Analysis of Protection Malfunctioning in Meshed Distribution Grids

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The thesis study was performed in close collaboration with Stedin

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Challenge the future

To Robby and Lalieta

Word of Thanks

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Summary

The electrical power system generates and supplies electric energy to consumers and it must operate in a safe manner at all times. Despite its good performance, disturbances such as the occurrence of short circuits can always take place. Short circuits can be accompanied by large currents and voltages and if not cleared in a short time, they can cause a disastrous effect on expensive system components and cause a risk to life. Because short circuits cannot be prevented, the system must be able to recognize them and take corrective action. This is done by the different protective systems, which are implemented throughout the power system. The electrical power system consists of a variety of grid structures, which are divided in protected zones and each zone has its own protective system. But it is experienced that during short circuits in some network sections the protective system is not able to detect and clear the short circuit properly. This can lead to unnecessary system and customer outages, damage of expensive system components, economical damage and a bad image for the network operator. The problem of incorrect operation of the protective systems in sub-transmission and distribution network structures is studied in this thesis.

Stedin is a Distribution System Operator in the western part of the Netherlands and in certain parts of their sub-transmission network a typical grid structure is used in which mal-operations of the protective system are experienced. The protection scheme consists of a combination of overcurrent and directional overcurrent relays. The operation and functioning of these relays and all other protection relays used in distribution networks are explained in chapter 2.

To study the cause of the protection scheme mal-operation in these typical network structures, a simplified model of one of such network sections is developed and analysed in chapter 3. The fault current behaviour due to symmetrical and unsymmetrical faults is analyzed as this leads to the relation between the short circuit location and the total fault current. This relation is very important for correct analysis of protective devices.

In Chapter 4, the analysis of the simplified meshed cable network section of Chapter 3 continues. The protective system, which consists of overcurrent and directional overcurrent relays is added to the simplified network model and first the detected fault currents are analyzed as a function of the short circuit location during all types of short circuits. Firstly, the purpose of this analysis is to determine whether the detected fault currents exceed the relays' current thresholds. Secondly, the fault current angles are analyzed as well to determine whether relay directionality takes place. The fault current angle represents the angular difference between the phase fault current and the voltage of the same phase during the short circuit. If this shift causes the fault current vector to lie within a predefined relay tripping zone, directionality is obtained and the relay directional restraint is exceeded. The results of this analysis show that for all short circuits, there exist certain *dead zones* within the protection zones of this network model. If a short circuit occurs within these dead zones, the directional overcurrent relay will not be able to detect the fault current, because the magnitude of the

directional relay detected fault currents are proven to be much lower than the relay current threshold.

Dead zones within the protection zones of the network are inacceptable and therefore possible strategies to mitigate their occurrence in this network model are studied in chapter 5. A good solution strategy must protect its concerning zone for 100%. There are four strategies analyzed and two of them are found to be promising in eliminating the existing *dead zones*.

Table of Contents

1

Introduction

The electrical power system generates and supplies electric energy to consumers. The electricity demand is growing everywhere around the world and it will continue in the future. Electricity supply has become indispensable and this results in an increasing emphasis on reliability and security of supply.
The power system should operate in a safe manner at all times, but despite the good system design, short circuits will always occur. Short circuit normally result in increased current levels which may contain destructive power and if not promptly cleared, it might have a disastrous effect on the expensive system components and cause a risk to human safety. Furthermore, without taking a proper action a fault can also result in long lasting system and costumer outages. That is why the implementation of adequate protection is very important in power system design. Only by applying detailed studies the objectives of the power system can be met. According to [1], the purpose of power system protection is to detect faults or abnormal operating conditions and to initiate corrective action. This will be thoroughly studied in this thesis.

In this chapter, power system protection is generally introduced. The focus will be mainly concentrated on the thesis problem definition and approach.

1.1 Power System Operation

The electrical power system consists of thousands of transmission and distribution lines, substations, transformers, and other equipment spread out and interconnected so that the whole system can operate in a way to deliver power as desired by the utility's customers. The operation of the present-day power system is shown in Figure 1.1.

1.1.1 Grid Structures

The power system of Figure 1.1 is divided into:
- Transmission grid, for voltage levels greater than 110 kV
- Sub-transmission grid, for voltage levels between 23 kV and 110 kV
- Distribution grid, for voltage levels lower than 23 kV

These grids are constructed by High Voltage (HV), Medium Voltage (MV) and Low Voltage (LV) networks, which are connected through substations or switch yards.

The transmission, also called the bulk power system, forms an electrical tie between all generators and provides for bulk power transmission into the sub-transmission and distribution grids. These grids take power from the transmission grid and deliver it to distribution substations in their network. From the distribution substations, the power is then transferred into the LV network to the costumers. In the substations the voltage is transformed from high to low or reverse using transformers. Large power plants are connected to the transmission grid and recently small generators, also called distributed generation, are connected to the sub-transmission and distribution grids. Loads are connected throughout the system varying form large industrial loads on transmission level to household loads on distribution level.

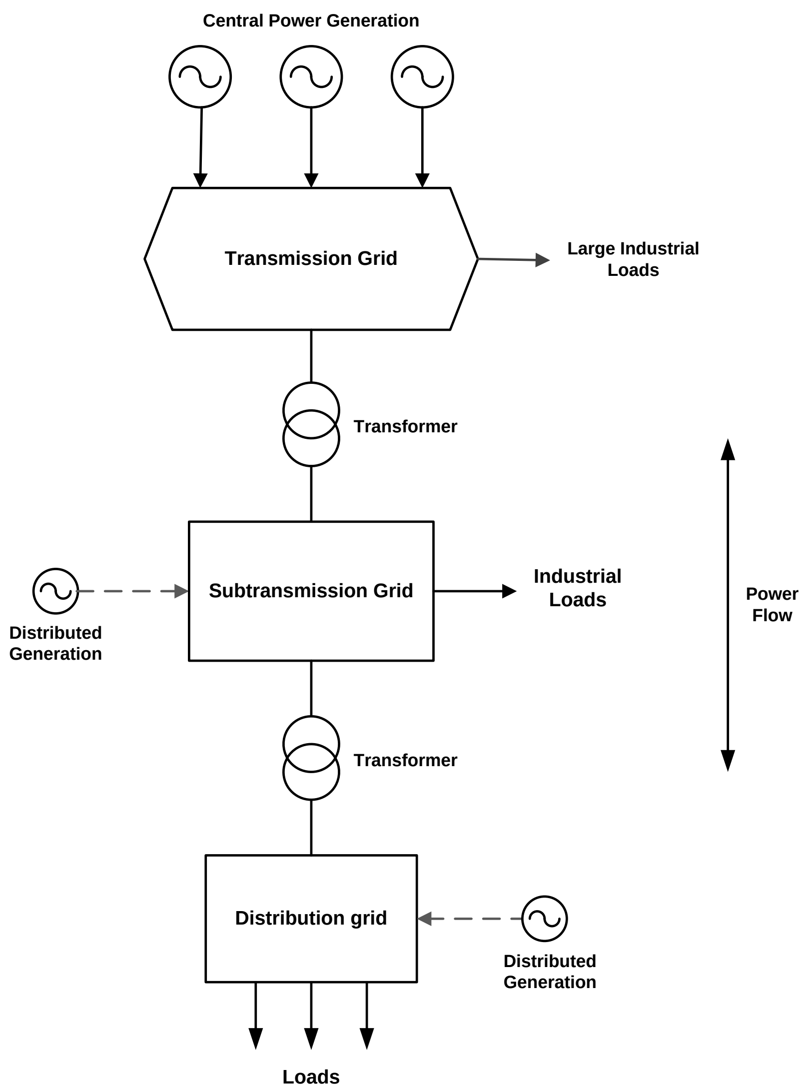

Figure 1.1: Illustration of the common Power System Operation

1.1.2 Network Topologies

For every part of the power system a certain network structure or topology is distinguished. According to [2], a network topology is understood as the whole electric circuits or connections in the power system (lines, cables, transformers and the coupling between rails) which finds itself between one or more feeding points and one or more extraction points.

When looking at the different network topologies, the network can first be divided into:
- A network section which is connected to only one point of supply, also known as *single point feeding*
- A network section which is connected to multiple points of supply, also known as *multiple point feeding*

Single Point Feeding

When networks with single-point feeding are considered, there are three network topologies possible:
1. "Radial" structure: there is only one path from the point of supply to the other levels of the system.
2. "Loop" structure: the electrical circuits form a loop with one point of supply.
3. "Meshed" structure: there is also one point of supply, but there is more than one electrical path between the distribution substations.

Examples of these network topologies are shown in the following figure:

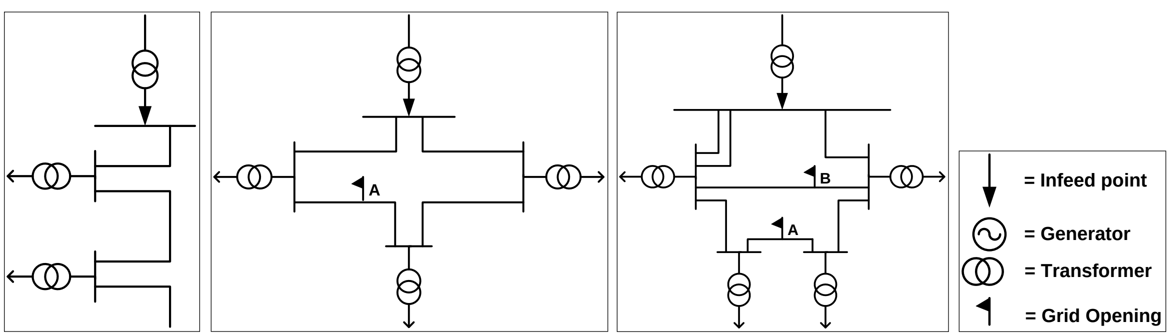

Figure 1.2: a) Radial structure b) Loop structure c) Meshed structure

In Figure 1.2 (b) and (c) there are symbols for grid openings on certain locations in the network. On these locations, in the actual network there are circuit breakers or other types of switches which can create a 'net opening' under particular circumstances. Due to these switches and grid openings, a ring structured network can be operated as a radial structured network and a meshed structured network can be operated as a ring structured or a radial structured network.

Multiple Point Feeding

When there are multiple sources connected to a network section, the network is nearly always operated in a meshed topology. This is shown in Figure 1.3. It can also be seen that there are grid openings on certain locations in this network. With the help of these openings the network can be operated as three separated radial network sections, each individually connected to one feeding point.

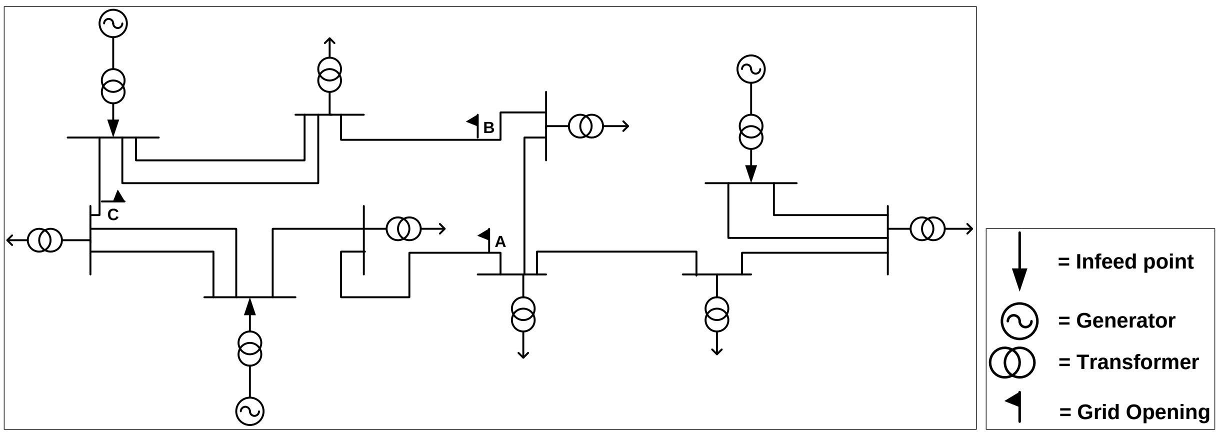

Figure 1.3: Meshed network topology used in transmission grids

In transmission systems there must be more than one electrical path between any two points in the network for reliability reasons. These grids are almost always operated as shown in Figure 1.3.

1.2 General Overview of Power System Protection

As previously mentioned, the power system must operate in a safe manner at all times. However despite the good system design, short circuits will always occur. Therefore the implementation of adequate protection is very important in power system design. The purpose of power system protection is to detect faults or abnormal operating conditions and to initiate corrective action. Protection relays provide corrective actions and they cannot prevent a fault occurrence but they have to detect the fault, take a correct action and due to this, minimize the system or component damage.

There are certain definitions used in system protection ([1], [3]) and some of them are applied in this thesis:

- *Reliability of a protective system* is defined as the probability that the system will function correctly when required to act.

- *Protective Relaying* is the term used to signify the science as well as the operation of protective devices, within a controlled strategy. Hereby maximum service continuity, minimum component damage and personal safety can be obtained during abnormal grid situations.
- *Dependability of a protection device* refers to the certainty that a relay will respond correctly for all faults for which it is designed and applied to operate.
- *Security in protective systems* is a term sometimes used to indicate the ability that a relay will not operate incorrectly for any fault.
- *Sensitivity in protective systems* is the ability of the system to identify an abnormal condition that exceeds a nominal "pickup" or detected threshold value and which initiates protective action when the sensed quantities exceed that threshold.
- *Selectivity in a protection system* restricts interruptions to only those components that are faulted. The protection device closest to the fault will operate and it requires certain grading (with timing or operating characteristics) to obtain selective operation.
- *Coordination of protective devices* is the determination of graded settings to achieve selectivity.

Fast and reliable protective system operation is required to achieve a certain level of power system reliability, because the system must survive severe fault conditions without resulting in system collapse. System faults can be rapidly removed by dividing the system into *protection zones*. Each zone has its own protective system which monitors the current and voltage in the zone. In case of a fault the protective system closest to the fault must respond and disconnect the concerning zone to clear the fault. In this way, correct fault detection will result in selective switching and disconnection of minimum grid section to isolate the fault.
The following figure gives an example of possible protection zones, with each system element located in its own protected region.

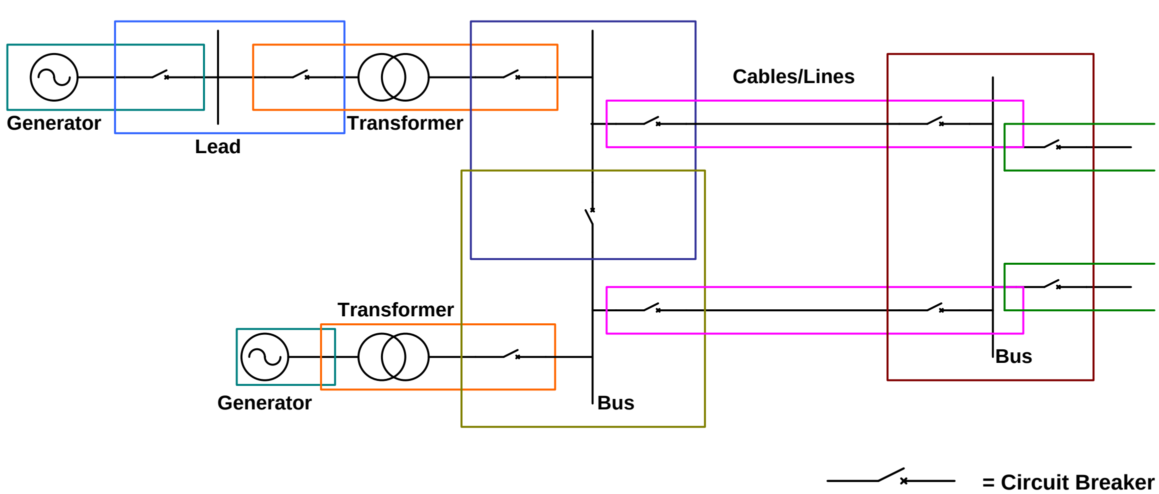

Figure 1.4: Zones of Protection

It is important that these zones of protection overlap, so no part of the system is left unprotected. If a fault occurs within such a zone, the protective system closest to the fault must act selectively and trigger the appropriate circuit breakers to isolate the involved zone from the remaining (healthy) power system.

1.3 Problem definition

Stedin is a Distribution System Operator (DSO) in the western part of the Netherlands. This DSO is responsible for the operation of the sub-transmission and distribution grids. Technical and economical motives have led to a grid evolution with a variety of grid structures. Therefore, in the Stedin network several locations of the sub-transmission grid are structured as shown in Figure 1.5. This part of the network is an underground cable network and it consists of two parallel connected cable sections. One section is constructed by a single cable while the other section contains two cables which at both ends form a junction back into a single cable.
Both parallel sections are protected with the same protection scheme and the corresponding protection zones are also shown.

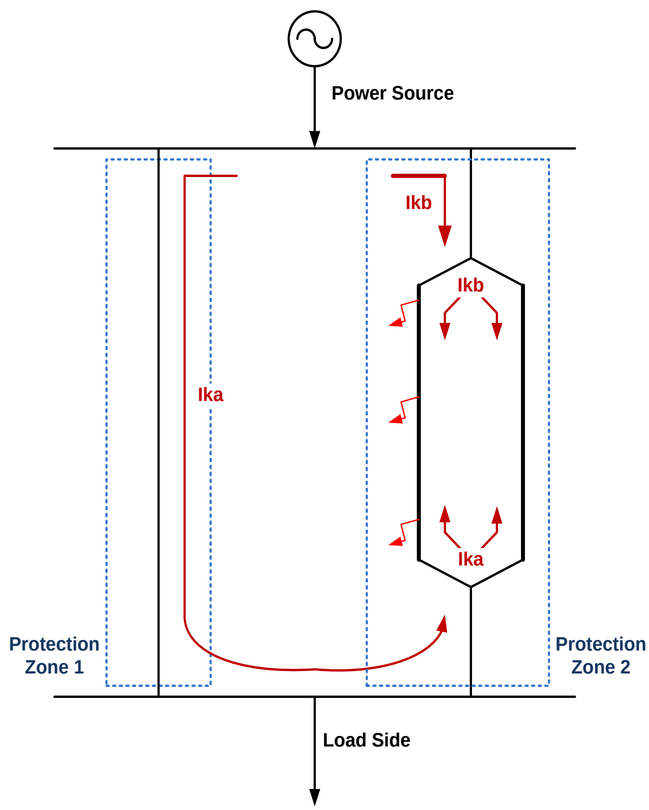

Figure 1.5: Circulating fault currents in a 25 kV sub-transmission network

If, for example, a short circuit occurs in protection zone 2, proper relay switching must isolate this zone from the network, while the power flow can continue through the sound section. According to Stedin experience in case of short circuits in such grid structures, the fault is not always detected adequately by the protective system. Normally, this results in mal-operation of the protection relays.

This part of the sub-transmission network has a meshed topology and during short circuits fault currents circulate through the cables to the fault location. This complicates the proper detection of the fault currents by the protective devices. If the protection equipment fails to trip, it may have a catastrophic effect on the system performance. In this case, the possibilities are:

- Prolonged fault current which could lead to long-lasting voltage dips
- Possible components damaged due to the long-lasting circulating high fault currents
- The possibility that the whole network section is switched off by the protective system at the feeding point

The above mentioned possibilities may result in unnecessary system and customer outages, economical damage and a bad image for the network operator.
The problem of incorrect operation of the protective system in such network structures will be studied in this thesis.

1.4 Objectives and Research Questions

As mentioned in paragraph 1.3, an incorrect operation of the protective system has occurred during faults on network sections designed as shown in Figure 1.5. To analyze this problem, the following objectives and corresponding research questions are compiled:

Objective 1:
Examination of the behaviour of the circulating fault currents during phase faults and earth faults which can occur on different locations in the network section.

The *research questions* that correspond to this objective are:

1. How are the circulating fault currents related to the short circuit location?
2. What is the impact of the fault location on the detected fault current?

Objective 2:
Investigate the behaviour of the protective system during short circuits

The *research question* related to this objective is:
1. Are the protection relays able to detect the fault currents?
2. Is the current direction detected correctly during different system faults?
3. What is the cause of relay mal-operation?

Objective 3:
Investigate the possible strategies that could mitigate the incorrect operation of the protective system during abnormal system behaviour.

The *research questions* defined for the third objective are:
1. Does a change in the network configuration or readjustment of relay settings have any effect on the occurrence of the incorrect relay tripping?
2. Are there other protection strategies that will not result in incorrect relay tripping?

1.5 Thesis Approach

This thesis describes the analysis of the protective systems in certain network sections during system faults. The setting values of the protection relays are determined by the network operator and could be investigated with the help of simulation programs. The characteristics of the relays are obtained from manufacturer data.

The problem of relay mal-function in the network section mentioned in paragraph 1.3 is studied by means of the following steps:

- *The fault current detection in the network during three-phase faults, double-phase faults and earth faults.* The protection system must be able to detect the fault current during abnormal grid situations. Because of the meshed network structure, it is important to determine how the fault currents circulate through the faulted network section and what is detected by the protection equipment.

- *The influence of the fault location on the relay operation.* During system faults in meshed networks, the fault currents circulate through the faulted network section in different directions. A change in the fault location will lead to changes in the network equivalent impedance and this will also have influence on the magnitude of the circulating fault currents. A change in the fault location can lead to a change in the detected fault current magnitude and hence in possible fault detection problems.

- *The impact of other protection strategies or another network configuration on the chance of protection relay malfunction.* There are different ways to protect meshed HV networks. The present protection scheme has shown a chance of malfunction during abnormal grid situations. A different network construction or other protection strategies can prevent relay mal-function.

The different system faults that can occur in the network are studied analytically. The analytical results are obtained by applying circuit theory and by deriving sequence networks looking into the system fault, as it is extensively explained in [4]. Furthermore, fault simulations are carried out in the actual network model from Stedin. The analytical results will then be verified with the obtained simulation results. The protection relays are analysed by comparing the fault current magnitudes and angles with the relay setting values and predefined tripping zones to assess whether fault detection takes place correctly.

There are certain condition strategies that can be studied to try to prevent incorrect operation of the protective system. First, changes will be made to the network construction. In the current situation, the cables in the studied network section are joined together and protected in pairs. They will be uncoupled and protected individually to see if this solves relay mal-function. This will be done analytically. Secondly, the protection scheme settings will be looked at to analyse whether readjustments must take place. Thirdly, alternative protection strategies will be individually implemented in the network and compared to the present protection scheme.

The system faults that are performed in this study are three phase, double phase and earth faults. For the earth faults the cable capacitance is also included in the calculations, because it influences the fault current angle and this angle is important to determine if relay directionality takes place. The actual network and simulations are performed in DIgSILENT's software package 'power factory'. The analytical results are programmed and calculated by making use of the numerical computing program MATLAB.

1.6 Thesis Outline

Chapter 2 – Chapter 2 will be based on the operating principles of protective systems and protection relays. Different protection schemes which are implemented in the power system are discussed.

Chapter 3 – In chapter 3, the main short circuits which occur in power systems are analyzed. These are phase faults and earth faults. This chapter will analyze the short circuits by applying the circuit theory and the method of sequence components, extensively explained in [4]. The analysis results in the relationship between the fault current magnitude and the short circuit location.

Chapter 4 – Chapter 4 analyzes the circulating fault currents which are detected by the protection relays. These fault currents will be obtained analytically and then verified with the simulated fault current values. Thereafter, the fault current phase angle is analyzed to determine whether the elay directionality can take place. With the results obtained in this chapter, the cause of incorrect operation of the protective system is obtained.

Chapter 5 – Chapter 5 deals with possible strategies for the mitigation of the cause of incorrect protective system operation. These strategies are studied analytically or by simulation and the results are compared to the current network situation.

Chapter 6 – This final chapter gives the conclusions of the research and some recommendations for further research.

2

Power System Protection

One of the tasks of an electricity grid operator is to limit the impact of a system disturbance. This should be done in order to prevent accidents, damages, unwanted supply interruptions and financial damage or claims. Power system protection plays a vital role in achieving these goals. Protective systems which make use of protection relays are implemented throughout the system to make sure that a fault is removed by isolating the faulted network section from the remaining (healthy) network as quickly as possible.

This chapter explains the general principles of protective system functioning and operation. In the second part of this chapter all protection relays which are mainly used in power systems will be discussed. This thesis study is related to the operation of overcurrent and directional overcurrent relays, therefore these relays will be discussed in more detail.

2.1 Fundamentals of Protective Systems

According to [3], the main purpose of the protective system is to detect a specific system hazard, such as a short circuit, on a system component and to selectively remove that hazard as quickly as possible. Due the protective system response, the system is restored to the best operating condition under the existing circumstances. The protective system is required to take decisions quickly, in terms of milliseconds, and based mainly on the limited information such as the history or state of the system at the point of observation.

There are two conditions that must be met in order to cause the protective system to trip and to remove a component from normal service [3]:

1. Violate an inequality constraint, $x>X_m$
2. Violate a time constant, $t>T_m$

The inequality constraint "x" stands for the observed system variables, such as the current, the voltage, the frequency or a combination of these variables to help determine phase differences or directionality. These conditions are further explained with the help of the decision flow chart shown in Figure 2.1.

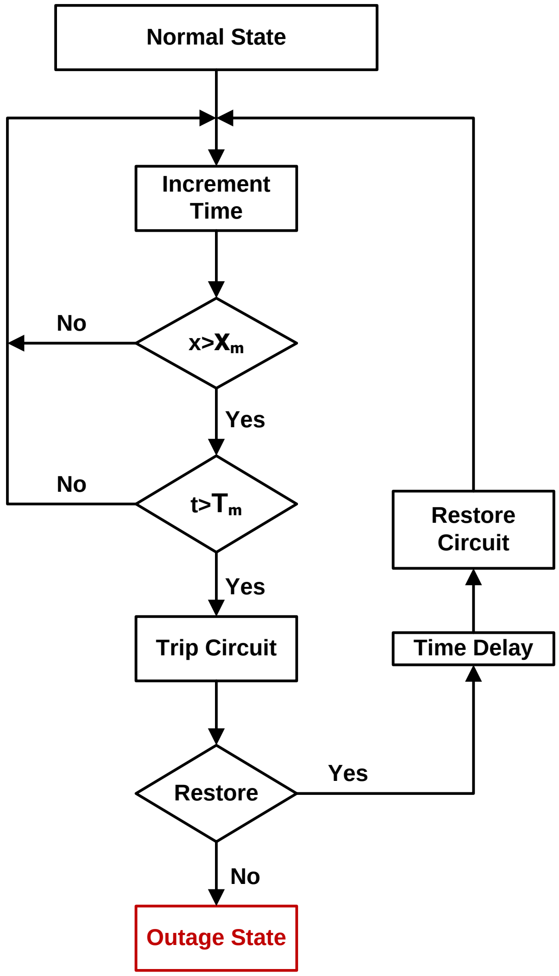

Figure 2.1: Flow chart of protection device tripping decision process

The protective device assumes that the normal state is the starting point. At any time instant, the protective device checks if any of the observed system variables, represented as "x", exceed their threshold value. If the threshold is exceeded (x>Xm), then the time threshold is checked. Only when both quantity and time thresholds are exceeded (x>Xm *and* t>Tm), a tripping action takes place.

Some power system disturbances in overhead lines (e.g. faults due to lightning strokes or branches that came in contact with the power lines) are cleared in a short time delay after the circuit is de-energized and the circuit can be successfully restored. If this is not the case if short circuits occur in underground cable networks. In such cases the circuit remains in the outage stage until the cause of the short circuit is determined and reparations take place.

2.1.1 Operational Aspects of Protection Devices

Protection devices must be able to make a distinction between normal and abnormal system conditions and take action if required. The protection devices consist of different functional elements which are arranged in such a way, that proper relay functionality is obtained. These elements are shown in Figure 2.2.

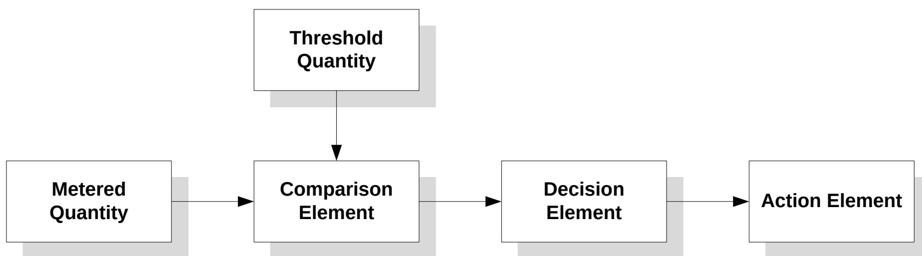

Figure 2.2: Protection device functional elements

Current Transformers (CT) and Voltage Transformers (VT) are applied to produce a scaled down replica of the actual system current and voltage signals. They provide the input parameters for the protection relays. The metered system quantities are mostly the voltage, the current, the frequency or a combination of them. The threshold setting is adjusted by the protection engineer and it is determined from network analysis calculations or with the help of simulation programs. The protection relay compares the metered system quantities with the threshold quantities. When the comparison element detects an abnormal grid situation, the decision element is triggered. Finally, if all required steps are satisfied, the decision element activates the action element and a trip commando will be generated at the circuit breakers nearest to the short circuit. This will result in the isolation of the faulted network section.

It is desirable that a relay removes a fault from the system as quickly as possible, but the above mentioned elements make the relay to operate after a predetermined time interval is surpassed. This time interval is needed to make secure relay decisions. The total time needed to take any (corrective) action is called the "clearing time" (Tc) and is defined as follows:

$$T_C = T_P + T_d + T_a \qquad (2.1)$$

- T_p = *comparison time,* which is the time needed by the relay to compare metered and threshold quantities.
- T_d = *decision time,* is the time needed by the relay to decide whether the relay needs to take action.
- T_a = *action time*, is the time needed by the relay action element to respond and the circuit breaker operating time

When a fault occurs within a network section, the fault will be observed by all the surrounding protection devices. In order to interrupt only the faulted network section, a restraint is needed to trip the devices closest to the fault. Time is often used as a restraint and the clearing time is applied for a proper time-coordination between the different protection devices within the power system.

2.1.2 Protection Relay Types

System faults usually result in very high current levels in the electrical power system. With the help of these high currents, protection relays can determine the presence of a fault and react accordingly. There are many different types of relays for a different purpose and with various design characteristics. There have been a lot of changes in the development of relay technology over the past thirty years. The first relays were electromechanical relays and they have been successively replaced by static, digital and numerical relays. More detailed information about the relay technology can be found in [5], [6].

Protective relays which are mainly used in sub-transmission and distribution grids are:

- overcurrent protection,
- directional protection,
- differential protection and
- distance protection.

These protective relays will be further explained in the next sections. The present work deals mainly with overcurrent and directional overcurrent protection relays. Therefore, the operation and functioning of these relays will be explained in more detail.

2.2 Overcurrent Protection

Overcurrent relays are the most common form of protection, which operate when excessive currents that flow in the power system during different system faults. They are simple protective devices and only one system variable, the current, needs to be monitored. They can also operate as overload protection with their current setting.

There are different relay characteristics that can be developed with the variable current and time. The choice for a certain relay characteristic depends on both the application and the need for coordination with other types of devices in the network.
There are two types of overcurrent protection relays available, namely:

- independent- or definite-time relay and
- inverse-time relay.

2.2.1 Definite-time Overcurrent Relays

When the applied relays operate with an independent time delay the current settings could have any desired current level above the rated current of the protected circuit. The time element provides the coordination for these relays. With the time settings, the circuit breaker nearest to the fault should be tripped in the shortest time. The remaining circuit breakers are tripped in succession with longer time delays when moving towards the source. According to [7], this type of relay is used when the source impedance is large in comparison with the impedance of the protected component. In that case, the fault level at the beginning of the protected element does not differ a lot from the fault level at the end of the protected element. The time/current operating characteristic of the definite time overcurrent relay is shown in Figure 2.3.

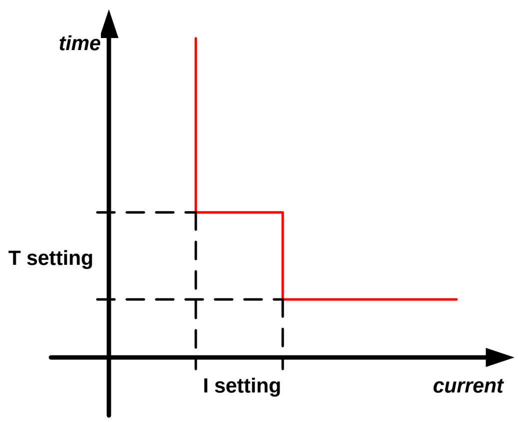

Figure 2.3: Operating Characteristic of a definite time/current relay

The disadvantage of using definite-time overcurrent relays is that the relays close to the source may have unacceptably high operating times for faults in their protected zones. This can be crucial because fault currents which are close to the source are of such high levels that they can only be allowed to persist for short periods.

2.2.2 Inverse-time Overcurrent Relays

An inverse-time stands for the time of relay operation that is inversely proportional to the fault current magnitude. The inverse-time relay operating characteristic is a function of both the time and current settings. Based on the speed of operation, these relays can be classified, in accordance with their characteristic, into 'inverse', 'very inverse' or 'extremely inverse'. The detailed information about obtaining these characteristics is beyond the scope of this thesis and can be found in ([3], [5]), [6]). The different characteristics of the inverse-time overcurrent relay are depicted in Figure 2.4.

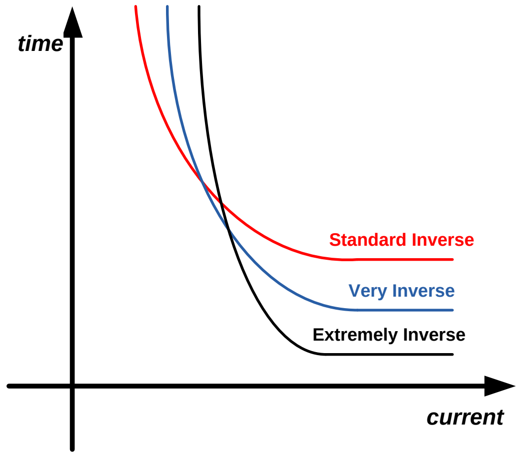

Figure 2.4: Operating Characteristics of an inverse-time relay

Due to its inverse-time character, this relay has the advantage of short tripping times for very high currents. Therefore faster operating times can be achieved close to the source, while still preserving selective relay operation. For this thesis study inverse-time overcurrent relays will not be considered.

2.2.3 Operating Requirements

The overcurrent relay measures only one system variable, the current. The relay obtains its measured quantities through current transformers. The overcurrent protection operating requirements are the overcurrent unit and the time restraint.

A trip commando is activated during abnormal system conditions when the relay restraining values are exceeded for some period of time. The operating requirements of the overcurrent relay are represented by the blocks in Figure 2.5.

Overcurrent Unit

The setting of the relay current threshold value determines whether the overcurrent unit will pick up an abnormal current in the protected zone. In practice the pick-up current (I_P) of the definite-time overcurrent relay is usually set to:

$I_P = 1.5 \times I_N$, with I_N being the nominal current of the protected object

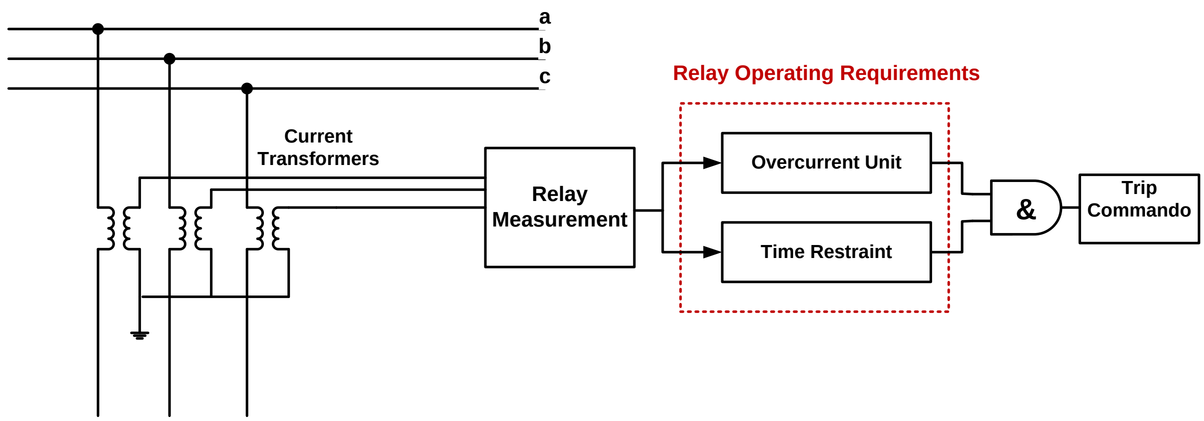

Figure 2.5: Representation of the overcurrent relay operating requirements

Time Restraint

The time restraint determines the total overcurrent relay operating time. The time restraint is used for time grading between the overcurrent relays and the downstream protection devices in the network. Therefore, selective fault clearing is achieved with the time restraint. With the relay time setting the clearing time (Tc) and a time discrimination margin between two successive relays is established. In practice, coordination time grading intervals (T_D) of about 0.5 seconds are used. This interval includes the circuit breaker opening time and a small error margin.

An example of time grading, when using definite-time overcurrent relays in radial systems with grading intervals of T_D = 0.5 seconds, is shown in Figures 2.6 (a) and (b). The coordination procedure starts with the relay located farthest away from the source, which in this case is relay C. This relay is adjusted to the lowest possible operating time or it could even be set to operate instantaneously. By applying time grading, the time settings for relays A, B and S will be:

$$T_{relay\ B} = T_{relay\ C} + T_D$$

$$T_{relay\ A} = T_{relay\ B} + T_D$$

$$T_{relay\ S} = T_{relay\ A} + T_D$$

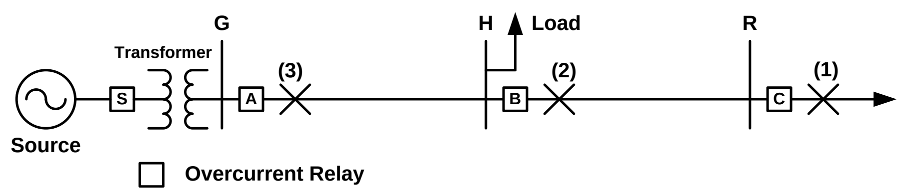

Figure 2.6 (a)

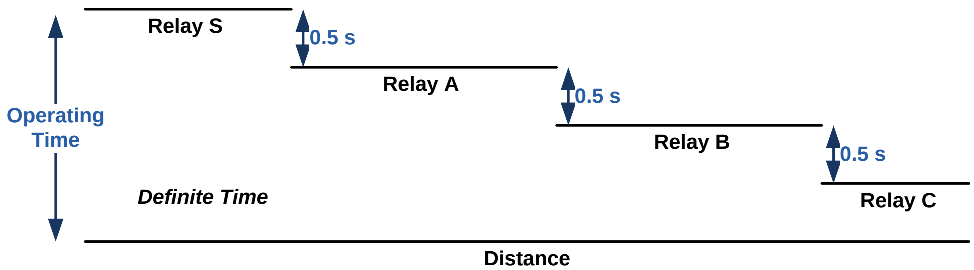

Figure 2.6 (b)

Figure 2.6: (a) Radial network with Overcurrent Relays and Circuit Breakers; (b) Time Grading between Definite-time relays by using grading intervals of T_D=0.5 seconds to obtain selective switching

2.3 Directional Overcurrent Protection

In meshed and loop network constructions or in networks with multiple connected sources, it is difficult to achieve selectivity with overcurrent relays only. Unlike the radial networks, the fault currents in meshed networks are not limited to one direction. Overcurrent relays are non-directional, the current measurement does not give an indication of the current direction. In case of meshed and loop networks satisfactory discrimination can be achieved by implementing directional overcurrent relays (DIR). They are placed in network locations where fault currents which flow in reverse direction (from load side to source side) must be detected.

An example of the difference between fault current behaviour during short circuits in radial and meshed networks is shown in Figure 2.7. In case of short circuits in radial networks the fault current flows from the source side to the load side (one direction only), as shown in Figure 2.7 (a), and overcurrent relays (IOC) can easily be used for fault current detection. The meshed network of Figure 2.7 (b) consists of two parallel cables and during short circuits, fault currents circulates through the mesh. At a certain point in the network, part of the fault current is directed from the load side to the source side. At locations where reversed currents can occur during short circuits, directional overcurrent relays (DIR) are placed (Figure 2.7 (b)). For selective switching directional overcurrent relays are implemented in combination with overcurrent relays to properly isolate the faulted network section.

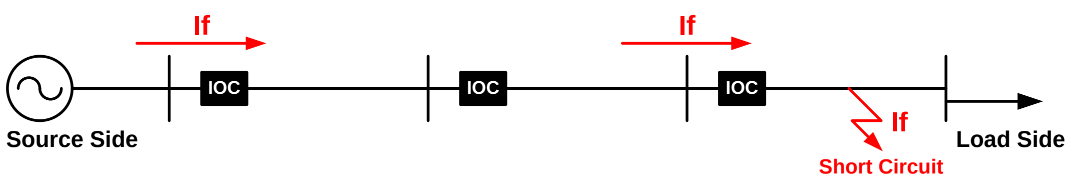

Figure 2.7 (a)

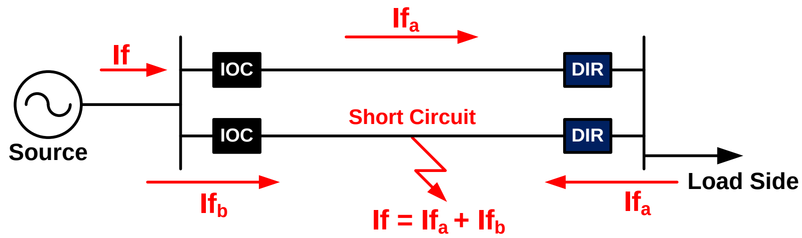

Figure 2.7 (b)

Figure 2.7: An example of a fault current direction when a short circuit occurs in (a) a radial network and (b) a meshed network

2.3.1 Operating Requirements

The directional overcurrent relay obtains its measured input quantities by instrument transformers. The required directional relay input parameters are both the system voltage and current. The directional relay is activated during abnormal system conditions when the relay restraining values are exceeded for some period of time.

The directional overcurrent relay contains three operating requirements, namely the *Overcurrent unit*, *Directional control facility* and the *Time restraint*.

The operating requirements of the directional protection relay are represented by the blocks in Figure 2.8. Only if all three conditions exceed the relay threshold values, a trip command is generated.

The overcurrent unit is activated during abnormal grid situations when the fault current magnitude exceeds the relay threshold value. Then the direction of the current is determined by the directional unit and when the relay determines that the current is directed from the load side to the source side, the directional unit of the relay is also activated. At the moment both current magnitude and direction are detected, the relay starts measuring the time. If these conditions continue until the time restraint is exceeded, the relay generates a trip commando to the nearest circuit breaker.

Overcurrent Unit

The overcurrent unit of the directional overcurrent relay consists of a current threshold. The pick-up current settings are determined in the same way as the settings of the overcurrent relays.

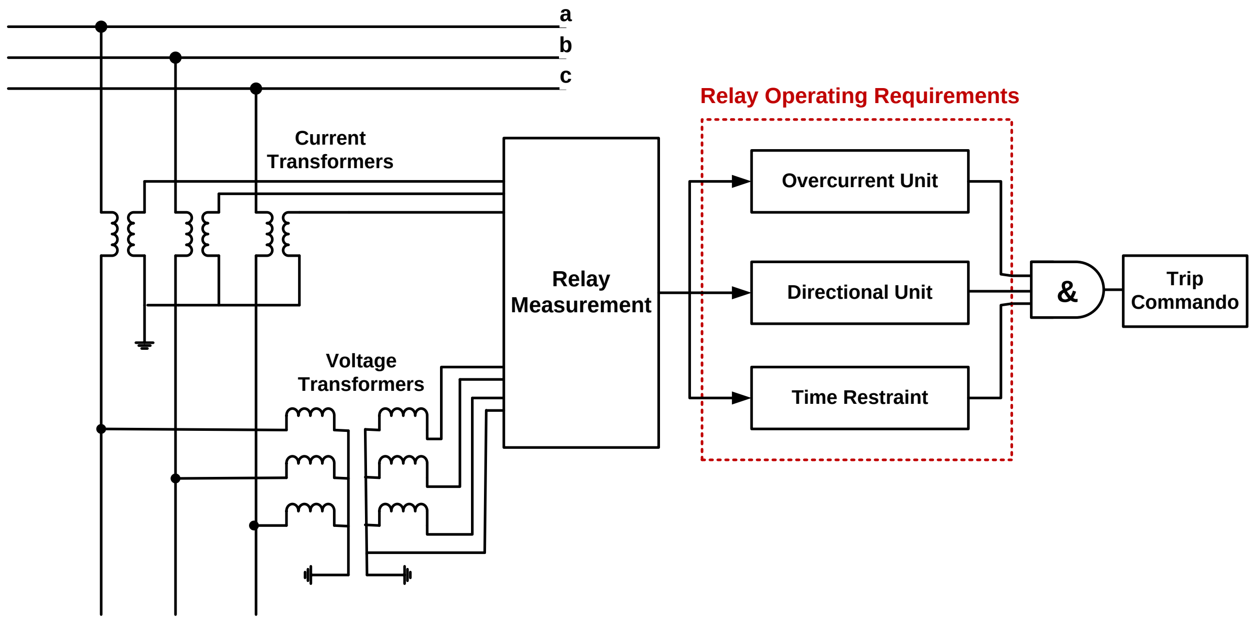

Figure 2.8: Representation of the directional overcurrent relay operating requirements

2.3.2 Directional Unit

It is said that the directional protection relay detects the direction of the current. In fact, it detects the sign of the power flow. The operating principle of the directional unit is originated on wattmeter movements. The relay input measured system parameters are the voltage (V) and the current (I). An operating torque is generated which can be defined as:

$$T = p \cdot \Phi_1 \cdot \Phi_2 \cdot \sin\theta \tag{2.2}$$

Where:
Φ_1 is the flux proportional to the current,
Φ_2 is the flux proportional to the voltage,
θ is the angle between Φ_1 and Φ_2.

When V and I are in phase, the fluxes are out of phase by 90° and this means that a maximum torque is generated. The angle of maximum torque (AMT) is according to [8] defined as the angle for which the displacement between voltage and current produces the maximum torque. This angle is also called the characteristic angle. The characteristic angle plays an important role in determining the direction of the power flow.

For relay directional detection the maximum torque can be easily obtained by measuring the current and voltage from the same phase. However, in practice when a fault occurs in one phase, the voltage of that phase might collapse. Therefore, the measured current of one phase will be compared with a chosen reference or polarizing voltage vector. Mostly the voltage difference between the sound phases is taken as the reference voltage.

Relay Tripping Zone

For detection of the current direction, the relay can be set to operate in 'forward' or 'reverse' direction. The 'forward' direction is generally used for directional relays to detect currents flowing from the load side to the source side. For current detection in this direction, a so called *forward direction zone* can be defined. If this zone has a certain measuring position defined as its bisector, then the forward direction is in evidence if the phasor of the selected phase current is in the range $\leq \pm 90°$ of the measuring position. In other words, directionality is obtained when the fault current phasor is situated within the defined forward direction zone which can also be referred to as the *relay tripping zone* as shown in Figure 2.9. This zone can be determined with the characteristic angle λ and a reference voltage. The relay tripping zone of Figure 2.9 corresponds to the phase A of a three-phase system. A boundary line divides the three phase system plane into a tripping zone and a non-tripping zone. The measuring position is the line perpendicular to the boundary line. The characteristic angle λ is defined by the angular difference between the measuring position and the polarization voltage phasor V_{B-C}.

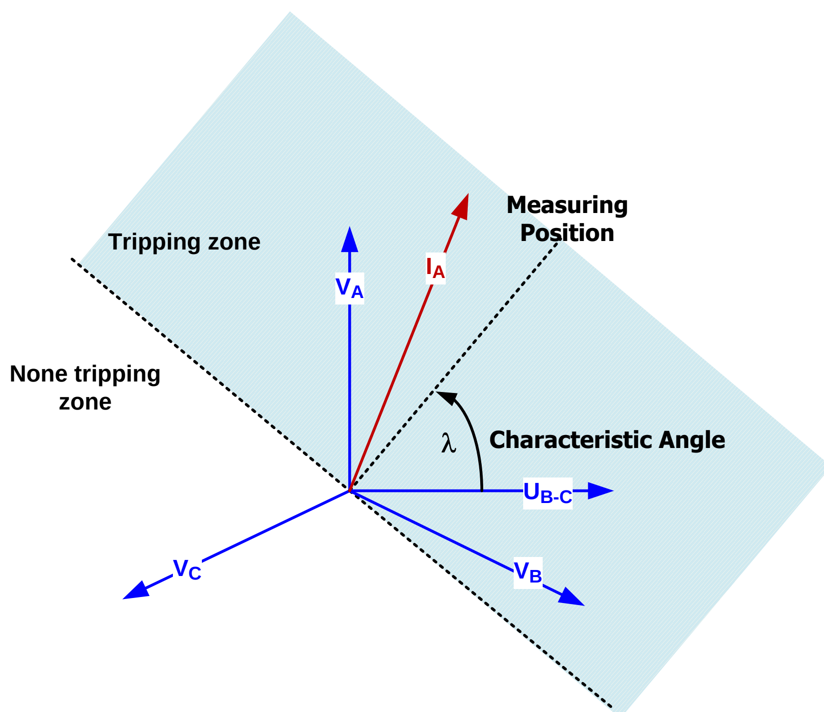

Figure 2.9: Overcurrent relay tripping zone corresponding to phase A of a three phase system

It can be clearly seen in Figure 2.9 that the characteristic angle λ specifies the measuring position relative to the reference voltage. In practice, there are three values for λ commonly used:

- $\lambda = 30^\circ$
- $\lambda = 45^\circ$
- $\lambda = 60^\circ$

Detailed explanation for obtaining these angles can be found in [9].

2.4 Other Types of Protection Relays

2.4.1 Differential Protection

Protection systems which make use of time grading and directional detection cannot always provide correct discrimination for complex networks and in some cases the relay tripping time settings can be unacceptably long at some points in the system. A solution strategy for such situations is the concept of 'unit' protection where sections of the network are being protected individually (as a unit) without reference to other network sections.
The simplest and most frequently applied form of 'unit protection' in transmission and sub-transmission systems is known as 'differential protection'. Differential protection can be used to protect various network components such as generators, transformers, busbars, cables or lines. The principle of differential protection is that the difference in current is measured between the input and output terminals of the protected zone. The zone of protection is everything that lies between the measuring points of the current transformers and these are situated at the beginning and the end of the protected network component.

According to Kirchhoff's current law, the sum of the currents entering and leaving the protected zone must always be equal to zero. This also means that the relay does not trip for faults outside its protection zone. A simplified overview of differential relay operation during different network situations is shown in figures 2.10 (a) and (b).
The current transformers, which form the boundaries of the protection zone, are connected in series on the secondary side. When an external fault occurs or during healthy system conditions, the currents just circulate through the current transformers circuit and no current flows through the differential measuring circuit. If an internal fault occurs, the fault currents flow toward the fault location from both sides. Due to this, the measured currents are not equal anymore and the difference in current will flow via the differential measuring branch. The differential relay immediately picks up a system fault and initiates tripping.

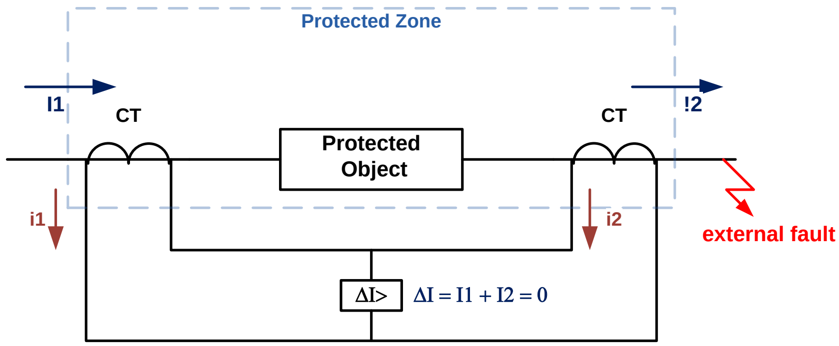

Figure 2.10 (a)

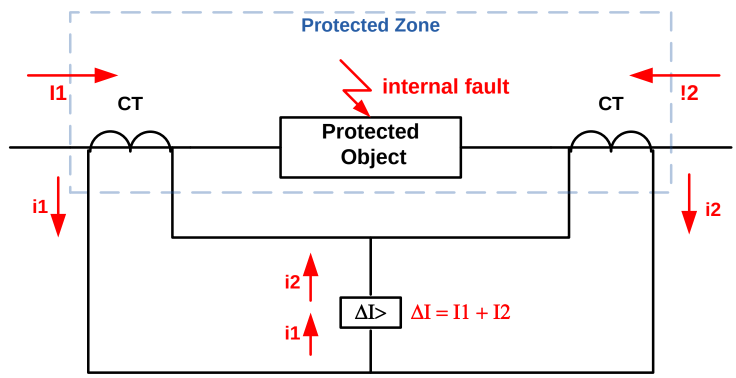

Figure 2.10 (b)

Figure 2.10: (a) Relay Operation during Healthy system condition or External faults; (b) Relay Operation during Internal faults

2.4.2 Distance Protection

Distance protection is mainly used in transmission systems and interconnected distribution networks. It provides an alternative method for the protection of overhead lines and cables, without the need to compare the measured quantities at both ends of the protection zone. Furthermore, distance protection is faster and more selective than overcurrent protection. The concept of this protection device is based on the impedance measurement of lines and cables. The impedance of a transmission line or cable is proportional to its length. The basic principle is that the distance relay measures the line impedance up to a predetermined point (the reach point). The line impedance is obtained from the measured voltage at the relaying point divided by the measured current as shown in figure 2.11.

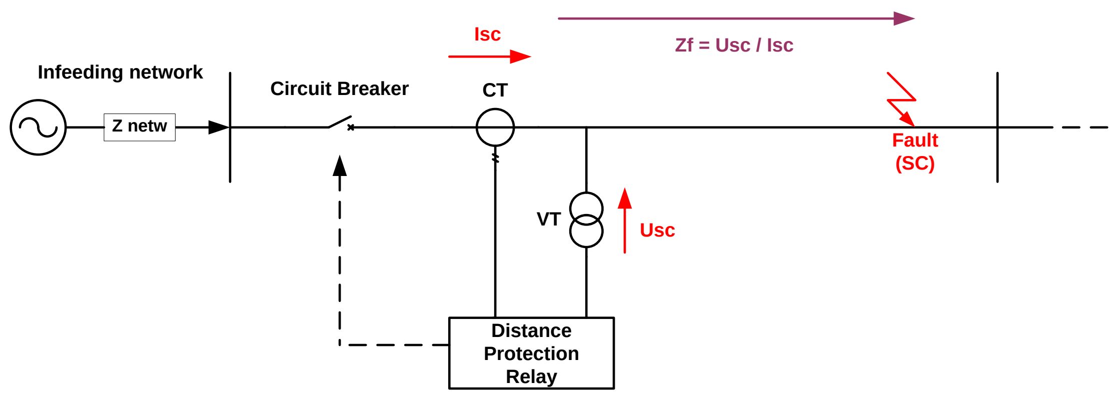

Figure2.11: Principle of the distance protection relay, impedance measurement

The measured impedance is then compared to the known line impedance. If the measured impedance is smaller than the set line impedance, the relay can assume that there exists a fault in the protected zone between relaying point and reach point. A trip command will be generated followed by the opening of the relevant circuit breakers.
However, if faults occur at short distance from the end of a long line and just beyond this end, it is not possible to accurately measure the impedance in order to achieve discrimination. Inaccuracies in distance measurements result from measuring errors, CT errors and the inaccuracy of the line impedance, which is usually based on calculation and not measurement [10]. For this reason, time delays must be incorporated to enable correct discrimination between internal and external faults.

Because a distance protection setting of 100% of the line length is not possible in practice, the line is divided in different stages:

- *Under-reaching stage or first zone*. This zone covers about 85% of the line/cable and thus includes a security margin of 10%-15% from the remote end of the line/cable.
- *Over-reaching stage or second zone,* covers the remainder 10%-15% of the line and can also extend to about 50% of the next line/cable section.

To ensure selectivity, the above stages or zones must be time delayed (graded) relative to the protection of adjacent lines/cables.

In figure 2.12 the distance relay protection scheme with three zones is shown including time grading between successive protection relays.

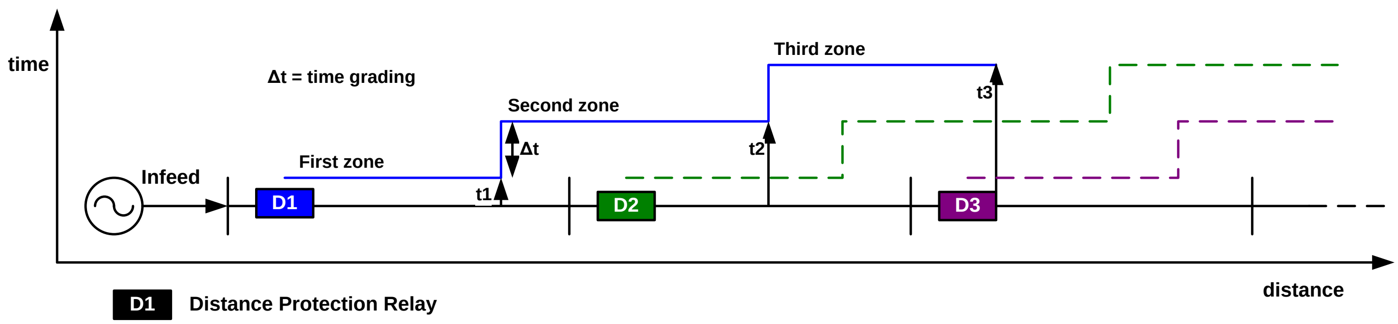

Figure 2.12: Distance relay protection scheme with three zones, including time grading

2.5 Conclusions

In this chapter the general fundamentals of sub-transmission and distribution grid protective systems are discussed. The principles and operational aspects of the mainly used protection relays are explained. It can be concluded that when a fault occurs in a loop or meshed network, the fault current circulates through the network and at a certain point part of this current is directed from load side to source side. In these types of networks a protection scheme consisting of overcurrent and directional overcurrent relays are mainly used to switch off the faulted section selectively. Instead of this protection scheme other types of protection relays, such as differential protection or distance protection relays can also be used.

3

Analysis of Short Circuits in a Meshed Network

In chapter 2 the general fundamentals of commonly used protection devices and the operational requirements of the different relays are discussed. As mentioned earlier, protective systems using protection relays are implemented in the system to make sure that a fault is removed by isolating the faulted network section from the remaining (healthy) network as quickly as possible. According to [4], a short circuit in the network is any failure which interferes with the normal current flow. Short circuits result in high currents and this can have a disastrous effect on the expensive system components.
The origin of a short circuit can be:

- Mechanical: breakdown of system components or conductors accidentally coming in contact, e.g. via a tool or animal.
- Electrical: insulation degradation of system components results in electrical breakdown.
- Due to an Operating Error: caused for example by closing a switching device by mistake, or earthing of one phase, etc.

A short circuit can also be defined according to the location where it occurs:

- The short circuit could occur inside system components (cables, motors, generators, transformers, etc) and will definitely lead to components degradation.
- A short circuit results in high fault currents which are transported by the surrounding system components. The occurrence of a short circuit in the vicinity of system components also leads indirectly to component deterioration and in time this can result in internal faults.

Based on their origin and location, short circuits can be characterized as to be:

- *Self – extinguishing*: the fault disappears on its own.
- *Fugitive*: the fault disappears with the help of protective devices and does not reignite when the system is re-energized.
- *Permanent*: the faulted section must be completely isolated from the remaining system and replacements or reparations need to take place before re-energizing the section again.

For correct application of protective devices it is important to know the distribution of the fault current throughout the system and also the voltages on different points in the system during the fault. These voltage and current values depend on:

- the type of fault which occurs,
- the fault location,
- the network construction,
- the short circuit power.

The different types of faults which can occur in power systems are:

- Three phase faults: a short circuit which involves all three phases of the system. They do not occur very frequently (roughly about 5% of all short circuits are three phase faults), but they have the most disastrous effect because they create the highest fault currents.
- Single line-to-ground faults: are the most occurring faults in the system (roughly about 70%-80% of all short circuits are single line-to-ground faults) and involve just one phase and ground. They create the lowest short circuit fault currents.
- Line-to-line faults: these short circuits do not involve ground and occur between two phases.
- Double line-to-ground faults: involve two phases and ground.

In this chapter, a meshed cable network section of the Stedin grid in which mal operation of the protective system is experienced, will be simplified and used as model for the analysis of all the above mentioned symmetrical and asymmetrical faults. The unsymmetrical faults will be analyzed with the help of symmetrical component analysis, which is extensively explained in [4]. This analysis will lead to an equation which describes the relationship between the short circuit location and the total fault current. It should be mentioned that all analyzed short circuits in this chapter are bolted faults, which means that the arc resistance is assumed to be zero. The required network component parameters are obtained from manufacturer data and given in *Appendix B*. The network analysis is performed with the help of the numerical computing program MATLAB.

3.1 Determination of a Meshed Network Analysis Model

Stedin is a Distribution System Operator (DSO) in the western part of the Netherlands. This DSO is responsible for the operation of parts of the Dutch sub-transmission and distribution grids. In the 25.6 kV sub-transmission network of Stedin certain network structures which are similar to the one shown in Figure 3.1 are used. The surrounding connected sub-transmission network is represented as the External Grid and there is also an outgoing load connected. This network section represents a three phase cable system and it also includes the protection schemes. The protection schemes consist of an overcurrent relay (IOC) in combination with a directional overcurrent relay (DIR).

The network consists of three cable sections which are protected individually:

- Section one consists of two parallel cables (Cables 1 and 2), which are joined together at both ends into one single cable again.
- Section two (Cables 3 and 4) is constructed in the same way as section one.
- The third section consists of a single cable (Cable 5) which is parallel with sections one and two.

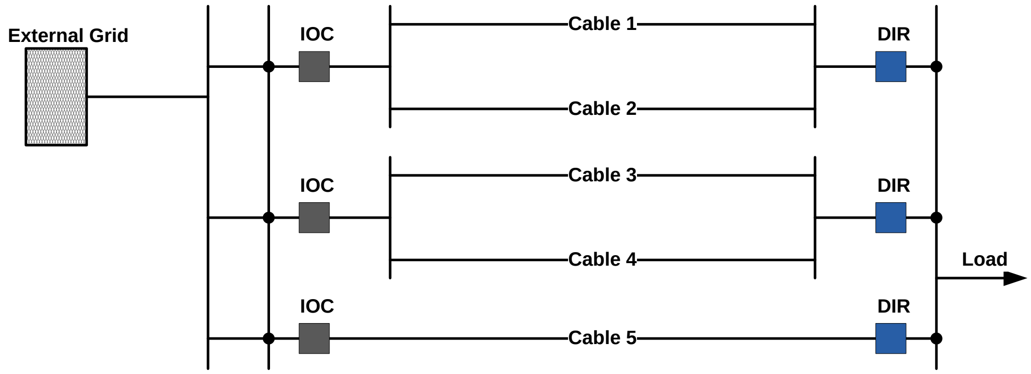

Figure 3.1: (Meshed) Network model including protection relays

From the actual network section shown in Figure 3.1 a simplified model will be made which can easily be analyzed. To do this, first the equivalent impedance network model is constructed and depicted in Figure 3.2. This model includes the impedances (Z) of all cables individually with the impedance Z being the total impedance of all three phases. The external network is represented by the equivalent system impedance (Z net) and a voltage source.

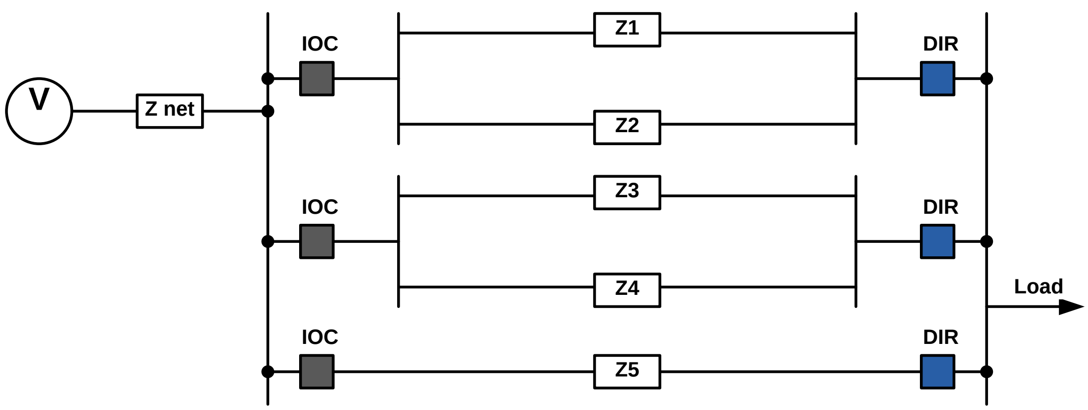

Figure 3.2: Equivalent Impedance network model, including protection relays

The short circuit analysis will be done for 'Cable 1'. The behavior of the fault currents in this cable section during short circuits on 'Cable 1' will be the same for faults in the other cable sections. This also counts for the operation of the protective system. That is why this impedance model can be simplified by replacing impedances Z_2, Z_3, Z_4 and Z_5, which are all mutually parallel. By using formula (3.1) the simplified equivalent impedance model is shown in Figure 3.3.

$For\ Z_1 = Z_2 = Z_3 = Z_4 = Z_5 = Z$

$$Z_{2,3,4,5} = Z_2//Z_{3,4,5} = \frac{Z_2 Z_{3,4,5}}{Z_2 + Z_{3,4,5}} = \frac{Z \cdot {}^1\!/_3 Z}{Z + {}^1\!/_3 Z} = \frac{{}^1\!/_3 Z^2}{{}^4\!/_3 Z} = {}^1\!/_4 Z = 0.25Z \tag{3.1}$$

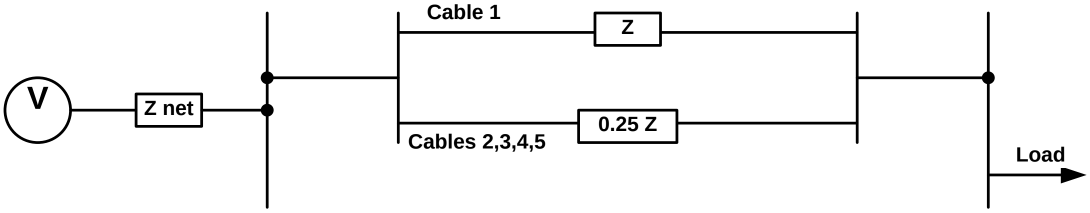

Figure 3.3: Simplified Equivalent impedance model

Network Impedance (Z net)

The network impedance is obtained from the network short circuit capacity S_k and the maximum short circuit current $I_{f(max)}$ which can flow through the network section. The maximum short circuit current through the network section is obtained by simulating a three phase short circuit on the network busbar, as shown in the following figure.

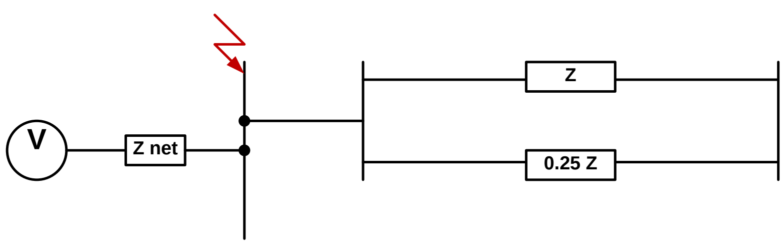

Figure 3.4: Three phase short circuit performed on the network busbar to obtain maximum short circuit current

The network impedance is calculated as follows:

$S_k = V \cdot I_f \overset{so}{\Rightarrow}$

$$I_{f(max)} = \frac{S_k}{V} = \frac{V^2 \cdot Z}{V} = VZ \tag{3.2}$$

The simulation results give the following:

Table 3.1: Simulation results for fault a short circuit on the network busbar

$V \quad (kV)$	$I_f \ (kA)$
$\frac{25.6\ kV}{\sqrt{3}} = 14.78$	19.077

BY making use of (3.2) and the parameters in Table 3.1 the total network impedance can be calculated as follows:

$$Z_{net} = \frac{V}{I_{f(max)}} = j0.7748\ \Omega \qquad (3.3)$$

3.2 Derivation of the Short Circuit Location

The simplified impedance network model of Figure 3.3 will be used to analyze short circuits on various locations of Cable 1 in the network section shown in Figure 3.1. This cable with a length L_{tot} is on each side connected to a joint. If a short circuit occurs on the cable at a certain distance L, a distance parameter "k" can be defined to indicate the location of the short circuit in percentage of the total cable length. The distance parameter k is defined as follows:

$$k = \frac{L}{L_{tot}} \times 100\% \qquad (3.4)$$

As shown in Figure 3.5, if a short circuit occurs on the cable at location k, the cable impedance Z will be divided in two parts, namely:

- $k \cdot Z$
- $(1-k) \cdot Z$

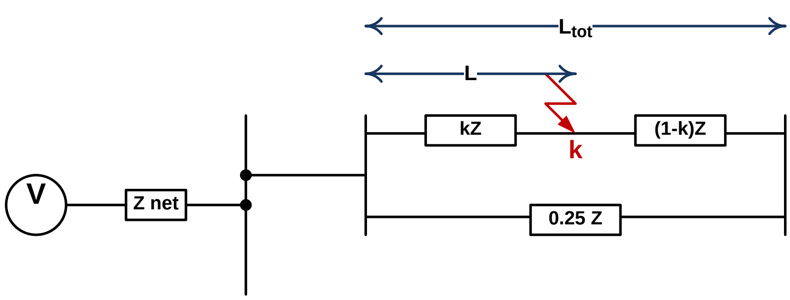

Figure 3.5: Network impedance model during short circuits occurring on certain location k of Cable 1.

During short circuits, large currents circulate through the network. The magnitudes of these short circuit currents in the different network sections are dependent on the impedances throughout the network. The fault location "k" determines the division of the faulted cable impedances and thus the equivalent impedance seen looking back from the fault into the system. If the short circuit location changes, the value of "k" and thus the equivalent impedance will also change. This means that the circulating fault currents and the total fault current are dependent on the location "k" of the cable where the short circuit takes place. This will be worked out in the following paragraphs.

3.3 Three-Phase Faults

A three phase fault is a symmetrical fault because all phases are involved equally at the same location. This is shown in Figure 3.6. Immediately after the short circuit occurs in the network, a short circuit current flows which is dependent on the network impedances and the fault location.

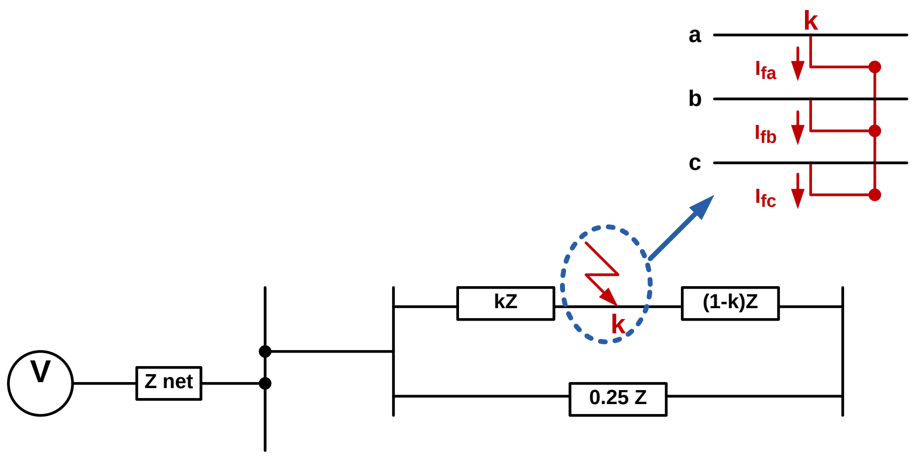

Figure 3.6: Overview of a three phase fault at fault point k in the simplified network model

Because a three-phase fault is a symmetrical fault, the total fault current can easily be derived by using Thevenin's Theorem, which creates an impedance model looking from the fault back into the network. In this model the currents produced throughout the network by the fault can simply be found by applying the voltage just before the fault occurs (V_f) to the fault point k. This model is constructed in Figure 3.7.

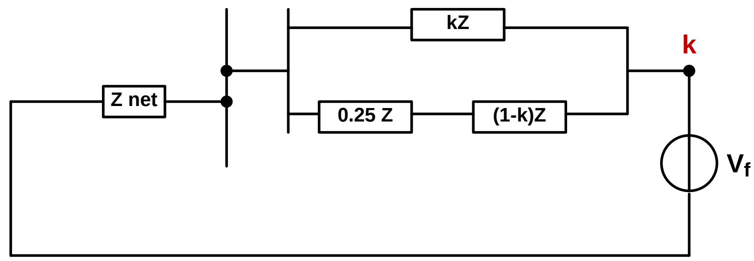

Figure 3.7: Equivalent impedance model with V_f applied to the fault location

With the model of Figure 3.7 the total Thevenin impedance can be obtained as a function of the fault location k as follows:

- First determine the sequence impedance of the parallel network section (Z_{par}):

$$0.25Z + (1-k)Z = 0.25Z + Z - kZ = Z(1.25-k) \overset{so}{\Rightarrow}$$

$$Z_{par} = kZ//Z(1.25-k) = \frac{kZ \cdot (1.25-k)}{kZ + (1.25-k)} = 0.75kZ(1.25-k)$$

- Together with the network impedance, the Thevenin impedance (Z_{th}) is:

$$Z_{th} = Z_{net} + 0.75kZ(1.25-k) \tag{3.5}$$

After a three phase fault occurs the system will stay symmetrical. This means that the impedance between each line and a common point stays the same. With the fault impedance Z_{th} equal in all phases and the voltage (V_f), the total fault current (I_k) as function of the fault location k can easily be defined:

$$I_f = \frac{V_f}{Z_{th}} = \frac{V_f}{Z_{net} + 0.75kZ(1.25-k)} \tag{3.6}$$

Equation (3.6) can graphically show how the total fault current varies with the fault location can be made. To do so, the location k is subdivided into parts of 10% cable length (k = 0, 0.1, 0.2… 1) and in every section the three phase fault current is analyzed. All required parameter values are given in Table 3.2.

Table 3.2: Network parameters used to obtain three phase fault currents

V_f	*Z net* (Ω)	*Z cable* (Ω)
$\frac{25.6\ kV}{\sqrt{3}} = 14.78\ kV$	$j\ 0.7748$	$(0.2364 + j0.2364)$

Substituting the parameters of Table 3.2 in (3.6) for 0%<k<100%, the three phase fault current as a function of fault location can be calculated as shown in Figure 3.8.

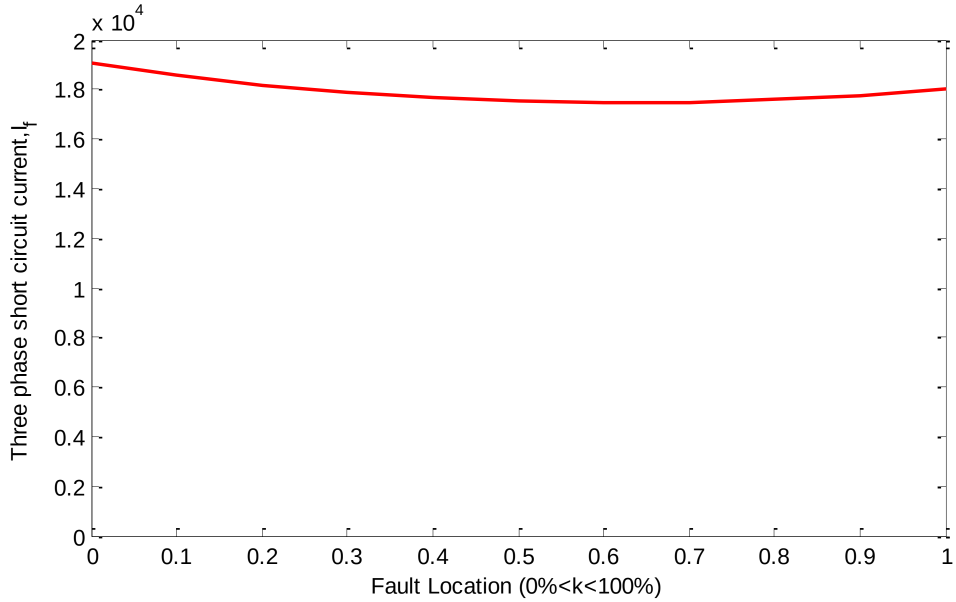

Figure 3.8: Three phase fault current as function of varying fault location 0%<k<100%.

3.4 Line-to-Line Faults

A Line-to-Line fault is an asymmetrical fault which occurs when two phases of the network are distorted, as shown in Figure 3.9. During the fault current period symmetry of the system is distorted and this results in unbalanced voltages and fault currents through the network. During an unbalanced network situation, the system can be analyzed with "the Method of Symmetrical Components", which is extensively explained in [4].

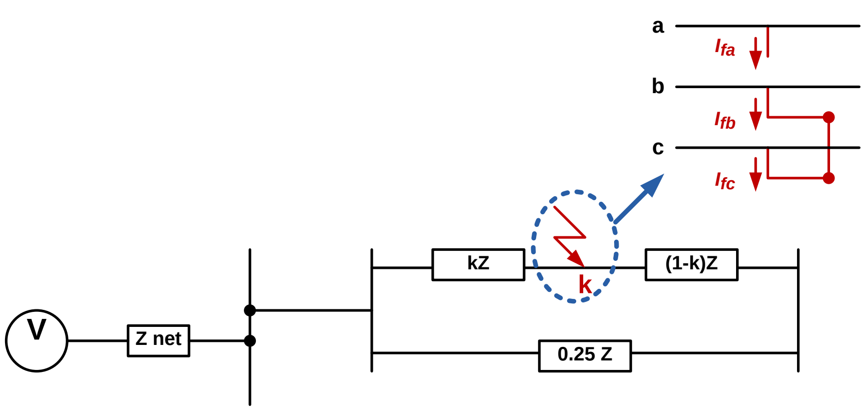

Figure 3.9: Overview of a phase to phase short circuit between phase b and phase c at location k

The line-to-line fault occurs at location k in the phases b and c. As explained in [4], the following relations are satisfied at the fault point, with $Z_{arc} = 0$:

- $I_{fa} = 0$
- $I_f = I_{fb} = -I_{fc}$ (3.7)
- $V_{kb} - V_{kc} = 0$

As explained in [4] the derived conditions for the positive and negative sequence currents are:

- $I_f^{(0)} = 0$
- $I_f^{(1)} = -I_f^{(2)}$
- $V_k^{(1)} - V_k^{(2)} = 0$

This indicates that the positive and the negative sequence networks should be connected in parallel. The zero sequence current is zero, because the short circuit does not involve earth. This means that the zero sequence network could be omitted during the analysis of the total fault current. The connection of the sequence networks during a double phase fault is shown in Figure 3.10 (a) and it is simplified to the network shown in Figure 3.10 (b).

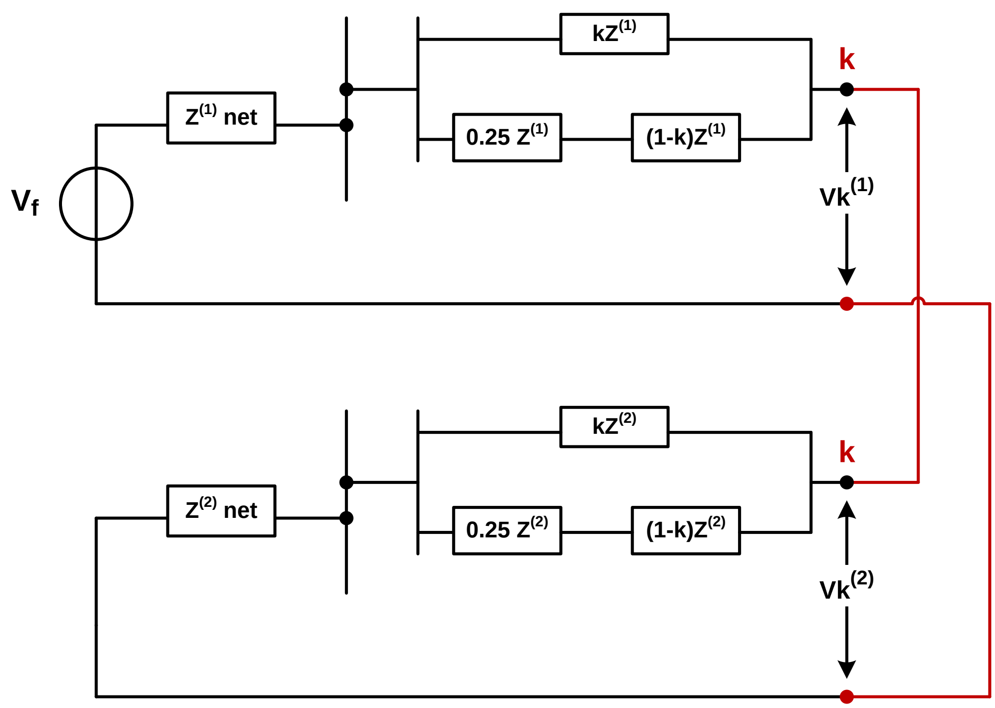

Figure 3.10 (a)

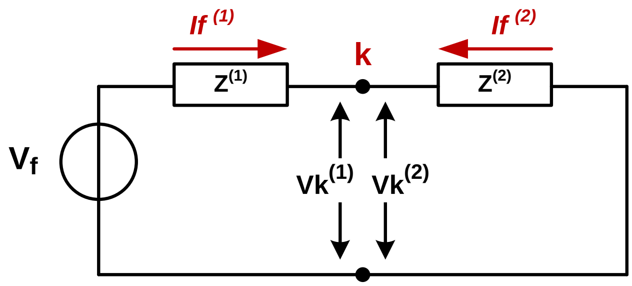

Figure 3.10 (b)

Figure 3.10: (a) Connected Positive and Negative Thevenin sequence networks during line-to-line faults; (b) Simplification of connected sequence networks during line-to-line faults

Because there are no sources involved in the studied network, the negative sequence impedance is equal to the positive sequence impedance. These impedances can easily be derived from Figure 3.10:

$$Z^{(1)} = Z^{(2)} = Z_{net} + 0.75kZ(1.25 - k) \tag{3.8}$$

According to (3.8) the positive and negative sequence currents can be expressed as function of short circuit location "k":

$$I_f^{(1)} = -I_f^{(2)} = \frac{V_f}{Z^{(1)} + Z^{(2)}} = \frac{V_f}{1.5kZ(1.25 - k) + 2Z_{net}} \tag{3.9}$$

After the sequence currents are determined, transformation to phase domain can be done to determine the phase fault currents and the total line-to-line fault current. As explained in [4], this transformation leads to the following relations between the sequence and phase components:

- $I_{fa} = 0$
- $I_{fb} = a^2 I_f^{(1)} + a I_f^{(2)}$ (3.10)
- $I_{fc} = a I_f^{(1)} + a^2 I_f^{(2)}$ (3.11)

The relation between the total line-to-line fault current as a function of the short circuit location k can be determined with the help of formulas (3.7), (3.9), (3.10) and (3.11). The relationship of the total fault current as function of the short circuit location is shown in Figure 3.11, for 0% < k < 100%. For the system variables, the network parameters and transformation operators of Table 3.2 are used.

Table 3.3: Network and transformation parameters used to obtain line-to-line fault currents

V_f	$Z^{(2)}$=$Z^{(1)}$ net (Ω)	$Z^{(2)}$=$Z^{(1)}$ cable (Ω)	Operator
$25.6\ kV$	$j\ 0.7748$	$(0.2364 + j0.2364)$	$a = (-0.5 - j0.866)$ $a^2 = (-0.5 + j0.866)$

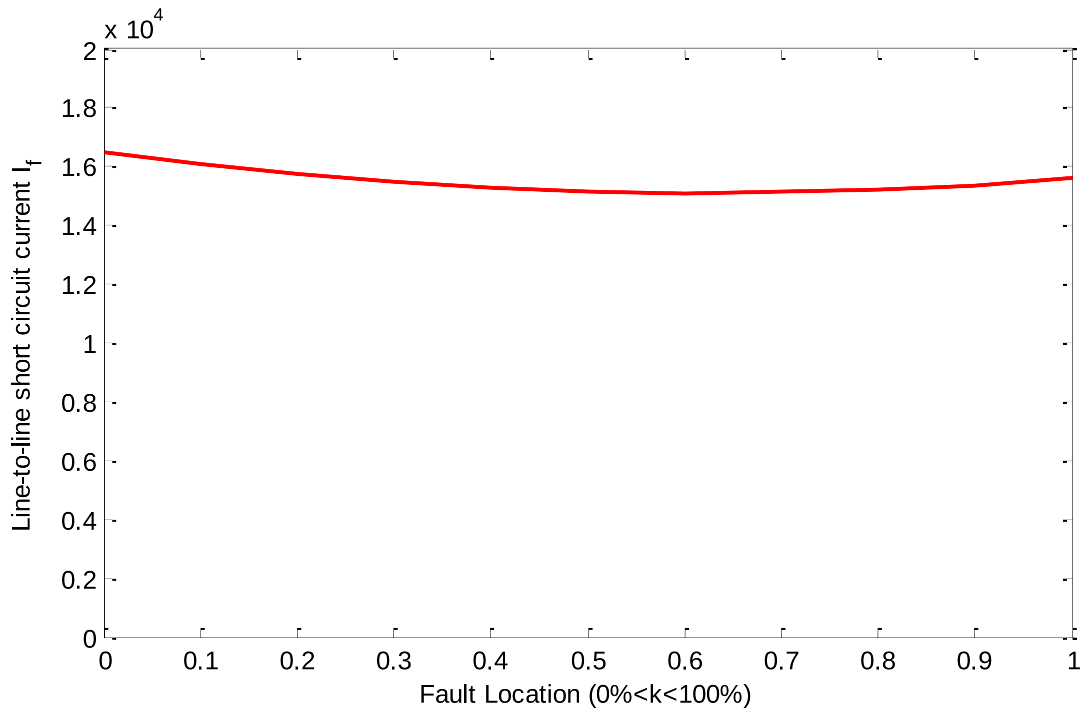

Figure 3.11: Line-to-line fault current as a function of the varying fault location 0%<k<100%

3.5 Single Line-to-Ground Faults

The single line-to-ground fault occurs most often in power systems. During these faults a single phase makes contact with ground. One example for a phase to ground fault is shown in Figure 3.12. Such a short circuit current could be caused by lightning when conductors make contact with grounded structures.

It should be kept in mind that for this study, the single line-to-ground fault is analyzed in an underground cable network.

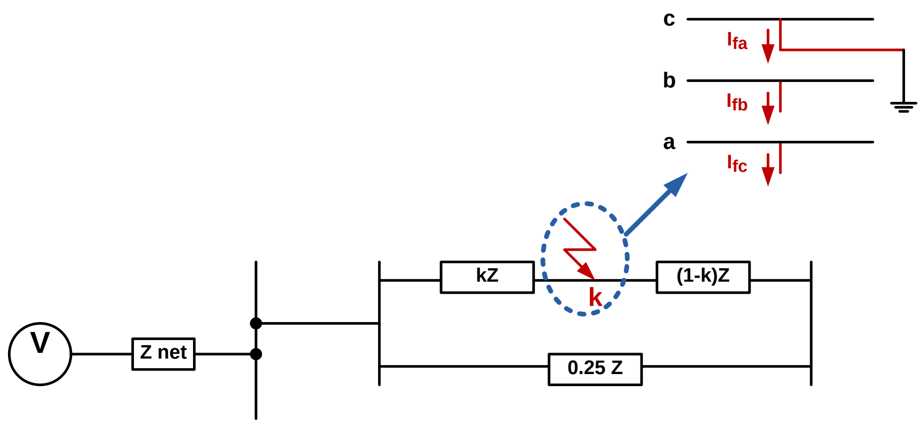

Figure 3.12: Overview of a single phase-to-ground fault on phase a at fault point k

To analyze the single line-to-ground fault in this network, the following network parameters are important:

- the system grounding,
- the cable capacitance,
- the zero sequence impedance.

3.5.1 System Grounding

Whenever a fault occurs between a system phase and the ground, the grounding method and grounding impedance of the network are important. During a fault to ground, the fault-current magnitude and associated overvoltages strongly depend on the system grounding.

The system can be grounded at a neutral point, which is the common point of three star connected windings (mostly a transformer star point). The different system grounding methods in sub-transmission and distribution networks are:

- *Solidly grounded neutral:* there exists an electrical connection between the neutral point and earth, shown in Figure 3.13 (a).

- *Isolated neutral:* there exists no electrical connection between the neutral point and earth, shown in Figure 3.13 (b).

- *High Impedance grounding, Resistance grounding, Reactance grounding and Peterson coil grounding:* for this method of earthing high impedance, resistance, reactance or coil, are used respectively between the neutral point and the earth. This is shown in figure 3.13 (c).

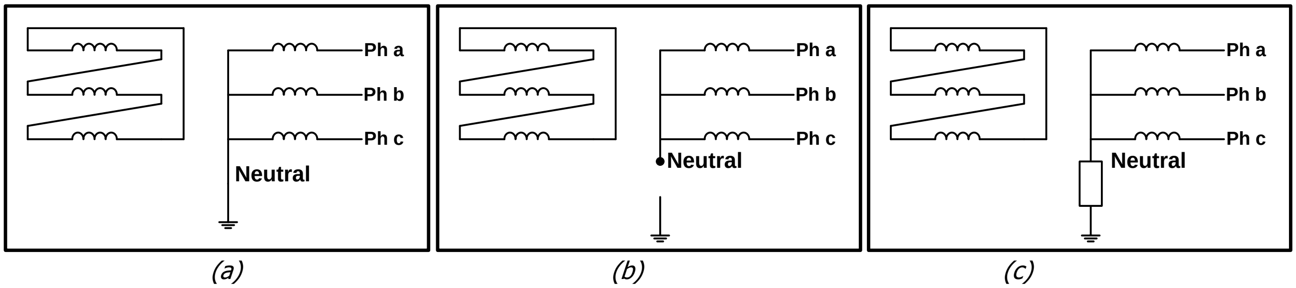

Figure 3.13: Methods of system grounding in distribution and sub-transmission networks, (a) solidly grounded neutral. (b) isloated neutral, (c) representation of high impedance grounding, resistance grounding, reactance grounding and Peterson coil grounding

Advantages and disadvantages of the above grounding methods can be found in [9].

The studied network section is a resistance grounded (R_g) network. According to [11], resistive grounding is used to prevent transient overvoltages and thereby reducing equipment damage. Other advantages are:

- When a ground fault occurs, the fault current is limited to lower values in order to prevent equipment damage and arc flash hazards.
- It allows the use of simple selective protection devices.

3.5.2 Cable Capacitance

A cable can be considered as a distributed capacitor. A capacitance exists due to the potential difference between the conductor and ground (potential across the insulation). In the absence of a fault, a balanced three-phase current circulates in the network's capacitances and because these currents are symmetrical, the current value in the neutral earthing is zero. If a single line-to-ground fault occurs a fault current will flow between the faulted feeder and ground. The circulating current is reclosed by the grounding impedance and the phase-to-earth capacitances of the healthy feeders. This is clearly shown in Figure 3.14 and in this case the fault current (I_f) is:

$$I_f = I_C + I_N$$

Where:

- I_C is the current that flows through the phase-to-earth capacitances of the healthy feeders,
- I_N is the current that flows through the neutral earthing impedance.

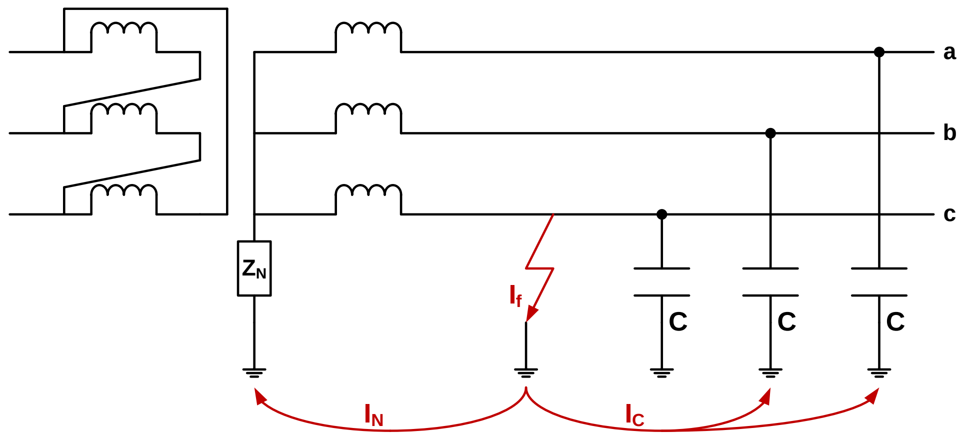

Figure 3.14: Ground fault current reclosed by the grounding impedance and the phase earth capacitances of the healthy feeders

The positive, the negative and the zero sequence capacitances of the cables are determined by the way the cable is shielded. A cable could be collectively shielded or individually shielded as displayed in Figure 3.15.

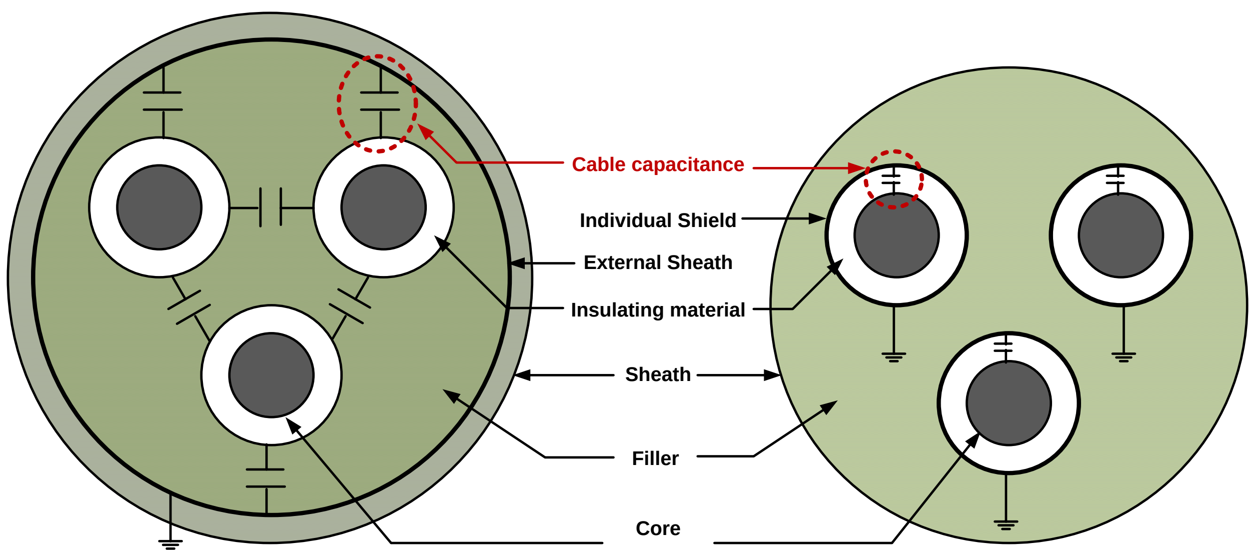

Figure 3.15: Collective shielded cable (left) and individually shielded cable (right), including the cable properties

The cables used for this study are three phase individually shielded cables. For these cables, the following counts for the positive, negative and zero sequence cable capacitances [12]:

$$C^{(0)} = C^{(1)} = C^{(2)} \tag{3.12}$$

Information about other cable structures and their capacitances can be found in ([9], [12]).

Capacitive Reactance

The capacitive reactance X_C of the cable is inversely independent on the cable capacitance (C) and the frequency (f) at which it operates. This relationship is given in formula (3.13).

$$X_C = \frac{1}{2\pi f C} \tag{3.13}$$

3.5.3 Sequence Impedances and Ground Fault Calculation

As mentioned earlier, the zero-sequence impedance is also important during ground fault analysis. The zero sequence impedance of the studied network can be determined in two steps, namely:

- first, the zero sequence of the external grid $Z_{net}^{(0)}$, should be obtained,
- secondly, the zero sequence impedance of the complete model $Z^{(0)}$, can be derived after simplifying the network impedance model

Zero-sequence impedance of the external grid

The network impedance is obtained by simulating a single phase-to-ground fault on the network busbar, as shown in Figure 3.16. By doing so, the maximum ground fault current $I_{fg(max)}$ which can flow through the network section is obtained.

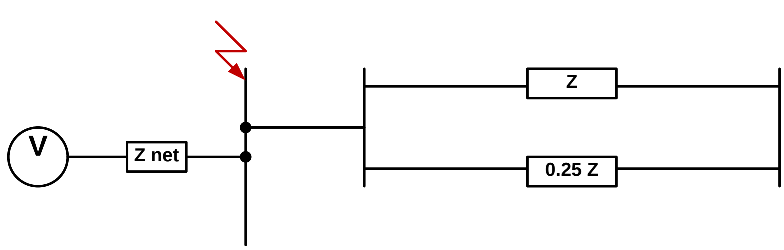

Figure 3.16: Single phase-to-ground fault performed on network busbar to obtain maximum ground fault current

With the maximum ground fault current, the network zero sequence impedance can be calculated as follows:

$$I_{fg(max)} = 3I^{(0)} = \frac{3V_f}{Z_{net}^{(1)} + Z_{net}^{(2)} + Z_{tot}^{(0)}} \quad \overset{so}{\Rightarrow}$$

$$Z_{tot}^{(0)} = \frac{3V_f}{I_{fg(max)}} - \left(Z_{net}^{(1)} + Z_{net}^{(2)}\right) \tag{3.14}$$

With: $Z_{tot}^{(0)} = 3R_g + Z_{net}^{(0)}$ (3.15)

If the network parameters and the parameters obtained from the simulation results, shown in Table 3.4 are substituted in (3.14) and (3.15), the network zero sequence impedance is:

$$Z_{net}^{(0)} = j4.5\ \Omega$$

Table 3.4: overview of the network parameters and parameters obtained from the simulation results

V_f (kV)	$I_{fg(max)}$ (kA)	$Z_{net}^{(1)} = Z_{net}^{(2)}$ (Ω)	R_g (Ω)
$\frac{25.6\ kV}{\sqrt{3}} = 14.78\ kV$	1.509	$j0.7748$	10

Sequence impedances of the complete network model

Figure 3.17 shows the single line-to-ground fault on location k of the studied network model including the network and cable capacitances. The cables and their capacitances form a π-structured network. One should note that this network model is a simplification of the detailed model shown in Figure 3.2. Therefore, the cable capacitances shown in Figure 3.17 are equivalents for all individual cable capacitances. This is done as follows:

- the capacitance per cable C_{Cable} , is equal for all cables in the studied network section,

- cables 2, 3, 4 and 5 are parallel connected in the detailed model and replaced by one single cable in the simplified model. This also holds for their capacitances:

  $$C_2//C_3//C_4//C_5 = C = C_2 + C_3 + C_4 + C_5 \tag{3.16}$$

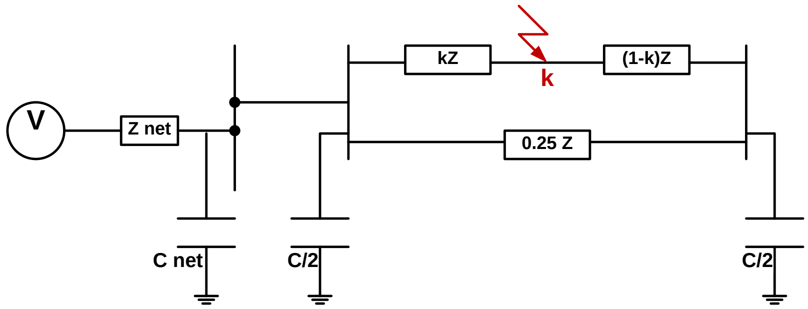

Figure 3.17: Single line-to-ground fault in the π-structured network model including the cable capacitances

To determine the sequence networks and impedances more easily, the network model of Figure 3.17 can be simplified first with the help of some intermediate steps which include the Y-Δ-Y transformation. The basic Y-Δ transform is explained in *Appendix A*. The simplification is done to obtain the replacement impedance of the network, when looking into the fault. With this impedance, the sequence impedances can easily be obtained.
The intermediate steps to simplify the network of Figure 3.17 are explained by means of Figures 3.18 (a), (b) and (c). The equivalent impedance (Z_i) shown in Figure 3.18 (c) is obtained as follows:

As shown in Figure 3.18 (a):

$$A_1 = (1-k)Z$$
$$A_2 = 0.25Z$$
$$A_3 = X_{(\frac{C}{2})}$$

$$X_p = X_{Cnet} // X_{(\frac{C}{2})} = \frac{X_{Cnet}X_C}{2X_{Cnet} + X_C} \tag{3.17}$$

As shown in Figure 3.18 (b):

$$D_a = (1-k)(Z + 2X_C) + 0.5X_C \tag{3.18}$$
$$D_b = \frac{2Z}{X_C}(1-k)(0.25Z + 0.5X_C) + 0.125 \tag{3.19}$$
$$D_c = (0.25Z + 0.5X_C) + \frac{0.125X_C}{(1-k)} \tag{3.20}$$

$$B_d = D_a$$

$$B_e = \frac{D_b kZ}{D_b + kZ}$$

$$B_f = \frac{D_c X_p}{D_c + X_p}$$

As shown in Figure 3.18 (c):

$$Z_i = \frac{Z_6 Z_4}{Z_6 + Z_4} + Z_5 + Z_{net} \tag{3.21}$$

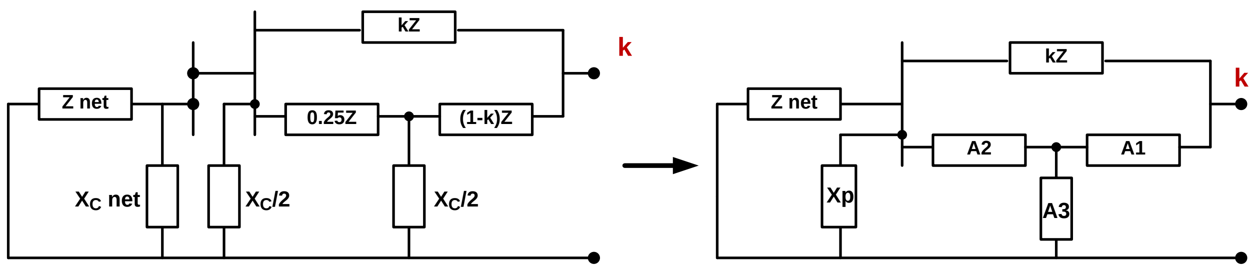

Figure 3.18 (a)

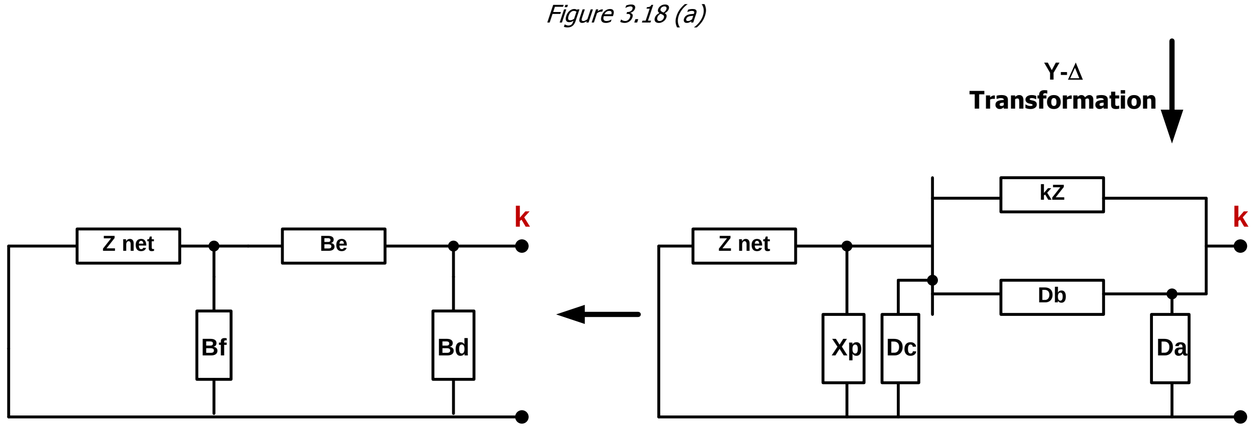

Figure 3.18 (b)

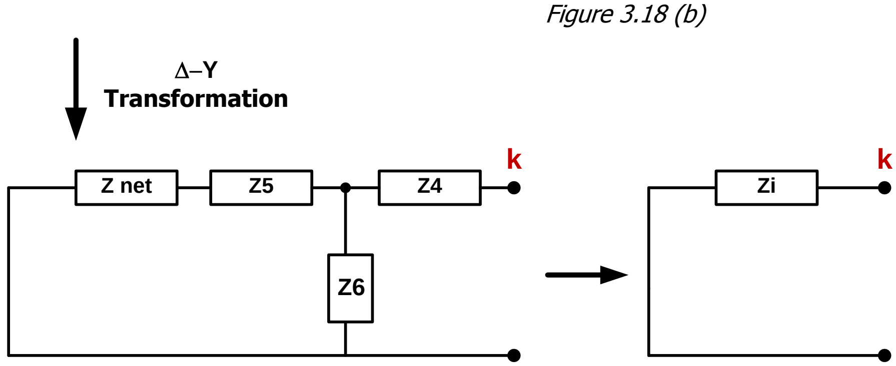

Figure 3.18 (c)

Figure 3.18 (a), (b), (c): Intermediate steps to simplify the network, by using Y-Δ-Y transformation

Fault-current Calculation

As shown in Figure 3.12, a single line-to-ground fault occurs on phase a in the network. As explained in [4], the following conditions are satisfied when $Z_{arc} = 0$:

- $I_{fb} = 0$
- $I_{fc} = 0$
- $V_{ka} = 0$

The sequence voltages and currents for the positive, negative and zero sequence components are:

- $V_k^{(0)} = -Z^{(0)} I^{(0)}$
- $V_k^{(1)} = V_f - Z^{(1)} I^{(0)}$
- $V_k^{(2)} = -Z^{(2)} I^{(0)}$
- $I_f^{(0)} = I_f^{(1)} = I_f^{(2)} = \frac{V_f}{Z^{(1)}+Z^{(2)}+Z^{(0)}}$ (3.22)

Equation (3.22) can be represented by a circuit as shown in Figure 3.19. The positive, negative and zero sequence impedances can be found by using equations (3.17) to (3.21) and they are derived as follows:

- $Z^{(1)} = Z^{(2)} = Z_i$ (3.23)
- $Z^{(0)} = 3R_g + Z_i$ (3.24)

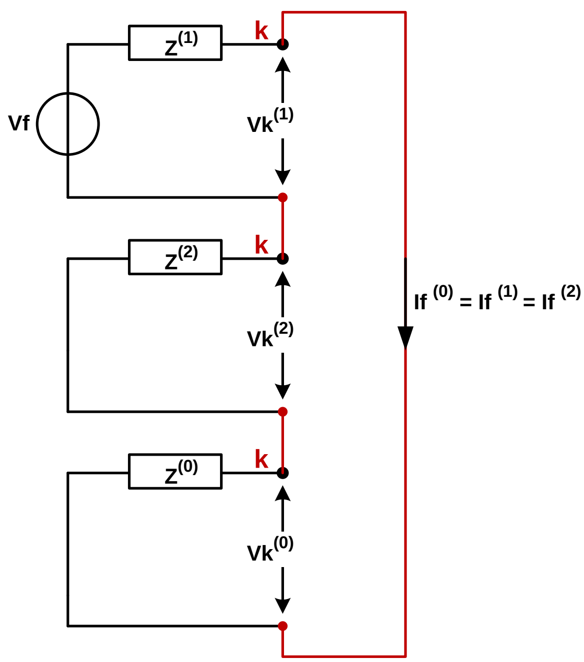

Figure 3.19: Interconnected sequence networks for the single line-to-ground fault

After the sequence currents are determined, the transformation from the sequence to the phase domain should be done in order to determine the total earth fault current. As shown in [4], the total fault current is:

- $I_{fa} = I_f^{(0)} + I_f^{(1)} + I_f^{(2)} = 3I_f^{(0)}$ (3.25)

The relation between the phase-to-earth fault current and the fault location k can also be plot, for 0% < k < 100%, by substituting the network parameters and transformation operators of Table 3.5 in formulas (3.23), (3.24) and (3.25). The graph of this relationship is shown in Figure 3.20.

Table 3.5: Network parameters used to obtain phase-to-earth fault currents

V_f (kV)	Rg (Ω)		$Z^{(1)}=Z^{(2)}$ (Ω)	$Z^{(0)}$ (Ω)	$C^{(1)}=C^{(2)}$ (μF)	$C^{(0)}$ (μF)
$\frac{25.6\ kV}{\sqrt{3}} = 14.78$	10	*net*	$j\ 0.7748$	$j\ 4.5$	20.886	18.529
		cable	$(0.2364 + j0.2364)$	$(0.781 + j0.842)$	2.522	2.496

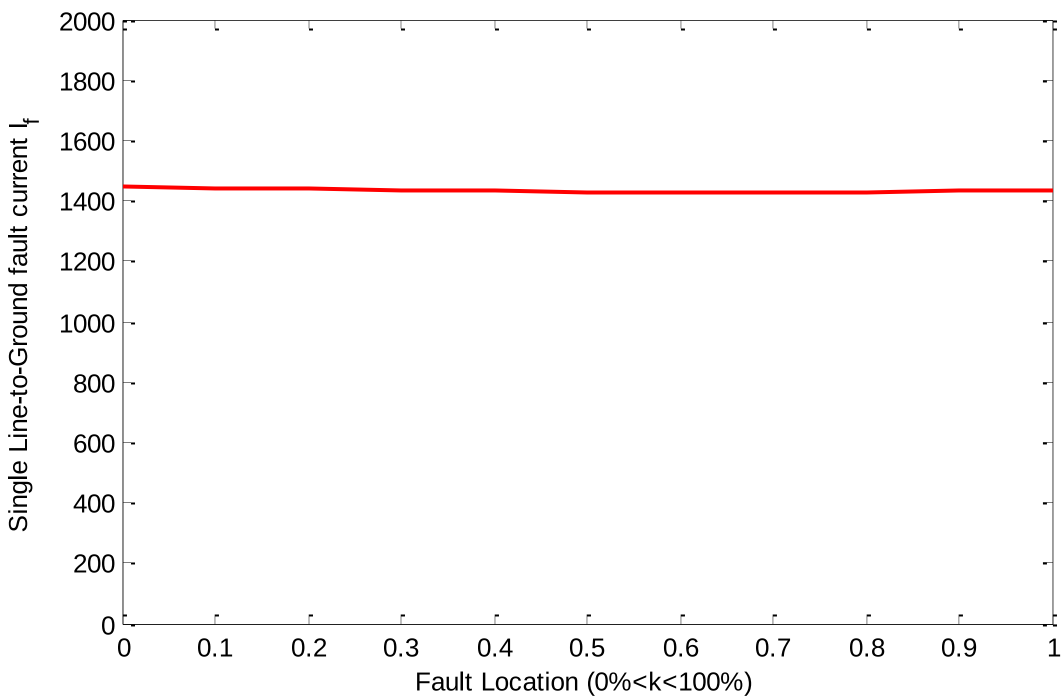

Figure 3.20: Single line-to-ground fault current as function of varying fault location 0%<k<100%

3.6 Double Line-to-Ground Faults

During a double line-to-ground fault, two lines are faulted and connected to ground. This is shown in Figure 3.21, for a short circuit between phase b and phase c to ground.

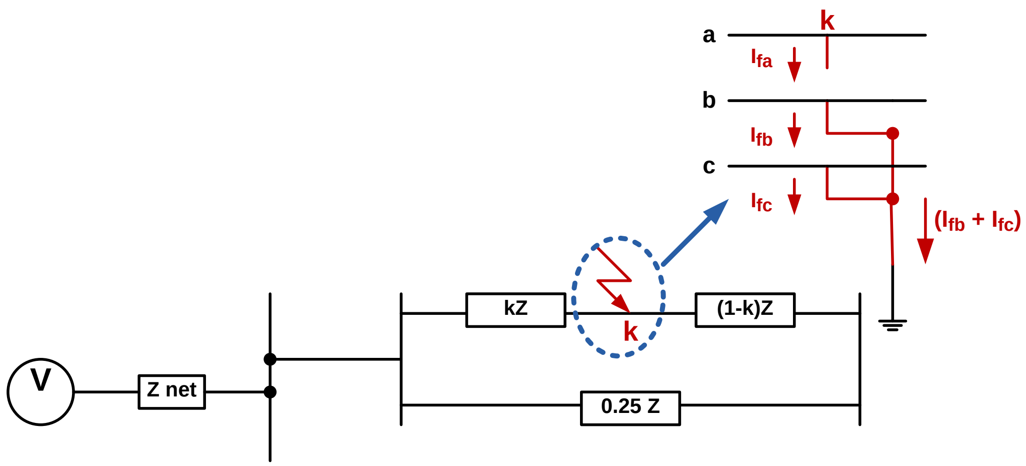

Figure 3.21: Overview of a double line-to-ground fault from phase b and phase c to ground at location k

According to [4] when a short circuit occurs between phases b and c at location k, the following relations exist with $Z_{arc} = 0$:

- $I_{fa} = 0$
- $V_{kb} = V_{kc} = 0$

As it has been explained in [4], the derived conditions for the positive, negative and zero sequence voltages and currents are:

- $V_k^{(1)} = V_k^{(2)} = V_k^{(0)}$
- $I_f^{(0)} + I_f^{(1)} + I_f^{(2)} = 0$

These conditions are satisfied when the positive, negative and zero sequence networks are connected in parallel, as shown in Figure 3.22.

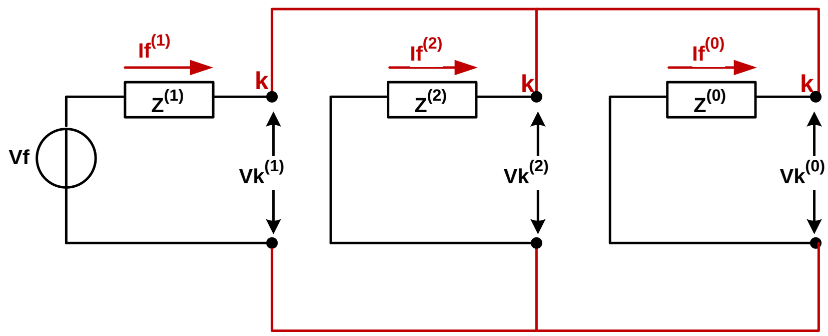

Figure 3.22: Interconnected sequence networks during a double line-to-ground fault

The sequence impedances are more or less the same as those which were obtained with equation (3.8) when studying line-to-line faults. In this case, the zero-sequence network is also included. For the sequence impedances the following relations hold:

- $Z^{(1)} = Z^{(2)} = Z_{net} + 0.75kZ(1.25 - k)$ (3.26)
- $Z^{(0)} = 3R_g + \left(Z_{net} + 0.75kZ(1.25 - k)\right)$ (3.27)

The equations for the positive, negative and zero sequence currents could be determined from Figure 3.22, as a function of k:

$$I_f^{(1)} = \frac{V}{Z^{(1)} + \frac{Z^{(2)}Z^{(0)}}{Z^{(2)} + Z^{(0)}}} \tag{3.28}$$

$$I_f^{(2)} = -I_f^{(1)} \cdot \frac{Z^{(0)}}{Z^{(2)} + Z^{(0)}} \tag{3.29}$$

$$I_f^{(0)} = -I_f^{(1)} \cdot \frac{Z^{(2)}}{Z^{(2)} + Z^{(0)}} \tag{3.30}$$

After the sequence currents are determined, the transformation to the phase domain can be done to determine the phase fault currents I_{fb} and I_{fc} and the total line-to-line to ground fault current at the fault location "k".
The transformation from sequence to phase domain gives the following relations:

- $0 = I_f^{(0)} + I_f^{(1)} + I_f^{(2)}$ (3.31)
- $I_{fb} = I_f^{(0)} + a^2 I_f^{(1)} + a I_f^{(2)}$ (3.32)
- $I_{fc} = I_f^{(0)} + a I_f^{(1)} + a^2 I_f^{(2)}$ (3.33)

And the total line-to-line to ground fault current is:

$$I_f = I_{fb} + I_{fc} \tag{3.34}$$

The current relations of equations (3.22) to (3.24) can be plot as a function of the fault location k, with 0% < k < 100%. This can be done by substituting the parameters of Table 3.6 in the concerning equations. The relations are plot in Figure 3.23.

Table 3.6: Network and transformation parameters used to obtain double line-to-ground fault currents

V (kV)	*Rg (Ω)*		$Z^{(1)}=Z^{(2)}$ (Ω)	$Z^{(0)}$ (Ω)	*Operator*
25.6	10	*net*	$j\,0.7748$	$j\,4.5$	$a = (-0.5 - j0.866)$
		cable	$(0.2364 + j0.2364)$	$(0.781 + j0.842)$	$a^2 = (-0.5 + j0.866)$

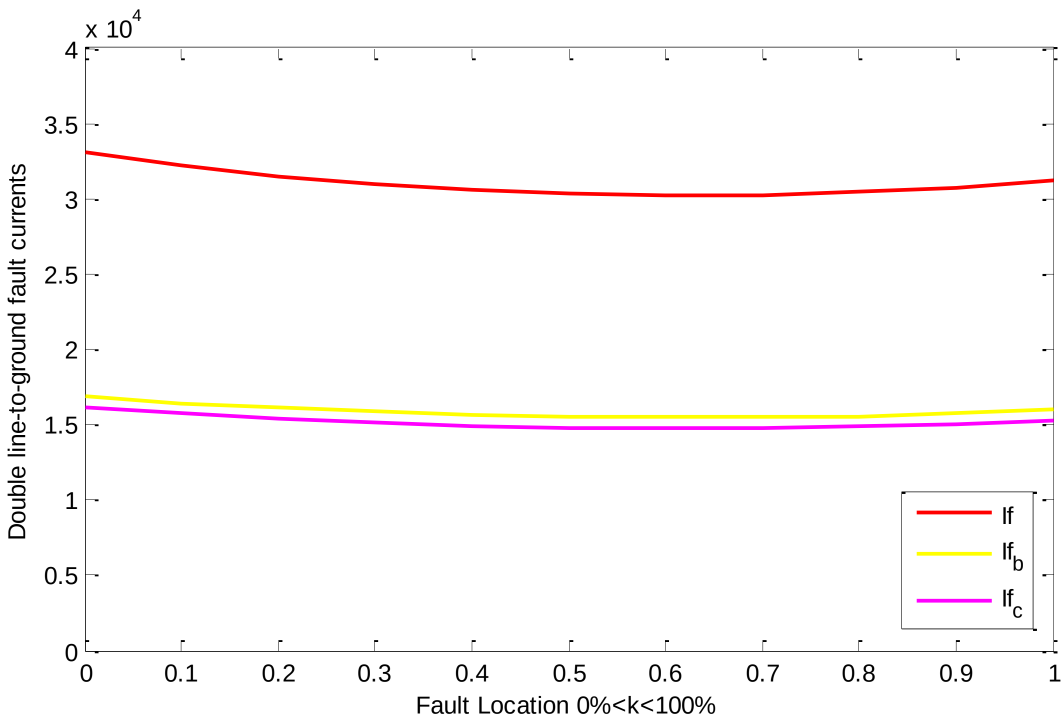

Figure 3.21: Double line-to-Ground fault currents, I_f, I_{fb} and I_{fc} as function of varying fault location 0%<k<100%

3.6 Conclusions

Short circuits can be of different origin and they can occur in the network at different locations. Based on these facts, short circuits can be characterized as to be:
- *Self – extinguishing*
- *Fugitive*
- *Permanent*

In this chapter, the different types of faults which occur in power systems are analyzed on different locations in the studied network. These are:
- Three-phase faults
- Line-to-line faults
- Single line-to-ground faults
- Double line-to-ground faults

The results of the analysis show lead to a relation between the short circuit currents and the fault location. This relation shows that the fault current magnitudes are dependent on the location where the fault occurs and this is very important for correct analysis of protective devices.

For the analysis of single line-to-ground faults in cable networks, the network grounding method and the cable capacitances play an important role. The results of this analysis show that the line-to-ground fault-current magnitudes largely depend on the system grounding impedance.

4
Analysis of the Directional protection Scheme

Short circuit currents can cause damage of the network components and can endanger human safety. To prevent a short circuit current to cause unwanted situations, protective systems are placed in the network. Protective relays detect the fault current and if their pick-up values are exceeded, the relay(s) closest to the fault must generate a trip command which causes the fault to be selectively switched off by the nearest triggered circuit breakers.

Protective schemes which consist of overcurrent and directional protection relays are mostly installed in network sections where the cables or lines are connected in parallel. This is also done in the studied network model used in Chapter 3. The analysis of protection relays is based on the network parameters that the relays see during system faults. Since the principles of both the overcurrent and directional relay are based on current detection, it is important to know the behaviour, the magnitude and the direction of the circulating fault currents during system faults.

In this chapter, the main effort is focussing on the analysis of the protective system in the studied network section of the Stedin sub-transmission network. This section is again shown in Figure 4.1, including its protective system and a short circuit occurring at location k on cable 1.

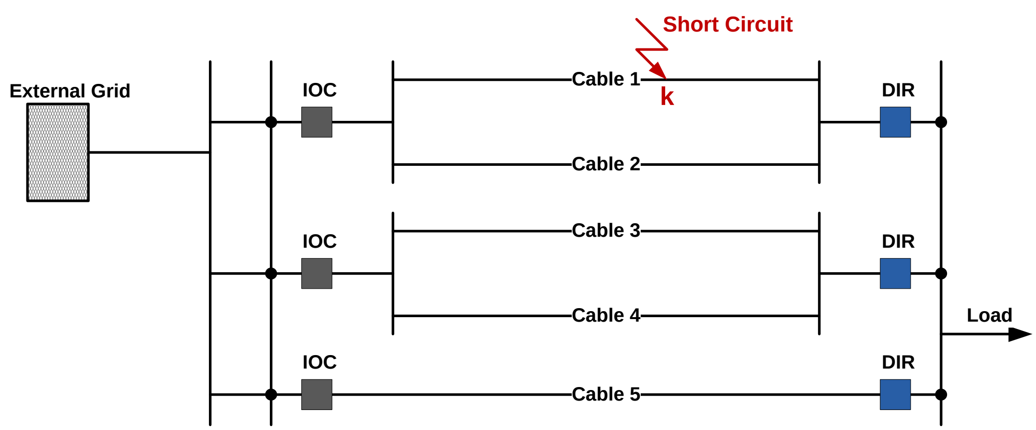

Figure 4.1: Analyzed sub-transmission network section including its protection schemes and a short circuit occurring on location "k"

In the first part of this chapter, the cable network of Figure 4.1 will be simplified in such a way that the fault currents through the protective relays can be easily derived. The detected fault current behaviour will be analyzed as a function of the short circuit location k for all system faults discussed in Chapter 3. The computed fault currents will be verified by simulations.

In the second part of this chapter the fault current angles are analyzes as well to determine whether the relay directionality takes place. The fault current angle represents the angular difference between the fault current and the system voltage during short circuits. If this shift lies within the predefined relay tripping zone, directionality is obtained and the relay directional restraint is exceeded. The fault current angle will also be analyzed for all previously described system faults as a function of the short circuit location "k".

The analysis of relay fault current detection and its direction will determine if a relay mal-operation takes place and what may be the cause. The chapter ends up with an overview of the cause of the relay malfunction during all system faults.

4.1 Protection Scheme Settings

As explained in paragraph 2.3, the protective system has certain settings which need to be adjusted by the grid operator. The possible setting for overcurrent, directional overcurrent and earth fault relays are:

- Current setting I> and time setting t>, which holds for the overcurrent and directional overcurrent relays. These settings can also be used against severe component overloading and as settings for back-up protection.

- Current setting I>> and time setting t>>, accounts for overcurrent and directional overcurrent relays. These time settings are used against excessive fault currents which flow through the network components due to double and three phase faults.

- Current setting Ie and time setting te, accounts for earth fault protection and are used to detect earth faults currents in grounded networks.

- Directional setting of the directional overcurrent relay is the setting which is used for the relay to detect currents in the forward or backward direction.

The protection relay settings for the protective system shown in Figure 4.1 are determined according to the corresponding DSO standards. The standards which are used by Stedin are summarized in Table 4.1.

Table 4.1: Standards for protection relay settings applied by the Distribution System Operator Stedin

Protection Relay	***I>***	***t>***	***I>>***	***t>>***	***Ie***	***te***
Overcurrent	$1.5 \times I_N$	0.3s, 0.6s, 0.9s, 1,2s, 1.5s, 1.8s, 2.1s, 2.4s, 2.7s, 3.0s	n/a for this study	n/a for this study		
Directional Overcurrent						
Earth fault					Value between 100A – 150A	0.3s, 0.6s, 0.9s, 1.2s
I_N is the nominal current that flows through the protected system components *t> and te depend on the time grading between the protection relays in the network*						

The impedance model of the analyzed network with its protective system and corresponding relay current and time settings is shown in Figure 4.2. The time settings are graded with other protection relays in the underlying network, which is not shown in this figure. The current settings are according to the standards explained in Table 4.1.

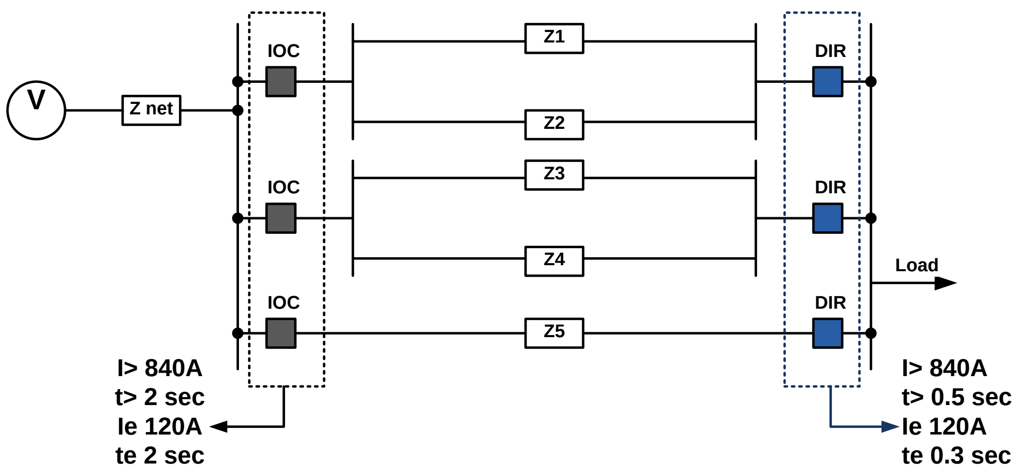

Figure 4.2: Impedance network model with protective system and corresponding relay current and time settings.

4.2 Analysis of Relay Fault Current Detection

As shown in Figure 4.1, the protection scheme, consisting of overcurrent (IOC) and directional overcurrent (DIR) relays, will be analyzed for faults occurring on 'Cable 1'. The circulating fault currents due to this short circuit and so the behaviour of relay detection and tripping, will not differ for a short circuit on 'Cables 2, 3, 4 and 5'. That is why the analysis of a short circuit on 'Cable 1' and the behaviour of corresponding protection relays can be assumed to be the same for short circuits on all the remaining cables and corresponding relays in this network. Therefore, the network of Figure 4.1 can be simplified to the network shown in Figure 4.3 to analyze the circulating and detected fault currents during short circuits.

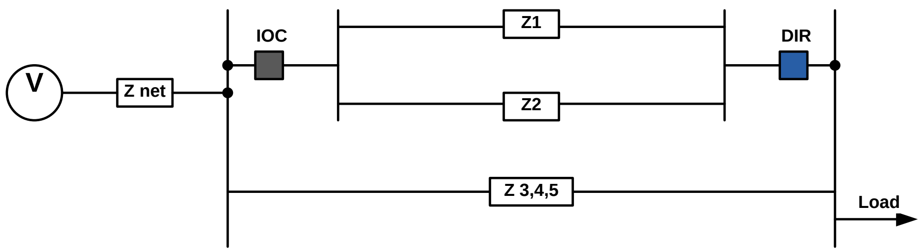

Figure 4.3: Simplified network model for the analysis of the protection scheme during faults on 'Cable 1'

When a short circuit occurs on 'Cable 1', there will be circulating fault currents through the network. To know whether the faulted section will be isolated by the corresponding protection relays, it is important to know which circulating fault current is detected by the relays respectively. These detected fault currents must exceed the relay setting values in order to activate the trip command.

The circulating currents caused by a fault current at the location k of 'Cable 1' are shown in the following figure:

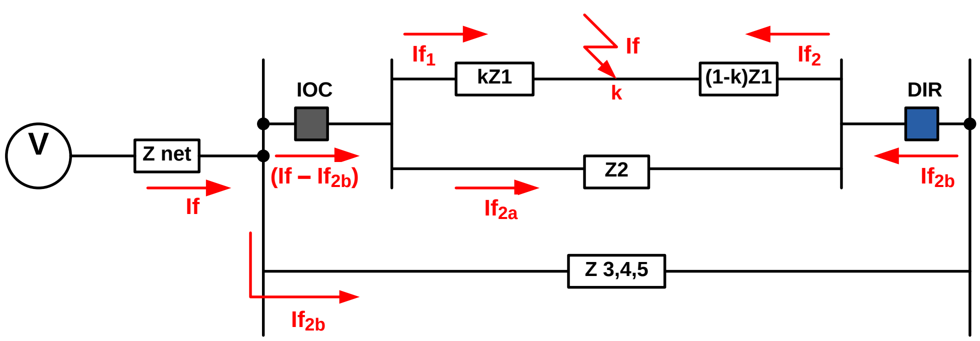

Figure 4.4: Circulating fault currents through the system during a fault current on 'Cable 1'

In Figure 4.4 it is clearly shown that the following circulating fault currents are detected by the corresponding protection relays:

- IOC detects circulating currents $(I_f - I_{f2b})$
- DIR detects circulating current I_{f2b}

To determine the detected fault currents, first I_{f2} needs to be determined.

$$I_{f2} = I_{f2a} + I_{f2b}$$

I_{f2a} flows through the impedance Z_2
I_{f2b} flows through the impedances $(1-k)Z$ and $Z_{3,4,5}$

In order to derive I_{f2} , the network in Figure 4.4 is further simplified to the network in Figure 4.5. In this figure, the impedance $Z_{2,3,4,5}$ is obtained by making use of (3.3):

$$Z_{2,3,4,5} = 0.25Z \overset{so}{\Rightarrow}$$

$$(1-k)Z + Z_{2,3,4,5} = Z(1.25-k) \tag{4.1}$$

This is the total impedance through which I_{f2} flows, as shown in the same figure.

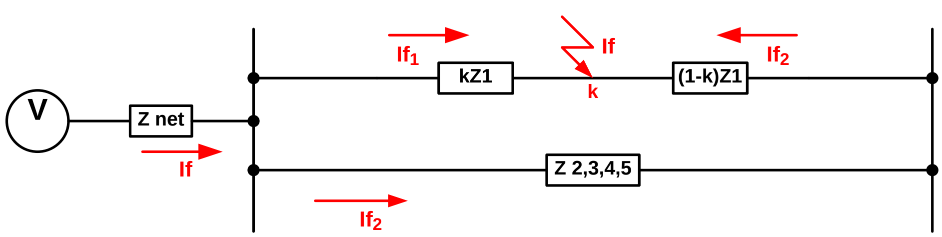

Figure 4.5: Simplified model for the derivation of I_{f2}

From Figure 4.5 and equation (4.1), the current I_{f_2} is calculated:

$$I_{f2} = \frac{kZ}{kZ + Z(1.25-k)} \cdot I_f = \frac{k}{1.25} \cdot I_f \tag{4.2}$$

The value of I_f in (4.2) is a function of the fault location k and it dependents on the type of the short circuit current. These derivations of I_f are determined in chapter 3 for different types of short circuits and they are also considered in this chapter.

The current I_{f2} can be divided into the following sub-currents by using (4.2):

$$I_{f2a} = \frac{Z_{3,4,5}}{Z_{3,4,5} + Z} \cdot I_{f2} = 0.25 \cdot I_{f2} = 0.2 \cdot k \cdot I_f \qquad (4.3)$$

$$I_{f2b} = \frac{Z}{Z + Z_{3,4,5}} \cdot I_{f2} = 0.75 \cdot I_{f2} = 0.6 \cdot k \cdot I_f \qquad (4.4)$$

It can be seen that the currents I_f , I_{f2} , I_{f2a} and I_{f2b} are all function of the fault location k.

4.3 Determination of Detected Fault Currents

With the help of formulas (4.2), (4.3), (4.4) and the short circuit analysis in chapter 3, the detected fault currents can be determined and graphically displayed as function of the fault location "k". It is important that the magnitudes of the fault currents through the relays exceed the relay current threshold. If this is not the case, relay tripping will not be activated and the fault will not be (selectively) switched off.

The analytical results obtained with above mentioned formulas can be verified by short circuit simulations. These simulations are done in an exact replica of the DSO network on the exact locations "k" as the analytical short circuit analysis. The results will be worked out throughout this paragraph.

4.3.1 Fault Current Detection during Three Phase Faults (Analytical versus Simulation Results)

When a three phase fault current occurs on location k of 'Cable 1' in the network of Figure 4.1, the total fault current and the fault currents detected by the relays are shown in Figure 4.6 (a). Using the same parameters of Table 3.2 and equations (3.6), (4.3) and (4.4), the total fault current and the detected fault currents can be obtained. The analytical results are graphically displayed as a function of the short circuit location k in Figure 4.6 (b). These results are verified with the simulation results, and the simulated graphs are shown in Figure 4.6 (c). In Figure 4.6 (c) the relay current threshold value is also included to check whether the detected fault currents exceed the relay settings.

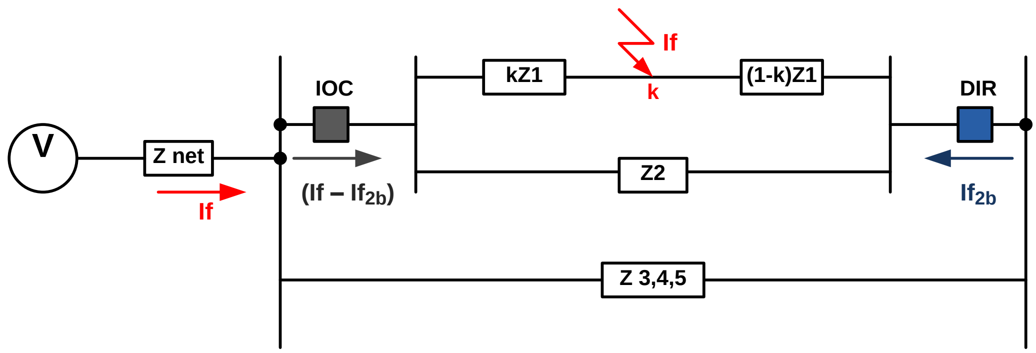

Figure 4.6 (a)

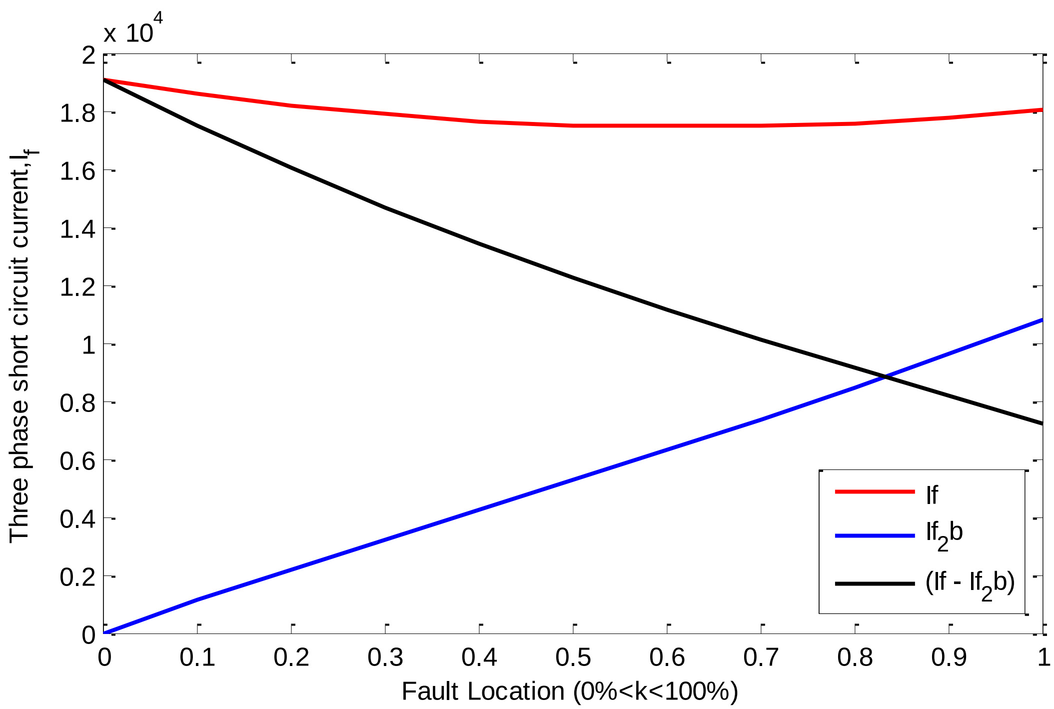

Figure 4.6 (b)

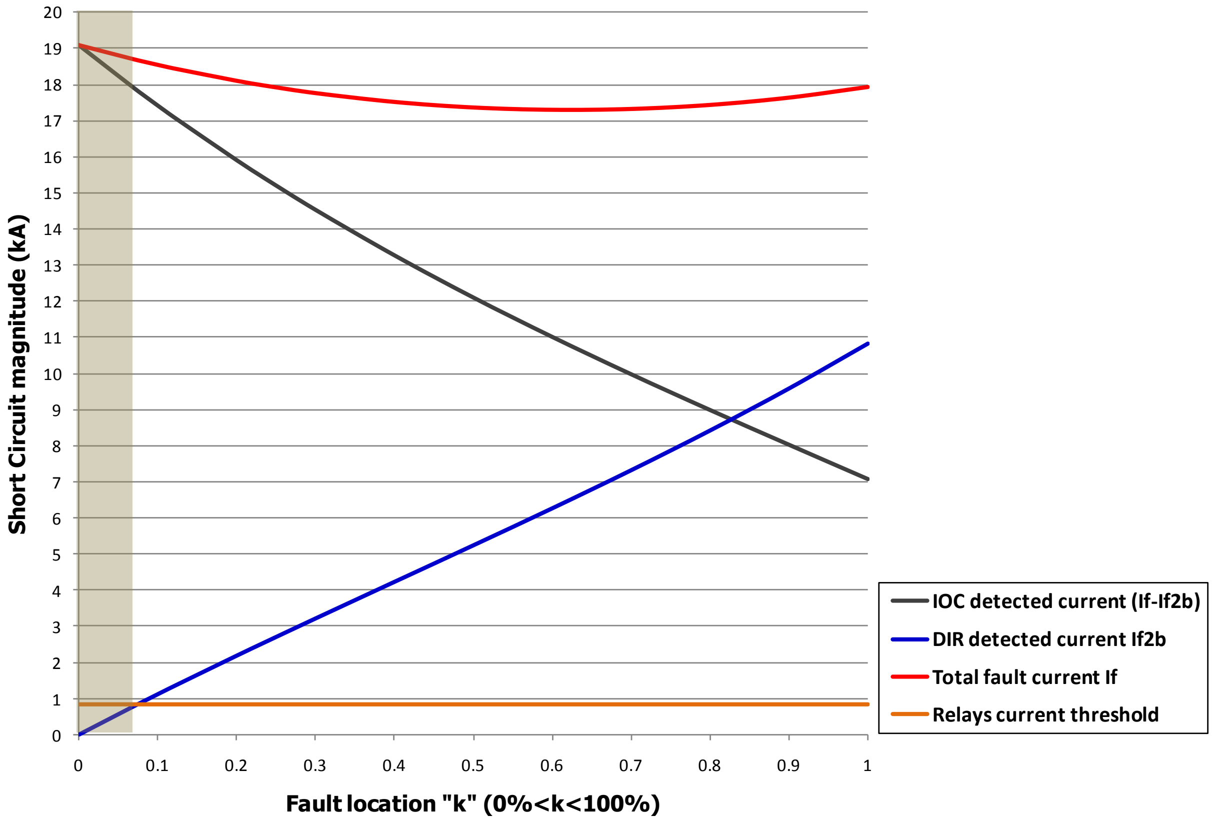

Figure 4.6 (c)

Figure 4.6: (a) Fault currents detected by the relays during three phase short circuits; (b) Graphical display of the analytical results; (c) Graphical display of the simulation results including relay current threshold value and resulting 'dead zone'

From the results for three phase fault current detection, shown in Figure 4.6, the following can be concluded:

– The analytical results are consistent with the simulation results. The graphs of the detected fault currents and the total fault currents show the same patterns in both Figures 4.6 (a) and 4.6 (b). The fault current magnitudes of the analytical and simulated results differ with less than 3% error margin. This means that the analytical analysis and the DSO programmed system model can both be assumed to be good and accurate.

– The pattern of the fault current detected by the DIR starts at zero Amps if k=0% and as k increases, the detected fault current magnitude also increases. It is clearly shown in Figure 4.6 (c) that for the DIR detection holds that if 0% < k < 8%, the detected fault current magnitude is lower than the relay current threshold value. The length of the cable section is 2 km, meaning that if in this case a three phase fault current occurs between 0% and 8% of the cable length (which is about the first 160 m cable length leaving the substation), the

directional overcurrent protection relay will not be able to detect the fault current because its magnitude is lower than the DIR current threshold value. This will result in non-selective relay tripping and it can be considered as relay mal-function.
The part of the cable where 0% < k < 8%, will be referred to as a certain *dead zone*.

– Three phase fault currents will always be detected by the IOC regardless of the short circuit location. This can be seen in Figures 4.6 (b) and 4.6 (c), where the fault currents measured by the overcurrent relays (IOC) are always above the IOC current threshold for any value of k.

4.3.2 Fault Current Detection during Line-to-Line Faults (Analytical Results versus Simulation Results)

When a line-to-line fault occurs on 'Cable 1' in the network of Figure 4.1, the total fault current and the fault currents detected by the relays are shown in Figure 4.7 (a). Using the same parameters of Table 3.3 and formulas (3.10), (4.3) and (4.4), the total fault current and the detected fault currents can be obtained. The analytical results are graphically displayed as a function of the fault location k in Figure 4.7 (b). The analytical results are verified with the simulated results and these are also graphically shown in Figure 4.7 (c). In this figure, the relay current threshold value is also included to check whether the detected fault currents exceed the relay current setting.

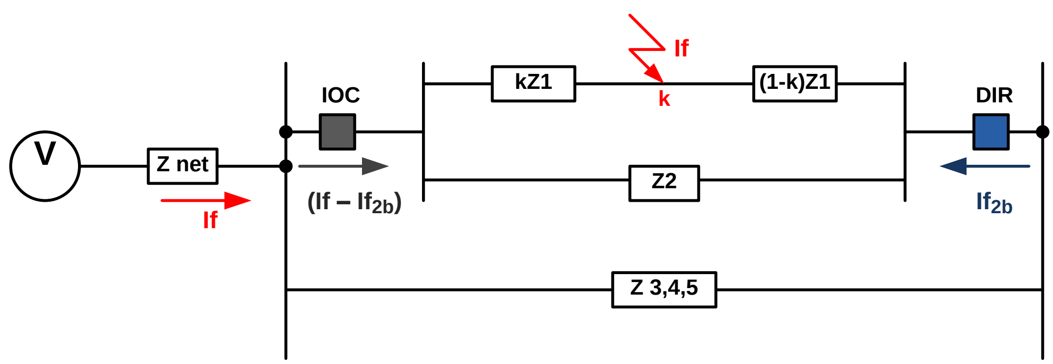

Figure 4.7 (a)

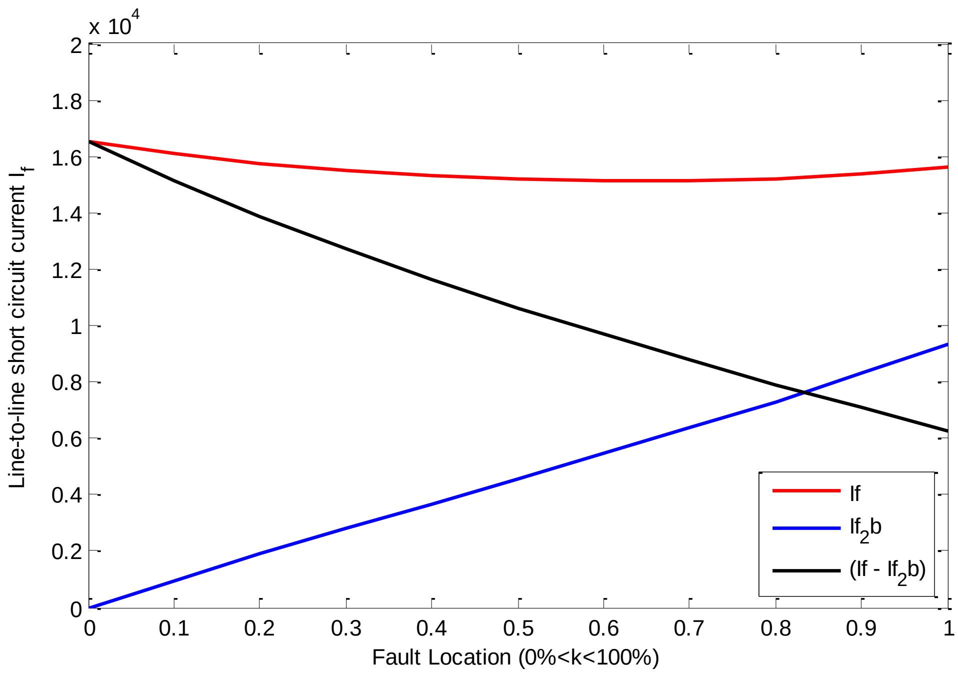

Figure 4.7 (b)

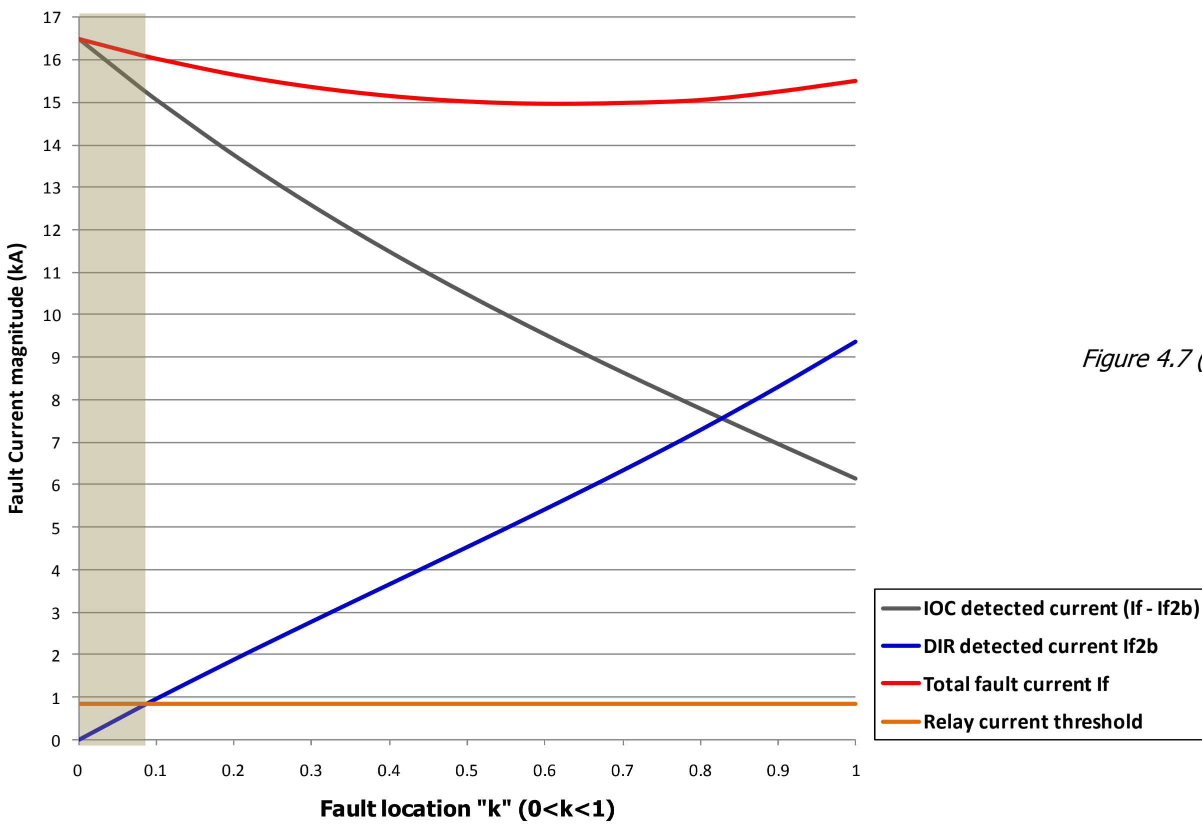

Figure 4.7 (c)

Figure 4.7: (a) Fault currents detected by the relays during line-to-line short circuits; (b) Graphical display of the analytical results; (c) Graphical display of the simulation results including relay current threshold value and the resulting 'dead zone'

From the results for line-to-line fault current detection, shown in Figure 4.7, the following can be stated:

– The analytical results are consistent with the simulated results. The graphs of the detected fault currents and the total fault currents show the same patterns in both Figures 4.7 (a) and 4.6 (b). The fault current magnitudes of the analytical and simulated results differ with less than 3% error margin. This means that the analytical analysis and the DSO programmed system model can both be assumed to be good and accurate.

– The pattern of the fault current detected by the DIR also shows a *dead zone* for 0% < k < 9%. Meaning that if a line-to-line short circuit occurs within the first 9% cable length leaving the substation (which is about 180 m of the 2 km long cable), the DIR will not be able to detect the fault current because its magnitude is lower than the DIR current threshold value.

– Line-to-line fault currents will always be detected by the IOC regardless of the short circuit location. This can be seen in Figures 4.7 (b) and 4.7 (c), where the fault currents measured by the IOC are always above the IOC current threshold value.

4.3.3 Fault Current Detection during Single Line-to-Ground Faults (Analytical Results versus Simulation Results)

When a single line-to-ground fault occurs on 'Cable 1' in the network of Figure 4.1, the total fault current and the fault currents detected by the relays are shown in Figure 4.8 (a). Using the same parameters of Table 3.5 and formulas (3.25), (4.3) and (4.4), the total fault current and the detected fault currents can be obtained. The analytical results are graphically displayed as function of short circuit location k in Figure 4.8 (b). The analytical results are verified with the simulation results, which are graphically shown in Figure 4.8 (c). In this figure the relays current threshold is also included to check whether the detected fault currents exceed the relay current setting.

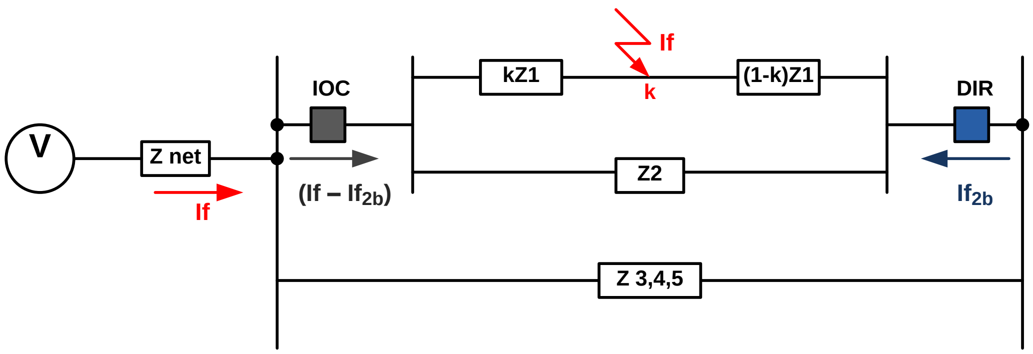

Figure 4.8 (a)

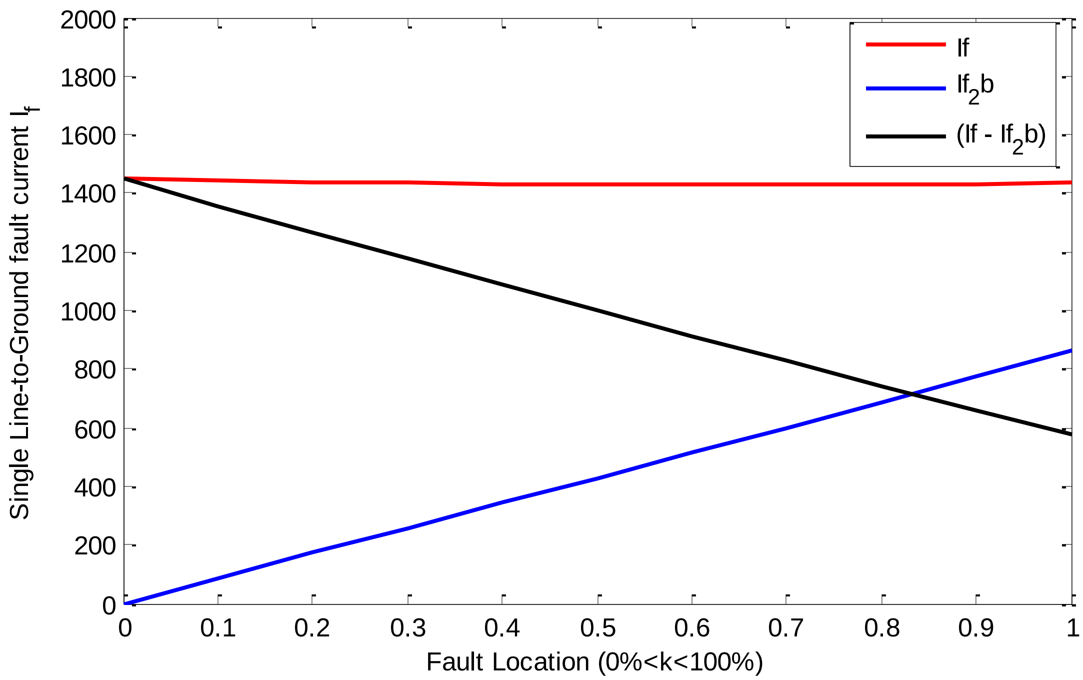

Figure 4.8 (b)

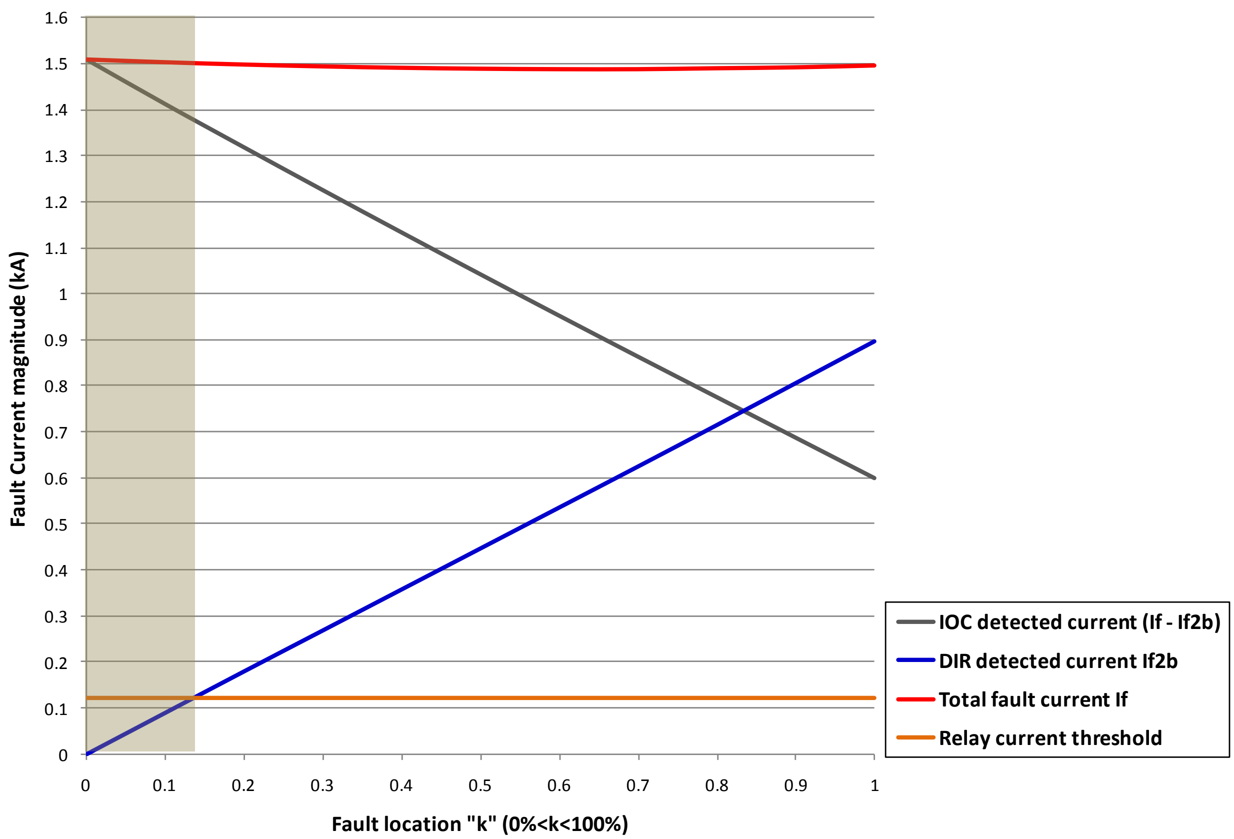

Figure 4.8 (c)

Figure 4.8: (a) Fault currents detected by the relays during single line-to-ground short circuits; (b) Graphical display of the analytical results; (c) Graphical display of the simulation results including relay current threshold value and the resulting 'dead zone'

Out of the results for single line-to-ground fault current detection, shown in Figure 4.8, the following can be stated:

– The analytical results are consistent with the simulation results. The graphs of the detected fault currents and the total fault currents show the same patterns in both Figure 4.8 (a) and 4.8 (b). The fault current magnitudes of the analytical and simulated results differ with less than 3% error margin. This means that the analytical analysis and the DSO programmed system model can both be assumed to be good and accurate.

– The pattern of the fault current detected by the DIR also shows a *dead zone* for 0% < k < 15%. Meaning that if a single line-to-ground short circuit occurs within the first 15% cable length leaving the substation (which is about 300 m of the 2 km long cable), the DIR will not be able to detect the fault current because its magnitude is lower than the DIR current threshold value.

– Single line-to-ground fault currents will always be detected by the IOC regardless of the short circuit location. This can be seen clearly in Figures 4.8 (b) and 4.8 (c), where the fault currents measured by the IOC are always above the IOC current threshold value.

4.3.4 Fault Current Detection during Double Line-to-Ground Faults (Analytical Results versus Simulation Results)

When a double line-to-ground fault occurs on 'Cable 1' in the network of Figure 4.1, the total fault current and the fault currents detected by the relays are shown in Figure 4.9 (a). Using the same parameters of Table 3.6 and formulas (3.32), (3.33), (3.34), (4.3) and (4.4), the total fault currents and the detected fault currents can be obtained. The analytical results are graphically displayed as a function of short circuit location k in Figure 4.9 (b). The analytical results are verified with the simulation results, which are also graphically shown in Figure 4.9 (c). In this figure the relay current threshold value is also included to check whether the detected current magnitudes exceed the relay current setting.

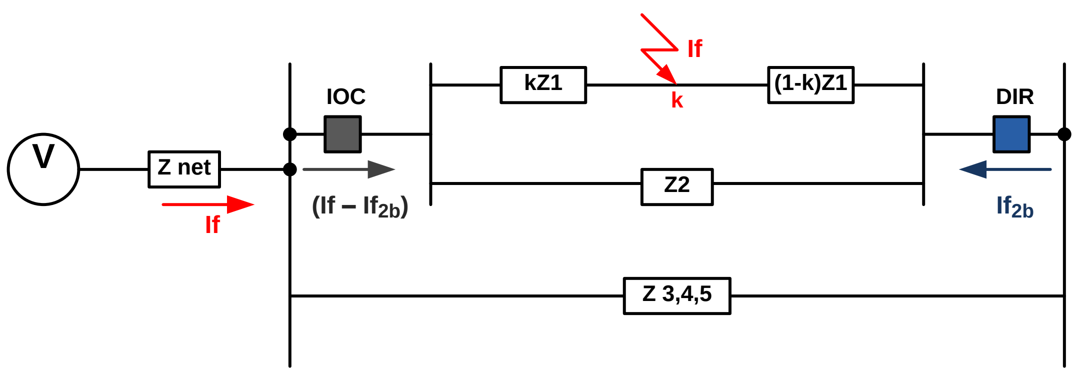

Figure 4.9 (a)

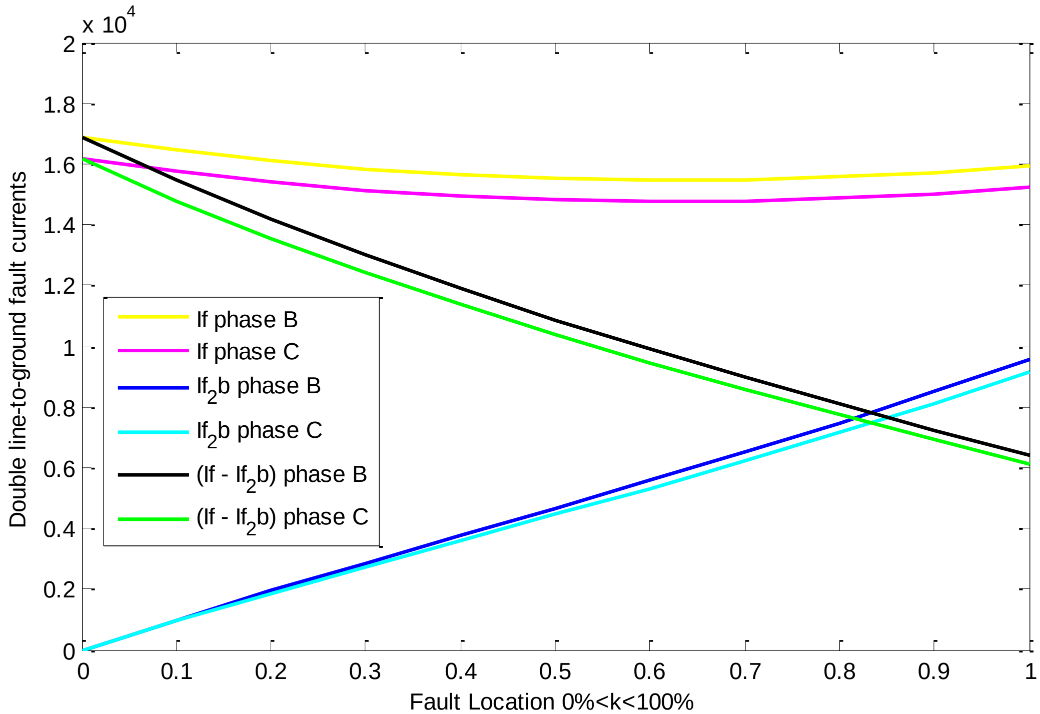

Figure 4.9 (b)

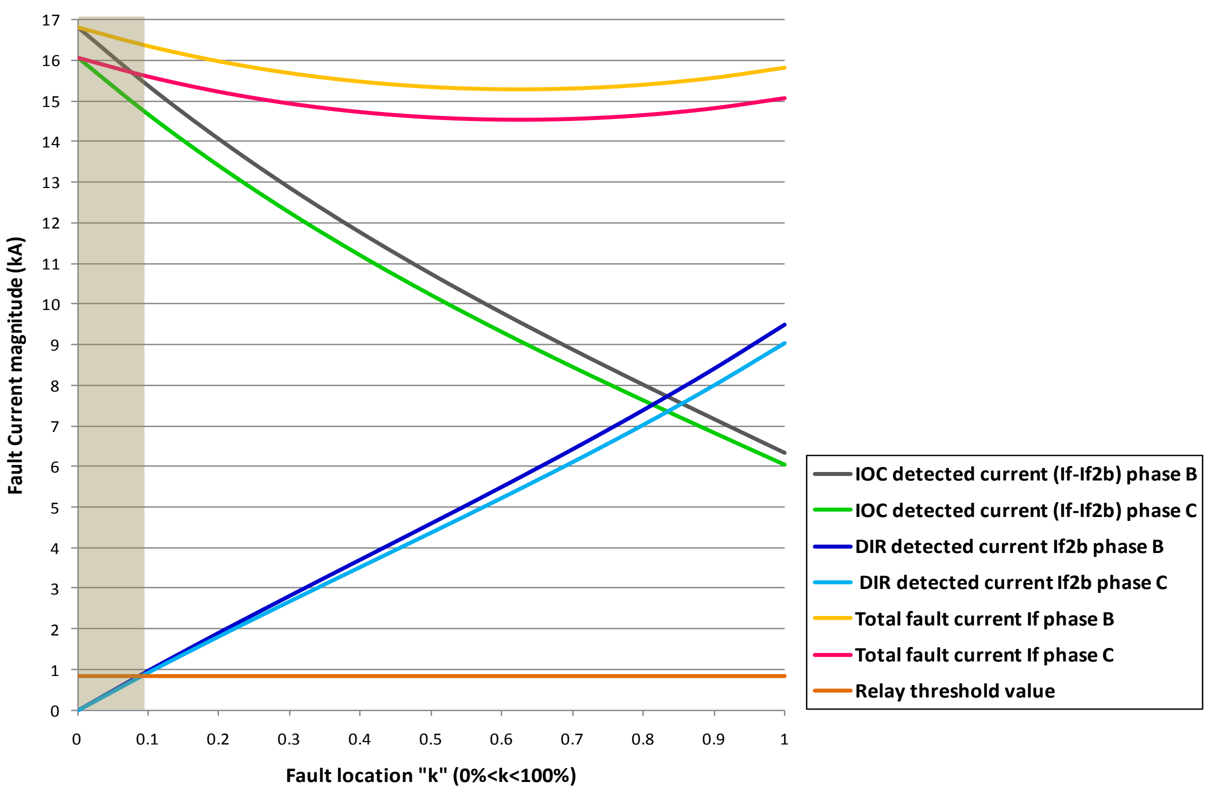

Figure 4.9: (a) Fault currents detected by the relays during double line-to-ground short circuits; (b) Graphical display of the analytical results; (c) Graphical display of the simulation results including relay current threshold value and the resulting 'dead zones'

From the results for double line-to-ground fault current detection, shown in Figure 4.9, the following can be stated:

- The analytical results are consistent with the simulated results. The graphs of the detected fault currents and the total fault currents show the same patterns in both Figure 4.9 (a) and 4.9 (b). The fault current magnitudes of the analytical and simulation results differ with less than 3% error margin. This means that the analytical analysis and the DSO programmed system model can both be assumed to be good and accurate.

- The pattern of the fault currents detected by the DIR also show a *dead zone* for $0\% < k < 9\%$. Meaning that if a double line-to-ground short circuit occurs within the first 9% cable length leaving the substation (which is about 180 m of the 2 km long cable), the DIR will not be able to detect the fault currents because their magnitude is lower than the DIR current threshold value.

- Double line-to-ground fault currents will always be detected by the IOC regardless of the short circuit location. This can be seen clearly in Figures 4.9 (b) and 4.9 (c), where the fault currents measured by the IOC are always above the IOC current threshold value.

4.4 Relay Directionality and Fault Current Direction Detection

As previously mentioned, directional overcurrent relays operate during the following conditions:

- The fault current is higher than the relay current threshold
- The current phasor with respect to the voltage is in a range referred to as the tripping zone
- The above two conditions continue for a time interval longer than the relay time setting

In the previous paragraph, the fault current magnitude was determined with the help of power system analysis methods. The results show that during the different short circuits certain dead zones are present in the network in which the fault current magnitudes are too low to be detected by the directional protection relays. However, the fault current magnitude detection is only one of the requirements to trigger directional relay activation. Obtaining the direction of the fault current flow is the most important requirement of the directional protection relay.

Direction determination for the phase current stages involves the use of one particular phase current (depending on the type of fault), a reference voltage which is the phase-to-phase voltage opposite to this phase current, and an optimum characteristic angle for this particular case. As mentioned in chapter 2, the characteristic angle specifies the measuring position relative to the reference voltage. The directional relay implemented in the Stedin studied network model is of relay type "Alstom PS441".

For the directional detection of this relay, different characteristic angles corresponding to the fault type are defined. The characteristic angles measure and detect the different fault types correctly as shown in Table 4.1.

Table 4.1: Characteristic angle settings to measure and detect the different fault types correctly

Trip	***Selected Measurement***		***Characteristic angle λ_L***	
	Current Measurement	***Voltage Measurement***	***Clockwise rotation***	***Counterclockwise rotation***
Phase A	I_A	U_{B-C}	+45°	+135°
Phase B	I_B	U_{C-A}	+45°	+135°
Phase C	I_C	U_{A-B}	+45°	+135°
Phase A-Phase B	I_A	U_{B-C}	+60°	+150°
Phase B-Phase C	I_C	U_{A-B}	+30°	+120°
Phase C-Phase A	I_C	U_{A-B}	+60°	+150°
Phases A-B-C	I_C	U_{A-B}	+45°	+135°

Fault Current Angles

The fault current angle is determined by complex calculations. In this case the term *complex current* may be used. A general example of obtaining the complex current of phase a, is as follows:

$$\overline{I_a} = \frac{\overline{V_{a-N}}}{\bar{Z}} = \frac{V_{a-N}\angle\alpha}{Z\angle\beta} = I_a\angle(\alpha-\beta) = I_a\angle\mu$$

With:

- I_a = the magnitude of the complex phase current
- μ = the phase of the complex phase current, which is the phase shift between the current and the phase-to-neutral voltage V_{a-N}

For this study the phase of the complex current μ is:

- Positive, if the current is shifted in counter clockwise direction with respect to the voltage
- Negative, if the current is shifted in clockwise direction with respect to the voltage

4.4.1 Fault Current Directional Detection during Three Phase faults

The detected complex fault currents as a function of the fault location k are obtained by applying the same parameters of Table 3.2 and formulas (3.6), (4.2) and (4.4). If the detected fault current is defined as $\overline{I_{fC}} = I_C \angle \mu$ then the results for all fault current angles (μ) detected by the directional overcurrent relay during three phase faults for 0% < k < 100%, are:

$-90° < \mu < -85.3°$

The phase shift μ of the current is with respect to the phase voltage V_{C-N}, because this voltage is used in formulas (3.6), (4.2) and (4.4) to determine the complex current.

As seen in Table 4.1 the tripping zone for three phase fault current detection is determined by:

- a characteristic angle $\lambda = +45°$ clockwise direction
- measuring the phase current I_C
- measuring the reference voltage V_{A-B}

In Figure 4.10 the three phase fault current vectors with respect to the voltage V_C are shown for all the above mentioned angles μ worked in the red area. It is also clearly seen that for every k, the measured fault currents are all within the tripping zone of the directional relay, which means that the directional element of the relay would have detected three phase fault currents irrespective of the fault location on the cable.

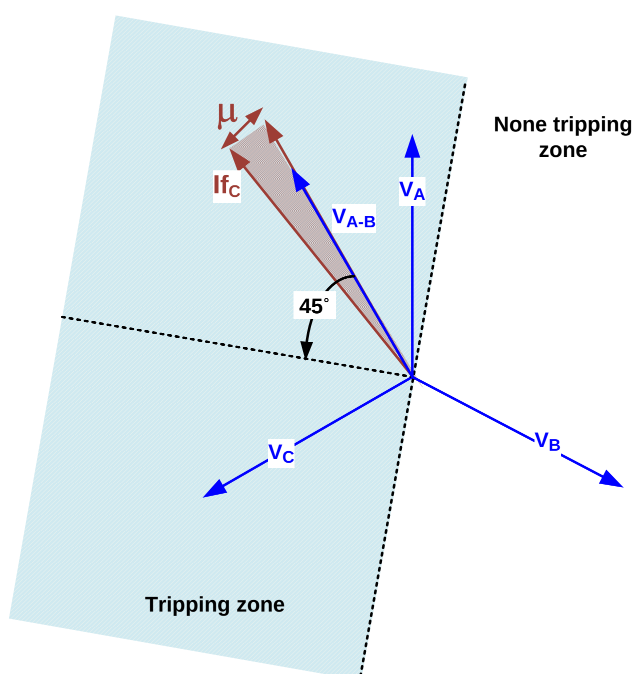

Figure 4.10: Relay directional detection of the three phase fault current vector I_{fc} for 0%<k<100%

4.4.2 Fault Current Directional Detection during Line-to-Line Faults

The detected complex fault currents as a function of the fault location k are obtained by using the same parameters of Table 3.3 and formulas (3.10), (3.11), (4.2) and (4.4). The detected fault current is defined as $\overline{I_{fB}} = I_B \angle \mu$.

If the line-to-line fault occurs between phases B and C, then the results for all detected fault current angles ($\boldsymbol{\mu}$) by the directional overcurrent relay for 0% < k < 100%, are:

- For phase C: $90° < \mu_C < 94.7°$
- For phase B: $-90° < \mu_B < -85.3°$

The measured current for fault detection is I_{fB} and the current angular shift $\boldsymbol{\mu}$ is with respect to the voltage $V_{B\text{-}C}$, because this voltage is used in formulas (3.10), (3.11) and (4.4) to determine the fault current angles.

As seen in Table 4.1 the tripping zone for detecting line-to-line faults between phases B and C is determined by:

- a characteristic angle $\lambda = +30°$ clockwise direction
- measuring the phase current I_C
- measuring the reference voltage $U_{A\text{-}B}$

In Figure 4.11 the line-to-line fault current vectors with respect to the voltage $U_{B\text{-}C}$ for the above mentioned angles $\boldsymbol{\mu}$ in both faulted phases are shown as the red areas. It is also clearly seen that for every "k", the measured fault currents I_{fc} are all within the tripping zone of the directional relay, which means that the directional element of the relay would have detected line-to-line fault currents irrespective of the fault location on the cables.

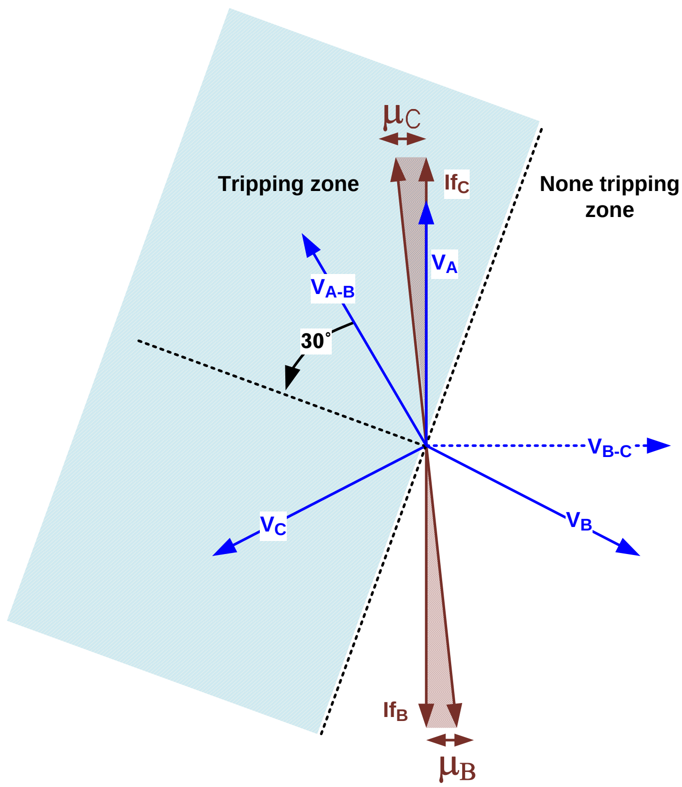

Figure 4.11: Relay directional detection of line-to-line fault current vector I_{fC} for 0%<k<100%

4.4.3 Fault Current Directional Detection during Single Line-to-Ground Faults

Single line-to-ground faults are the most frequent faults in the power systems. Their fault currents may be limited in magnitude by the neutral earthing impedance or by the earth contact resistance. Earth fault relays are completely unaffected by load currents because the relays respond only to the residual current of the system. A residual component only exists when a fault current flows to earth. Therefore, according to [6], the earth fault relay can be given a setting which is limited only by the design of the equipment and the presence of unbalanced leakage or capacitive currents to earth (which are only a few percent of the system rating).

The residual component is extracted from the system component by connecting the line current transformers in parallel. This makes the residual current (I_{rsd}) the vector sum of the currents of the three phases:

$$I_{rsd} = I_A + I_B + I_C \qquad (4.5)$$

The residual voltage of the system is the vector sum of the three phase voltages. According to [6], the residual voltage can for example be obtained by connecting the secondary windings of three single-phase units in broken delta. This makes the voltage developed across its terminals the vector sum of the phase to ground voltages and hence the residual voltage of the system. Thus, the residual voltage (V_{rsd}) is the vector sum of the phase-to-ground voltages of the three phases:

$$V_{rsd} = V_{AN} + V_{BN} + V_{CN} \tag{4.6}$$

Figure 4.12 illustrates an example of a simple connection applied to obtain measurements of the system reference parameters. During a balanced system (normal operation), no residual parameters are measured, because all balanced vectors add up to zero.

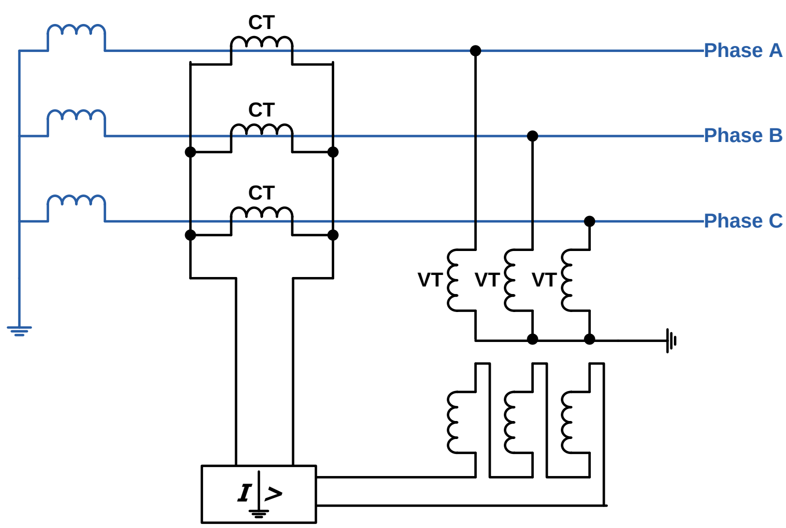

Figure 4.12: Example of a simple connection for obtaining voltage and current reference parameters

With I_{rsd}, V_{rsd} (chosen polarization voltage) and the characteristic angle a tripping zone for earth fault detection can be defined in the same way as explained in chapter 2. According to ([6], [9]), the following settings for the characteristic angle λ to detect earth faults are usually applied:

- $\lambda = 0°$ for resistance earthed systems
- $\lambda = -45°$ for solidly earthed distribution systems
- $\lambda = -60°$ for solidly earthed transmission systems

The studied network is resistance grounded, so a characteristic angle $\lambda = 0°$ is used.

Directional earth fault protection is activated when the following conditions are satisfied:

- the amplitude of the residual current I_{rsd} rises above the relay setting threshold,
- the residual current I_{rsd} phase displacement with respect to a polarizing voltage (the residual voltage V_{rsd}) is in a range referred to as the tripping zone,
- the above two conditions continue for a time interval longer than the relay time setting.

The detected fault current phasors and residual currents as a function of the fault location k are obtained by using the same parameters of Table 3.5 and formulas (3.25), (4.2), (4.4), (4.5) and (4.6). The detected residual currents are defined as $\bar{I} = I_{rsd}\angle\mu$.

If the single line-to ground fault occurs in phase A, then all detected residual current angles ($\boldsymbol{\mu}$) by the directional overcurrent relay for 0% < k < 100%, are:

- $0° < \mu < -11.8°$

The current angular shift $\boldsymbol{\mu}$ is with respect to the residual voltage U_{rsd}, because this voltage is used in formulas (3.10), (3.11) and (4.4) to determine the fault current angles.

As previously mentioned, the tripping zone for detecting single line-to-ground faults is determined by:

- the characteristic angle $\lambda = 0°$,
- measured residual current I_{rsd} ,
- measured residual or reference voltage U_{rsd} .

In Figure 4.13 the residual current vectors I_{rsd} with respect to the residual or reference voltage U_{rsd} for the above mentioned angles $\boldsymbol{\mu}$ in both faulted phases are shown as the red areas. It is also clearly seen that for every “k”, the measured residual currents are all within the tripping zone of the directional relay, which means that the directional element of the relay would have detected single line-to-ground faults irrespective of the fault location on the cables.

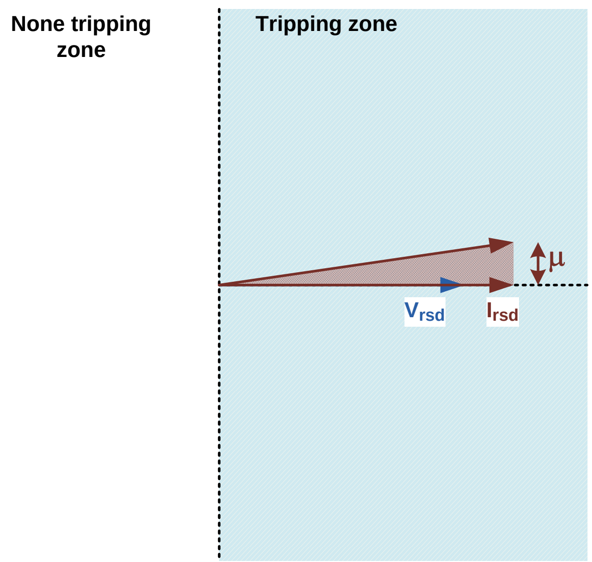

Figure 4.13: Relay directional detection of single line-to-ground fault residual current vector I_{rsd} for 0%<k<100%

4.4.4 Fault Current Directional Detection during Double Line-to-Ground Faults

The detected complex fault currents as function of the fault location "k" are obtained by using the same parameters of Table 3.6 and formulas (3.32), (3.33), (4.2) and (4.4). The detected fault current is defined as:

$\overline{I_{fC}} = I_C \angle \mu$

If a double line-to-ground fault occurs between phases B and C and ground, then the results for all detected fault current angles (μ) by the directional overcurrent relay for 0% < k < 100%, are:

- For phase C: $-179° < \mu_C < -175.7°$
- For phase B: $0.2° < \mu_B < 5°$

The angular shift $\boldsymbol{\mu}$ of the current I_{fC} is with respect to the voltage $V_{B\text{-}C}$, because this voltage is used in formulas (3.32), (3.33) and (4.4) to determine the fault current angles.

It can be seen that in Table 4.1 the tripping zone for detecting line-to-line faults between phases B and C is determined with:

- a characteristic angle $\lambda = +30°$ clockwise direction,
- measuring the phase current I_C ,
- measuring the reference voltage $V_{A\text{-}B}$.

In Figure 4.14 the double line-to-ground fault current vectors with respect to the voltage $V_{B\text{-}C}$ for the above mentioned angles μ in both faulted phases are shown as the red areas. It is also clearly seen that for every k, the measured fault currents I_{fc} are all within the tripping zone of the directional relay, which means that the directional element of the relay would have detected double line-to-ground faults irrespective by the fault location on the cables.

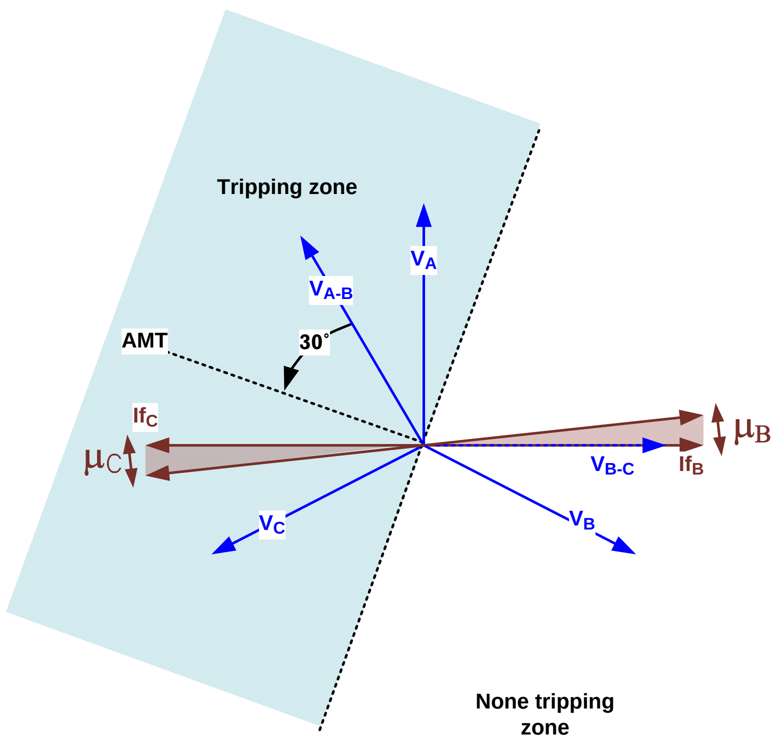

Figure 4.14: Relay directional detection of double line-to-ground fault current vectors I_{fc} for 0%<k<100%

4.4 Conclusions

In this chapter the analysis of relay fault current detection during different short circuits is discussed. The protection scheme consists of the combination of an overcurrent relay and a directional overcurrent relay. The detected fault currents through each relay separately are plotted as a function of the short circuit location k on the cable, with 0%< k <100%. The results of this analysis show that for all short circuit currents which can occur in the system, there exists certain dead zone within the protection zones. If any system fault occurs within these dead zones, the directional overcurrent relay will not be able to detect the short circuit current. The circulating fault currents cannot be detected by the DIR because of their low magnitude, which is much lower than the DIR current threshold value. The dead zones for all short circuits respectively are given in Table 4.2. These dead zones in the studied network section are indicated as red areas in Figure 4.15.

Table 4.2: Dead zones in the studied network section for all short circuits respectively

System Fault	***Dead Zone***	***Cable Length***
Three phase Faults	0% < k < 8%	~ 160 m of 1,97 km
Line-to-Line Faults	0% < k < 9%	~ 180 m of 1,97 km
Single Line-to-Ground Faults	0% < k < 15%	~ 300 m of 1,97 km
Double Line-to-Ground Faults	0% < k < 8%	~ 160 m of 1,97 km

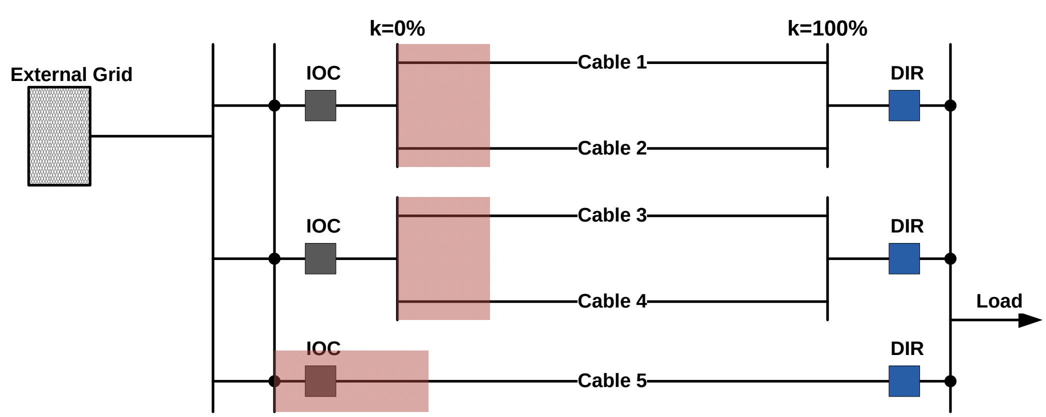

Figure 4.15: Representation of "dead zones" within studied network section

The second part of this chapter is focused on the relay directional detection. With the help of the predefined relay tripping zones and the phase difference between the detected fault current and system voltage, it is shown that the directional protection relay properly detects the direction of the short circuit current during all system faults. The results thus show that the direction of the fault currents is always detected by the directional overcurrent relay during any system fault irrespective of the short circuit location k. This also holds for short circuits occurring within the dead zones. Therefore, the relay directionality settings are correct.

The presence of these *dead zones* in the network of the DSO is inacceptable. It is thus necessary that possible solution strategies are studied to mitigate them.

5

Possible Strategies to Mitigate Dead Zones

The analysis of the protective systems of the studied network section displayed in Figure 4.1 shows that there exists certain *dead zones*. If any system fault occurs within these *dead zones*, the directional relay will not be able to detect the circulating fault current, because its magnitude will be lower than the directional relay current threshold. The results will be a prolonged circulating fault current which can cause long-lasting voltage dips, system component damage and unnecessary outages.
The dead zones are clearly shown in Figure 4.12 and vary from 8% to 15% of the cable length during the different system faults, which is about 160 m to 300 m of the 2 km cable length. But the protective system as it is, must protect 100% of its zone, hence it does not fulfil the grid operator's expectations.

In this chapter, possible strategies will be analyzed to mitigate or eliminate the "dead zones" within the protected zones in order to obtain secure network protection. Each paragraph in this chapter explains a different solution strategy, including their corresponding zone protection. Attention will also be paid to assuring complete protection of the network section.

5.1 Disconnect Cable Junctions into Separate Parallel Cables

As shown in Figure 5.1, the cable junctions in the network can be uncoupled into separate cables. Each cable will be protected individually with the same protection scheme that is currently applied (combination of overcurrent and directional overcurrent relays). The relay threshold setting values also remain the same.

The network of Figure 5.1 is simplified to the network shown in Figure 5.2. Again, power system analysis can be applied to study the behaviour of the circulating fault currents during the different system faults on 'Cable 1'. Before doing so, the following derivations are important:

- The network total impedance Z_{tot}:

$$Z_{tot} = [(0.25Z + (1-k)Z)\ //\ kZ] + X_{net} = 0.8kZ(1.25-k) + X_{net} \tag{5.1}$$

- The circulating fault currents through the protection relays:

For the directional overcurrent relay counts:

$$I_{DIR} = \frac{kZ}{kZ + Z(1.25 - k)} \cdot I_f = 0.8k \cdot I_f \tag{5.2}$$

For the overcurrent relay counts:

$$I_{IOC} = I_f - I_{DIR} \tag{5.3}$$

It should be noted that again all derivations are as function of the short circuit location k.

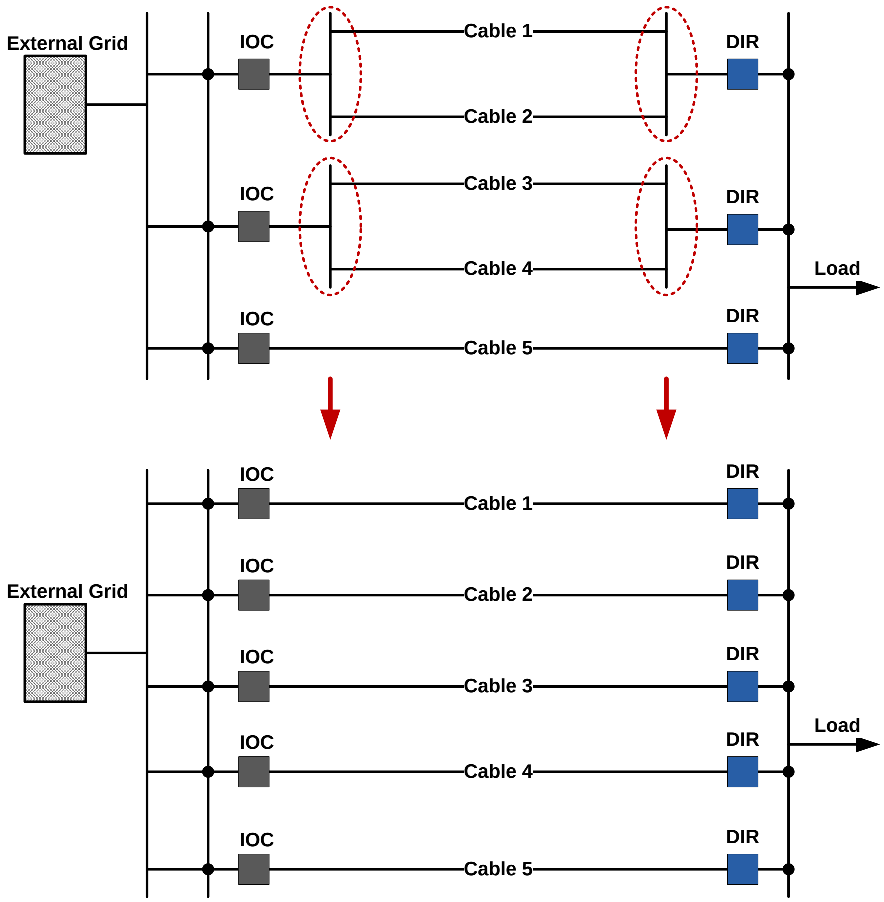

Figure 5.1: Uncoupling of the cable junctions into separate cables, which are protected individually

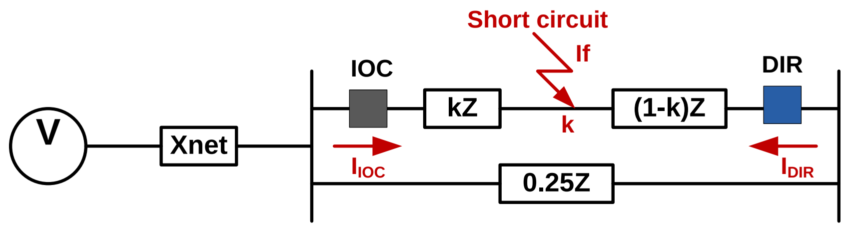

Figure 5.2: Simplified network model including protection relays and circulating fault currents

The short circuit analysis is done in a similar way as explained in chapter 3, but for obtaining the sequence impedances, equation (5.1) is used. The detected fault currents are obtained in a similar way as was done in chapter 4, by making use of formulas (5.2) and (5.3).

The input network parameters are the same as those used in Tables 3.2, 3.3, 3.5, and 3.6 and from the results the following conclusion can be drawn:

There are still *dead zones* available in the network for every system fault. These *dead zones* are summarized in Table 5.1:

Table 5.1: Available "dead zones" during short circuits in the studied network

System Fault	***Dead Zone***	***Cable Length***
Three phase faults	0% < k < 6%	~ 120 m of 1,97 km
Line-to-line Faults	0% < k < 7%	~ 140 m of 1,97 km
Single line-to-ground Faults	0% < k < 13%	~ 260 m of 1,97 km
Double line-to-ground Faults	0% < k < 6%	~ 120 m of 1,97 km

The results show that the "dead zones" obtained in chapter 4 are somewhat reduced (with about 2% cable length), but they are not completely eliminated. These zones are represented as the red areas in Figure 5.3. This means that uncoupling the cable junctions into separate cables and protecting each of them with the same protection scheme does not provide complete zone protection.

It should be pointed out that uncoupling the cable junctions into separate cables requires additional space for 2 extra feeder connections in both the substations at the receiving and sending ends of this network section.
Moreover, protecting the cables individually requires two additional protective schemes including instrument transformers.

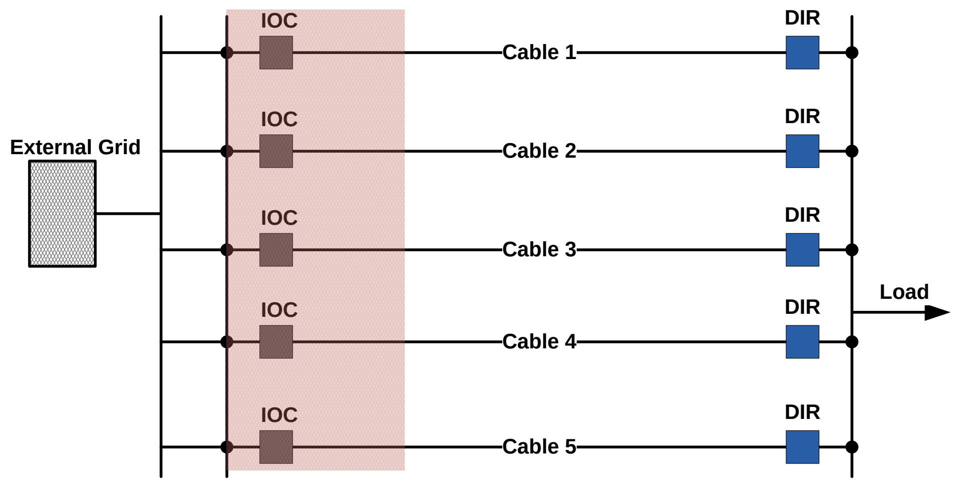

Figure 5.3: The representation of the dead zones within the network section with currently used protection scheme

5.2 Readjustment of Protection Relay Settings

The protection scheme of the studied network section consists of an overcurrent (IOC) and directional overcurrent (DIR) protection relays, shown in Figure 5.4. As discussed in chapter 2, each relay has certain restraints that need to be set by the grid operator. These restraints are:

- a current set value,
- a time set value,
- a directional element, which only counts for the directional overcurrent relay. The directional element of the relay is predefined by the manufacturer and as shown in Chapter 4, the fault current direction through the directional relay is always detected for all system faults in the studied network. Therefore, readjustment of this setting cannot be considered in this paragraph.

It should be noted that the studied network section consists of parallel cables connected to only one bulk source of supply. This is also clearly shown in Figure 5.4. Because there is only one source of supply, a system fault at any location in this network section will always result in a circulating fault current through the protective relays that will not vary in amplitude a lot. Thi is shown in the same figure.

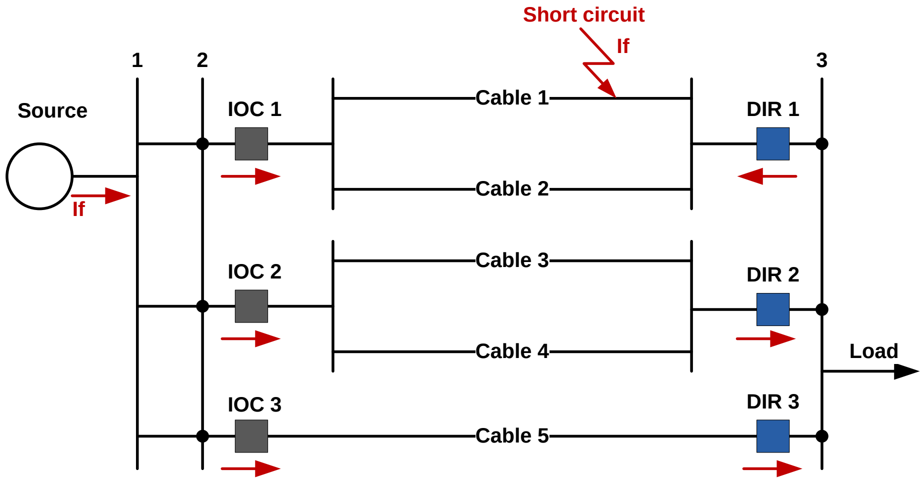

Figure 5.4: Network section with single source supply and circulating fault currents during short circuits

In case of a short circuit, the relays must detect the fault current and switch off the faulted network section selectively. But it was clearly shown in chapter 4, that the fault current through the directional relays cannot be detected if the system faults occur in certain available *dead zones* on the cables which are depicted in Figure 4.12. One of the possibilities to try to eliminate these zones is by changing the relays current and/or time settings. Because the protection scheme is the same in all the parallel network sections, only one section will be highlighted during this analysis.

Readjusting the relays current and time settings

Figure 5.5 shows one part of the network section with the protective relays and their threshold settings.

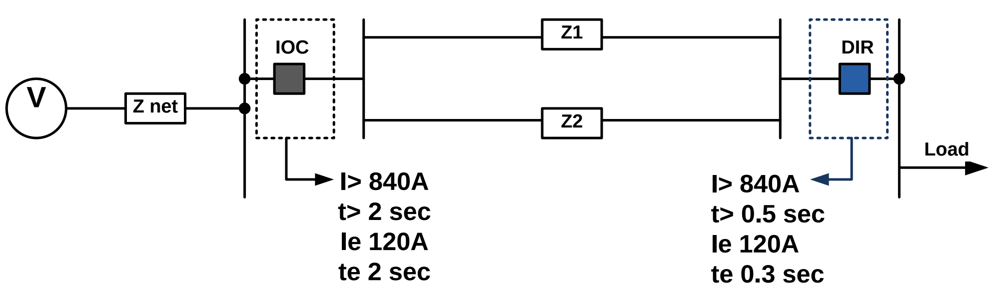

Figure 5.5: Network section including protection relays and their threshold settings

The IOC time settings are relatively high (2 seconds), because they are graded with other protective systems in the underlying network, so that selective switching can take place. Thus, these time settings cannot be readjusted.

According to [3], in similar networks which are connected to one supply source, the DIR needs to be almost an instantaneous device. This means that it must be adjusted to operate very fast with no intentional time delay.
If the DIR time settings, as shown in Figure 5.5, are compared with the grid operator standards for protection relay settings, represented in Table 4.1, it seems that they are already set to operate after the shortest possible times. But it should also be noted that even if the DIR tripping times were reduced to lower values, it would not have any influence on the available "dead zones".

The current settings of the two displayed relays are also according to the grid operator standards for protection relay settings, represented in Table 4.1.
According to [3], in similar networks which are connected to one source of supply, the DIR needs to have a very low pickup current value that is set just above the tapped load current. Network simulations show that the total load current through both parallel cables is about 320 A, during normal (healthy) grid operation. In situations where one of the other parallel branches in the network of Figure 5.4 is out of service, the total load current through the parallel cables of Figure 5.5 is enhanced to 540 A. This means that for both phase and earth faults, the DIR current setting could be lowered to, for example, 600 A. The available "dead zones" do not disappear, but they are reduced to the indicated cable lengths shown in Table 5.2.

Table 5.2: Available dead zones after readjusting DIR current setting values

System Fault	***Dead Zone***	***Cable Length***
Three phase faults	k < 6%	~ 120 m of 1,97 km
Line-to-line Faults	k < 6%	~ 120 m of 1,97 km
Single line-to-ground Faults	k < 8%	~ 150 m of 1,97 km
Double line-to-ground Faults	k < 6%	~ 120 m of 1,97 km

As shown in chapter 2, the I> and the Ie setting of the DIR are not directionally dependent. This means that the directional relay immediately detects a current if it is higher than its current threshold value, irrespective of the current direction. Only after current detection, the directional element of the relay determines the detected current direction.
The DIR current setting can be reduced to, for example, 600 A but the load current during normal (healthy) grid operation can be any value lower than the maximum current which can flow through the cable (1.5 x nominal cable current = ~ 800 A). This means that at the instant the load current exceeds the relay current threshold value during normal grid operation, the DIR will be continuously detecting the current. This is not the way directional overcurrent relays should operate.

Activating and adjusting the I>> and t>> settings of the IOC relays

As shown in Table 4.1, the I>>, Ie>> and t>>, te>> settings of the currently used protection scheme are not activated in this network section. If coordinated properly, these settings of the IOC relays could be activated and adjusted in such a way that fast selective switching could be obtained when short circuits occur within the *dead zones*. The analysis of chapter 4 shows that when the fault location k varies from 0% to 100% cable length, the detected fault currents through the IOC relay decreases from a maximum to a minimum magnitude respectively. This can be clearly seen in Figures 4.6, 4.7, 4.8 and 4.9. These figures also show that the opposite happens for the DIR detected fault current magnitudes and this creates the 'dead zone' in the network.

The purpose for activating the I>>, Ie>> and t>>, te>> of the IOC relays is to detect short circuits currents of high magnitude which result from system faults occurring within the 'dead zones'. During these system faults the detected IOC fault currents must be high enough to exceed the I>>, Ie>> thresholds of the IOC and instantaneous tripping could be generated with instantaneous tripping times for t>>, te>> (equal to the relay clearing time, Tc). For selective tripping with these settings activated, the following conditions should be fulfilled:

- The detected fault current magnitudes $I_{f(IOC)}$ must exceed the thresholds $I \gg_{IOC}$, $Ie \gg_{IOC}$ during phase and earth faults respectively.
- The IOC relays must not trip for system faults occurring outside their protected zone
- $t \gg_{IOC}$, $te \gg_{IOC}$ must be lower than $t >_{DIR}$, $te >_{DIR}$ respectively, to obtain selective tripping

Herewith, these conditions are analyzed separately.

1. *Analysis of the detected fault current magnitudes during phase and earth faults*

The results of the analysis in Chapter 4 shows that for all phase faults and earth faults the *dead zones* in the network section exist when system faults occur at locations which are largely between 0% < k < 10% and 0% < k < 15% respectively. The corresponding IOC maximum detected fault current magnitudes are shown in Table 5.3.

Table 5.3: IOC detected maximum fault current magnitudes during phase and earth faults which occur within the available 'dead zones'

Type of Short circuit	***Short circuit location within available 'dead zone'***	***Corresponding IOC detected fault current magnitudes $I_{f(IOC)}$***
Three Phase Fault	0% < k < 10%	$\mathbf{18.48\ kA} < \boldsymbol{I_{f(IOC)}} < 19.03\ kA$
Double Phase Fault	0% < k < 10%	$\mathbf{15.99\ kA} < \boldsymbol{I_{f(IOC)}} < 16.454\ kA$
Single Phase-to-Ground Fault	0% < k < 15%	$\mathbf{1.36\ kA} < \boldsymbol{I_{f(IOC)}} < 1.51\ kA$
Double Phase-to-Ground Fault	0% < k < 10%	$\mathbf{15.61\ kA} < \boldsymbol{I_{f(IOC)}} < 16.\mathbf{08\ kA}$

The I>>, Ie>> settings of the IOC relay must be lower than the above shown detected fault current magnitudes for phase and earth faults which occur within the 'dead zones'.

2. IOC relays must not trip for faults outside their protected zones

To prevent the IOC relays to trip for system faults outside their protected zone can not only be achieved by time grading, but the I>>, Ie>> threshold must be high enough to ignore fault currents flowing to a short circuit outside the protected zone. The highest fault currents flowing through the IOC relays to a short circuit outside its protected zone ($I_{f(IOC\ outside,max)}$) are obtained by the scenario displayed in Figure 5.6. The figure shows a system fault occurring at the rail just behind the protected zone during a situation where one of the parallel sections of the studied network section is out of service.

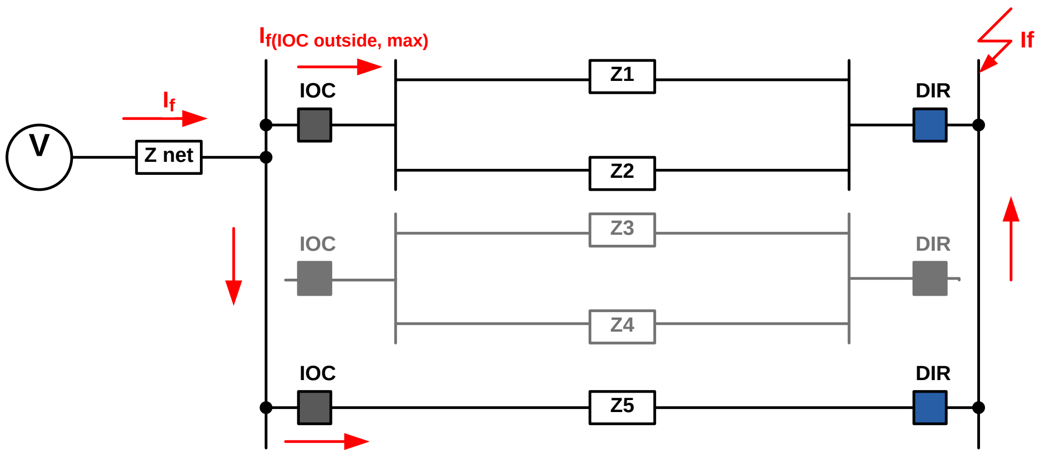

Figure 5.6: The highest fault current flowing through the IOC relay to a short circuit on the rail behind the protection scheme, while one of the parallel sections is out of service (grey section)

The maximum magnitudes for $I_{f(IOC\ outside,max)}$ during phase and earth faults on the rail are summarized in Table 5.4.

Table 5.4: The maximum magnitudes of the highest detected fault currents through the IOC relays ($I_{f(IOC\ outside,max)}$) for a short circuit outside the protected zone and one parallel section of the network out of service

Type of Short Circuit	$\boldsymbol{I_{f(IOC\ outside,max)}}$
Three Phase Fault	$\mathbf{11.405\ kA}$
Double Phase Fault	$\mathbf{9.877\ kA}$
Single Phase-to-Ground Fault	$\mathbf{0.987\ kA}$
Double Phase-to-Ground fault	$\mathbf{10.123\ kA}$

To prevent the IOC relays to trip for short circuits outside their protected zone, the I>>, Ie>> settings must be higher than the obtained currents $I_{f(IOC\ outside,max)}$ in the above analyzed scenario.

3. $t \gg_{IOC}$, $te \gg_{IOC}$ must be lower than $t >_{DIR}$, $te >_{DIR}$ to obtain correct time grading

By making the time settings t>> and te>> of the IOC relays lower than the time settings t> and te> of the DIR, selective relay switching can be obtained without long-lasting circulating fault currents in the network section. The shorted tripping time possible is the relay operating time or relay clearing time (Tc), which is mostly about 0.3 seconds (almost instantaneous). Time grading in the studied network section where the t>>, te>> settings of the IOC relays are also activated can be done as shown in Figure 5.7. It should be noticed that the Ie> setting of the DIR is readjusted from the present setting of 0.3 second to the proposed setting of 0.5 seconds. The remaining present relay time settings remain unchanged, while the t>> and te>> are added to the protective system.

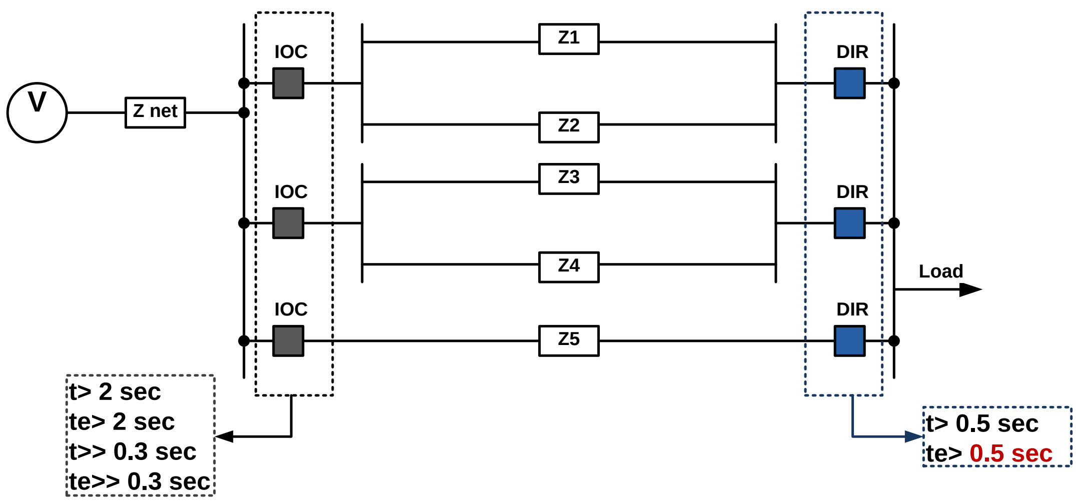

Figure 5.7: Time grading in the studied network section where the t>>, te>> settings of the IOC relays are activated. The DIR present setting is readjusted from 0.3 seconds to the proposed setting of 0.5 seconds

By satisfying the three conditions to achieve selective relay tripping, the settings for I>> and Ie>> can be established. These settings can be obtained from the analyzed conditions 1 and 2, Tables 5.3 and 5.4. If the results of these tables are compared, the following current settings are proposed:

– $I \gg_{IOC} = 14\ kA$, or any other current magnitude in the range: $11.4\ kA < (I \gg_{IOC}) < 15.61\ kA$
– $Ie \gg_{IOC} = 1.2\ kA$, or any other current magnitude in the range: $0.99\ kA < (Ie \gg_{IOC}) < 1.36\ kA$

With these settings an example of a three phase fault current as function of the short circuit location k is analyzed. The detected fault currents of paragraph 4.3.1 are further analyzed with the additional IOC relay settings. The results are shown in Figure 5.8. This figure shows the IOC and DIR current characteristic together with the detected fault currents. It is clearly shown that system faults which occur within the *dead zones*, are detected by the I>> setting of the IOC relay and it can be selectively switched off after the time restraints are exceeded.

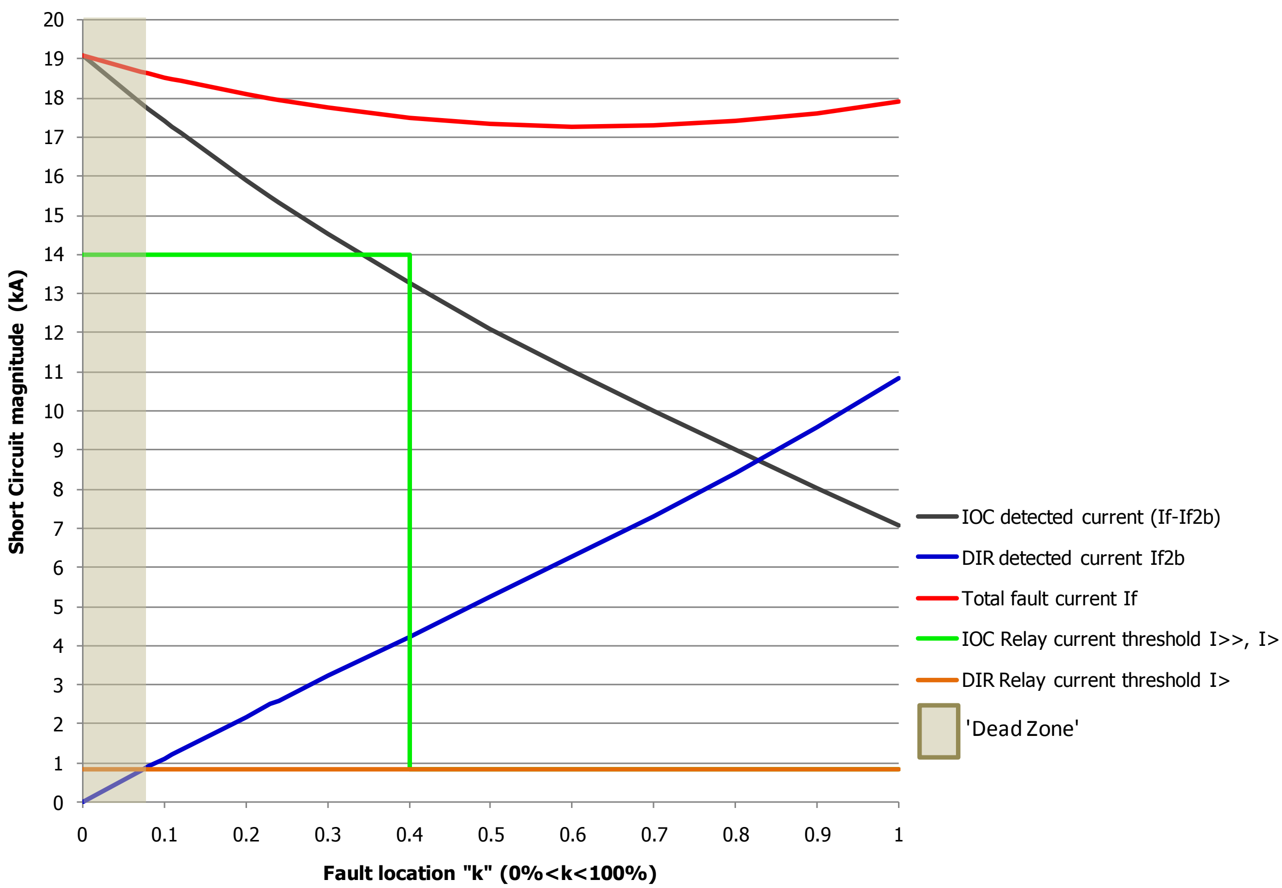

Figure 5.8: IOC and DIR current characteristic together with the detected fault currents. It is clearly shown that short circuits which occur within the 'dead zones', are detected by the by the I>> setting of the IOC relay

The operating principle of this proposed protection scheme can be explained with the help of Figures 5.8 and 5.9. Figure 5.8 shows that if a three phase fault occurs within the first 35% of the cable length (this includes the 'dead zone'), the fault current $I_{f(IOC)}$ in Figure 5.9, will exceed the I>> setting of the IOC relay and its corresponding circuit breaker will switch off the fault current after 0.3 seconds. With the left side of the cable switched off, the total fault current will now flow through the DIR and this relay will cause the circuit breaker to switch off the fault current after 0.5 seconds. The faulted cable will then be completely isolated from the remaining network. If a system fault occurs between 35% < k < 100%, the fault current will only be detected by the I> settings of both the IOC and DIR relays and in this case the DIR relay trips first after 0.5 seconds and thereafter, the IOC relay trips after 2 seconds. The same holds for relay operation during earth fault currents with the settings Ie>>, te>>, also shown in Figure 5.9. It should be noticed that the DIR time setting te> is adjusted from 0.3 seconds to 0.5 seconds to obtain selective relay tripping when earth faults occur within the 'dead zones'.

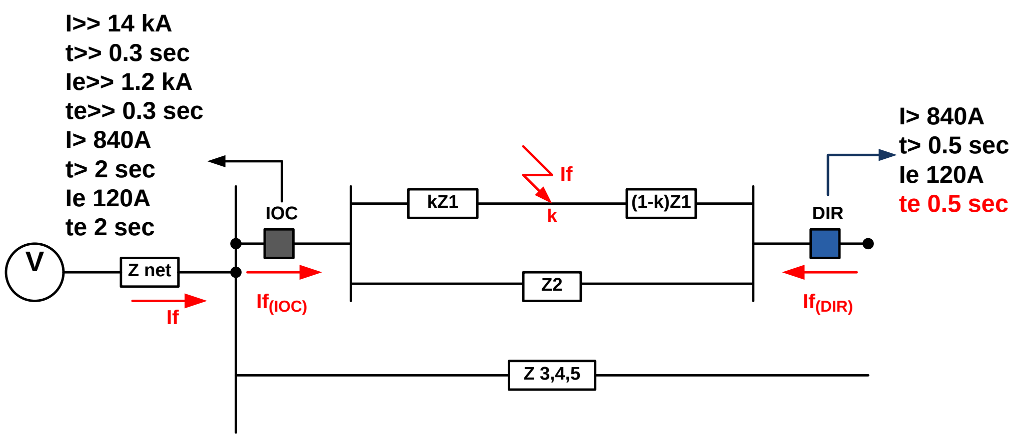

Figure 5.9: Protection scheme settings and the circulating fault currents during short circuits between 0%<k<100% on the cable of the studied network section

The results of this analysis shows that by activating and adjusting the I>>, Ie>> and t>>, te>> settings of the IOC relays and by proper time grading between these relays, the *dead zone* problem is completely overcome. For system faults within the protected zone, irrespective of the short circuit location, selective switching takes place when the proposed protection scheme is used.

The only requirement for implementing this protection scheme is:

– The IOC relays should have the possibility to accommodate both the I>, t> and I>>, t>> settings and they need to be adjusted properly.

5.3 Differential Protection Scheme

It is clearly shown in the previous chapters and paragraphs that the currently used protection scheme (consisting of overcurrent and directional overcurrent relays) cannot provide 100% cable protection in the studied network. An alternative protection scheme which has been used for many years to protect individual sections of networks or pieces of equipment is called 'current differential' or 'zone' protection. Differential protection calculates the sum of all currents flowing in and out of the protected object. According to [10], the basic principle of the scheme

is expressed in Kirchhoff's current laws which state that the geometric sum of the currents entering or leaving a node must be 0 at all time.
This convention, applied to one of the studied parallel cable sections, is shown in Figure 5.7. Here the currents flowing into the protected zone are positive, while the currents leaving the protected zone are negative. Furthermore, the zone of protection includes everything between the current transformers, where current measurements are made for the protected component.

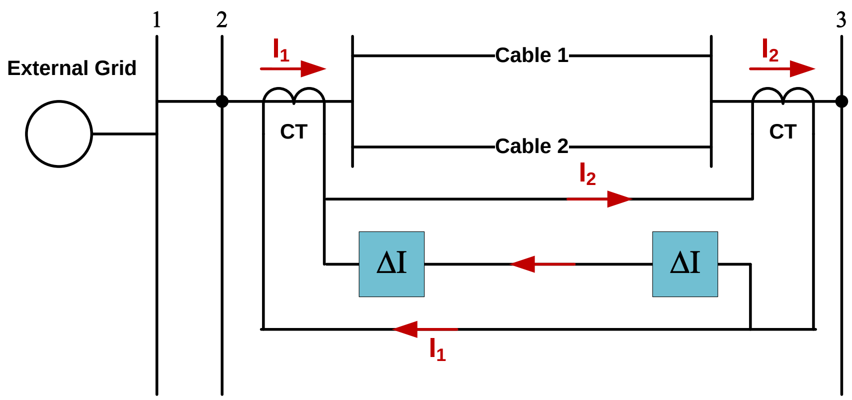

Figure 5.10: Line differential Protection scheme implemented on one of the parallel cable sections

The current transformers (CT's), if ideal, should have equal secondary currents, which circulate through the interconnecting conductors, which are called pilot wires. For feeder differential protection, the CT's are relatively far apart and that is why three connection wires are used. Two current differential relays are connected at both terminals in the differential core which, in the event of an internal fault, trip the circuit breakers in their respective stations. Detailed information about this connection method can be found in [10].

During healthy situations the current measured by the relay must fulfill the following requirement:

$$\Delta I = I_1 + I_2 = 0 \tag{5.4}$$

In case of a system fault on the protected unit, the input current would no longer be equal to the output current and the sum of these currents would not be equal to zero anymore. If the sum of the currents is higher than the relay current restraint, the relay is activated and a trip commando is generated to isolate the faulted zone from the system.

General factors which affect the Differential Relay sensitivity

The pick-up value ΔI of the differential relay seems like a fixed value but in practice however, a false differential current resulting from transformation errors of the current transformers must be considered. The different sources of errors are all thoroughly explained in [5], [6] and [10]. These sources of error give rise to a 'spill' current through the relay even without a fault being present within the protected zone. This limits the relay sensitivity that can be obtained. The 'spill' current in the relay is dependent on the magnitude of the through current, being negligible at low values of through-fault current. But in the event of large fault currents, CT saturation may cause a rapid increase of this 'spill' current.
Setting the operating threshold of the protection relay above the maximum of spill current will result in poor relay sensitivity. By making the differential setting approximately proportional to the fault current, the sensitivity for low level faults is greatly improved. The bias characteristic for a modern differential relay that overcomes the problems due to errors is shown in Figure 5.11. More detailed explanation about the relay threshold settings will not be included in this thesis.

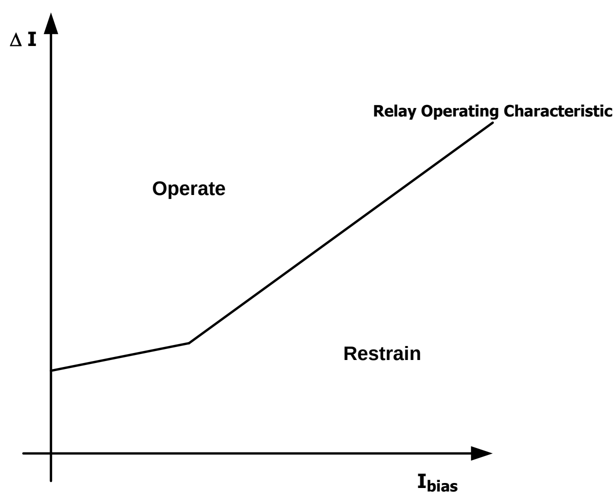

Figure 5.11: Typical bias characteristic of the differential protection relay

Fault current detection ΔI

The currents I_1 and I_2 during short circuits can be derived from the same simplified model which is used in chapter 4.2. This model is redrawn in Figure 5.12 with all the circulating fault currents including the currents which are measured by the differential relays. By using (4.2), (4.3) and (4.4) the following holds for the currents through the differential measuring points (mp) in Figure 5.12:

$$I_{f2} = |I_{f2b}| = |(0.6k \cdot I_f)| \tag{5.5}$$

$$I_{f1} = (I_f - |I_{f2b}|) = 0.3k \cdot I_f \tag{5.6}$$

If the measuring transformers with transformer ratio 500 A primary current to 5 A secondary current, the relay measured current ΔI can be obtained with the help of the transformer current ratio:

$$\Delta I = (I_1 + I_2) \cdot {}^{5A}/_{500A} = \frac{(I_1 + I_2)}{100} \tag{5.7}$$

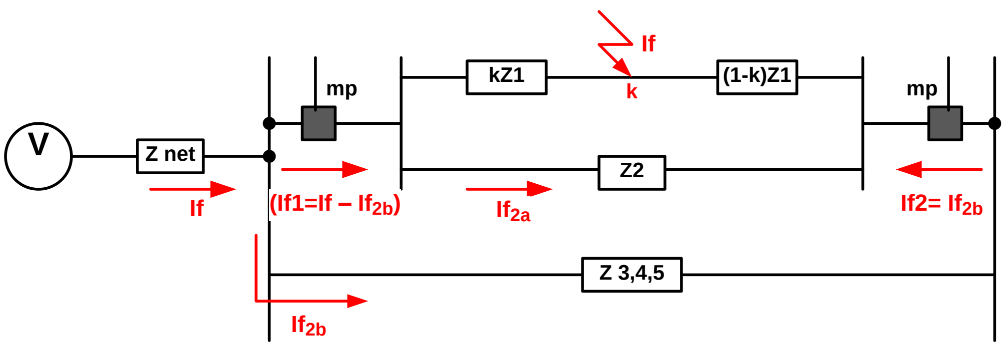

Figure 5.12: Circulating fault currents and currents through the differential relay measuring points

With the help of equations (3.6), (3.10), (3.11), (3.25), (3.32), (3.23), (5.4), (5.5), (5.6), (5.7) and Tables 3.2, 3.3, 3.5, 3.6 the relay current ΔI can be determined for all different system faults, as function of short circuit location k, with 0% < k < 100%. The ΔI graphs during phase faults are shown in Figure 5.13 and the ΔI graph during single line-to-ground faults is shown in Figure 5.14.

It should be noted that the 'spill' current, which is caused by transformer errors, is not included in the measured results shown in the following figures.

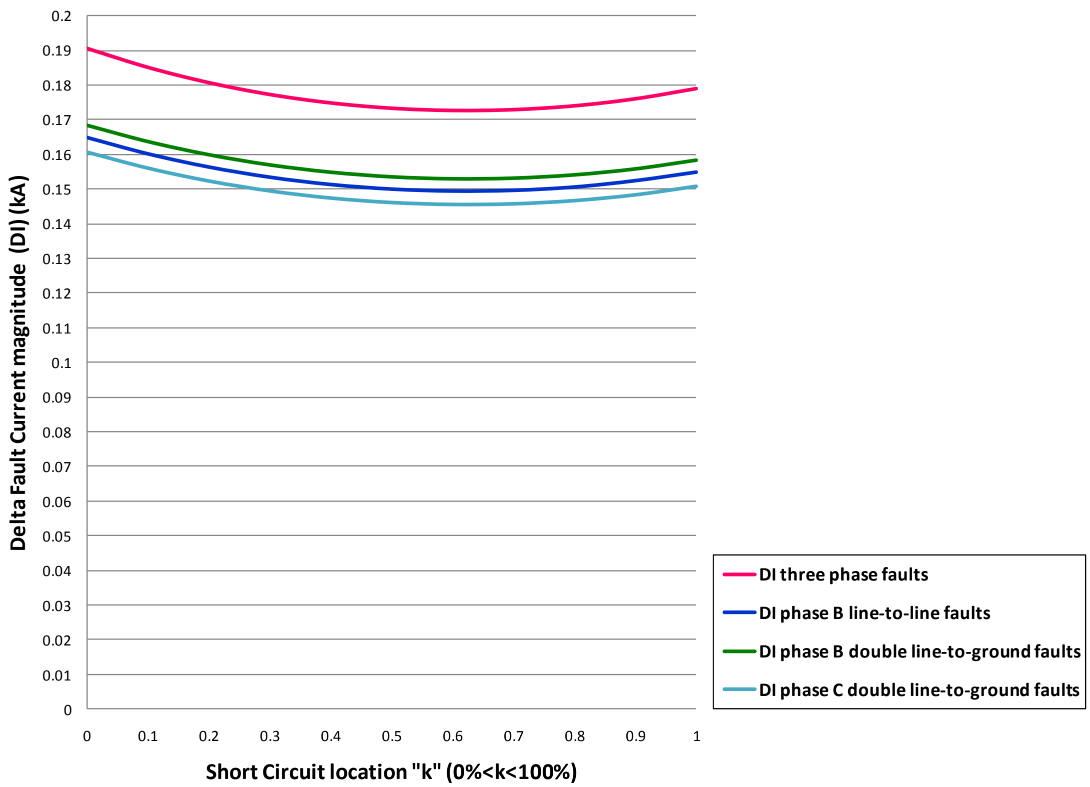

Figure 5.13: Measured delta I (DI) through the current differential relay during phase faults

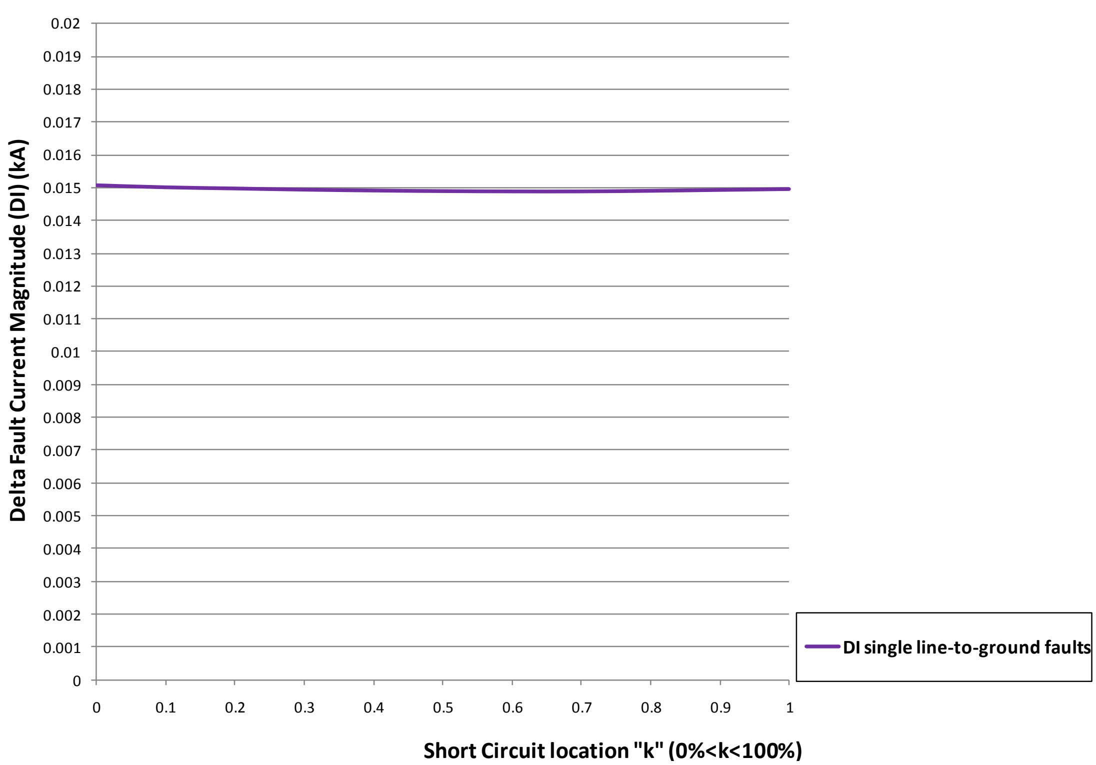

Figure 5.14: Measured delta I (DI) through the current differential relay during single line-to-earth faults

When the ‘spill’ currents of the measuring transformers are included in the detected fault current behaviour as function of the short circuit location, the differential protection scheme could be a good alternative for eliminating the available ‘dead zones’ in this network section. Furthermore, there are other aspects that also need to be taken in account while considering this option:

- According to [10], differential protection is 100% selective and it provides correct discrimination. However, it only protects the circuit or zone between their current transformers and does not provide a measure of back-up protection to other parts of the networks.
- The measured system parameters must come from identical current measuring transformers which are mounted near the ends of the protected unit. However, as shown in Figure 5.10, the differential relay is connected to each of the measuring points via pilot wires or optical fibers or other high frequency communication equipment. They are needed to send current information between the ends of the protected unit and the relay. This makes the differential protective system more expensive than any other protective system without a communication system.

More detailed information about applying differential protection can be found in [10].

5.4 Distance Protection Scheme

Another alternative method for protecting the studied network is by implementing a distance protection scheme. From [3], [9] some advantages of this protection scheme over the other protection schemes are summarized as follows:

- The tripping decision can be determined with local measured quantities, so there is no need for comparisons between the quantities at both ends of the protected units.
- It provides no large operating times close to the energy source, which is the main problem when using overcurrent protection.
- Unlike the differential protection scheme, this scheme can also respond to external faults by providing a time delayed back-up protection function.
- Distance relays are much less affected than overcurrent relays by changes in generation and system configuration.

As mentioned in chapter 2, the distance relay operates on the principle of comparing the voltage and current in some way to obtain a measure of the ratio between these quantities. The impedance of the short circuited cable varies from zero to a finite value dependent on the short circuit on location “k”. In [13], is shown that with the voltage/current ratio and the cable impedance per km, the distance to the fault can be determined in the following way:

CT transformer ratio = $N_{CT} = \frac{V_p}{V_s}$

VT transformer ratio = $N_{CT} = \frac{I_p}{I_s}$

$$\frac{V_p}{I_p} = \frac{N_{CT}}{N_{VT}} \cdot l \cdot Z_C \tag{5.8}$$

With: V_p- measured phase voltage
V_s – transformer secondary voltage
I_p - measured phase current
I_s – transformer secondary current
l - distance from the measuring point to the fault in percentage of the total line length
Z_C - impedance of the cable in Ω

Because $\frac{N_{CT}}{N_{VT}}$ and Z_C are constants, the impedance calculated by a distance relay for faults on the cable depends on the distance l.

The distance protection relays can be implemented in one part of studied network as is shown in Figure 5.15. For the impedance Z_C in formula (5.8) holds:

$$Z_C = Z_{cable1} // Z_{cable2} = 0.5Z \ (\Omega) \tag{5.9}$$

There are two distance protection relays required, one directed towards the load and one directed towards the source, indicated by the arrows above D1 and D2. It can be seen that both relays make use of Zone 1 extension:

- *Zone 1:* the high speed instantaneous zone with no intentional delay, set to provide 80-85% cable section coverage. This is shown in Figure 5.15 as the distance D1 – A. The maximum distance l from the measuring point D1 to zone 1 boundary A is 85%, which makes the maximum zone 1 cable impedance Z_{D1-A} equal to $(0.85 \cdot Z_C)$.
- *Zone 2:* covers the remaining 15% over the cable section and it overreaches the protection section by 20-30%. This is the distance behind zone 1 boundary A in the same figure.

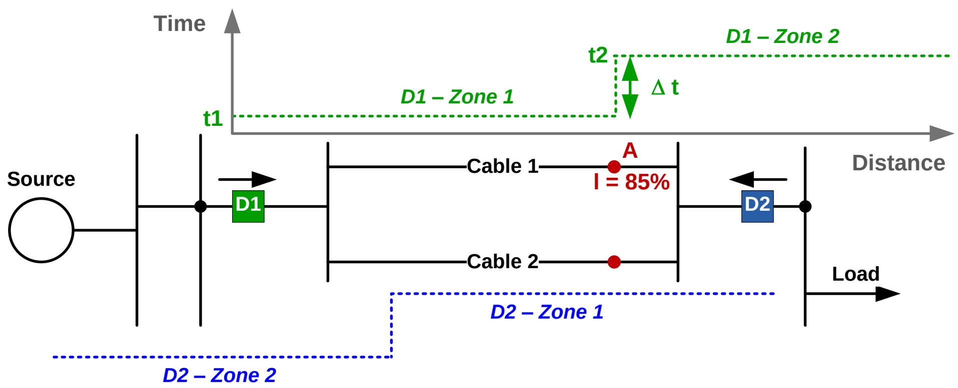

Figure 5.15: Suggestion for implementing distance protection relays. Relay D1, with its zone 1 covering 85% of the cable length, (distance D1-A). The time-distance characteristic represents the corresponding relay zone tripping times.

If the relay detects a fault within its zone 1, the following conditions must hold concerning the short circuit location "k" and the short circuit impedance Z_{D1-k}:

– 0% < k < 85%
– $0 < Z_{D1-k} < Z_{D1-A}$

Beside these conditions it can be stated that the relay generates a circuit breaker trip command when:

$$Z_{D1-k} < Z_{D1-A} \overset{so}{\Rightarrow} (Z_{D1-k} - Z_{D1-A}) < 0 \tag{5.10}$$

If this relation is not satisfied, the system fault will not be detected in zone 1 and it will not be switched off after t1 seconds. In such cases, the system fault could be located just behind zone 1 or in zone 2 of the relay and must be switched off after a certain time delay (Δt) or after t2 seconds. This also counts for relay D2 but only in opposite direction.

The distance protection scheme can have an important disadvantage when it is implemented on relatively short cables. In most cases, the measuring current and voltage transformers have a deviation of about 5% due to measuring errors (also mentioned in the previous paragraph). If these deviations of both the voltage and the current measurements are taken into account, the measured maximum zone 1 impedance of Figure 5.15 is increased by:

$$Z_{D1-A} \uparrow 5\% = \frac{V \uparrow 5\%}{I \downarrow 5\%} = \frac{1.05V}{0.95I} = 1.1053 Z_{D1-A} \tag{5.11}$$

In the studied network the cable length is 1.97 km, which is relatively short. This has the disadvantage that the difference between the measured impedances Z_{D1-k} obtained from two

distances l between the measuring point D1 and two different locations k on the cable is very small. With an increase in the maximum zone 1 impedance due to the measuring transformer deviations, it may be practically impossible to implement the distance relay for such short cables because the increase in the zone 1 impedance may cause zone 1 of the relay to stretch beyond whole cable length. This is explained more clearly with the help of the following example.
Figure 5.16 is a simplified model of Figure 5.15, where only D1 is taken into account with its zone 1 and zone 2 settings. The following counts for the cable impedance Z_C if $Z = 0.3343\ \Omega$:

Substituting Z into equation (5.9) gives:

$$Z_C = 0.5Z = 0.1672\ \Omega$$

Therefore, i $l = 85\%$f the maximum zone 1 cable impedance Z_{D1-A} is:

$$Z_{D1-A} = 0.85Z_C = 0.1421\ \Omega$$

Due to the deviation of about 5% in the measured impedance, the maximum zone 1 impedance is, according to formula (5.11), increased by:

$$Z_{D1-A} \uparrow 5\% = 1.1053Z_{D1-A} = 0.157\ \Omega$$

If $(Z_{D1-A} \uparrow 5\% = 0.157\ \Omega)$ is compared with the measured total line impedance $Z_C = 0.1672\ \Omega$, then the deviated impedance corresponds with the cable length in the following way:

$$l = \frac{Z_C}{Z_{D1-A} \uparrow 5\%} = \frac{0.157\ \Omega}{0.1672\ \Omega} \times 100\% = 93.9\%$$

This means that the deviation in measured impedances causes the zone 1 to stretch along almost the whole cable length. If a fault occurs on $l = 90\%$, which is just outside zone 1, the distance protection relay will detect this fault within its zone 1 due to the deviated impedance. This may result in false tripping.

This simple analysis indicates that replacing the current protection scheme with a differential protection scheme does not seem a good alternative to eliminate the available 'dead zones' within the network, because the cables in this network section are relatively short. Further analysis of this protection scheme is not included in this thesis.

5.5 Conclusions

In this chapter there are different possibilities summarized to mitigate the *dead zones* in the studied network and the following can be concluded:

Disconnecting the cable joints into parallel connected cables and protecting each cable separately with the currently used protection scheme (the combination of overcurrent and directional overcurrent protection), still results in available 'dead zones'. This still means that the studied network section will not be protected for 100% against system faults.

The available 'dead zones' can be handled with by activating and properly adjusting the I>>, Ie>> and t>>, te>> settings of the IOC relays in the currently used protection scheme. With these settings, the IOC relays can generate a trip commando instantaneously when a system fault occurs within the available 'dead zones'. The I>>, Ie>> settings of the IOC relays must be such that they are lower than the respective fault currents which flow due to a short circuit within the 'dead zones'. Moreover, these settings should still be higher than the fault currents which flow through this network section as result of a short circuit in the downstream network (external to the protected zone).
For selective switching the IOC relays and the t>>, te>> functions of the DIR relays must be time coordinated with the t>, te> settings of the DIR relays. Therefore, the te> setting of the DIR relay must be increased from 0.3 seconds to 0.5 seconds. The protection scheme with the proposed settings in order to obtain selective tripping during faults within and also outside of the 'dead zones' is shown in the following fugure:

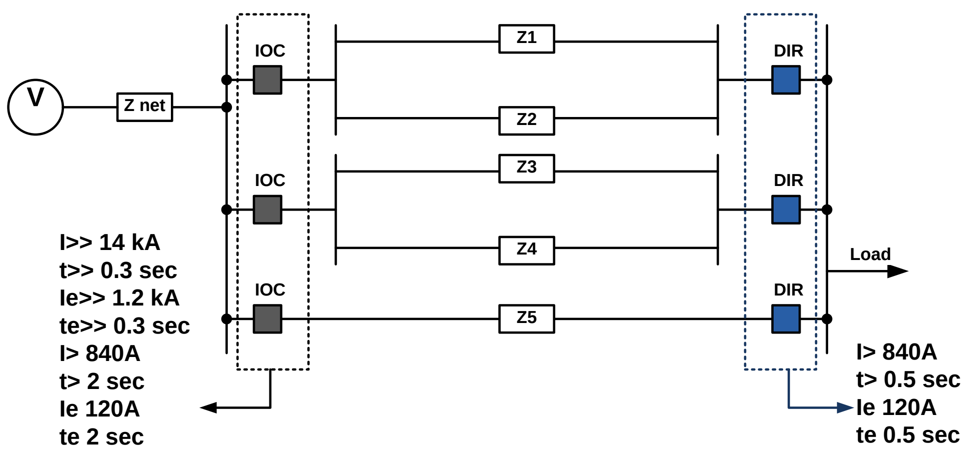

Figure 5.16: The protection scheme with the proposed settings in order to obtain selective tripping during faults within and also outside of the 'dead zones'

A good alternative protection scheme for the studied network can be differential protection. The basic principle of the scheme is expressed in Kirchhoff's current laws which state that the geometric sum of the currents entering or leaving a node must add up to 0 at any point in time. It should be kept in mind however, that this protection scheme requires pilot wires or optical fibers or other high frequency communication equipment which makes this scheme expensive.

Implementing distance protection relays can also be an alternative to eliminate the available *dead zones* in the studied network. But the analysis of this scheme requires more research to determine whether phase and earth fault currents will be detected during short circuits.

6

Conclusions and Recommendations

This study is performed to analyze protection mal-operation in meshed distribution grids. The study is focused on a part of an underground 25.6 kV sub-transmission cable network which is a meshed structured network and consists of three cable sections. Each section is protected individually and the used protection scheme includes both overcurrent and directional overcurrent relays. For this study the mal-operation of such protection schemes which occurred in these types of structured networks, are analyzed. This is done by applying short circuit analysis to the network section and analyzing the circulating and detected fault currents. Furthermore, the analysed results are verified with network simulation results. The overall results of this analysis lead to the cause of mal-operation of the protection relays during system faults. In this chapter, the main conclusions of this study are given and recommendations, which can be used for further analysis, are proposed.

6.1 Conclusions

Fault current detection during phase and earth faults

The different fault currents which flow through the studied sub-transmission network vary with the short circuit location along the length of a cable. The relationship between the total fault current and the short circuit location is very important when analyzing the protective devices. This relationship can be used for the analysis of the detected fault currents and the behaviour of the relay during system faults. It is found that incorrect relay tripping occurs due to the presence of certain *dead zones* along the length of the cables. If any type of system fault occurs within these *dead zones*, the circulating fault current magnitudes are found to be lower than the directional relay current threshold. These *dead zones* are found to exist because the network is connected to just one single point feeding. Therefore, it can be concluded that generally this phenomenon will always occur in complex network structures with single source feeding. In the studied network the total cable length is 1.97 km and it is shown that the dead zones cover about 10% of the total cable length during phase faults and 15% of the total cable length during earth faults.

Protection scheme analysis

The protection scheme consists of an overcurrent relay and a directional overcurrent relay. The overcurrent relay is found to operate correctly during any type of short circuit, irrespective of the short circuit location. The circulating fault currents through the overcurrent relays, during short circuits on any location in the network section, are of such magnitude that the current threshold is always exceeded. However, this is not the case when analyzing the directional overcurrent relays. Even though the circulating fault currents cannot be detected by the directional relay if the short circuit occurs within the 'dead zones', it is found from the analysis that the directional relay will always be able to determine the direction of the current flow correctly. The angular difference between the phase-fault current and the corresponding phase-to-neutral voltage, places the fault current vector in a predefined tripping zone during all types of short circuits irrespective of the short circuit location. This means that the directional relays correctly recognize these fault currents directed from the load side to the source side. Therefore, it can be concluded that the directional element of the directional protection relay works perfectly.

Possible strategies to mitigate *dead zones*

Different possibilities are analyzed to mitigate the present *dead zones* in the network:

- The analysis concludes that a change in the complex network structure still results in available *dead zones*, because the network stays complex and remains coupled to a single source feeding. Moreover, a change in the network structure may require additional space and outgoing or incoming feeder fields in the connected substations.

- It is found that adjustments in the currently used protection scheme prevent the occurrence available *dead zones*. For achieving this, the I>>, Ie>> and t>>, te>> of the overcurrent relays need to be activated and adjusted. The analysis shows that with proper settings and time coordination, the overcurrent relay trips instantaneously (after 0.3 seconds) for system faults which occur within the *dead zones* and shortly thereafter (after 0.5 seconds) the directional overcurrent relay trips. This means that the system fault is isolated selectively. For system faults occurring outside of the *dead zones*, the present settings of the protection scheme will also cause the short circuit to be isolated selectively. Therefore, it is concluded that with the proposed settings for I>>, Ie>> and t>>, te>> and proper time coordination between the overcurrent and directional overcurrent relays in the network section, selective switching can be achieved when system faults occur within as well as outside the *dead zones*.

- An alternative protection scheme which can be implemented in the network to mitigate the 'dead zones' is the differential protection scheme. With the proper settings the differential protection scheme will work perfectly, but due to the required pilot wires or optical fibers or other high frequency communication equipment this scheme becomes expensive.

- Another alternative protection scheme which seems promising to replace the present protection scheme is the distance protection relay. The cables are ~1.97 km which is relatively short and it is proven that this forms a barrier for implementing this scheme. Due to a deviation in the relay measured values (caused by transformer errors) anmd the relatively short cable length, the zone 1 impedance is increased from 85% to almost 95% of the total cable length. This means that for a system fault that occurs just after zone 1 (for example on 90% of the cable) it should be detected in the relay zone 2, but due to the deviation the short circuit can be detected in zone 1 and this may result in false relay tripping.

6.2 Recommendations

- The power system analysis results show that there are certain 'dead zones' available on the cables of the studied network section. It should be stated that these 'dead zones' are the minimum available 'dead zones' because they are obtained by analyzing *bolted* short circuits or direct short circuits within the network. It is recommended that a further study can be done, which takes into account the impact of the fault impedance (between lines and from one or two lines to ground) on the available 'dead zones'.

- An alternative protection scheme to mitigate the 'dead zones' is the distance protection scheme. It is proven that this protection scheme cannot be implemented due to the relatively short length of the cables. However, an extensive study is needed to determine whether phase and earth fault currents in this network section will be detected and selectively switched off when implementing directional protection relays.

Appendix A

Basic $Y - \Delta$ Transformation

The $Y - \Delta$ transformation is used to establish equivalence for networks with three terminals. Figure A.1 shows both the Y and Δ connected impedances. The Δ-connection can always be replaced by its equivalent Y or reversed, for purposes of calculation.

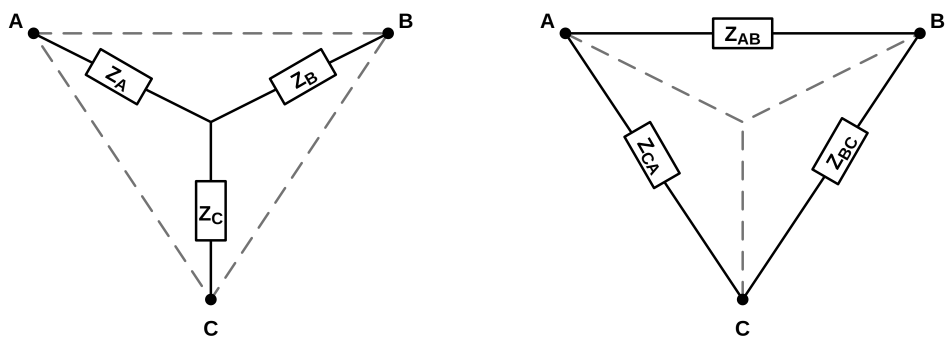

Figure A.1: Overview of Y (left) and Δ (right) impedances

Equations for the transformation from Δ to Y

The general idea is to compute the impedance Z_Y at a terminal node of the Y circuit with the impedances from the adjacent nodes in the Δ circuit. Z_Y in terms of the delta impedances Z_Δ's is:

$$Z_Y = \frac{product\ of\ adjecent\ Z_\Delta's}{sum\ of\ Z_\Delta's}$$

If this is related to Figure A.1, then the following equations are valid:

$$Z_A = \frac{Z_{AB}Z_{CA}}{Z_{AB} + Z_{BC} + Z_{CA}}$$

$$Z_B = \frac{Z_{BC}Z_{AB}}{Z_{AB} + Z_{BC} + Z_{CA}}$$

$$Z_C = \frac{Z_{CA}Z_{BC}}{Z_{AB} + Z_{BC} + Z_{CA}}$$

Equations for the transformation from Y to Δ

The general idea is to compute the impedance Z_Δ in the Δ circuit by:

$$Z_\Delta = \frac{sum\ of\ pairwise\ products\ of\ Z_Y's}{the\ opposite\ Z_Y}$$

If this is related to Figure A.1, then the following equations are valid:

$$Z_{AB} = \frac{Z_A Z_B + Z_B Z_C + Z_C Z_A}{Z_C}$$

$$Z_{BC} = \frac{Z_A Z_B + Z_B Z_C + Z_C Z_A}{Z_A}$$

$$Z_{CA} = \frac{Z_A Z_B + Z_B Z_C + Z_C Z_A}{Z_B}$$

Appendix B

Network Data Sub-Transmission Network Section

The studied network section of Figure B.1 is part of the 25.6 kV sub-transmission network, operated by Stedin a Dutch Distribution System Operator. The parameters of this network section are given in the table B.1.

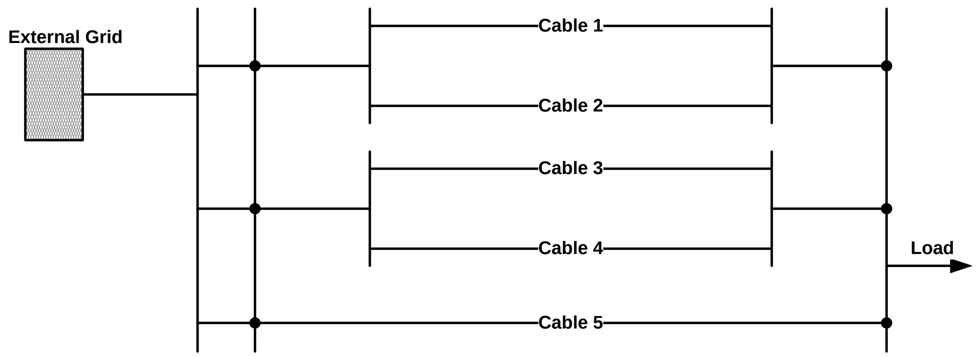

Figure B.1: Studied network section

It should be stated that all cables used in this network section are equal in type and have a length of 1.95 km. Therefore, the parameters in Table B.1 count for all cables.

Table B.1: Network element types and parameters

Element	***Sequence Impedance (Z) (Ω)***		***Sequence Capacitances (μF/km)***	
	Positive/Negative ($Z^{(1)} = Z^{(2)}$)	***Zero ($Z^{(0)}$)***	***Positive/Negative ($C^{(1)} = C^{(2)}$)***	***Zero ($C^{(0)}$)***
Cable	$(0.2364 + j0.2364)$	$(0.7809 + j0.8417)$	0.32	0.3167

Appendix C

MATLAB Short Circuit Calculation Models

The analytical analysis models to calculate the short circuit currents are programmed in MATLAB. These models are shown in the following sections.

C.1 Three Phase Fault Current Calculation

The MATLAB models for calculating three phase fault currents as function of fault location “k” are is as follows:

```
% Evita Parabirsing, Msc Final Thesis Project (init file)
% Initial values for calculating Three phase fault currents
clear all;
%network parameters
V_net_ph_ph=25.6*10^3;
V_net_ph_gr=V_net_ph_ph/(sqrt(3));
%pos sequence reactance of the network
X_net=j*0.7748;
%pos sequence resistance and reactance of the cables
R_1=0.2364;
X_1=j*0.2364;

save('init');
```

```
% Evita Parabirsing, Msc Final Thesis Project (main file)
% Calculation of Three phase fault currents
clear all;
clc;
% load initial values
in=load ('init');

% Formula for the three phase short circuit current as function of short
% circuit location 'k',(for k= 0,0.1;0.2;0.3;0.4;0.5;0.6;0.7;0.8;0.9;1;):
l=1;
m=1;
n=1;

for k=0:0.1:1
I_k(l)=in.V_net_ph_gr/(in.X_net+0.75*k*(1.25-k)*(in.R_1+in.X_1));
l=l+1;
I_k2b(m)=0.6*(k*in.V_net_ph_gr)/(k*0.75*(in.R_1+in.X_1)*(1.25-k)+in.X_net);
m=m+1;
I_k2(n)=(k*in.V_net_ph_gr)/(1.25*0.75*k*(in.R_1+in.X_1)*(1.25-k)+in.X_net);
n=n+1
end
```

```
I_k1=I_k-I_k2b;
I_sett=0,084*10^4;

figure(1);
plot([0:0.1:1],abs(I_k),'r',[0:0.1:1],abs(I_k2b),'b',[0:0.1:1],abs(I_k1),'k',
'LineWidth',2);
YLIM([0 2*10e3])
xlabel('Fault Location (0%<k<100%)');
ylabel('Three phase short circuit current,I_f');
```

C.2 Line-to-Line Fault Current Calculation

The MATLAB models for calculating line-to-line fault currents as function of fault location "k" are is as follows:

```
% Evita Parabirsing, Msc Final Thesis Project (init file)
% Initial values for calculating Line-to-Line fault currents
clear all;
%network parameters
V_net_ph_ph=25.6*10^3;
V_net_ph_gr=V_net_ph_ph/(sqrt(3));
%pos sequence reactance of the network
X_net=j*0.7748;
%pos sequence resistance and reactance of the cables
R_1=0.2364;
X_1=j*0.2364;
%sequence transformation parameters
a=(-0.5+j*0.866);
a2=(-0.5-j*0.866);

save('init');

% Evita Parabirsing, Msc Final Thesis Project (main file)
% Calculation of Line-to-Line fault currents
clear all;
clc;
% load data & initial values
in=load ('init');

% Formula for the three phase short circuit current as function of short
% circuitlocation 'k'(for k= 0,0.1;0.2;0.3;0.4;0.5;0.6;0.7;0.8;0.9;1;):
l=1;
m=1;
n=1;

for k=0:0.1:1
I_k(l)=    in.a2*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-k)*(in.R_1+in.X_1)))+
in.a*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-k)*(in.R_1+in.X_1)));
l=l+1;
I_k2(n)=(k*in.a2/1.25)*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-
k)*(in.R_1+in.X_1)))+(k*in.a/1.25)*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-
k)*(in.R_1+in.X_1)));
```

```
n=n+1
I_k2b(m)=(0.6*k*in.a2)*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-
k)*(in.R_1+in.X_1)))+(0.6*k*in.a)*(in.V_net_ph_ph/(2*in.X_net+1.5*k*(1.25-
k)*(in.R_1+in.X_1)));
m=m+1;
end

I_k1=I_k-I_k2b;

figure(1);
plot([0:0.1:1],abs(I_k),'r',[0:0.1:1],abs(I_k2b),'b',[0:0.1:1],abs(I_k1),'k',
'LineWidth',2);
YLIM([0 2*10e3])
xlabel('Fault Location (0%<k<100%)');
ylabel('Line-to-line short circuit current I_f');
```

C.3 Single Line-to-Ground Fault Current Calculation

The MATLAB models for calculating single line-to-ground fault currents as function of fault location "k" are is as follows:

```
% Evita Parabirsing, Msc Final Thesis Project
% Initial valus for calculating Single Line-to-Ground fault currents
clear all;
%network parameters
V_net_ph_ph=25.6*10^3;
V_net_ph_gr=V_net_ph_ph/(sqrt(3));
%pos and zero sequence reactance of the network (incl transformer)
X_net_1=j*0.7748;
X_net_0=j*4.5;
%pos and zero sequence impedance of the cables
R_1=0.2364;
X_1=j*0.2364;
R_0=0.780908;
X_0=j*0.8416959;
%pos and zero sequence capacitance
X_C_1=-j*136.6;
X_C_0=-j*151.476;
X_C_120=-j*47.5507;
%transformer grounding
R_g=30; %3*resistance grounded
%sequence transformation parameters
a=(-0.5+j*0.866);
a2=(-0.5-j*0.866);

save('init');


% Evita Parabirsing, Msc Final Thesis Project (main file)
% Calculation of Single Line-to-Ground fault currents
clear all;
clc;
```

```
% load data & initial values
in=load ('init');

% Formula for the three phase short circuit current as function of short
% circuitlocation 'k'(for k= 0,0.1;0.2;0.3;0.4;0.5;0.6;0.7;0.8;0.9;1;):

%pos and neg sequence impedance:
l=1;

for k=0:0.1:1
R_a_1(l)=k*(-0.239+j*10103.568)+(0.239-j*12629.524);
R_b_1(l)=k*(k*(-0.189-j*0.189)+(0.2362+j*0.2362));
R_c_1(l)=(k*(363222.982+j*8.614)-(454031.1+j*8.614))/(k*(-
0.0599+j*2669.69)+(0.0599-j*3301.18));
l=l+1;
end

R_1_p=(R_a_1.*R_b_1)./(R_a_1+R_b_1+R_c_1);
R_2_p=(R_b_1.*R_c_1)./(R_a_1+R_b_1+R_c_1);
R_3_p=(R_a_1.*R_c_1)./(R_a_1+R_b_1+R_c_1);

Z_1=((R_3_p.*(j*0.7748+R_2_p))./(j*0.7748+R_2_p+R_3_p))+R_1_p;
Z_2=Z_1;

%zero sequence impedance:
n=1;

for k=0:0.1:1
R_a_0(n)=(0.239-j*12629.524)-k*(0.239-j*10103.568);
R_b_0(n)=k*((0.781+j*0.842)-k*(0.625+j*0.674));
R_c_0(n)=((513708.153+j*25.073)-k*(410964.27+j*31.77))/((0.1557-j*3029.05)-
k*(0.1973-j*2391.017));
n=n+1;
end

R_1_z=(R_a_0.*R_b_0)./(R_a_0+R_b_0+R_c_0);
R_2_z=(R_b_0.*R_c_0)./(R_a_0+R_b_0+R_c_0);
R_3_z=(R_a_0.*R_c_0)./(R_a_0+R_b_0+R_c_0);

Z_0=((R_3_z.*(j*4.5+R_2_z))./(j*4.5+R_2_z+R_3_z))+R_1_z;

% total zero sequence fault current magnitude: I_f_0=I_f_1=I_f_2
I_f_0=in.V_net_ph_gr./(Z_1+Z_1+Z_0+30);
% Total phase to earth fault current:
I_k= 3*I_f_0;

m=1;
for k=0:0.1:1
I_f_relay(m)=0.6*k*I_k(m);
m=m+1;
end

I_k_2 = I_k-I_f_relay;
```

```
figure(1);
plot([0:0.1:1],abs(I_k),'r',[0:0.1:1],abs(I_f_relay),'b',[0:0.1:1],abs(I_k_2)
,'k','LineWidth',2);
YLIM([0 0.2*10e3])
xlabel('Fault Location (0%<k<100%)');
ylabel('Single Line-to-Ground fault current I_f');
```

C.4 Double Line-to-Ground Fault Current Calculation

The MATLAB models for calculating double line-to-ground fault currents as function of fault location "k" are is as follows:

```
% Evita Parabirsing, Msc Final Thesis Project
% Initial valus for calculating Double Line-to-Ground fault currents
clear all;
%network parameters
V_net_ph_ph=25.6*10^3;
V_net_ph_gr=V_net_ph_ph/(sqrt(3));
%pos and zero sequence reactance of the network (incl transformer)
X_net_1=j*0.7748;
X_net_0=j*4.5;
%pos and zero sequence impedance of the cables
R_1=0.2364;
X_1=j*0.2364;
R_0=0.780908;
X_0=j*0.8416959;
%pos and zero sequence capacitance
X_C_1=-j*136.6;
X_C_0=-j*151.476;
X_C_120=-j*47.5507;
%transformer grounding
R_g=30; %3*resistance grounded
%sequence transformation parameters
a=(-0.5+j*0.866);
a2=(-0.5-j*0.866);

save('init');
```

```
% Evita Parabirsing, Msc Final Thesis Project
% Calculation of Double Line-to-Ground fault currents
clear all;
clc;
% load data & initial values
in=load ('init');

% Formula for the three phase short circuit current as function of short
% circuitlocation 'k'(for k= 0,0.1;0.2;0.3;0.4;0.5;0.6;0.7;0.8;0.9;1;):
l=1;

for k=0:0.1:1
Z_1(l)= in.X_net_1 + 0.75*(in.R_1+in.X_1)*k*(1.25-k);
```

```
Z_2(l)= in.X_net_1 + 0.75*(in.R_1+in.X_1)*k*(1.25-k);
Z_0(l)= in.X_net_0 + in.R_g + 0.75*(in.R_0+in.X_0)*k*(1.25-k);
l=l+1;
end

I_f_1= in.V_net_ph_gr./(Z_1+((Z_2.*Z_0)./(Z_2+Z_0)));
I_f_2= -(I_f_1).*(Z_0./(Z_2+Z_0));
I_f_0= -(I_f_1).*(Z_2./(Z_2+Z_0));

I_f_b= I_f_0 + I_f_1.*in.a2 + I_f_2.*in.a;
I_f_c= I_f_0 + I_f_1.*in.a + I_f_2.*in.a2;

p=1;

for k=0:0.1:1
I_f_b_relay(p)=0.6*k*I_f_b(p);
I_f_c_relay(p)=0.6*k*I_f_c(p);
p=p+1;
end

I_k=I_f_b-I_f_c;
I_k_2=I_f_b-I_f_b_relay;
I_k_3=I_f_c-I_f_c_relay;

figure(1);
plot([0:0.1:1],abs(I_f_b),'y',[0:0.1:1],abs(I_f_c),'m',[0:0.1:1],abs(I_f_b_re
lay),'b',[0:0.1:1],abs(I_f_c_relay),'c',[0:0.1:1],abs(I_k_2),'k',[0:0.1:1],ab
s(I_k_3),'g','LineWidth',2);
YLIM([0 0.2*10e4])
%[0:0.1:1],abs(I_k),'r',
xlabel('Fault Location 0%<k<100%');
ylabel('Double line-to-ground fault currents');
```

Appendix D

List of Abbreviations, Symbols and Indices

D.1 List of Abbreviations

CB: Circuit Breaker
CT: Current Transformer
DG: Distributed Generation
DIR: Directional Overcurrent Relay
DSO: Distribution System Operator
HV: High Voltage
IOC: Instantaneous Overcurrent Relay
LV: Low Voltage
MV: Medium Voltage

D.2 List of Symbols

C: Capacitance [F]
I: Current [A]
L: Cable Length [km]
P: Active Power [W]
Q: Reactive Power [Var]
R: Resistance [Ω]
S: Apparent Power [VA]
V: Voltage [V]
X: Reactance [Ω]
Z: Impedance [Ω]
f: Frequency [rad/s]
k: Short circuit location in terms of percentage [%]
t: Time [s]
Δ: Difference [-]
μ: Short Circuit Current Angle [˚]
λ: Characteristic Angle [˚]
π: Proportional Integration

D.3 List of Indices

c:	Clearing time
d:	Decision time
e:	Earth
f:	Fault / Short circuit
g:	Ground
min:	Minimum
max:	Maximum
N:	Nominal
net:	Network
p:	Comparison time, phase
sc:	Short Circuit
th:	Thevenin
tot:	Total

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