-up Protection, for transmission lines, Zone 2 distance relay.

Applying a similar procedure a Region of Vulnerability is found for PEFD-A; XXVI T_3 contacts are always closed. Since Z_3 is a distance unit, the triggering event will be also an electrical fault or a load condition. However, this RV will be bigger is size due to the Z_3 setting. Generally, this RV size would be 120% of the longest line beyond A-B, and particularly for this case the RV size is 120 % the BC line impedance. See Figure 57.

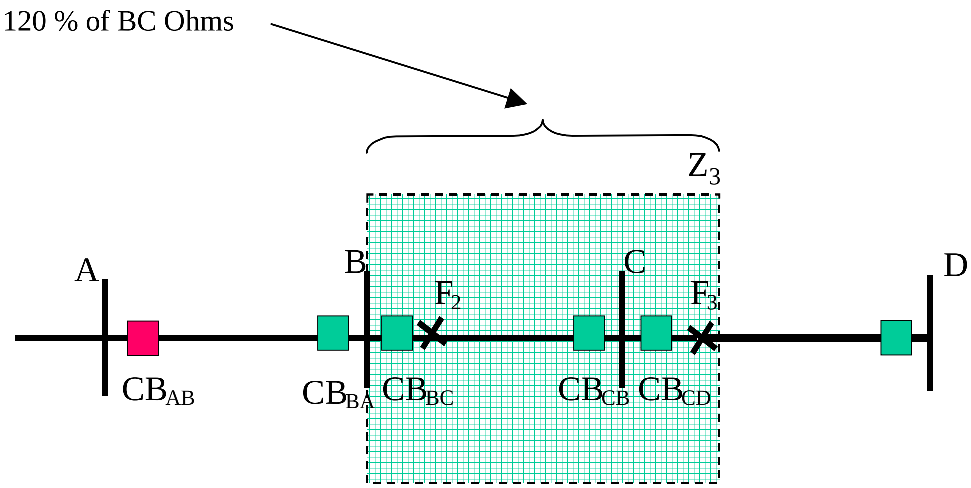

Figure 57: Region of Vulnerability for Back-up Protection, for transmission lines, Zone 3 distance relay.

From Figure 56 and Figure 57 it can be concluded that the occurrence of any electrical faults or load conditions [2] located in the Region of Vulnerability will become the Hidden Failure triggering issue for the relay associated with CB_{AB}. The consequences of both cases are the correct operation of the circuit breakers for which the fault is internal, and an unwanted trip of $CB_{AB,}$ double contingency.

7.2.2. Region of Vulnerability for UFLS program.

The same methodology will be applied for the UFLS program, in order to find a Region of Vulnerability. This procedure will be summarized as follows:

a) A PEFD-A is assumed on a element of the protective system
b) An analysis is performed to the remaining "healthy" elements. The questions to include are what kinds of relays are in use?, Which inputs they receive? And so on…

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[2] As a note, distance relays may react and operate for load conditions when the loadability of these devices is exceeded.

c) What kind of conditions are required to operate the "healthy" relay(s)

d) Identify the Power System "events" which would operate the "healthy" relay(s), and trigger the Hidden Failure Modes.

Analyzing again Figure 58, we should remember that this logic schematic has a PEFD-A XXXII, T contacts are always closed. Then the Region of Vulnerability is defined as a Power System zone where the occurrence of an "event" will meet the required condition for the 81 relay contacts to close, becoming the Hidden Failure triggering issue. Since relay 81 is an under-frequency unit element, and it reacts to the frequency value, the "event" in question should necessarily leave the Power System area with a mismatch in load and generation. The fault current distribution within the Power System is pretty much enclosed in the fault location surrounds, since the transmission lines impedance will attenuate the fault current magnitude. In this case, the frequency distribution follows a uniform pattern, due to the synchronism characteristic of the Power System.

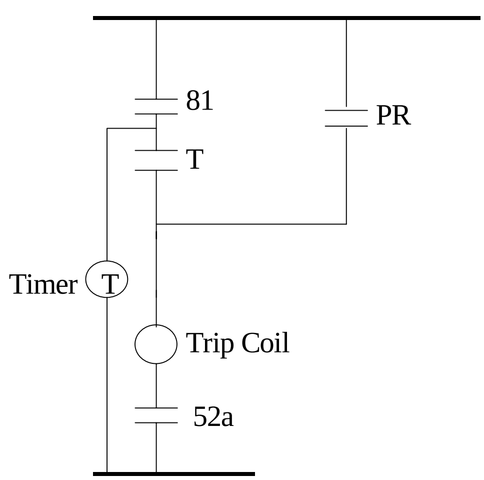

Figure 58: Under-Frequency Load Shedding logic schematic.

Figure 59 shows a local UFLS program designed to shed load for under-frequency conditions at bus H. The Region of Vulnerability associated to this scheme would be practically the whole system since a frequency deviation is constant over a wide-area. In this case, due to the protection system being analyzed characteristics would be better to talk about a Condition of Vulnerability rather than a Region of Vulnerability. The critical factor for this Condition of Vulnerability would be the under-frequency relay setting. The closer the under-frequency setting to the nominal frequency values the bigger the risk of a Hidden Failure occurrence.

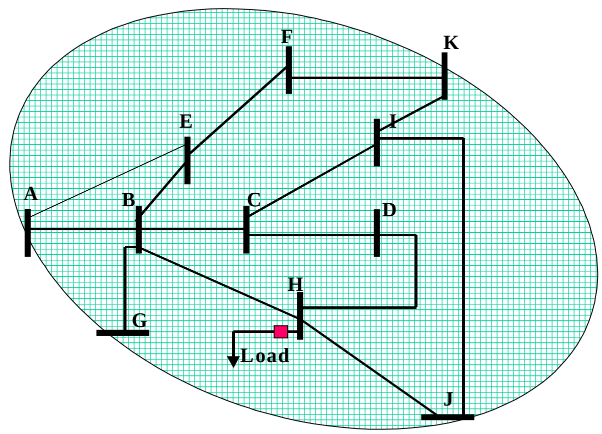

Figure 59: UFLS Region of Vulnerability.

7.3. Areas of Consequence

The term Area of Consequence was developed on this research. By definition it is an expansion of the Region of Vulnerability concept, and it is related with the identification of the overall effects of the Hidden Failure(s) in the Power System. The Area of Consequence is not a fixed region and it's defined when the disturbance analysis is performed.

The Area of Consequence extension or size for a specific disturbance may be small. For example, lets analyze a double contingency situation, where two lines are tripped, one line tripped correctly, because of the occurrence of an internal fault and the other one was an unwanted trip caused by a Hidden Failure. If both lines have a successful reclosing action, and the post disturbance parameters are controllable, the Area of Consequence of this disturbance is in fact small and not severe, since the system could return to the normal state, serving all loads at all times. On the other hand, the Area of Consequence of another disturbance may be large. This would be the case when; the second contingency triggers another events, such as a Special Protection System and the behavior of the disturbance bring severe consequences in terms of line trips and load interruptions. It should be clear that the cases when the Power System starts an uncontrolled separation due to an Out of Step condition or because of overload, are included in the Area of Consequence if the Hidden Failure, either directly or not have caused those conditions to happen.

7.4. Regions of Vulnerability and Areas of Consequence on Real Disturbances

The Region of Vulnerability and Area of Consequence concepts will be applied to a disturbance analyzed in Chapter 6. This analysis will identify the Region of Vulnerability and the Area of Consequence associated to each Hidden Failure.

07/02/96, WSCC

Region of Vulnerability for HF1

The transmission line protection scheme for the three 345 kV transmission lines is Segregated Phase Comparison, as Jim Bridger SPS states [26]. This scheme is dependent on the current magnitude only. Analyzing the conditions of the specific PEFD-A on the SPCU relay located on the Bridger terminal of the Bridger-Goshen 345-kV line, it can be found that the line to ground fault occurred on the Jim Bridger-Kinport 345-kV line did occur inside the SPCU relay Region of Vulnerability. This HF1 has a current magnitude related Region of Vulnerability. The Region of Vulnerability size would depend on the fault detector setting, which in fact was the Hidden Failure triggering issue for the unwanted circuit breaker operation. See Figure 60.

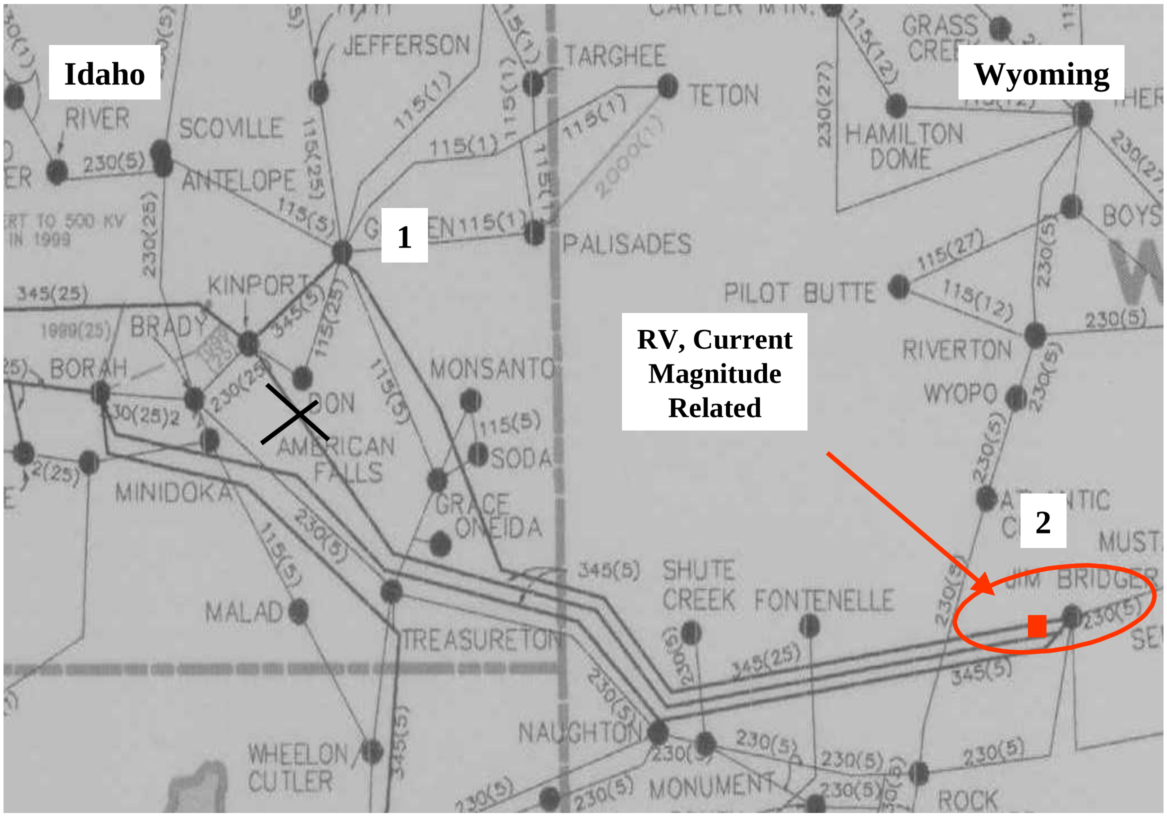

Figure 60: HF1, Region of Vulnerability.

Area of Consequence, for HF1

The Area of Consequence of HF1 goes beyond the second contingency surroundings since the Jim Bridger Generation Rejection Scheme was activated as result of this Hidden Failure.

Region of Vulnerability for HF2

Figure 61 shows the part of the WSCC system where the initial events took place. It can be seen with bold lines HF1 and HF2 locations. At Round-up station, the PEFD-A (corrosion on lugs) caused the KD-11 relay to be always closed; this condition allowed the fault detector operation to become the Hidden Failure triggering issue. This fault detector is a distance relay and receives current and voltage as input parameters, so the Region of Vulnerability is related to the location of an electrical fault or load conditions. From the WSCC report [28], an electrical fault never occurred around the Round-Up-LaGrande 230 kV line, and the fault detector relay was operated, triggering the Hidden Failure by "abnormal" Power System conditions coming from the SPS effects on the Power System. Figure 62 shows the Region of Vulnerability for HF2.

Figure 61: HF1 and HF2, Scenario.

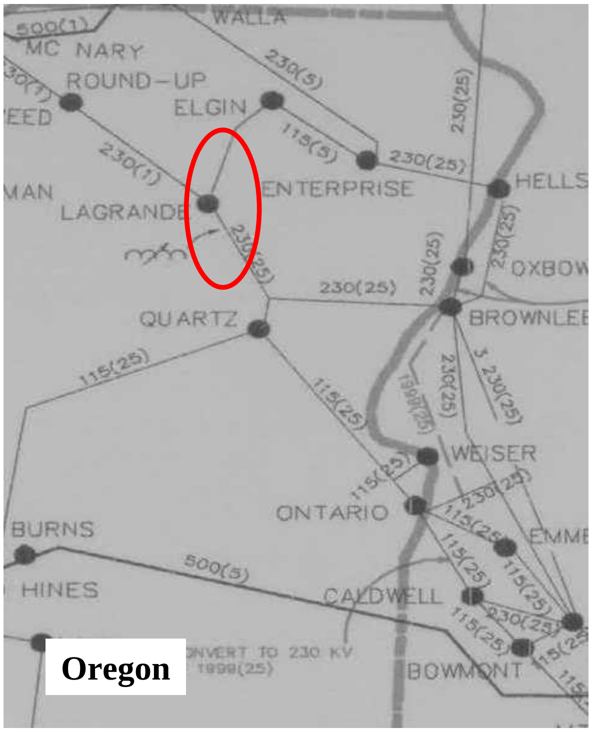

Figure 62: Zoom in the HF2 Region of Vulnerability.

Area of Consequence, for HF2

The Area of Consequence of this Hidden Failure includes the triggering of the voltage collapse condition.

Region of Vulnerability for HF3

HF3 caused the MillCreek station breaker of the MillCreek-Antelope 230 kV transmission line to trip. HF3 was caused by a PEFD-B, related to human negligence, as it was mentioned in Chapter 6, section a). As in the UFLS program, for this case the Conditions of Vulnerability better fits our needs, since the relay operation was correct, but inappropriate. The vulnerable conditions are identified as mild under-voltages and mild overloads.

Figure 63 shows the MillCreek-Antelope line and the bold line denotes approximately the remote Back-up protection, zone 3 reach. The circle marks the location of the vulnerable conditions.

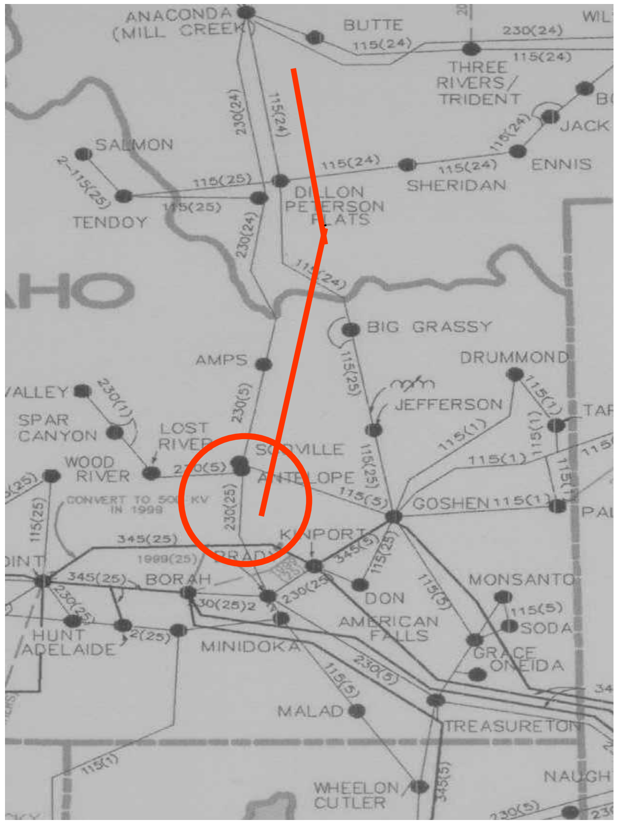

Figure 63: HF3, Region of Vulnerability.

Area of Consequence, for HF3

As mentioned previously, MillCreek-Antelope 230 kV line trip and the 300 MW interruption caused power swings leading to rapid overload /voltage collapse and angular instability [11].

8. Chapter 8 Conclusions

This document explored Hidden Failures in protection systems, which have been identified as key contributors in the degradation of Power System wide-area disturbances. The original definition of Hidden Failure was extracted from reference [1], and new developments include the Hidden Failure sequence of events and a methodology for Hidden Failure identification. This method is based on Protection Element Functionality Defects (PEFD), which are applicable to all the elements included in the protective chain.

The development related to PEFD classified PEFD-A and PEFD-B. The first group is concerned to hardware failures such as a relay contact that fails closed. The second group is related to relay settings, human errors or negligence.

Protective schemes for Generators, Buses, Transformers and Transmission lines were analyzed. The abnormal Power System conditions that each Power System element may have were enumerated. A catalogue of the relays or relay systems, in charge of detecting and stopping the continuous presence of the abnormal conditions was developed. Relay families organized this catalogue. The relation between the abnormal condition and the protective relays, "the abnormal condition-protective relaying interface" was developed for Primary and Back-up protection. The relaying schemes for five Special Protection Systems were described.

Thirty-three Hidden Failures Modes were included based on the relaying implementation for Primary protection, Back-up protection and Special Protection Systems. These Hidden Failures Modes were based on PEFD-A, which is related to hardware failures.

Hidden Failure Modes analysis related to PEFD-B must be performed on a general approach. As it was seen along the document, not all the analyzed logic schematics will allow the PEFD-A to remain hidden, i.e., not all logic schematics may have Hidden Failures related to PEFD-A, such as the overcurrent relay logic schematic. If the logic schematics were analyzed for Hidden Failures related to PEFD-B, all of them would be prone to Hidden Failures. A PEFD-B, such as a wrong setting, will remain undetected until a fault occurs and the relay sends an incorrect trip signal to the circuit breaker. This is a Hidden Failure related to PEFD-B. Another example would be the case of the differential protection applied to a power transformer. If after maintenance, the crew leaves a CT shorted, no current will flow to the relay, and the scheme will not trip during low load conditions. When the load increases, the protection will trip due to a Hidden Failure related to PEFD-B, human error or negligence.

Wide-area disturbances based on NERC reports were analyzed and Hidden Failures were identified employing the developed methodology. The theoretical and philosophical ideas and concepts included along the document found a real counterpart, since a number of the defined Hidden Failures Modes were identified from the NERC wide-area disturbance reports. This represents the validation of the work, and strengths the research results.

The mechanisms in the disturbances may be summarized in Figure 64, which represents a philosophical protection scheme. Hidden Failures occur when this protection scheme is "armed" by the PEFD-A on one of the relays, closing its contacts permanently. The application of this scheme may take the form of Primary protection, Back-up protection or Special Protection Systems, as can be seen in Table 8.1.

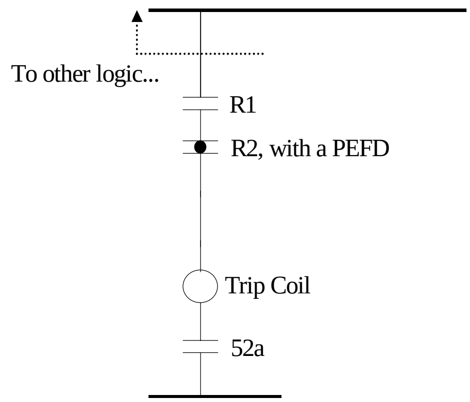

Figure 64: Mechanisms in the disturbances.

Scheme	R1	R2	Application
Primary Protection	Fault detector	Directional relay	Transmission line pilot scheme
Back-up Protection	Zone 2 or Zone 3 units of a distance relay	Timer	Back-up protection of a transmission line pilot scheme.
Special Protection System	Fault detection relays	Power flow relays	Generation Rejection
Special Protection System	Under-frequency relay	Timer	Under-Frequency load shedding.
Special Protection System	Under-voltage relay	Timer	Under-Voltage load shedding.

Table 8.1 Mechanisms in the Disturbances.

Regions of Vulnerability were identified as Power System physical areas in which the occurrence of an event will uncover a Hidden Failure of a nearby protection system. The specific protection system and the relay settings were important factors for the different Regions of Vulnerability. For some schemes the term Condition of Vulnerability was developed. Areas of Consequence represent the overall observation of the disturbance degradation, from the initial contingency until the last actions made in order to control the Power System.

Regions of Vulnerability and Areas of Consequence will bring the initial steps towards the problem solution. New developments regarding these topics will be performed in the future. Further research directions are oriented towards the development of a computer-based tool to track the regions of vulnerability in real time.

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10. Vita

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