ADAPTIVE OVERCURRENT PROTECTION APPLICATION FOR A MICRO-GRID SYSTEM IN SOUTH AFRICA

`

LINDOKUHLE VULINDLELA DLAMINI

216088333

Dissertation submitted in fulfilment of the requirements for the degree *Master of Electrical Engineering* at the Faculty of Engineering at the

University of Johannesburg, Auckland Park Campus

Supervisor: Dr. Ali N. Hasan

2019

ABSTRACT

The non-directional overcurrent protection (International Electrotechnical Commission standard IEC 617 or American National Standards Institute ANSI/Institute of Electrical and Electronic Engineers IEEE C37.2 standard device number 51) is one protection type/relay function that has stood the test of time. The latest generation of relays has brought about enhanced capabilities. The most popular overcurrent protection, which is the Inverse Definite Minimum Time (IDMT) function, has proven to provide coordination of electrical nodes with ease. This is one of the oldest but extremely reliable relay characteristic.

A number of new protection functions and enhancements to existing functions are commensurate to the advanced technical capabilities of the newer generation protective devices. The new development techniques include "acceleration", which is a technique of sending the circuit breaker status of the near end of a line or feeder to the far end to influence the relay decision at the far end. Impedance protection, unit line protection, etc. have come with many advanced characteristics and properties. The enhancements to protection devices bear special features but cannot substitute inverse time overcurrent protection, which, up to now, is a reliable backup in feeder protection schemes in South Africa. The superior feature is the capability to achieve coordination between a series of protective devices. This is achievable without excessive damage to the electrical components of the circuit.

The dissertation presents the application of the IDMT IEC standard inverse curve to achieve a reliable protection in the event of both a three-phase bolted fault and a single phase to ground (SLG) fault. It is essential to first treat the different overcurrent functions that are in use, for example, the instantaneous overcurrent and high set overcurrent protection (I>> device number 50) in order to accentuate the advantages of applying inverse time overcurrent (I>) to achieve effective coordination in series connected protective devices. More importantly, this research treats series parallel networks / mesh networks, which provide complexities in respect of coordination between series connected devices. To achieve the necessary selectivity, the use of directional element (IEC/ANSI device number 67) is explored and it is advocated for such networks. The marshalling of relay device 67 is meticulously done to prevent

nuisance operations and to achieve a high level of selectivity and reliability of circuit breaker operation.

Distributed generation (DG), topology changes, changes in operating mode of the network, impedance changes, etc. is likely to cause a bidirectional flow of power in a micro-grid system. The bidirectional flow of power is a complexity that is resolved by methodically fashioning the tripping logic of an intelligent electronic device (IED) relay to achieve a dependable operation.

The mesh power networks under investigation in the upcoming case studies all have important features of interest to this research. The features include bi-directional power flow and parallel paths for power flow, which may "confuse' the relay and cause it to make a wrong decision.

The networks build in a power simulator aggregates the possible complex features mentioned. The solutions provided, as presented in this dissertation, apply the features of directionality, the settings groups and selectivity of protection operation. This research further proves through experiments that, without such features, a mal-operation of protection is experienced; such mal-operations are sympathetic tripping and incorrect coordination of protection tripping.

ACKNOWLEDGEMENT

My sincere gratitude to my supervisor Dr Ali Hasan for guidance and support throughout my research. It has been a mammoth task, but he showed dedication to the course and generosity to share information and experience beyond measure.

To God be the glory! He gives me courage and hope, and makes a way where there seems to be none.

To my wife and children, I stole your time to work on this research. I owe you. Thanks a lot!

To my former colleagues at the Power Utility, MJ, PTMash, Siya and David. Thank you guys for sharing your knowledge.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS AND ACRONYMS

IDMT	Inverse Definite Minimum Time
OC	Overcurrent
IED	Intelligent Electronic Device
kVA	kilo Volt Amp
FLC	Full Load Current
PS	Plug Setting
PSM	Plug Setting Multiple
CDG	**C**urrent operated Induction **D**isk **G**enerator – A Generl Electric relay model
I>	Inverse Time overcurrent
I>>	High Set or Instantaneous Overcurrent
pu	pick-up
SLG	Single Line to ground
DG	Distributed Generation
IPP	Independent Power Producers
MW	Mega Watt
CT	Current Transformer
VT	Voltage Transformer
SI	Standard Inverse
CTR	CT Ratio
EHV	Extra High voltage
HV	High Voltage
MTA	Maximum Torque Angle
IoT	Internet of Things

GOOSE	Generic Object Oriented Substation Event
RTA	Relay Torque Angle
V_{POL}	Polarising voltage
MVA	Mega Volt Amperes
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and electronic Engineers
Z1	Positive Sequence Impedance
Phi Z1	Phase angle of the positive sequence impedance
MCCB	Miniature Circuit Breaker
LV	Low Voltage (< 1000 V)
MV	Medium Voltage (> 1000 V but < 22 kV)
kA	Kilo Amps
STC	Short time Current
RMS	Root Mean Square
kV	Kilo Volts
PCC	Point of Common Coupling
SLG	Single Line to Ground
SI	Standard Inverse
5P10	Protection current transformer has 5% error at 10 times nominal current.
10P10	Protection current transformer has 5% error at 10 times nominal current.

PUBLICATIONS

A. Published Conference Papers

1. Hasan, AN and LV Dlamini (2018). "Proposed Adaptive Overcurrent Protective Relaying In A Reliable Micro-grid System." In SAUPEC. University of the Witwatersrand, Johannesburg, January 2018. Johannesburg: SAIEE.

B. Submitted Conference Papers

2. Ali N. Hasan and Linda Dlamini, "Overcurrent Protection Philosophy Using Microprocessor Based Relays For a South African Power Distribution Network" In IEEE Power Africa Conference, 2019, Nigeria.

CHAPTER 1: INTRODUCTION

1.1 General View into the State of Security of Supply

The world power demand is expected to grow by 1.7% per year until the year 2030. South Africa, as a developing country, has also experienced an increase in demand [1]**.** This necessitates, among others things, optimisation of energy usage, a usage plan for demand-side management and reliability in the operating of the power utility service [2, 3]. Reliability as a continuum has dependability at one end and security of supply at the opposing end [4].

Security of supply objective is of utmost importance to the user of electricity. It is important because any power disruption results in loss of supply, which could have a devastating effect on the operations of some of the major businesses, utilities and hospitals. A power cut incident in India in 2001 bears the example of an unbearable chaos when there is a power cut [5].

Dependability of supply is of interest to the power utility as it ensures that a fault in the power system is cleared dependably, without fail, in order to protect the power plant from possible damage [4].

The vast power distribution networks in South Africa, which comprise primarily the state power utility company, Eskom, and a small component of municipalities and private distribution networks, contain a multitude of different electrical protection systems. A great amount of work has been done in upgrading the networks to the newer generation relays but there are still some remnants old generation relays, especially in private networks and in municipalities. Municipalities account for 43% of the volume of electricity sales and the state of their infrastructure is described as deteriorated, with growth in loading and without correlating network upgrades [6].

As a result of the above, the network has aged and it is in a terrible state of maintenance. The drive is to strike a balance between the two ends of the reliability spectrum, security of supply and dependability of supply respectively. As a consequence, all unnecessary power interruptions need to be eliminated, hence the need to investigate possible protection mal-operations [7].

The benefit of adopting a new philosophy into protection settings application is that whenever there is a fault in a ring system, the correct breakers should isolate the fault. The relays protecting the unaffected areas must block the incorrect trip. This is the contribution of the study to the body of knowledge [4].

1.2 Short Circuits

Short circuits in a power system are very dangerous because they may result in extremely high currents. As a result, precision in the detection of currents and a short fault clearing time as is consistent with the magnitude of the fault current level are required for the power system [8]. Two of the possible fault types are investigated in this research, and these are:

a) Symmetrical three phase faults are the most severe faults or the heaviest form of short circuiting [9] [10]and
b) Phase to ground fault are the most common faults [8] [10].

Three Phase Symmetrical Faults

The common terminology of a 'bolted' fault means that the fault has zero impedance to earth. This is an important consideration because as the fault impedance increases, the fault current diminishes [11].

In the case of a line, the impedance is used in fault calculations. Low voltage lines take into consideration the resistance of the line, whereas the high voltage lines (11 kV and above) only consider the line reactance which is inductive in nature. In case of rotating machines, we consider the transient reactance (X_d') in the fault calculations [10] [12].

Unsymmetrical Faults - Single Phase to Ground Fault

To analyse unsymmetrical faults, the method of symmetrical components is used. The most common of all the short circuit faults is single line to ground faults (SLG). For an unloaded synchronous generator with a neutral grounded through an impedance Z_N [13]. In phase domain the conditions as described in (1) exist, whereby the B and C- phase currents are non-existent, while the A-phase current is high as in (2).

$$I_b = I_c = 0 \qquad (1)$$

and

$$\boldsymbol{V}_{AG} = \boldsymbol{Z}_F \boldsymbol{I}_A \text{ [14] [15]} \qquad (2)$$

When (1) and (2) are transformed to the sequence domain, they become (3) and (4):

$$\begin{pmatrix} \mathbf{I}a0 \\ \boldsymbol{I}a1 \\ \boldsymbol{I}a2 \end{pmatrix} = 1/3 \begin{pmatrix} 1 & 1 & 1 \\ 1 & a & a2 \\ 1 & a2 & a \end{pmatrix} \begin{pmatrix} \boldsymbol{I}a \\ 0 \\ 0 \end{pmatrix} \qquad (3) \text{ [16]}$$

and

$$(V_0 + V_1 + V_2) = Z_F\,(I_0 + I_1 + I_2) \qquad (4)$$

This brings us to the concept of sequence networks, and (3) shows that all three-sequence currents are equal. The sequence network is shown in Figure 1 [17].

To satisfy (3) and (4), the sequence networks must be connected in series as in Figure 1.

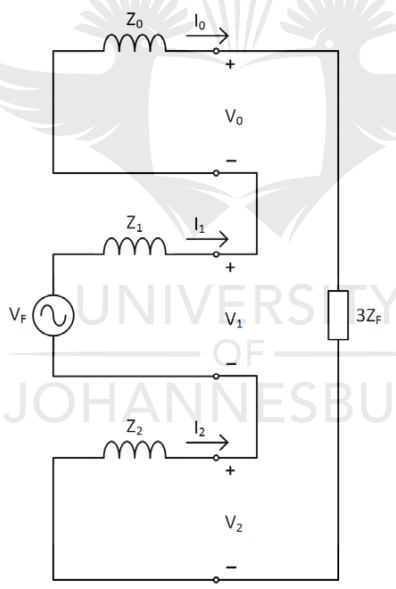


Figure 1: Sequence Network for SLG fault [18]

From the sequence network in figure 1, the positive sequence current ($\mathbf{I}_1$), the negative sequence current ($\mathbf{I}_2$) and the zero sequence network ($\mathbf{I}_0$) are all equal as shown in (5).

$$\mathbf{I}_1 = \mathbf{I}_2 = \mathbf{I}_0 \qquad (5)$$

The fault is in the A-phase and the A-phase sequence currents are as shown in (6) where the positive sequence, negative sequence and zer-sequence currents are all equal to one another.

$$\mathbf{I}_{a1} = \mathbf{I}_{a2} = \mathbf{I}_{a0} \qquad (6)$$

The resultant equation for fault current is:

$$\boldsymbol{If} = \boldsymbol{Ia} = \boldsymbol{3Ia}0 = \frac{3\boldsymbol{Ea}}{Z0+Z1+Z2+3\,Zf} \qquad (7)\ [15]$$

From this discussion, it can be concluded that the unaffected phases will have no current flowing through them, while the faulted phase will have a high current. Equation (7) shows the fault current represented in terms the sequence currents, the fault impedance (Z_f) and the A-phase emf (E_A). A specific case study of SLG shall be outlined in Chapter 5 where there is bidirectional flow of current.

1.3 Overcurrent Protection

Combinations of protection philosophies, types, functions and characteristics as applied in power systems are too numerous to count. Protection against excess current, for example, overload and overcurrent protection, were some of the earliest protection systems to evolve [19]. Overcurrent protection is a type of protection that was developed for the purpose of protecting against excess current [20]. It is not an overload protection, although it does offer some measure of overload protection with the settings that are usually adopted [19]. Overcurrent protection is renowned for the important characteristics of selectivity, reliability and discrimination [21].

When applied to series connected feeders, there has to be a number of overcurrent relays that coordinate with one another so that the relay closest to a fault operates first. Therefore, only faulted sections of the network must be isolated during a fault [22].

Overcurrent protection can be divided into the following different types: Instantaneous overcurrent, IEEE 37.2 device number 50;

a) Definite time overcurrent, IEEE 37.2 device number 50;

b) Inverse Time Overcurrent, IEEE 37.2 device number 51;

c) Directional Overcurrent, IEEE 37.2 device number 67 [22].

It is not a coincidence that we apply the same device number for both instantaneous and definite time overcurrent. They are similar in the sense that both are defined by the current, the time setting in modern relays could either be 0 seconds (or anything close to 0 seconds) and definite time is also a much lower time setting as seen in Figure 2 [22].

The three different types of Inverse Time Overcurrent, referred to as Inverse Definite Minimum Time (IDMT) overcurrent are:

a) Normal Inverse,
b) Very Inverse, and
c) Extreme Inverse [22].

The characteristic curves are plotted relative to one another in figure 2.

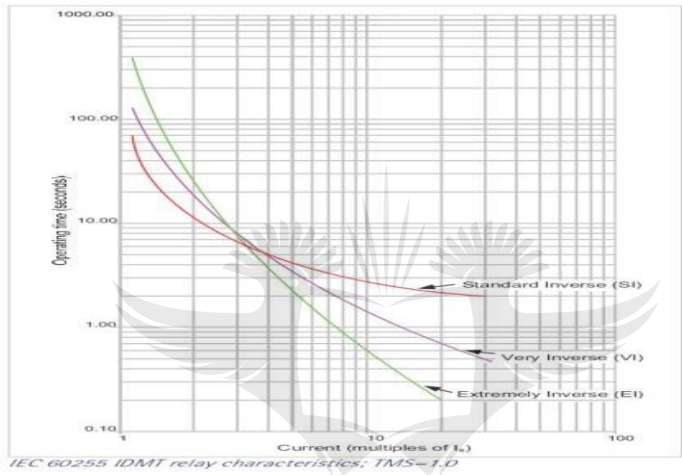


Figure 2: Different types of IDMT Curves [23]

In a ploy to achieve grading with fuses, which are incidentally, the cheapest means of protection and most commonly applied at consumer level overcurrent protection is often applied. It normally works as a backup to instantaneous protection types, such as. impedance protection and unit line differential protection. These are differential in nature and they are applied in transformers, busbar protection and line protection, and are always set to operate instantaneously but will not operate for a fault out of their zone of protection [24] [25] [26] [27]. This necessitates the application of overcurrent protection as a backup to provide reliable operation of protection in a series network where coordination is of importance [4, 28]. Overcurrent protection coordination in a series network works better when grading is by both current and time. This is a concept of inverse time overcurrent. It has an inverse time relationship and it is called Inverse Definite Minimum Time (IDMT) function or characteristic. This effectively means that the higher the fault current, the quicker the operating time of a relay [2] [29].

Figure 3 shows a series network with 4 series substations or nodes denoted Sub A to Sub D. Load could be connected at any of the nodes (Sub A to D) and protection coordination is essential. For a fault F1 at Sub D, only the circuit breaker at Sub D is supposed to trip on IDMT.

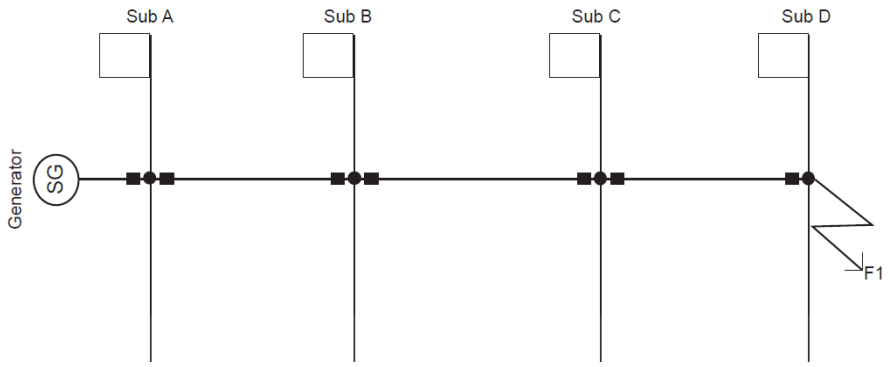


Figure 3: A series network of power nodes

The corresponding trip curves for IDMT overcurrent are supposed to grade in such a way that the circuit breaker at Sub D should be the quickest to operate. If it fails, C should operate as backup and so on [19]. The grading margin between them is dealt with in section 1.5. Figure 3 shows the grading curves for the different series substations.

The Time Multiplier Setting (TMS) determines the "speed" of the IDMT curve. The lower the TMS, the faster the curve, hence the lowest curve in the set is the fastest and the closest to the fault under investigation. This set of curves show grading with time and current [19].

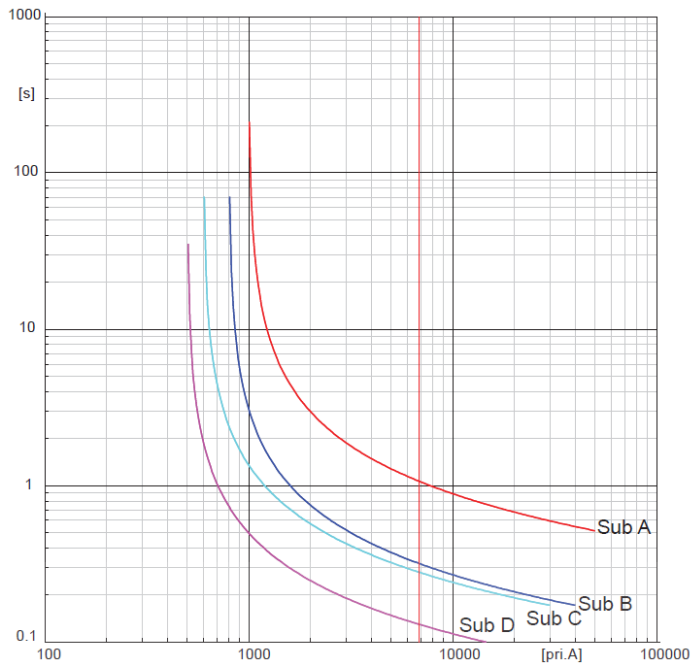


Figure 4: IDMT Overcurrent Grading

1.4 Micro-grid System

In South Africa, electricity supply has been an exclusive domain of the state power utility, Eskom. Eskom supplies about 35000 MW of power in South Africa, while Independent Power Producers (IPPs) account for only 2000 MW [7]. IPPs provide an opportunity for entrepreneurs and local residents to produce their own power and, through grid-tie agreements, be able to connect to the power utility grid [30].This is the idea of a localised grid, equipped with local control and it is called a micro-grid system. A micro-grid system is meant to be more dependable as it can operate in an island mode, whereby it is completely isolated from the main power grid or even export power back into the grid [7, 19] [31]. There has been accelerated improvements in performance and cost of energy storage, and this makes micro-grid systems more attractive [32].

A typical micro-grid system is as portrayed in Figure 5 A micro-grid is connected to a utility grid but can also work autonomously. It generally connects distributed generators and loads [21] [33]. In a system such as this, power flows in both directions to and from the power grid, as well as to and from the power storage.

In some applications, differential protection relays are applied at specific areas of a micro-grid. The differential relays are protecting the specific zone of application and will not operate for a fault outside of the zone [34]. This strengthens the case for applying O/C as a backup.

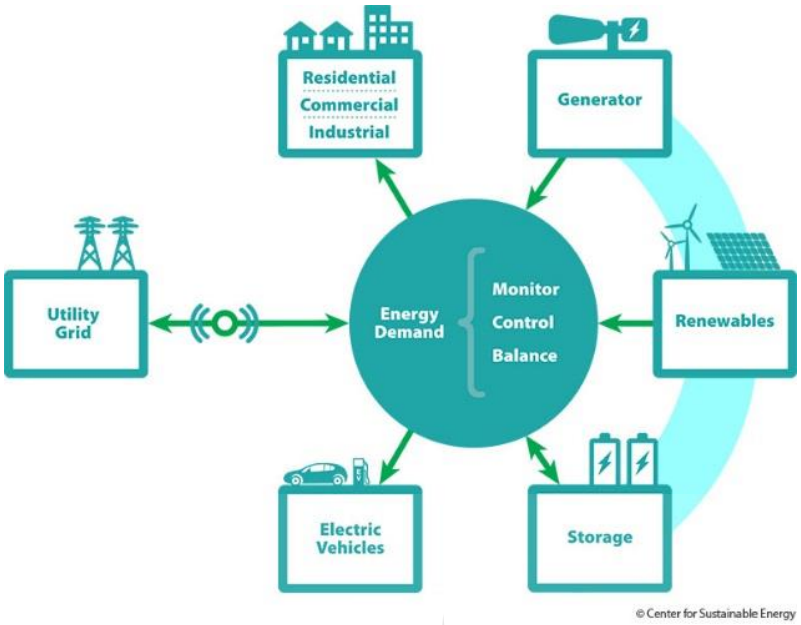


Figure 5: A Micro-grid diagram [32]

1.5 Protection Objective

When a fault condition arises in a power system, the faulted element must be isolated. This has to happen reliably. Furthermore, it must be selective, sensitive and must operate with speed. These are the objectives of electrical protection. Reliability is of the utmost importance, not neglecting of course, the essentiality of the others. Reliability is the focus of this research study as it pertains to grading and speed of operation of protection, hence dependability and security of supply. It is important because relays and circuit breakers are installed to act upon the occurrence of a fault in a power system, that is, should a fault occur, protection is expected to operate; and it must act reliably without fail. It must act correctly, selectively, dependably and with speed. It becomes an even bigger challenge to achieve the protection objectives when variables such as a grid-tie system, a smart grid, a micro grid, co-generation and tri-generation are introduced into the equation – the operational characteristics of a distribution grid. More sophisticated tools and improved technological capabilities provide protection and control enhancements needed to cope with the latest developments [35].

What is key in power system protection is the detection of faults and the subsequent clearance thereof. These are achieved through a number of specialised hardware. The hardware

equipment includes circuit breakers, current transformers, voltage transformers and relays [36].

1.6 Fault Detection

The interface between the relay measuring element and the primary plant is achieved through instrument transformers, current transformers (CTs) and voltage transformers (VTs). The CTs and VTs provide the three currents and the three voltages of a three phase system respectively. The choice of CT ratios is based on the primary service current given as follows in (8).

$$I_{PS} = \frac{S}{(\sqrt{3}\,U_S)} \qquad (8)$$

Where:

S = Apparent Power in Volt Amperes (VA),

U_S = Service Voltage in Volts,

And I_{PS} = Primary Service Current in Amps

A typical example: In an 8 MVA, 11 kV system, one would typically apply an 800/1 CT ratio [35].

1.7 Coordination, Discrimination and Fault Isolation

This study treats the Inverse Definite Minimum Time (IDMT) function and considers only the standard inverse (SI) curve as given by equation (2). The IDMT curves are plotted in a log-log graph, or semi-log graphs as it is common practice to respond to the "skewness" towards large values of fault currents. The curves are obviously hyperbolic in shape, asymptotic to the current and the time axis as shown in Figure 6. This is to depict the inverse proportionality between the trip time and the fault current [19].

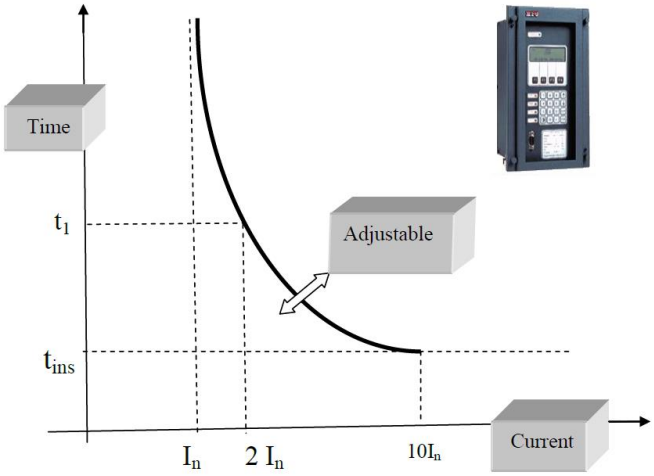


Figure 6: Inverse Time Characteristic [23]

Depending on the magnitude of the overcurrent fault, the fault may be detected by more than one element upstream from the fault, but its isolation should be performed by the element closest to the fault. That is the principle of proper protection co-ordination. Depending on the Plug Setting (PS), the other elements upstream from the fault will show a "start" or pick-up indication on the Intelligent Electronic Device (IED) relay to indicate that a fault was detected [19].The trip time for a standard inverse curve is given by equation (9):

$$\text{Required Trip Time} = \frac{0.14 \times \textbf{Time Multiplier}}{\left(\left(\frac{\textbf{Fault Current}}{\text{Plug Setting*Ct Ratio}}\right)^{0.02} - 1\right)} \qquad (9)$$

CT Ratio (CTR) is normally selected to be close to the Full load current (FLC). Therefore, if we apply (10).

$$CTR = FLC \qquad (10)$$

Equation (10) can be represented as in (11).

$$\text{Required Trip Time} = \frac{0.14 \times \text{Time Multiplier}}{\left(\left(\frac{\textbf{Fault Current}}{\text{Plug Setting*FLC}}\right)^{0.02} - 1\right)} \qquad (11)$$

Correct coordination prevents a mal-operation (or mis-coordination) of protection. Equation (9), (10) and (11) are applied in the calculations of trip time for Standard Inverse IDMT overcurrent.

1.8 Problem Statement

The introduction of embedded generation into a utility grid brings about problems of mis-coordination of protection. This is caused by the bi-directional flow of power, that is, power flowing from either end of the point of consumption. The static set of protection settings, specified for the standard vertical network, may coordinate well when there is no embedded generation. The introduction of embedded generation at the distribution level introduces undesirable mal-operations of protection coordination [37]. To this end, mis-coordination of protection happens when the element that is supposed to trip and isolate the fault fails to do so; instead, another element farther from the fault operates. Similarly, when the element that is not affected by the fault sympathetically operates [38].

With the use of the new generation of protective relays, we aim to have adaptive protective relaying so that whenever a change in the configuration of the primary plant is implemented, the secondary plant devices respond by automatically changing the protective relay settings. This necessitates automatic migration from one settings group to another. Furthermore, there is a need for selective isolation that ensures that security of supply is maintained in the areas of the network that are not faulted. The case study in Chapter 5 treats the adaptive overcurrent relaying by applying a logic that ensures that the direction of the overcurrent fault is not misjudged by the numerical relay.

Algorithms for integrated adaptive instantaneous overcurrent and adaptive undervoltage have been developed for use in low voltage systems. This is meant to address the shortcomings of applying either one on its own [39]. This fails to address the coordination problem between a series nodes of a power system.

Although we term this adaptive protective relaying application, it is sometimes discrete in form rather than continuous. The aim is to develop one or two groups of settings corresponding to each of the possible network configurations and to be able to juggle between these groups of settings in response to the changes in the mode of operation or system configuration. This is done to cater for the three phase bolted fault in a mesh network and to meticulously fashion settings that will ensure that the direction decision is correct in the case of single line to ground fault.

Without the desired adaptivity, each time the distributed generator (DG) is put online, the protection settings have to be inserted manually. This could be a tedious exercise which can open up an opportunity to make an error which may impose a risk of protection mis-operation.

We intend having this process happening automatically in a smart grid by using intelligent devices that are able to communicate their statuses among one another and to take instructions.

Justification for this research was founded on the basis that in the current situation, there is no known standard that dictates the correct approach to the application of protection settings, particularly at distribution level, to counteract the effect of mis-coordination caused by DG. The treatment of inverse time overcurrent, typically the IDMT overcurrent, which is widely applied is therefore well befitting, given the need to have a reliable network as regards to dependability and security of power supply.

The Eskom standard on Protection Settings Philosophy for EHV and HV networks asserts that protection settings are supposed to meet the system and customer requirements, and that leaves the decision to the operator of the network as well as the customer to make the necessary detailed specifications [40].

1.9 Research Objectives

The aim of this research is to establish selectivity when applying overcurrent protection by making the overcurrent function more adaptable to the state of dual direction of power flow resulting from the connection of Distributed Generation (DG) at the point of consumption. The objective is twofold, dependability – ensuring the fault is dependably isolated and security of supply – ensuring that an incorrect trip is prevented.

Firstly, the type of overcurrent protection is investigated, high set or inverse time with a view to establish the most suitable arrangement that offers proper coordination in a mesh network (series-parallel). Secondly, the dependability problem is investigated with respect to a three phase bolted fault by comparing an application with non-directional overcurrent and one with directional current, and demonstrating that the breakers that are supposed to trip do indeed trip. Thirdly, a full demonstration of the directional overcurrent concept is performed with a single line to ground (SLG) fault on a 132 kV system ensuring proper selectivity that ensures security of supply to areas not affected by the fault.

The study was performed using DigSilent Power factory 2018 by working out the fault levels, configuring the instrument transformers (Current transformers and Voltage Transformers), as well as a microprocessor based relay type ABB REF615 relay. Suitable relay settings were manually calculated. IDMT overcurrent protection was selected and the desired grading

margin as applied in the calculations is 0.4s. The choice thereof as a simulation tool is justified on the basis of it being highly respected and widely used in the power utility, Eskom.

1.10 Methodology

This research is an experimental research that seeks to determine a reliable operation of overcurrent protection in a micro-grid system by varying the protection settings and/or migrating from one group of settings to another. The outcome is the same, selective coordination, when there is supervision over the measured quantities and/or while the settings groups are varied.

Positivism

As this is scientific research, it follows the positivism philosophy, which claims that the reality is stable and can be observed and described from an objective viewpoint. The three case studies aim at proving selective coordination of overcurrent protection at a certain fault current and fault position while varying the direction and polarisation component to ensure we achieve reliable results. The grading and characteristic curves, as defined by the time multiplier and current pick-up settings, remain the same in the experiments being performed. The choice of directional or non-directional power flow is exercised in one case study and the choice of a polarising component and supervision in another [41].

Quantitative Analysis

This research seeks to use quantitative analytical techniques to observe the reality in terms of quantification and objectivity to make conclusions that are generalisable, that, indeed the selective protection (Dependent variable) is achievable with adaptive protection. With directional overcurrent protection, the desired reliability is realisable when logic controls are applied to optimise the application of numerical relays in the automation of relay decisions. Similarly, for a single line to ground fault, the usual polarising components that are applied may not be sufficient and the problem is overcome by applying supervision components that are not real but computational.

Adopted Methodology

In this research, adaptive overcurrent protection is investigated by examining the different types of overcurrent protection as applied in electricity user networks. We go on to examine the concept of adaptability and to treat three different cases where mis-operation of protection

is experienced with the use of basic IDMT overcurrent. With simulations, solutions are provided for each of the cases being examined.

1.11 Synopsis of the Dissertation

Chapter 2 introduces protection types for power systems, that is, protection types that are widely used as instantaneous protection. These protection types are outlined in a form of literature review by explaining their applicability and effectiveness. An opinion is adopted that IDMT overcurrent is a backup protection for some of the instantaneous protection types. The shortfalls in instantaneous protection types are examined and the choice of IDMT curve, standard inverse (SI curve) is also discussed.

Chapter 3 presents the comparison between the different types of overcurrent protection, instantaneous/high set, definite time and IDMT. The requirement for protection coordination is emphasised in the application of IDMT.

Chapter 4 presents the treatment of a three phase bolted fault as a case study. Directional overcurrent is introduced and the benefits explored in terms of security of supply.

Chapter 5 presents a protection problem in a case study, whereby an SLG fault occurs and directional overcurrent protection completely misjudges it, resulting in incorrect protective relaying decision. A logical solution is formulated with the use of a supervision current element.

Chapter 6 concludes the study with a summary of results and the recommendations.

CHAPTER 2: LITERATURE REVIEW

2.1 Introduction

This chapter explains the use of overcurrent protection as a backup to other instantaneous protection types and as a means to achieve coordinated operation of circuit breakers for a series network. A Literature Survey is conducted on the application of electrical protection in general and IDMT overcurrent in particular in a mesh network.

2.2 Defining Key Concepts

In this section the key concepts or variables relevant to the study are defined:

Smart Grid

An electricity grid as "a network of synchronised power providers that are connected by transmission and distribution lines and operated by one or more control centres". This suggests that for the electricity grid to be smart, the actions of all the users and the generators and those that do both (user and generator roles) must be intelligently integrated, in order to efficiently deliver sustainable, economic and secure electricity supplies [42].

Smart grid technologies are those technologies aimed at improving reliability, flexibility, accessibility and profitability, as well as supporting renewable energy initiatives in an electricity grid [43].

The electrical grid is, therefore, generally "dumb" or without intelligence. The introduction of monitoring and control using computer intelligence makes it "smart". Monitoring and control are the major proponents and a critical part of the future smart grid power system [44].

Micro-grid

A micro-grid system is described as a system consisting of energy consumption and generation in an interconnected fashion at a distribution level. These can operate in an island mode (off-grid) or in a connected mode, whereby local generation is connected to the utilities grid [45].

A micro-grid is essentially a subset variation of a smart grid whereby local power generation (Distributed Generation – DG) or embedded generation using solar, gas generation or any renewable form of energy generation is applied. This generation occurs on-site at consumption points [46].

Grid-tie

Grid tying is when small-scale renewable electricity generators connect to the utility power grid as power producers. [47] This implies that locally generated power is tied to the grid or imported into the mains electrical grid. These are sometimes referred to as distributed generation (DG) [48] [49].

Embedded Generation

Similar to grid-tie, this refers to independent small generation plants that are grid-tied. These includes photovoltaic power generation and other renewable forms of power generation such as photovoltaic (PV), wind and gas generation [50].

Adaptive Relaying

Adaptive protection is defined as "an online activity that modifies the preferred protective response to a change in system conditions or requirements in a timely manner by means of externally generated signals or control action" [48]. This implies that the protection scheme has a capability to change protection settings in response to the change in the power system parameters [51].

Adaptive Overcurrent Relaying

Adaptive Overcurrent Relaying is overcurrent protection which is adaptive. Overcurrent protection is normally referred to as phase overcurrent protection. Phase overcurrent protection is applied on line protection as an alternative to a fuse. It is meant to minimise equipment damage and enhance coordination. Therefore, it limits outage time and voltage dip duration [52]. The pick-up relay setting for this protection is always higher than the full-load current [52].

The focus of the research is on positive phase sequence overcurrent as opposed to negative phase sequence due to the nature of common short circuit faults. Negative phase sequence overcurrent does not respond to balanced load and so it can have an insignificantly low pick-up setting as opposed to the normal (or positive phase sequence) phase overcurrent protection [53]. Therefore, negative phase sequence overcurrent is not very popular in distribution systems under consideration in this study [53].

It is purported that instantaneous overcurrent protection "makes a reduction in tripping time and improves the overall system grading by allowing the discrimination curves behind it to be lowered" [53] [20]. This protection is sometimes referred to as "High Set" overcurrent protection and it operates well when the source impedance is small in comparison with the circuit impedance [53]. This is the case when the faster curve is lowered and the subsequent curves can also be lowered [53].

Directional Overcurrent protection is the overcurrent protection that has a directional power flow element [54]. This type of overcurrent relaying is applied when the selectivity can be achieved by directional relaying [54]. This feature allows the relay to operate for faults in one direction only. It can be time-overcurrent or instantaneous in nature [54].

Phase Overcurrent under consideration applies the Inverse Definite Minimum Time (IDMT) characteristic. For simplicity, the study does not mix the different IDMT characteristics. There are three types of IDMT characteristics that are widely used in the power utility in South Africa. These are: Standard (or normal) Inverse; Very Inverse and Extremely Inverse. This study focuses on Standard Inverse as it is the most widely used [55].

2.3 Reliable Power System

When a fault condition arises in a power system, the faulted element must be isolated. This has to happen reliably. Furthermore, it must be selective; sensitive and must operate with speed. These are said to be the objectives of electrical protection. Reliability is of the utmost importance; not neglecting of course, the essentiality of the others. Reliability is the focus of this research study. It is important because relays and circuit breakers are installed to act in a power system upon the occurrence of a fault and prevent damage to equipment. Should a fault occur, protection is expected to operate; and it must act reliably and without fail. It must act correctly, selectively, dependably and with speed to minimize of a short circuit. [56] It becomes even more challenging to achieve the protection objectives when variables such as a grid-tie system, a smart grid, a micro grid and co-generation are introduced into the equation. The listed variables are explained below [56].

Reliability is described as having the two extremes in its spectrum: dependability and security. The consumers would prefer to have a secure power supply and the utility supplier would prefer to operate a dependable power system. These two cannot be provided consistently at

the same time – not with the traditional way of configuring our vertically integrated power systems protection. Dependability, as one extreme in the reliability spectrum, will allow the disconnection of power system components, transformers, feeders, etc. to allow for effective isolation of a faulted element. Security, as the other extreme, will tend to be more selective in nature, isolating only the intended area and generally being more tolerant to prevailing fault conditions as it tends to avoid initiating an incorrect trip. There is a trade-off here; a dependable protection scheme will assuredly prevent damage – it is prone to unnecessary operation which can lead to cascading outages. The security aspect on the other end will expose the equipment to a risk of damage due to it being "fault tolerant" in nature [55].

Morden power systems operate close to their security limits, therefore, high speed of operation is required to prevent damage to equipment, to prevent system instability and to maximize safety. [57] This is why the integrity of protection is so important in a power system. This warrants a closer look at how, without compromising dependability or security of the power supply, protection is to be applied in a modern system [57].

2.4 Adaptive Protection Concept and Overcurrent Protection

It is asserted that many relays are adaptive to a limited extent, referring to many protection functions as it were. [58] A good example is (IDMT) overcurrent and earth fault, which adapts its trip time to the current level. The IDMT function was applied in electromechanical relays, for example, the CDG11, CDG16 and CDG36 relays, and carried over to the subsequent generations of relays, the solid state and furthermore to numerical relays and IEDs (Intelligent Electronic Devices). This makes it one of the first in adaptive type protection, yet, in its original form, it has limitations of its own [59].

Figure 7 depicts the different overcurrent characteristics as shall be dealt with in detail in chapter 3.

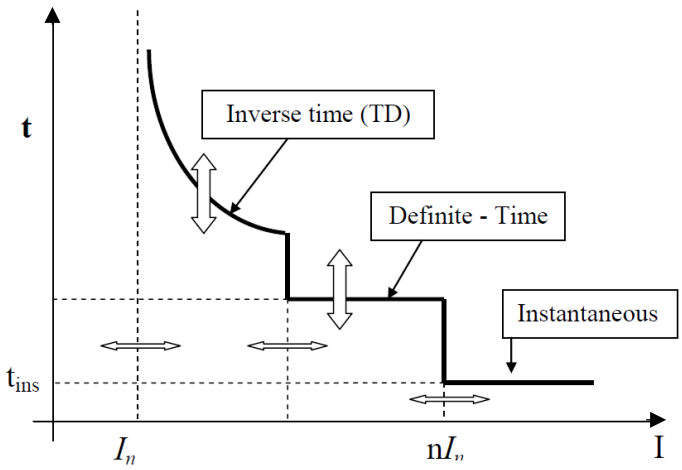


Figure 7: Mixed Curves for overcurrent Protection [23]

One limitation in the development and application of protection of relay settings is that relay settings are developed offline and are invariably in operating [59]. This poses a challenge when the changes mentioned above are introduced in the power system. To this end, much effort has been put into making traditional protection functions adaptive by using intelligent devises and having advanced control circuitry. A control circuit or input logic is what makes a difference between current adaptive protection and traditional current protection [60].

During online operation, the central controller monitors the grid breaker statuses and uses the event and action tables to configure the relays appropriately. This is achieved through effective and fast communication from the IEDs to the controller [60]. When a comparison is done between the hard wiring and the GOOSE (Generic Object Oriented Substation Event) messaging using the IEC 61850 standard, it is concluded that the permissive overreach transfer trip communication speed with IEC 61850 is faster than using hard wiring [60].

When applied to overcurrent protection, adaptive protection dynamically determines the pick-up current and time multiplier. This requires continuous real-time scanning and simulations of the power system to reconfigure the protection settings. This helps ensure timeous update of the system information [51].

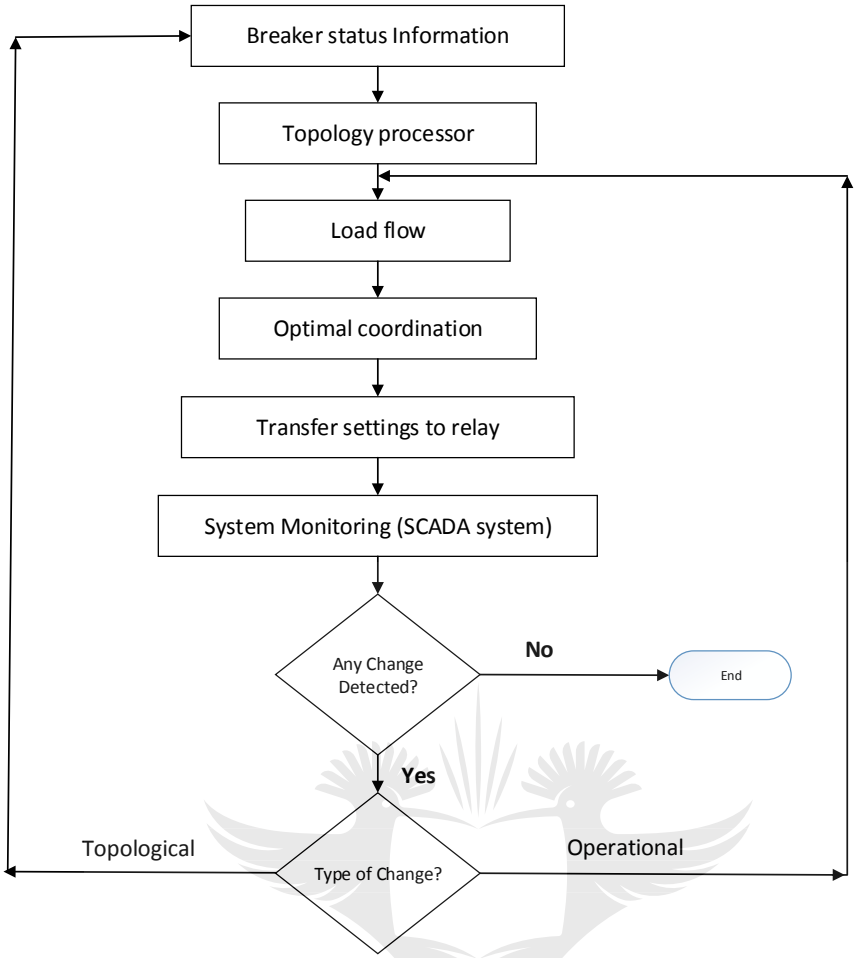


Figure 8: Adaptive Relaying Co-ordination Algorithm [20]

2.5 Instantaneous Type Protection

Various types of protection types operate instantaneously and as earlier mentioned, inverse time overcurrent protection acts as back-up for those various protection types. The instantaneous protection types could be any of the following:

a) Differential protection,
b) Impedance protection,
c) Buszone protection, etc. [7, 48, 52, 61].

2.6 Adaptive Relays

The dilemma posed by the two ends of the reliability spectrum can only be resolved by having more dynamism in protection schemes [7]. Adaptive protection is defined as the ability of the protection system to automatically alter its operating parameters in response to changing power system conditions, to provide reliable relaying decisions. Changes that require

adaptability are topology changes, for example, Distributed Generation (DG), operating mode change and line impedance load changes. This chapter addresses these changes and demonstrates the relaying decisions that are necessary [62].

A nouvelle configuration mechanism called the source concept provides for adaptivity in the application of IEDs. What it effectively means is that, whereas in the past there were single function relays with separate analog and binary inputs, the new applications use the same set of inputs to accomplish the different protection functions. This was an important development towards adaptive protection [63].

2.7 Smart Energy Management and the IoT

The capabilities of IEDs are vast and superior to its predecessors. These include communication among devices, communication to the control centre and interoperability among one another. These capabilities can be exploited by using the Internet of Things (IoT) innovation. IoT has been in use in Building Management and more research is done in this area of application [64, 65]. The same innovation can be applied to a smart grid to achieve some level of automation of energy management [65].

Energy management in a smart grid or micro-grid systems requires monitoring and control of when the embedded generation shall export power into the grid and when it shall operate in islanded mode [66]. Smart grids and similarly micro-grids are self-sufficient systems that find quick solutions for sustainable, reliable, safe and quality electricity to the consumer. Such monitoring and control are nowhere close to full implementation in many countries, and South Africa is no exception. This is evident with poor performing power utility network [65, 67].

Smart grid technologies are the inevitable future and a massive transformation from the current situation. The concept comes with new technologies and systems that have potential to affect the way utilities conduct their business, choose their technologies and structure their processes. [55, 33] This research does not focus on the use of information about the loading to optimise production and distribution of electricity as intended in a smart grid; however, it is concerned about reliability with DG and ease of integration into the traditional grid [33].

2.8 IEC 61850 GOOSE messaging

Communication starts from a relay device responding to an applied setting. The applied relay setting can be viewed as a command to the IED relay device based on the power system conditions or a prediction of system conditions such as equipment failures or fault conditions that require certain action to be taken. The actions taken include the operation of circuit breakers and other equipment [68].

Gereric Object Oriented Substation Event (GOOSE) messaging are mechanisms for distributing status information in a substation [69]. These are normally circuit breaker and isolator statuses as binary inputs, as well as start and trip signals. The application of GOOSE messaging is limited to within a substation [69] [70] [71].

2.9 Topology Changes

A number of topologies are in use in power systems. The main ones that illustrate the point under discussion (the effect in the fault levels) are the following:

a) Secondary Selective 'Main-Tie-Main' arrangement: Two bus arrangement on the secondary or load connection point coupled by a bus coupler. Each bus is capable of carrying the entire load. (See Figure 9)
b) Main-Tie-Main Topology: Main-Tie-Main arrangement and Main-Main arrangement, shown in Figure 10, are some of the popular arrangements.
c) Ring Bus Arrangement: As shown in Figure 11. This arrangement is common at medium voltage levels [72].

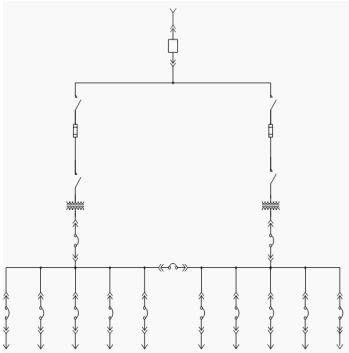


Figure 9: Secondary Selective 'Main-Tie-Main' Arrangement [73]

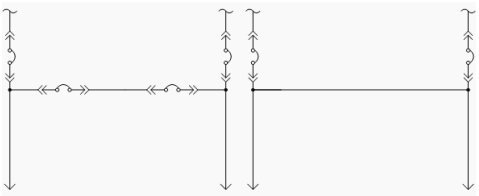


Figure 10: Main-Tie-Tie-Main Arrangement and Main-Main Arrangement [73]

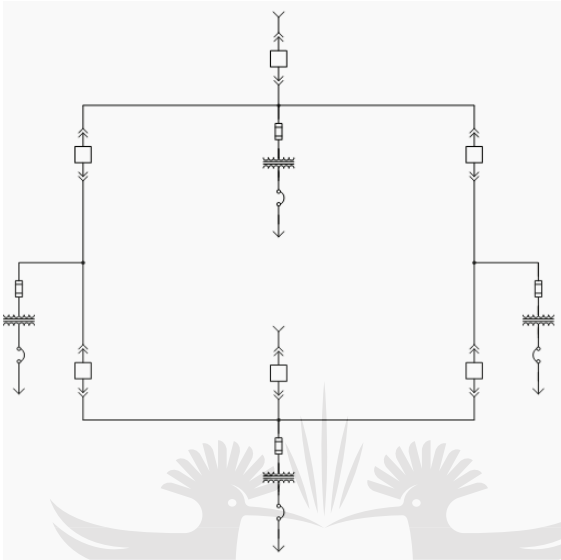


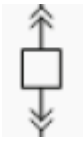
Figure 11: Ring Bus Arrangement [73]

Figure 9, 10, 11 symbols are as follows:

 - Isolator

 - Fused isolator

 - Transformer

 - Circuit Breaker

 - Dead end feeder

 - Load

2.10 Distributed Generation (DG)

As at April 2016, the 102 Independent Power Producers have been procured by the South African Power Utility Company – Eskom, to the value of 6400 MW [74]. It is a clear indication of the extent to which DG has penetrated the power utility in South Africa. To this end, the conditions for interconnection to the Eskom grid have remained rudimentary, so has the protection settings philosophies [75, 73].

Penetration of IPPs in South Africa stands at 139556 installations, accounting for 285 MW peak of electrical power [30]. To this end, the National Energy Regulator of South Africa (NERSA) distribution network code stipulates only four conditions for co-generation:

a) Voltage Regulation – to guard against overvoltage,
b) Power Quality constraints – to limit frequency variations,
c) Combined short circuit contributions not to exceed the network design value and
d) It is to be equipped with phase and earth fault protection [37, 64].

2.11 Operating Mode Change

A distributed generator can either operate in a standalone mode, islanded mode or parallel with the utility operation. As shown in Figure 12, these modes can be varied by opening or closing any of the circuit breakers [76] [77]. An enhanced adaptive bus protection is essential when there is more than one generator connected to the bus [78].

Standalone mode

Only load circuit breaker and any of the generator circuit breakers is closed while the utility supply Point of Common Coupling (PCC) stays open [78].

Islanded mode

The generator circuit breakers are closed while the PCC circuit breaker is open, while the loads are open [78].

In parallel with utility operation

The generator circuit breakers for the three generators are closed and the PCC circuit breakers are also closed [78].

The modes of operation explained above are interchangeable, and the protection settings in a micro-grid are supposed to adapt to the changes.

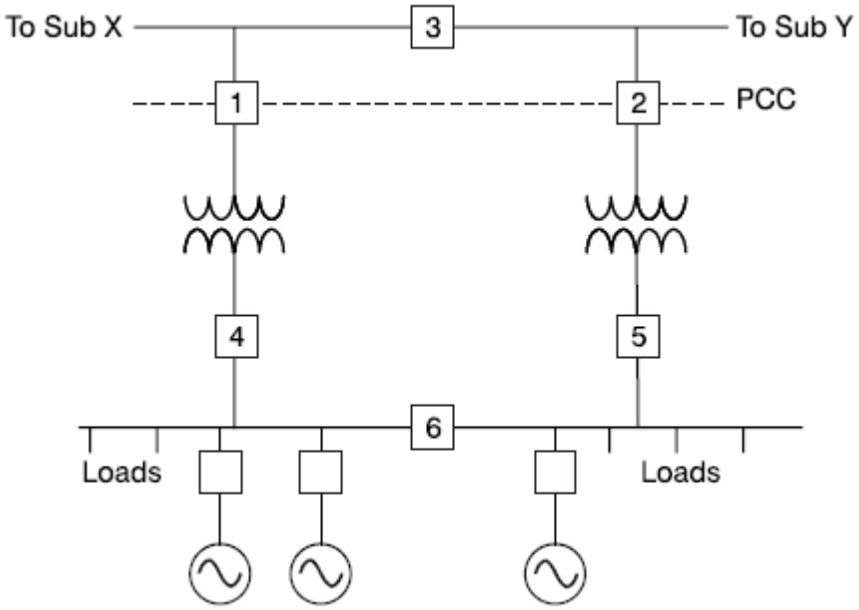


*Figure 12: Modes of Operation Changes [**76**]*

2.12 Effect of Line Impedance Load Changes in Fault Currents

Simple computations of fault levels, as shall be illustrated, show that a simple change in the circuit impedance, for example, addition or elimination of a transformer into the network, addition or elimination of a line in a dual feeder network, result in a change in impedance which has a direct impact on the fault levels [75].

The following illustration depicts a system with two transformers paralleled: a 3MVA and a 4MVA transformers supplied by a single 18.75MVA generator. For the purpose of fault calculations, these components are represented by their impedances [75].

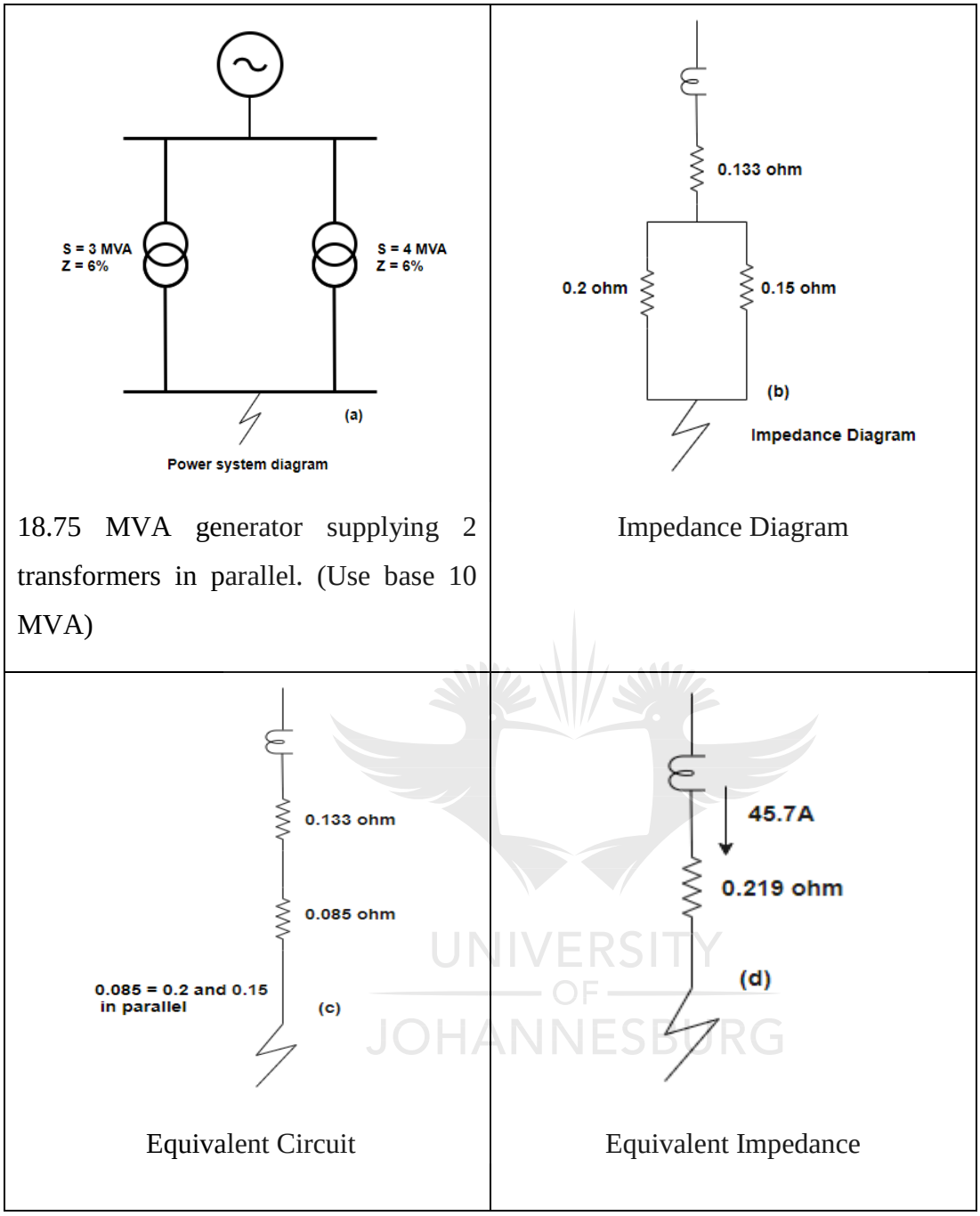


Figure 13: Effect of System Impedance on the Fault Levels [75].

Considering different permutations of the circuit, Table 1 shows the different possible fault levels.

Table 1: Different Circuit permutations and the respective fault levels.

Circuit Arrangement	Total Impedance	Fault Level
3MVA//4MVA in circuit	0.219 Ω	45.7 MVA
Only 3 MVA in circuit	0.333 Ω	30.03 MVA
Only 4 MVA in circuit	0.283 Ω	35.33 MVA

2.13 Multiple Settings Groups

Relay settings parameterisation or migration of relay settings from one group to another can be done locally on the relay or remotely by control signals from a control centre. Numerical relays have that functionality – a number of groups of settings and a capability to migrate from one group to another [51].

To summarise, adaptive protection systems are able to monitor and update the relays' settings in accordance with distribution network or micro-grid state, based on offline analysis and online operation.

2.14 Directional Relay Marshalling Problem

IEEE 37.2 device 67 is able to circumvent most of the problems relating to bi-directional flow of current. The method used to detect the direction of current flow is the quadrature method [55].

The IED has a standard marshalling matrix that has to be fashioned for directional faults. The quadrature method of detecting the direction of the fault is widely applied in protective relays and it operates as depicted in Figure 14.

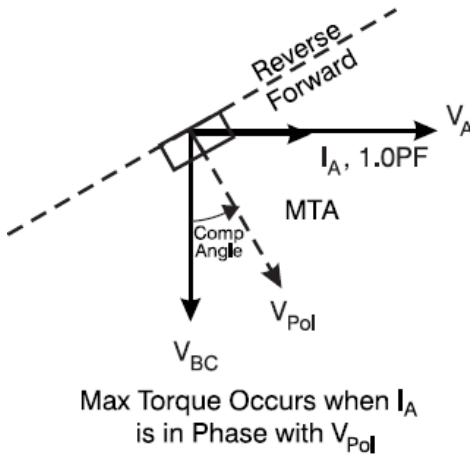


Figure 14: Quadrature method for determining the direction of a fault [76]

Maximum Torque angle (MTA) or sometimes referred to as Relay Characteristic Angle (RCA) is the angle by which the applied voltage must be displaced to produce maximum sensitivity; this is meant to centre the relay characteristic [76].

Vpol is a fictive voltage and it is meant to be a "memory" voltage, fictive in the sense that it is not real but an imaginary quantity defined to give direction reference. It is set to last for a certain duration of time – the validity period of the fictive Vpol. This time setting is the longest expected operating time for a three phase bolted fault [76].

2.15 Research Focus

This research focuses on the application of adaptive IDMT overcurrent protection system with a normal/standard inverse characteristic to effect reliability in the tripping regime of a micro-grid system. This requires a closer look at the following variables:

a) The time multiplier setting,
b) Grading margins, and
c) Logic input to the IED to effect adaptability.

2.16 Conclusion

There are benefits to applying overcurrent protection with and without adaptive reviewing of protection settings. [79] The benefit to applying adaptive protective relaying is that it provides more versatility in terms of applying DG in a micro-grid and changing the topology without fear of sympathetic tripping or a compromised dependability of a power system. [38] At the

same time, the chance of losing supply to unaffected areas when there is no adaptive protection is not entirely a bad thing from the perspective of the utility supply aiming to operate with precaution to protect the plant and equipment.

Many authors concur with the view that protection will operate reliably if it is adaptable. The relationship between adaptive overcurrent relaying, as a case in point (independent/predicting variable) and a reliable micro-grid system (dependant/predicted variable) is achieved through the application of intelligent electronic devices (IED relays), a control centre and a fast and effective communication between the IEDs and control centre.

Chapter 3: CASE STUDY 1: COMPARISON BETWEEN DEFINITE TIME AND INVERSE TIME OVERCURRENT

3.1 Introduction

This chapter introduces overcurrent protection in general terms, and provides specific justification for the application of IDMT overcurrent protection for the purpose of selective coordination in a series network. This is done by comparing definite time with inverse time IDMT, in response to a three phase bolted fault. For this purpose, a series network was selected for the study of load flows as well as fault levels.

The different types of overcurrent protection were discussed in the previous chapter. This chapter focuses only on illustrating the superiority of inverse overcurrent protection over the definite time overcurrent in respect of discrimination and tripping coordination.

3.2 Experiment Setup

This experiment is based on a real-life network at a power station. The air-conditioning supply network consists of different boards, designated as substation 1, 2 and 3, where substation 1 is the upstream substation that consists of a 15/0.42 kV transformer feeder.

The true settings were calculated based on the IEC/ ANSI standard inverse curve for IDMT overcurrent. The network and the corresponding relays were built on Powerfactory 2018 according to the relay settings in 3.3. After proving the network to be stable by checking the loads in the different sections of the network, fault levels were determined at the three series substations as indicated in section 3.3.

The next step was to to calculate the settings for both definite time (High set I>>) and IDMT overcurrent (I>).

The aim of protection settings is to get the fastest possible fault clearance with suitable grading to allow only the affected plant to be isolated correctly. The selection of protection functions in the newer more sophisticated protection schemes is informed by the need for coordination of protection tripping in a series network [80] [81]. The following points were considered in this setting document:

a) The approach used was a bottom-up grading.

b) Normal IDMT Inverse curves were used.

c) All IDMT over current functions allow grading with downstream protection and cater for high impedance faults.

d) In this experiment, grading margins between 150 – 250ms were allowed since numerical or microprocessor based relays are used. This would take care of breaker operating times and any relay and CT tolerances.

e) The downstream circuits are protected by the moulded case circuit breakers (MCCBs) and, in the worst case, they will clear the faults in less than 30ms, provided that the fault current exceeds the current pickup setting of the MCCB (Normally set between 10 and 15 times the rated current). On the incomer, the time delay for the high set overcurrent trip can therefore be set to 50ms. The advantage of a shorter time is the reduction in arc energy, hence a more comfortable PPE requirement.

f) No grading margins are required between the feeder side (e.g., MV) and the incomer side (LV) of a circuit.

g) Settings calculations approach is a science and an art, in the sense that the scientific approach used is not rigid. There is flexibility to customise the settings to meet the requirements for correct discrimination and grading in a series of electrical nodes.

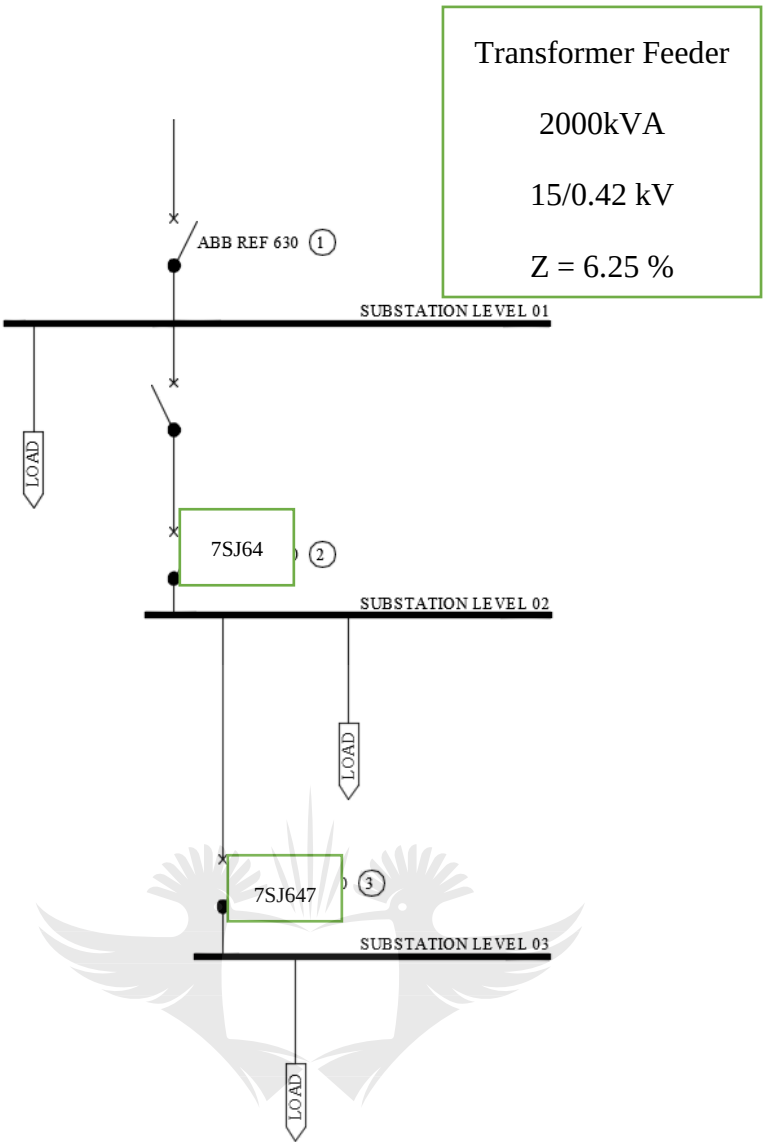


Figure 15: Series network for this case study

3.3 Relay settings

The microprocessor relay type ABB REF630 used in this experiment for the transformer feeder to Substation 1, Feeder to substation 2 and 3 used Siemens 7SJ64 relays. The fault levels were calculated using Power factory 2018. Manual calculations were dealt with in 2.10 and three-phase bolted faults as well as SLG faults shall be dealt with in chapters 4 and 5 respectively.

The resultant relay settings for all three substations are outlined below. For the IDMT trip time, the IEC equation, equation (12) was applied.

$$\text{Required Trip Time} = \frac{0.14 \times \text{Time Multiplier}}{\left(\left(\frac{\textbf{Fault Current}}{\text{Plug Setting*FLC}}\right)^{0.02} - 1\right)} \qquad (12)$$

Substation 1 Settings

Relay Type: ABB REF630

Table 2: Fault Levels at Substation 1

Fault Levels		
3 Phase Fault Current	44.252 KA	
1 Phase Fault Current	46.165 kA	

Table 3: Transformer information at Substation 1

TRANSFORMER INFORMATION		
Transformer rating	2000 kVA	
Vector Group	DyN11	
Rated Voltage	15/0.42 kV	
HV Rated Current	76.98 A	
LV Rated Current	2749.29 A	
Transformer Impedance	6.25%	

FLC

Table 4:Actual Relay Settings applied to the relay at Substation 1

Three Phase Non-directional Overcurrent Protection (PHLPTOC: 1)

Three Phase Non-directional Overcurrent Protection (PHLPTOC) is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection.

Operation

Set to	On

Base value selector phase, phase to phase

Set to	Phase Grp 1

Phase current measurement mode of function

Set to	DFT

Number of start phases

Set to	1 out of 3

Curve parameter A - Parameter A for customer programmable curve

Set to	28.2000

Curve parameter B - Parameter A for customer programmable curve

Set to	0.1217

Curve parameter C - Parameter A for customer programmable curve

Set to	2.00

Curve parameter D - Parameter A for customer programmable curve

Set to	29.10

Curve parameter E - Parameter A for customer programmable curve

Set to	1.00

Reset delay time - Delay time provided to reset the timers

Set to	0.02

Minimum operate time - Minimum operate time delay for IDMT curves

Set to 0.04

Start value

This overcurrent protection shall be set to 150% to 200% of the highest prospective load current.

Set to 1.500 PS

Start value multiplier - Multiplier for scaling the start value

Set to 1

Time Multiplier - Time multiplier in IEC / ANSI curves.

Set to 0.1 TM

Operating curve type - Selection of time delay curve type

Set to IEC Norm. Inv.

Type of reset curve

Set to Immediate

Operate delay time

Set to 0.269 s

Three-phase non-directional overcurrent protection: Instantaneous stage (PHIPTOC: 1)

Three Phase Non-directional Overcurrent Protection (PHIPTOC) is used for single-phase, two-phase and three-phase non-directional overcurrent and

short-circuit protection. The instantaneous stage PHIPTOC always operates with the DT characteristic.

Operation

Set to	On

Base value selector phase, phase to phase

Set to	Phase Grp 1

Number of start phases

Set to	1 out of 3

Reset delay time - Delay time provided to reset the timers

Set to	0.02

Start value. This overcurrent protection shall be set to < 0.5 pu of the prospective fault current.

Set to	**22126.0**

Start value multiplier - Multiplier for scaling the start value

Set to	1

Operate delay time

Set to	0.2 s

Substation 2 Settings

Relay Type: SIEMENS 7SJ64

Table 5: Fault Levels at substation 2

3 Phase Fault Current on 420V	45.653 kA	
1 Phase Fault Current on 420V	21.164 kA	
Incomer Cable Rating	2.980 kA	

FLC

Table 6: Actual Settings applied to the relay at Substation 2

Three Phase Non-directional Overcurrent Protection (IDMT Ph)

Three Phase Non-directional Overcurrent Protection (IDMT Ph) is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection.

The (IDMT Ph) non-directional overcurrent protection shall be set to 105% to 120% of the full load current.

Ip

Pickup

Set to 1.120

PS

T IEp Time Dial

Set to 0.080

TM

Trip

Time

Set to | 0.214 | seconds

IEC

Curve

Set to | Normal Inverse |

Three-phase non-directional overcurrent protection: Instantaneous stage (DMT Ph)

Three Phase Non-directional Overcurrent Protection (DMT Ph) is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection. The instantaneous stage (DMT Ph) always operates with the DT characteristic.

This overcurrent protection shall be set to < 0,5 of the prospective fault level.

I>> Pickup

Set to | **22826.5** |

T I>> Time Delay

Set to | 0.200 |

Substation 3 Settings

Relay Type: SIEMENS 7SJ64

Table 7: Fault Levels at Substation 3

3 Phase Fault Current on 420V	25.495 kA	
1 Phase Fault Current on 420V	9.217 kA	
Full Load Current	1.487 kA	

FLC

Table 8: Actual Settings applied to the relay at substation 3

Three Phase Non-directional Overcurrent Protection (IDMT Ph)

Three Phase Non-directional Overcurrent Protection (IDMT Ph) is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection.

The (IDMT Ph) non-directional overcurrent protection shall be set to 105% to 120% of the full load current.

Ip

Pickup

Set to 1.120 PS

T IEp Time Dial

Set to 0.080 TM

Trip

Time

Set to 0.205 seconds

IEC

Curve

Set to | Normal Inverse |

Three-phase non-directional overcurrent protection: Instantaneous stage (DMT Ph)

Three Phase Non-directional Overcurrent Protection (DMT Ph) is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection. The instantaneous stage (DMT Ph) always operates with the DT characteristic.

This overcurrent protection shall be set to < 0,5 of the prospective fault level.

I>> Pickup

Set to | **12747.500** |

T I>> Time Delay

Set to | 0.050 |

3.4 Discussion of Results: Fault Levels and Characteristic Curves

When using the bottom up approach in determining the IDMT as well as the I>> overcurrent trip settings for the network in figure 15, Substation 03 is the starting point. This is represented by the bottom curve (blue) in figure 16. The IDMT curves grading is acceptable, that is about 0.2 seconds when judging from the 1000 A, however, the I>> that was calculated based on the full load current results Substation 1 and Substation 2 having very similar operating currents. They operate at 22126 and 22826 respectively.

These are within 3% of each other and within the CT allowable error, typically for the protection class 5P10 and 10P10 that are 5% and 10% allowable error respectively. In this

scenario any one of the two Substation 1 or 2 will trip for a fault of around 2500 A at the furthest end (Substation 3). This is a reality as depicted in figure 16, the two vertical parts of the curves for Substation 1 and 2.

In the case of IDMT overcurrent, grading margin can be manually factored into the trip time formula (11) in section 1.5. However, the instantaneous setting cannot be compromised. That is why substation 1 instantaneous element will operate faster than Substation 2 (although marginally so).

The instantaneous setting will not be compromised for the following reasons:

a) If the fault is sustained a moment longer, we risk damaging the equipment, according to the relationship:
   Energy = Power x time
b) There is a limit to the fault that the equipment can be subjected to due to ratings of equipment, hence the current setting cannot be increased as it may end up exceeding the short time rating (STC) of the equipment.

As indicated in the settings in section 3.3 and depicted in figure 16, the high set or definite time settings are based on the highest fault current at the substation. It was intended not to exceed half of the fault level. The trip times selected for the high set is 0.2 for substation 2 and 3, and 0.05 for substation 3. These can be selected arbitrarily, but in our decision we have taken cognisance of the equipment ratings, cable ratings and maximum load at the substations.

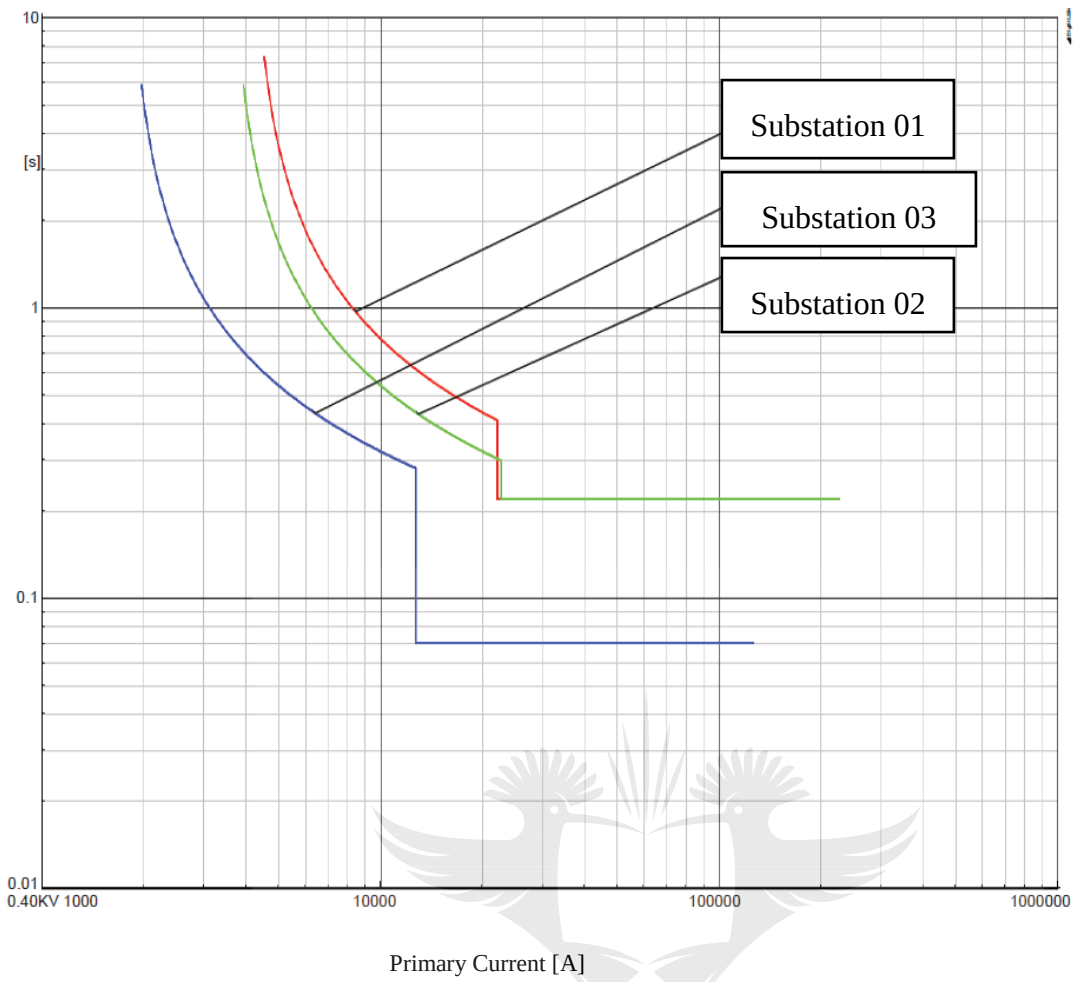


Figure 16: Grading Curves depicting both IDMT and Definite Time O/C

3.5 Conclusion

It can be seen that with definite time, it is difficult to distinguish between a fault at one point or another. Therefore, discrimination is poor when this type of protection is applied, hence the preference is IDMT overcurrent when selectivity is of importance.

CHAPTER 4: CASE STUDY 2: THREE PHASE BOLTED FAULT IN A MESH NETWORK

4.1 Introduction

This chapter addresses the fundamental problem of a three-phase bolted fault where there is no directional element, that is the basic IEEE 37.2 device 50 [22]. The problem that arises when there is bi-directional flow of power. This is a typical scenario that happens in a micro-grid where there is a traditional utility network and a distributed generation (DG) in the form of either PV or any other renewable form of generation. The neutral earthing method applied to the built network in the simulator is solid earthing.

4.2 Experiment Setup

This study is based on an existing power network whereby generation, represented in the network as external network at 132 kV level, and a DG both supply the network. The purpose of the study is to determine the logic input to the relay at the customer level that will minimise interruption in the event of a three-phase bolted fault. A mesh network is considered and built into a power simulator, Powerfactory 2018. The flow of power in this network is therefore bi-directional and the objective of protection setting for the relays at the consumer point is to prevent unnecessary interruptions.

Similar networks can be found in the sugar industry where the concept of bagasse cogeneration is applied; bagasse is burnt and used to generate power [82]. Other similar industries do follow a similar arrangement where power generation is performed at consumer point using gas generation, a pyrolysis process, wind power, hydropower, biomass and/or solar photo voltaic [83] [84]. Similarly, PV generation is becoming popular and, in such a network, it is difficult to achieve protection selectivity due to the bi-directional flow of power introduced by the presence of DG. Due to the voltage levels in the distribution network and for the purpose of voltage regulation, there are transformers in the renewable plant. This is an important factor because it contributes to the increase in fault levels. Earthing is maintained consistently as solid neutral earthing.

Bi-directional flow of power as depicted in Figure 17 brings about the discrimination problem. This is resolved with the direct application of directional overcurrent (device 67).

In sub B, relay R2 and R3 compete for fault F1 and F2, whereas they should operate respectively for F1 and F2 exclusively. This ensures that at sub B, supply to the user is secured.

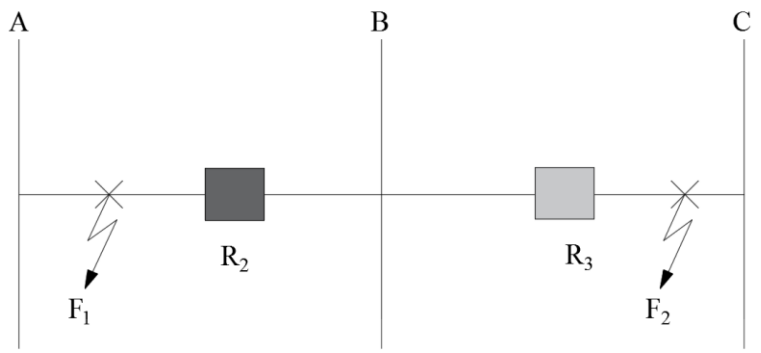


Figure 17: The discrimination problem in a series network.

A further problem is when there is a mesh network as in Figure 18. There are parallel paths for power flow and our simplified objective is to ensure that for a fault F1 as in Figure 18, only R2 and R3 relays should operate. R1, R2, R3 and R4 are the overcurrent relays in the respective zones as per figure 18.

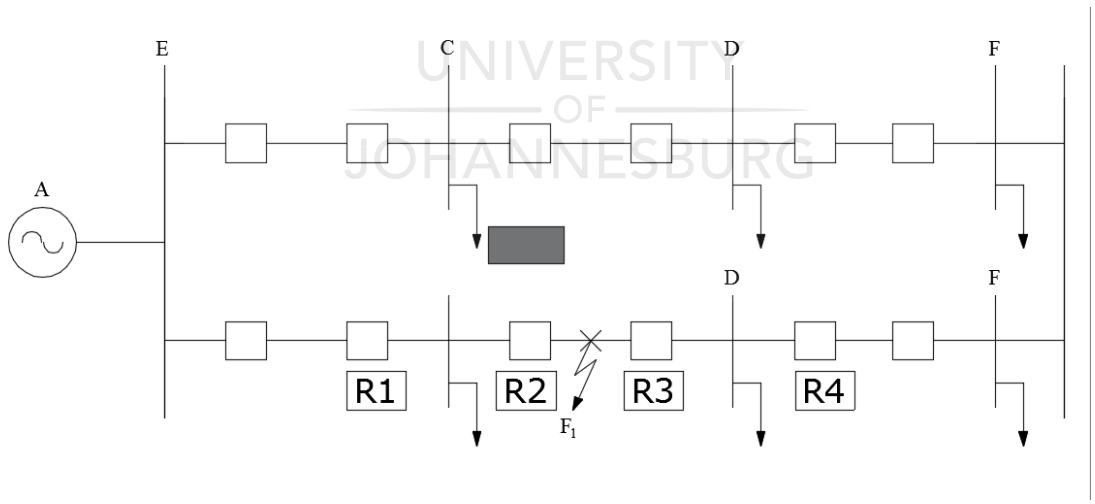


Figure 18: Discrimination problem in a mesh network [85]

It is essential to monitor the state of the plant, when it is online and out of service, and apply that information as input to the IED. This can be used to dynamically change settings groups

with the IED. The settings group change will result in the relay becoming directional or non-directional as required to achieve proper selectivity in fault isolation.

In Figure 19, the same network can be used to illustrate another point, the different modes of operation of a DG. These are:

a) Grid connected, R1, R2 and R3 closed. This is when the voltage and frequency control are dependent on the grid.
b) Autonomous/ Islanded operation R1 and R2 circuit breakers (CB) closed, R3 CB open. Independent control of voltage and frequency. This is necessary when the grid is unstable or has a fault.
c) On test, R3 CB open.

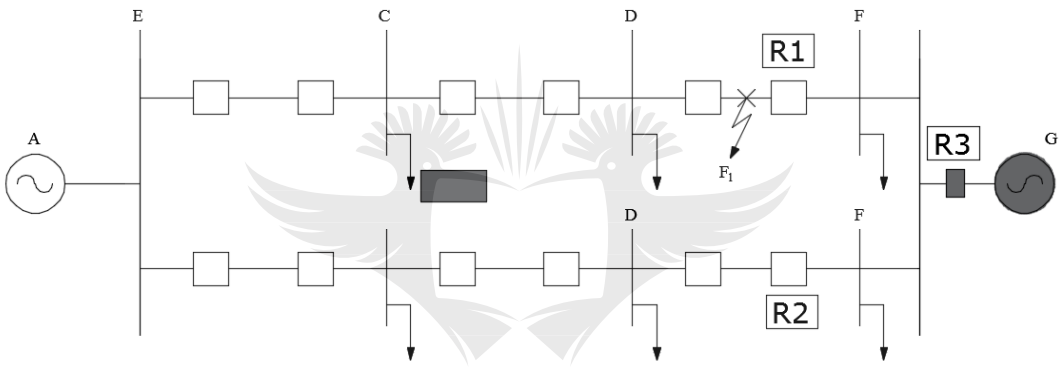


Figure 19: Inclusion of DG in a mesh network

The circuit elements is figure 19 are as follows:

R1, R2 and R3 – Relays

A – Utility network,

G – Distributed Generator.

The objective of the experiment is to operate in the DG in autonomous mode when a fault, F_1 in figure 19, occurs in the utility network. This requires R1 and R2 relays to operate as a device 67 when DG is out of circuit and migrate to device 50 settings when DG is in circuit.

The network used in this experiment is shown in Figure 20. It is a mesh network supplied from the traditional power grid and consists of a renewable source. This network has all the necessary features for the discussion of a three phase bolted fault in a micro-grid system.

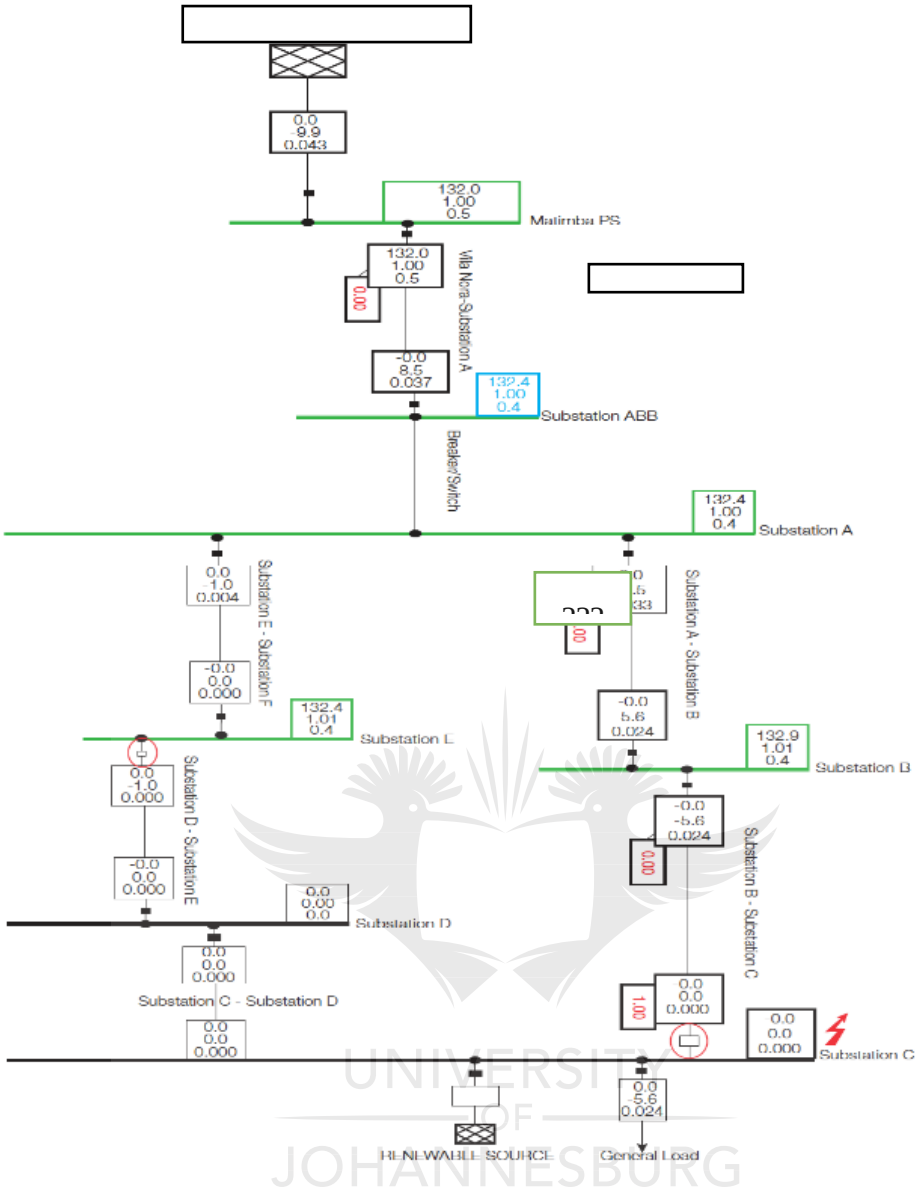


Figure 20: Network used in the experiment

The parameters of the network are as shown in Table 9.

Table 9: Network Parameters

	Length [m]	**Z1 [Ω]**	**phi Z1 (deg)**	**Z0 [Ω]**
PS-Substation A	20	6.37	72.991	26.603
Substation A – Substation B	30	10.223	74.009	35.046
Substation B – Substation C	80	25.481	72.991	106.414
Substation C – Substation D	34.29	10.922	72.991	45.612
Substation D – Substation E	29	9.882	74.009	33.878
Substation E – Substation A	14.7	4.682	72.991	19.563

The relay settings and current transformers (CT) Ratios, re-engineered for proper co-ordination, are shown in Table 10 and 11.

Table 10: CT Ratio, VT Ratio and Relay Type

Protection Type	**Overcurrent**
Current Transformer (CT) Ratio	500/1
Voltage Transformer (VT) Ratio	132000/110 V
Relay Type	ABB REF 615

Table 11: Settings for Incomer to each substation

Substation	PS	TM	GroupSettings
Matimba	0.5	0.346	N/A
Substation A	0.5	0.111	Group 1: Non-Directional, Group 2: Directional
Substation B	0.5	0.089	Group 1: Non-Directional, Group 2: Directional
Substation C	0.5	0.05	Group 1: Non-Directional, Group 2: Directional

4.3 System Modelling

IDMT O/C is an inverse time overcurrent protection. For the calculations of the trip times in the Root Mean Square (RMS) simulations, the line parameters in the preceding section were used. The trip time for an International Electrotechnical Commission (IEC) Standard Inverse (SI) characteristic is given by (13).

$$\text{Required Trip Time} = \frac{0.14 \times \text{Time Multiplier}}{\left(\left(\frac{\text{Fault Current}}{\text{Plug Setting*Ct Ratio}}\right)^{0.02} - 1\right)} \tag{13}$$

$$\text{Plug Setting Multiplier (PSM)} = \frac{\text{Fault Current}}{\text{FLC*p.u}} = \frac{\text{Fault Current}}{\text{Plug Setting*Ct Ratio}} \tag{14}$$

Therefore:

$$\text{Required Trip Time} = \frac{0.14 \times \text{Time Multiplier}}{\left(\left(\frac{\text{Fault Current}}{\text{Plug Setting*Ct Ratio}}\right)^{0.02} - 1\right)} \tag{15}$$

Using the definition of PSM in equation (3), we get:

$$\text{Required Trip Time} = \frac{0.14 \times \text{Time Multiplier}}{\left(\left(\frac{\text{Fault Current}}{\text{FLC*p.u}}\right)^{0.02} - 1\right)} \tag{16}$$

Where:

FLC = Full load current

p.u = the multiple of full load current for which protection is intended.

CT Ratio = Current Transformer Ratio.

Equation (14), (15) and (16) are applied calculate the trip times and ensure a good grading margin is achieved in a series network.

4.4 Fault Simulations Under Steady State

In this analysis, a load flow is performed, followed by fault simulations. The objectives are the following:

a) To prove that the relays are properly graded both in time and current through time curves;
b) To determine the relay trip times based on the network parameters used; and
c) To compare the simulated trip times to the required setting trip times.

Figure 21 shows the relay operating curves for steady state analysis using the parameters in Table 11 for the network in figure 20. For a fault of 1218.959 Amperes depicted by a blue vertical line, Substation C, the furthest substation from the power generation source, trips at 0.386 seconds, substation B trips at 0.976 seconds and Substation A at 1.655 seconds. This shows a good grading margin of 0.59 and 0.679 seconds respectively. Similarly for a larger fault of 2927.77 Amperes, depicted by a red line in figure 21, grading is expressly clear between the different substations.

Once these were ascertained with satisfaction, the next step was to do the dynamic analysis.

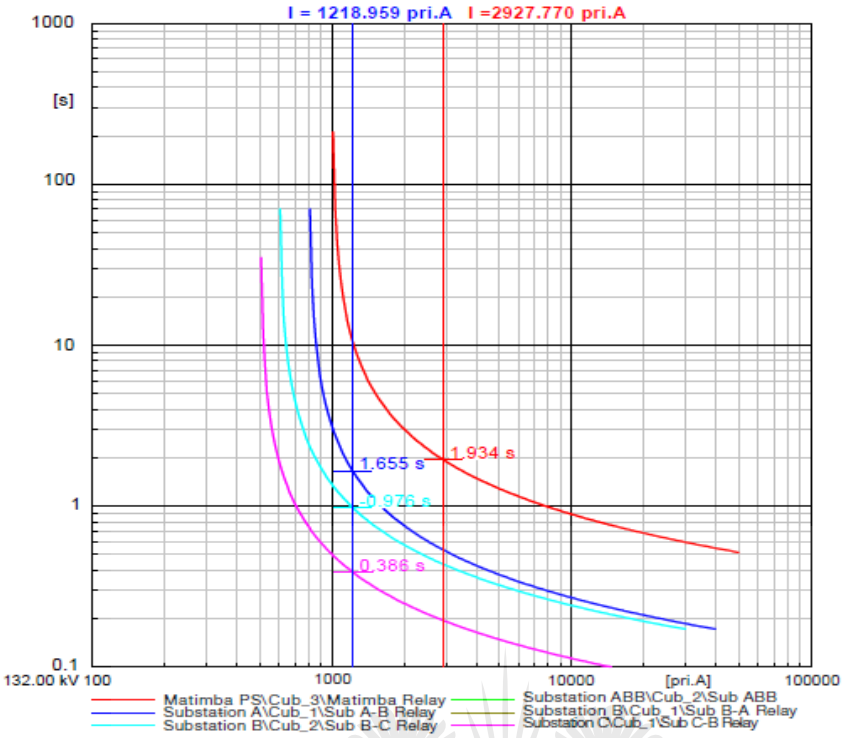


Figure 21: Time graded curves for dynamic simulations

4.5 Dynamic Analysis

A dynamic RMS 3 phase fault was simulated at the end of the feeder to determine which circuit breaker operates first to isolate the fault. The objective is to prove the coordination between the different circuit breakers in the network. The main focus is to prove the correct tripping in the meshed network under the two conditions, with the DG in network and with DG out of the network. This is proven with group 1 settings, non-directional.

The simulation is repeated with group 2 settings, directional and the result is that the relays close to the fault did not operate as purposed to ensure continuity of supply to substation C from renewable source at C. A carrier signal will instantaneously be sent to the feeder breakers to Substation C (C-D and B-C) to open as a precaution to prevent the renewable supplying to the fault. In that way the load is sustained through the renewables. Once an investigation has been done and the fault has been cleared, the system can be brought back to normal operation.

Migration between the two groups of protection settings is achieved through logic inputs to the IED relays. This is provided for in the marshalling of the relays configured for this network, the ABB REF 615 relay.

Table 12: Logic Inputs to the relay Sub C incomer

Incomer	**Renewable Source**	**Group 1 Settings**	**Group 2 Settings**
PS supply breaker	X	1	0
Substation A	1	1	0
Substation A	0	0	1
Substation B	1	1	0
Substation B	0	0	1
Substation C	1	1	0
Substation C	0	0	1

4.6 Discussion of Results

The results clearly show that there is sufficient coordination for a fault on the feeders as shown in Figure 22. The feeder with the applied overcurrent settings trips the relay in 1.069 seconds on a fault of 7 kA. All the other downstream relays do not see the fault as group 2 settings are in operation. It can also be seen from the dynamic time domain simulation that the circuit breaker contacts isolate the fault as expected in 1.069 seconds. The time could not be exactly 1.2 seconds to the setting range that does not allow a time multiplier of less 0.05. It can be noted that for a fault higher than 7 kA, the grading margin of, typically 0.4 seconds, is flouted; therefore, the decision to use group 2 settings makes sense. A fault current 7 kA is the three-phase fault current at substation C that takes into account the contribution of DG to the fault levels.

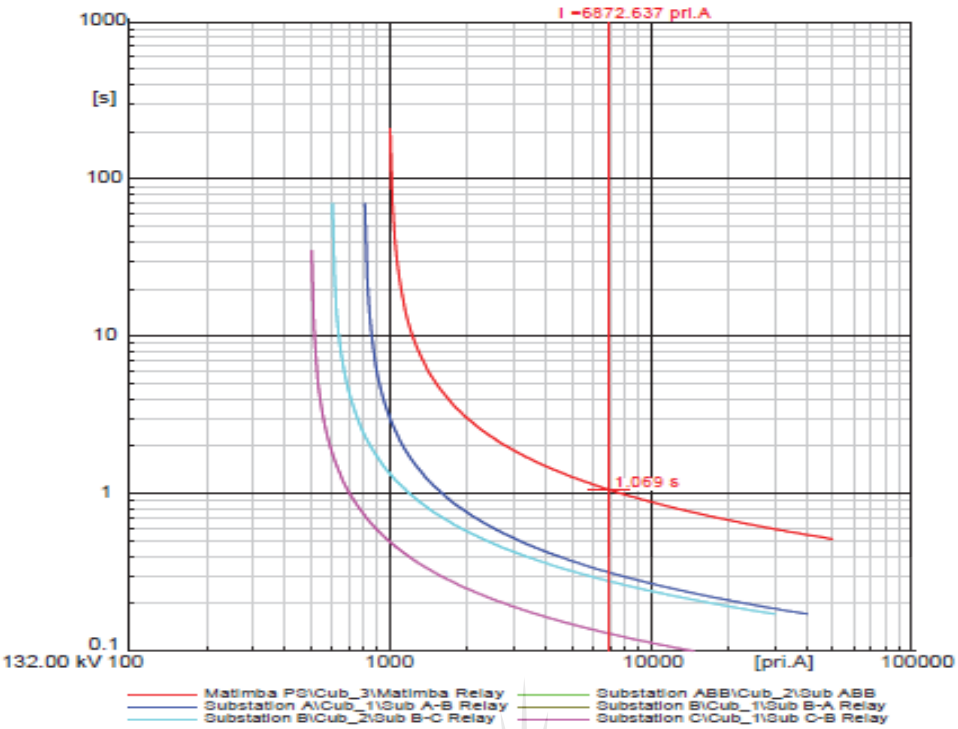


Figure 22: Time graded curves for dynamic simulations

4.7 Conclusion

It has been shown that proper coordination of protection tripping can be achieved, firstly with control of protection settings by centralising the function for proper management. This ensures that each substation or busbar setting is not calculated in isolation, but the grading information is taken into account. Secondly, when there is unidirectional power flow, the applied O/C settings must be directional, operating for a fault in the opposite direction to the power flow. This results in a quicker isolation of fault [52].

The relay trip logic should be in such a way as to consider factors relating to a fault at the furthest end of the network. When DG or embedded generation (especially PV generation) is connected at the consumption end of the network, it is necessary to isolate embedded generation from the network completely because of its combustibility nature of PV plant, hence the application of non-directional O/C to trip upstream breaker (Power Station) at 1.069 s in this experiment.

The selection of settings group and migration from one group to another is achieved through the correct marshalling of logic input to the IED.

CHAPTER 5: CASE STUDY 3: OVERCURRENT PROTECTION PHILOSOPHY USING MICROPROCESSOR BASED RELAYS FOR SLG FAULT

5.1 Introduction

This chapter discusses a solution to the protection problem that arises during an SLG fault, whereby the two phases that are not faulted tend to misjudge the direction of overcurrent fault resulting in an incorrect relaying decision. The problem is resolved by using other techniques in addition to mere application of directional overcurrent quadrature method.

An incorrect relaying decision leads to improper discrimination and loss of service to sections of the network that are otherwise not affected. The proposed microprocessor based relaying solution is devised, as presented in this chapter, whereby the microprocessor relay is marshalled for reliable operation under SLG fault conditions and for sensitivity to the direction of power flow. The solution prevents possible mal-operation of protection and ensures accurate selectivity.

5.2 System Modelling

Most of the high-voltage distribution lines in South Africa are part of the interconnected grid. These are modelled, for practical purposes, as a series of nodes or substations with power sources on either end. In the application of directional overcurrent protection, the power distribution networks have a myriad of relay types in all relay generations, that is, electromechanical, solid state and microprocessor based. It is worth mentioning here that the older generations of relays do offer the directional overcurrent function, although with limited capabilities. Protective relaying decisions are critical because proper selectivity could mean the difference between productivity and loss thereof. A philosophy is outlined, whereby microprocessor based solutions are applied in order to achieve proper discrimination [37, 40].

Decision making is a a result of intelligence that is built into the device. The earlier generation of CDG series of relays, for example, operates for an overcurrent and has no built-in intelligence to decide if the direction of overcurrent warrants the action of sending a trip signal to the circuit breaker. The Disc Type Directional IDMT Overcurrent & Earth Fault Relay

Model: CDD21/31/41, however, was designed to distinguish between the directions of current flow. [85] This relay still lacks some intelligence though. Further developments to the newer microprocessor based Intelligent Electronic Devices (IEDs), such as the ABB REF615, can be marshalled to make intelligent decision [86].

With the misty weather conditions in some areas of South Africa, the SLG faults are prevalent. These are transient faults and the action taken by protection is to trip the faulted phase and reclose instead of interrupting all the phases [87]. It is therefore important to handle this type of fault. The fault was applied in the A-phase, but it must be noted that what applies in the A-phase equally applies to the other two phases [75].

The type of distribution substations in the selected network are primary substations, as these serve as load centres from which the customer substations connect. The design concept is referred to as the 'N-1' reliability network, a 'safety net' reliability standard for the core grid. In such a network, a single component failure is not supposed to affect the electricity supply [88] [89].

It is on this premise that this case study is formulated. The objective is to ensure that incorrect protection operations are avoided. The objective is to prevent a breaker operation for an SLG fault in the reverse direction in A-phase, not to mention to have an effect on the B- and C-phases.

5.3 Experiment Setup

Maximum Torque Angle (MTA)

A phase relationship between voltage and current is used to determine the direction of current flow. In the event of an overcurrent fault, the direction of current flow can be determined by the phase relationship between phase voltage V_A and phase current I_A; however, during a fault on the A-phase, V_A collapses, hence the choice of a voltage that is independent of A as a polarising component. That voltage is the quadrature voltage V_{BC}. Similarly, I_B is polarised by V_{CA} and I_C by V_{AB} [76].

The angle by which current applied to the relay must be displaced from the voltage applied in order to produce maximum torque is referred to as maximum torque angle (MTA) [62].

In this experiment the MTA of 0° is applied.

Tripping Logic

A deductive analysis method was applied, beginning from the top event of interest. [87] The top event is the desired outcome. In this case, it is to allow only the correct "trip decision". This is achieved by applying the relay logic as shown in Figure 23.

A fault condition must exist, that is, phase overcurrent event 3. The phase current must exceed the pick-up setting. Event 5 is the polarising component as contemplated above. The polarising component voltage, the voltage collapse, event 4 and the supervision line-to-line current in event 6 should all be 1, for the decision in the top event 1 to be a "true" or 1.

The breaker pole under investigation is pole B, which must block the trip for a reverse fault in phase A.

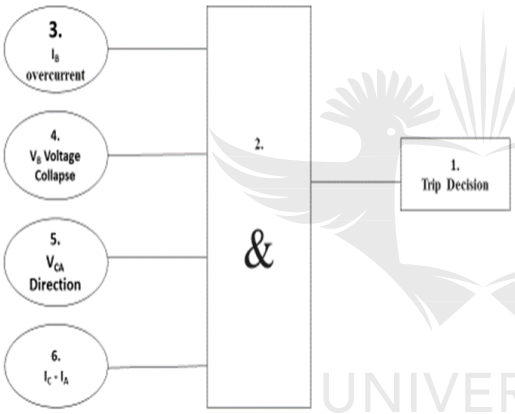


Figure 23:Microprocessor Relay Tripping Logic

Event 6, the line-to-line current magnitude, must be in the same direction as the fault current. This input is necessary to ensure that, indeed, the fault is in the forward direction and this is the solution to the protection problem at hand – misjudgement of direction.

5.4 Experiment Setup

The network under consideration has generation on the two ends. The generator specification is as follows:

S = 940 MVA;

P = 846 MW at power factor of 0.9 leading;

The generators are solidly earthed.

A single line to ground fault is simulated at about 50% of the length of Sub C to Sub D line as indicated in Figure 24. The protection under consideration is at Sub C on the Sub B feeder and the relay is set for directional phase overcurrent. The overcurrent pick-up and the MTA settings are applied.

The significance of the term MTA as the torque angle has diminished due to the capabilities of the latter electromechanical relays to have phase shifting components to produce maximum torque at the applied angle. Modern microprocessor based relays can accept any angle ranging from -90° to +90° [76].

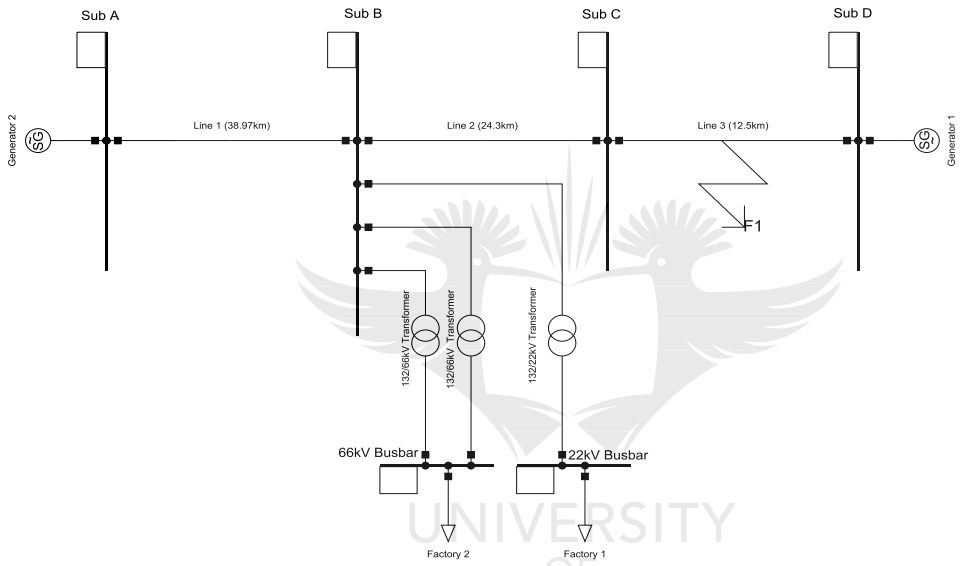


Figure 24: The network under discussion

In this experiment, an angle of 0° is applied as a setting to a relay in order to demonstrate the protection problem under investigation. Any relay that has directional component can be used to demonstrate the protection problem, although the solution devised here can only be applied in IEDs.

The network considered for this discussion is a 132 kV network with four substations in series. Either side of the network is a series of substations leading to power generation in a ring formation as shown in Figure 24.

A 132 kV transmission is generally done via overhead lines and it is suitable for this study as the SLG faults are more prevalent in overhead lines. These faults are generally of a transient nature and therefore it makes sense to trip the single faulted phase and reclose [19, 21, 52].

5.5 Discussion of Results

Network Simulation

The network was built into a power simulator and the relevant data was extracted and presented as Table 13.

Figures 25 and 26 show the resultant currents and voltages as measured by the relay.

Table 13: Experimental results

Measured Quantity	**Parameter**	**Measurements**		
		Red Phase	***White Phase***	***Blue Phase***
Voltages at Sub B	Phase Voltage	0°	96.83 kV	103.79 kV
	Phase angle	0°	-135.7°	131.43°
Currents at Sub B	Line Currents	1.84 kA	0.17 kA	0.20 kA
	Phase Angle	108.92°	-64.38°	-63.74°

Grid: Grid System Stage: Grid | | Annex:

		rtd.V. [kV]	Voltage [kV]	Voltage [deg]	c-Factor		Sk" [MVA]	Ik" [kA]	Ik" [deg]	ip [kA]	Ib [kA]
Line 2 (24.3km)		Sub B				A	139.98 MVA	1.84 kA	108.92	3.85 kA	
						B	12.90 MVA	0.17 kA	-64.38	0.35 kA	
						C	15.03 MVA	0.20 kA	-63.74	0.41 kA	
Line 3 (12.5km)		Sub D				A	528.66 MVA	6.94 kA	106.13	15.59 kA	
						B	12.90 MVA	0.17 kA	115.62	0.38 kA	
						C	15.03 MVA	0.20 kA	116.26	0.44 kA	
Sub D	A	132.00	0.00	0.00	1.10		2419.95 MVA	31.75 kA	-85.54	82.60 kA	31.75
	B		73.78	-99.38			0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
	C		73.19	94.39			0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
Line 3 (12.5km)		Sub C				A	163.02 MVA	2.14 kA	104.65	4.46 kA	
						B	69.12 MVA	0.91 kA	-76.35	1.89 kA	
						C	80.67 MVA	1.06 kA	-75.75	2.21 kA	
Generator 1						A	2259.68 MVA	29.65 kA	-86.27	78.14 kA	
						B	69.12 MVA	0.91 kA	-76.35	2.39 kA	
						C	80.67 MVA	1.06 kA	-75.75	2.79 kA	

Figure 25: Line currents during the SLG Fault

		rtd.V. [kV]	Voltage [kV]	[deg]	c-Factor	Sk" [MVA]	Ik" [kA]	[deg]	ip [kA]	Ib [kA]
Sub A	A	132.00	0.00	0.00	1.10	2419.95 MVA	31.75 kA	-85.54	82.60 kA	31.75
	B		73.78	-99.38		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
	C		73.19	94.39		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
Line 1 (38.97km Sub B	A					163.02 MVA	2.14 kA	104.65	4.46 kA	
	B					69.12 MVA	0.91 kA	-76.35	1.89 kA	
	C					80.67 MVA	1.06 kA	-75.75	2.21 kA	
Generator 2	A					2259.68 MVA	29.65 kA	-86.27	78.14 kA	
	B					69.12 MVA	0.91 kA	-76.35	2.39 kA	
	C					80.67 MVA	1.06 kA	-75.75	2.79 kA	
Sub B	A	132.00	0.00	0.00	1.10	419.10 MVA	5.50 kA	-71.56	11.70 kA	5.50
	B		96.83	-135.70		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
	C		103.79	131.43		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
Line 1 (38.97km Sub A	A					204.32 MVA	2.68 kA	108.48	5.70 kA	
	B					0.36 MVA	0.00 kA	-64.24	0.01 kA	
	C					0.42 MVA	0.01 kA	-63.41	0.01 kA	
Line 2 (24.3km) Sub C	A					214.77 MVA	2.82 kA	108.40	6.00 kA	
	B					0.36 MVA	0.00 kA	115.76	0.01 kA	
	C					0.42 MVA	0.01 kA	116.59	0.01 kA	
132/66kV Transf 66kV Busba	A					0.00 MVA	0.00 kA	0.00	0.00 kA	
	B					0.00 MVA	0.00 kA	0.00	0.00 kA	
	C					0.00 MVA	0.00 kA	0.00	0.00 kA	
132/66kV Trans 66kV Busba	A					0.00 MVA	0.00 kA	0.00	0.00 kA	
	B					0.00 MVA	0.00 kA	0.00	0.00 kA	
	C					0.00 MVA	0.00 kA	0.00	0.00 kA	
132/22kV Transf 22kV Busba	A					0.00 MVA	0.00 kA	0.00	0.00 kA	
	B					0.00 MVA	0.00 kA	0.00	0.00 kA	
	C					0.00 MVA	0.00 kA	0.00	0.00 kA	
Sub C	A	132.00	0.00	0.00	1.10	668.51 MVA	8.77 kA	-73.29	19.43 kA	8.77
	B		91.25	-132.98		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00
	C		99.65	127.66		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00

Figure 26: Line voltages during fault

The voltage V_A is the phase voltage as measured by the instruments at B looking in the direction of C. Therefore, the current angles are offset by an 180° when looking at substation C feeder B. Hence the angles are as depicted in the phasor diagrams in Figures 27, 28 and 29 for the A, B and C - phases respectively.

The phasors of interest will therefore be:

$I_A = 1.84$ kA ∟ -72°

$I_B = 0.17$ kA ∟115.62°

$I_C = 0.20$ kA ∟116.26° and

$V'_{AB} = 96.83$ kV ∟44.3°

$V'_{BC} = 138.35$ kV ∟175.78°

$V'_{CA} = 103.79$ kV ∟131.43°

The nominal voltages are as follows:

$V_{AB} = 132$ kV ∟30°

$V_{BC} = 132$ kV ∟-90°

$V_{CA} = 132$ kV ∟150°

Protection Problem

When an SLG fault occurs, there is an effect on the faulted phase, phase A (Scenario A) and the other two phases, B and C (Scenario B).

Figures 28 and 29 show that for the reverse phase A SLG fault, the B and C phase directional elements at Sub C on the Sub B feeder will make an incorrect forward decision. In the event that the phase currents in phases B and C are higher than the pick-up current settings, an overcurrent trip will be initiated.

Scenario A

The normal line voltage for the system in this study is 132 kV, and it can be noted that the faulted phase voltage collapses to about to 0 V.

Phase A experienced an overcurrent condition, a phase voltage collapse, the polarising component in the reverse direction and a high supervision line current; therefore, the trip is blocked, as shown in Figures 27 and Table 14. The only input that is not active (0) is the polarising component which happens to be in the opposite direction to the phase current.

Phase A experienced a voltage collapse. The A-phase voltage does not always drop to 0 V considering a possibility of an existence of a fault impedance in the event of an arc to earth or

a lack or direct connectivity to earth. This has no significance in the settings determination for voltage collapse.

In this experiment, it is observed that all phase currents are in the forward direction. However, only A has the polarising component (V_{BC}) in the opposite direction. This results in a correct decision to block the trip in A phase. In this case, the line-to-line current supervision does not matter as the decision is as expected.

In this scenario, the line-to-line supervision is in the same direction as the current I_A (or a logic 1), but this only indicates that there is a fault in the phase but obviously the decision, based on the direction of the fault, is a "block" and not a "trip".

The phase shift from the steady state to the transient state, as can be seen in the phasor diagrams, is based on the charging of the two healthy phase capacitances and the discharging of the faulty A-phase capacitance. This is evident when comparing the voltages V_{AB}, V_{CA}, V_{BC} against V_{AB}', V_{CA}' and V_{BC}' respectively.

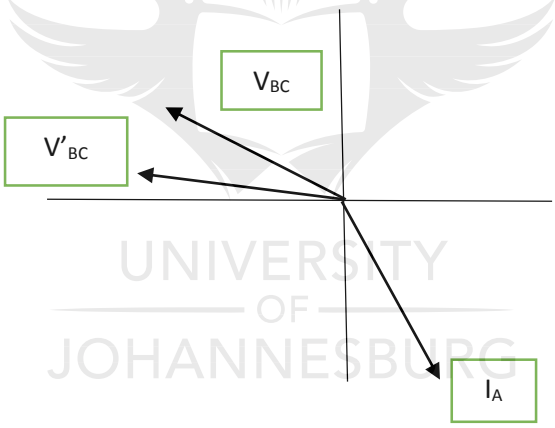


Figure 27: A-phase current during fault at MTA = 0°

Scenario B

The B and C phases experienced a dip less than 25%, therefore a setting of less than 75% (90 kV), 50% of nominal voltage should suffice as a setting for voltage collapse (event number 4 in Figure 23).

Phase B and C experienced possible overcurrent, depending on the pick-up setting, possible voltage collapse (the 50% or more depending on the severity of the fault dip – as stated above), the polarising component is in the same direction as the phase currents but (Figures 28 and 29) and the direction of the supervision is opposite (logic 0).

The overcurrent trip for phases B and C was initiated at Sub C, the fault condition, that is, event 3, but due to the opposing of the supervision line-to-line current, the trip is inhibited (result = 0 in the logic table).

Figures 28 and 29 show that B and C phases appear to be in the forward direction, the same direction as the polarising component. Therefore, if IB and IC are above the pick-up value, the two phases will make an incorrect decision resulting in the isolation of feeder B at substation C.

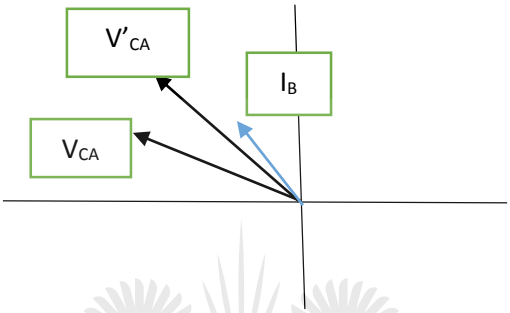


Figure 28: B-phase current during a fault at MTA = 0°

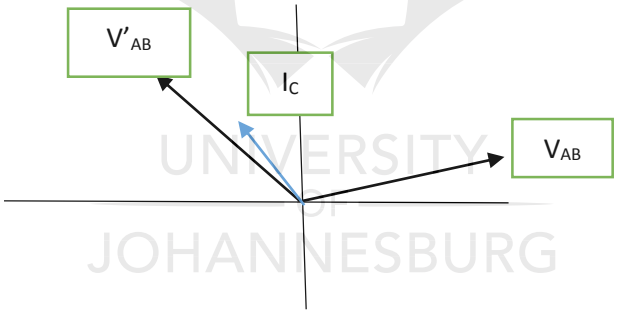


Figure 29: C-phase current during a fault at MTA =0°

The line-to-line currents as shown in the next section proved very useful as inputs to the logic in Figure 23, for supervision, in order to make the correct "tripping" decision. The truth table, Table 14, shows the applied logic with the trip decision for all three phases.

Table 14: Truth table for tripping decisions.

Breaker Pole Tripping Decisions	**Parameter**	**Phase**		
		Red Phase	***White Phase***	***Blue Phase***
Voltages at Sub B	I>>	1	0	0
	Phase Voltage Collapse	1	Don't Care	Don't Care
	Polarising Component	0	1	1
	Supervision – Line to line Current	$\mathbf{I_B}$-$\mathbf{I_C}$	$\mathbf{I_C}$-$\mathbf{I_A}$	$\mathbf{I_A}$-$\mathbf{I_B}$
		1	0	0
Trip Decision		**0**	**0**	**0**

Supervision Line-to-line Current

Supervision by using line-to-line current yields the desired results. The A, B and C phases are supervised respectively with $I_B – I_C$, I_C-I_A and I_A-I_B.

The actual figures for all line-to-line currents are as follows:

$\mathbf{I_B}$-$\mathbf{I_C}$ = 0.17 kA ∟115.62° – 0.20 kA ∟116.26° = **30.07** ∟**300°** This is in the same direction as I_A – Logic 1.

$\mathbf{I_C}$-$\mathbf{I_A}$ = 0.20 kA ∟116.26° – 1.84 kA ∟ -72° = **2.04** kA ∟**109°** This is in the opposite direction to I_B – Logic 0.

$\mathbf{I_A}$-$\mathbf{I_B}$ = 1.84 kA ∟ -72° – 0.17 kA ∟115.62° = **2.0** kA ∟**288°** This is in the opposite direction to I_C – Logic 0.

From these computations, it can be deduced that the supervision component for phase A will result in a logic of 1 due to the current direction; however, the B and C phases (or white and blue phases) supervision currents are in the opposing direction.

The line-to-line currents are the phasor difference between the currents, that is, I_B-I_C, I_C-I_A for IB and I_A-I_B for I_A, I_B and I_C respectively. The white and blue phases would have otherwise tripped had there been no line-to-line current supervision.

Now since the breaker at Sub C looking towards Sub B is blocked from tripping, the correct breaker at C (looking towards D) will trip and isolate the fault and the supply from B to C will be maintained.

Table 14 indicates that the trip decision is 0 (or block) when the logic is applied to the B- and C-phases (White and Blue). The B- and C- phases will block due to the line-to-line current being in the opposite direction. This logic is applied only to microprocessor based relays.

The thresholds for the both voltage and current settings need to be selected with great caution.

The microprocessor based relays are a revolutionary innovation in the field of Electrical Protection as they bring with them the flexibility to customise the protection philosophy. Practitioners in the power system have a responsibility to standardise philosophies for ease of maintenance.

5.6 Conclusion

The incorrect judgement of direction of current flow by B- and C-phases in the event of an A-phase was prevented by applying the logic in the flow diagram above. Event 4, voltage collapse, has no bearing on the decision in the case of phases B and C. Current supervision in event 6 in the tripping logic flow diagram is key to the decision to block the trip in the event of an SLG on the red phase.

The experiment proved that, with the older generation of relays, there is a shortcoming as the SLG fault can result in incorrect isolation. A philosophy that has a supervision logic ensures that the relay decisions are kept in check in order to prevent nuisance disconnections.

The philosophy was applied to a numerical relay type ABB REF615, which was able to provide reliable operation in the event of reverse direction overcurrent faults, even when the overcurrent pickup was set low. A-phase did not operate for a reverse fault and B- and C-phases also blocked the trip due to the applied logic that ensures that there is “supervision” input to the trip logic of the relay.

This philosophy enhances security of supply by eliminating nuisance incorrect operation of protection and selectively operating for faults only in the protected zone.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

IDMT O/C protection meets the performance and design criteria for system protection devices of:

a) Being Cheap,
b) Simplicity - Ease of implementation and maintenance,
c) Operating with selectivity, and
d) Operating reliably, that is dependably and with security.

Based on the experiments conducted on the application of IDMT overcurrent in a micro-grid system, the outcomes yielded the following:

a) In all practicality and realism, time-graded overcurrent protection is a legendary form of protection, has stood the test of time and it finds its application to be more reliable in ensuring coordination of tripping. It has proven to ease the way into selective operation of protective devices, hence it provides dependability and security of supply. In Chapter 3 superiority of IDMT O/C over other types of overcurrent was illustrated.
b) The most severe fault is a three-phase bolted fault. The objective for selective operation is to ensure that when a fault occurs, IED protective devices operate with flawless selectivity and leave as much of the network as possible unaffected. This requires selectivity beyond the usual series coordination. In a mesh network, a directional element is essential to ensure that the unaffected parts maintain supply to the load. This is the essence of a micro-grid as illustrated in the case study in Chapter 4.
c) In the event of an SLG fault, the most common of all short circuit faults, an incorrect decision by the relay, can be costly if it results in the isolation of unaffected parts of the network. More importantly, at the Extra High Voltage levels (EHV) and some high voltage levels that transmit using overhead lines, the prevalence of SLG faults requires clever logic and accurate decisions by the IED protective devices. A logic input is devised in the Chapter 5 case study to aid in the correct decision making.

The results of the experiments can be summarised as follows:

Table 15: Experiments Results Summary

Experiment Number	Objective/ Hypothesis	Case	Solution
1	IDMT Overcurrent offers better coordination of protection tripping than instantaneous overcurrent.	A series circuit supplying air conditioning at a power station.	When applying a consistent approach into settings calculations. Instantaneous O/C, based on the fault levels fails to coordinate while IDMT generally coordinates and offer perfect grading between series nodes.
2	In a 3 phase bolted fault, selectivity fails when there is a bidirectional flow of current.	A 132 kV network supplied from a power generation station and having a DG.	The application of directional and non-directional overcurrent protection based on the logic input of breaker statuses. A seamless migration between the different settings groups makes it possible to isolate the faulted section selectively while ensuring that the unaffected areas are not interrupted.
3	An incorrect directional decision made by the relay on power flow direction of the unaffected phases.	A 132 kV transmission network with bidirectional flow of power.	The traditional quadrature method is insufficient and correct judgement is achieved by applying line current supervision.

6.2 Recommendations

Standardisation of electrical protection philosophies is suggested, whereby the utility operator will device standard relay tripping logic for each of the possible scenarios. These should aim at minimising incorrect breaker tripping operations as this can be costly to both the utility operator and the power user.

Further studies need to be pursued in the field of electrical protection, with the aim of taking advantage of the new capabilities offered by the IED devices, the enhanced features of the IEC61850 Generic Objective Oriented Substation Event (GOOSE) messaging and other features necessary for a fully-fledged micro-grid system.

Bibliography

[1] Beyond Petrleum (BP) Statistics, “BP Energy Outlook 2030” Report , BP, London, 2011.

[2] A. Hasan, K. Ouahada, T. Marwala and B. Twala, “Optimization of the Compressed Air-Usage in South African Mines,” Conference Proceedings in *IEEE Africon 2011*, Livingstone (Zambia), 2011.

[3] A. Hasan, "Effective Use of Artificial Intelligence in predicting Energy Consumption and Underground Dam Levels in Two Gold Mines in South Africa," thesis, Johannesburg (South Africa): University of Johannesburg, 2013.

[4] A. Hasan and L. V. Dlamini, “Proposed Adaptive Overcurrent Protective Relaying In A Reliable Micro-Grid System,” Conference Proceedings in South African Universities Power Engineering Conference (SAUPEC), Wits University, South Africa, 2018.

[5] M. M. Abrar, “Power cut off and Power Blackout in India a Major threat- An Overview,” International Journal of Advancements in Research & Technology, vol. 5, no. 7, pp. 8-15, 2016.

[6] Council of Scientific and Industrial Research (CSIR), “The State of Municipal Infrastructure In South Africa and its Operation and Maintenance,” Report, CSIR, Pretoria (South Africa), 2006.

[7] B. Z. Zaameski, “The Advancement of Adaptive Relaying in Power Systems Protection.,” Report, Virginia Polytechnic Institute and State University, Blacksburg, 2012.

[8] Bussmann, “Short Circuit Current Calculations - Cooper Industries,” Electronic Source, Eaton, Houstin (U.S), 2014.

[9] Vedat Esen, Bulent Oral, Tahir Cetin Akinci, “The determination of short circuits and grounding faults in electric power systems using time-frequency analysis,” Journal of Energy in Southern Africa, vol. Vol 26, no. May 2015, pp. 123-130, 2014.

[10] HVlab, ELEC9713, Online Lecture, Topic: “Industrial and Commercial Power Systems (Fault calculation methods),” University of South Wales, Newport (Wales), Mar 9, 2010.

[11] D. Sweeting, “Applying IEC 60909, Fault Current Calculations,” Journal article, IEEE Transactions on Industry Applications, vol. 48, no. 2, pp. 575-580, 2012.

[12] International Electrotechnical Commission (IEC), “IEC 60909-0:2016 Short Circuit Currents In Three Phase AC Systems,” Report, IEC, Geneva, Switzerland, 2016.

[13] A. Megahed, “Simulation of Internal Faults in Synchronous Generators,” Journal article, IEEE Transactions on Energy Conversions, vol. 14, no. 4, pp. 1306-1311, 1999.

[14] P. Anderson, “Reliability Analysis,” in Power System Protection, New York, Wiley Interscience, pp. 1043 - 1087, 1998.

[15] D. J. Glover, T. J. Overbye and M. S. Sarma, “Unsymmetrical Faults,” in Power system analysis & design, Wardsworth Group, pp. 365-405, 2002.

[16] S. W. D. Grainger John J., “Unsymmetrical Faults,” in Electric Power Systems, McGraw Hill, pp. 470-527, 1989.

[17] S. Hanneinen, “Single phase earth faults in high impedance grounded networks (Characteristics, Indication and locations),” Report, VTT Energy, Finland, 2001.

[18] S. Das, S. N. Ananthan and S. Santoso, “Estimating Zero-Sequence Line Impedance and Fault Resistance Using Relay Data,” Journal article, IEEE Transactions on Smart Grids, vol. 10, no. 2, pp. 1635-1645, November 2019.

[19] ALSTOM, "Network Protection & Automation Guide (NPAG)," Saint-Ouen (France): Alstom Grid, Chapte 3 - Chapter 5, May 2011.

[20] M. Bamber, M. Bergstrom, A. Darby, S. Darby, G. Elliott, P. Harding, G. Lloyd, A. Marshall, A. Millard, A. Myat, P. Newman, A. Perks, S. Pickering, S. Potts, S. Richards, J. Royle, P. Rush, B. Smith, M. Stockton, P. Wilkinson, A. Wixon and J. Wright, "Overcurrent Protection for Phase and Earth Faults," in Network protection and automation guide, Johannesburg, ALSTOM Grid, pp. 122-151, 2002.

[21] S. Saini, "Overcurrent Relay Coordination For Phase And Earth Faults," in *Proceedings of 7th IRF International Conference*, Pune, India, 2014.

[22] C. Kriger, S. Behardien and J. Retonda-Modiya, "A Detailed Analysis of the GOOSE Message Structure in an IEC 61850 Standard-Based Substation Automation System.," Journal article, International Journal of Computers Communications and Control, vol. 8, no. 5, pp. 708-721, 2013.

[23] M. Tawfeeq, "Lecture notes: Part 5 - Power System Protection, Overcurrent Protective Relays," Electronic source, King Saud University College, Riyadh (Saudi Arabia),

[24] W. Elmore, "Protective Relaying Theory and Applications," Electronic source, Basel, New York: New York: Marcel Dekker, 2004.

[25] Z. Gajic, "Differential Protection for Arbitrary Three Phase Power Transformers," Thesis, Lund University, Lund (Sweden), 2008.

[26] C. Martin, S. Chase, T. Nguye, D. Hawaz, J. Pope and C. Labuschagne, "Bus Protection Considerations for Various Bus Types," Conference Proceedings in 69th annual Georgia Tech Protective Relaying Conference, Atlanta (Georgia), 2015.

[27] D. Thomas, C. Christopoulos, Y. Tang and P. Gale, "Validation of a novel unit protection scheme based on superimposed fault currents," Conference Proceedings in Developments in Power systems protection conference, 2001.

[28] N. Hodge, "www.agcs.Allianz.com," Allianz, 2016. [Online]. Available: https://www.agcs.allianz.com/assets/PDFs/GRD/GRD%20individual%20articles/Power_blackout_risks_article.pdf. . [Last Accessed 11 November 2018].

[29] E. S. III and S. Zocholl, “Aspects of Overcurrent Protection for Feeders and Motors,” Conference Proceedings in Pennsylvania Electric Association Relay Committee Spring Meeting, Matamoras (Pennsylvania), 1995.

[30] Eskom SOC Ltd, “Guide and overview to the Independent Power Producer (IPP) Process in South Africa and Eskom,” Electronic source, Eskom, Johannesburg, 2010.

[31] David Lipschitz, "Grid tying and net metering for systems under 1 MW,″ Publication in periodical, Engineering News, 22 October 2010.

[32] Amplus Solar, "Microgrid the future,″, website, Gurgaon, India: https://amplussolar.com/blogs/microgrids-the-future, 2017.

[33] T. Considine, W. Cox and E. G. C. PhD, “Understanding Microgrids as the Essential Architecture of Smart Energy,” Conference Proceedings, in Grid-Interop Forum, Chicago, IL, 2012.

[34] L. Buque and C Chowdhury, “Modelling and simulation of an adaptive differential current protection scheme for a Solar PV microgrid,” Conference Proceedings in UCT Annual publications Conference, Cape Town (South Africa), 2014.

[35] S. Lazarou, V. Vita, L. Ekanamou, “Protection Schemes of Meshed Distribution,” Journal article, Energies, vol. 11, no. 3106, pp. 1-10, 2018 Januaty 2018.

[36] Qual-Tech Engineers, Inc., “Overcurrent Coordination Guidelines For Industrial Systems,” Report, Qual-Tech Engineers, Inc., Houston, 2018.

[37] National Energy Regulator of South Africa (NERSA), “South African Distribution Code - Network code,” Standard, ver. 6, July 2014.

[38] J. Roberts, T. L. Stulo and A. Reyes, “Sympathetic Tripping Problem Analysis and Solutions,” Conference Proceedings in 24th Annual Western Protective Relay Conference, Spokane (Washington), 2002.

[39] L. Juan, H. JingHan, Z. Hao, X. feixiang, B. ZhiQian and T. Yip, "Research on adaptive protection based on integrated protection," Conference Proceedings in International Conference on Advanced Power System Automation and Protection, 2011.

[40] Eskom, "Protection phillosophy," Report, Eskom SOC Ltd, Johsnnesburg, 2016.

[41] D. M. Christopher Bolan, "Computer Security Research: Approaches and Assumptions," in *We-B Centre & Edith Cowan University*, Joondalop WA (Australia), 2004.

[42] D. Bipath, D. D. Beer, T. Yusuf, T. Audat, L. Libate, N. Faleni, P. Mpondo and V. Nemaxwi, "Case study on the introduction of smart grids into municipalities, residential and industrial areas," Conference proceedings in South African Institute of Electrical Engineers (SAIEE) Smart Grid Conference, Johannesburg, 2015.

[43] A. Masambe, "Reliability benefit of smart grid technologies: A case for South Africa," Journal article, Journal of Energy in, vol. 26, no. 3, 2015.

[44] Pei Zhang, Fangxing Li, N, "Next-Generation Monitoring, Analysis, and Control for the Future Smart Control Center," Journal article, IEEE Transaction on Smart Grid, vol. 1, no. 2, pp. 186-191, 2010.

[45] T. Spearing, L. Electric and R. St.John, "Scaling down a small island control and distribution system for deployment as a Microgrid power solution in Africa," Conference proceedings in PIESA conference, South Africa, 2015.

[46] H. Farhangi, "The Path of The Smart Grid," Journal article, Institute of Electrical and Electronic Engineers (IEEE) power and energy magazine, vol. 8, no. 1, pp. 18-28, 2010.

[47] D. Fritz, "Tying small scale renewable energy systems to the South African grid," *Ernegize*, pp. 62-64, July 2013.

[48] A. Oudalov and A. Fidigatt, "Adaptive Network Protection In Microgrids," Journal article, International Journal of Distributed Energy Resources, vol. 4, no. 3, pp. 2-24, 2008.

[49] A. F. Sarabia, “Impact of distributed generation on distribution system.,” Report, Aalborg University, Aalborg (Denmark), 2011.

[50] South African Local Government Association (SALGA), “Status of Small Scale Embedded Generation (SSEG) In South African Municipalities,” Report, SALGA, Pretoria, 2016.

[51] Shoaib Munuwar, Muhammad Naeem Arbab, Sana Ullal Khan, “Protection of Microgrid by Using Adaptive Relaying Scheme,” Journal article, International Journal of Engineering Works, vol. 4, no. 9, pp. 160-165, 2017.

[52] The Effectiveness of Distribution Protective Working Group of IEEE/PSRC, “Distribution Line Protection Practices-Industry Survey Results,” Journal article, IEEE Transactions on Power Delivery, vol. 3, no. 2, pp. 514-524, 1988.

[53] E. Schweitzer, M. Feltis and A. Elneweihi, “Improved Sensitivity and Security for Distribution Bus and Feeder Relays,” Conference proceedings in IEEE WESCANEX 93 Communications, Computers and Power in the Modern Environment, Saskatoon (Canada), 1993.

[54] Héctor J. Altuve, Karl Zimmerman, and Demetrios Tziouvaras, “Maximizing Line Protection Reliability,,” Conference proceedings in 69th Annual Conference for Protective Relay Engineers, Atlanta, Georgia (U.S.), 2016.

[55] John T. Tengdin, Eric A. Udren, “The 2008 Revision of Institute of Electrical and Electronic Engineers (IEEE) C37.2 Standard Power System Devise Function Numbers, Acronyms and Contact designations,” Report, IEEE PES Substations Workgroup, New York City, 2006.

[56] M.E. Valdes, I. Purkayastha and T. Papallo, “The Basics Of Protective Coordination,” Journal article, IEEE Trans. Ind. Appl. , vol. 40, no. 4, pp. 932-940, 2004.

[57] National Program on Technology Enhanced Learning (NPTEL), Online Lecture, Topic: “Lecture 4: Desirable Atributes of Protection,” NPTEL, [Online]. Available: https://www.google.co.za/search?sourceid=navclient&aq=&oq=Lecture+4%3a+Desir

able+Atributes+of+Protection%2c+Dehli%2c+2016&ie=UTF-8&rlz=1T4PLXB_enZA839ZA839&q=Lecture+4%3a+Desirable+Atributes+of+Protection%2c+Dehli%2c+2016&gs_l=hp....0.0.2.2348807..... [Last Accessed 17 April 2019].

[58] Institute of Electrical and Electronic Engineers, "Feasibility of adaptive protection and control," Journal article, IEEE Transactions on Power Delivery, vol. 8, no. 3, pp. 975 - 983, 1993.

[59] Z. Li, "Study on Adaptive Protection System of Power Supply and Distribution Line," Conference proceedings in 2006 International Conference on Power System Technology, Chongqing (China), 2006.

[60] J. L. Ruiz, "Performance Comparison Of A Permissive Overeach Transfer Trip (POTT) Scheme Over IEC 61850 And Hard-wire," Report, University of Tennessee, Chattanooga, 2012.

[61] A. Lantero, "Energy.gov," Department of energy, 17 June 2014. [Online]. Available: https://www.energy.gov/articles/how-microgrids-work. [Last Accessed 23 February 2019].

[62] A. Y. Abdelaziz, H. Tallat, N. A and A. A. Hajjar, "An Adaptive Protection Scheme for Optimal Overcurrent Relay Coordination in Interconnected Power Systems," Conference proceedings in Seventh International Middle-East Power Systems Conference MEPCON'2000, Egypt, 2001.

[63] B. Kasztenny and K. Kuras, "The Source Concept Considerations in a Protective Relay," Conference proceedings in Protection Relay Conference proceedings, 2007.

[64] Internet of Things Innovation, "IoT Innovation Report," Report, Springwise Intelligence Ltd., New York, 2018.

[65] U.S Department of Energy, "The Internet of Things (IOT) and Energy Management in the Modern Building," Report, U.S Department of Energy, Washington D.C, 2016.

[66] IEEE Power Engineering Societ Substations Committee, “IEEE Trial-Use Recommended Practice for Data Communications Between Intelligent Electronic Devices and Remote Terminal Units in a Substation,” e-Book, IEEE, New York, 2001.

[67] R. Bayindir, I. Colak, G. Fulli and K. Demirtas, “Smart grid technologies and applications,” Journal article, Renewable and Sustainable Energy Reviews, vol. 66, pp. 499-516, 2016.

[68] Institute of Electrical and Electronic Engineers, “Processes, Issues,Trends and Quality Control of Relay settings,” Report, IEEE press, New York, 2007.

[69] OMICRON, “OMICRON,” 2019. [Online]. Available: https://www.omicron.jobs/en/. [Last Accessed 28 February 2019].

[70] Y. Rangelov, N. Nikolaev and M. Ivanova, “The IEC 61850 standard — Communication networks and automation systems from an electrical engineering point of view,” Conference proceedings in 19th International Symposium on Electrical Appaaratus and Technologies (SIELA), 2016.

[71] H. J. Rodriguez, C. Wester, D. Baigent, L. Frisk, S. Kunsman and L. Hossenlop, “First IEC 61850 Multivendor Project in the USA,” Report, IEEE Press, New York, 2016.

[72] Bill Brown; P.E Jay Guditis; Square D Critical Power Competency Cente, “Critical-Power Automatic Transfer Systems – Design and Application,” Report, Schneider Electric, Johannesburg, 2006.

[73] K. Kauhaniemi and L. Kumpulainen, “Impact of distributed generation on the protection of distribution networks,” Conference proceedings in 2004 Eighth IEE International Conference on Developments in Power System Protection, Amsterdam (Netherlands), 2004.

[74] Eskom, “Eskom Homepage,” Eskom, 2018. [Online]. Available: http://www.eskom.co.za/. [Last Accessed 23 February 2019].

[75] T. Davis, P"rotection of Industrial Power Systems," Book, Oxford: Pergamon Press, 1998.

[76] J. Horak, “Directional Overcurrent Relaying concept,” Conference proceedings in 59th Annual Conference for Protective Relay Engineers, Texas, 2006.

[77] H. Stutvoet, “Generator operation modes,” 2016. [Online]. Available: https://www.svri.nl/en/generator-operation-modes/. [Last Accessed 2019 February 2019].

[78] H. Zhen, X. Zhang and J. X. Qi, “An adaptive protection scheme based on topology-recognition for shipboard electrical power systems,” Article in periodical, Energy Procedia, pp. 2902-2908, January 2011.

[79] A. N. Sarwade, “A New Adaptive Technique for Enhancement of Zone-2 Settings of Distance Relay,” Journal article, Energy and power engineering, vol. 4, no. 1, 2012.

[80] Institute of Electrical and Electronic Engineers, "C37.113-2015 - IEEE Guide for Protective Relay Applications to Transmission Lines," Standard, New York: IEEE, 2016.

[81] Institute of Electrical and Electronic Engineers, "C37.230-2007 - IEEE Guide for Protective Relay Applications to Distribution Lines," Standard, New Tork: IEEE, 2008.

[82] C, Dinakaran, ""Study of a Cogeneration plant in sugar mill by using Bagass as a fuel," Journal article, International Electrical Engineering Journal (IEEJ), vol. 7, No. 6, 2016.

[83] P. A. Brownsort, “BIiomass Pyrolysis Processes: Performance Parameters and Their Influence on Biochar System Benefits,” Report, University of Eidenburgh, Eidenburgh (U.K), 2009.

[84] A. Pandarum, “Trends and statistics of Solar PV Distributed Generation in South Africa,” Presentation in SA Energy storage, Eskom, Johannesburg, 2018.

[85] Gitbook, "ALSTOM Cdd21 Relay Manual," 2017. [Online]. Available: https://legacy.gitbook.com/book/elimtermoole/alstom-cdd-21-relay-manual/details. [Last Accessed 24 March 2019].

[86] manualslib.com, "Feeder protection and control REF615 product guide," Manuals lab, 2018.

[87] Constant Power Loads (CPL) Engineering Ltd, "Electric power distribution systems," *Energies,* vol. 10, no. 1656, pp. 1-20, 2017.

[88] M. Ovaere, "Electricity Transmission Reliability Management," Report, Economics, International Association for Energy, Cleveland, Ohio, 2016.

[89] The New Zealand Electricity Authority, "Grid Reliability Standards," The New Zealand Electricity Authority, 2019. [Online]. Available: https://www.ea.govt.nz/operations/transmission/grid-reliability-standards/. [Last Accessed 18 April 2019].