Cape Peninsula University of Technology

INVESTIGATION OF THE APPLICATION OF IEC61850 STANDARD IN DISTRIBUTION BUSBAR PROTECTION SCHEMES

by

Mkhululi Elvis Siyanda Mnguni

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Supervisor: Prof. R. Tzoneva
Co-supervisor: Prof. P. Petev

Bellville campus

DECLARATION

I, Mkhululi Elvis Siyanda Mnguni, declare that the contents of this dissertation/thesis represent my own unaided work, and that the dissertation/thesis has not previously been submitted for academic examination towards any qualification. Furthermore, it represents my own opinions and not necessarily those of the Cape Peninsula University of Technology.

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ABSTRACT

Busbars are the most important components in the distribution networks. Faults on the busbar are uncommon, however an occurrence of a busbar fault can lead to a major loss of power. Busbars are the areas in a substation where the levels of current are high and therefore the protective relay application is very critical. In order for the protection scheme to be successful it is important to carry out the following specifications: Selectivity, Stability, Sensitivity, and Speed. To meet all of the above requirements protection must be reliable, meaning that the protection scheme must trip when called up to do so (dependability) and it must not trip when it's not supposed to (security).

The thesis focuses on the reverse blocking busbar protection scheme with aim to improve the speed of its operation and at the same time to increase operational reliability, flexibility and stability of the protection during external and internal faults by implementation of the extended functionality provided by the IEC61850 standard-based protective IEDs. The practical implementation of the scheme by the use of IEC 61850 standard communication protocol is investigated. The research analyzes in detail the reverse blocking busbar protection scheme that is used at the moment in the power systems and it develops an improved IEC 61850 based reverse blocking busbar protection scheme for a distribution network. The proposed scheme is designed for a radial type of a distribution network and is modeled and simulated in the DigSILENT software environment for various faults on the busbar and its outgoing feeders. The results from the simulations are used further for implementation of the designed protection scheme.

A laboratory test bench is build using three compliant with the IEC 61850 standard ABB IEDs 670 series, CMC 356 Omicron test injection device, PC, MOXA switch, and a DC power supplier. Two ways of the reverse blocking signals between the IEDs implementation are considered: hard wired and Ethernet communication by using IEC 61850 standard GOOSE messages.

Comparative experimental study of the operational trip response speed of the two implementation shows that the performance of the protection scheme for the case of Ethernet communication is better

The thesis findings and deliverables will be used for postgraduate studies of other students, research, short courses, and solution of industrial problems.

Keywords: Busbar, Power system, reverse busbar blocking scheme; IEC61850; Distribution, Protection relays, IEDs, GOOSE message, laboratory test bench

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All my colleagues at CSAEMS for the support

DEDICATION

This thesis is dedicated to my mother **Nomsa Mnguni** and my daughter **Naledi.** Further dedication goes to my grand-mother **N.S Sokhela** and to the entire family for all their committed support and patience.

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GLOSSARY

Current Transformer - A device that transforms current from one magnitude to another magnitude

Discrimination - The ability of two or more protection systems to decide which one should react to a certain fault and then take corrective action.

GOOSE - is a high performance multi-cast messaging service for inter-IED communications, and is used for fast transmission of substation events.

Interchange ability - Ability to replace an IED with a different IED from a different vendor without any impact.

Interoperability - Ability of two or more IEDs, regardless of the vendor, to exchange information and use that information for correct execution of specified functions.

Supervisory Control and Data Acquisition - is a process control system that enables a system operator to monitor and control processes distributed among various remote sites.

Numerical Relay - A relay capable of acquiring instantaneous samples of voltage and/or current and process them using a mathematical algorithm

Substation Configuration description Language - is a description language for communication in electrical substations related to the IEDs.

Voltage Transformer - A device that transforms voltage from one magnitude to another magnitude

Busbar - A common connection point in a distribution network substation

Distribution -The conveyance of electricity through a distribution network

Protection system - A system, which includes equipment, used to protect facilities from damage due to an electrical or mechanical fault or due to certain conditions of the power system.

GOOSE	-	Generic Object Orientated Substation Event
CT	-	Current Transformer
HV	-	High Voltage
IEC	-	International Electrotechnical Commission
IEDs	-	Intelligent Electronic Devices
SAS	-	Substation Automation System
SCL	-	Substation Configuration Language
SCADA	-	Supervisory Control and Data Acquisition
VT	-	Voltage Transformer
VDM	-	Vector Diagram Monitor
A/D	-	Analogue to Digital
UCA	-	Utility Communication Architecture
CU	-	Central Unit
MMI	-	Man Machine Interface
SV		Sample Value
LAN	-	Local Area Network
PCB	-	Printed Circuit Board
PIOC	-	Instantaneous Phase Overcurrent Protection
EFPIOC	-	Instantaneous Residual Overcurrent Protection
OC4PTOC	-	Four Step Phase Overcurrent Protection
EF4PTOC	-	Four Step Residual Overcurrent Protection
SMAI	-	Signal Matrix Analog Input
SMBI	-	Signal Matrix for Binary Inputs
SMBO	-	Signal Matrix for Binary Outputs
CMMXU	-	A function block used for measuring phase current
VMMXU	-	Function block used for measuring phase - phase voltages
A1DADR	-	Disturbance Report for Analog Signals
B1RBDR	-	Disturbance Report for Binary Signals
GOOSEBINRCV		Goose Binary Receive function block

Nomenclature

VA Is the volt-ampere burden

I Is the amperes

V Is Volts

t Is the trip time.

TMS Is Time Multiplier Setting.

I_r Is the current setting

E_R Is Relay timing error (IEC 60255-4)

E_{CT} Is the CT ratio error (%)

t Is the operating time of relay nearer the fault (s)

t_{CB} Is the CB interruption time (s)

t_o Is relay overshoot time (s)

t_s Is safety margin (s)

V_n Is the nominal voltage

V_B Is the base voltage

S_b Is the apparent power

Z_f Is the impedance of the network feeder in ohms

R_f Is the resistance of the network feeder in ohms

X_f Is the reactance of the network feeder in ohms

V_n Is the nominal voltage at the connection point

S_f Is the fault level of the network feeder (VA)

c Is the voltage factor

R Is the resistance of the network

X Is the reactance of the network

X_d'' Is the sub-transient reactance of the generator in ohms

R_g Is the resistance of the generator in ohms

K_g Is the voltage correction factor in per unit

x_d'' Is the per unit sub transient reactance of the generator in per unit

V_g Is the nominal generator voltage

V_n Is the nominal system voltage

S_g Is the rated generator capacity

$\sin\theta_g$ Is the power factor of the generator in per unit

Z_t Is the positive sequence impedance of the transformer in ohms

R_t Is the resistance of the transformer in ohms

X_t Is the reactance of the transformer in ohms

u_k Is the impedance voltage of the transformer

S_t is the rated capacity of the transformer

V_t Is the nominal voltage of the transformer at the high or low side

I_t is the rated current of the transformer at the high or low side

P_{kt} Is the total copper loss in the transformer windings

R_c Is the resistance of the cable in ohms

X_c Is the reactance of the cable in ohms

R Is the quoted resistance of the cable in ohms per km

X Is the quoted reactance of the cable in ohms per km

L_c Is the length of the cable

n Is the transformer ratio

V_{t2} Is the transformer nominal secondary voltage

V_{t1} Is the transformer nominal primary voltage

t_p Is the specified tap setting

Z_{HV} Is the impedance referred to the primary (HV)

Z_{LV} Is the impedance at the secondary (LV)

I_k'' Is the initial symmetrical short current

I_P Is peak short circuit current

k Is the constant factor

c Is the voltage factor

V_n Is the nominal voltage at the short circuit location

Z_k Is the equivalent short circuit impedance

$Z_{k(1)}$ Is the equivalent positive sequence short circuit impedance

$Z_{k(2)}$ Is the equivalent negative sequence short circuit impedance

$Z_{k(0)}$ Is the equivalent zero sequence short circuit impedance

k Is an adjustable time multiplier

I Is the measured phase current value

$I \geq$ Is the set start (pickup) current value

α and β are curve set-related parameters

CHAPTER ONE
INTRODUCTION

1.1 Introduction

Power system is designed to generate electric power in sufficient quantity and its aim is not just to be capable to meet the current loads but it must also be flexible to meet future demands. An electric power system is divided into three major divisions which are known as generation, transmission and distribution. Since electric power is generated and transmitted over vast territories and are exposed to all different types of conditions, different types of failures and abnormalities can occur. These can damage the equipment and also can result in substantial loss of power. To avoid this problem each element in the power system should be protected. The ideal function of a protective device is to notice the occurrence of faults and quickly to isolate the fault section from the power system as soon as possible in order to keep it stable.

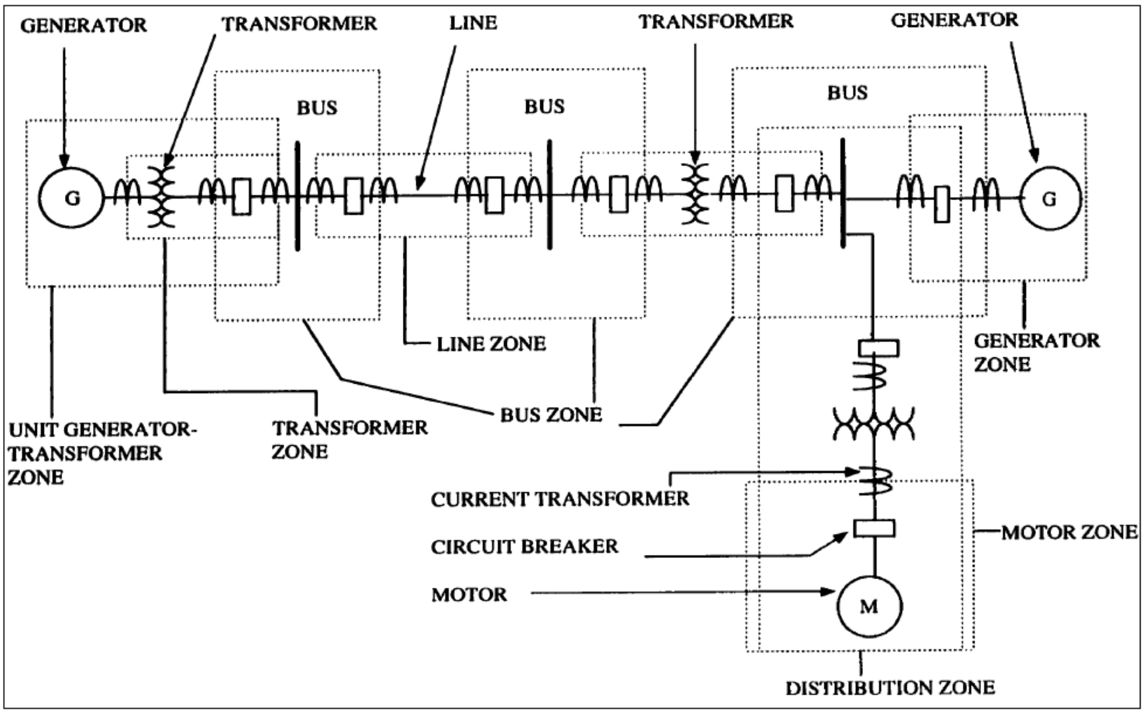

Figure 1.1: **Typical Relay protection zones in a power system (Gill,2000)**

Protection schemes used in power systems must comply with the requirement of the electrical protection standard which requires operational speed, reliability, security, stability and sensitivity and its purpose is to minimize damage when the fault occurs. The equipment used for protection is not designed to prevent the fault in the system but to limit the damage caused by the fault. Electrical power system is separated into protection zones so that it can achieve its objective (protected and stable operation) as shown in Figure 1.1 above. Some of the zones overlap to another zone to make sure that the system is protected. In each zone there is a major element that is protected using a protective relays (Warrington, 1978).These relays are responsible for protecting the zone by opening circuit breakers so that the zone is disconnected from the remaining system when a fault occurs.

A well designed protection scheme must be able to protect the entire power system Unrestricted forms of line protection, such as overcurrent and distance schemes, meet this requirement, although faults in the busbar zone are cleared only after some time delay

Line protection scheme that is not limited for example unit and distance protection usually fit the requirement of using them as protection for busbar. A problem with this scheme is when a fault occurs within the busbar zone. It takes longer to clear the fault due to time delay. Since Busbar is one of the critical elements in the power system because all electrical circuits are connected into it (NPAG, 2002). Due to its importance it is required for the busbar to have a fast dedicate protection system. This document describes research done on an existing busbar protection scheme by developing an algorithm that is capable of applying IEC61850 standard to improve its speed during internal faults and stability during external faults

This chapter explains the components that are found in power systems. It also covers the importance of a busbar in distribution networks. This chapter also covers the 1.2 Awareness of the problem, 1.3 Instrument transformers, 1.4 Protective relay, 1.5 problems, 1.6 Problem statement, 1.7 Sub-problems, 1.8 Research aim and objectives, 1.9 Objectives, 1.10 Hypothesis, 1.11 Delimitation of research, and 1.12 Motivation for the research project 1.13 Assumptions, 1.14 Research methodology, 1.15 Simulation, 1.16 Data collection and 1.17 Documentation method

1.2 Awareness of the problem

Busbars are the most important components in the distribution networks. Faults on the busbar are uncommon however an occurrence of a busbar fault can lead to a major loss of power. Busbars are the areas in a substation where the levels of current are high and therefore the protective relay application is very critical. Most circuits in the power system are connected to this node (busbar) as shown in Figure 1.2 below and therefore a sufficient protective system is required to protect the busbar in the substation.

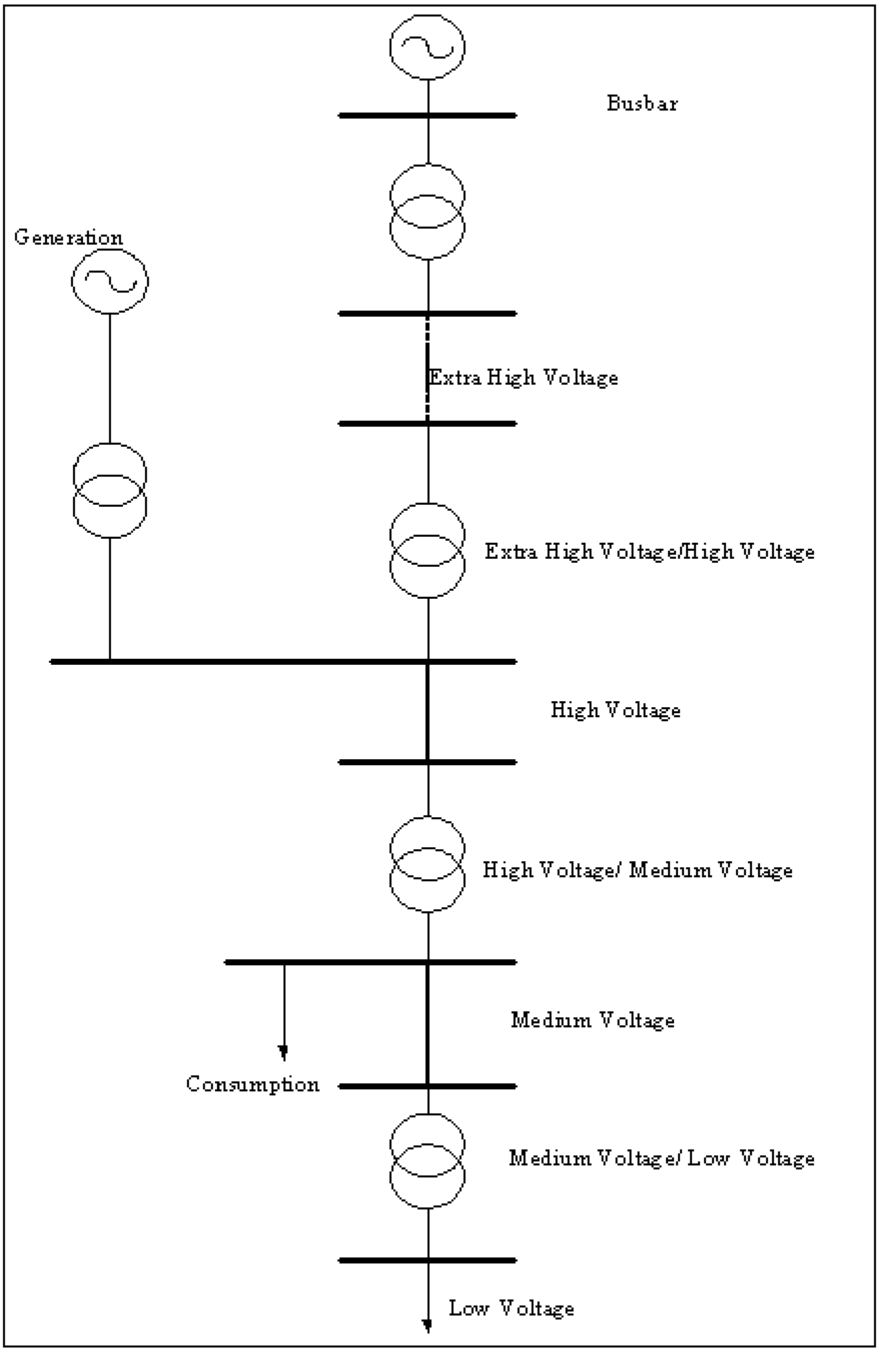

Figure 1.2: Block schematic of a transmission and a distribution system

In a case of a false tripping by a distribution busbar protection, outages will take place for large number of customers and at the same time transmission level busbar may drastically change the system topology, jeopardizing the power systems stability and reliability (Kasztenny and Kuras, 2001). This reminds designers of busbars importance and the need of good protection (Marot, 2004). A busbar protection system should therefore use a scheme with high integrity. The statistics show that the majority of busbar faults are caused by the following reasons (Gill, 2000):

- Insulation failure due to deterioration of material

- Flashover caused by prolonged and excessive overvoltage
- Failure of a circuit breaker to clear fault current leading to its short circuit
- Human error in operating and maintaining switchgear
- Foreign object falling across busbar

1.2.1 Basic requirements for busbar protection

The main concept for busbar protection is to safeguard the entire busbar system, minimize the damage and repair costs where fault occurred, and most importantly to ensure safety of personnel. In order for the protection scheme to be successful it is important to carry out the following specifications:

- Selectivity

To discover the faulty part and then to isolate it, and this requires proper discrimination between zones

- Stability

To leave all healthy circuits intact and make sure continuity of power supply. To be stable for all external faults

- Sensitivity

To detect the lowest fault and irregularities in the system and operate properly

- Speed

To produce a scheme that has fast operation speed in order to minimize danger to the surroundings. The time taken to detect and clear the internal fault on busbar is also critical because the damage depends on the fault duration. The busbar protection therefore must be carefully monitored to prevent inadvertent operations.

To meet all of the above requirements protection must be reliable, meaning that the protection scheme must trip when called up to do so (dependability) and it must not trip when it's not supposed to (security).

1.2.2 Busbar protection types

It is mandatory for a busbar protection scheme to have a good security since an unwanted operation might create severe consequences. A protection scheme that fails to operate or has slow operation in a case of internal fault can actually create a fatal consequences that lead to damaging of the entire busbar (Hodgkiss, 1960).There are several types of bus bar protection schemes namely frame earth protection scheme, arc protection scheme, reverse blocking protection schemes and many more but this thesis only focuses on the reverse blocking scheme for busbar protection.

1.3 Instrument Transformer

Substations use power lines for distribution that run high voltages and also carry high currents. Instrument transformers are connected into these lines and serves as an input source of currents and voltages to relays, meters, and control devices.

1.3.1 Current Transformer

A current transformer is basically a transformer which steps-down the current in a known ratio. The primary side has one or more turns coupled with the distribution line. This connection can be done in series with the distribution line. The secondary side is connected to a relay

1.3.2 Voltage Transformer

It is a device that is used to step-down the voltage of electricity in a known ratio. The primary side of the voltage transformer is connected across the distribution line. The secondary side is linked to the relay with voltage which is a constant fraction of the voltage in the line.

1.4 Protective Relays

It is a device that gives instruction to disconnect a faulty section part and ensures that the remaining system is still fed with power .It is also used for monitoring the system parameters. It can be instructed to operate fast if needed so (dependability) and must not operate incorrectly (discrimination, stability). Each relay is required to protect a specific zone in the system. Short history of the development of various types of the relays is given below (Krishina, 1989).

1.4.1 First generation

- Electromagnetic relays

First generation relays were electromechanical relays and they have major disadvantages that each function of the scheme has a separate relay. They had a lot of mechanical parts that may become corroded because of the environment conditions and this affected their operation. A modification for these relays introduced printed circuit boards (PCBs) with static components to reduce the amount of the relays in a scheme but this modification also came with some disadvantages such as performance.

1.4.2 Second generation

- Static relays

In this all of the relays functions are derived from electronic components provided on the printed circuit boards (PCB). Inter connection wiring diagram is still not reduced. Their disadvantages are that they use large amount of electronic components made by different manufacturers. If these electronic components are not tested with quality control, the chances of failure during relay life time are high.

1.4.3 Third generation

- Static relays with Integrated Circuits (ICs)

With these relays a number of components were reduced because components were built in one integrated chip and the relay size was also reduced. The advantage that came with the modification was that the relay became semi numeric and some functions can be programmable by means of interfacing them through a computer.

1.4.4 Fourth generation

- Microprocessor based relays

These relays brought all functions in one IC and have monitor feature which facilitates power supply failure, clock frequencies and other patterns such as auto test for electronic circuits functions that are used regularly .They have several advantages and the most important one is that they have improved speed of operation compared to conventional relays. Later it was discovered that the software had some problems and some modification was needed to be developed. Each protection relay function had separate software and hardware. Several developments were done such as the same protection functions were taken to one platform to provide common software and from here the developers moved to universal software for all types of relays for a particular manufacturer. The developments continue towards universal hardware and each manufacturer acquired proprietary based protocol for communication.

Then the issue was how to suit the acquired different protocols to accomplish a new development. A need for one standard with universal protocol for communication was considered. The International Electrotechnical Commission (IEC) formed a group where the protocols were standardized creating an environment where relays can communicated using common protocol. The new standard IEC 61850 was developed. (De Mesmaeker et al., 2005)

1.5 Problems and a need for future developments

A well designed protection scheme of the busbar in power system must be able to cover the whole busbar against all types of faults. Line and distance protection can be used as a busbar protection even though it will not work well when a fault occurs in busbar zone due to time delay to clear the fault. This is a problem when an internal fault occurs because when unit protection is applied to feeders the busbars are not protected and protection engineers tend to overlook this problem. Therefore a dedicated protection scheme that is fast during internal faults and stable during external faults for busbars in distribution level is highly needed (NPAG, 2002). It has been discovered that the area of digital busbar protection research has not been active and it is stated that a little work has been done on the development of algorithms suitable for protecting busbars at distribution level (Gill, 2000). Another concern for busbar protection is the current transformer saturation and most algorithms that proposed solutions in the past for busbar protection dealt with CT saturation problem by introducing a special circuitry. The main issue with introducing an additional circuitry in the protection scheme is that it increases its complexity. This also increases the possibility of incorrect protection and low stability due to multifunction of its components. Another problem is that the increase of number of components in protection schemes increases the cost and therefore destroys the purpose to build cheap and stable protection scheme that is easy to implement. Some circuits connected to the busbar may have their current transformers rated insufficient. This creates a danger of CT saturation and this will threaten the security of busbar protection. From the previous research it was discovered that there are no schemes with inherent immunity to CT saturation (Gill, 2000), (Kasztenny and Kuras, 2001).

From the previous research it was also discovered that the principle of high-impedance busbar protection faces major problems when applied to complex busbar arrangements. When this protection is applied on busbar the zones of protection are often required to adjust their boundaries based on changing of busbar configuration, therefore switching secondary currents. This operation is never considered safe and should be avoided whenever possible (Brunello, 2003).Digital busbar protection schemes for medium and large voltages were not attractive to users until recently. The reasons behind this were that the schemes available in the market were expensive, difficult to apply, and were considerably slow. Due to modern digital relays all these factors have changed because the digital relays are much faster, with better algorithms for security and became affordable after introduction in late 2001 and early 2002 of a phase-segregated microprocessor-based busbar relay (Brunello, 2003).

The thesis focuses on the reverse blocking busbar protection scheme with aim to improve the speed of its operation and at the same time to increase operational reliability, flexibility and stability of the protection during external and internal faults by implementation of the extended functionality provided by the IEC61850 standard-based protective IEDs. The thesis also investigates the practical implementation of the scheme by the use of IEC 61850 standard communication protocol. The developed algorithms are simple to be implemented and provide better performance.

1.6 Problem statement

There are various algorithms that have been proposed in the past to improve reverse blocking busbar protection scheme but most of them are still using hardwiring connection such as copper wire for sending blocking signals. The problem is that the hardwired system creates a propagation time delay for the blocking signal. Some solutions to this time delayed blocking signals involve additional circuitries and this creates multifunction in the schemes, which leads to problems with stability, more especially during external faults, and lack of speed when it comes to internal faults. By making use of the new technology a new algorithm can be developed by implementation of the IEC 61850 standard for implementation of the busbar protection schemes as a new solution of these protection problems.

Problem statement: To investigate the application of the IEC61850 standard in the distribution busbar protection scheme and to improve flexibility of the scheme, circuit stability when there is an external fault, the protection action speed when there is an internal fault, and also to improve the performance of the distribution busbar protection by development of reliable and cost effective algorithms

1.7 Sub-Problems

1.7.1 Design and implementation of a work station

Produce a Laboratory test-bench developed to simulate a substation environment including all the components that are needed for the implementation of the IEC 61850 standard application.

1.7.2 Development a model for the reverse blocking scheme for busbar protection

Busbars using the current protection element for reverse blocking schemes are investigated. Development and performing simulation case study for the existing hardwired reverse blocking protection scheme using appropriate simulation software. Analysis of the simulation results and a new algorithm is development for the improvement of the current scheme.

1.7.3 Improved busbar protection scheme analysis in DigSILENT environment

A case study on current busbar protection with devices that are non-compliant to IEC 61850 standard. Investigations based on the scheme requirements. Second case study: The investigation is based on devices that are IEC 61850 standard compliant. Verification of the application efficiency and setting issued for the protective devices.

1.7.4 Investigation of the reliability of the reverse blocking scheme for busbar protection

Protection equipment that fails to be stable during external faults and fails to discriminate under fault conditions can create serious problems for the power system through increased disruption. The reliability of the protection scheme is investigated.

1.7.5 Development of methods for relay setting and calculation

Relay settings are calculated in order to provide good protection for the busbar and that of the maintenance personnel. Time and setting of relays are made by selecting the proper current tap and adjusting the time dial to the number which corresponds to the characteristics required.

1.7.6 Fault analysis

Internal and external types of fault are applied within the busbar in order to analyze the protection scheme employed. A minimum single to phase and maximum three phase faults are simulated in the distribution network where the protection scheme is applied

1.7.7 Real- time implementation on using different software and hardware platforms

A test bench created in the laboratory environment is used to implement the protection scheme. Implementation of the scheme in real-time by using different software tools and hardware platforms as follows:

- Omicron CMC 356

This is used for modeling and signal injection simulation. It consists of the test basic software (including the device database) and the VD Monitor (Vector Diagram Monitor).This equipment is used to operate all the test system's functions with additional VD monitor. Other test monitors are also available to simplify, automate and thus to speed up tests for various types of relay.

- DigSILENT PowerFactory software

This software is used for power systems modeling, simulation and co-ordination of the protection devices

- Protection and Control IED Manager Tool (PCM600)

This software is used for configuration of the ABB Intelligent Electronic Devices (IED) used to build the protection scheme.

- Communication Configuration Tool (CCT600)

This CCT600 software is used to program and configure the IEC 61850 station bus engineering for ABB IEDs used in this project

1.7.8 Comparison between two busbar protection schemes builds with relays from different generation

Comparison of the operating results of the conventional relay used with the current protection scheme and the digital relays with the proposed IEC 61850 standard-based protection schemes. The analyses are based on the elements response results, accuracy, speed, stability, compatibility and the most important cost.

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1.8 Research aim and objectives

The aim of this project is to improve the existing reverse blocking busbar protection scheme by development an algorithm for operation of the scheme that improves flexibility of the scheme, circuit stability when there is an external fault, the protection action speed when there is an internal fault, and also to improve the performance of distribution busbar protection without using additional circuitry .The protection scheme developed must also be easy to implement. This is achieved by application of IEC61850 standard for communication and utilization of GOOSE messaging to improve busbar protection and expand this novel application to the busbar protection field.

1.9 Objectives

The aim stated above is achieved through the following objectives:

- To identify and study reverse blocking busbar protection scheme used in distribution systems.

- To review and analyze the existing literature for busbar protection scheme development.
- To develop a test bench in a laboratory environment for future simulation and experiments.
- To select the best algorithm for busbar protection scheme that is going to be implemented.
- To analyze the IEC 61850 standard-based protection relays available on the market and determine and analyze their functions for busbar protection.
- To select the IEC 61850 standard based protection relays that are going to be used on the thesis developments
- To implement the current reverse blocking busbar protection scheme using the standard based IEDs and investigate its performance
- To develop an algorithm for reverse blocking busbar protection scheme using IEC 61850 standard that is fast and stable during various faults.
- To define the interface performance of IEDs in the busbar protection scheme
- To use simulation package to study the efficiency, speed, sensitivity and reliability of the developed algorithm
- To compare the performance of the current and IEC 61850 standard-based schemes and make recommendations for future improvements

1.10 Hypothesis

A possibility exist for developments of a reliable reverse blocking busbar protection scheme that is stable and reliable for any power distributed network by implementing comprehensive protection audit, developing an algorithm with protection philosophy based on systems requirements, and by conducting protection co-ordination studies. The application of the IEC 61850 standard employs permission digital busbar protection to be done in an intelligent, reliable and cost effective way

1.11 Delimitation of research

The thesis focuses only on the application of IEC61850 in distribution busbar protection scheme. The research analyzes in detail the reverse blocking busbar protection scheme that is used at the moment in the power systems and it develops an improved IEC 61850 based reverse blocking busbar protection scheme. The proposed scheme is modeled, set up using PCM600 and CCT600 software and implemented in a protection laboratory test bench environment. The simulation is based on the analysis of the following:

- Case study for internal faults

- Case study for external faults
- GOOSE communication between the relays

Comparison of the performance of the existing and proposed reverse blocking busbar protection scheme implemented by the IEC61850 standard based relays is done. The following protection schemes are not included in the research investigations of the thesis:

- Arc protection scheme
- Frame- earth protection scheme
- Phase comparison protection scheme
- Directional blocking protection scheme
- Differential Protection scheme

1.12 Motivation for the research project

The fundamental need of our society is cost effective and without interruptions electricity. This electricity is generated, transmitted and distributed making use of different topologies responsible for transporting energy over short and long distances to the end-consumers. The nodes where voltage transformation and routing of energy flow is done by means of the installed switchgear are called substations. Some of these power grids are controlled by supervisory control and data acquisition (SCADA) systems which support energy trading and access to substation equipment and are controlled by substation automation systems (SAS). Since unintentional power outages can be a problem SAS is composed of electronic equipment that is used to continuously control, monitor and protect the equipment in the substation. SAS can be defined as a distributed soft real-time system. It represents one possible type of a data acquisition and process control system composed of Intelligent Electronic Devices (IED).These IEDs are connected by a high-speed communications network with possibly routers and gateways (Preiss and Wegmann, 2003).

IEC61850 has become a global standard for communication and integration of the IEDs. With development of the new digital technology for protection, the researchers have made a good significant achievement in the development of suitable algorithms for the application of the IEC61850 standards-based relays. These algorithms apply principles similar to these of their electromechanical counterparts. Substantial improvements have taken place in transmission line and transformer protection but busbar protection using digital techniques has received almost no attention (Gill, 2000).A literature survey has revealed that very few algorithms for protection busbar have been proposed in the past especially at the distribution level. The previous schemes have issues with speed and stability. Some proposed solutions for this problem make use of additional circuitries that jeopardize stability in the system and some solutions are not fast enough to clear the fault when it comes to the internal faults. These challenging problems motivated the decision to investigate the application of IEC61850 standard on distributed busbar scheme protection.

1.13 Assumptions

Based on the research that has been done till now in the field, the following assumptions are used:

- GOOSE communication is faster than wired based communication.
- The co-ordination for protection should be in such a manner that the relay closest to the fault should operate first.
- The shortest operating time should be at the relay nearest to the fault
- The disruption of the system due to the fault should be minimum
- The other relays must have enough additional operating time to prevent them from operation
- It is possibly to provide a fast fault clearance say <10ms for large current.

1.14 Research Design and Methodology

The research aim is to develop an algorithm that is meant to improve the reverse blocking busbar protection scheme and focuses on three components namely improving hardwiring, stability during external fault and speed (time taken to clear the fault) for internal fault on a busbar. Making use of the new IEC61850 standard-based technology the above objective can be met. The research methods that will be used in achieving the thesis aim are:

1.14.1 Literature review

Since there are several schemes used for busbar protection a detailed research focuses only on reverse blocking busbar protection scheme. The information is gathered by reading IEEE published journals, related books, interview with specialist engineers, and through Internet.

1.14.2 Methods for protection

Due to the fact that there are several busbar protection schemes, one scheme was selected which is reverse blocking busbar protection scheme for the thesis and the reason this particular scheme was selected is because of the following:

- It is currently the best scheme to use for busbar protection compared to other existing schemes.
- When it comes to external faults it has better performance in terms of stability than the other schemes.
- When it comes to internal fault it has better performance in terms of speed than other schemes.
- The methods to be used in the commissioning of the scheme will also be provided.

1.14.3 Simulation

Simulation software is used to analyze the protection scheme making use of one line diagram for modeling of all protection components. The analyzed model includes the architecture of the power system to be protected as well as the selection of the model of IEDs that are used to implement the functions and the communication within the protection scheme other. Making use of the new technology digital relays have made possible several alternative tools to be used in order to protect, collect, store, and distribute the power system information in an efficient and economical manner. For this thesis the protection functions of the Intelligent Electronic Devices (IED) that are used are based on specific vendor algorithms meaning that the effects of these IEDs on the system is studied and mathematical model of each is implemented. A one line diagram of a distribution network is simulated using DIgSILENT, and for IEDs programming PCM600 and CCT600 software are used. A test bench in the laboratory environment is developed for simulation and practical work.

1.14.4 Data collection

The simulation results are conducted in order to collect practical protection data for the conventional reverse blocking busbar protection scheme and for the IEC 61850 standard-based protection scheme. Comparison between the above two schemes data is done to perform an effective assessment of busbar protection in distribution systems

1.15 Thesis chapters

The documentation of the research investigations is divided into seven chapters and two appendixes as follows:

1.15.1 Chapter One

This chapter explains the components that are found in power systems. It also covers the importance of a busbar protection in distribution networks. The awareness of the problem, problem statement, research objectives, and motivation for the research work, hypothesis, and delimitation of research, assumptions, and research methodology are described.

1.15.2 Chapter Two

This chapter reviews the literature of busbar protection used in power systems.It explains the different methods that were used to improve the busbar protection. Various papers and articles based on busbar protection were reviewed and compared.

1.15.3 Chapter Three

This chapter explains a detailed busbar protection theory in the distribution network level. It also describes the busbar protection schemes that are currently in use and in operation. The theory of overcurrent protection devices is also explained. The digital busbar protection schemes are also covered.

1.15.4 Chapter Four

This chapter describes a detailed configuration of busbar protection scheme at a distribution level. The distribution network that is modeled and used as a simulation base for overcurrent protection is described. The protection for this network is only based on the busbar distribution level. The network consists of one income source that supplies two different feeders. Different types of faults are analyzed making use of DigSILENT software package. This chapter also describes the design of the protection algorithm parameters and investigation of the protection scheme operation using different types of faults applied to the network. Simulations are done for both conventional and IEC 61850 standard based relays. The effect of fault clearing times on the stability of the network during different fault levels is analyzed. The protection device time grading and co-ordination setting are analyzed.

1.15.5 Chapter Five

This chapter explains the importance of process engineering and basic aspects of the IEC 61850 standard utilized by the ABB 670 IEDs. The effect of using Ethernet networks and IEC 61850 protocols for protection, integration, and automation. The use of IEC 61850 GOOSE messages to communicate high-speed information between ABB 670 IED’s is analyzed.

1.15.6 Chapter Six

This chapter describes development of a laboratory test bench and experiments done in it to investigate the operation performance of the implemented reverse blocking protection scheme for the two cases of communication of data between the IED hard-wired and Ethernet GOOSE messages. A laboratory test bench was developed to investigate and compare conventional hard-wired and GOOSE communication-based blocking signals. A distribution busbar reverse blocking scheme was designed and modeled for the laboratory test bench. This test bench was utilized to improve the performance and reliability of the busbar reverse interlocking scheme at the distribution level. The same power network used in Chapter four is used for these practical studies.

1.15.7 Chapter Seven

The results obtained, the key findings, and the thesis deliverables are summarized in this chapter. The recommendations for possible future work and the extension of the project is also discussed in this chapter.

1.15.7 Appendix A

This Appendix describes the software tool package used for IED configuration and all ABB 670 series function blocks that were used to build the reverse blocking protection scheme. These blocks are described in different categories which are based on their functions.

1.15.8 Appendix B

This Appendix shows all the settings for the IED configuration and all ABB 670 series function blocks that were used to build the reverse blocking protection scheme.

1.19 Conclusion

Different types of components that are found in power systems are explained and analysed. The importance of a busbar protection in distribution networks is described. In the next chapter the literature of busbar protection in power systems is described and different types of papers and articles based on busbar protection are reviewed

CHAPTER TWO
LITERATURE REVIEW

2.1 Introduction

Busbars are one of the important elements as they are used as a central point for distribution in the power system. If a fault occurs on the busbar all components connected to it will therefore be interrupted. Due to a high magnitude of currents caused by the fault a high-speed operation of the busbar protection scheme is required to limit equipment from being damaged. It is necessary to provide an effective protection scheme that will be dedicated for the busbar. However, this high-speed clearing of the fault must be balanced and able to discriminate between external and internal faults. Incorrect tripping for a fault may cause large outages, and jeopardize power system stability. Previous researchers discovered that during high fault magnitudes the possibilities of CT saturation are high which results to an incorrect operation of the busbar protection scheme (Eissa, 2004). Faults on busbars do not occur frequently. They only represent small percentage (6-7%) of fault in power system (Hodgkiss 1960) (Andersson and Hill, 1999). It is true that the numbers of faults that can occur within the busbars are minimum but they cannot be completely neglected. If a fault occurs on the busbar it may cause damage to equipment and injure personnel. In order to avoid these issue protective devices such as relays should be employed to trip the circuit breakers for isolating of the faulted area from the power system. The protection scheme in the power system should be designed in such a manner that it must cover the whole system from all type of faults (Gill, 2000).

A literature survey has revealed that different bus configurations, current transformer saturation, speed and stability are the factors that make the busbar protection scheme complicated. Making use of digital technology, researchers have made progress in developing suitable algorithms for the use in the microprocessor based relays and these developed algorithms are based on the same principles as their counterpart electromechanical relays. Progressive improvement using digital techniques has been done in other elements of the power system but busbar protection has received almost no attention (Schweitzer, 1996).

From previous research it can be revealed that a few algorithms for busbar protection have been proposed and they have not found a good solution when it concerns speed, future proof and other factors involved such as stability during external faults and speed during internal faults. The objective of this literature review is to examine the aspects that relate to busbar protection.

This chapter presents a review of the existing literature of busbar protection that is used in power systems. It compares and analyzes the different methods that were developed and used to improve the busbar protection. In 2.2 the requirements toward operation of the busbar protection schemes are explained, 2.3 cover the different types of busbar protection. In 2.4 the overview of different bus configurations is covered. In section 2.5 the techniques employed for busbar protection are explained, section 2.6 covers the problems for the current transformers saturation. The importance and the benefits of the IEC 61850 standard-based digital relays are shown in 2.7, a literature review of the existing papers for busbar protection is presented in 2.8. Lastly section 2.9 presents the review discussions and gives conclusion.

2.2 Requirements towards operation of the busbar protection

Busbar protection requires high standards of protection. A failure-to-trip during internal fault and false tripping of a busbar in the course of the load service can cause complete blackouts. During external faults the busbar protection scheme needs to be stable. Therefore slow clearing of fault can produce an additional wide damage at the location of the fault. This can lead to high attention of short circuit power at the station buses. It is therefore essential to strengthen the need of speed and stability in the busbar protection schemes. (Funk and Ziegler, 1997).

2.3 Different types of busbar protection

Busbars were often left out without any dedicated protection due to the understanding that they have high degree of reliability. They were considered as safe. It was also accepted that back up protection would provide sufficient busbar protection if applicable. These protection methods had various problems and one of them is that they cannot distinguish between external or internal busbar faults. This required that the protection algorithm that takes care for both types of faults had to be implemented. These protection schemes for a busbar should cover the whole busbar against all types of faults

A line protection that is not restricted such as overcurrent and distances ones usually meets this requirement, but when it comes to busbar internal faults, time taken to clear the fault becomes a problem (Gill, 2000). When a unit protection scheme is employed to feeders, busbars are partly protected and this leads to the busbars are left without a specific protection (Hodgkiss, 1960). A good busbars protection scheme demands high speed operation, reliability and stability. If it fails to operate during an internal fault or false trip and is not stable during external faults a disastrous effect on the power system can happen, creating complete blackout (Eissa, 2004).

2.4 Different bus configurations

Different types of bus configurations are used in power systems. They are utilized for transmission, distribution and switching substations at voltages up to 345 kV. The bus layout is based on arrangement of equipment within the substation and can vary according to the number of circuits and voltage levels connected to. The busbar configurations can be as follows (Bulletin, 2001)

2.4.1 Radial bus

A radial bus configuration is shown in Figure 2.1 below. It consists of one main bus that has power at all times and all circuits are connected to it. This configuration is the simplest, but provides the least amount of system reliability. When a bus faults or failure of circuit breakers to operate under fault conditions occur, and these conditions are not cleared, they can result in complete loss of the substation. This radial bus configuration is generally limited to distribution and sub transmission voltage levels (Nack, 2005).

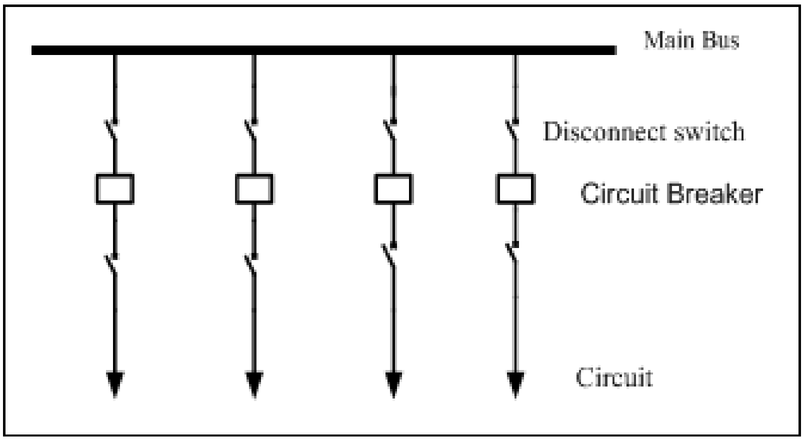

Figure 2.1: The Radial bus configuration (Bulletin, 2001).

Radial bus configuration has few advantages in terms of being the cheapest, and small land area is required. It is easily expandable and also has simple operation. The most important advantage for the radial bus is that the application of protective relaying is simple. The disadvantage of the single bus is lowest reliability and if the failure of the circuit breaker or the fault on the busbar is not cleared, causes loss of the entire substation.

2.4.2 Main and transfer busbars

This configuration consists of two independent buses as shown in Figure 2.2, namely a main and a transfer busbars. The main bus is normally energized. All incoming and outgoing circuits are fed from the main bus through their associated circuit breakers and switches under normal operating conditions. The advantage of this configuration is that any circuit breaker can be removed from service for maintenance without creating any outages. It is also easy to expand if needed. The problems that are encountered for using this configuration are the increase cost in comparison to the radial bus, complexity of operation and have low reliability (Nack, 2005).

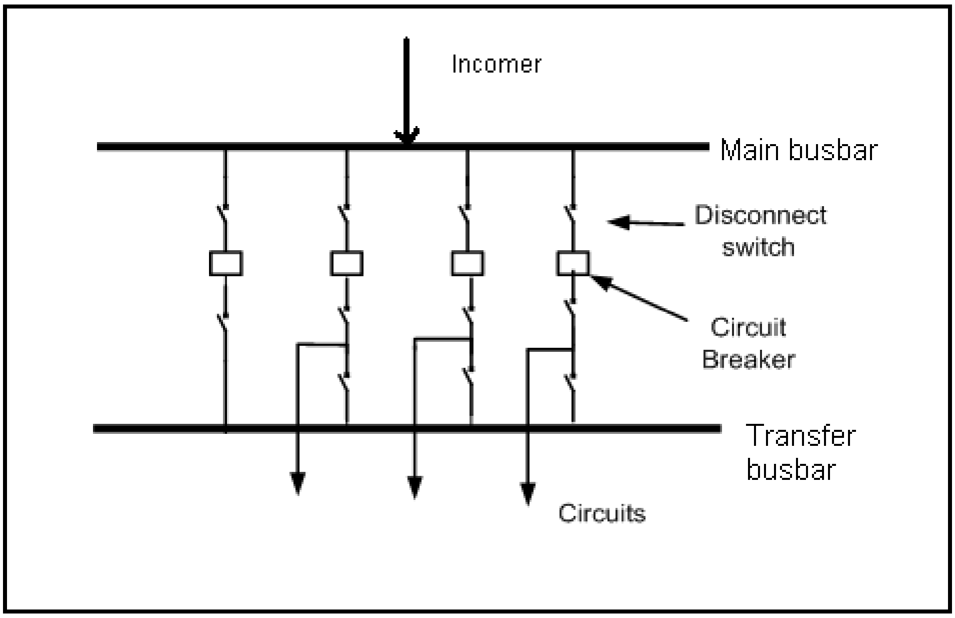

Figure 2.2: **The main and transfer bus configuration (Bulletin, 2001).**

2.4.3 Double Breaker double bus

This busbar configuration has two main buses-each energized during normal operation as shown in Figure 2.3. It is configured in such a way that each circuit requires two breakers to add more reliability. This configuration is only used in large generation stations (Nack, 2005).The advantage of this busbar configuration is that no interruption of service to any circuits due to busbar fault and it has double feed to each circuit. The disadvantage of this configuration is that two circuit breakers are required for each circuit and this carries high cost.

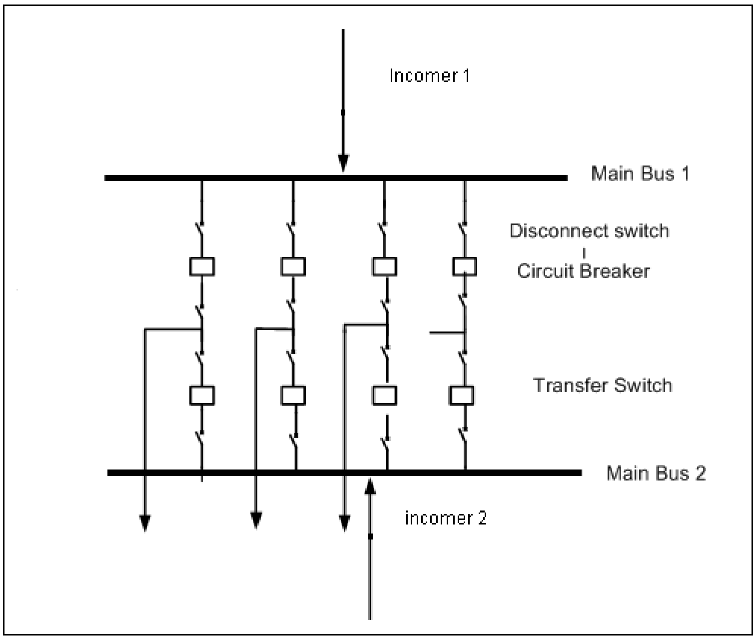

Figure 2.3: **Double breaker double bus configuration (Bulletin, 2001).**

2.4.4 Ring busbars

A ring busbar configuration is accomplished by interconnecting the two open ends of the buses through another sectionalizing breaker as shown in Figure 2.4. This results in a ring with each bus section separated by a circuit breaker. Separate circuit breaker bypass services are not required in this case. This bus configuration has high reliability and its operation is flexible. The main advantage of the ring busbar is that any breaker can be removed from the service for maintenance without causing any power blackouts in the system. The problem for a ring bus is that each circuit has to have its own power (Nack, 2005).

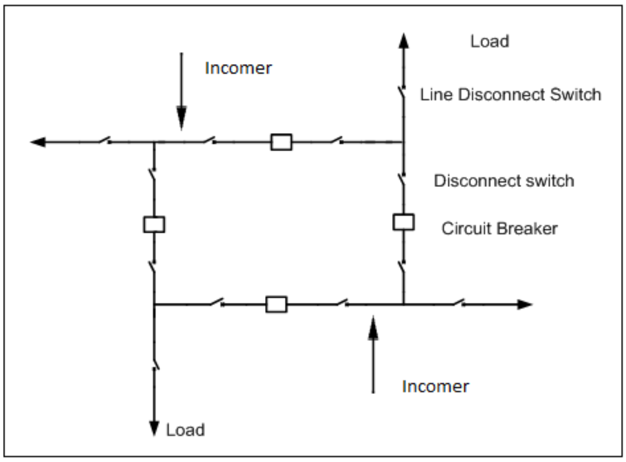

Figure 2.4: **The Ring Bus Configuration (Bulletin, 2001).**

2.4.5 Breaker and a Half

This configuration consists of two main buses as shown in Figure 2.5, each normally energized during normal operation. It is configured in such a way that every two circuits have three breakers where each line is connected to the center circuit breaker. This type of configuration is commonly used when a ring busbar is upgraded in order to provide more terminals. This configuration has high reliability and any breaker can be removed from service during maintenance without an outage to the system. The disadvantages of this configuration are that it requires a large land area, it is expensive, and control and protective relaying is complex (Nack, 2005).

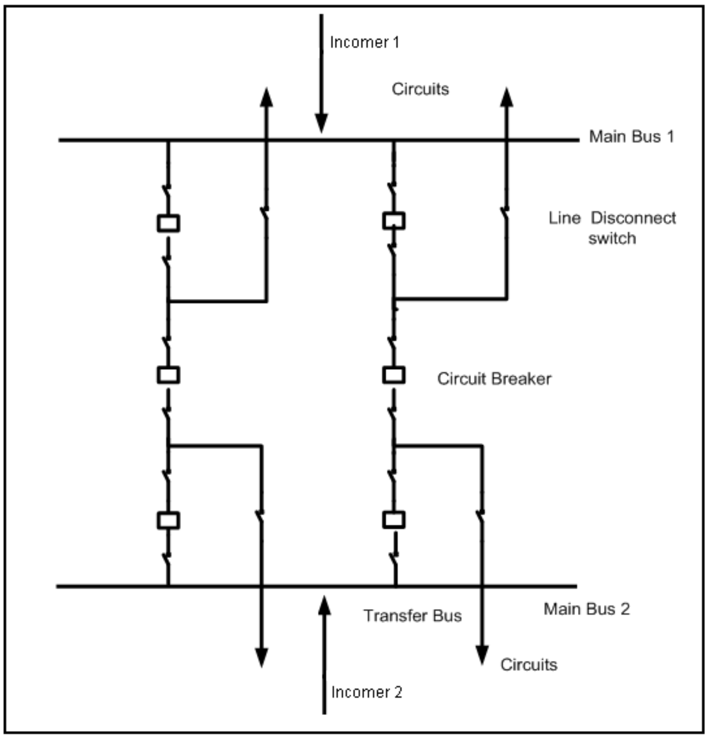

Figure 2.5: **The Breaker and a half configuration (Bulletin, 2001).**

2.5 Busbar Protection Techniques

A protection technique employed for a busbar is dependent on the protection requirements that are based on the performance speed and stability during external faults. Common methods of protecting busbars make use of the following schemes: overcurrent-based interlocking also known as reverse blocking scheme, overcurrent-based differential protection, high-impedance differential protection, and percentage differential protection (Sachdev, 2000).Short description and analysis of these protection technique is given below.

2.5.1 Interlocking Scheme

This is a protection method used for distribution busbars that have one incoming feeder. This protection is achieved by placing an overcurrent relay on an incoming feeder and also at all outgoing feeders as shown in Figure 2.6 These relays are configured to sense fault currents on the feeders, to detect feeder faults and trip the circuit breakers. The relay on the incoming feeder is set to trip the circuit breaker of the busbar unless blocked by any of the outgoing feeders. To avoid creation of race conditions a short coordination time grading is required depending on the protection devices used (Kasztenny et al., 2001).Such busbar protection schemes are common in medium-voltage systems (www.energy.siemens.com AG, 2005)

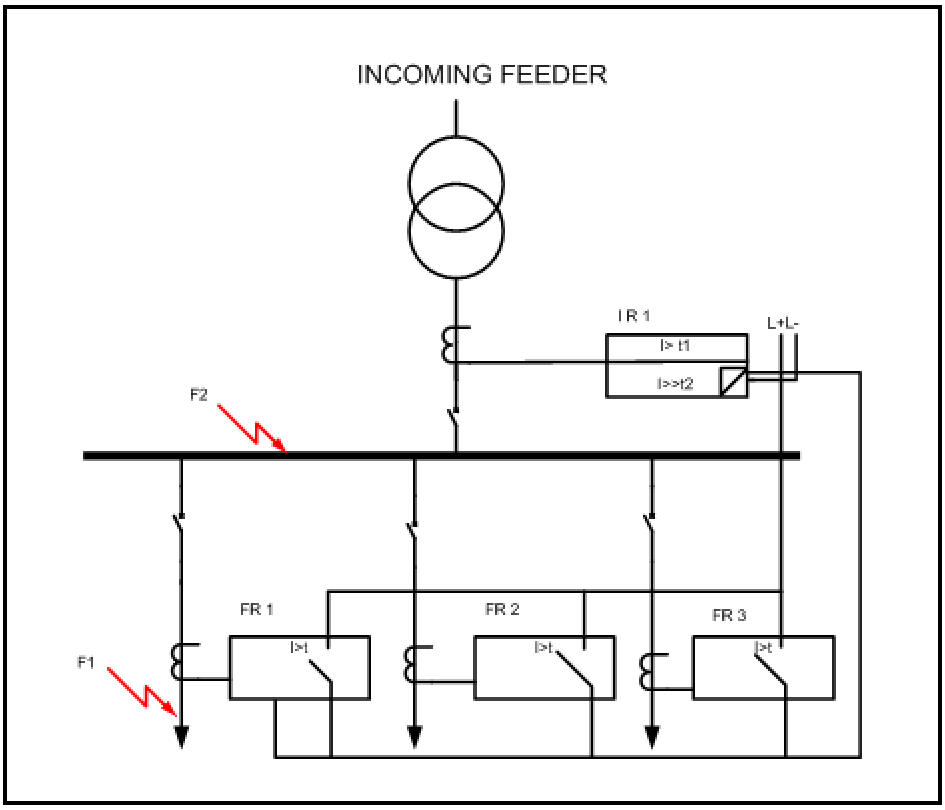

Figure 2.6: The distribution busbars protection using interlocking scheme (Siemens AG, 2005)

2.5.1.1 Operation of the scheme in a case of a fault at the outgoing feeder

When fault (F1) occurs on the outgoing feeder as shown in Figure 2.6 the incoming feeder relay IR1 picks up. Outgoing feeder relay FR1 also picks up and a blocking signal is sent to binary input BI1 of the relay IR1 via the pick-up signal of FR1. The operation of the Inverse Definite Minimum Time (IDMT) elements of the IR1 is blocked until the relay FR1 clears the fault on the outgoing feeder. To operate the backup protection relay IR1 of the incoming feeder utilizes a second stage I> t1 in

IR1 .This backup protection is used when the FR1 relay has operated and the IR1 relay still sees the fault at the FR1(www.energy.siemens.com AG, 2005).

2.5.1.2 Operation of the scheme in a case of a fault on the busbar

When the fault (F2) occurs on the busbar as shown in Figure 2.6, the relay IR1 picks up the fault and instantaneously trips the incoming circuit breaker open. In this case there is no blocking signal sent to the relay IR1 of the incoming feeder from relay FR1, FR2, and FR3 on the outgoing feeders. This means that there is no time delay taken by relay IR1 of the incoming feeder to trip the circuit-breaker on the incoming feeder. The busbar fault within a short period is disconnected and the extension of the fault is limited. This scheme is effective and fast for busbar protection in a system that utilizes one incoming feeder and radial outgoing feeders (www.energy.siemens.com AG, 2005).

Traditionally this scheme requires a lot of overcurrent functions to work efficiently. Multiple relays are also needed; therefore a large quantity of copper wiring is required. This problem can be solved by use of digital relays. These digital relays make it possible to integrate all required overcurrent functions into fewer relays and also to reduce the wiring. They also improve the performance of the scheme by shortening the coordination time and speeding up the operation (www.energy.siemens.com AG, 2005).

2.5.2 Differential Protection Scheme

The function of a bus differential protection is based on the Kirchhoff's first law which states that the sum of all currents connected to one differential protection zone is zero during normal conditions. When the sum of the currents is not zero then an internal fault has occurred. In such interpretation busbars enable efficient implementation of digital bus differential relay algorithm employing that any differential zone can be represented by three quantities as shown in Figure 2.7 where I_{in} is total instantaneous incoming current flowing into the bus, I_{out} is total instantaneous outgoing current flowing from the bus and I_d is instantaneous differential current regardless the number of actually connected feeders (Gajic et al, 2007).

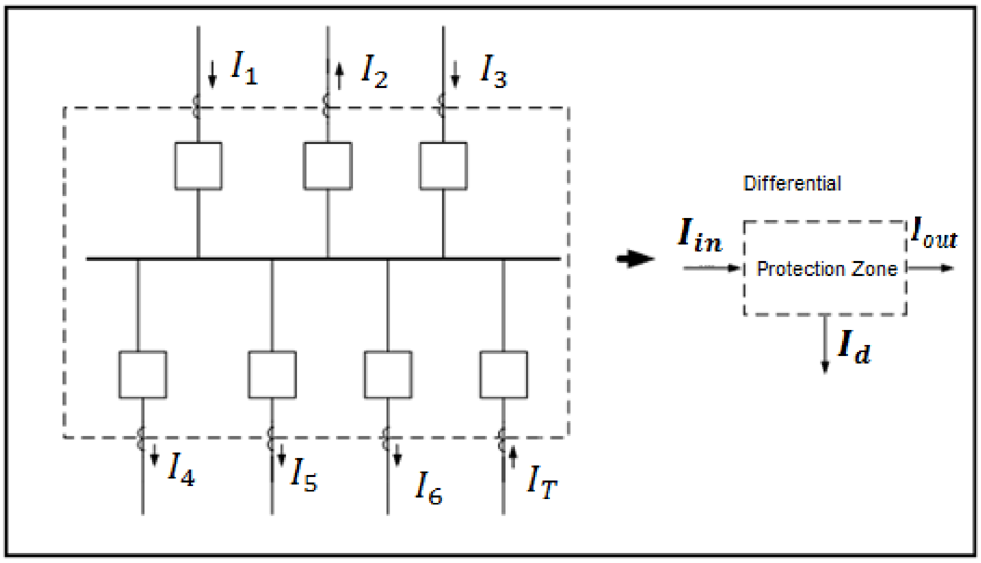

Figure 2.7: The representation of the differential protection zone of a single busbar (Gajic et al, 2007)

2.5.2.1 Operation

The operation makes use of circulating current arrangement at the extremities of the zone. The currents are reduced in level by CTs and are continuously compared. The operating coil of the relay is connected to the secondary windings of the CTs in such a way that the current flowing through it is equal to the sum of the secondary currents of the CTs. In a case of an external fault as shown in Figure 2.8, the current leaving the bus is equal to the sum of all of the currents entering the bus and the current flowing through the operating coil of the differential relay is zero (Gill, 2000).

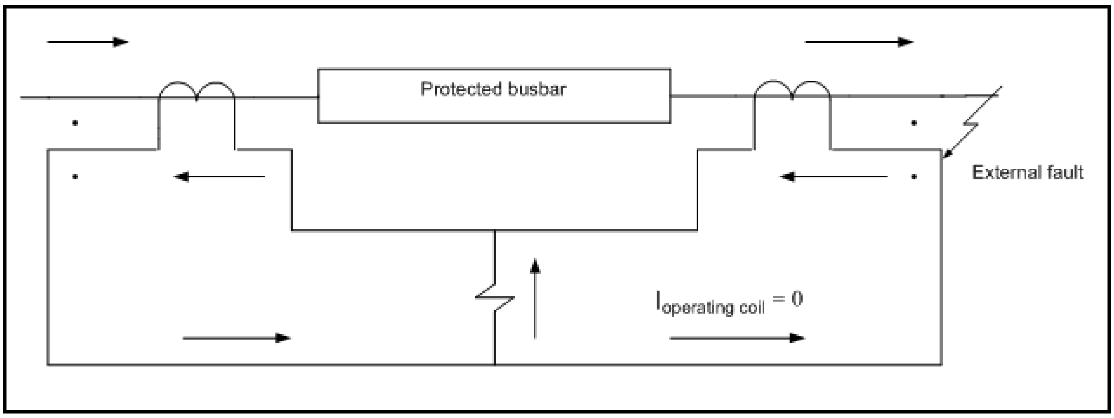

Figure 2.8: A basic differential scheme during normal operation and external faults (Gill, 2000).

When an a fault is at the busbar (internal fault) as shown in Figure 2.9, the total currents coming into the busbar is equal to the sum of fault current and this courses the current to flow through the operating relay. An ideal differential relaying scheme profits on the advantage that the summation of the currents is zero for external faults.

These conditions occur only if the CT's behavior is ideal for the differential protection requirements (Gill, 2000).

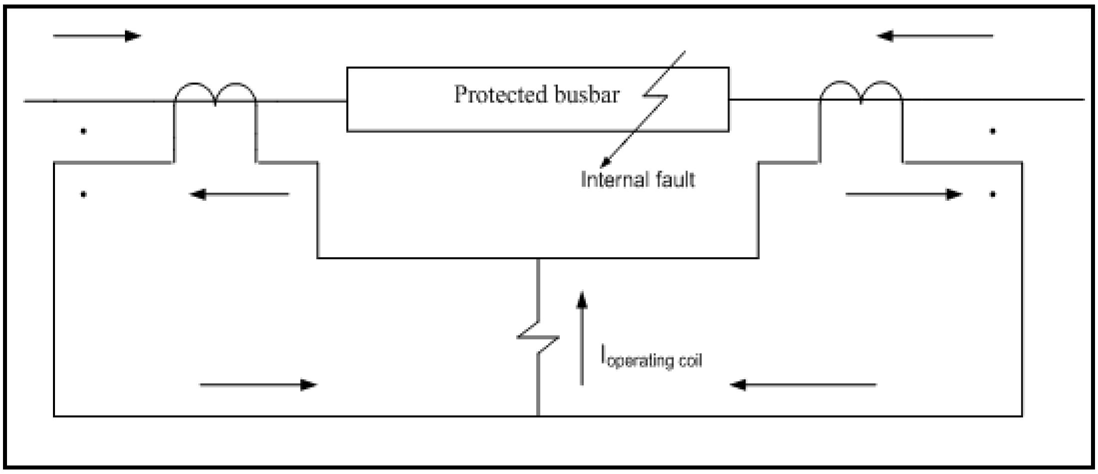

Figure 2.9: **A basic differential schemes during internal faults (Gill, 2000).**

The biggest problem implementing this protection busbar scheme is the fact that the current transformer (CTs) secondary current is non-linear due to CT's saturation. From the previous research it has been discovered that there are two most common busbar protection schemes applied in power systems (Kasztenny and Kuras 2001). They are high impedance differential protection and low impedance protection (de Oliveira and Koede, 2002). Low impedance differential protection scheme has advantage of tolerating substantial CT saturation and dedicated current transformers (CTs) are not required. This scheme is capable of providing high speed tripping. High-impedance protection requires dedicated current transformers (CTs) and this is a problem in terms of cost (Kasztenny and Kuras 2001).

2.6 Current Transformers for protection

Relays need accurate replica of the regular conditions for correct sensing and operation. These relays are not connected directly into the power lines. Devices such CTs and VTs are used to deliver accurate information from the higher-system voltages to the relays. This is done through CTs and VTs reducing voltage and current quantities into the ideal values that are used by the relays (Blackburn, Domin 2006).

2.6.1 Equivalent circuits of current and voltage transformers

The equivalent diagrams for an instrument transformer are shown in Figure 2.10.The exciting magnetizing impedance Z_e is shown in two parts where $Z_e^{'}$ is associated with the leakage flux within the transformer core and its related leakage reactance

$X; Z_e^{"}$ is the flux that does not influence the core, where, X_p is the leakage reactance from the flux that does not cut off the transformer core R_P and R_s are the resistance of the primary and secondary windings respectively. For VTs the value of $(R_P + R_s) + j(X_p + X)$ is kept low to minimize the loss of the voltage and shift to the phase angle from primary to secondary. The Z_e shunt impedances are kept high to minimize current loss from the primary to secondary parts (Blackburn, Domin 2006).

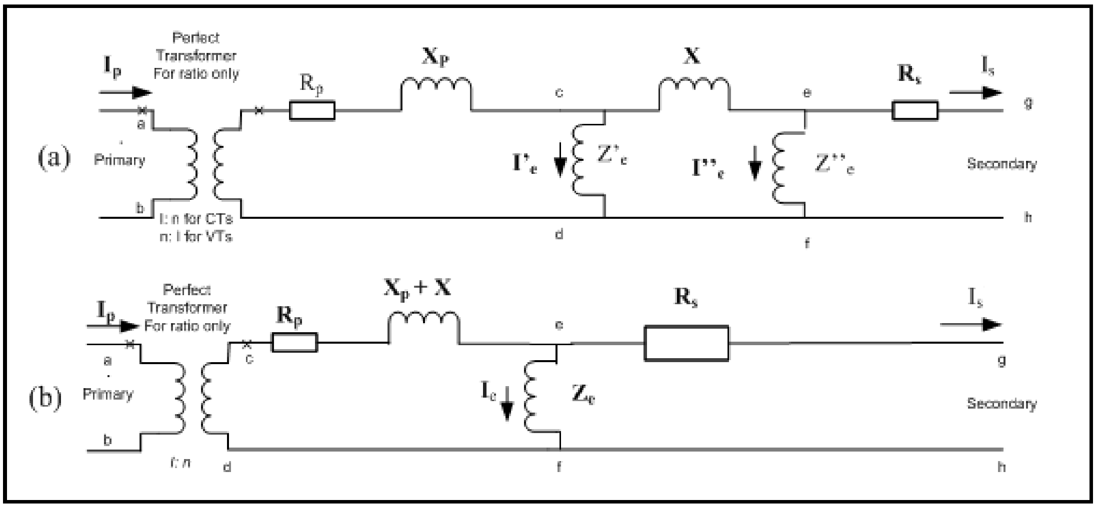

Figure 2.10: **The Equivalent diagrams for instrument transformers with ideal transformers, (a) for a significant leakage flux in transformer core class T CTs and VTs and (b) for a negligible leakage flux in transformer core class C CTs (Blackburn, Domin 2006).**

The turn's ratio *n* reduces the quantities on the primary side. Its offer voltage or currents at the secondary side to energize the relays or other protection devices. The loads contain impedances which are referred as burden and it can be either be from one loading device or the total devices that are loaded. The burden is in volt–amperes with a given current or voltage. The burden impedance Z_B for CTs and VTs are calculated using the equations below:

$$Z_B = \frac{VA}{I^2} \text{ (for CTs)} \qquad (2.1)$$

$$Z_B = \frac{V^2}{VA} \text{ (for VTs)} \qquad (2.2)$$

Where VA is the volt-ampere burden

I is the amperes

V is Volts

2.6.2 CT Saturation

Most of the previous proposed protection solutions have major problems with the CT saturation. It occurs when the flux density required to produce the secondary current exceeds the limits of the saturation flux density of the core. The CT saturation is dependent on the following factors (Andrichak, 1995).

- CT ratio
- Core cross-sectional area
- Connected burden
- Magnitude of burden
- Presence and amount of remanent flux (if any)
- Amount and direction of a dc offset in the current (if any)
- Saturation flux density of the core steel

A typical case of CT saturation as shown in Figure 2.11 is a full offset current wave having a time constant of approximately 30 milliseconds. The time taken when the secondary current starts to saturate is dependent on the factors listed above.

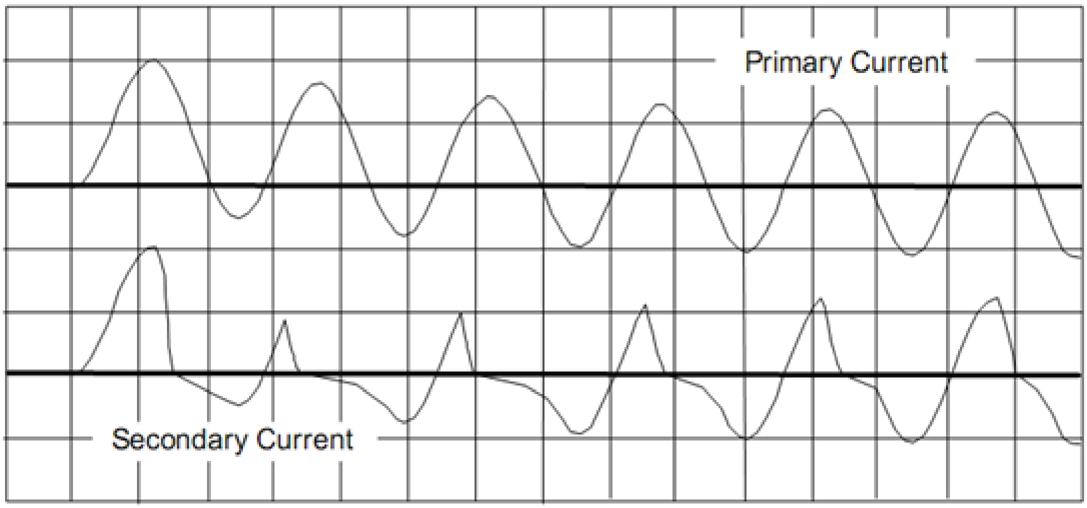

Figure 2.11: The Effect of the CT saturation (Andrichak, 1995).

It can be noted from the graph that at least five cycles of secondary current are distorted when it is compared to the primary current. In severe conditions this CT saturation can even occur sooner. This distortion in the secondary currents causes problems in the busbar differential protection creating abnormalities in the protective relays operation (Andrichak, 1995).

Since the CTs used in the differential protection schemes are in series with the line, they carry large amounts of currents during internal and external faults. A high level of current can cause CTs to saturate resulting in different secondary currents out of the two CTs. This results in the flow of a differential current in the operating element of the relay while the fault is outside the protection zone. Saturation of the CTs can therefore cause the differential relays to operate during external faults. It is essential that steps be taken to detect CT saturation and block the relay operation when it is necessary (Schweitzer, 1996).

2.7 IEC 61850 standard-based Digital relays

The reason why IEC 61850 is seen as the one solution is because it fulfills all the needs for communications within protective IEDs. IEC61850 is a global standard for communication inside substations, which integrates many latest technologies and derives many novel applications in a substation, especially in the power system protection realm (Brand et al, 2004)

The main target of the IEC61850 standard is to make the interoperability between different vendors' intelligent electronic devices (IEDs) easy. This is done by including standardized data model, abstract communication services interface and substation configuration language (SCL). These features include the following.

- Serial transmission of sample value
- High speed peer to peer GOOSE communication
- Standardized data model for protection

2.7.1 Serial transmission of Sample Values

The IEC61850 standard part 9-1 specifies the mapping of analogue samples over serial unidirectional multi-drop point-to-point link. This explains the serial communication between an electronic voltage or current transformer/transducer and a protection unit. The part 9-2 specifies the mapping of analogue samples over bi-directional, bus type serial link, which allows multiple use of data, also changing parameters of the electronic transformers/transducers and the transmission of supervision data, commands and trips (Brand, 2004).

The good thing about this is that is easy to identify that the digital data cannot be distorted by aging of the hardware. Furthermore optical fibers are recommended in the standard as process bus. The optical fibers are inherent to be immune from electromagnetic interferences coming from the switchyard. When it comes to issues such as data calibration or testing, the standard-based protection IEDs do not need these operations with data. Another advantage is that the data flow in the protection IED will be simplified and a second transformer for current and voltage measurements is not necessary. The analogue to digital (A/D) conversion and the related filtering for the current and voltage signal are also not required. The protection IED is a perfect element for protection algorithm improvement in the field of operation speed and reliability (Brand, 2004).

2.7.2 High speed peer to peer GOOSE communication

GOOSE messages are used to design distributed applications between IEDs. This communication can be used to both the bay level and the process level. The GOOSE introduction is to coordinate several IEDs and is processed to realize special applications such as interlock and trip. The communication mechanism guarantees that GOOSE communication has high reliability and is also suitable for real time protective functions. GOOSE communication replaces the wiring by an Ethernet cable between IEDs (Fan and Ma, 2007). A protection IED can take multiple roles as it can get real-time data via GOOSE from other IEDs. Therefore GOOSE communication is designed to take this task and it has been verified that it can satisfy the requirements (Jianzhong, 2005).

2.7.3 Standardized data model for protection

The standardization of the data model and the data exchange is to help to the operator to understand that the IED performs the following functions: Start, Alarm and Trip output, as well as parameterization. The standardized protection model wraps the specifics of the IED and makes the difference to disappear between the different vendors protection IEDs. Each protection function presents a common property. Same data model and same date property are foundation of interoperability. They also simplify the protection model (Su et al., 2005).

2.7.4 IEC 61850 standard benefits

A global market needs global standards, where each device must have the ability to be integrated in any system with its own global principle of operation. Thinking global means cost reduction by equalizing competitors and their specific functions and by standardizing maintenance and operation procedures (Mbango 2009*)*

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As cited in (Andersson, et al., 2003), the new standard IEC61850 offers several benefits for the design of protection and metering functions in a substation. The copper wires are cut down in terms of quantity. Manual labor for testing the copper wires and connecting is reduced. Maintenance time is also reduced and ideal redundancy of functions used in the substation is improved. An additional the benefits of the IEC61850 standard include the following (Mackiewicz, 2006):

- Object-oriented architecture
- Lowers communication infrastructure costs
- Reduces effort in engineering and commissioning
- Lowers installation and maintenance costs
- Lowers wiring costs
- Provides a complete set of services
- Interoperability without gateways / routers

2.7.5 Distribution Busbar Protection

A typical distribution busbars utilizes a single incoming feeder that supplies multiple radial feeders as shown in Figure 2.12a. Figure 2.12b shows the architecture for the distribution busbar protection (Mohan and Chatterjee, 2010).Traditionally dedicated protection systems are not designed and implemented for distribution busbars. When a fault occurred it was cleared by means of time delayed protection upstream. Introduction of the new IEC61850 standard based protection now allows development of innovative protection schemes in order to improve the algorithms for distribution system busbars protection (Ranta et al., 2009).The investigation of the thesis are based on development of IEC 61850 standard-based protection scheme for the architecture from Figure 2.12a and 2.12b

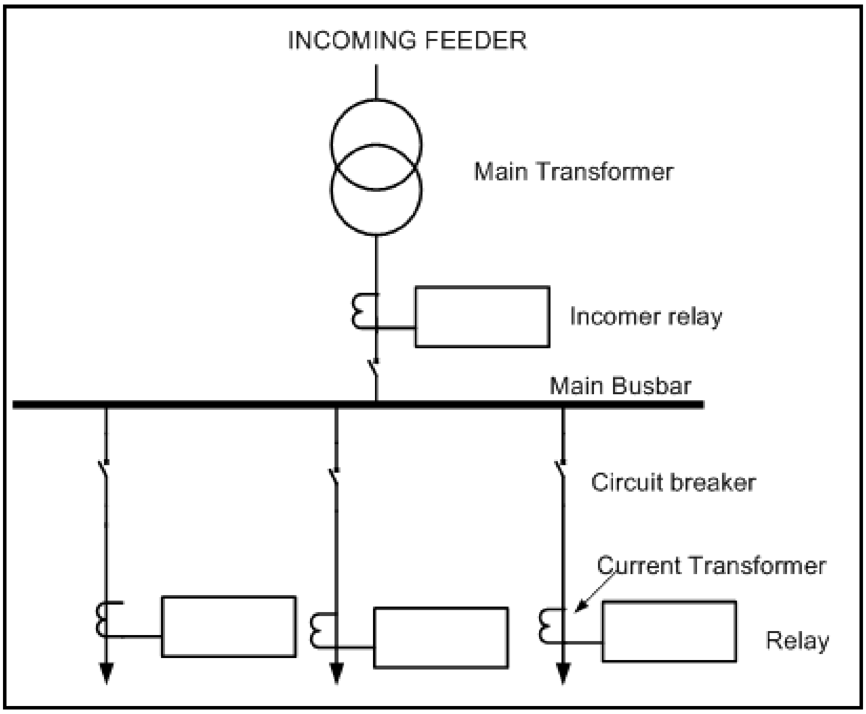


Figure 2.12a: **The Distribution Busbar system (Mohan and Chatterjee, 2010).**

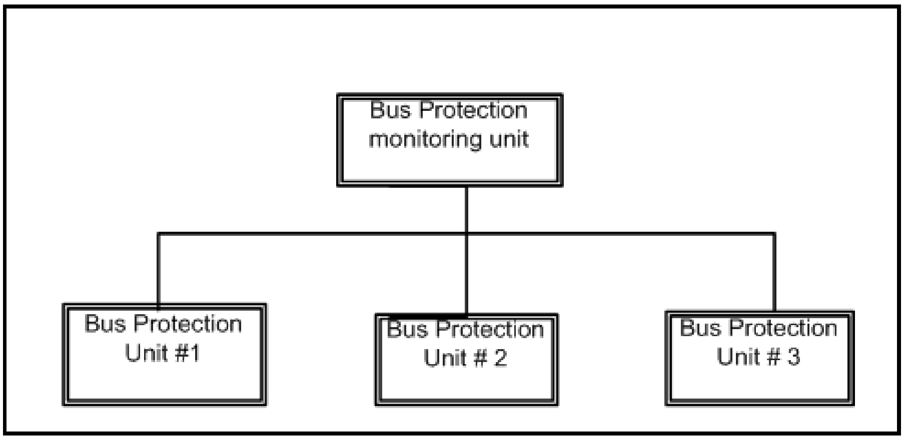


Figure 2.12b: **The architecture for distributed bus protection (Mohan and Chatterjee, 2010).**

2.8 Literature review of existing papers for busbar protection

A literature review has been done according to five viewpoints which are:

- History of busbar protection in power systems
- Different types of busbar protection schemes
- Traditional busbar protection using conventional protection devices
- The development of modern IEC 61850 standard-base Intelligent Electronic Devices (IEDs)
- History of communication used in the substations

Figure 2.13 shows a graph of the number of papers reviewed starting from 1914 up to 2013. These papers are selected according to the field of protection in power systems and focusing on the history of busbar protection.

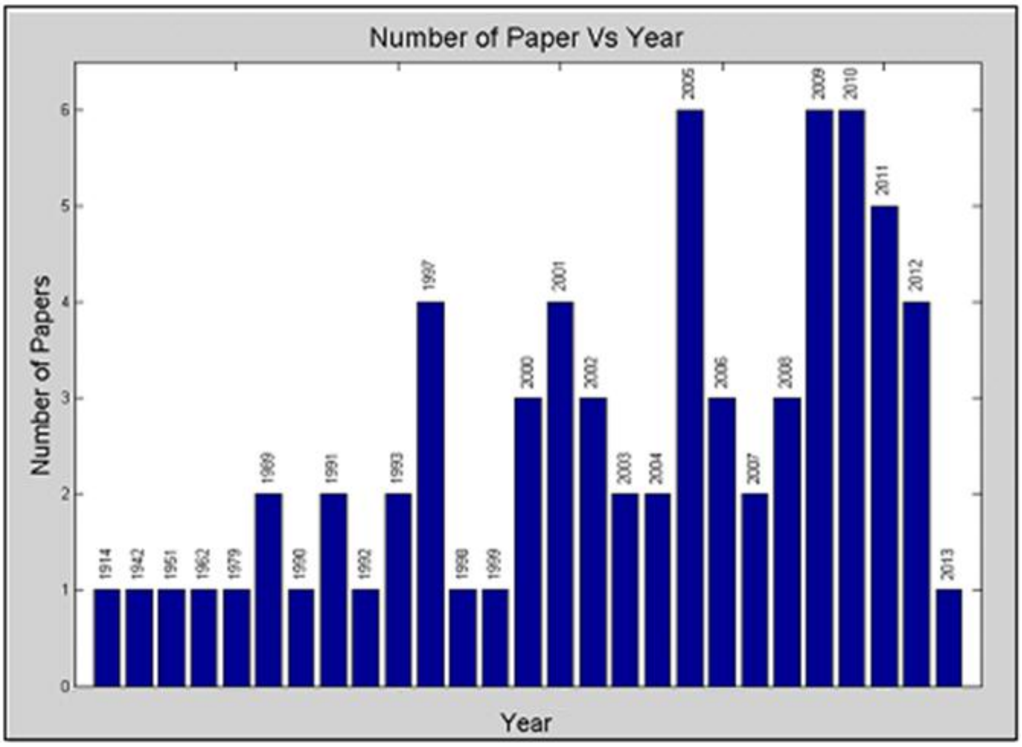


Figure 2.13: The IEEE papers for busbar protection publication rate per year

From the graph above it can be seen that from the year 1914 up to January 2013, sixty nine IEEE papers have been published that focus on the field of busbar protection. The graph also shows that during the years 2005, 2009 and 2010 the number of published papers based of busbar protection reaches its peak. In year 2005 the research of the implementation of digital protection for busbars started to increase. As the years went by, the researchers constantly focused on the digital protection for the transmission busburs. The distribution bubsbar were neglected. This serves as a reason for the thesis investigations. The thesis focuses on improving the busbar protection at the distribution level.The following key words are used:

Busbar protection, Bus protection, feeder protection, overcurrent protection, zone interlocking scheme, protective relaying, digital signal processors, unrestrained differential protection, CT saturation, wavelet transform, design of microprocessor relays, IEC 61850 substation, IEC 61850 standard, GOOSE communication and development of microprocessor relays. From these key words a general review of the papers are shown in Tables 2.1 up to 2.44 including their protection aspects. The survey and comparison of the IEEE papers is carried out using the following criteria.

- Paper author and year
- Aim of the paper
- Method of the protection

- Structure of the system
- Used hardware / software
- Advantages / Drawbacks
- Achievements

2.8.1 Review and analysis of the Differential protection methods for busbars

The developments of the Differential protection methods for busbar as shown in Table 2.1 Leyburn and Lackey (1951) used biased differential relay for protection of generators, power transformers, feeders and busbars. They discovered that the generators needed more protection than any other component in power systems. Royle and A Hill (1989) later used Differential Busbar Protection based on low impedance biased schemes. This method managed to eliminate the stabilizing resistance by using segregated and combined function scheme. When it came to develop a CT saturation detector for the busbar protection Yang *et al*., (1990) used a percentage differential scheme combined with a hybrid bus scheme in order to improve the reliability. Kumar and Hansen (1993) developed a busbar protection technique that is based on the low-impedance differential scheme. Requirements for a fast trip and security against unwanted relay operations are achieved by multiprocessing. Three microcomputers were used for the purpose. The protection algorithm is based on the relationship between restraining and differential currents and a restraining factor. Fernández (2001) used a waveform models and RL-model. Hughes and Legrand (2001) introduced numerical system for busbar protection by developing a new technique that makes use of average phase angle compensation simulation. Zadeh et al., (2005) developed a fuzzy neuro method and a symmetrical component to stabilize the busbar protection during CT saturation. Van Zyl, (2006) has evaluated modern trend of implementing high impedance differential protection by operating numerical overcurrent relays in series with external stabilizing resistors. This offers a number of advantages when compared to the traditional electromechanical-type high impedance relays. The method proposed by Kang, 2008 used single-slope operation for busbar differential relay in conjunction with the compensating algorithm. However these methods for differential protection create complexity of the busbar protection. The literature review illustrates that the differential protection for busbars is mostly implemented at the transmission level, not in distribution level. The literature review also shows that the CT saturation detector uses an additional circuit and this creates possibility for mal-operation of the schemes.

Table 2.1: **Differential protection methods and a CT saturation detector for busbar protection**

PAPER	Aim of the paper	Method of protection	Structure of the system	Used hardware / software	Advantages / Drawbacks	Achievements
(Leyburn and Lackey, 1951*)*	To analyze protection for power system based on present-day practice and recent progress.	Differential protection for generators, power transformers, feeders and busbars	A single busbar system with one source and three feeders in parallel	Biased differential relay	A combination of different protection schemes are applied in one system and this can lead to maloparation.	The method used began with an examination of generator protection and it was discovered that negative-phase-sequence protection should be improved since the generator protection needed most attention
(Royle and A Hill, 1989)	To develop a low impedance biased differential busbar protection	Differential Busbar Protection	A Segregated and Combined Function Scheme is used	A differential measuring and auxiliary relays	The advantage is that stabilizing resistance is not required and it reduces the level of bias	The new methods eliminates the requirement for a stabilizing resistance and guarantee stability throughout the fault
(Yang et al.,1990)	To develop CT saturation detector algorithm incorporation with percentage for differential scheme	To improve the reliability of the conventional percentage differential scheme.	A hybrid bus scheme using the percentage differential method for primary protection and for back up protection. The phase comparison method is used	A combination of percentage differential principle and the phase comparison scheme is used	A lot of tests had to be made so that the conclusion of the results is accurate	The saturation detection and the hybrid bus protection algorithm were proven to be simple, efficient and accurate
(Fernández,2001)	To develop a new algorithm for CT saturation detection to improve the performance of busbar differential protection scheme	Algorithm that detects the saturation of the CT using impedance measurements instead of a model for the CT secondary current.	A busbar differential protection.	A waveform models and RL-model based algorithm for the CT saturation detection are used	This CT saturation detector is an addition circuit and this creates possibility for mal-operation	A new algorithm for busbar differential protection shows a fast response time
(Hughes and Legrand, 2001)	To develop a new techniques for busbar protection system to improve speed reliability, sensitivity and stability	Differential busbar protection	General theory research	Average phase angle compensation simulation for numerical protection devices for busbar protection.	A numerical system improves speed reliability, sensitivity and stability when compared to non-numeric conventional systems.	Numerical busbar protection improve the overall utilization of the network and is beneficial for the electrical substation. These methods offers to the operator flexibility.

(Rasher and Rica, 2002)	To investigate the necessity for bus protection in medium voltage systems	Differential busbar protection	Computer simulation of the protection system for various busbar configuration	Simulation based project	Improve availability and security	A number of bus configurations were developed to meet different levels of power system reliability
(Pave and Leonid, 2003)	To deal with different features of transients in current transformer groups for differential busbar and busway protection	A differential protection is applied for busbar protection	Three generator-transformer units (GTU) connected to a busbar system	A modern microprocessor-relay	The drawback is that the algorithm used is not fast	It is discovered that extreme CT saturation appears when Direct Current Components(DCC) percentage in the resource current of this CT is maximal
(Kang et al., 2004)	To develop and evaluate stability of busbar differential relay during external faults using CT saturation detector.	To understand the technique used to stabilize the busbar differential relay not to delay the operating time of the relay	A third-difference function of the current was used as a detection algorithm at the start and the end of CT saturation	A current differential relay is used.	The technique used had to be repeated for both internal fault and external fault	Discrimination between internal and external faults .The sensitivity of the relay remains stable during CT saturation.
(Cheng Li-jun, 2004)	To Improve CT saturation by using synchronizing identification and phase current comparison	To identify a synchronized principle and the phase current comparison algorithm for CT saturation checking	A simulation and theory based research project	The synchronizing identification and phase current comparison methods are used	Need to understand the behavior of the busbar protection scheme and the main requirement	The two methods were successfully implemented to improve CT saturation for numerical busbar protection
(Guzmán et al., 2005)	to explain a reliable protection scheme that includes busbar protection and advanced zone selection;	A differential protection system that is appropriate for the protection of multiple busbar arrangements	A bus arrangement with four buses and eight terminals.	A differential relay	The scheme is fast	An innovative busbar protection scheme with advanced zone selection that is safe for external faults is achieved
(Zadeh et al., 2005*)*	To present a new methodology for busbar protection with stability during CT saturation by utilizing Fuzzy - neuro and symmetrical component	Busbar Protection for 230 kV double busbar	Adaptive fuzzy network with a 230 kV double busbar is used	A fuzzy -neuro differential relay	It is fast and accurate	The proposed scheme is stable during CT saturation
(Kang, 2008)	To propose single-slope operation for busbar differential relay in conjunction with the compensating algorithm	A busbar current differential protection that operates in conjunction with a CT compensating algorithm is explained	A single one line diagram with 154 kV double busbar systems with 12 feeders.	Busbar differential relay / algorithm was implemented on the TMS320C6701 digital signal processor	The complexity of busbar differential relay when aligned with CT compensation	The algorithm used achieves greater stability on external faults and is sensitive to internal faults

2.8.2 Review and analysis of the protection methods based on the hardware / software

A summarized analysis of the hardware / software used for busbar protection based on different methods is shown in Table 2.2. Lidgate *et al*., (1979) derived an interlocking logic for secondary circuits for conventional double busbar substations. The method was presented by auxiliary relays which were used for evaluating logic diagrams for a complex switching network. The method of Pei *et al*., (1991) used single chip microcomputer (SCMC) with CPU MCS 8098 to design busbar protection. The problem with this design is that it needs to have an analog to digital (A/D) converter within the chip and in this way it cannot satisfy the requirement for high accuracy although it proved to be reliable and also has self-check functions against break of the CT connections. Ing *et al*., (1991) developed a neural network numerical busbar protection system (NBPS).His system made use of ABB relays. The scheme used a computational intensive algorithm and focused on a distribution busbar protection systems.

A year later Schweitzer *et al*., (1992) upgraded a distribution system by applying a new microprocessor based relays. Their reason was to improve distribution protection and reduce maintenance costs. Belvaux *et al*., (1993), Peck *at al*., (1993), Wong and Kalam, (1996), Funk and Ziegler, (1997) and Stockton, (1999) used a decentralized structure that consists of numerical busbar protection relays. Belvaux *et al*., (1993) used software LSA MASS to control the numerical protection devices and his method reduced the normal hard wiring between the conventional components. Peck *at al*., (1993) developed numerical busbar protection (BBP) which provides improvements when compared with the conventional systems. Wong and Kalam's, (1996) method is constructed on a UNIX platform which uses an object oriented database management system .Stockton's, (1999) method utilized programmable logics devices which substantially improved protection, control and monitoring facilities.

About a year later Mohindar and Sachdev, (2000) developed a computerized switching schemes for interlocking logic in substations. They used a graphic interface to interact with the user. The interface is based on Computer-aided design (CAD).In year 2000 Gill et al.,(2000) published a paper that explained busbar protection that utilizes the positive- and negative-sequence models. They made use of a real-time playback simulator (RTPS) to test the microprocessor-based bushar protection scheme.

Brewis and Hearfield, (2001) used a single busbar with one incomer and a single busbar with two incomers (Sectionalized) to investigate the performance of busbar protection scheme. They made use of Blocking and Unblocking busbar zone logic for the protection scheme. The problem with this scheme is that it made use of hard wiring for communication between the relay. The method of Bo and Han, (2009) for protection is based on Global Positioning System (GPS) technique where it detects the fault using the generated high frequency transient signals and records the time instant that corresponds to the moment of the fault at that busbar. Chothani et al., (2012) developed a trainer kit at a laboratory environment that uses a Digital Signal Processor (DSP) TMS320LF2407A tool to discriminate between an internal fault and an external fault on a busbar. In 2013 Khodadadi and Shahrtash, (2013) developed a new non communication-based scheme that can discriminate between external and internal faults by taking note of the busbar properties. The method used mathematical morphology (MM) filter analyzing the transients that were captured.

Table 2.2: **The methods for busbar protection based on the hardware / software**

PAPER	Aim of the paper	Method of protection	Structure of the system	Used hardware / software	Advantages / Drawbacks	Achievements
(Nellist and Mathews, 1962)	To design an air-core toroids or linear couplers for busbar protection	By applying linear couplers for busbar protection	N/A	Research base d project	Improve stability	A technique of design to secure optimum performance of voltage summation circuits is achieved
(Lidgate et al.,1979)	To evaluate the derivation of interlock logic and the secondary interlock circuits for conventional double busbar substations.	Interlocking scheme	A double-busbar substation system	An auxiliary relays	The drawback is the complexity of switching high power networks	A new approach to the derivation of logic diagrams for a complex switching network is achieved
(Pei et al.,1991)	To improve a new scheme capable to automatically accommodate bus structure change and can correctly determine new summations of current.	A summation of current around each bus zone for all switching patterns in a substation making use of differential protection scheme	A double bus arrangement with two bus sections. The second one is the double bus arrangement with three bus sections	A single chip microcomputer (SCMC) with CPU MCS 8098 is used.	Need to have an A/D converter within the chip cannot satisfy the requirement for high accuracy.	The designed busbar protection relay based on SCMCs 8098 is proven to be reliable and also has self-check functions against break of CT and PT connections
(Ing et al.,1991)	To develop and apply neural network technique in numerical busbar protection systems (NBPS)	A neural network for preprocessing the data and restore the distorted signals.	A distributed busbar protection system	ABB Relays	The drawback is that the algorithm for this scheme is computational intensive	It could be revealed that the application of a neural network to renovate distorted current values is possible.
(Schweitzer et al.,1992)	To investigate and analyze additional features of more advanced digital distribution relays	To upgrade a distribution system by applying a new microprocessor based relays	A distribution system with one source as incomer and three outgoing feeders.	A distribution system arrangement with digital distribution relays is utilized	Modifying traditional protection schemes requires buying and installation of additional equipment	Advanced digital distribution relays improve distribution protection and reduce maintenance costs
(Belvaux et al.,1993)	To improve substation protection by applying numerical controlled protection devices	Feeder protection and digital busbar protection	Decentralized system with a double busbar and a bus coupler	The software LSA MASS is used	The advantage for using digital protection is that it can integrate several programmable protection functions.	This protection system reduces the normal hard wiring between the conventional components.
(Peck at al.,1993)	To develop a new bay-oriented structure that consists of numerical busbar protection relays	A numerical busbar protection base on the central unit	Decentralized system	ABB relays	The advantage is that amount of hardwire and spare parts are reduced	The new numerical busbar protection (BBP) provides improvements when compared with the conventional systems

(Wong and Kalam, 1996)	To develop a new approach for intelligent system in the protection	Distributed Intelligent Power System Protection	Decentralized based on an Intelligent System for Power Protection (ISPP)	A prototype is constructed at Unix platform which uses an object oriented database management system	The drawback for this method is that the object oriented technique is based on C language which is complex for protection engineers	A multi- agent system which involves case-based and object oriented approach in the improvement of a distributed intelligent system for protection in power system is achieved
(Funk and Ziegler,1997)	To investigate the design and service experience when using numerical busbar protection	Numerical low impedance differential busbar protection	Decentralized system	Numerical relays	The advantage for this scheme is that it is fast and easy for commissioning it	The numerical busbar protection scheme reduces maintenance expenditure due to complete self-monitoring
(Stockton, 1999)	To investigate protection of distribution Systems	A directional and non-directional overcurrent busbar protection	Decentralized method	Modern overcurrent relays	Can provide faster fault clearance times	By utilizing the programmable logics the protection, control, and monitoring facilities are substantial improved
(Mohindar and Sachdev, 2000)	To design a software application that can be employed to generate interlocking schemes	A computerized switching schemes for interlocking logic in substation	A computer-aided system for designing interlocking schemes	A graphic interface is developed to interact with the user, application software, and data base/ Computer-aided design (CAD)	Training of operators because of the complex configuration that are based on Interlocking scheme	A new computer-aided system for interlocking schemes in a substation is developed
(Gill et al.,2000)	To implement and test a microprocessor-based bushar protection scheme	Busbar protection that utilizes the positive- and negative-sequence models	A double busbar configuration with five different circuits	A real-time playback simulator is used (RTPS) A delta-impedance relay is applied	The scheme is capable of fault detection in the busbar protection zone	The proposed system offers an effective protection scheme with substantial improvements
(Brewis and Hearfield, 2001)	To discuss issues to be considered in the design of busbar protection schemes	To investigate the performance of busbar protection schemes that use instantaneous elements	A Single Busbar with One Incomer and Single Busbar with Two incomers (Sectionalized)	Blocking and Unblocking busbar zone protection scheme logic is used	Still made use of hard wiring for communication between the relay	Implementation of blocking scheme provided improvement and its cost effective
(Bo and Han, 2009)	To analyse the response to different power systems and fault conditions that are based on the positional protection techniques	To design a new integrated protection scheme that has high response speed in fault detection	Bewley-Lattice diagram for a multi-end transmission line is used	Global Positioning System (GPS) based technique detects the fault using the generated high frequency transient signals and records the time instant corresponding to the moment of the fault at that busbar	The complexity of detailed station communication network has to be reduced	Results show the developed scheme is insensitive to all fault types and has high accuracy and speed in fault detection

(Chothani et al., 2012)	To develop a low voltage busbar relaying scheme and implement it in a laboratory environment	To use a real time Digital Signal Processor(DSP) based Differential Protection for Low Voltage Busbar	A three phase busbar system with current transformers, line components, fault switches and DSP trainer kit	A Digital Signal Processor(DSP) TMS320LF2407A and a trainer kit	The advantage of using DSP based differential scheme gives better stability/ there are no drawbacks	A lab scale implementation of differential relying scheme has been achieved. The scheme has accomplished to discriminate between internal fault and external fault on busbars.
(Khodadadi and Shahrtash, 2013)	To develop a new non communication-based scheme that can discriminate between external and internal faults by taking note of the busbar properties	The scheme is applied on a three-terminal lines in Iran's Transmission Grid to discriminate between external and internal faults	A Three-terminal transmission line is used as the structure	A mathematical morphology (MM) filter is used for analyzing the transients that are captured.	The scheme is based on high-frequency components to discriminate the captured transients that are triggered by faults whether to group them as high transient, or low transient or very-low transients	The proposed scheme outclasses other non-communication schemes because of the high security and dependability that it has. .

2.8.3 Review of the protection methods for busbars based on digital protection devices

A summarized analysis of the digital protection methods for busbar protection is given in Table 2.3 below. Evans *et al.,* (1997) described a series of reliability studies that are based on two digital busbar protection schemes. They compared the conventional busbar protection with the digital protection by applying the protection scheme in a double busbar system with eight outgoing circuits. They discovered that digital busbar protection is more reliable and has the ability to remain stable in the event of external faults. Andersson and Brunner, (2002) looked into the benefits of how to utilize the IEC61850 standard in substation automation. Their task was to improve the overall system reliability for the busbar protection scheme and also to reduce the number of hard wiring in the system. Stringer, (2003) used a busbar overcurrent protection by applying reverse interlocking scheme. Although he made use of digital relays but the communication between them was hardwired. (Kasztenny, and Cardenas, 2005) looked into a new phase-segregated solution for interlocking schemes for single-income distribution busbars and a high-end microprocessor based protection schemes. They applied scheme in a centralized busbar protection and in a distributed busbar protection. Apostolov, (2005) used directional comparison bus protection scheme to explain GOOSE and GSSE messages as defined in IEC 61850 standard. He substituted hardwired analog inputs of the conventional IEDs with the GOOSE or GSSE messages.

Duncan and Self, (2005), Bo *et al*., (2006) and Zou and Gao, (2008) Investigated the various protection schemes that use IEC61850 standard. Their method was to replace hard wiring by implementing the IEC 61850 standard for communication to improve the performance of the scheme. On the other hand Schwarz, (2007) used basic implementation of the IEC 61850 using Intelligent Electronics Devices (IEDs) to provide training for utility engineers. Skendzic et al, (2007) have evaluated the impact of IEC 61850-9-2 standard Process Bus on Power System Protection and Control Reliability by means of Sampled Value (SV) concept analysis. His proposes to digitize the CTs and VTs so that they can get rid of hardwire connection between CTs and IEDs and use Process bus for communication. Nan-hua and Xin-hua (2009) used the IEC 61850 standard GOOSE communication to reduce complexity of an action triggering function between the IEDs. Aguilar and Ariza, (2010) investigated the communication protocols between multivendor IEDs. Zadeh *et al.,* (2011) developed and implemented a superimposed directional comparison technique for bus protection (DCBPU) that is based on an IEC61850 process bus. They used the fault detection and directional functions in all feeders and sent GOOSE messages via a station bus to a central unit to implement distributed directional comparison bus protection. The problem with this method is that when the central unit maloperates or stop operating the whole system will collapse. Apostolov, (2011) investigated the impact of IEC61850 standard on busbar protection. His objectives were to reduce the cost of the system by utilizing process bus based on the differential protection scheme. His aims were to apply IEC61850 standard for the bus differential schemes communication by using two types’ devices as solution, namely: Peripheral units and central units. His results showed that using process bus reduces the possibility of CT saturation. The speed performance of the directional comparison bus protection scheme by utilizing peer-to-peer GOOSE communication is also improved. (Tanaka et al., 2012) developed a peer-to-peer connection between Merging Units (MUs) and Intelligent Electronic Devices (IEDs) in order to separate the Sample Value (SV) messages of 32 bays on the process bus.

Table 2.3: **The methods for busbars based on the digital protection**

PAPER	Aim of the paper	Method of protection	Structure of the system	Used hardware / software	Advantages / Drawbacks	Achievements
(Evans et al., 1997)	To explain a series of reliability studies that are completed on two digital busbar protection schemes.	Digital busbar protection making use of high impedance based on one zone discrimination	A double busbar system with eight outgoing circuits	Modem digital relays	The advantage is that digital busbar protection is more reliable compared to the conventional busbar protection	The two digital busbar protection schemes has the ability of the to remain stable in the event of external fault
(Andersson and Brunner, 2002)	To investigate the benefits of utilizing IEC61850 standard in substation automation	To improve the overall system reliability in a substation automation by using the IEC 61850 standard	A single busbar with a one in-feeder and one out-feeder	New communication technology known as IEC61850 standard is utilized	Complexity of implementing the IEC61850 standard	By implementing the IEC61850 standard a number of hard wiring will be reduced
(Stringer, 2003)	To develop an enhanced technique of applying sensitive bus fault protection by means of digital overcurrent relays	A busbar overcurrent protection is applied by using zone or reverse interlocking scheme	A network consists of one source and two feeders	digital overcurrent relay	The drawback is that the communication between the relays uses hardwire.	The Scheme provides a faster clearing for bus faults and this is achieved by setting the coordination closer than traditional overcurrent protection methods
(Kasztenny, and Cardenas, 2005)	To investigate a new phase-segregated solution for interlocking schemes for single-income distribution busbars and a high-end microprocessor based protection schemes.	Distribution Busbar protection high-impedance principle, low-impedance principle , and interlocking schemes	A Centralized busbar protection and Distributed busbar protection	Phase-Segregated Busbar microprocessor-based Relays	The advantage of using phase segregated it offers extra modularity at the IED level	The new microprocessor based protection schemes provide a faster tripping time with modern features
(Apostolov, 2005)	To explain GOOSE and GSSE messages as defined in IEC 61850 and what method they can be utilized for different distributed applications.	A directional comparison bus protection is used	A distributed protection	A HMI system using IEC 61850 standard	The advantage is that sampled values interface substitutes the hardwired analog inputs of conventional IEDs which is joined with the GOOSE or GSSE messages that substitute the hardwired binary inputs	The scheme provides a backup functions in a complete cost effective integrated solution for protection, control, metering, monitoring, event reporting, recording and analysis

(Duncan and Self, 2005)	To Investigate the various protection schemes that use IEC61850 Standard	To replace hard wiring by implementing IEC 61850 for communication to improve the performance of the scheme	One incomer feeder connected to a busbar that consists of three outgoing feeders	The new IEC61850 standard UCA 2.0 protocol is used to allow communication between IEDS within the substation	The Software tools for the configuration require a number of settings. The lack of engineers who understand the standard	Allows easy fault and misoperations and the implementation leads to cost reduction
(Bo et al., 2006)	To investigate novel integrated protection scheme for distribution system	A conventional directional overcurrent protection systems is implemented into the relay	A centralized protection system is used	Central protections relay using one communication standard such as IEC61850.	The protection scheme is user friendly and manageable when it comes to practical implementation	A new integrated overcurrent protection scheme for distribution system is achieved by improving its performance
(Schwarz, 2007)	To analyze the basic implementation of IEC 61850 using Intelligent Electronics Devices (IEDs)	To understand what aspects of the automation systems is covered by IEC61850 and to provide training for utility engineers.	The application of tools for various tasks	IEC 61850-1, and IEC 61850-2,Communication networks and systems in substations	Vendors, users, and system integrators have to go through a learning curve	IEC 61850 Standard is a new comprehensive and a powerful tool for communication in substation automation
(Lundqvist, 2007)	To implement IEC 61850 standard in a user friendly way	To design a user friendly system for new substations	Double bus with a bay controller	ABB IED 670 series that comply with IEC61850 standard have been utilized	The implementation of IEC61850 has been a challenge during the development of the ABB IED 670 series family	With long term experience of numerical protection a user friendly implementation of IEC61850 is possible
(Jianzhong and Xu, 2007)	How to utilize GOOSE message to improve busbar protection, what are the benefits of IEC61850 and non-conventional instrument transformers	To investigate benefits and impacts of protection application. to improve protection performance using GOOSE messages	Single and double busbar	High speed peer to peer GOOSE communication	There is still a lot that needs to be researched for the application of the IEC61850 in the protection field specially on busbar	IEC61850 standard is believed to have bright window for protection applications
(Zou and Gao, 2008)	To investigate distributed busbar protection scheme	To analyzed a digital distributed busbar protection based on reliability requirements	A system used is a distributed busbar protection that is without a central unit	IEC61850 communication standard is used	Since the system is not centralized Peer-to-peer communication is used	From analyzing the results the proposed scheme showed high reliable and feasible distributed busbar protection
(Hakala-Ranta et al., 2009)	How to improve reliability and performance of the protection system is studied	To improve the reliability and performance of the system using GOOSE communication between protection and control devices	A System Single Line Diagram that consist one IED at the incomer with one busbar and three IEDs at outgoing feeders	Utilizing of ABB REF615 devices/IEC 61850 standard	Better performance compare to the traditional schemes/ It is a new application therefore there is plenty to understand	GOOSE increases operating reliability and makes the system easy to be extended and to be reconfigurable

(Nan-hua and Xin-hua 2009)	Comparison study between traditional method and GOOSE method schemes for busbar protection	To compare speed performance between two methods utilized for busbar protection	Single Bus-bar single and main transformer for the first experiment and a pairs of main transformer and sub-bus connection for the second experiment	IEC61850 standard making use of GOOSE messages protection technique .results were analyzed using Shenzhen NARI Technologies	IEC61850 standard with the horizontal communication creates a large learning curve for engineers who are used to traditional protection schemes	GOOSE communication is a good solution for improving speed performance of a scheme and it also increases reliability and flexibility
(Brand, 2009)	Extension of substation with one new bay without reengineering the substation and retesting the existing part	To apply the IEC 61850 standard GOOSE communication to reduce complexity of action triggering function between IEDs	Topology Based Interlocking scheme Example with connectivity part numbers and electric potential attributes	IEC 61850 standard making use of GOOSE communication service	Operators will need training because of the complexity of using IEC61850 standard and. the standard data model extensions to hold the appropriate topology attributes	The complexity triggering function functions between IEDs are reduced
(Tournier and Werner, 2010)	To evaluate architectures applicability for both transmission and distribution substations. Challenges such as scalability, reliability, real-time and cost efficiency of theprocess bus are considered	To compare different process bus solutions based on real- time constraints	Five process bus architectures are structured for the system	IEC61850 standard used as the communication infrastructure for the process bus.	Vendors and users have to go through training and will be constraints at the beginning because the new technology needs to be studied	A full redundant architecture including process bus device provides a high reliability and High availability Seamless Redundancy **(**HSR)shows a cost effect for distribution substation
(Aguilar and Ariza, 2010)	To investigate communication protocols between multivendor IEDs	Time comparison between traditional hardwired and IEC 61850 based breaker failure scheme	A System Single Line Diagram that consist one incomer fed to one busbar with three outgoing feeders	Four IEDs from different vendors /Traditional hard wiring method and IEC61850 standard communication	Lack of people who has the knowledge of the standard leads to problems when trying to configure the IEC61850 based protection scheme	Test show that IEC61850 standard based scheme is faster than a traditional wired breaker failure scheme.
(Miranda and Netto, 2010)	To improve reliability a complete scheme needed to be developed	To compare results between hard copper wiring and the IEC 61850 standard communication for a bay control	A system with one bay consist of one circuit breaker, two line switch and one earth switch controlled via IEC 61850	IEC61850 standard using GOOSE messages for communication and also using bistable equipment simulator at a laboratory environment	The problem is that implementation is expensive and has complex solution	The use of replacing functional circuits with process bus reduces electrical connections involved

(Zadeh et al., 2011)	To develop and implement a superimposed directional comparison technique for bus protection (DCBPU) that is based on an IEC61850 process bus	A directional comparison bus protection unit (DCBPU) is investigated in order to provide a high speed bus fault clearing in the IEC61850 process-bus environment.	High speed peer-to-peer communications-based bus protection system is used	A six feeder model is simulated in PSCAD/EMTDC software tool. The results are imported from COMTRADE files to MATLAB where DCBPU is simulated	The fault detection and directional functions in all feeders send GOOSE messages via a station bus to a central unit to implement distributed directional comparison bus protection. The proposed scheme is cost effective.	The proposed protection scheme did not lose dependability and security due to the packet loss and delay and it provides a high speed protection.
(Tanaka et al., 2011)	To develop a Process Bus for Busbar Protection	A low impedance differential busbar protection	A one-and-a-half circuit breaker bus and double busbar system arrangement is configured with a 32 bays	A IEC61850-9-2, Merging Unit (MU), Intelligent Electronic device (IED)	The drawback is that the cost for relay hardware will increase when compared to existing systems. The advantage is that the length and number of copper cables can be reduced	The process bus application to busbar protection and (Voltage Selection Scheme) VSS achieve high reliability, interoperability long lifetime, and easy maintenance.
(Kanabar, 2011)	To analyze the impact of Sampled Value (SV) loss and delay on the protection functions for busbar and distance	To investigate the correct measure for SV loss/delay by using IEC61850-9-2 based process bus communication network for digital protection system	IEC61850-9-2 communication network using Sampled Values (SV) was done in a laboratory environment to test impact of SV loss/delay on bus differential and line distance protection functions	Intelligent electronic devices (IEDs) and Merging Unit (MU) /The power system model is simulated using PSCAD/EMTDC software Results are analyzed using MATLAB	SV are unlike GOOSE messages. They are not repeated several times and therefore the analysis of the protection function is important. Currently IEDs used in substation are not signed for SV contingencies	The results show that the protection device may lose security, and mis-operate during an external fault due to SV loss/delay in certain conditions.
(Tanaka et al., 2012)	To develop a peer-to-peer connection between Merging Units (MUs) and Intelligent Electronic Device (IED0 in order to separate the Sample Value (SV) messages of 32 bays on the process bus.	Busbar protection making use of Low impedance differential protection	A one-and-a-half circuit breaker bus and double busbar system arrangement is configured with a 32 bays	A busbar protection scheme with IEDs and MUs is used. IEC61850-9-2 process bus is used for communication	The drawback is that the cost for relay hardware will increase when compared to existing systems. The advantage is that the length and number of copper cables can be reduced	The process bus application to busbar protection and (Voltage Selection Scheme) VSS achieve high reliability, interoperability, long lifetime, and easy maintenance.

2.8.4. Review of the protection methods based on simulation

2.8.4.1 PSCAD/EMTDC and EMTP simulation

A summarized analysis of the different methods for busbar protection that use PSCAD/EMTDC and EMTP software package tools are given in Table 2.4.1 below. Batty et al., (1997) improved unit protection scheme which works on the information restricted in the superimposed currents formed by a fault current. They modeled a double bus grid system with four sources and simulated it with the EMTP package. Villamagna and Crossley (2006) used a test bench that consists of an Electro-Magnetic Transients Program / Alternative Transients Program (EMTP/ATP) simulator to perform the effect of the CT saturation on a differential relay for various faults. Chothani, (2011) investigated the same problem as Villamagna and Crossley (2006) but PSCAD/EMTDC software package was used for simulation. The technique they used is based on the ability to detect all types of faults within its zone and to be stable during out of the zone faults. (Zou and Gao, 2012) also used PSCAD/EMTDC simulation software tool to develop a new technique with an extra high speed for busbar protection making use of the propagation theory of the traveling wave.

2.8.4.2 EMTDC and MATLAB simulation

A summarized analysis for different methods for busbar protection that use EMTDC and MATLAB software package tool are given in Table 2.4.2 below. Gill, (1998) used positive and negative –sequence models to perform differential busbar protection. He developed a method that is able to detect the difference between internal and external faults using voltages and currents measurements from the relay at the bus location. A power systems simulation software EMTDC was used as the simulator and MATLAB was used for further analysis. The problem with the technique used is that it has too many symmetrical components which may create high possibilities of maloperation. Two years later Mohindar *et al*., (2000) used the same software package to simulate the effect of the CT ratio-mismatch and the CT saturation in busbar protection. Xu and Grasset, (2002) later investigated the effectiveness of the busbar differential protection scheme based on reliability and stability requirements. Analyses were performed using the Real Time Digital Simulator (RTDS) and MATLAB software making use of a single busbar with one in-feeder and one out-feeder on each protection zone. Dashti and Pasan,(2009) used the ABB REB500 differential relay in a substation with a busbar that has four feeders and one 250-MVAR reactor to design two detectors of the CT saturation. A PSCAD/EMTDC simulator and MATLAB software package are used to filter the noise from the current signals.

2.8.4.3 Wavelet transforms (WT)

Summarized analyses of the different methods for busbar protection that use wavelet transforms (WT) are given in Table 2.4.3 below. Jiang et al., (2001) investigated the application of the wavelet transforms to detect busbar faults in power systems in order to develop new protection principles. The new protection principles were based on transient Based Protection (TBP) and Wavelet transform (WT). Wang et al., (2005) used wavelet transforms to develop a scheme that uses numerical protection for distribution busbar. Gafoor and Rao, (2006) also used wavelet transforms to develop a scheme that is able to detect busbar faults and to discriminate them from external faults. Popov, (2009) used discrete wavelet transform (DWT) to produce a transient based protection scheme that provides a fast fault clearing time. Moni *et at*, (2010) used a Wavelet Packet Transform Analysis tool to overcome the problems of the CT saturation and the CT ratio mismatch. Eissa, (2012) develop a method that is based on extracting the windowed wavelet transform of fault generated transients in order to discriminate between the busbar faults.

2.8.4.4 EMTP simulation for busbar protection

A summary of the different methods for busbar protection that use EMTP simulation are given in Table 2.4.4 below. Deng and Suonan, (2010) used an inductance model and EMTP simulator to distinguish between faults in and outside of a bus-bar protection zone. Suonan et at., (2010) also used the same simulator to analyze and solve the impact of the CT saturation. They made use of impedance differential protection based principle capable to discriminate between internal fault and external fault making use of the ratio between the fault components of the voltage and the fault components of the differential current of the busbars.

Table 2.4: Methods for busbar protection based on simulation

PAPER	Aim of the paper	Method of protection	Structure of the system	Used hardware / software	Advantages / Drawbacks	Achievements
Table 2.4.1: PSCAD/EMTDC and EMTP simulation						
(Batty et al.,1997)	To develop a novel unit protection scheme which works on the information restricted in the superimposed currents formed by a fault	A unit protection scheme based on superimposed currents is used	A double bus grid system with four sources has tobe modeled for simulation	The EMTP package is used for simulation	The advantage of the scheme is that it has a much faster response time when a fault occures	A basic robust and reliable unit scheme that is based on current transients is achieved
(Villamagna and Crossley 2006)	To is investigate the performance and the effect of CT saturation of a differential relay for various faults	To use differential protection for various faults on a typical Electro-Magnetic Transients Program/Alternative Transients Program (EMTP/ATP) simulator	A 415-V transmission-line test bench system	An Electro-Magnetic Transients Program / Alternative Transients Program (EMTP/ATP) and a test bench were used	Two different models are used and compared and this requires time and accuracy when transporting data	The proposed algorithm improves the protection stability of the differential relays
(Chothani, 2011)	Using a differential busbar protection to improve stability against external faults and effect of CT saturation	To investigate and evaluate the effect of high resistance for different types of internal and external faults and CT saturation	An existing 230KV power transmission systems model	PSCAD/EMTDC software package.	The proposed technique has the ability to detect all types of faults within its zone and is stable during out of zone faults /For simulation purpose certain components had to be developed that were not in the PSCAD library using programming in Fortran 77 compiler	For internal faults the tripping time is within 20ms. The scheme is able to detect severe CT saturation during all types of external faults with better security. The scheme is highly sensitive in case of high resistance in-zone faults
(Chothani, 2011)	To develop a correct discrimination of busbar faults and improve the effect of CT saturation	To study fault zone identification scheme for busbar and produce a scheme that is stable during CT saturation by presenting a new support vector machine (SVM) that is fault based	400 kV Indian busbar system model	A support vector machine (SVM) based fault zone identifier and PSCAD/EMTDC software package was used for modeling existing 400 kV Indian busbar system	A number of experiments with different size of training datasets had to be analyzed in order to get proper conclusion	The results shows that the scheme proposed can effectively distinguish between in-zone faults and out of zone fault on the busbar and also it is immune to CT saturation

(Zou and Gao , 2012)	To develop a new technique with an extra high speed for busbar protection making use of propagation theory of traveling wave	To create a an extra high-speed busbar protection scheme making use of transient directional traveling wave	A 230-kV busbar system model is constructed	A PSCAD/EMTDC is used as a simulation software tool	The discrimination of the fault is based on the transient directional traveling wave	The protection scheme developed is virtually immune to CT saturation

Table 2.4.2: EMTDC and MATLAB simulation						
(Gill ,1998)	To analyze and study the performance of differential busbar protection based on internal and external faults	Able to detect the difference between internal en external faults using voltages and currents measurements from the relay at the bus location	The technique developed was generated on a Sun SPARC workstation using the power systems simulation software, EMTDC	It uses positive and negative –sequence models, EMTDC and MATLAB for simulation	The technique used consists of many symmetrical components which may create high possibilities of maloperation	The technique used provided a stable performance and is reasonably fast for busbar protection
(Mohindar et al.,2000)	To explain a digital method for protecting busbars	A technique uses positive- and negative-sequence models	A SaskPower substation with 230 and 138 kV busbars was modeled	A EMTDC Software is used for transient-simulation	The advantage of the scheme is that it is not affected by CT ratio-mismatch	The method used is stable during CT saturation
(Xu and Grasset, 2002)	To investigate the effectiveness of busbar differential protection scheme according to reliability and stability	To design a new algorithm that utilizes phase comparison to improve stability of busbar protection under CT saturation	A single busbar with a one in-feeder and one out-feeder on each protection Zone simulation	Analyses were performed by an RTDS and MATLAB software environments	Thousands of RTDS tests have to be done in order to conclude the result	Results show that current phase comparison method improves stability of busbar protection
(Dashti and Pasan, 2009)	To design two detectors for CT saturation for stabilizing busbar differential protection.	To apply busbar differential scheme in order to develop the best CT saturation detector	A substation with a busbar that has four feeders and one 250-MVAR reactor	A differential relay REB500 PSCAD/EMTDC simulator is used and MATLAB software package used to filter white noise from current signals	Extensive studies have to be performed and various combinations of algorithms is developed The disadvantage is that the method may create maloperation	The combined method provided fast and reliable results and was able to detect CT saturation in all cases.

Table 2.4.3: **Wavelet transforms (WT)**

(Jiang et al.,2001)	To investigate the application of wavelet transforms to detect faults in a power system faults in order to develop a new protection principles based on the wavelet transform	Differential Busbar Protection	Double busbar	The protection schemes are based on transient Based Protection (TBP) and Wavelet transform (WT)	This scheme can be used to protect more than one component that is in the network of the system.	A good selectivity, fast response to the fault, immune to the parameters of supply sources is achieved by the new scheme. Primary system interfacing is simple and easy to implement.
(Wang et al., 2005)	To develop a scheme that uses a new numerical protection for busbars	The protection method is based on polarities of transient current waves for identification of the internal and external faults to busbars	A distributed busbar protection system in a single-phase busbar systems	A wavelet transforms are used	The advantage is that it can improve the reliability of the distributed protection.	A new numerical protection for busbar that is based on polarity comparison of transient current waves is achieved. This method makes use of wavelet transform modulus
(Gafoor and Rao, 2006)	To investigate the application of Wavelet Transform (WT) for detection of busbar faults and to discriminate them from external faults.	A Wavelet Transforms (WT) based scheme for detecting busbar faults	Four generators are connected to two 220KV busbar sections.	A WT based busbar protection scheme	The proposed scheme is simple, fast, reliable and stable under various conditions	The proposed scheme is prove to be fast, stable and reliable in detecting the internal faults and discriminating them from the external faults.
(Wang and Dong, 2008)	To decompose the fault current signals into different frequency bands making use of the wavelet multi-resolution	To analyze the principle of wavelet multi-resolution signal decomposition for differential busbar protection	A single-line diagram of one 500kV power system	The proposed scheme utilizes power frequency currents and Alternative Transients Program (ATP) for simulation	The complicated extensive series of simulation studies had to be done in order to conclude the results	High frequency currents were able to prove the performance of the busbar protection scheme and the technique used is reliable and stable under various conditions
(Popov 2009)	Investigation on the effectiveness of the protection principles	To produce a transient based protection scheme that provides a fast fault clearing time	A radial network with a detailed dynamic model of the Doubly-Fed Induction Generator (DFIG) wind turbine unit.	The proposed protection scheme made use of a transient-based technique based on discrete wavelet transform (DWT)	The transient methods used were implemented in the Field Programmable Gate Arrays (FPGA) which can create complexity to protection engineers.	The scheme only makes use of current measurements and therefore it is cost-effective. Lack of sustained fault current problems are solved by the proposed protection

(Moni et at, 2010)	To review different aspects of busbar protection schemes	To overcome the problems of CT saturation and ratio mismatch of CT secondary making use of A Wavelet Packet Transform Analysis tool	A decentralized busbar protection scheme with individual Bay Units (BU) connected to a central unit (CU)	Microprocessor based relay/ A Wavelet Packet Transform Analysis tool was used for busbar fault analysis	Introduction of the WPT algorithm can create maloperation if the settings are not accurate	The novel prospect to design relays inconjuction with wavelet transform analysis provides faster clearance of faults and can be used for busbar differential protection
(Eissa, 2012)	To develop a method that is based on extracting the windowed wavelet transform of fault generated transients in order to discriminate between busbar faults	To differentiate between faults in a busbar protection zone or outside the zone	A single 230kV busbar model with four sources and two feeders is simulated	An alternative transient program (ATP) is used to generate data and wavelet transform (WT) is used to test the performance of the proposed algorithm	The proposed technique for faults discrimination is given in the conventional techniques and therefore cannot properly solve the fault current-based magnitude The technique uses additional measures.	Discriminating the faults during CT saturation, ratio-mismatch, and early CT saturation is successfully achieved by the proposed technique

Table 2.4.4: **The EMTP simulation for busbar protection**						
(Deng and Suonan,2010)	To distinguish between faults in and outside a bus-bar protection zone	Identify the internal fault and external fault on bus-bar with different current transformer (CT) by using inductance and the resistance parameters	Made use of one busbar that is fed by two sources	An inductance model and EMTP simulator were utilized	The algorithm utilized for identifying the faults is complicated for the first time users	The scheme proposed can be used to identify the internal and the external faults on a bus-bar
(Suonan et at., 2010)	To analyze and solve the impact of CT saturation	To apply an effective principle that is capable to discriminate between internal fault and external fault making use of ratio between the fault components of the voltage and the fault components of the differential current of the busbar	A breaker-and-a-half busbar system was configured and used for applying the protection scheme	EMTP simulation is used to verify the results making use of the impedance based principle	Busbar fault component network had to be analyzed in detail	Based on the simulation the results proved that the principle works It is used to detect a CT saturation

2.9 Discussion

The literature review analyses the various techniques used for busbar protection. Digital algorithms for busbar protection schemes in terms of speed, stability, security and dependability have place a huge burden and responsibility among protection engineers. The area of digital busbar protection at a distribution level has not been subjected to active research and little work has been reported on the development of algorithms that are suitable for protecting these busbars. Most proposed busbar protection schemes developed by the previous researchers focused on the transmission level. The studies have focused on the current transformer (CT) saturation. These digital protection algorithms that were proposed in the past for protecting busbars have been focused on using differential protection. This scheme used various platforms applying different methods and simulators. All have been concentrating on solving the CT saturation problem. No algorithm proposed in the past has inherent immunity to the CT saturation. The stability of the algorithm during the fault conditions is provided by using special means, such as: a special circuitry, two algorithms working in conjunction, and choice of a restraint factor. The additional circuitry increases the complexity of the protection scheme that leads to possibility of incorrect operations due to malfunction of its components .Also an increase in the number of components increases the total cost.

The enhanced busbar protection scheme at a distribution level described by Stringer, (2003) offers a faster clearing for bus faults compared to the traditional overcurrent protection techniques. The scheme used hardwires connection for communication between the bus relays and the feeder. A digital overcurrent relay with programmable I/O contacts is used to set and be responsible for blocking signals to constrain the operation of the relay at the incomer feeder. The method used for the scheme is based on programming the relay sitting on the incomer feeder It is set for a lower pickup to improve sensitivity for the fault at the busbar. The method also serves as backup protection for the relays at the feeder. The problem with Stringer, (2003) busbar protection scheme is that the protection devices used are not compliant to the IEC61850 standard. This means that they use hardwiring via programmable I/O contacts of the digital relays. In order to achieve this connection an auxiliary DC power supply is needed. This supply must constantly power the programmable I/O contacts in order to keep the connection. If it happens the power supply fails the connection will be lost and therefore the scheme will fail to operate. By introducing relays that are compliant to IEC61850 standard the problem of using hardwire for communication will be solved by means of using horizontal communication also known as GOOSE messages between the IEDs

The application of protective (IED's) that comply with the IEC 61850 standard has proven to be the solution to a reliable protection of any power system. The IEC 61850 is a new communications standard that allows the development of new range of protection and control applications that result in significant benefits compared to the conventional hard wired solutions. It reliably supports interoperability between the protective relays and control devices from different manufacturers in the substation. This is a necessity in order to achieve substation level interlocking, protection and control functions and to improve the efficiency of microprocessor based relays applications.

2.11 Conclusion

This chapter began with the overview of the busbar protection in the electrical power systems. A wide-range review of various developments completed by researchers in the field of busbar protection is also presented. Although previous researchers focused on protecting busbars at the transmission level there is still a large amount of work that needs to be done. Protection of busbars at the distribution level has been neglected for a long time and most distribution substations do not have dedicated protection schemes. When it comes to busbars in distribution networks protection can be accomplished mainly in two different ways, namely: blocks able for overcurrent protection at the incoming bays to the switchgear and locating arc detectors inside the enclosure. This thesis is only concentrating on improving the busbar blocking scheme for a distribution network. The reason for this is because; based on the review it was found that this scheme is the most convient for this type of networks.

Chapter Three presents the theoretical aspects of busbar protection. It also covers the protection schemes that are currently used for busbars at the distribution level.

CHAPTER THREE
THEORETICAL ASPECTS OF BUSBAR PROTECTION

3.1 Introduction

Busbars play an important role in power transmission and distribution. They are employed as a central distribution point for all feeders. In the case of a fault, current on the busbar becomes high, resulting to mechanical destruction which would affect all feeders. The problem is that the busbars are usually left out without specific protection because it is assumed that they have high reliability. It was feared that if a busbar had a dedicated protection scheme it might mal-operate and end up affecting the whole power system. The other reason was that back up protection was assumed to be good enough to provide decent bus protection. Due to problems such as loss of loads and long time to clear the faults, when using back up protection, a dedicated busbar protection scheme is required (Hodgkiss, 1960).

When it comes to a dedicated busbar protection the high speed operation, reliability and stability is in demand. Instability of the power system might be caused by case of a failure to trip during an external fault or false tripping during service of the busbar. This will lead to a complete blackout. Precision and reliability are important factors when designing a busbar protection scheme. Literature review has shown that small distribution substations used for medium voltage make use of overcurrent relays to provide busbar protection and large substations make use of differential protection schemes (Mohan and Chatterjee, 2010).

This chapter explains a busbar theory at the distribution network level. It also covers the busbar protection schemes that are currently in use and their operation. The theory of the overcurrent protection devices is also explained. The digital busbar scheme is also considered in this chapter. In 3.2 a number of busbar protection schemes are explained, section 3.3 describes the overcurrent protection relays, 3.4 considers the digital protection application, 3.5 presents the reliability considerations and 3.6 gives conclusion.

3.2 Busbar protection schemes

There are a number of protection schemes designed for busbars. The most used are as follows (Prévé, 2006):

- System protection used to cover busbars

- Frame-earth protection
- Differential protection
- Phase comparison protection
- Reverse blocking / interlocking protection

The scheme for a system protection is used at small substations, while phase comparison protection for busbars has become obsolete. A detailed explanation of the frame earth protection, differential protection, and reverse interlocking protection for busbars is discussed further.

3.2.1 System protection used to cover busbars

The system that is used to cover busbar protection consists of overcurrent or distance protection. Making use of this system the busbar will be inherently protected. This technique or method is applied to simple distribution systems by implementing over current protection. This system also can be used as back up protection by using time grading in a case where slow protection action is required (Elmore, 2004).

3.2.2 Frame-Earth Protection

Frame earth protection for busbars has been extensively used in the past. This method can be applied to various layouts of busbar protection, each having certain capability. Frame earth protection schemes are still in existence and provide effective service for busbar protection. Introduction of numerical relays has added to a decline in application of a frame leakage system (NPAG, 2002).

3.2.3 Single-Busbar Frame-Earth Protection

This protection scheme in a single busbar layout is seen as an earth fault system and is utilized for measuring currents that flow from the switchgear frame to the earth. This scheme is designed in such a way that an instantaneous relay as shown in the Figure 3.1 is energized by the current sensed by the CT that is mounted on the earthing conductor. It is important that no other earth connections are allowed to link to the structural steelwork. This guarantees that the CTs and the principal earth connection are not shunted, because that behaviour might result in increasing of the effective setting leading to the possibility of maloperation of the relay. It is critical that the switchgear should be insulated from the ground by making use of concrete as a foundation (Elmore, 2004).

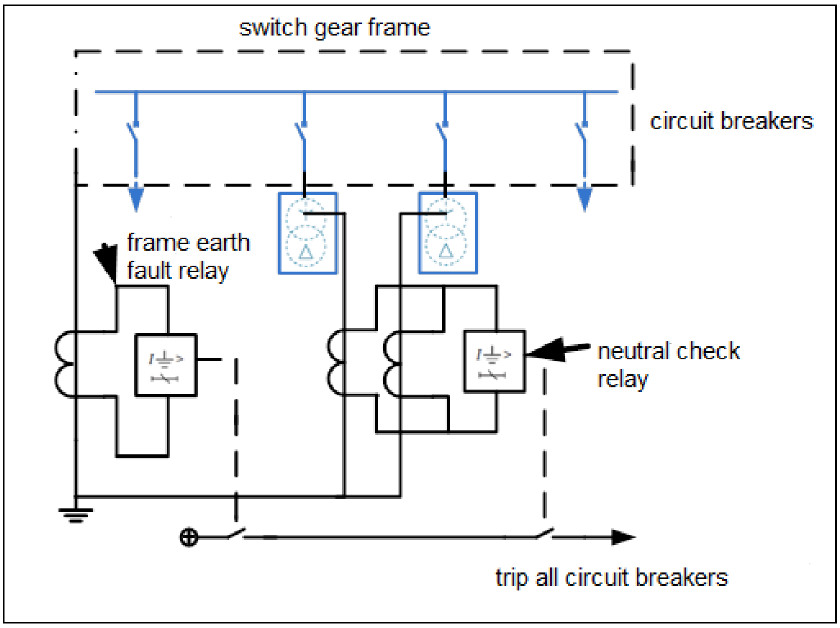


Figure 3.1: The Single-Busbar Frame-Earth Protection (Elmore, 2004).
)

3.2.4 Frame-Earth Protection (Sectioned Busbars)

This system divides the busbar into sections and the protection is also done separately. This is done by dividing the frame in to sections each using a dedicated earth conductor. Each section consists of a separate CT and a protection relay. These sections are now treated as separate zones as shown in Figure 3.2. This system is arranged in such a way that the protective relay only trip when the fault is within its respective zone (NPAG, 2002).

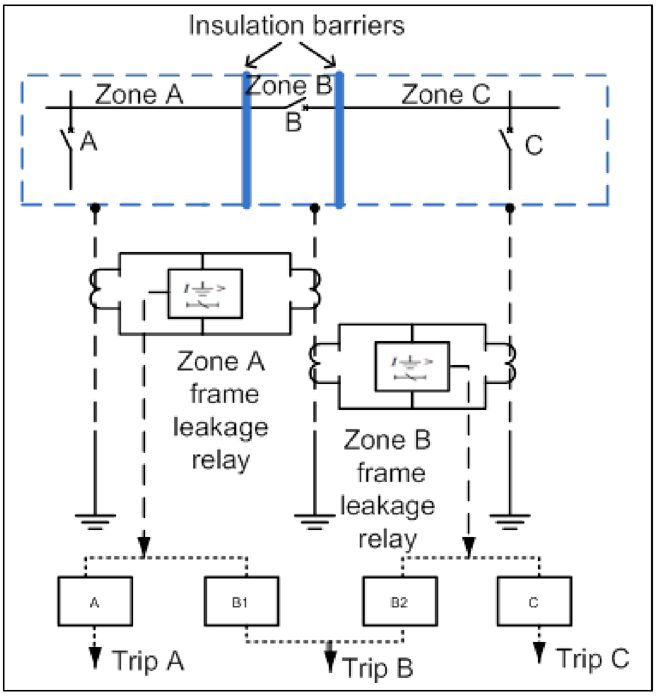


Figure 3.2: A Frame – Earth Protection (Sectioned Busbar) (Elmore, 2004).

3.2.5 Frame-Earth Scheme - Double Bus Substation

In this system protection is provided as single bus insulation with additional trip circuits connected to the auxiliary bus as shown in Figure 3.3 to operate for all faults.

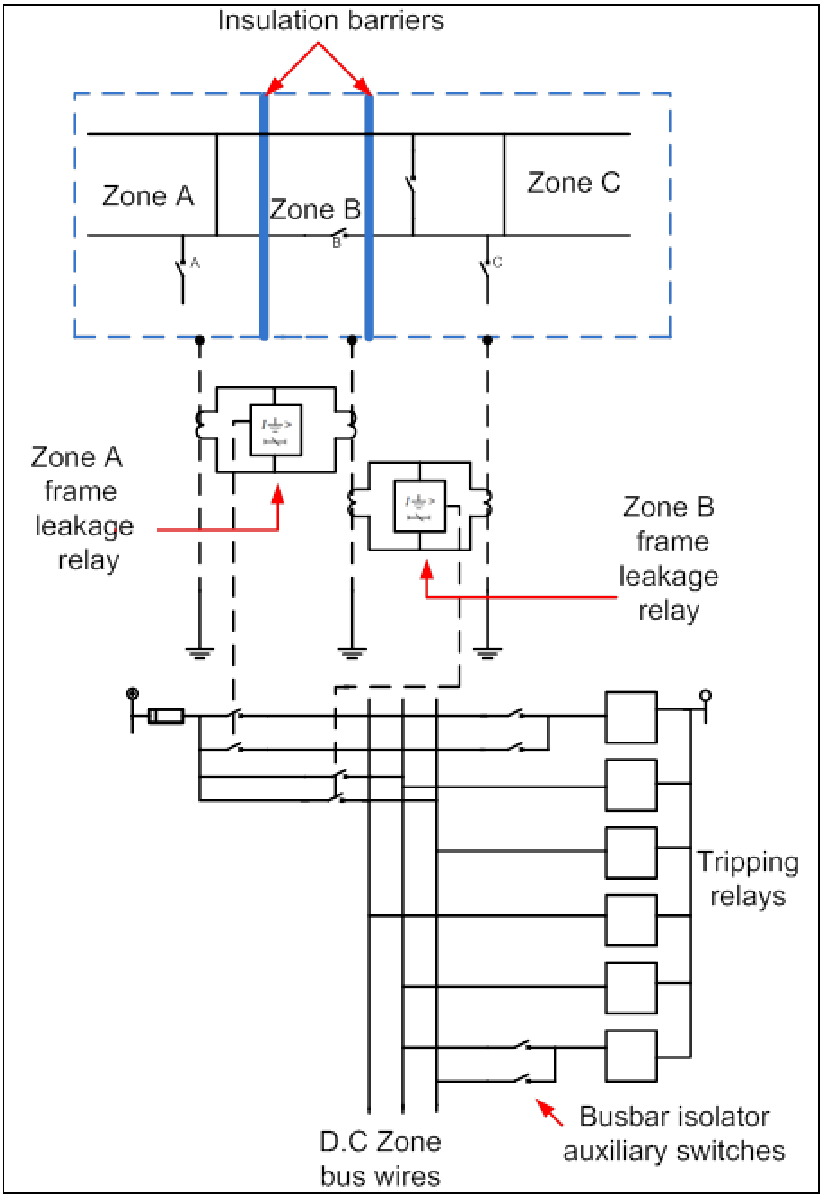


Figure 3.3: **The Frame – Earth Scheme - Double Bus Substation (NPAG, 2002)**

A check system is used to provide security to the equipment against events caused from operation due to human error or mechanical shock. This check system is not applicable for small equipment. If the low voltage wiring is faulty the check system must prevent the operation caused by the current passing to earth via the switchgear frame. The operation is provided by energizing the protection relay using the neutral current. If the check system for the neutral is not offered, the frame earth relays will operate after a short time delay (NPAG, 2002).

3.2.6 Differential protection for busbars

Differential protection operation directly uses the Kirchhoff's current law where it is required that the currents going into a node are equal to current leaving the node. When the sum of the currents is not equal to zero by comparing their magnitude or phase the difference is referred as a fault current as shown in Figure 3.4. When the busbar has a fault also known as internal fault, the total currents entering it is not equal to zero. If the fault is on the bus the sum of the all currents.

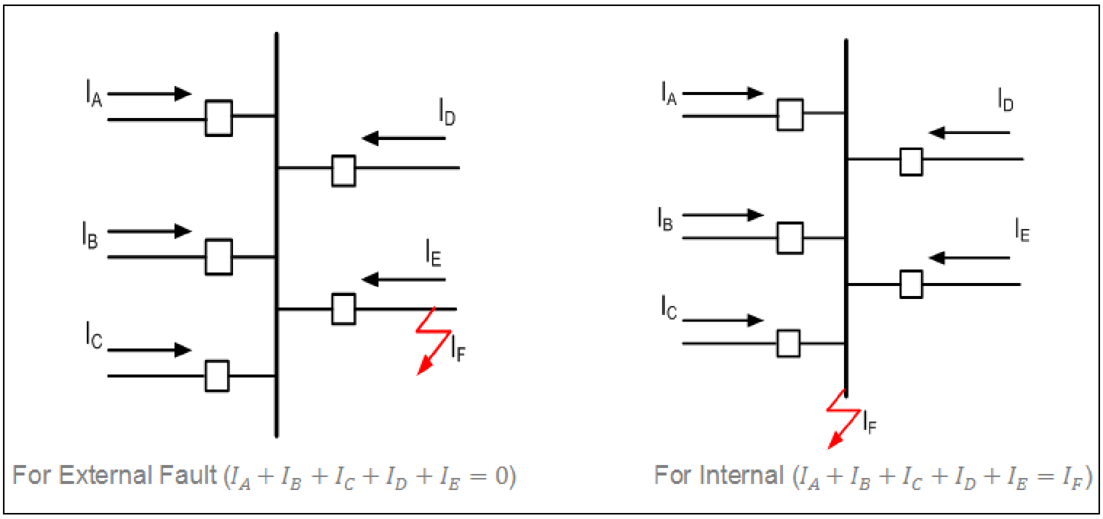


Figure 3.4: **The Differential protection for a busbar (Andrichak and Cargenas,1995)**

There are numerous methods can be used to apply the scheme.. Figure 3.5 shows an arrangement where one relay is employed with several CTs connected in parallel. This method is also useful for earth fault protection system for a busbar. An additional protection for phase faults can be achieved by connecting balanced group CTs in each phase in conjunction with three phase element relay as shown in Figure 3.5 below. In order to have a good performance for the scheme it is recommended to configure the phase and earth fault settings to be identical (Andrichak and Cargenas, 1995) and (Mohammed, 2005).

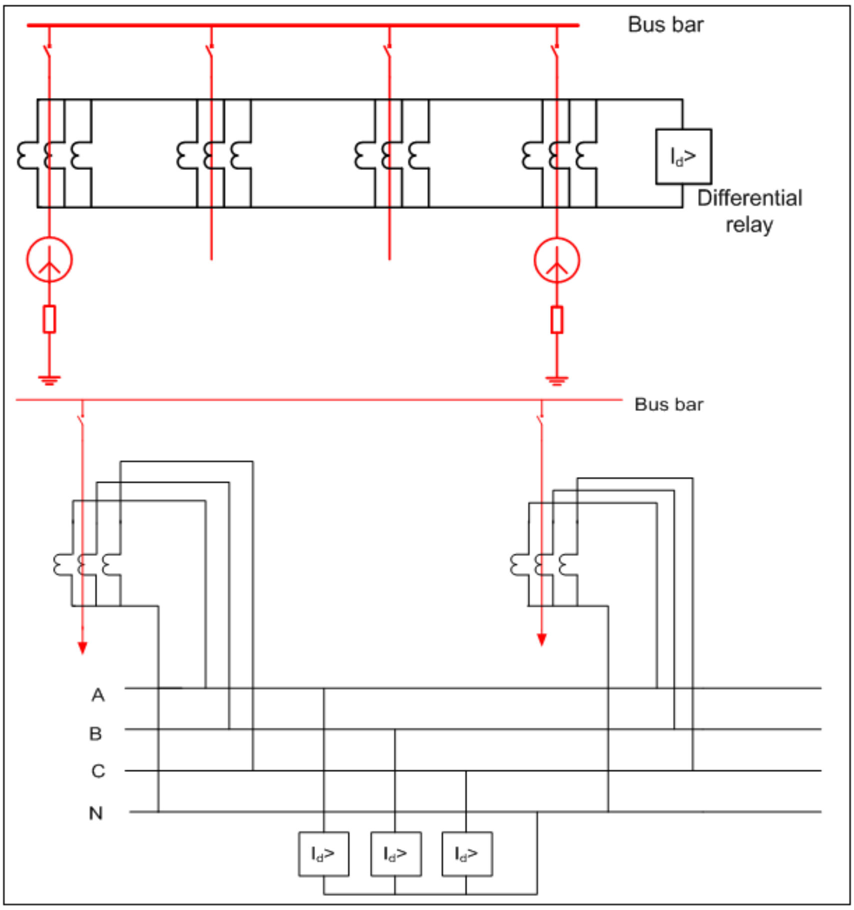


Figure 3.5: **Basic Circulating Current Schemes (NPAG, 2002)**

3.2.6.1 High Impedance Differential Protection

High impedance differential protection scheme has been in use for over fifty years because of its robust, fast and secure operation. This scheme makes use of the voltage across the differential junction points. The CTs that are utilized require low secondary leakage impedance. This arrangement is important especially when a serious saturation on the CTs during external faults occurs and, the voltages do not advance above certain level. This is caused because of the CTs have lower impedance path in comparison with the input impedance of the protection relay. The disadvantages for the scheme are that it requires dedicated CTs which adds extra cost. During a busbar fault it requires an additional voltage limiting varistor that is utilized to absorb energy (Kasztenny and Brunello, 2004).

3.2.6.2 Low Impedance Differential Protection

Low impedance differential protection scheme do not require dedicated CTs. This scheme has capabilities to tolerate substantial CT saturation during external faults. It also provides relatively high tripping speed. Introduction of microprocessor based relays makes this scheme to become attractive to most protection engineers because of its advance algorithms for percent differential protection functions. Re-configuration of busbar protection became less complex. Possibilities of replacing Data Acquisition Units (DAU) in bays by utilizing distribution architectures have become implementable (Kasztenny and Brunello, 2004).

3.2.6.3 Differential Protection for Sectionalized Busbars

When a differential protection is employed for sectionalized busbars it is required that divided bus utilizes separate circulating current. Zones are used to divide the sections and are designed in such a way that they are overlapping across the section switches, so the whole system is protected as shown in Figure 3.6 below (Elmore, 2004).

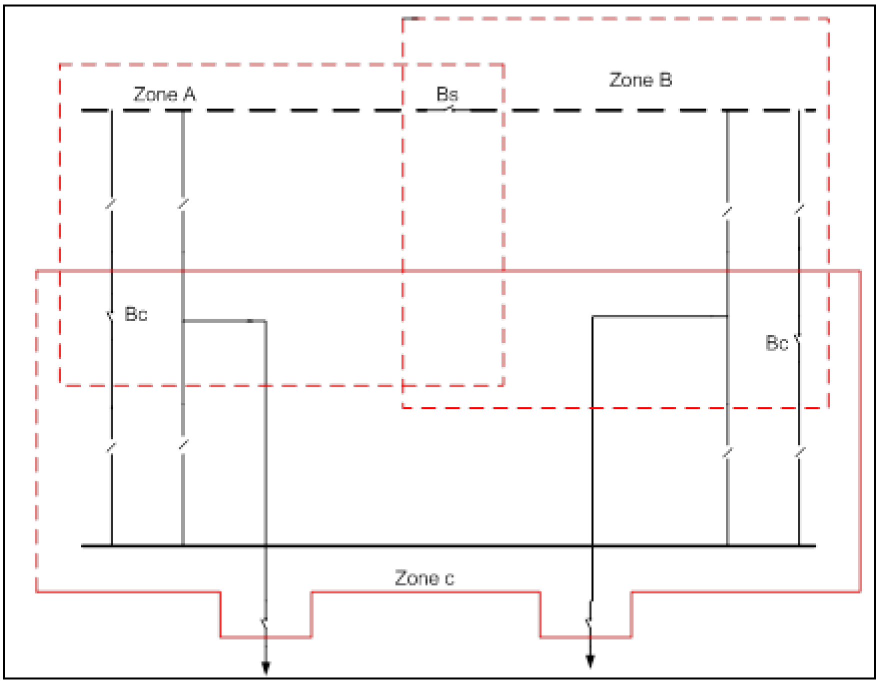


Figure 3.6: The Zones of Protection for Sectionalized Busbars (NPAG, 2002)

In a double busbar layout system the two busbars are handled as separate zones. Where the busbar is coupled, the zones will overlap. This system is designed in such a way that an isolator switch is connected between the busbars. It must be associated to an appropriate zone by means of early make and late break auxiliary contacts. This is to guarantee that when the isolators are closing, the auxiliary switches operate before the main contacts of the isolator. When the isolators are opened, their main contacts open before the auxiliary switches. The secondary circuits of the two zones are briefly paralleled and are linked through the circuit isolators during the transfer operation.

3.2.6.4 Location of the Current Transformers

In an ideal protection system the zones should overlap and have a separate discrimination protection circuits. The system is designed in such a manner that where the zones overlap there should be a circuit breaker across to cover both zones. With this system CTs must be installed on both sides of the circuit breaker as shown in Figure 3.7a. This is an ideal arrangement for basbar zone protection because it covers all primary circuits. Figure 3.7b shows an arrangement where the CTs are installed at one side of the circuit breaker. This is not ideal because it leaves a small region of the primary circuit unprotected. This unprotected region is called short zone. The disadvantage for this arrangement is when a fault is at the short zone: the circuit breaker will open but the fault current will still be flowing if there is a source of power in the circuit. This is not good for the system. A special protection needs to be provided to detect faults in the "short zone" and a trip signal to be sent to the next upstream breaker.

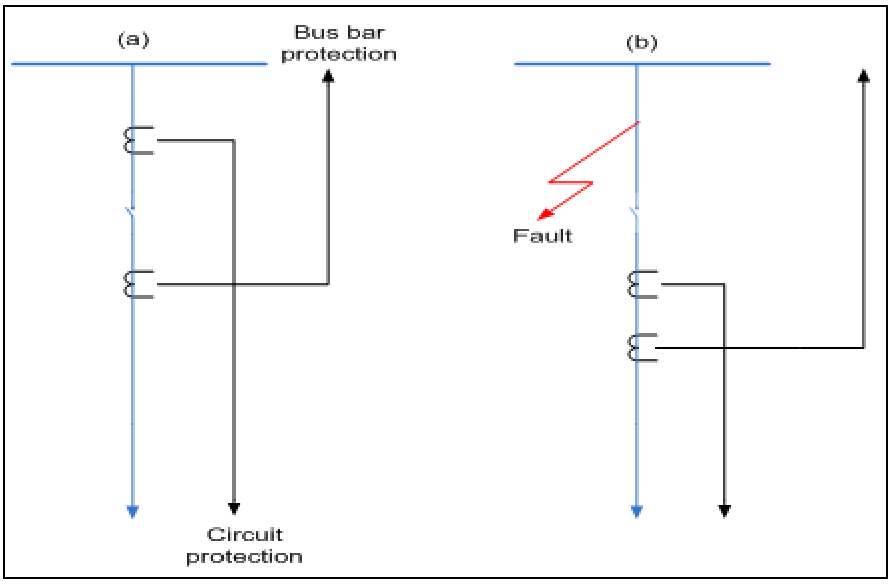


Figure 3.7a: **Current transformer mounted on both sides of the breaker (NPAG, 2002)**
Figure 3.7b: **Current transformer mounted only on a circuit side of the breaker with fault shown not cleared by the circuit protection (NPAG, 2002)**

3.2.7 Reverse blocking / interlocking protection

In a distribution busbar system traditionally when a fault occurs it was cleared by time delay protection upstream relays. With the introduction of numerical technology a simple protection scheme such as busbar blocking scheme can be applied to protect a distribution system with a single source. This scheme is achieved by installing an overcurrent relay on an incoming feeder circuit and also installing overcurrent relay in all out feeders as shown in Figure 3.8 below (Kasztenny and Brunello, 2004) where the number 50 means instantaneous overcurrent. The overcurrent relay on the incomer is set to trip for a fault at the busbar unless it is blocked by any overcurrent relays on the feeder. A time grading is required to coordinate these overcurrent relays in order to avoid race conditions. The advantages for utilizing this scheme are as follows:

- Modifications for the scheme to suit substation extension are easy.
- It utilizes overcurrent elements that are already supplied by the feeder protection relays.
- It requires minimal cost in comparison with the differential protection scheme.
- It has faster fault clearance in comparison to a system that utilizes trip originated by upstream feeder protection (Kasztenny and Brunello, 2004).

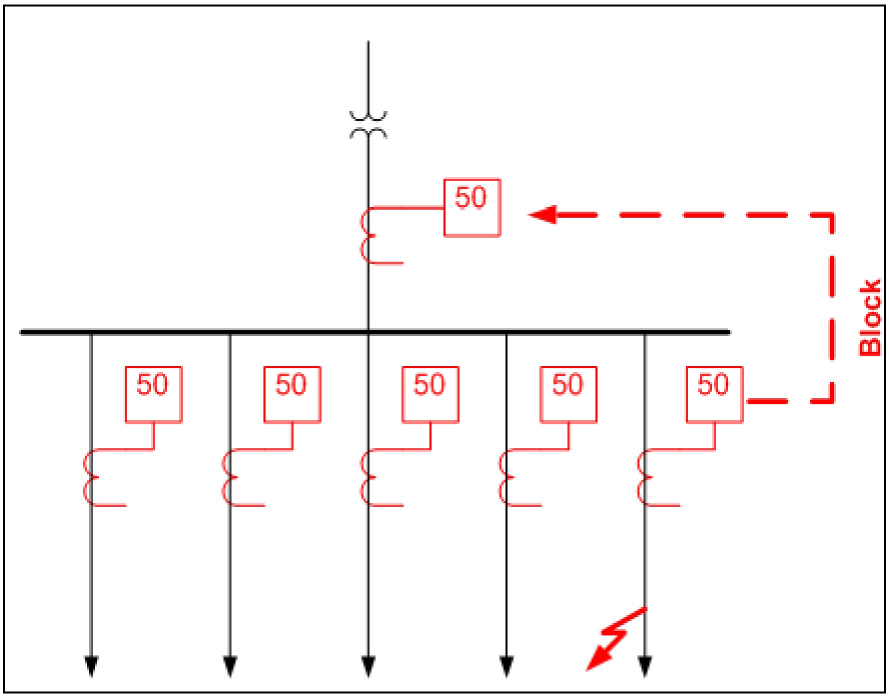


Figure 3.8: **The Illustration of the interlocking scheme (Kasztenny and Brunello, 2004).**

3.3 Overcurrent protection relays

Busbar blocking scheme utilizes over current protection relays with a basic principle of time grading system and discrimination fault protection. It is important to understand the different types of fault currents that can flow within the network. The relay data settings that are required are as follows NPAG, 2002)

- A one line diagram with type and rating of the protection device.
- The impedances of all components and feeder circuits
- The fault currents minimum and maximum values
- The maximum load current through the devices used for protection.

3.3.1 Principles of Time/Current Grading

Correct relay co-ordination can be achieved by utilizing three possible methods, namely:

- Time co-ordination
- Current co-ordination
- Combination of time and overcurrent

The general aim of all three methods is to provide accurate discrimination (So and Li, 2000),

3.3.1.1 Discrimination using the time parameter

All protection relays are configured with a suitable time setting to control circuit breaker nearest to the fault to operate first. This method utilizes overcurrent protection relays with a definite-time delay element. If the current element settings are below the fault current value discrimination will not be achieved. When this process occurs the protection relay is known as an independent definite-time delay relay. For each relay the tripping time interval must be extended in such a way that the relays in the upstream do not trip until circuit breaker closest to the fault location operates. The disadvantage for utilizing this method is that severe faults take the longest clearance time (Elmore, 2004).

3.3.1.2 Discrimination using the current parameter

The impedance value between the fault and the power supply source plays an important role in discrimination using the current method. Hence, the protection relays operating various circuit breakers are set to trip at appropriate tapered values of the current. This is done in such a way that only the protection relay closest to the fault trips its breaker. Current discrimination utilizes the rating of the current them of circuit breaker In order for distribution systems to achieve proper current discrimination it is essential for the device at the downstream to have a lower instantaneous tripping value and current rating than the device on the upstream (NPAG, 2002).

3.3.1.3 Discrimination using both time and current parameters

Limitations caused by the employment of either time or current co-ordination independently lead to an inverse time overcurrent relay characteristic to be developed. This method has operation time that is inversely proportional to the fault current level. Figure 3.9 below shows the two relays with different settings for current/time characteristics In a scenario where the two feeders with a huge deviation of fault current between them and a fast operating time is needed. The fast operating time is possible to be achieved by utilizing the protection relay nearest to the power source, where the fault level is the highest. This method defeats the disadvantages of using time grading or current grading individually. The method of setting the over overcurrent protection relay characteristics begins with choosing the correct characteristic to be applied for each relay. It is then followed by the current settings of the protection device. In the final stage, relays time settings and grading margins are selected. (Elmore, 2004).

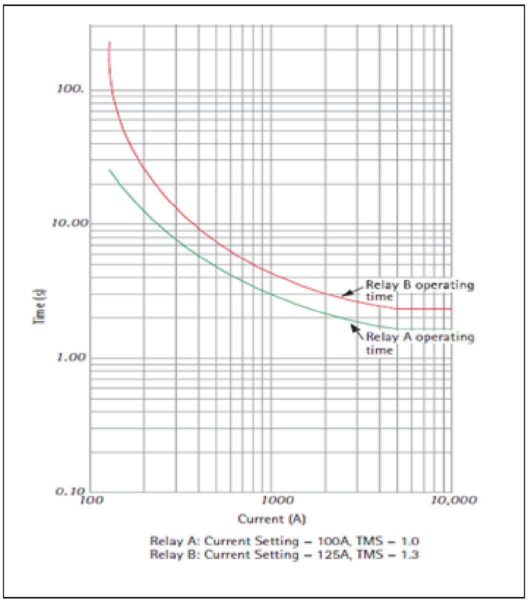


Figure 3.9: **A characteristic of two relays with different current/time settings (NPAG, 2002)**

3.3.2 The standard Inverse Definite Minimum Time (IDMT) overcurrent relays

IDMT relay has current/time tripping characteristics that are varied according to the requirement of the protection devices utilized in the network. In order to have a correct design it is required to use IEC60255 standard that defines the characteristics of the IDMT relays. The standard characteristics are as follows (Elmore, 2004).

- Standard Inverse
- Very Inverse
- Extremely Inverse
- Definite Time

Table 3.1: Characteristics of the relay based on the IEC 60255 standard

Relay Characteristic	Equation (IEC 60255)
Standard Inverse (SI).	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very Inverse (VI)).	$t = TMS \times \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)).	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long time standard earth fault).	$t = TMS \times \frac{0.14}{I_r - 1}$

Where:

t is the trip time.

TMS is Time Multiplier Setting.

I_r current setting is the Plug setting multiplier (PSM)

3.3.3 Relay current setting

Overcurrent relay used for protection in power systems requires a minimum operating current. The minimum operating current is introduced as the current setting of the relay. Current setting is selected in a sense that the protection relay do not trip in a case of maximum load current. The protection relay is required to trip for current equal or bigger than the minimum designed fault current. The purpose of using overcurrent protection in primary systems is for isolating faults location from the rest of the healthy system. Usually current setting chosen must be higher than the rated maximum circuit current based on the system involved. The current setting in all relays features hysteresis. Therefore the volume of hysteresis within the current settings is referred by a pick-up/drop-off ratio of the protective device. The current setting value for a modern protective device is typically 0.95 therefore minimum current setting is roughly 1.05 times of the rated circuit current (Elmore, 2004).

3.3.4 Relay time grading margin

The grading is depended on the entire interval of the speed operation of a relay and the circuit breakers. In the past the value of 0.4 seconds was a normal grading margin. With introduction of the modern circuit breakers and the relays with lower overshoot time 0.3 seconds is now reasonable. Most systems utilize grading margin that are fixed. The value of grading margin can be calculated for each relay location. The calculated value is more precise margin and it consists of the following fixed times:

- Circuit breaker fault interrupting time
- Overshoot time
- Safety margin
- Variable time for the relay and CT errors

Typical relay errors based on the technology utilized are shown in Table 3.2 below in high fault levels grading margin that is fixed can be used in order to have short relay operating times. Grading margin can be defined by modifying the relay closest to a fault to have +2E as maximum for timing error. E is the timing error, (So et al., 1997) (NPAG, 2002).

Table 3.2: **The relay timing errors with standard IDMT (NPAG, 2002).**

	Electro-mechanical	Static	Digital	Numerical
Timing error (%).	7.5	5	5	5
Overshoot time (s).	0.05	0.03	0.02	0.02
Safety margin (s).	0.1	0.05	0.3	0.03
Overall grading margin – relay to relay(s).	0.4	0.035	0.3	0.3

The equation calculating minimum time interval of grading margin, $t^{'}$ shown below:

$$t^{'} = \left(\frac{2E_R + E_{CT}}{100}\right)t + t_{CT} + t_o + t_s$$

Where:

E_R = Relay timing error (IEC 60255-4)
E_{CT} = is the CT ratio error (%)
t = is the rating time of relay nearer the fault (s)
t_{CB} = is the CB interruption time (s)
t_o = relay overshoot time (s)
t_s = safety margin (s)
For the Definite Time characteristics the CT error allowance is neglected, hence:

$$t^{'} = \left(\frac{2E_R}{100}\right)t + t_{CT} + t_o + t_s$$

3.4 Digital protection

Digital protection application for busbars has lagged behind in comparison with the application of the protection functions. Generally static technology is still utilized in busbar protection schemes, but now introduction of the digital technology has become mature enough to be considered for busbar protection. Digital technology provided multiple communication paths for protection relays to link to various units. Figure 3.10 shows the algorithm adopted for distributed processing of the measured values (Hodgkiss, 1960); .Each feeder has a Processing Unit (PU) that utilizes the storing information such as currents, voltages, circuit breaker and isolator status, etc. It uses high-speed fibre-optic for communication to link data to a Central Unit (C U). In large substations it is required to utilize more than one central unit while in small stations co-location is used for the units.

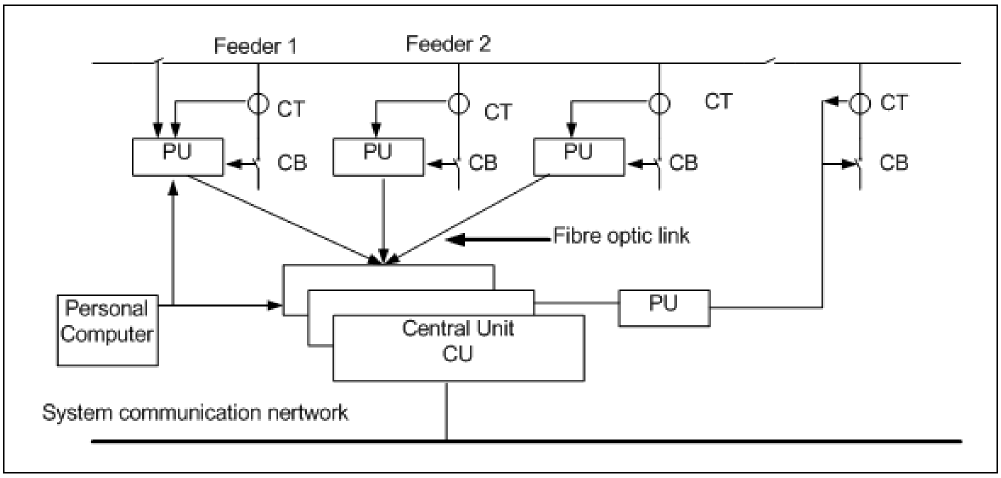


Figure 3.10: **Algorithm adopted for distributed processing of the measured values (NPAG, 2002)**

The central unit performs calculations required for the protection functions. The available protection functions are as follows:

- Protection monitoring
- Backup over-current protection
- Breaker failure
- Dead zone protection

In order to monitor functions such as circuit breakers and isolator disturbance a recording function must be provided.

3.5 Reliability considerations

The literature review shows that comparison between conventional protection schemes and modern numerical schemes in terms of reliability has revealed improvement when utilizing numerical relays. The digital protection schemes have better performance in comparison with protection that uses electromechanical relays. A comparison study between different generations of protection relays is shown below in Table 3.3. Digital relays reduce the number of external components and software algorithms are used to perform different functions. They also have monitoring functions which provide alarm facilities when the scheme is faulty. These advantages create the following improvements of the development and operation of the protective schemes (Lohmann, 2001):

- Object-oriented architecture
- Lower communication infrastructure costs
- Reduced effort in commissioning
- Lower installation and maintenance costs
- Reduced wiring costs
- Provide a full set of services

- Enable interoperability without gateways / routers

Table 3.3: Overview of protection relays generations and their capabilities.

Generation capability	IED	Digital relay	Solid state	Electromagnetic
Self-checking & reliability	yes	yes	yes	no
System integration & digital environment	yes	yes	no	no
Functional flexibility & adaptive Relaying	yes	yes	no	no
Complete Substation Automation	yes	no	no	no
Functional capability	high	medium	low	Very low

3.6 Discussions

When it comes to the capabilities IEDs is considered as the ideal devices for the thesis. ABB IEDs are chosen and IEC 61850 standard is used as the platform for communication. These IEDs are selected based on their functional flexibility and adaptive relaying.

3.7 Conclusion

This section covered the busbar theory with protection functions and applications in a distribution environment. The ability, advantage and disadvantages between busbar protection schemes utilized are discussed. The theoretical aspects that require understanding in order to perform busbar protection studies using various schemes are described.

The next chapter describes simulation studies of a selected distribution network done to design its protection scheme and analyze its performance.

CHAPTER FOUR
SIMULATION STUDIES OF THE DISTRIBUTION BUSBAR PROTECTION SCHEME

4.1 Introduction

A distribution busbar reverse blocking scheme is designed and simulated in this chapter. A DIgSilent software package is the suitable program that is utilized for the simulation.

A model of the distribution network is selected and its parameters are calculated. The fault currents are calculated for different fault locations. Various types of faults are applied to the network in order to be able to configure the setting of the protective devices. Two case studies are considered:

- Conventional relays are used for design and simulation of the reverse blocking scheme a case study 1.
- IEC 61850 standard compliant relays (IEDs) are used for design and simulation of the reverse blocking scheme the case study 2.

ABB relay models from the DIgSilent library are used in the simulation.The effect of the different fault levels over the fault clearing times and the stability of the network are investigated. The protection devices time grading and co-ordination setting are analyzed in order to have an efficient busbar protection scheme. The results are compared and analyzed.

The material of the chapter is presented as follows:

The model of the distribution network and its simulation are introduced in part 4.2. Calculation of the short circuit currents is done in part 4.3. Selection of the busbar protection characteristics is presented in part 4.4. The protection algorithm and its parameters design are presented in part 4.5. Part 4.6 presents the results of the investigated two case studies. Discussion of the results is done in part 4.7 and part 4.8 presents the conclusion.

4.2 Distribution network modelling

4.2.1 Selected distribution network in one line diagram

The aim of this chapter is to construct and model a single line diagram with its relevant equipment and simulate it. The network system has generation, buses, transformer, network connections, cable interconnection and loads. The distribution network that is developed and a load flow study are carried out. Distribution networks are characterised based on their short circuit capacity. The basic requirement for a distribution network is to determine the total fault level and the contribution of the short circuits within it. In a radial network generally for medium voltage (MV) and low voltage (LV) the fault current contribution is determined by the short circuit impedance of the transformer. When a short circuit occurs within the network a high fault current is created that leads the network to fail. Therefore protection devices are needed to protect the distribution system not to fail when faults arise. Overall these elements influence the power quality performance of the network. The distribution network that is studied is shown in Figure 4.1 with its data in the form of One Line Diagram (OLD). The study of the network is focusing on the fundamentals of single phase and three phase short circuit currents calculation and how they contribute to the network protection.

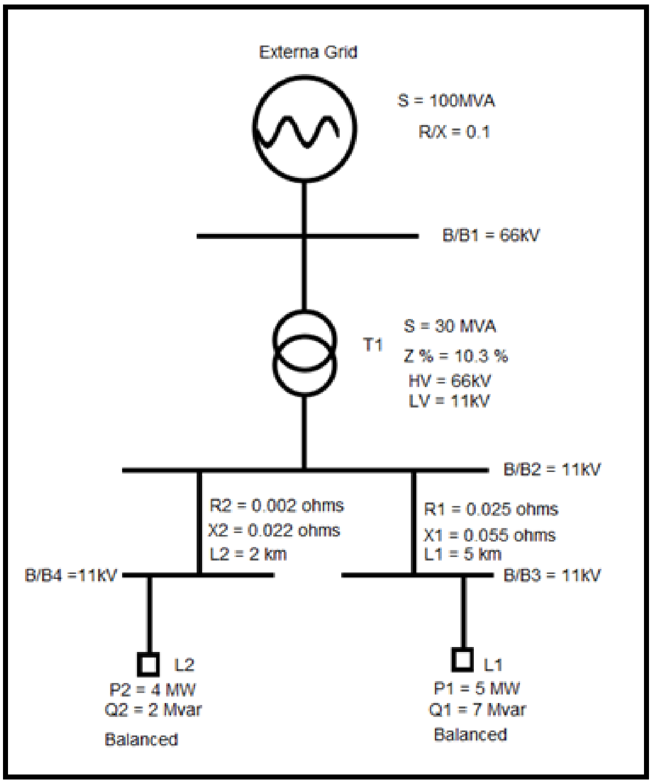


Figure 4.1: **One line diagram of the studied distribution network**

4.2.2 Preparation of Data for calculation of the load flow in DIgSILENT

Load flow calculation is a collective computational process used for distribution system simulations. Planning, control and operation of the distribution network require such calculations in order to analyze the steady state performance of the system. This is implemented under various operating conditions and equipment configurations. This load flow calculation is focusing on determining voltage magnitude V voltage angle ϑ of the nodes, including the active P and reactive Q power flow on all branches. An AC load flow, balanced, positive sequence is performed making use of Newton-Raphson method for current and power equations simulation**.** The distribution network that is selected and modelled for simulation has the following parameters as shown in Table 4.1.

Table 4.1: The parameters of the considered distribution network

Basic Data: Name = External Grid Load Flow data: Bus Type = “SL” (Slack) Angle = 0.0 deg Voltage Set Point = 1.0 pu VDE/IEC Short-Circuit: Short Circuit power “Sk” = 100MVA	Transformer Type = 2- Winding transformer Rated power = 30MVA Rated voltage HV = 66kV Rated voltage LV = 11kV Impedance = 10.3% Vector group = HV YN Vector group = LV YN
High side voltage bus = 66kV	Low side voltage buses = 11k
Line1 Name = Line B2 to B3 Rated value = 11kV Rated current = 0.283kV Type of Line = Cable Length line = 5km Laying = ground	Line 2 Name = Line B2 to B4 Rated value = 11kV Rated current = 0.283kV Type of Line = Cable Length line = 2km Laying = ground
Load 1 Name: L1 Load Flow: Balanced/Unbalanced = Balanced Active power = 5 MW Reactive power = 7 Mvar Power factor = 0.9 Voltage = 1.0 p.u	Load 2 Name: L2 Load Flow: Balanced/Unbalanced = Balanced Active power = 4 MW Reactive power = 2 Mvar Power factor = 0.9 Voltage = 1.0 p.u

The data shown in the above table are completed on the network system model in DIgSILENT shown in Figure 4.2(a) where the result boxes in the blue colour represent the active, reactive and apparent power below. Figure 4.2(a) also show result boxes in the red colour represent voltage in kV, voltage in p u and the phase angle.This distribution network is simulated and analyzed The objectives for the experiment are to develop different case studies of load flow analysis, short circuit analysis and execution of load flow calculation. These assessments are done in order to design the protection of the distribution network system.

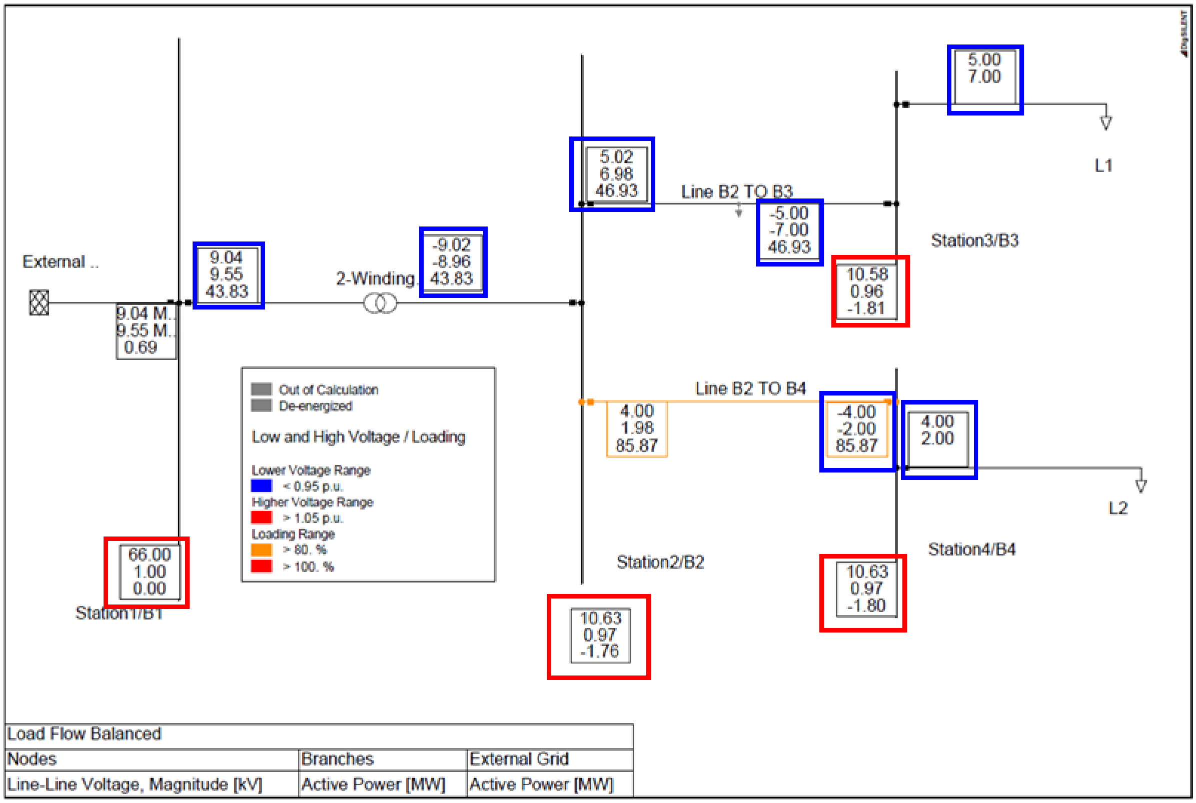


Figure 4.2(a): One line diagram of the load flow calculation for the studied distribution network

4.2.3 Load flow results

Once the load flow is successfully executed the results for the three phase voltages and three phase currents are shown in Figure 4.2(b) below where phase A is represented in red, phase B in yellow and phase C in blue. The results show that the voltages and currents are balanced with a 120 degrees phase shift**.** This is recorded during normal condition in the distribution network. Table 4.2 shows different voltage levels in the network from bubar1 up to busbar 4, Table 4.3 shows voltage deviation profiles of the calculated load flow which are within IEEE standard 141-1993 voltage criteria.

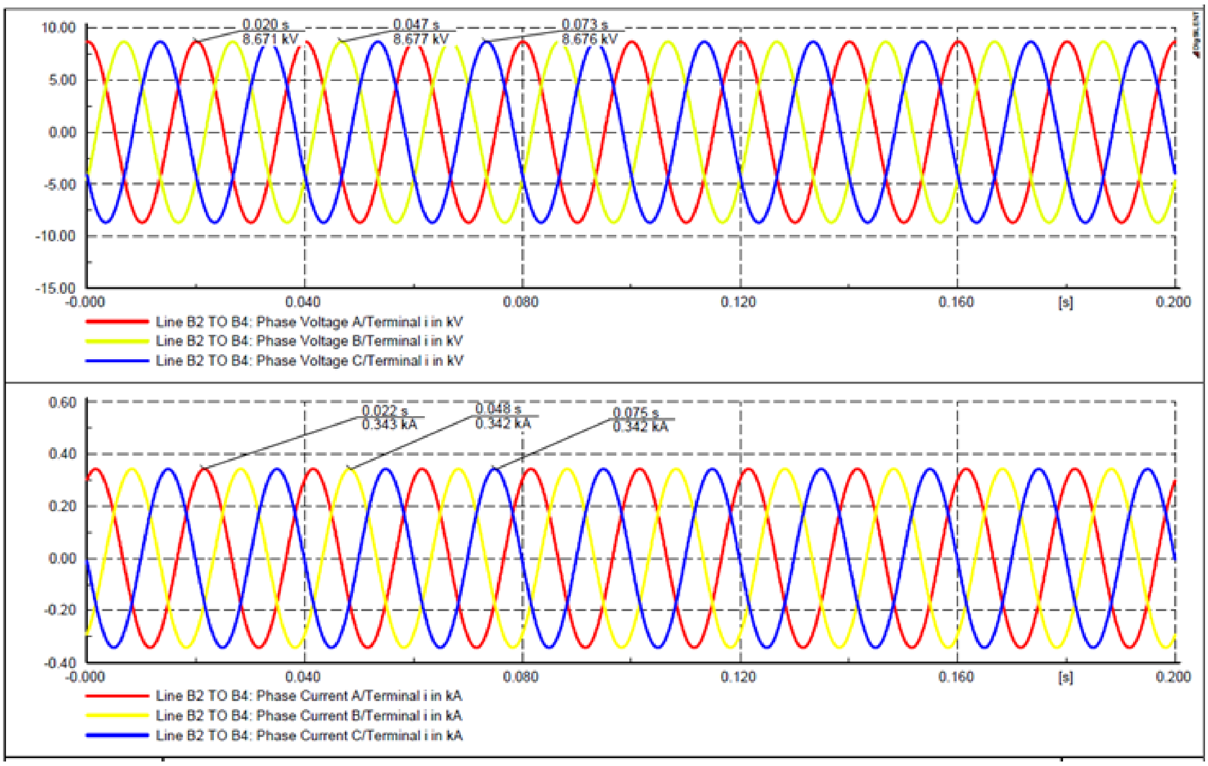


Figure 4.2(b): Three phase voltages and currents for the simulated distribution network

Table 4.2: The load flow results for the different voltage levels in the network

Load Flow Calculation		Complete System Report: Substations	
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1.00 kVA
		Model Equations	0.10 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 1

	rtd. V [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Generation [MW]	[Mvar]	Motor Load [MW]	[Mvar]	Load [MW]	[Mvar]	Ext. Infeed [MW]	[Mvar]	Compensation [Mvar]
Station1 B1	66.00	1.00	38.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.04	9.55	0.00
Station2 B2	11.00	0.97	6.14	-1.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Station3 B3	11.00	0.96	6.11	-1.81	0.00	0.00	0.00	0.00	5.00	7.00	0.00	0.00	0.00
Station4 B4	11.00	0.97	6.13	-1.80	0.00	0.00	0.00	0.00	4.00	2.00	0.00	0.00	0.00

Table 4.3: The load flow results for the busbar voltages

Load Flow Calculation		Complete System Report: Voltage Profiles	
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1.00 kVA
		Model Equations	0.10 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 1

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]	Voltage - Deviation [%] -10 -5 0 +5 +10
Station1 B1	66.00	1.000	66.00	0.00	
Station2 B2	11.00	0.966	10.63	-1.76	
Station3 B3	11.00	0.962	10.58	-1.81	
Station4 B4	11.00	0.966	10.63	-1.80	

The results analyses show that voltage at the load buses are generally averaging around 0.96 per unit. The loading on a transformer and cables are within normal working capabilities. The generator reactive outputs are within the limits that are defined by the generator capability curves. The voltage criteria are within the IEEE standard 141-1993.

The next procedure is to calculate the short circuit currents as a preliminary step before the design of the protection scheme.

4.3 Calculation and simulation of the short circuit currents

The objective for the short circuit study is to apply a calculation methodology in order to be able to specify fault ratings for all electrical devices that are used for protection. Therefore short circuit current calculations in the distribution network are implemented in order to identify other potential problems. There are five general steps that are followed when calculating short circuit currents based on the IEC 60909 standard in the distribution network. These steps are as follows:

- Construction of the distribution network and its relevant parameters
- Calculation for short circuit impedance for all relevant components
- Refer all impedances to the reference voltage
- Calculate balanced three-phase short circuit currents
- Calculate single-phase to earth short circuit currents

The Construction of the distribution network and its relevant parameters is already done in section 4.2.1

4.3.1 Calculation of short circuit impedances

The element in the network can be represented by equivalent impedances Z_{eq} for the balanced systems. The equations used in the DIgSilent software to calculate the network impedances for each element are represented in Table 4.4,

Table 4.4 **Equation for calculations of impedance for each element in the distribution network**

Element	Equation
Upstream	$Z_{eq} = \frac{V_n^2}{S_{SC}}$
Busbar One	$X = 0.15 \times 10^{-3}$, R **is negligible,** $V_n =$ **66kV**
Transformer T1	$Z_{B(LV)} = \frac{V_B^2}{S_T}$, $Z_T = Z_B X_{zpu}$
Busbar Two	$X = 0.15 \times 10^{-3}$, R **is negligible,** $V_n =$ **66kV**
Line One	$Z_{line1} = (R_1 + X_1)$
Line Two	$Z_{line1} = (R_2 + X_2)$

Busbar Three	$Z_B = \frac{(P_1 + jQ_1)}{S_B}$ **,** $V_n =$ **11kV**
Busbar Four	$Z_B = \frac{(P_1 + jQ_1)}{S_B}$ **,** $V_n =$ **11kV**
Load One	$Z_{load1} = \frac{cV_B^2}{S_B} COS^{-1} PF$
Load Two	$Z_{load2} = \frac{cV_B^2}{S_B} COS^{-1} PF$

Where V_n is the nominal voltage
V_B is the base voltage
S_b is the apparent power
P is the active, power
Q is the reactive power
X is the reactance of each component
R is the resistance for each component
PF is the power factor
c is the voltage factor

Short circuit impedances of every component of the distribution network are calculated using the calculated parameters. To calculate the impedances, resistance and reactance of the feeders in the network the following equations are used:

$$Z_f = \frac{cV_n^2}{S_f} \tag{4.1}$$

$$R_f = \frac{Z_f}{\sqrt{1 + \left(\frac{X}{R}\right)^2}} \tag{4.2}$$

$$X_f = \frac{X}{R} \times R_f \tag{4.3}$$

Where Z_f is the impedance of the network feeder in ohms
R_f is the resistance of the network feeder in ohms
X_f is the reactance of the network feeder in ohms
V_n is the nominal voltage at the connection point
S_f is the fault level of the network feeder (VA)
c is the voltage factor
$\frac{X}{R}$ is the X/R ratio of the distribution network in per unit

R is the resistance of the network
X is the reactance of the network

4.3.2 Calculation of the generator sub- transient reactance and resistance

With voltage regulation in the modeled network the sub- transient reactance and resistance of the generator is estimated using the following formulas:

$$X_d^{"} = x \times K_g \times \frac{V_g^2}{S_g} \tag{4.4}$$

$$R_g = \frac{X_d^{"}}{\frac{X}{R}} \tag{4.5}$$

$$K_g = \frac{V_n}{V_g} \frac{c}{1 + x_d^{"} \sin\theta_g} \tag{4.6}$$

Where:

$X_d^{"}$ is the sub-transient reactance of the generator in ohms
R_g is the resistance of the generator in ohms
K_g is the voltage correction factor in per unit
$x_d^{"}$ is the per unit sub transient reactance of the generator in per unit
V_g is the nominal generator voltage
V_n is the nominal system voltage
S_g I s the rated generator capacity
$\sin\theta_g$ is the power factor of the generator in per unit

4.3.3 Calculation of the transformer impedance, resistance and reactance

The calculations of the impedance, resistance and reactance of the two winding distribution transformers make use of the following equations.

$$Z_t = u_k \frac{V_t^2}{S_t} \tag{4.7}$$

$$R_t = \frac{P_{kt}}{3I_t^2} \tag{4.8}$$

$$X_t = \sqrt{Z_t^2 - R_t^2} \tag{4.9}$$

Where Z_t is the positive sequence impedance of the transformer in ohms
R_t is the resistance of the transformer in ohms
X_t is the reactance of the transformer in ohms
u_k is the impedance voltage of the transformer

S_t is the rated capacity of the transformer

V_t is the nominal voltage of the transformer at the high or low side

I_t is the rated current of the transformer at the high or low side

P_{kt} is the total copper loss in the transformer windings

4.3.4 Calculation for the resistance and reactance of the cables

Usually cables are supplied in ohms per kilometer from the manufacturer. Therefore there is a need to convert the ohms based on the length of the cable to ohms. The calculation of the resistance and reactance of the cables are as follows:

$$R_c = R \times \frac{Lc}{1000} \tag{4.10}$$

$$X_c = X \times \frac{L_c}{1000} \tag{4.11}$$

Where R_c is the resistance of the cable in ohms

X_c is the reactance of the cable in ohms

R is the quoted resistance of the cable in ohms per km

X is the quoted reactance of the cable in ohms per km

L_c is the length of the cable in m

4.3.5 Calculations of the referring impedance of the distribution network

Since the network has the multiple voltage levels the impedances of the components that are calculated earlier needs to be converted to a reference voltage. This is done in order for them to be implemented in a single equivalent circuit. The equations for this calculation are as follows:

$$n = \frac{V_{t2}\left(1 + t_p\right)}{V_{t1}} \tag{4.12}$$

$$Z_{HV} = \frac{Z_{LV}}{n^2} \tag{4.13}$$

$$Z_{LV} = Z_{HV} \times n^2 \tag{4.14}$$

Where n is the transformer ratio

V_{t2} Is the transformer nominal LV voltage

V_{t1} Is the transformer nominal HV voltage

t_p Is the specified tap setting

Z_{HV} Is the impedance referred to the primary (HV)

Z_{LV} Is the impedance at the secondary (LV)

Once these calculations are completed the next step is to apply them into the modeled distribution network in the software environment of the DigSilent package

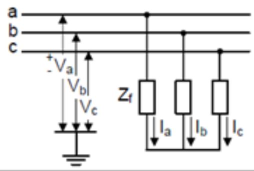
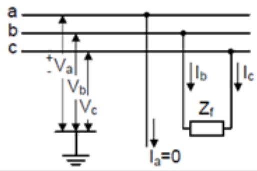
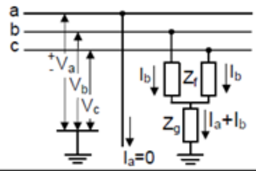
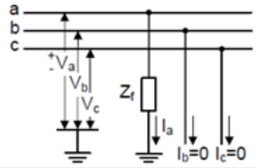
4.3.6 Short circuit simulation

Power system is developed in such a way that the electricity is supplied safely and reliably to the loads. The major features taken into account in the design and operation of the electrical systems is the handling of the short circuits. Short circuits (SC) are classified in four types namely:

- Three phase SC
- Line-to-line SC
- Double line-to-ground SC
- Single line-to-ground SC

The circuit diagram of the fault point, boundary conditions and a description of the different short circuits given above are shown in Table 4.5 below

Table 4.5: **Different types of short circuit faults in the three phase network**

Fault	Circuit diagram of the fault point	Boundary conditions	Description
Three-phase SC		$I_a+I_b+I_c=0$ $V_a=Z_f\ I_a$ $V_b=Z_f\ I_b$ $V_c=Z_f\ I_c$	• Connection of all conductors with or without simultaneous contact to ground • Symmetrical loading of the three external conductors • Calculation on a single-phase basis
Line-to-line SC		$I_a=0$ $I_b=-I_c$ $V_b-V_c=Z_f\ I_b$	• Unsymmetrical loading • All voltage non-zero • SC current higher than in a three-phase SC near-to-generator
Double line-to-ground SC		$I_a=0$ $V_b=(Z_f+Z_g)I_b+Z_g\ I_c$ $V_c=(Z_f+Z_g)I_c+Z_gI_b$	• The leakage current flowing to ground is a capacitive ground fault current
Single line-to-ground SC		$I_b=I_c=0$ $V_a=Z_f\ I_a$	• Very frequent occurrence in low voltage networks

The short circuit currents are applied to check the rating of the equipment in the network during the planning stage. In this case the interest is based on the maximum expected currents and minimum expected currents to manage the design of the protection scheme. Therefore the protection devices are required to protect the distribution network and not to fail when faults occurs. The tool used for the short circuit analysis is the DIgSILENT simulation software. This tool has of functions such as co-ordination of protection equipment for system planning and protection relay settings for system operations. Once all parameters of the network are complete the next step is to calculate the required short circuit current levels making use of the DIgSILENT simulation tool. Different case studies are developed with utilization of a Single-Line-Diagram (SLD). The short circuit location and its requirements are chosen. The initial three phase short circuit current $I_k^{''}$, single phase to earth short circuit current $I_{kl}^{''}$, and the peak short circuit current I_p of the system operation are simulated and taken into consideration. The initial short circuit current is considered as the sum of an AC symmetrical and DC decaying components. A basic differentiation is made between the components for faults far from the generator and the components for faults closer to the generator. The maximum and minimum short circuit current values are calculated using the IEC 60909 standard. The short circuit current calculation for the fault levels involves also the short circuit power $S_k^{''}$. The equations used are represented as follows:

$$I_k^{''} = \frac{cV_n}{\sqrt{3}Z_k} \tag{4.15}$$

$$I_{kl}^{''} = \frac{\sqrt{3}cV_n}{Z_{k(1)} + Z_{k(2)} + Z_{k(0)}} \tag{4.16}$$

$$k = 1.02 + 0.98e^{\frac{-3}{X/R}} \tag{4.17}$$

$$I_p = k \times \sqrt{2}I_k^{''} \tag{4.18}$$

$$S_k^{''} = \sqrt{3}I_k^{''}V_n \tag{4.19}$$

Where $I_k^{''}$ is the initial symmetrical short current

I_P is peak short circuit current

k is the constant factor

c is the voltage factor

V_n is the nominal voltage at the short circuit location

Z_k is the equivalent short circuit impedance

$Z_{k(1)}$ is the equivalent positive sequence short circuit impedance

$Z_{k(2)}$ is the equivalent negative sequence short circuit impedance

$Z_{k(0)}$ is the equivalent zero sequence short circuit impedance

The short circuit are applied in to the distribution network at specific locations namely: busbar B2 (substation2/2), load 1(line B2 to B3) and load 2 (Line B2 to B4) respectively as shown in Figure 4.3 where boxes in the red colour represent short circuit power, initial symmetrical short current and peak short circuit current.

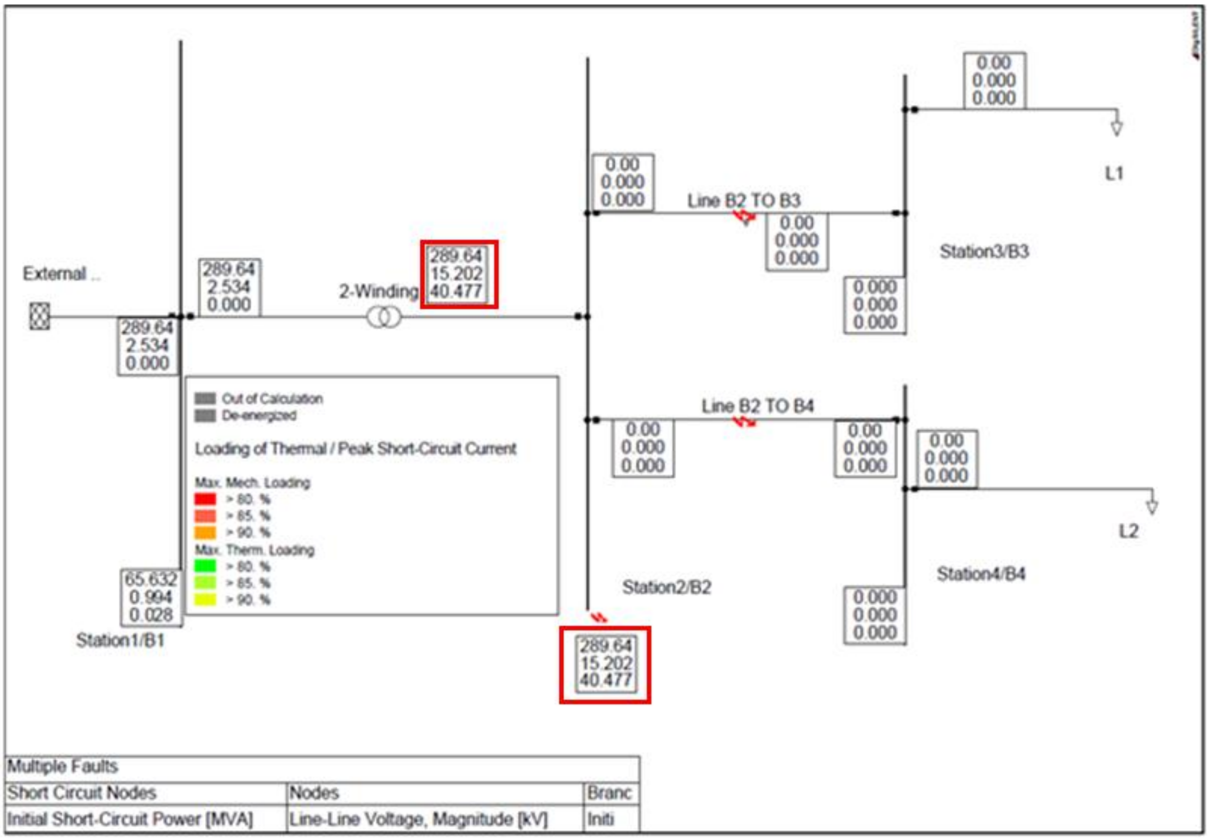


Figure 4.3: One line diagram of the studied faults in the distribution network

4.3.7 Results from the simulation of the short circuit currents

The three phase network is normally treated as a balanced symmetrical system. When the fault occurs in the power network systems the symmetry is normally disturbed as shown in Figure 4.4 below. The only case that is exceptional is when a three phase fault occurs, because all three phases are involved. Investigation of the influence of every one of the considered faults is described below.

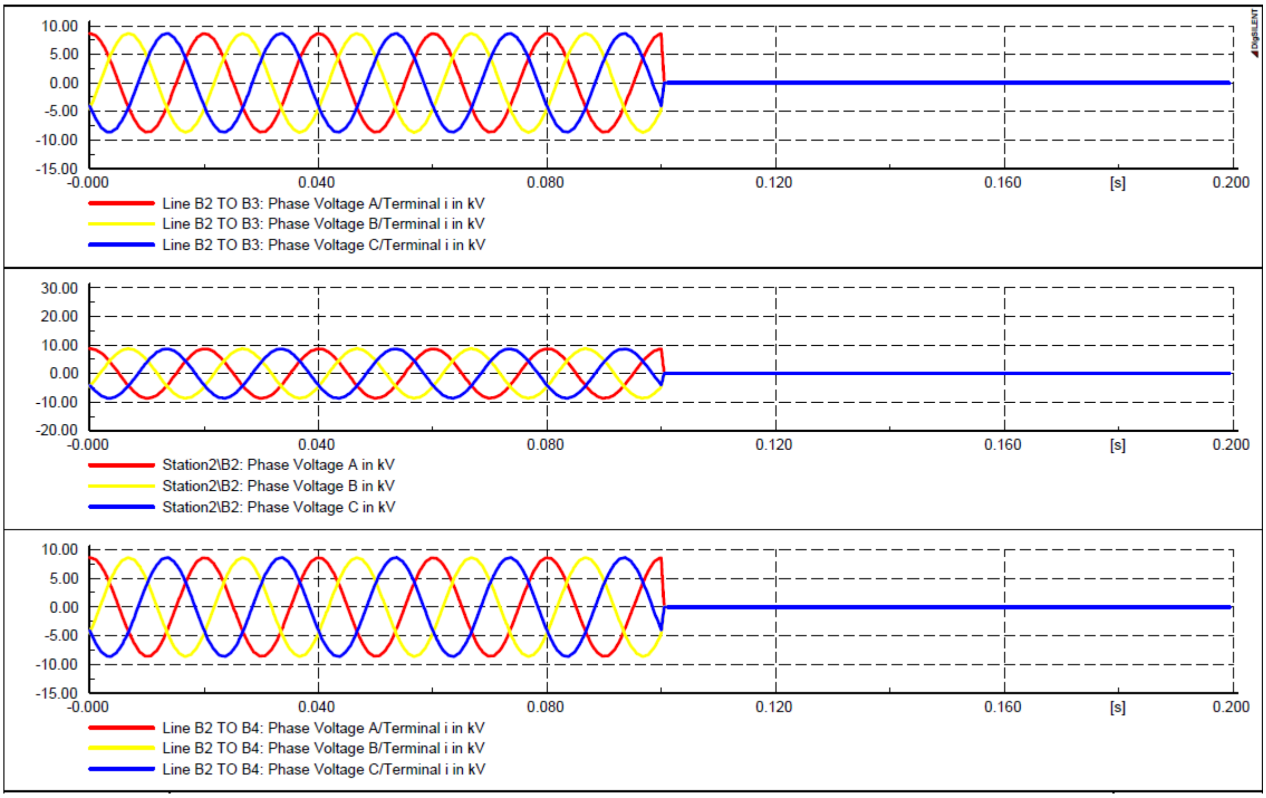


Figure 4.4: **Three phase voltages when short circuits are introduced in the distribution network into a busbar B2 (substation2/2), a load 1(line B2 to B3), and a load 2 (Line B2 to B4) respectively**

When protection is designed and implemented in the network system it is essential to know the fault current distribution throughout the system. The purpose of these simulations is to be able to specify fault ratings for all electrical devices that are used for protection. Therefore short circuit current calculations in the distribution network are implemented in order to identify other potential problems. It is important to know voltages due to the fault in the different nodes within the network. It is also required to know the current amplitude at any relaying point so that the fault is to be cleared with precise discrimination. The parameters that are required for each set of faults are as follows (NPAG, 2002)

- Where the fault is applied
- Which phase is affected
- Which feeders are affected
- Which elements are affected
- Current and voltage sequence
- Maximum fault current
- Minimum fault current

4.3.7.1 Results for the single phase to ground and three phase short circuit on the busbar B2

The results for the single phase to the ground short circuit are shown in Table 4.6.The fault location on the busbar B2 is shown in blue and the results show that the fault is at the phase A to the ground. The fault location on the feeder is shown in green. The results shows that the two winding transformer in the station 1 is the power component that is affected .The line to ground voltage zero, positive and negative sequence are shown in brown and the zero, positive and negative sequences currents are shown in red. In Table 4.7 the three phase short circuit results on the busbar B2 in the station 2/B2 are shown. The same colour codes as for the single phase to the ground short circuit are used to show the results. The fault location is on the busbar B2, all three phases are affected and both feeders are affected.

Table 4.6: Results of the single phase to the ground short circuit on the busbar B2

Fault Locations with Feeders Short-Circuit Calculation according to IEC60909	Single Phase to Ground	/ Max. Short-Circuit Currents
Asynchronous Motors Always Considered	Grid Identification Automatic Conductor Temperature User Defined: No	Short-Circuit Duration Break Time: 0.10 s Fault Clearing Time (Ith): 1.00 s c-Voltage Factor User Defined: No
Grid: Grid	System Stage: Grid	Annex: / 1

			rtd.V. [kV]	Voltage [kV]	Voltage [deg]	c-Factor	Sk" [MVA/MVA]	Ik" [kA/kA]	Ik" [deg]	ip [kA/kA]	Ib [kA]	Sb [MVA]	EFF [-]
Station2													
B2		A	11.00	6.98	-1.17	1.10	2.22 MVA	0.35 kA	-1.17	0.93 kA	0.35	2.22	0.00
		B		6.99	-120.00		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00	0.00	1.00
		C		6.99	120.00		0.00 MVA	0.00 kA	0.00	0.00 kA	0.00	0.00	1.00
Line B2 TO B3	Station3	A					0.00 MVA	0.00 kA	-3.66	0.00 kA			
		B					0.00 MVA	0.00 kA	-3.66	0.00 kA			
		C					0.00 MVA	0.00 kA	-3.66	0.00 kA			
Line B2 TO B4	Station4	A					0.00 MVA	0.00 kA	-3.62	0.00 kA			
		B					0.00 MVA	0.00 kA	-3.62	0.00 kA			
		C					0.00 MVA	0.00 kA	-3.62	0.00 kA			
2-Winding Trans	Station1	A					2.22 MVA	0.35 kA	178.83	0.93 kA			
		B					0.00 MVA	0.00 kA	176.35	0.00 kA			
		C					0.00 MVA	0.00 kA	176.35	0.00 kA			

				rtd.V. [kV]	Line to Ground Voltages [kV]	Line to Ground Voltages [deg]	0-1-2 Sequence Voltages	0-1-2 Sequence Voltages [kV]	0-1-2 Sequence Voltages [deg]	Sk" [MVA]	Currents [kA]	Currents [deg]	0-1-2 Sequence Currents	0-1-2 Sequence Currents [kA]	0-1-2 Sequence Currents [deg]
Values at Observation Location															
B2	Substation : Station2														
			A	11.00	6.98	-1.17	U1	6.98	-0.39						
			B		6.99	-120.00	U2	0.05	-93.59						
			C		6.99	120.00	U0	0.05	-93.61						
Cub_0.1 /Lne to : Station3	Line B2 TO B3	Terminal i	A							0.000	0.000	-3.66	I1	0.000	0.00
			B							0.000	0.000	-3.66	I2	0.000	0.00
			C							0.000	0.000	-3.66	3*I0	0.000	-3.66
Cub_0.2 /Lne to : Station4	Line B2 TO B4	Terminal i	A							0.000	0.000	-3.62	I1	0.000	0.00
			B							0.000	0.000	-3.62	I2	0.000	0.00
			C							0.000	0.000	-3.62	3*I0	0.000	-3.62
Cub_0.0 /Tr2 to : Station1	2-Winding Transformer	LV-Side	A							2.216	0.349	178.83	I1	0.116	178.83
			B							0.000	0.000	176.35	I2	0.116	178.83
			C							0.000	0.000	176.35	3*I0	0.349	178.83

Table 4.7: Results of the three phase short circuit on the busbar B2

Fault Locations with Feeders Short-Circuit Calculation according to IEC60909	3-Phase Short-Circuit	/ Max. Short-Circuit Currents
Asynchronous Motors Always Considered Decaying Aperiodic Component (idc) Using Method: B	Grid Identification Automatic Conductor Temperature User Defined: No	Short-Circuit Duration Break Time: 0.10 s Fault Clearing Time (Ith): 1.00 s c-Voltage Factor User Defined: No
Grid: Grid	System Stage: Grid	Annex: / 1

		rtd.V. [kV]	Voltage [kV]	Voltage [deg]	c-Factor	Sk" [MVA/MVA]	Ik" [kA/kA]	Ik" [deg]	ip [kA/kA]	Ib [kA]	Sb [MVA]	Ik [kA]	Ith [kA]
Station2													
B2		11.00	0.00	0.00	1.10	324.47 MVA	17.03 kA	-87.58	45.35 kA	17.03	324.47	17.03	17.70
Line B2 TO B3	Station3					0.00 MVA	0.00 kA	0.00	0.00 kA				
Line B2 TO B4	Station4					0.00 MVA	0.00 kA	0.00	0.00 kA				
2-Winding Trans	Station1					324.47 MVA	17.03 kA	92.42	45.35 kA				

4.3.7.2 Results for the single phase to ground and three phase short circuits on the line (B2 to B3) for the load 1

The results for the single phase to the ground short circuit are shown in Table 4.8.The fault location is shown in blue colour and the result shows that the fault is on the phase A to the ground. The fault location is shown in green colour. The results show that the two winding transformer in the station 1 and the line (B2 to B3) feeding load 1 are affected by this fault. The line to ground voltage zero, positive and negative sequences are shown in brown colour and for the currents are shown in red colour. Only positive sequence is affected by this fault. In Table 4.9 the three phase short circuit results at the line B2 to B3 for load 1 are shown. The same colour codes as for the single phase to the ground short circuit are used to show the results. Three phase fault is located on the line (B2 to B3) and it does not affect the line (B2 to B4) that feeds the load 2.

Table 4.8: **Results of the single phase to ground short circuit results on the line (B2 to B3) for the load 1**

Short-Circuit Calculation according to IEC60909	Single Phase to Ground	/ Min. Short-Circuit Currents
Asynchronous Motors Always Considered	Grid Identification Automatic Conductor Temperature User Defined: No	Short-Circuit Duration Break Time: 0.10 s Fault Clearing Time (Ith): 1.00 s c-Voltage Factor User Defined: No
Fault Distance from Terminal i: ... del\Network Data\Grid\Station2\B2 Line: \Demo\Project_v14(1)\Network Model\Network Data\Grid\Line B2 TO B3		Absolute: 2.50 km Relative: 50.00 %

Grid: Grid — System Stage: Grid

		rtd.V. [kV]	Voltage [kV]	Voltage [deg]	c-Factor	Sk" [MVA]	Ik" [kA]	Ik" [deg]	ip [kA]	Ib [kA]	Sb [MVA]	EFF [-]
Fault Location:												
Line B2 TO B3	A		5.96	-3.39	1.00	1.89	0.30	-3.39	0.75	0.30	1.89	0.00
	B		6.74	-121.89		0.00	0.00	0.00	0.00	0.00	0.00	1.49
	C		6.37	124.01		0.00	0.00	0.00	0.00	0.00	0.00	1.67
between:												
B2 /Station2		11.00	6.34	-1.10								
			6.35	-120.00								
			6.35	120.00								
Line B2 TO B3	Station3				A	1.89	0.30	-3.42				
					B	0.00	0.00	-54.60				
					C	0.00	0.00	-54.60				
Line B2 TO B4	Station4				A	0.00	0.00	-5.94				
					B	0.00	0.00	-5.94				
					C	0.00	0.00	-5.94				
2-Winding Transforme	Station1				A	1.89	0.30	176.58				
					B	0.00	0.00	127.28				
					C	0.00	0.00	127.28				
and:												
B3 /Station3		11.00	5.96	-3.39								
			6.74	-121.89								
			6.37	124.01								
Line B2 TO B3	Station2				A	0.00	0.00	0.00				
					B	0.00	0.00	0.00				
					C	0.00	0.00	0.00				

Line B2 TO B3	U1	6.34	-0.39	A	1.892	0.298	176.61	I1	0.099	176.61
	U2	0.04	-98.11	B	0.000	0.000	0.00	I2	0.099	176.61
	U0	0.47	-145.82	C	0.000	0.000	0.00	3*I0	0.298	176.61

SHC on line:	Line B2 TO B3							rtd. V.	11.00 kV	
Voltages	[kV] [deg]	A	5.96	-3.39	A - B	10.92	29.46	U1	6.34	-0.39
		B	6.74	-121.89	B - C	11.00	-90.00	U2	0.04	-98.11
		C	6.37	124.01	C - A	11.05	149.37	3*U0	1.42	-145.82

Table 4.9: **results of the three phase short circuit on the line B2 to B3 for load 1**

Short-Circuit Calculation according to IEC60909	3-Phase Short-Circuit	/ Max. Short-Circuit Currents
Asynchronous Motors Always Considered Decaying Aperiodic Component (idc) Using Method B	Grid Identification Automatic Conductor Temperature User Defined No	Short-Circuit Duration Break Time 0.10 s Fault Clearing Time (Ith) 1.00 s c-Voltage Factor User Defined No
Fault Distance from Terminal i: ... del\Network Data\Grid\Station2\B2 Line: \Demo\Project_v14(1)\Network Model\Network Data\Grid\Line B2 TO B3		Absolute 2.50 km Relative 50.00 %

Grid: Grid						System Stage: Grid							
		rtd.V. [kV]	Voltage [kV]	[deg]	c-Factor	Sk" [MVA]	Ik" [kA]	[deg]	ip [kA]	Ib [kA]	Sb [MVA]	Ik [kA]	Ith [kA]
Fault Location:													
Line B2 TO B3			0.00	0.00	1.10	303.63	15.94	-86.10	40.99	15.94	303.63	15.94	16.33
between:													
B2 /Station2		11.00	0.48	-20.54									
Line B2 TO B3	Station3					303.63	15.94	-86.10					
Line B2 TO B4	Station4					0.00	0.00	0.00					
2-Winding Transformer	Station1					303.63	15.94	93.90					
and:													
B3 /Station3		11.00	0.00	0.00									
Line B2 TO B3	Station2					0.00	0.00	0.00					

Short Circuit Location	Voltages [kV]	[deg]	Sk" [MVA]	Ikss [kA]	[deg]
Line B2 TO B3	0.00	0.00	303.631	15.937	93.90
SHC on line: Line B2 TO B3	11.00	0.00			

4.3.7.3 Results of the single phase to the ground and the three phase short circuits on the line (B2 to B4) for the load 2

The results for single phase to ground short circuit are shown in Table 4.10a.The fault location is shown in blue colour. The result shows that the fault affects only phase A to the ground. The fault location on the feeder is shown in green colour. The results show that the two winding transformer in the station 1 and the line (B2 to B4) are the electrical components that are affected by this fault .The line to ground voltage zero, positive and negative sequences are shown in brown colour and the currents are shown in red colour. Only the positive sequence is affected by this fault. In Table 4.10b the three phase short circuit results at the line (B2 to B4) for the load 2 are shown. The same colour codes as for the single phase to the ground short circuit are used to show the results. Three phase fault is located on the line (B2 to B4) and it does not affect the line (B2 to B3) that feeds the load 1.

Table 4.10a: Single phase short circuit results for the line B2 to B4 for the load 2

```
Short-Circuit Calculation according to IEC60909                 Single Phase to Ground  / Min. Short-Circuit Currents

Asynchronous Motors               Grid Identification                 Short-Circuit Duration
   Always Considered                 Automatic                           Break Time                  0.10 s
                                                                         Fault Clearing Time (Ith)   1.00 s
                                  Conductor Temperature               c-Voltage Factor
                                     User Defined             No         User Defined                No

Fault Distance from       Terminal i:     ... del\Network Data\Grid\Station2\B2        Absolute                1.00 km
Line:        \Demo\Project_v14(1)\Network Model\Network Data\Grid\Line B2 TO B4        Relative               50.00 %

Grid: Grid                                                  System Stage: Grid

                           rtd.V.       Voltage       c-        Sk"          Ik"          ip       Ib        Sb       EFF
                            [kV]     [kV]    [deg]  Factor     [MVA]     [kA]   [deg]    [kA]     [kA]     [MVA]     [-]
Fault Location:
  Line B2 TO B4          A           6.19    -2.09   1.00       1.96     0.31   -2.09    0.82     0.31      1.96    0.00
                         B           6.51  -120.78              0.00     0.00    0.00    0.00     0.00      0.00    1.27
                         C           6.35   121.67              0.00     0.00    0.00    0.00     0.00      0.00    1.57

between:
B2       /Station2         11.00     6.34    -1.14
                                     6.35  -120.00
                                     6.35   120.00

  Line B2 TO B3           Station3                       A      0.00     0.00   -4.63
                                                         B      0.00     0.00   -4.63
                                                         C      0.00     0.00   -4.63

  Line B2 TO B4           Station4                       A      1.96     0.31   -2.10
                                                         B      0.00     0.00  -46.73
                                                         C      0.00     0.00  -46.73

  2-Winding Transforme    Station1                       A      1.96     0.31  177.90
                                                         B      0.00     0.00  149.29
                                                         C      0.00     0.00  149.29

and:
B4       /Station4         11.00     6.19    -2.09
                                     6.51  -120.78
                                     6.35   121.67

  Line B2 TO B4           Station2                       A      0.00     0.00    0.00
                                                         B      0.00     0.00    0.00
                                                         C      0.00     0.00    0.00

                                    0-1-2 Sequence Voltages              Sk"            Ikss         0-1-2 Sequence Currents
Short Circuit Location                      [kV]     [deg]              [   ]        [  ]    [   ]          [  ]     [  ]

Line B2 TO B4                          U1    6.35    -0.39      A       1.964       0.309   177.91    I1    0.103   177.91
                                       U2    0.04   -94.67      B       0.000       0.000     0.00    I2    0.103   177.91
                                       U0    0.21  -139.26      C       0.000       0.000     0.00  3*I0    0.309   177.91

SHC on line:     Line B2 TO B4
                               A   6.19    -1.14     U1     6.35    -0.39
                               B   6.51  -120.78     U2     0.04   -94.67
                               C   6.35   121.67     U0     0.21  -139.26
```

Table 4.10b: Three phase short circuit calculation for the line B2 to B4 for the load 2

```
Short-Circuit Calculation according to IEC60909                 3-Phase Short-Circuit   / Max. Short-Circuit Currents

Asynchronous Motors               Grid Identification                 Short-Circuit Duration
   Always Considered                 Automatic                           Break Time                  0.10 s
                                                                         Fault Clearing Time (Ith)   1.00 s
Decaying Aperiodic Component (idc) Conductor Temperature              c-Voltage Factor
   Using Method                B     User Defined             No         User Defined                No

Fault Distance from       Terminal i:     ... del\Network Data\Grid\Station2\B2        Absolute                1.00 km
Line:        \Demo\Project_v14(1)\Network Model\Network Data\Grid\Line B2 TO B4        Relative               50.00 %

Grid: Grid                                                  System Stage: Grid
                        rtd.V.     Voltage      c-       Sk"                Ik"            ip       Ib       Sb        Ik      Ith
                         [kV]    [kV]   [deg]  Factor   [MVA]       [kA]        [deg]     [kA]     [kA]    [MVA]      [kA]     [kA]
Fault Location:
   Line B2 TO B4                 0.00    0.00   1.10    315.97     16.58       -87.50    44.09    16.58   315.97     16.58    17.22
between:
B2       /Station2      11.00    0.18   -2.70
  Line B2 TO B3                 Station3                   0.00      0.00         0.00
  Line B2 TO B4                 Station4                 315.97     16.58       -87.50
  2-Winding Transformer         Station1                 315.97     16.58        92.50
and:
B4       /Station4      11.00    0.00    0.00
  Line B2 TO B4                 Station2                   0.00      0.00         0.00

Grid: Grid                  System Stage: Grid                                            Annex:             / 2
                                                rtd.V.         Voltages            Sk"           Currents
                                                 [kV]       [kV]     [deg]        [MVA]        [kA]     [deg]
Values at Observation Location
SHC on line:    Line B2 TO B4                   11.00       0.00      0.00
Asynchronous Motors               Grid Identification                 Short-Circuit Duration
   Always Considered                 Automatic                           Break Time                  0.10 s
                                                                         Fault Clearing Time (Ith)   1.00 s
Decaying Aperiodic Component (idc) Conductor Temperature              c-Voltage Factor
   Using Method                B     User Defined             No         User Defined                No

                                                        Voltages                    Sk"            Ikss
Short Circuit Location                                [kV]    [deg]                [MVA]        [kA]     [deg]
Line B2 TO B4                                         0.00     0.00               315.970      16.584   -87.50
```

4.3.7.4 Application of the results from the short circuit current calculation

Table 4.11: The simulation results done in all three locations in the distribution network

Fault type	Fault location	$S_k^{''}$ [MVA]	$I_k^{''}$ [kA/kA]	I_p [kA/kA]
Single phase to ground fault	Station2/B2	2.01	0.317	0.845
Three phase Fault	Station2/B2	324.47	17.030	45.354
Single phase to ground fault	Line (B2toB3)	1.89	0.298	0.752
Three phase Fault	Line (B2toB3)	303.63	15.937	40.986
Single phase to ground fault	Line (B2toB4)	1.96	0.309	0.821
Three phase Fault	Line (B2toB4)	315.97	16.584	44.089

Table 4.11 represents the simulation results for all fault types and locations in the distribution network. The results give an indication for all the short circuit currents at their locations where the protection devices have to be installed. From the results it is now possible to select a specified setting and fault rating the protection devices that are used for the scheme.

The next procedure is to configure the protection devices based on the result in Table 4.11.

4.4 Selection of the busbar protection scheme characteristics

Generally when choosing an over current protection of busbars, there are overcurrent elements in the protection devices that need to be understood. Usually the protection devices used for the schemes are produced with these elements. These overcurrent elements are mainly in three groups namely definite current, definite time, and inverse time. Each group has its own operating characteristics. The overcurrent setting for the protection devices is done by selection of some parameters. These parameters require time-current characteristics for both instantaneous and time delay elements. The relay characteristics generally should all confirm with BS142 / IEC or ANSI/IEEE standards. Simulations performed in the thesis are done according to the IEC60909 standard.

4.4.1 Definite current characteristics

Definite current characteristics occur when measured current exceeds some predetermined value causing the relay to operate instantly as shown in Figure 4.5 below where t represents time and I represents current. When implementing this characteristic the relay setting are selected is such a manner that the relay furthest from the power source will operate. This method allows the relay with the lower setting to operate first disconnecting the load close to the fault. The disadvantages of this type of protection are that selectivity is low at high values of short circuit currents and also the relay has poor discrimination.

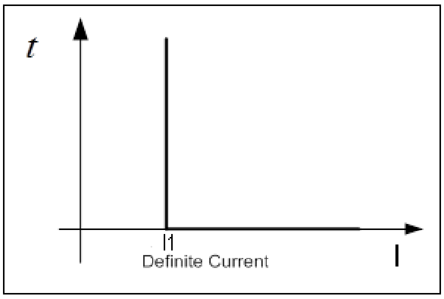


Figure 4.5: Definite -current characteristic of overcurrent relays

4.4.2 Definite time-current characteristics

This characteristic of the relays allows the setting to be changed to manage different levels of current by utilizing different operating times as shown in Figure 4.6 below. The settings can be configured in such a way that the circuit breaker closest to the fault opens in shortest time, although the remaining circuit breakers are tripped in a longer time delay sequence going backwards towards the source direction. The tripping times difference for the same current is known as the discrimination margin. The advantage of this method is that the protection is more selective.

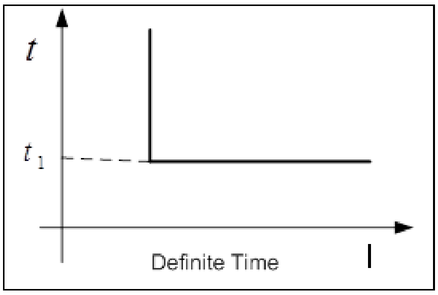


Figure 4.6: Definite -Time characteristics of overcurrent IEDs

4.4.3 Inverse-time characteristics

The basic attribute of the inverse-time characteristics is that it permits the IED's to operate in a time which is inversely proportional to the fault current as shown in Figure 4.7 below. Its advantage over the definite -time is that for very high currents tripping times is much shorter.

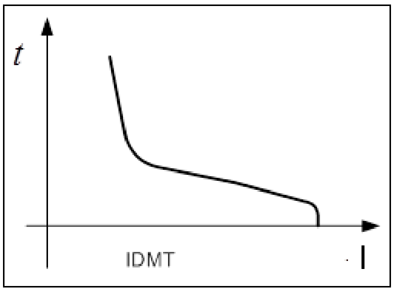


Figure 4.7: **Inverse-time characteristics of overcurrent relays**

A combination of the overcurrent protection elements above are selected and used in this thesis. Some parameters of these elements needed to be completed using DigSILENT software and therefore certain requirement had to be followed. The basic requirements when setting protection for a busbar scheme is that it must be stable when the fault occurs outside the bus and it must also be with reliable operation speed to minimize the damage from spreading through the network. The DigSILENT simulation software poses some recommendation that needed to be followed. The recommendations are as follows (DigSILENT basic training notes 2007:115):

- The protection devices that behave upon a single switch must be kept in the same cubicle.
- The protection devices that behave upon a number of switches linked to the same busbar should be placed in that specific busbar.
- The protection devices that behave upon a number of switches linked into the same busbar system must also be kept in the same station.
- The protection device must be stored in the same folder with its instrument transformers.

The definite time and the inverse time characteristics will be used further in the scheme. The definite time characteristic is for maximum short circuit created by three phase faults. The inverse time characteristic is for minimum short circuit created by single phase to ground faults. These characteristics are combined and applied by each protection devices that are used.

4.5 The algorithm of the reverse blocking schemes

A busbar reverse blocking scheme is investigated in this thesis. Figure 4.8 as shown below explains the algorithm of the reverse blocking schemes in which time discrimination between the incoming feeder and the outgoing feeder protection is sustained. This method required that all relays must be equipped and set with time-overcurrent, instantaneous overcurrent, time-overcurrent-earth, instantaneous overcurrent-earth IDMT and DT elements. The incoming feeder curve is required to be slower than the outgoing feeder for all fault currents. It is also important to have a suitable grading time margin between the two curves with 0.4 seconds for the electromechanical relays and 0.3 seconds for the digital relays.

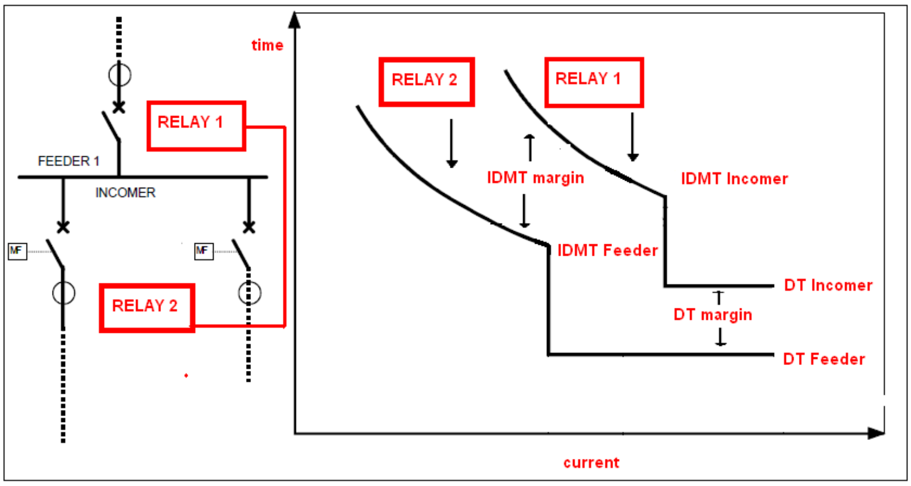


Figure 4.8: **The Grading time determination for the relays (distribution Automation Handbook, 2011)**

4.5.1 Relay Co-ordination and Selective protection

The chosen protection principle has a huge impact to the speed of the protection. The quicker the operation of the protection scheme the lesser the harm. It is therefore critical to have a protection scheme that has fast operation when fault occurs. A reliable selectivity is important for protection. Protection scheme must make sure that it limits interruption of supply. It must also indicate a clear sign of the areas where there is fault within the distribution network. This reliable selectivity makes it possible to apply action to the faulty area of the network and still supply power to the areas that are not affected. It is therefore important to pay attention to the protection operating speed. This speed is influenced by a proper selection of the protection principle. Protection of short circuits in a power system is accomplished in four methods. These different methods are as follows (distribution Automation Handbook, 2011):

- Time – graded protection.
- Time - and current- graded protection.
- Time - and direction-graded protection.
- Current-and impedance- graded protection.

4.5.2 Time- graded protection

This protection method utilizes a principle of time grading the relays operation in such a manner that the relay closest to fault operates first. The method is used with either inverse time or definite time characteristics. The principle of definite time relay is that its operating time does not depend on the amplitude of the fault current. Definite time relays are used when the operating time needs to be speeded up and they are suitable for high magnitude fault currents. The principle of inverse-time relay is the higher the magnitude of the fault current the shorter the operating time. Inverse time protection is suitable for the distribution network that is used in this thesis. Protection relays usually have four characteristic time-current curves. They based on IEC 60255-151 and BS 142 standards and are as follows:

- Normal inverse.
- Long time inverse.
- Very inverse.
- Extremely inverse.

The operating time of the relay is calculated using the equation below:

$$t = \frac{k\beta}{\left(\frac{I}{I \geq}\right)^{\alpha} - 1} \tag{4.20}$$

Where:

k is an adjustable time multiplier
I is the measured phase current value
$I \geq$ is the set start (pickup) current value
α and β are curve set-related parameters

When the normal, very or extremely inverse time characteristics are used the relay should start once the energizing current exceeds 1.3 times the set start current according to the standard. The long time inverse relay should start once the energizing current exceeds 1.1 times the set start current. The parameters for α and β are define in the Table 4.12 below (distribution Automation Handbook, 2011) This thesis only focuses on Time–graded protection as it is used for developing an improved reverse blocking scheme for busbar protection at the distribution level.

Table 4.12: The parameters for characteristic curve

Types of characteristic	α	β
Normal inverse	0.02	0.14
Very inverse	1.0	13.5
Extremely inverse	2.0	80.0
Long-time inverse	1.0	120.0

Correct discrimination between protection devices is important when protection is applied in power systems. This discrimination is also known as grading margin. In order to achieve a correct grading margin the following factors are taken into account:

- Fault interrupting time of the circuit breaker
- Relay overshoot
- Errors, and
- The safety margin

The used equipment in the distribution network for the reverse blocking protection scheme is the ABB conventional relays and ABB IEDs. These protection devices are used in the simulation with different fault events being implemented within the distribution network. These devices are configured in such a way that their settings must be capable of operating for both phase and earth overcurrent conditions.

4.5.3 Design of the parameters of the reverse blocking scheme

The flow chat for relay setting shown in Figure 4.9 below is used for the protection scheme. The theory aspects that are used for the protection scheme are explained in Chapter three under section 3.2.7. The method that is followed for determining current setting is explained in Chapter three section 3.3.3 and time grading in section 3.34 .The method use for setting the DT and IDMT elements are explain in Chapter three under section 3.3.2 The results of the two case studies are recorded and compared.

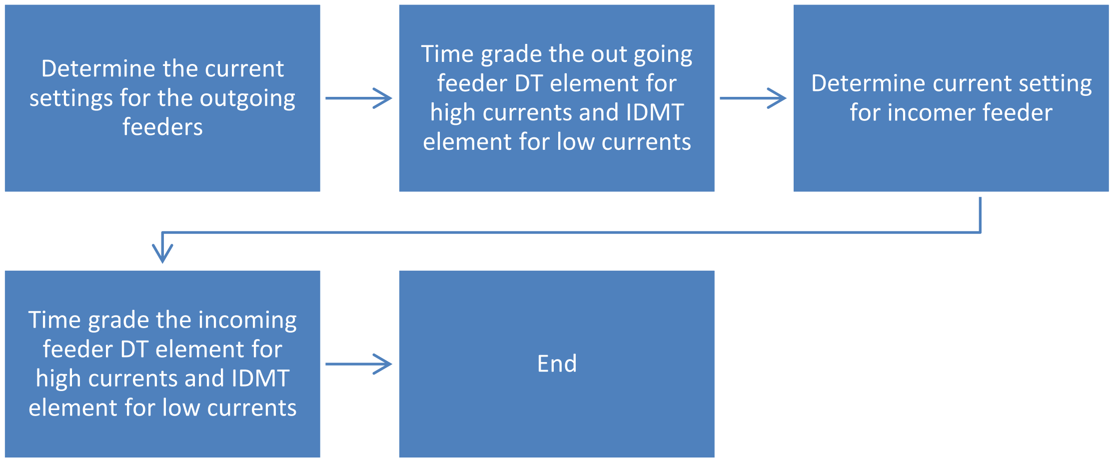


Figure 4.9: **Flowchart for Setting Blocking Scheme –for a Single Incomer Substation**

4.6 Case studies

The designed settings of the protection devices from the reverse blocking scheme are used to investigate the quality of the protection operation in the DigSILENT software environment for the considered distribution network. Two case studies are considered on the basic of the ABB protection devices. Case study 1: the relays are hardwired for implementation of the blocking signals. Case study 2: the relays are IEC 61850 standard-based and communication through Ethernet. The models of the above two protected systems are simulated in DigSILENT software tool. The results of the simulation are recorded and compared.

4.6.1 Case study one

Conventional relays are used for protection implementation in this case. One relay is installed at the main incomer on the LV side of the transformer, named (Relay C). One relay named (Relay A) is installed on the outgoing feeder that feeds load 2 and the other relay named (Relay B) is installed on the outgoing feeder that's feeds load 1. The aim of this study is to execute a short circuit current in the network where each relay is located making use of the IEC 60909 standard method. Two sets of simulations are done for each protection device, namely minimum short circuit with single phase to ground fault type and maximum short circuit with three phase fault type. A combination of inverse time and definite time characteristics are used for the busbar protection. The inverse time is selected for longer grading time. The definite time element is selected for shorter grading time. The reason for this is to have a protection scheme that is effective and has high sensitivity. The grading time for the different stages is discussed in Chapter three.

4.6.1.1 Single phase to ground fault on line (B2 to B4) for relay A

Time overcurrent characteristics, pickup current and time dial for minimum short circuit current had to be calculated using equation (4.20) and applied for the relay A. For this project a suitable settings for relay A in this case study are shown in Table 4.13 below.

Table 4.13: Relay A setting for the single phase to ground fault

Characteristics	IDMT (51N)	DT (51N)
Current Setting	0.08	5
Dial Time	0.05	0

A short circuit current for a single phase to ground fault at the feeder A (line B2 to B4) is simulated as shown in Figure 4.10 below also referred as external fault for the busbar protection scheme. The data shown in Figure 4.10 where the result boxes in the blue colour represent the short circuit power, initial symmetrical short current and peak short circuit current, result boxes in the red colour represent three phase voltage in kV. Using IEC 60909 methods the minimum power fault level $S_k^{''}$ of 1.96MVA, a short circuit current $I_k^{''}$ of 0.309kA and a peak current I_p of 0.821kA are recorded as shown in Table 4.14 below.

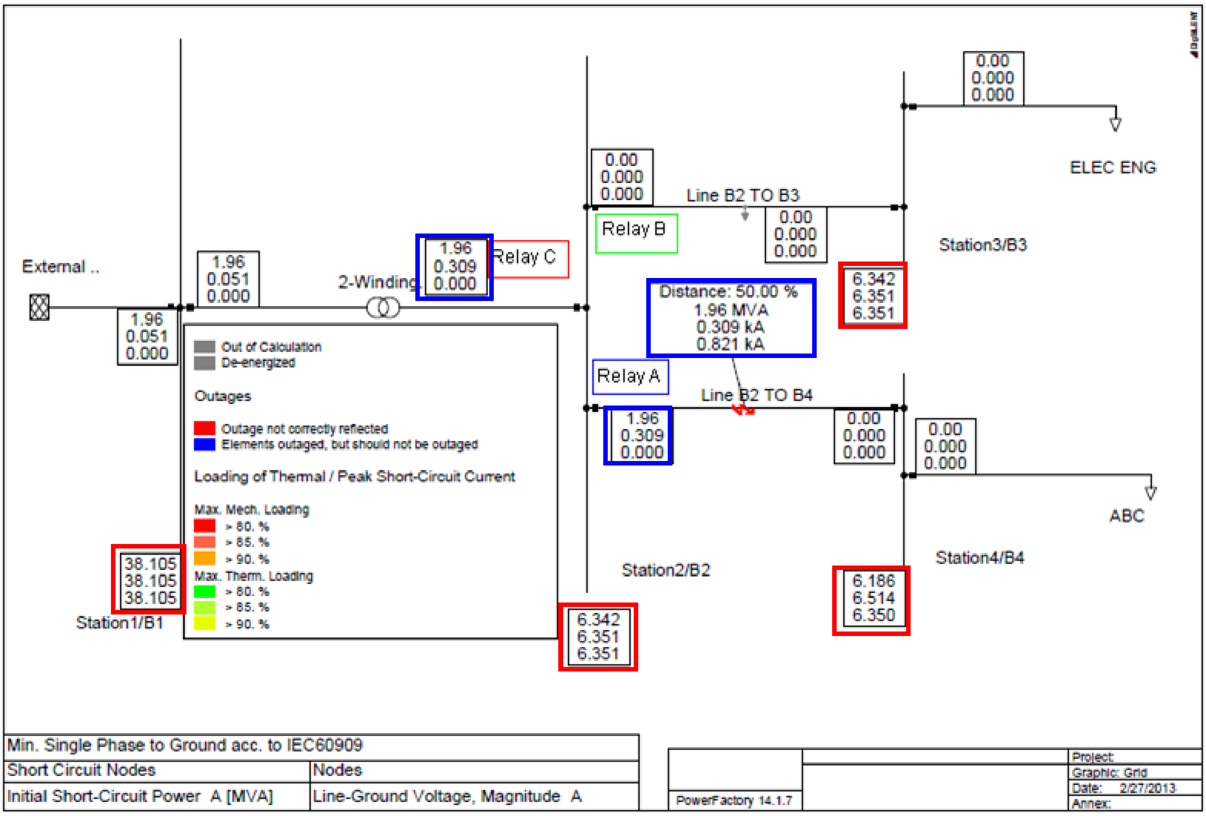


Figure 4.10: Single phase to ground fault in a line (B2 to B4)

Table 4.14: Minimum short circuit calculation results according to the IEC 60909 standard

Fault Location	S''_k [MVA]	I''_k [kA/kA]	I_P [kA/kA]
Line B2 to B4	1.96	0.309	0.821

A time/current curve of the Relay A is used to analyze the results and the scheme performance. Two types of elements are used for this curve namely inverse definite minimum time (IDMT) and definite time (DT) for earth fault currents. This time/current curve definition shows for the single phase to ground fault simulated in Figure 4.10 that the tripping time issued by the relay A is 0.527 seconds. The IDMT and DT elements displayed tripping time of 9999.99s as shown in Figure 4.11 below. When the protection element displays 9999.99 sec for the tripping time it means that it did not see the fault and therefore it will not trip the relay (DigSILENT GmbH, 2009:31). The phase elements for both IDMT and DT characteristics are not affected by this fault type therefore they did not trip. Table 4.15 below shows the results for the relay A tripping times. Since the fault is a single phase to the ground the Ground Time Overcurrent Element (51N) is active and it tripped at 0.527 seconds.

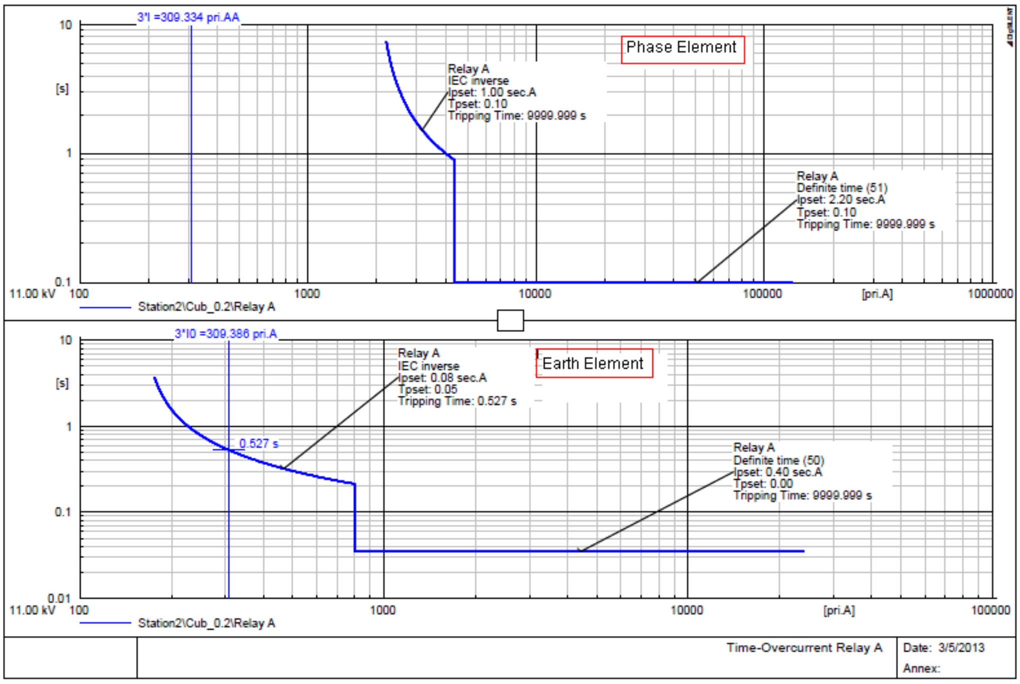


Figure 4.11: Station2\B2 Relay A protection response for a minimum single phase to the ground fault with a clearing time of 0.527 seconds

Table 4.15: The results for the relay A protection response for a minimum single phase to the ground fault

Relays Tripping Times
Short-Circuit Calculation according to IEC60909 — Single Phase to Ground / Min. Short-Circuit Currents

Relay A	B2 / Station2					0.527 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents A :	0.155 sec.A	309.33 pri.A		9999.999 s
		B :	0.000 sec.A	0.04 pri.A		
		C :	0.000 sec.A	0.04 pri.A		
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents	0.155 sec.A	309.39 pri.A		0.527 s
50N1 (IN>>1)	(IEC: IE>t ANSI: 51N)	Currents	0.155 sec.A	309.39 pri.A		9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle Upol,I	2.09 deg	F: 9999.999 s	R:	9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle Upol,I	2.11 deg	F: 9999.999 s	R:	9999.999 s
67P (3I>—>)	(IEC: I>t ANSI: 51)	Currents	0.155 sec.A	309.33 pri.A		9999.999 s
32P2 (I1>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	2.09 deg	F: 9999.999 s	R:	9999.999 s
32N2 (I2>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	2.09 deg	F: 9999.999 s	R:	9999.999 s

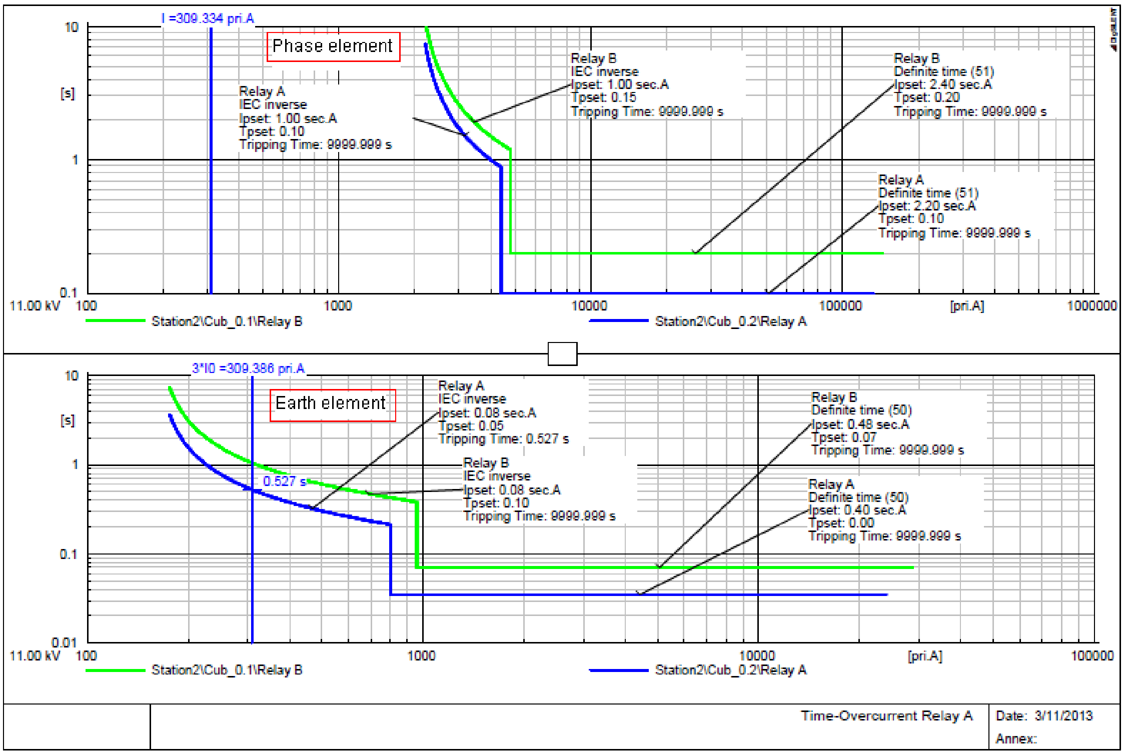


Figure 4.12: **Relays Protection response to a single phase to ground fault for the outgoing feeders to loads 1 and 2**

The network shown in Figure 4.10 has a busbar B2 with two outgoing feeders that feed the load 1 and load 2. The simulation focuses on protecting the busbar B2 and the line feeding Load 1 and load 2. Figure 4.12 above shows the tripping characteristics for both feeders when single phase to ground fault occurs on line (B2 to B4). Relay B tripping characteristic is represented in green color and this for the relay A in blue color. It can be seen from the results that relay B does not see the single phase to the ground fault that occurred in the line (B2 to B4) that feeds the load 2. Therefore the Relay B tripping time displayed 9999.999 seconds for both the IDMT and the DT elements. This means that for the fault at the line (B2 to B4) the relay B did not trip. This ensured that the protection is correct and no false tripping or unwanted tripping will be experienced when the scheme is implemented.

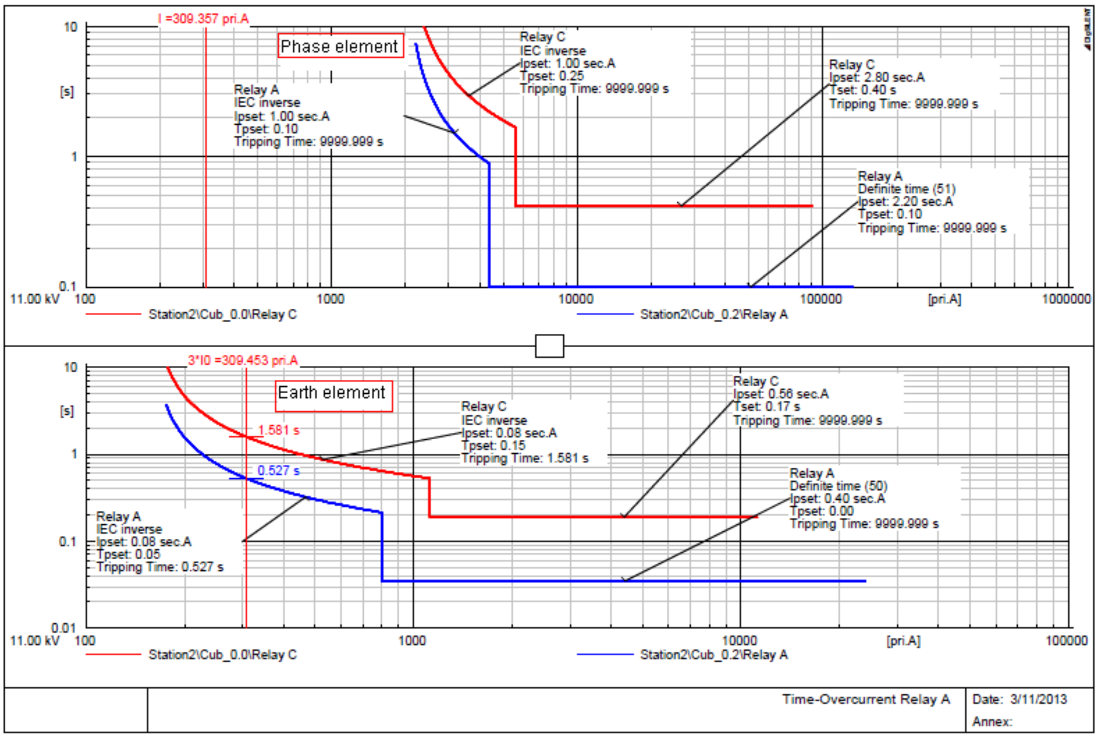


Figure 4.13: **Relay A time-overcurrent response and Relay C acting as back-up protection for the single phase to ground fault.**

The single phase to ground fault indicated in Figure 4.10 is picked-up by two protection devices. With utilization of an IDMT and DT earth element for the relay A and the IDMT and the Instantaneous Overcurrent (IOC) earth elements for the relay C, a sequence tripping response of 0.527 and 1.581 seconds is recorded as shown in Figure 4.13.The phase element tripping times displayed are 9999.99 seconds for both relay A and C meaning that they did not trip for this fault. The results also show that the relay A represented in blue colour which is close to the fault has responded in 0.527 seconds while the direct up-stream relay C represented in red followed with a response delayed with 1.581 seconds. This algorithm suggests that should the relay A fail to operate then the next up-stream relay C will operate in 1.581 seconds. Therefore the relay C operates as a backup protection for the relay A.

4.6.1.2 Three phase fault in the line (B2 to B4) for the relay A

The three phase fault in the line (B2 to B4) is known as external fault for the busbar B2 protection scheme. Time overcurrent characteristics, pickup current and a dial time for maximum short circuit current had to be calculated using equation (4.20) and applied for the relays A. The suitable settings for the relay A in this case study are shown in Table 4.16 below.

Table 4.16: **Relay A setting for three phase protection**

Characteristics	IDMT (51P)	DT 51P)
Current Setting	1	2.2
Dial Time	0.1	0.1

The next step is to simulate the maximum short circuit current in the line (B2 to B4) as shown in Figure 4.14 (a) The data shown the result boxes in the blue colour represent the short circuit power, initial symmetrical short current and peak short circuit current .Figure 4.14 (b) shows the recorded results for the three phase voltages and currents in the line (B2 to B4) when a short circuits are introduced in the distribution network The execution time for the short circuit event is 0.1 seconds. During the short circuit period the phase current increase and the phase voltage decrease creating the system to be unbalanced. The maximum fault level $S_k^{''}$ of 315.97MVA, a short circuit current $I_k^{''}$ of 16,584kA and a peak current I_p of 44,089kA are recorded as shown in Table 4.17 below. After the 0.1 seconds the fault is cleared in the line (B2 to B4) and the phase voltages and currents goes back to their normal condition.

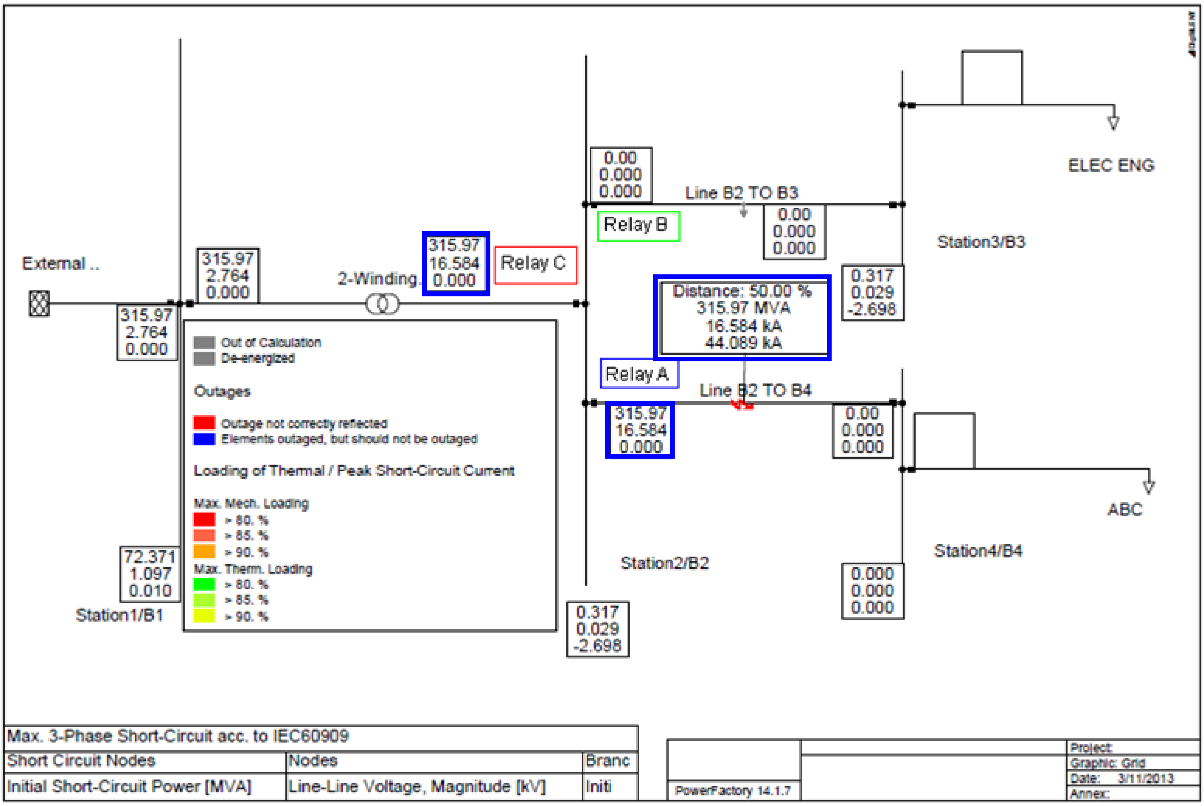


Figure 4.14(a): Three phase fault between a Substation2/B2 and a Substation4/B4

Table 4.17: **Maximum Short circuit calculation results according to IEC 60909 standard**

Fault Location	S_k'' [MVA]	I_k'' [kA/kA]	I_P [kA/kA]
Line B2 to B4	315.97	16.584	44.089

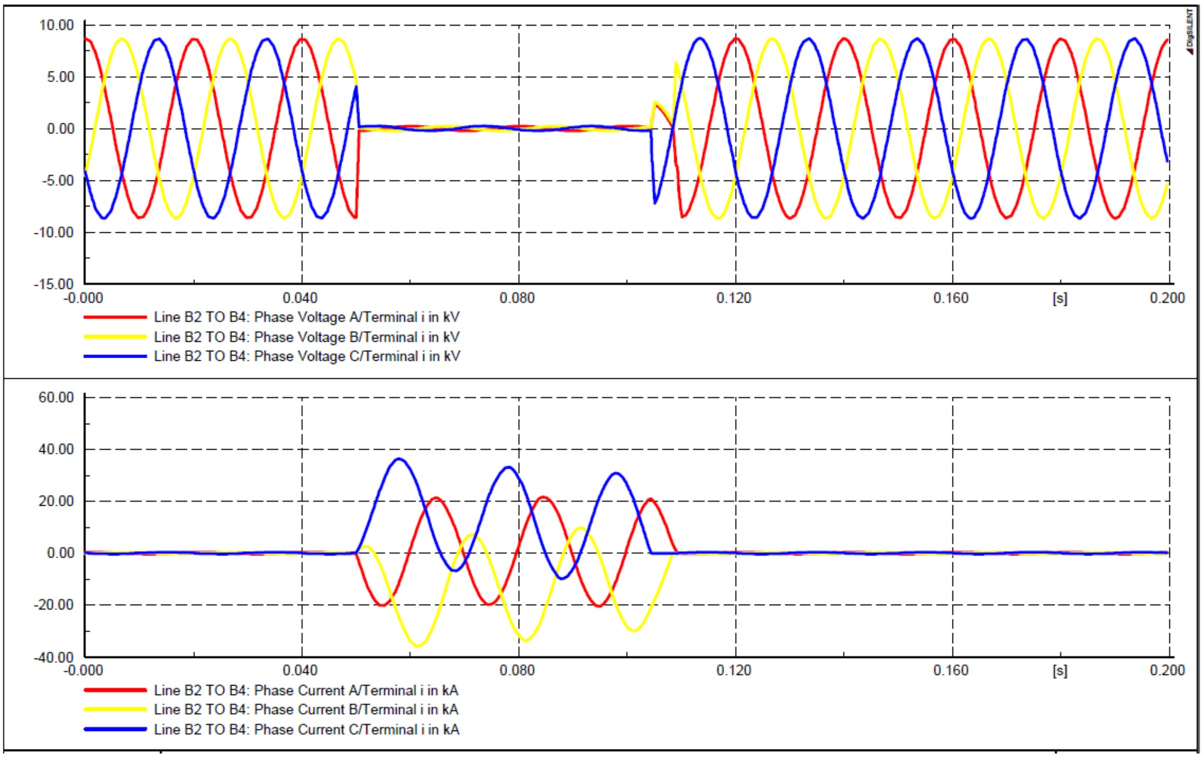


Figure 4.14(b): **Three phase voltages and currents in the line (B2 to B4) when three phase fault is introduced in the distribution network**

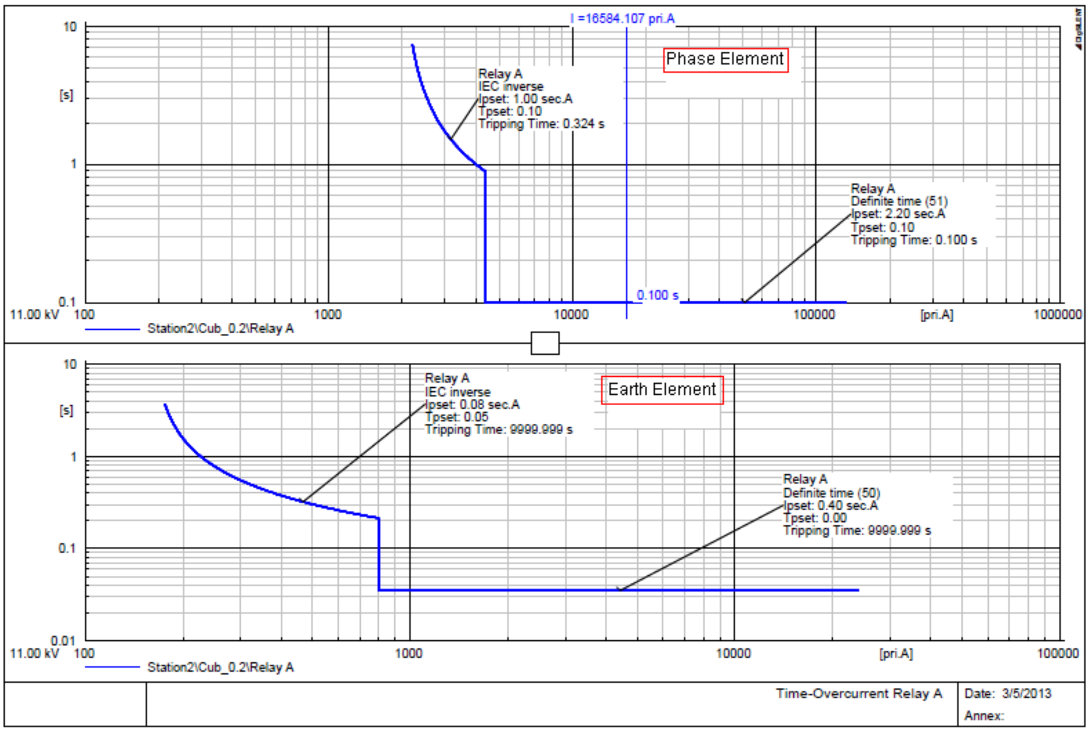


Figure 4.15: **Relay A protection response for the three phase fault with a clearing time of 0.100 seconds for the DT and 0.324 seconds for the IDMT element respectively**

A time/current curve of the Relay A is used to analyse the results and the performance of the protection scheme. Two types of elements were used for this curve namely Inverse Definite Minimum Time (IDMT) and Definite Time (DT) for the three phase fault currents. This time/current curve definition shows for the three phase fault simulated in Figure 4.14(a) that the tripping times obtained for the relay A are 0.100 seconds for the DT and 0.324 seconds for the IDMT elements as shown in Figure 4.15 above. The earth element displays 9999.99 seconds for the tripping time. This fault only affects the phase fault currents therefore only the phase faults elements tripped as shown in Table 4.18.

Table 4.18: **The result for the relay A protection response to the three phase short circuit**

Relays Tripping Times Short-Circuit Calculation according to IEC60909		3-Phase Short-Circuit / Max. Short-Circuit Currents			
Relay A	B2 / Station2				0.100 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents A :	8.292 sec.A	16584.11 pri.A	0.324 s
		B :	8.292 sec.A	16584.11 pri.A	
		C :	8.292 sec.A	16584.11 pri.A	
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
50N1 (IN>>1)	(IEC: IE>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle Upol,I	87.50 deg	F: 9999.999 s	R: 9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle Upol,I	90.00 deg	F: 9999.999 s	R: 9999.999 s
67P (3I>—>)	(IEC: I>t ANSI: 51)	Currents	8.292 sec.A	16584.11 pri.A	0.100 s
32P2 (I1>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	87.50 deg	F: 9999.999 s	R: 9999.999 s
32N2 (I2>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	-90.00 deg	F: 9999.999 s	R: 9999.999 s

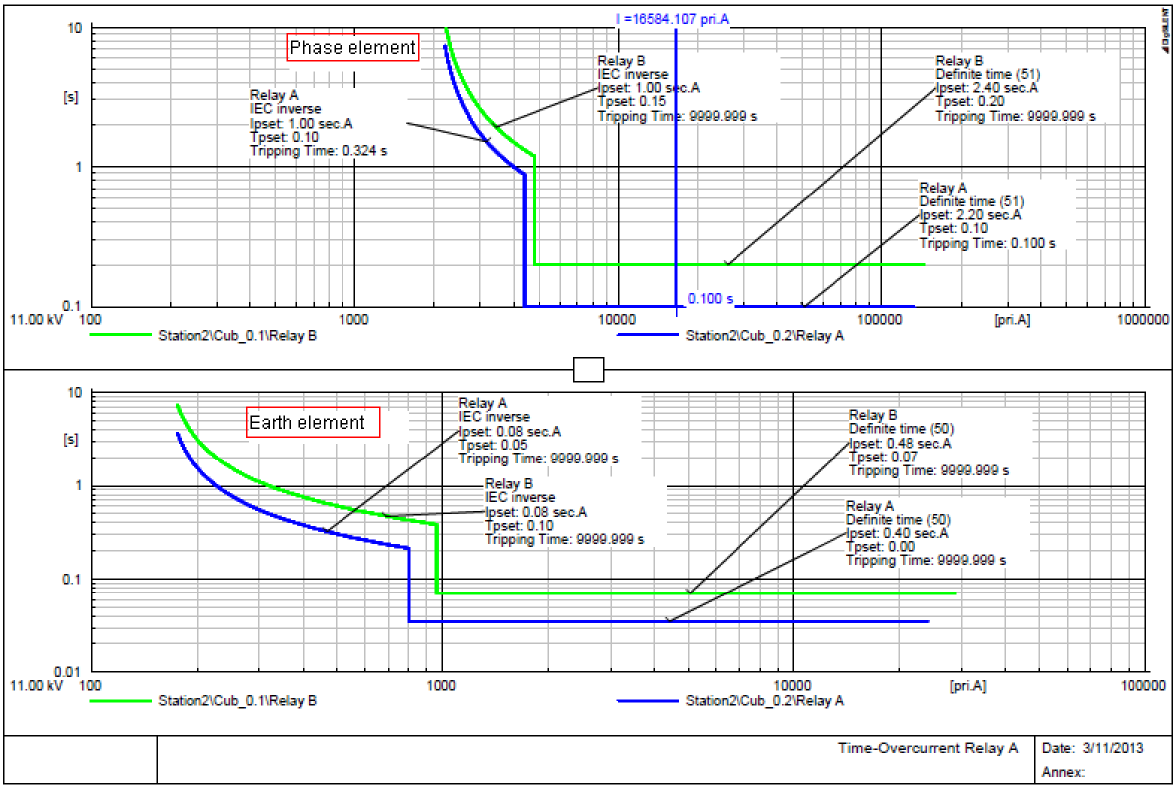


Figure 4.16: **Protection responses of the Relay A and B to the three phase fault**

Figure 4.16 above shows the simulated tripping characteristics for both feeders line (B2 to B3) for the load 1 and the line (B2 to B4) for the load 2 when a three phase fault occurs. It can be seen from the results that the relay B shown in green does not see the three phase fault that occurs in the line (B2 to B4). Therefore Relay B tripping time is displayed as 9999.999 seconds for both the IDMT and the DT elements. This means that for the fault in line (B2 to B4) the relay B did not trip. This ensures that the protection is correct and no false tripping or unwanted tripping will be experienced when the scheme is implemented.

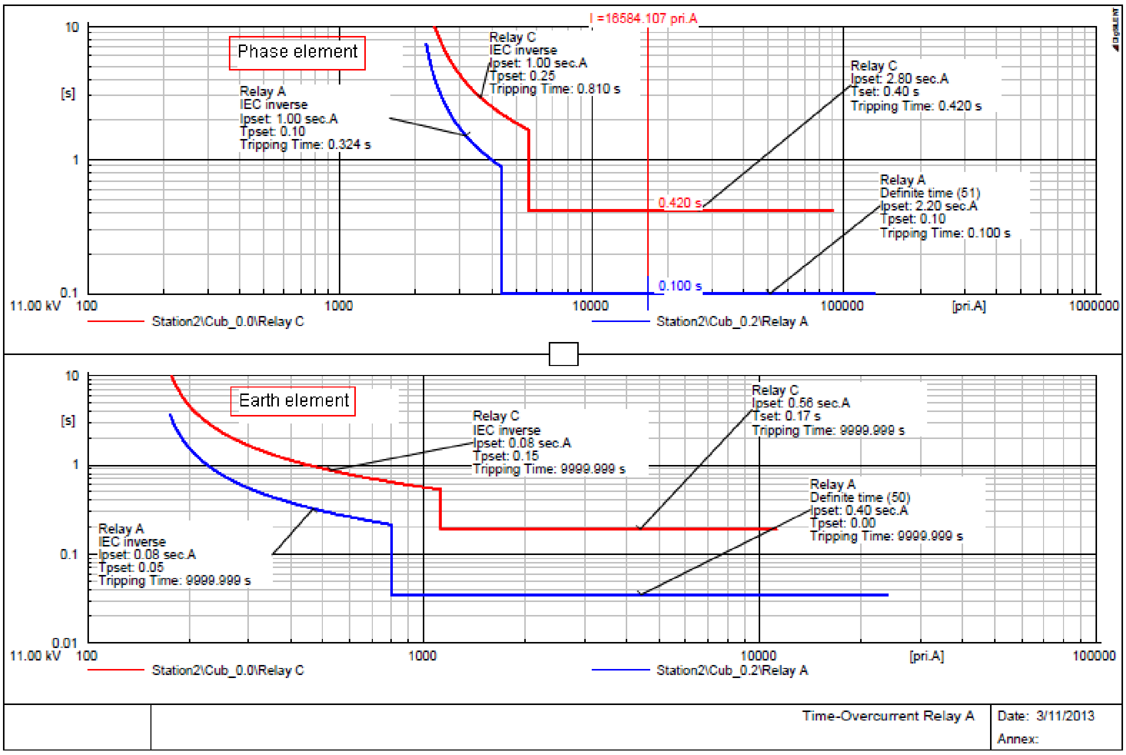


Figure 4.17: **Characteristic of the Relay A time-overcurrent response and of the Relay C acting as a back-up protection device for the three phase fault**

The three phase fault indicated in Figure 4.14 (a) is picked-up by A and C protection devices. With utilization of the IDMT phase element for the relays A and C, a sequence tripping response of 0.324 and 0.810 seconds is recorded as shown in Figure 4.17.The earth elements tripping times are 9999.99 seconds, meaning that they did not trip for this fault. The results also show that the relay A which is close to the fault responses in 0.324 seconds while the direct up-stream relay C follows with a response delayed by 0.810 seconds. This algorithm suggests that should the relay A fail to operate then the next up-stream relay C will operate in 0.810 seconds. Therefore the relay C is used as a backup protection for the relay A. For faster tripping time the DT characteristic of the relay A responds in 0.100 seconds and the instantaneous characteristic for the relay C delays by 0.420 seconds respectively. This protection method makes use of a scheme called reverse blocking as explained in Chapter two.

4.6.1.3 Single phase to ground fault in the line (B2 to B3) for the relay B

Same algorithms as the single phase to ground fault in the line (B2 to B4) for the relay A are implemented for the single phase to ground fault in line (B2 to B3) The difference between the two algorithms is the earth protection settings for the relay B. Time overcurrent characteristics and time dial for minimum short circuit current had to be calculated using equation (4.20) and applied for the relay B. The calculated settings for the relay B in this case study are shown in Table 4.19 below. The data shown in Figure 4.18 where the result boxes in the blue colour represent the short circuit power, initial symmetrical short current and peak short circuit current, result boxes in the red colour represent three phase voltage in kV and documented in a sequence as show below. The minimum fault levels are recorded as shown in Table 4.20.

Table 4.19: **Relay B setting for earth protection**

Characteristics	IDMT (51N)	DT (51N)
Current Setting	0.08	5
Dial Time	0.1	0.07

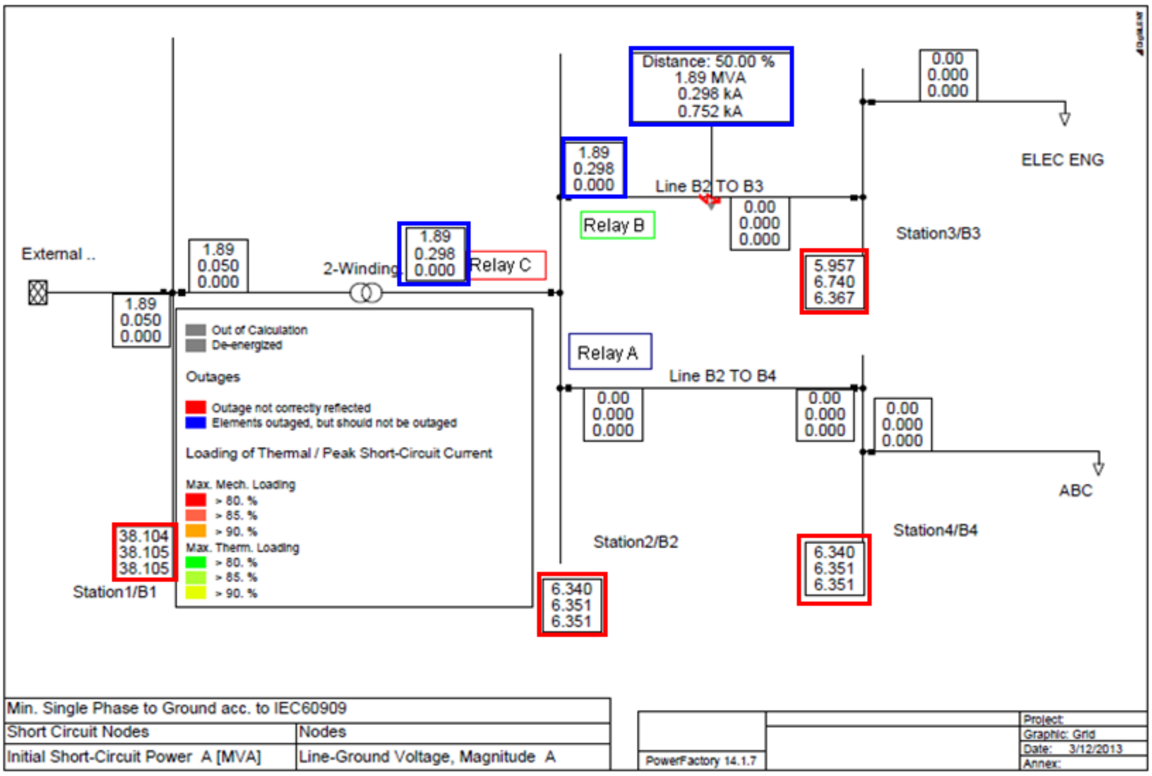


Figure 4.18: **DigSILENT simulation diagram for a single phase to ground fault in a line (B2 to B3)**

Table 4.20: **Short circuit results according to the IEC 60909 standard**

Fault Location	S_k'' [MVA]	I_k'' [kA/kA]	I_P [kA/kA]
Line B2 to B3	1.89	0.298	0.752

The result for the single phase to ground fault in the Line (B2toB3) feeding the loads 1 are shown in Figure 4.19. The tripping time for earth element for the relay B is 1.117 seconds. The IDMT and DT element for the phase element show tripping time of 9999.99s for the phase element meaning it is not affected by this fault.

Figure 4.20 shows the simulated tripping characteristics for both the line (B2 to B3) feeding the load 1 and for the line (B2 to B4) feeding the load 2 when a single phase to ground fault occurs. It can be seen from the results that the relay A shown in blue on the line (B2 to B4) does not see the single phase to ground fault that occurs on the line (B2 to B3). Therefore the Relay A tripping time is displayed as 9999.999 seconds for both the IDMT and the DT elements. This means that for the fault at line (B2 to B3) relay A did not trip. This ensures that the protection is correct and no false tripping or unwanted tripping will be experienced when the scheme is implemented.

The single phase to ground fault indicated in Figure 4.18 is picked-up by B and C protection devices. With utilization of the IDMT earth element for the relay B and C, a sequence tripping response of 1.117 and 1.675 seconds is recorded as shown in Figure 4.21.In the case the relay C is used as a backup protection if it does not trip. The phase elements tripping times are 9999.99 seconds, meaning that they did not trip for this fault. The results also show that the relay B which is close to the fault responses faster than the up-stream relay C. Table 4.21 below shows the results for the relay B tripping time. Since the fault is single phase the ground only the Ground Time Overcurrent Element (51N) trips at 1.117 seconds.

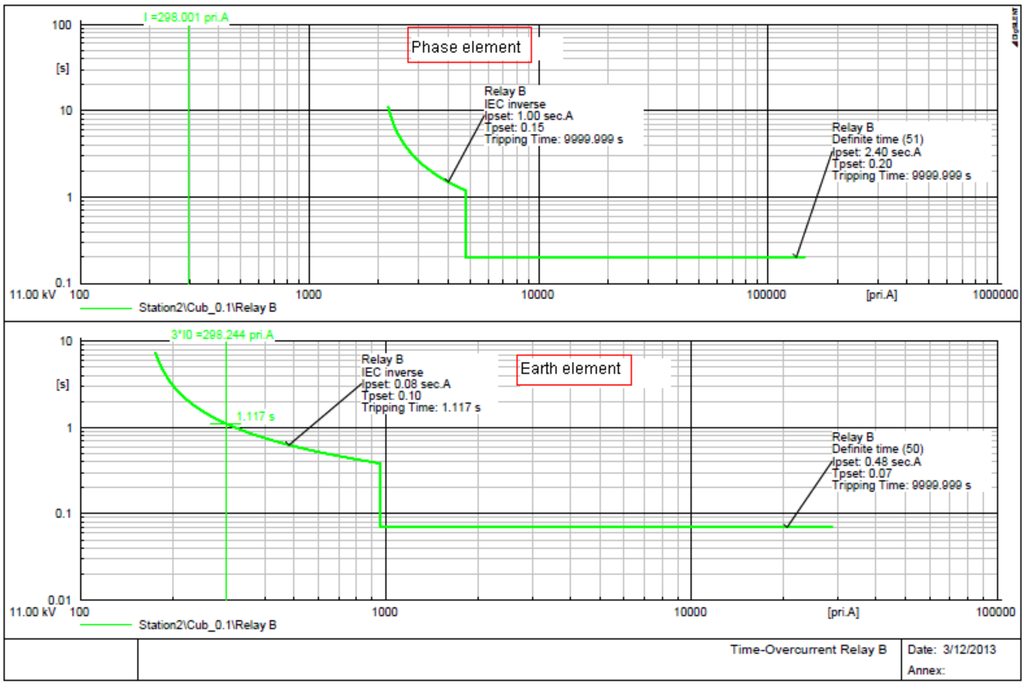


Figure 4.19: **Relay B protection response for the minimum single phase to the ground fault with a clearing time of 1.117 seconds**

Table 4.21: The result for the relay B protection response for the single phase to the ground fault

Relays Tripping Times
Short-Circuit Calculation according to IEC60909 Single Phase to Ground / Min. Short-Circuit Currents

Relay B	B2 / Station2				1.117 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents A :	0.149 sec.A	298.00 pri.A	9999.999 s
		B :	0.000 sec.A	0.19 pri.A	
		C :	0.000 sec.A	0.19 pri.A	
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents	0.149 sec.A	298.24 pri.A	1.117 s
50N1 (IN>>1)	(IEC: IE>t ANSI: 51N)	Currents	0.149 sec.A	298.24 pri.A	9999.999 s
46 (Insc>)	(IEC: I2>t ANSI: 46)	Currents	0.050 sec.A	99.29 pri.A	9999.999 s
46A (InscA>)	(IEC: I2>t ANSI: 46)	Currents	0.050 sec.A	99.29 pri.A	9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle Upol,I	3.39 deg	F: 9999.999 s	R: 9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle Upol,I	3.48 deg	F: 9999.999 s	R: 9999.999 s
67P (3I>—>)	(IEC: I>t ANSI: 51)	Currents	0.149 sec.A	298.00 pri.A	9999.999 s
32P2 (I1>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	3.39 deg	F: 9999.999 s	R: 9999.999 s
32N2 (I2>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	3.39 deg	F: 9999.999 s	R: 9999.999 s

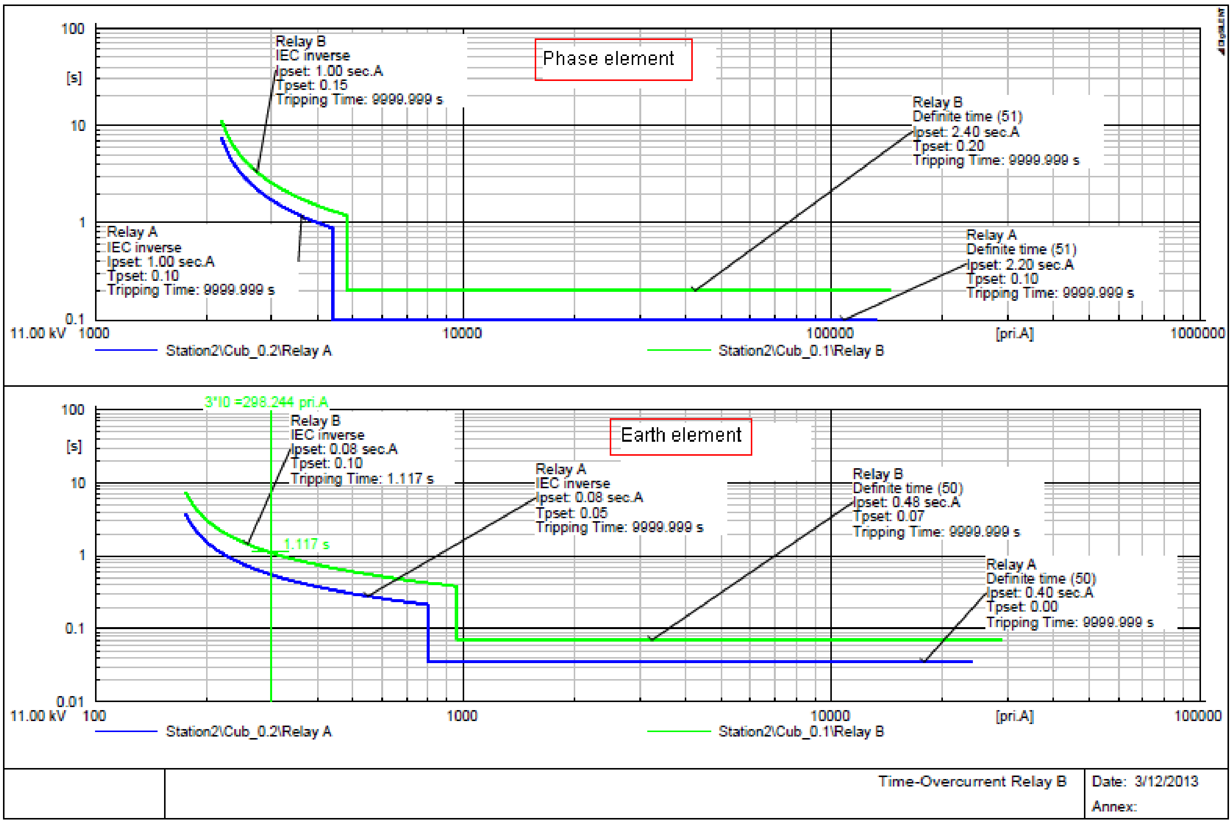


Figure 4.20: Protection responses to the single phase to the ground fault on a line (B2 to B3) for the relays A and B

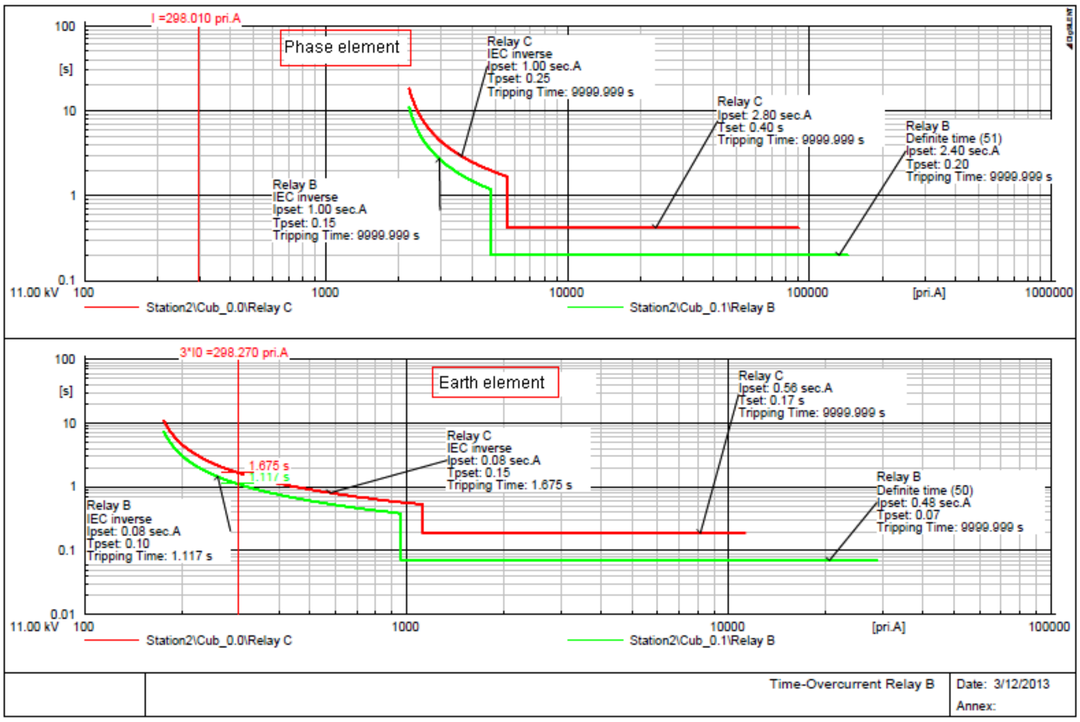


Figure 4.21: **Relay B time-overcurrent response of 1.117 seconds and Relay C acting as back-up protection with time response of 1.675 seconds for the single phase to the ground fault in the line (B2 to B3) feeding the load 1**

4.6.1.4 Three phase fault type at the line (B2 to B3) for the relay B

The same steps as for the single phase to the ground fault in the line (B2 to B3) for the relay B are followed for the three phase fault in the line (B2 to B3). The results are recorded and documented in a sequence as show below. The only differences are the relay's settings. Time overcurrent characteristics and the dial time for short circuit current are calculated using equation (4.20) and applied to the relay B. The settings for the relay B are shown in Table 4.22. Simulation diagram is shown in Figure 4.22 where boxes in the blue colour represent short circuit power, initial symmetrical short current and peak short circuit current. The maximum fault level $S_k^{''}$ of 303.63MVA, a short circuit current $I_k^{''}$ of 15.397kA and a peak current I_p of 40.986kA are recorded as shown on Table 4.23.

Table 4.22: **Relay B setting for three phase protection**

Characteristics	IDMT (51P)	DT (51P)
Current Setting	1	2.4
Dial Time	0.15	0.2

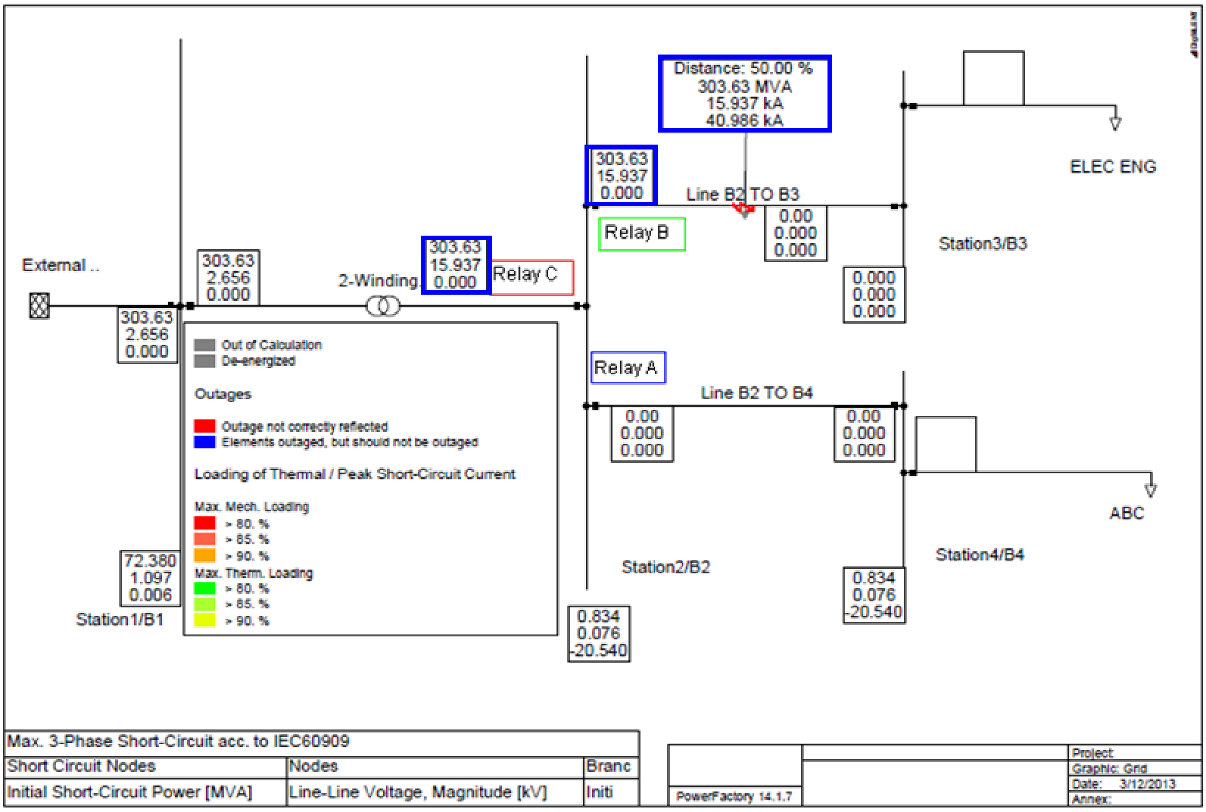


Figure 4.22: DigSILENT simulation diagram for the three phase fault in the line (B2 to B3) that feeds the load 1

Table 4.23: Minimum short circuit calculation results according to the IEC 60909 standard

Fault Location	S_k'' [MVA]	I_k'' [kA/kA]	I_P [kA/kA]
Line B2 to B3	303.63	15.937	40.986

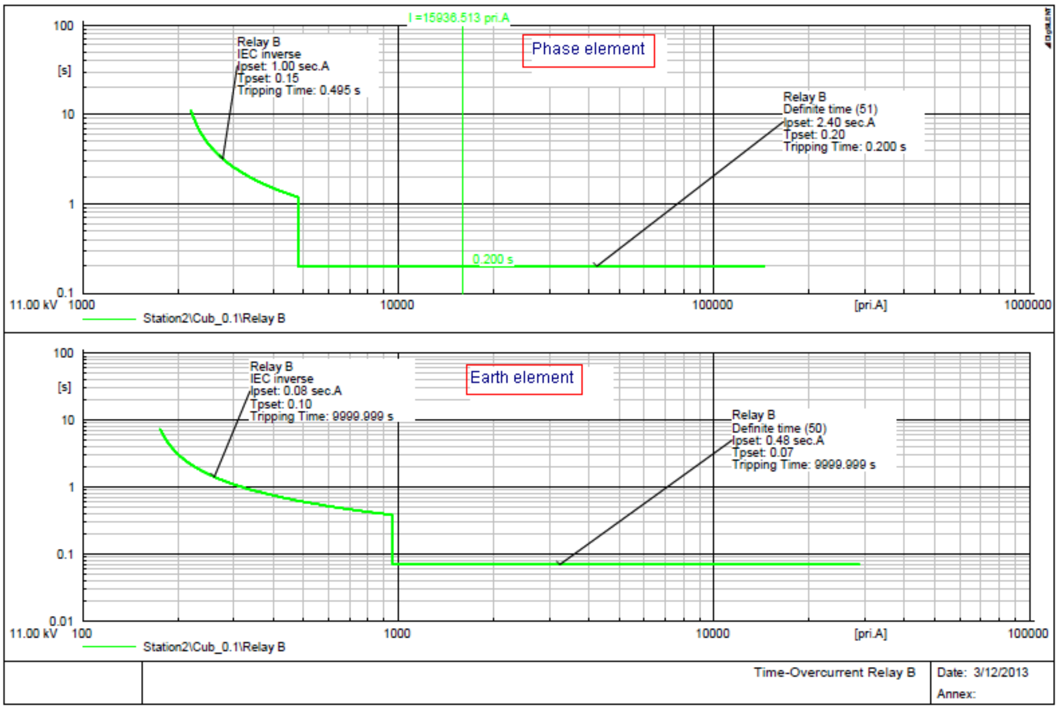


Figure 4.23: Relay B protection response for the three phase fault with a clearing time of 0.200 seconds for DT and 0.495 seconds for IDMT elements respectively

A time/current curve of the Relay B is used to analyse the results and the performance of the protection scheme. This time/current curve definition shows that the tripping times obtained for the relay B are 0.200 seconds for the DT and 0.495 seconds for the IDMT elements as shown in Figure 4.23 above. The earth element displays 9999.99 seconds for the tripping time. This fault only affects the phase fault currents therefore only the phase faults elements tripped. Table 4.24 shows the results for the three phase faults where the phase time overcurrent element (51P) tripping time response is 0.495 seconds and of the directional phase time overcurrent element is 0.200 seconds.

Table 4.24: **The result for the relay B protection response for the three phase fault**

Relays Tripping Times
Short-Circuit Calculation according to IEC60909 — 3-Phase Short-Circuit / Max. Short-Circuit Currents

Relay B	B2 / Station2				0.200 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents A :	7.968 sec.A	15936.51 pri.A	0.495 s
		B :	7.968 sec.A	15936.51 pri.A	
		C :	7.968 sec.A	15936.51 pri.A	
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
50N1 (IN>>1)	(IEC: IE>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
46 (Insc>)	(IEC: I2>t ANSI: 46)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
46A (InscA>)	(IEC: I2>t ANSI: 46)	Currents	0.000 sec.A	0.00 pri.A	9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle Upol,I	86.10 deg	F: 9999.999 s	R: 9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle Upol,I	-180.00 deg	F: 9999.999 s	R: 9999.999 s
67P (3I>—>)	(IEC: I>t ANSI: 51)	Currents	7.968 sec.A	15936.51 pri.A	0.200 s
32P2 (I1>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	86.10 deg	F: 9999.999 s	R: 9999.999 s
32N2 (I2>—>)	(IEC: I>dir ANSI: 67)	Angle Upol,I	123.69 deg	F: 9999.999 s	R: 9999.999 s

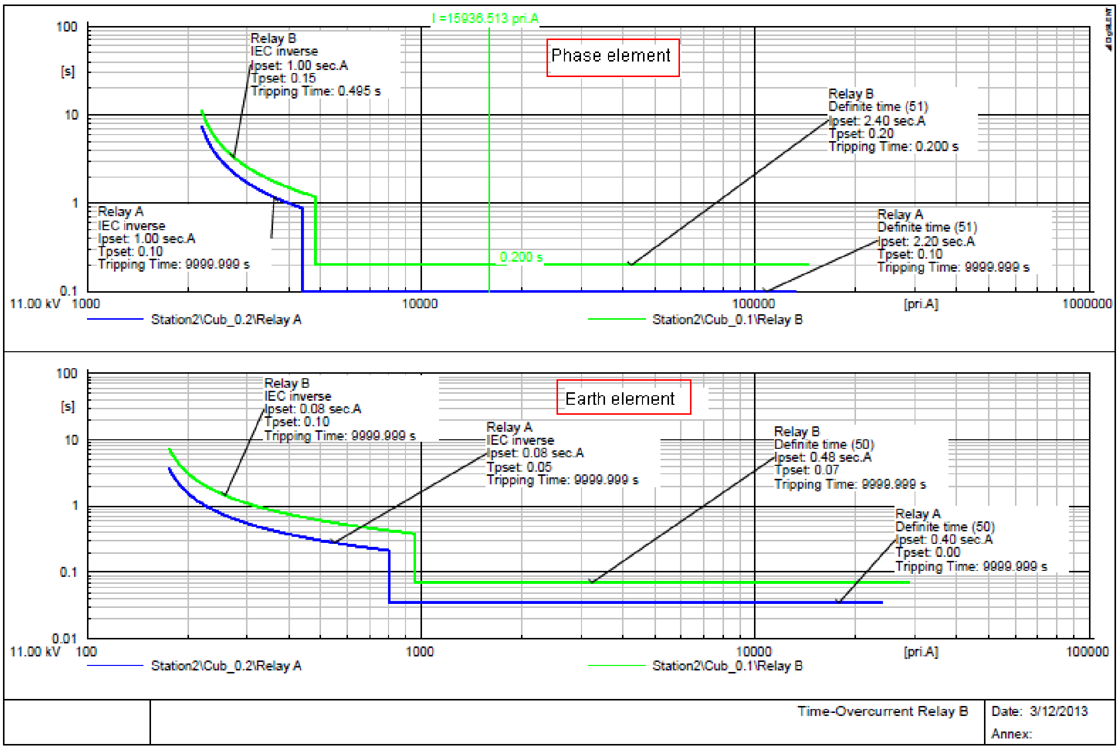


Figure 4.24: **Protection responses to the three phase fault for the relays A and B in the outgoing feeders**

Figure 4.24 above shows the simulated tripping characteristics for both the line (B2 to B3) feeding the load 1 and the line (B2 to B4) feeding the load 2 when a three phase fault occurs. It can be seen from the results that the relay A shown in blue does not see the three phase fault that occurs on the line (B2 to B3). Therefore Relay A tripping time is displayed as 9999.999 seconds for both the IDMT and the DT elements. This means that for the fault in the line (B2 to B3) the relay A did not trip. This ensures that the protection is correct and no false tripping or unwanted tripping will be experienced when the scheme is implemented

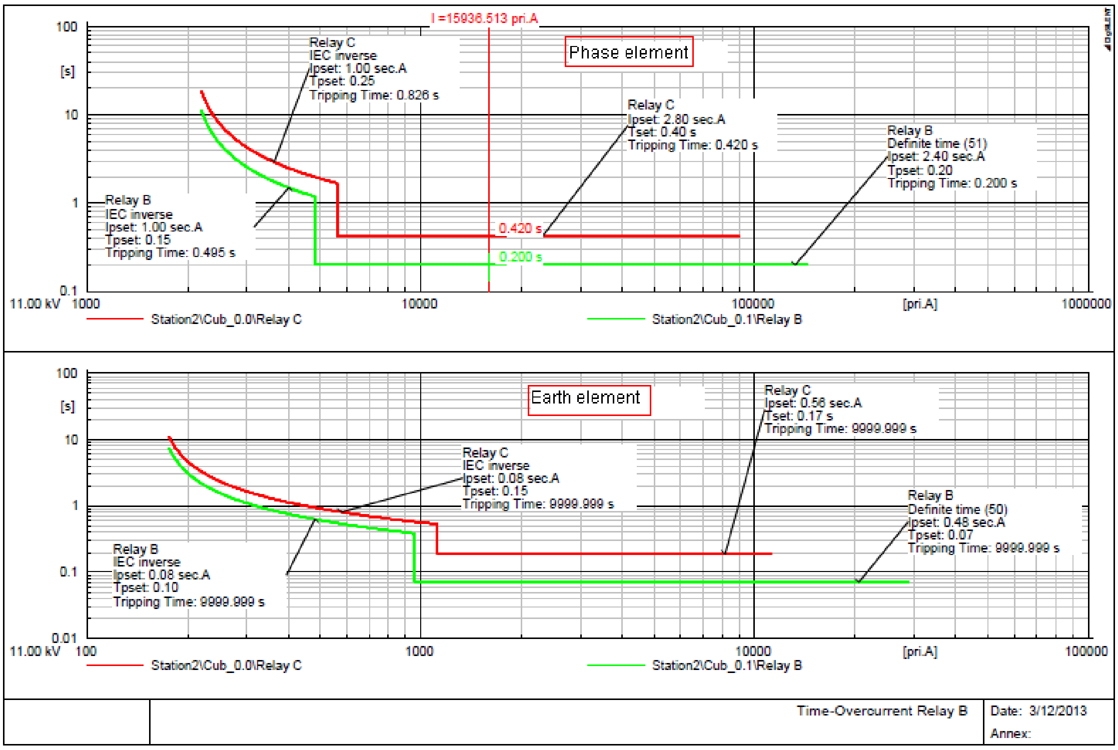


Figure 4.25: **Characteristics elements for relay B and C for three phase fault**

The three phase fault indicated in Figure 4.22 is picked-up by the B and C protection devices. With utilization of the DT and IDMT phase elements for the relay B, and the relay C. A sequence tripping response of 0.2 and 0.495 seconds for the relay B and 0.42 and 0.826 for the relay C are recorded as shown in Figure 4.25.The earth elements tripping times are 9999.99 seconds, meaning that they did not trip for this fault. The results also show that the relay B which is close to the fault responses in 0.495 seconds while the direct up-stream relay C follows with a response delayed by 0.826 seconds. This algorithm suggests that should the relay B fail to operate then the next up-stream relay C will operate. Therefore the relay C is used as a backup protection for the relay B. For faster tripping time the DT characteristic of the relay B responds in 0.2 seconds and the instantaneous characteristic for the relay C delays by 0.420 seconds respectively.

4.6.1.5 Single phase to ground fault at the busbar B2 for the relay C

Busbars plays an important role in the power system. This is where different electrical nodes of power systems are connected. A long time delay for tripping is not allowed or acceptable for the busbar faults. It is therefore important to have a fast protection system that can detect busbar faults with high selectively. Time overcurrent characteristics, pickup current and time dial for minimum short circuit current are calculated using equation (4.20) and are applied in the relays C. The suitable settings for this relay are shown in Table 4.25 below

Table 4.25: Relay C setting for earth protection

Characteristics	IDMT(51N)	DT(51N)
Current Setting	0.08	
Dial Time	0.15	
Pick up current		7
Time Setting		0.17

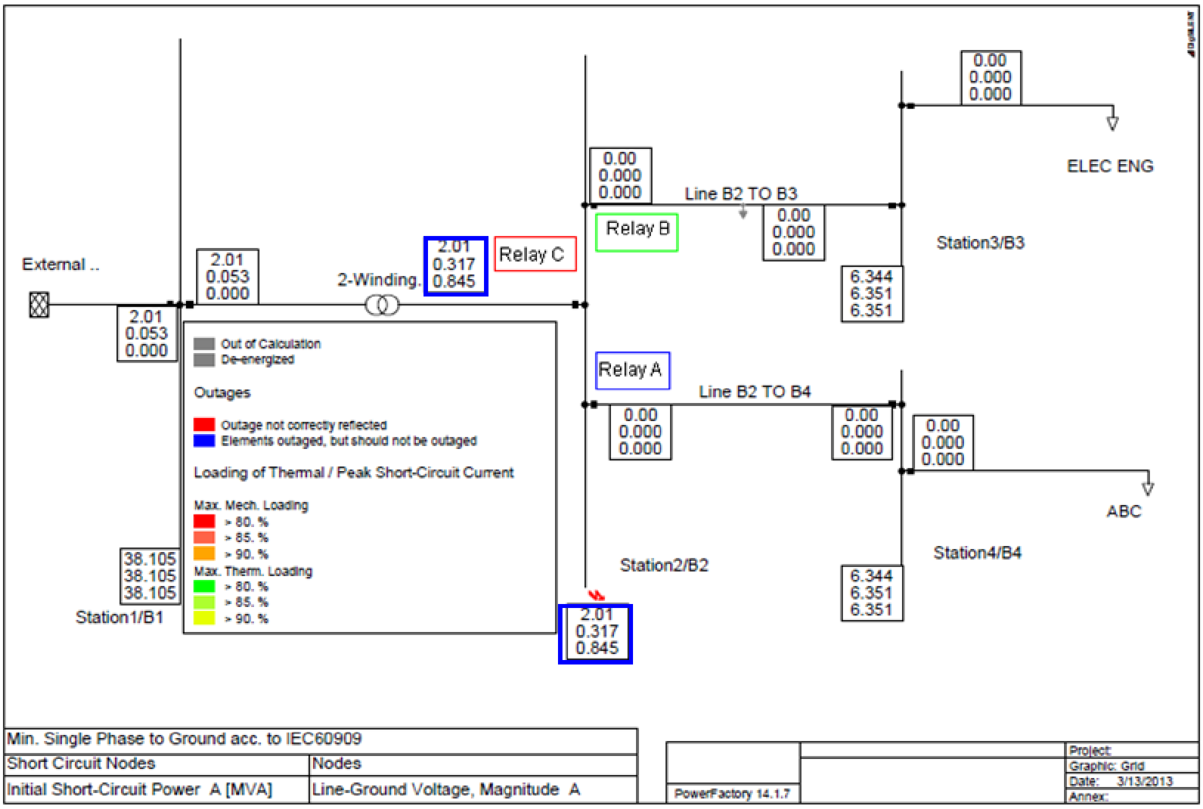


Figure 4.26: **DigSILENT simulation diagram of the single phase to the ground fault on the busbar B2**

A single phase to ground fault was introduced on the busbar B2 as shown in Figure 4.26 where boxes in the blue colour represent short circuit power, initial symmetrical short current and peak short circuit current. This particular fault is also known as internal fault. The minimum fault level $S_k^{''}$ of 2.01MVA, a short circuit current $I_k^{''}$ of

0.317kA and a peak current I_p of 0.845kA are obtained from the simulation recorded as shown in Table 4.26 below.

Table 4.26: **Minimum Short circuit calculations results according to IEC 60909 standard**

Fault Location	S_k'' [MVA]	I_k'' [kA/kA]	I_P [kA/kA]
Station 2/B2	2.01	0.317	0.845

A definite time and inverse characteristic model is chosen for the relay C that is placed on the incomer feeder of the station2/B2. A time/current curve of the relay C is used to analyze the performance of the protection scheme. These time/current curves assist with additional information that is needed for the protection, such as lowest and highest fault current levels. With a fault as shown in Figure 4.26, the relay C responds with an earth normal inverse tripping of 1.532 seconds. The response characteristic curve of the relay C is shown in Figure 4.27 below. The phase element tripping time is 9999.99 seconds meaning that it does not trip for this fault. Table 4.27 below shows the results for the relay C tripping time. Since the fault is a single phase the ground only the Ground Time Overcurrent Element (51N) trips at 1.523 seconds.

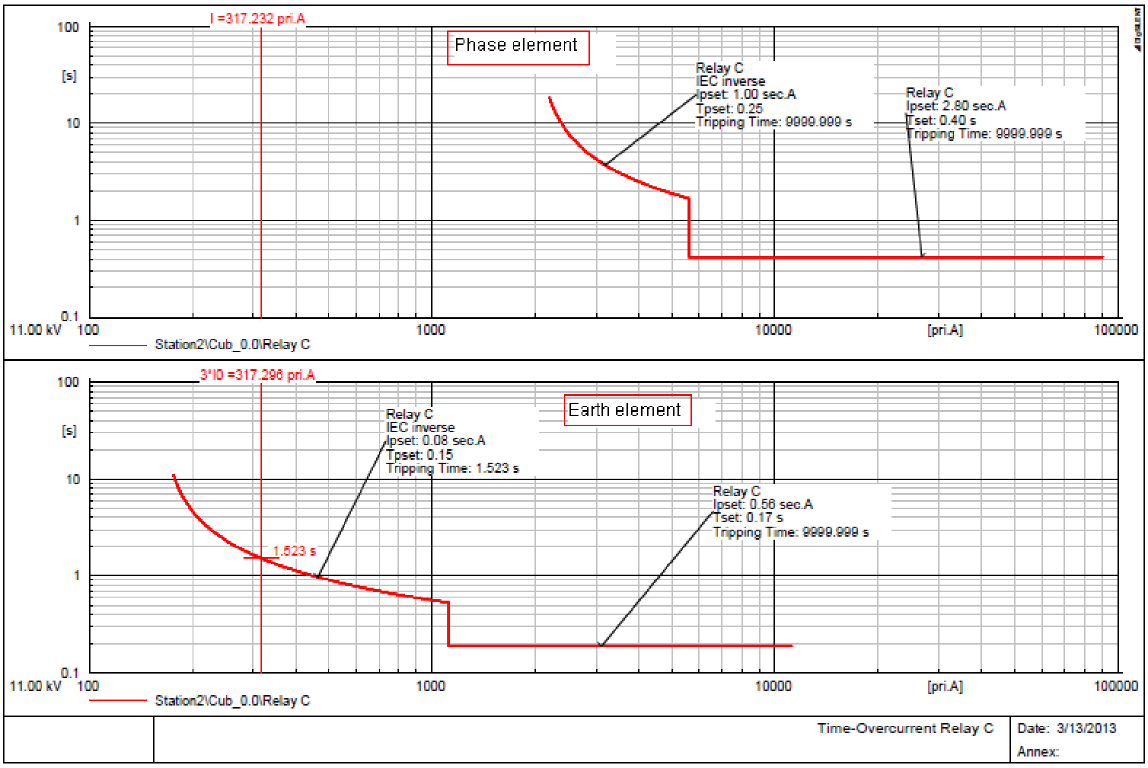


Figure 4.27: **Relay C protection response for the minimum single phase to ground fault with a clearing time of 1.523 seconds**

Table 4.27: The result for the relay C protection response for the single phase to ground fault

Relays Tripping Times Short-Circuit Calculation according to IEC60909			Single Phase to Ground	/ Min. Short-Circuit Currents		
Relay C	B2 / Station2					1.523 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents	A :	0.159 sec.A	317.23 pri.A	9999.999 s
			B :	0.000 sec.A	0.03 pri.A	
			C :	0.000 sec.A	0.03 pri.A	
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents		0.159 sec.A	317.30 pri.A	1.523 s
50P2 (3I>>2)	(IEC: I>> ANSI: 50)	Currents	A :	0.159 sec.A	317.23 pri.A	9999.999 s
			B :	0.000 sec.A	0.03 pri.A	
			C :	0.000 sec.A	0.03 pri.A	
50N2 (IN>>2)	(IEC: IE>> ANSI: 50N)	Currents		0.159 sec.A	317.30 pri.A	9999.999 s
46 (Insc>)	(IEC: I2>t ANSI: 46)	Currents		0.053 sec.A	105.73 pri.A	9999.999 s
46A (InscA>)	(IEC: I2>t ANSI: 46)	Currents		0.053 sec.A	105.73 pri.A	9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-178.83 deg	F: 9999.999 s	R: 9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle	Upol,I	-178.83 deg	F: 9999.999 s	R: 9999.999 s
32P2 (I1>—>)	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-178.83 deg	F: 9999.999 s	R: 9999.999 s
32N2 (I2>—>)	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-178.83 deg	F: 9999.999 s	R: 9999.999 s

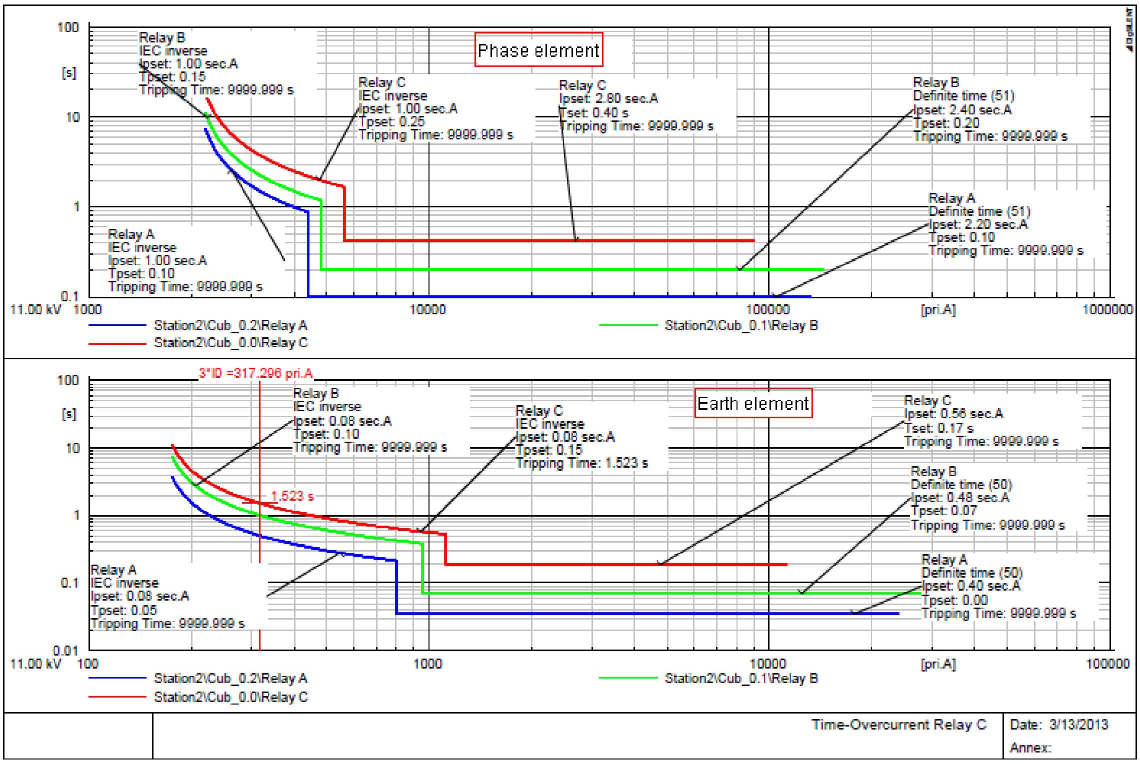


Figure 4.28: Relays A, B and C protection responses when the minimum single phase to the ground fault is applied on the busbar B2 in the substation2/B2

The relay C on the incoming feeder is configured in such a manner that it trips for the fault in the busbar B2 of station2/B2.Although the outgoing feeders of load 1 and load 2 are fed from the busbar B2 the relays A and B do not see the fault. This resulted for relay A and B tripping time to be 9999.999 seconds as shown in Figure 4.28. The response is correct because only the upstream relay needs to trip and the outgoing feeder relays is not necessary to trip.

4.6.1.6 Three phase fault on the busbar B2 for the relay C

Time overcurrent characteristics, pickup current and dial time for maximum short circuit current are calculated using equation (4.20) and applied to the relay C. The settings for this relay are shown in Table 4.28 below

Table 4.28: **Relay C setting for phase protection**

Characteristics	IDMT(51P)	IOC(50P)
Current Setting	1	
Time Dial	0.25	
Pick up current		2.8
Time Setting		0.4

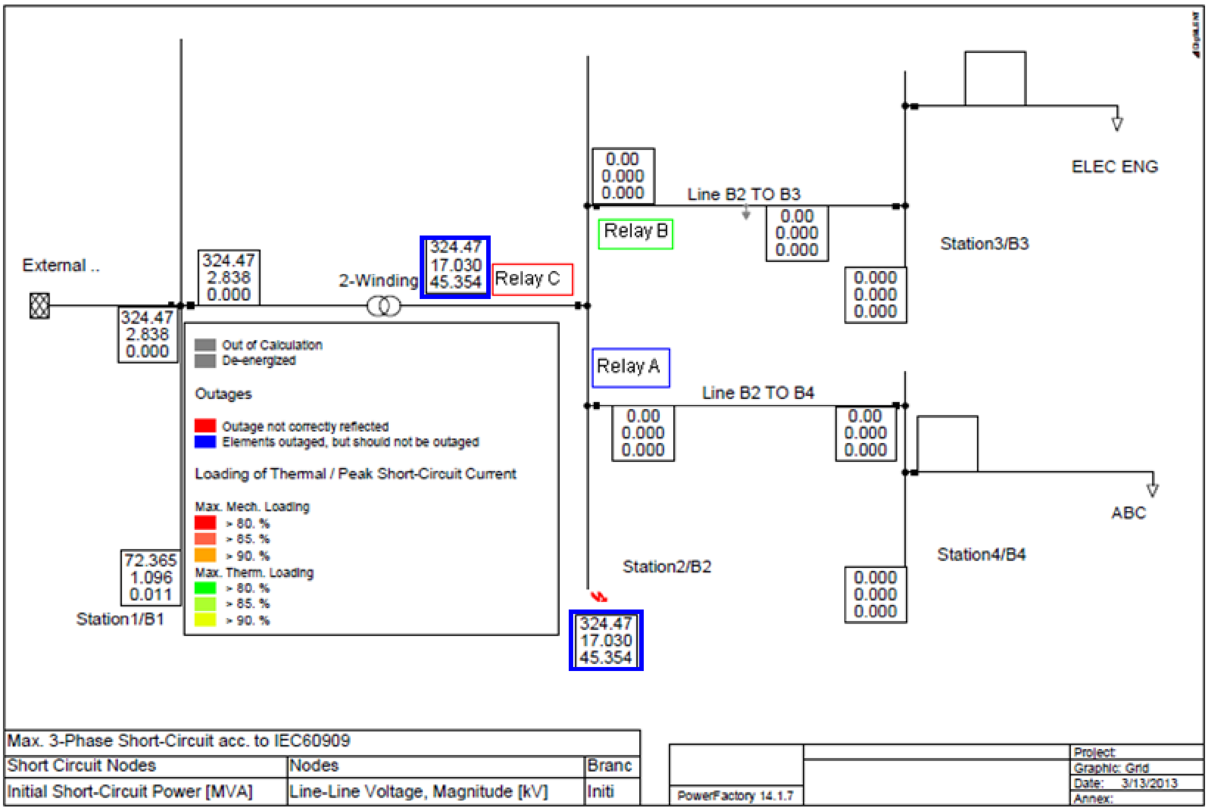


Figure 4.29 (a): DigSILENT simulation diagram for the three phase fault on the busbar B2

A three phase fault is introduced on the busbar as shown in Figure 4.29 (a) where boxes in the blue colour represent short circuit power, initial symmetrical short current and peak short circuit current.This particular fault is also known as an internal fault. Figure 4.29 (b) shows the recorded results for the three line-line voltages in the busbar B2 when the three phase fault is introduced in the distribution network.The execution time for the short circuit event is 0.420 seconds. During the short circuit period the line voltages decrease down to zero due to the fault current creating the system to be unbalanced. The fault level S_k'' of 324.47MVA, a short circuit current I_k'' of 17.030kA and a peak current I_P of 45.354kA are obtained as results from the simulation as shown on Table 4.29 below.

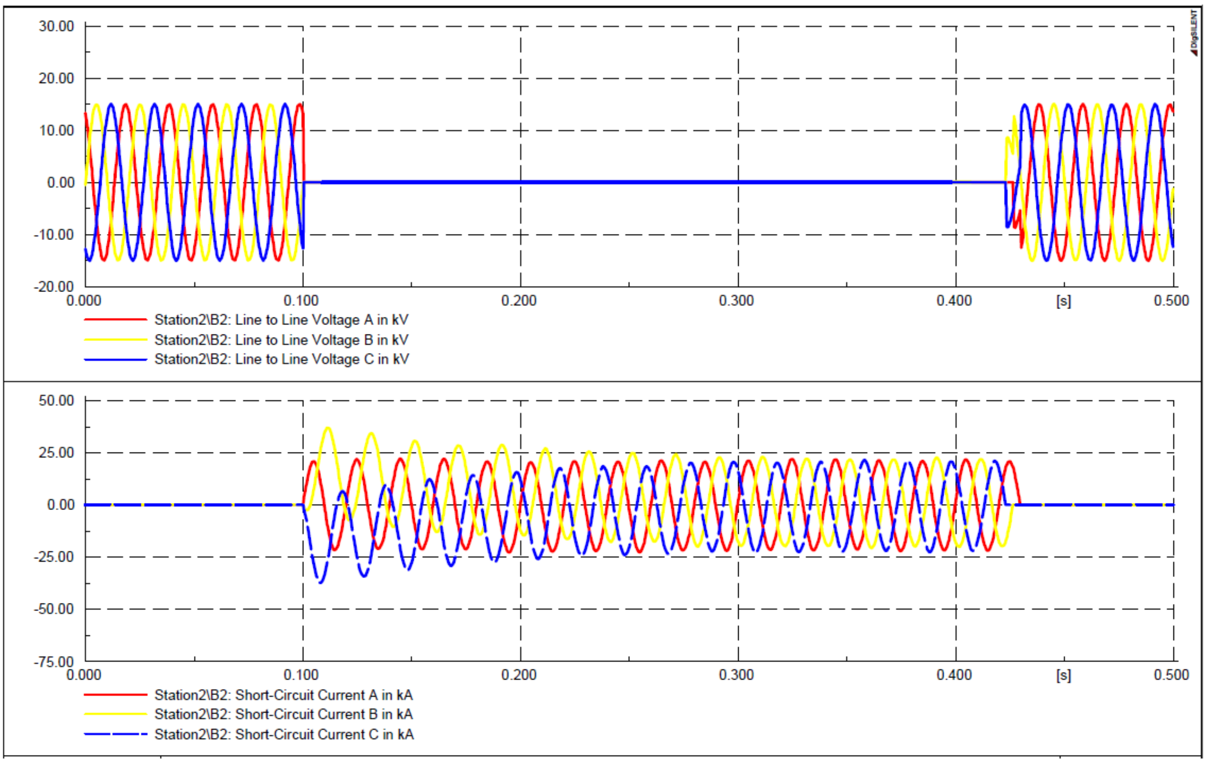


Figure 4.29 (b): **Recorded results for the three line-line voltages of the busbar B2**

Table 4.29: **Maximum Short circuit calculations results according to IEC 60909 standard**

Fault location	S_k'' [MVA]	I_k'' [kA]	I_P [kA]
Station 2/B2	324.47	17.030	45.354

The protection algorithm used here is the same as the one explained previously for the single phase to the ground fault. Under the fault shown in Figure 4.29(a), the relay C which is the bus protection device responded with an instantaneous phase tripping of 0.420 seconds and a normal inverse phase tripping of 0.800 seconds as shown in Figure 4.30 below.The earth element tripping time is 9999.99 seconds meaning that it does not trip for this fault.

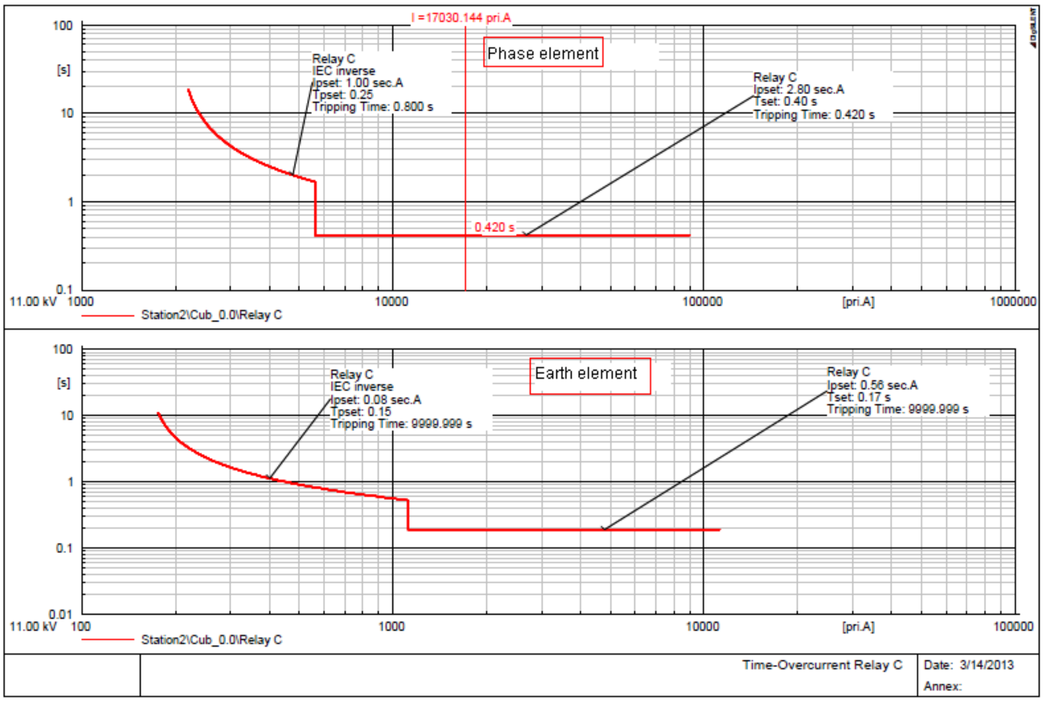


Figure 4.30: **Relay C protection response to the three phase fault on the busbar B2**

Table 4.30 shows the results for the three phase faults where phase instantaneous overcurrent element (50P) tripping time response is 0.420 seconds and time overcurrent element (51P) tripping time response is 0.800 seconds

Table 4.30: **The result for the relay C protection response for the three phase fault**

Relays Tripping Times
Short-Circuit Calculation according to IEC60909   3-Phase Short-Circuit / Max. Short-Circuit Currents

Relay C	B2 / Station2					0.420 s
51P (3I>)	(IEC: I>t ANSI: 51)	Currents	A :	8.515 sec.A	17030.14 pri.A	0.800 s
			B :	8.515 sec.A	17030.14 pri.A	
			C :	8.515 sec.A	17030.14 pri.A	
51N (IN>)	(IEC: IE>t ANSI: 51N)	Currents		0.000 sec.A	0.00 pri.A	9999.999 s
50P2 (3I>>2)	(IEC: I>> ANSI: 50)	Currents	A :	8.515 sec.A	17030.14 pri.A	0.420 s
			B :	8.515 sec.A	17030.14 pri.A	
			C :	8.515 sec.A	17030.14 pri.A	
50N2 (IN>>2)	(IEC: IE>> ANSI: 50N)	Currents		0.000 sec.A	0.00 pri.A	9999.999 s
46 (Insc>)	(IEC: I2>t ANSI: 46)	Currents		0.000 sec.A	0.00 pri.A	9999.999 s
46A (InscA>)	(IEC: I2>t ANSI: 46)	Currents		0.000 sec.A	0.00 pri.A	9999.999 s
Dir OC	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-92.42 deg	F: 9999.999 s	R: 9999.999 s
Dir EF	(IEC: I>dir ANSI: 67N)	Angle	Upol,I	153.43 deg	F: 9999.999 s	R: 9999.999 s
32P2 (I1—>)	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-92.42 deg	F: 9999.999 s	R: 9999.999 s
32N2 (I2—>)	(IEC: I>dir ANSI: 67)	Angle	Upol,I	-90.00 deg	F: 9999.999 s	R: 9999.999 s

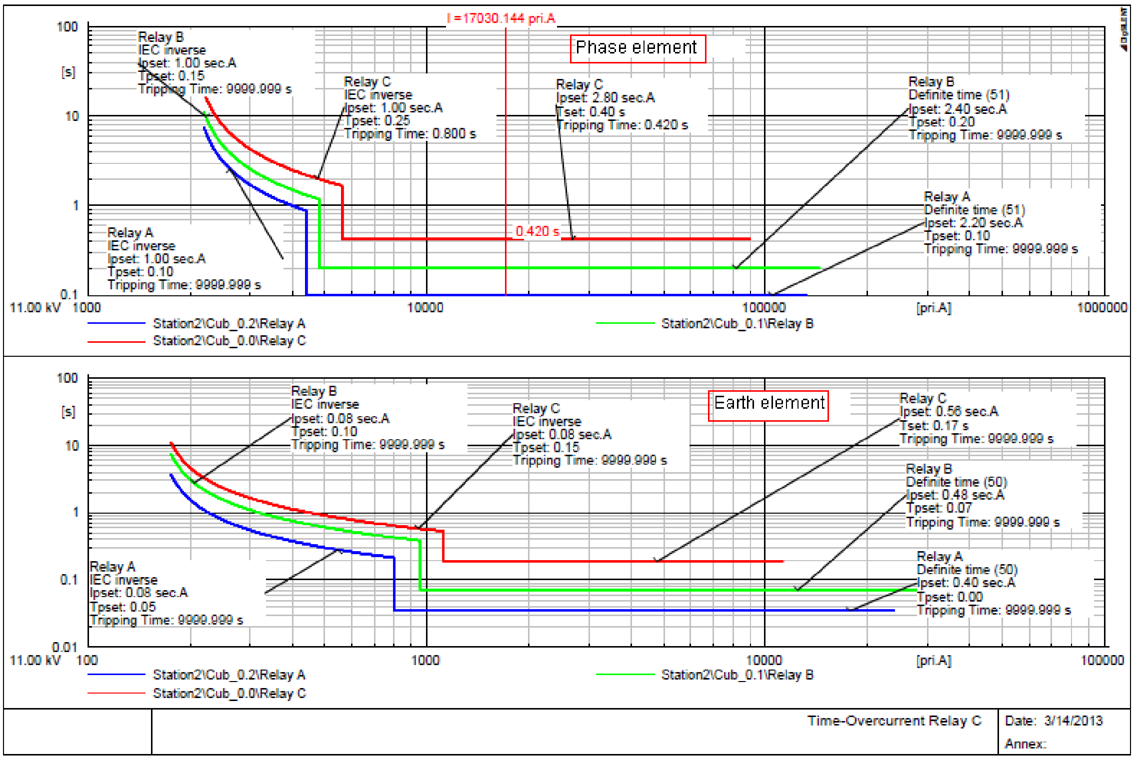


Figure 4.31: **Relays A, B and C protection responses when a three phase fault is applied on the busbar B2**

The relay C on the incomer to the busbar B2 feeder is configured in such a manner that it trips for fault at the busbar of the station2/B2. Although the protection devices on the outgoing feeders that feed the substation4/B4 and the substation3/B3 are being fed from this busbar they do not see the fault. This can be seen from the tripping times of the relays A and B of 9999.999 seconds as shown in Figure 4.31 above. For this specific fault the earth elements did not see the fault and therefore they did not trip. From the result it can be said that the response of the protection method used is correct because only the upstream relay trips and the outgoing feeder relays do not trip.

4.6.1.7 Case study one results

All results for the case study one are all presented in Table 4.31. The results are divided into eight parts, namely:

- Protection Device
- Fault Location
- Fault Type
- Protection function
- Short circuit power $S_k^{''}$ in MVA
- Initial symmetrical short current $I_k^{''}$ in kA
- Peak short circuit current I_p in kA
- Tripping Time in seconds

Table 4.31 **Combined results for the different faults in the distribution network used in the case study one**

Protection Device	Fault Location	Fault Type	Protection function	Short circuit power (S_K'') in MVA	Initial symmetrical short current (I_k'') in kA	Peak short circuit current (I_p) in kA	Tripping Time in seconds
Relay A	Line (B2toB4)	Single phase to ground fault	51N (IN>)	1.96	0.309	0.821	0.527
Relay A	Line (B2toB4)	Three phase Fault	51P(3I>)	315.97	16.584	44.089	0.100
Relay B	Line (B2toB3)	Single phase to ground fault	51N (IN>)	1.89	0.298	0.752	1.117
Relay B	Line (B2toB3)	Three phase Fault	51P(3I>)	303.63	15.937	40.986	0.200
Relay C	Station2/B2	Single phase to ground fault	51N (IN>)	2.01	0.317	0.845	1.523
Relay C	Station2/B2	Three phase Fault	51P(3I>)	324.47	17.030	45.354	0.420

4.6.2 Case study two

In this case study the same procedure as this for the case study one is followed. The only difference with this case study is the fact the conventional relays used in case study one are substituted by IEDs. The reason for this exercise is to later apply the GOOSE communication between the IEDs using internet cable instead of using copper wire from one relay to other. Note the IEDs had to be configured in the same way as the relays so that the protection results should be the same when it comes to stand alone protection performance. The reasons for this practise it to make sure that only the speed performance between the GOOSE communication and Hardwire is compared. The same network was simulated. When this is achieved the GOOSE engineering of the IEDs is done in Chapter six and therefore a laboratory test bench is developed to assist the comparison between GOOSE and hardwire communication.

Case study two followed the same steps that were implemented in the case study one. The results from the simulation for the minimum single phase fault and the three phase fault were recorded. These results were documented as follows:

4.6.2.1 Single phase to ground fault in the line (B2 to B4) for IED A

For the fault shown in Figure 4.10, the results for the IED A fault response are shown in Figures 4.32, 4.33 and 4.34 below. Table 4.32 below shows the results for the IED A tripping time. Since the fault is the single phase to the ground only the Ground Time Overcurrent Element (51N) trips at 0.527 seconds.

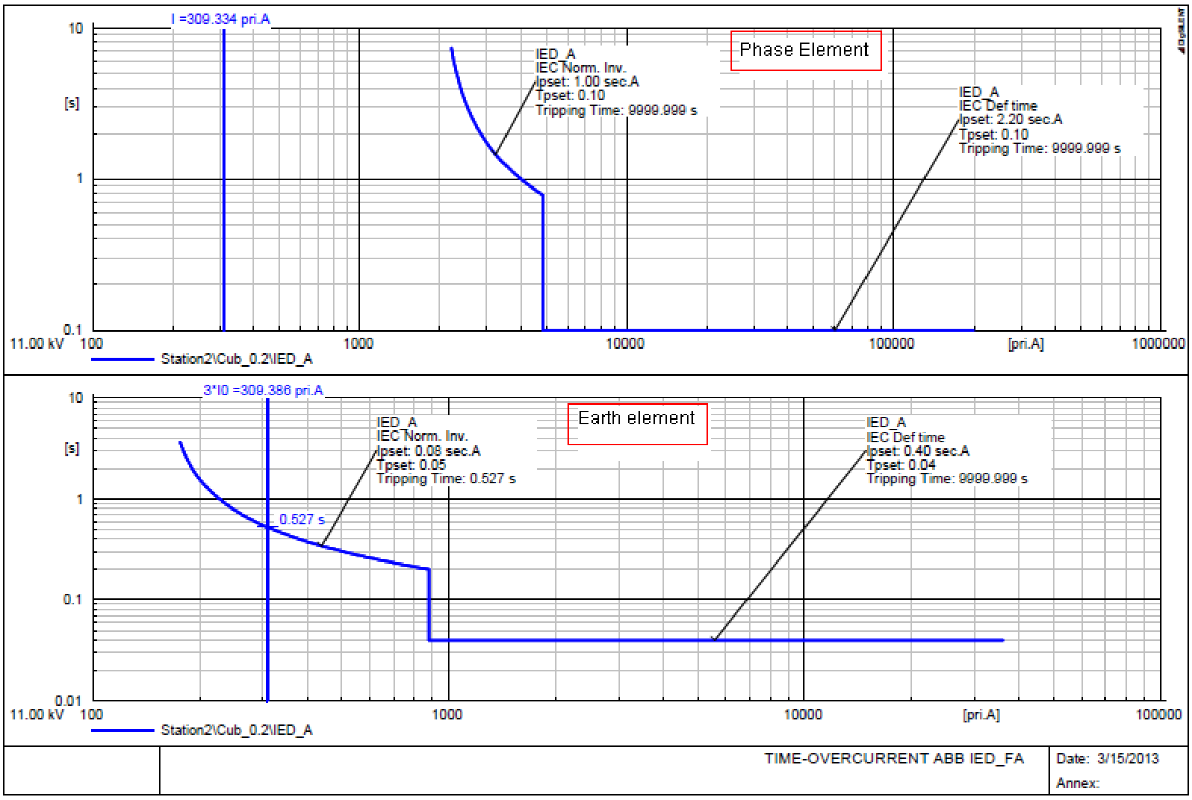


Figure 4.32: The IED A protection response to the minimum single phase to the ground fault with a clearing time of 0.527 seconds

Table 4.32: The result for the IED A protection response for the single phase to the ground fault

Relays Tripping Times Short-Circuit Calculation according to IEC60909				Single Phase to Ground	/ Min. Short-Circuit Currents	
IED A	B2 / Station2					0.527 s
51P-1(1)	(IEC: I>t ANSI: 51)	Currents	A :	0.155 sec.A	309.33 pri.A	9999.999 s
			B :	0.000 sec.A	0.04 pri.A	
			C :	0.000 sec.A	0.04 pri.A	
51P-1(2)	(IEC: I>t ANSI: 51)	Currents	A :	0.155 sec.A	309.33 pri.A	9999.999 s
			B :	0.000 sec.A	0.04 pri.A	
			C :	0.000 sec.A	0.04 pri.A	
51N-1(1)	(IEC: IE>t ANSI: 51N)	Currents		0.155 sec.A	309.39 pri.A	0.527 s
51N-1(2)	(IEC: I>t ANSI: 51N)	Currents		0.155 sec.A	309.39 pri.A	9999.999 s

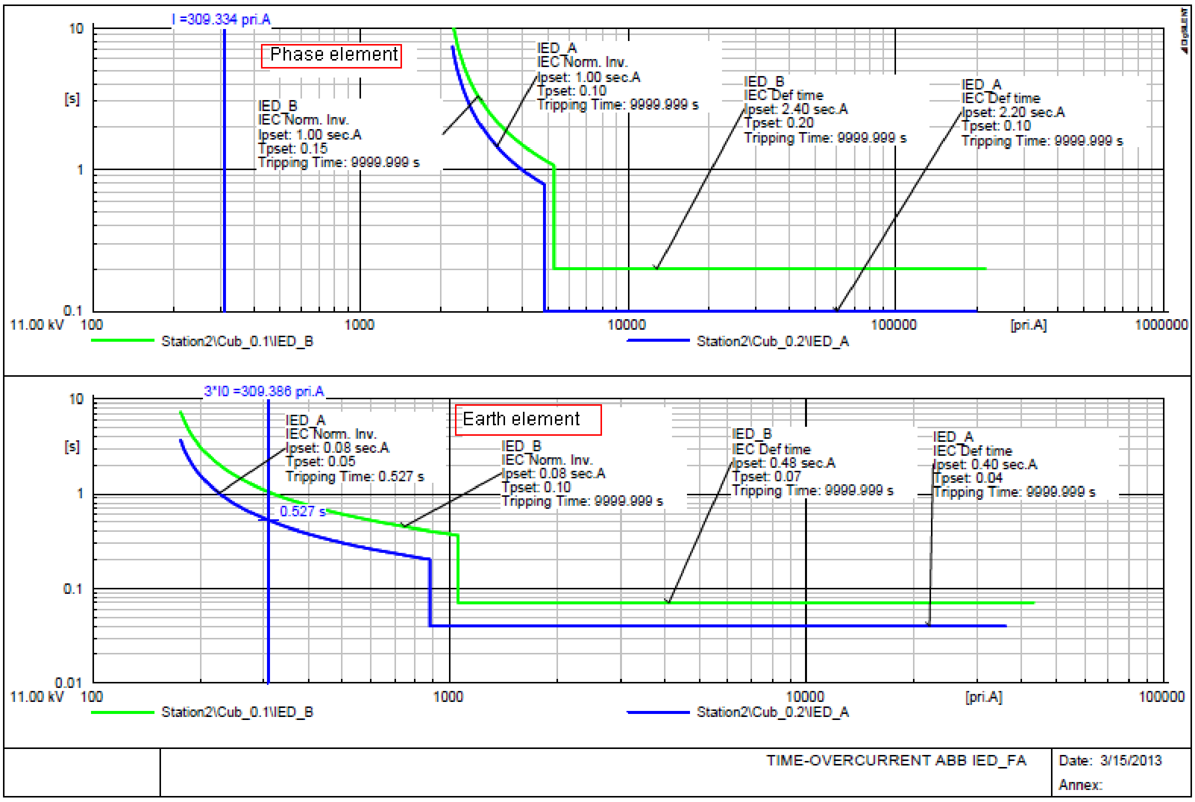


Figure 4.33: Protection responses to the single phase to the ground fault for the IEDs A and B on the outgoing feeders

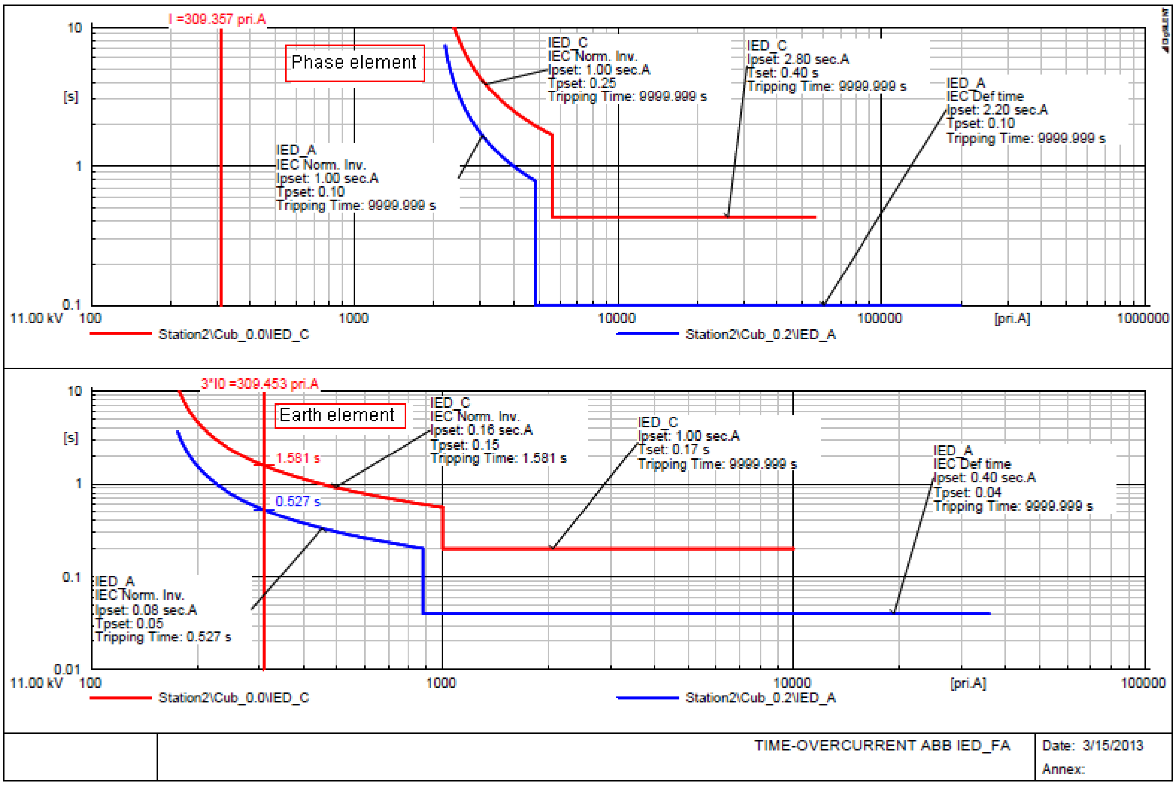


Figure 4.34: IED A time-overcurrent response and IED C acting as back-up protection for the single phase to the ground fault.

4.6.2.2 Three phase fault on the line (B2 to B4) for the IED A

For a fault shown in Figure 4.14, the results for the IED A are shown in Figure 4.35, 4.36 and 4.37 below. Table 4.33 shows the results for the three phase faults where phase time overcurrent element 51P-1(1) tripping time response is 0.324 seconds and 51P-1(2) is 0.100 seconds.

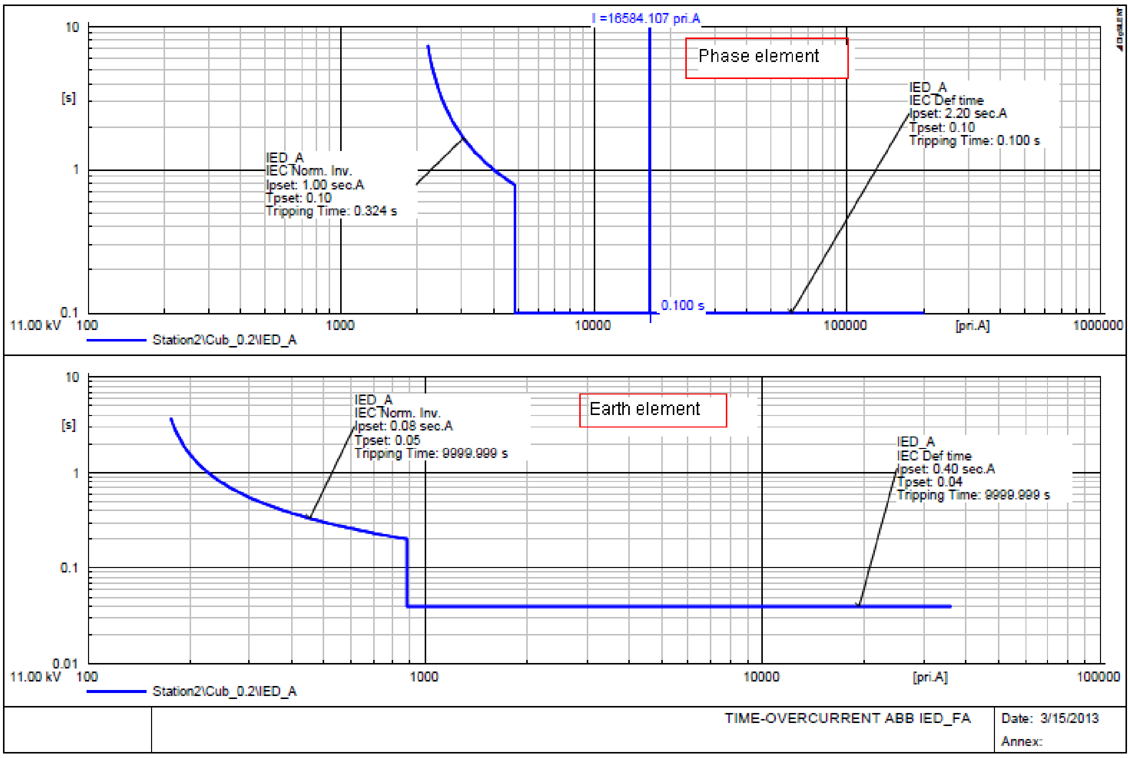


Figure 4.35: The IED A protection response for the three phase fault with a clearing time of 0.100 seconds for the DT and 0.324 seconds for the IDMT element respectively

Table 4.33: The result for the IED A protection response for the three phase fault

Relays Tripping Times
Short-Circuit Calculation according to IEC60909 — 3-Phase Short-Circuit / Max. Short-Circuit Currents

Relay	Branch	Terminal	/Station	Type				Tripping Times
IED A		B2	/ Station2					0.100 s
51P-1(1)	(IEC: I>t ANSI: 51)			Currents	A :	8.292 sec.A	16584.11 pri.A	0.324 s
					B :	8.292 sec.A	16584.11 pri.A	
					C :	8.292 sec.A	16584.11 pri.A	
51P-1(2)	(IEC: I>t ANSI: 51)			Currents	A :	8.292 sec.A	16584.11 pri.A	0.100 s
					B :	8.292 sec.A	16584.11 pri.A	
					C :	8.292 sec.A	16584.11 pri.A	
51N-1(1)	(IEC: IE>t ANSI: 51N)			Currents		0.000 sec.A	0.00 pri.A	9999.999 s
51N-1(2)	(IEC: I>t ANSI: 51N)			Currents		0.000 sec.A	0.00 pri.A	9999.999 s

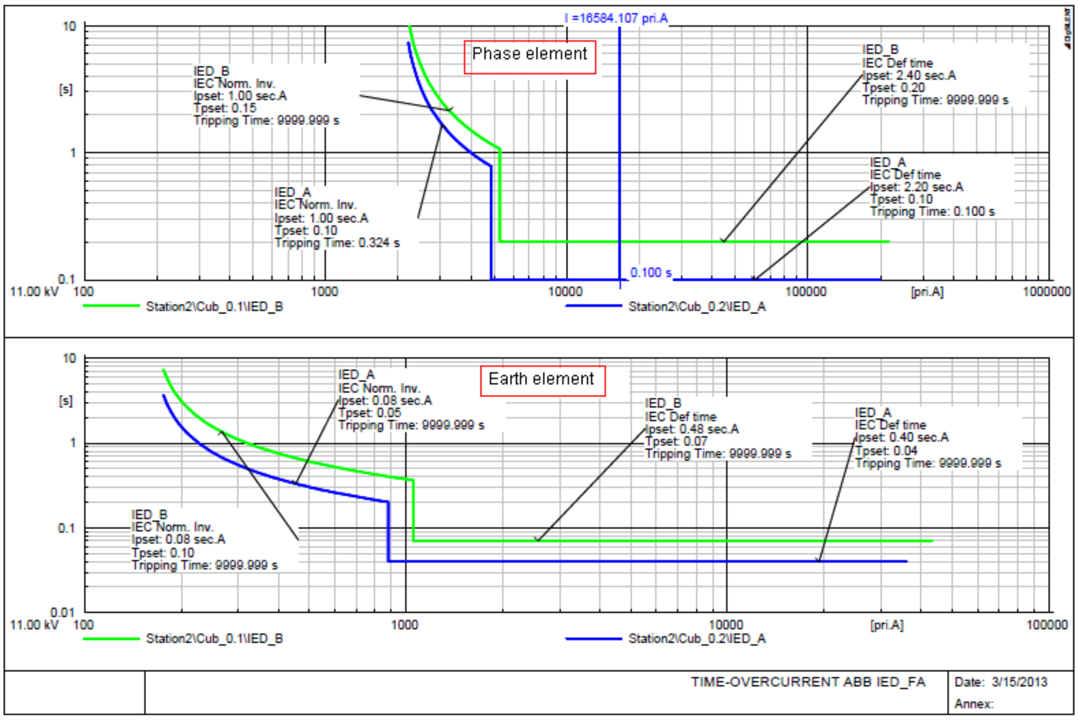


Figure 4.36: IEDs A and B protection responses to the three phase fault

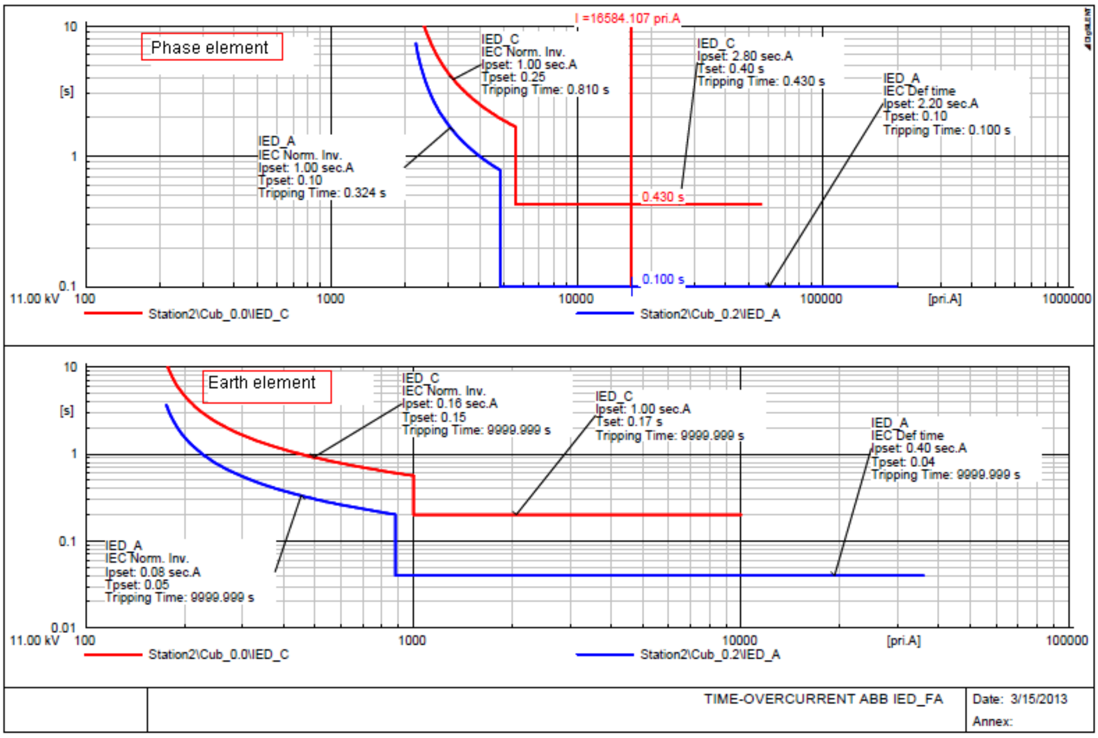


Figure 4.37: IED A time-overcurrent response and IED C acting as back-up protection response to the three phase fault

4.6.2.3 Single phase to the ground fault on the line (B2 to B3) for the IED B

For the fault shown in Figure 4.18, the results for the IED B are shown in Figures 4.38, 4.39 and 4.40 below. Table 4.34 below shows the results for the IED B tripping time. Since the fault is the single phase to the ground only the Ground Time Overcurrent Element (51N) trips at 1.117 seconds.

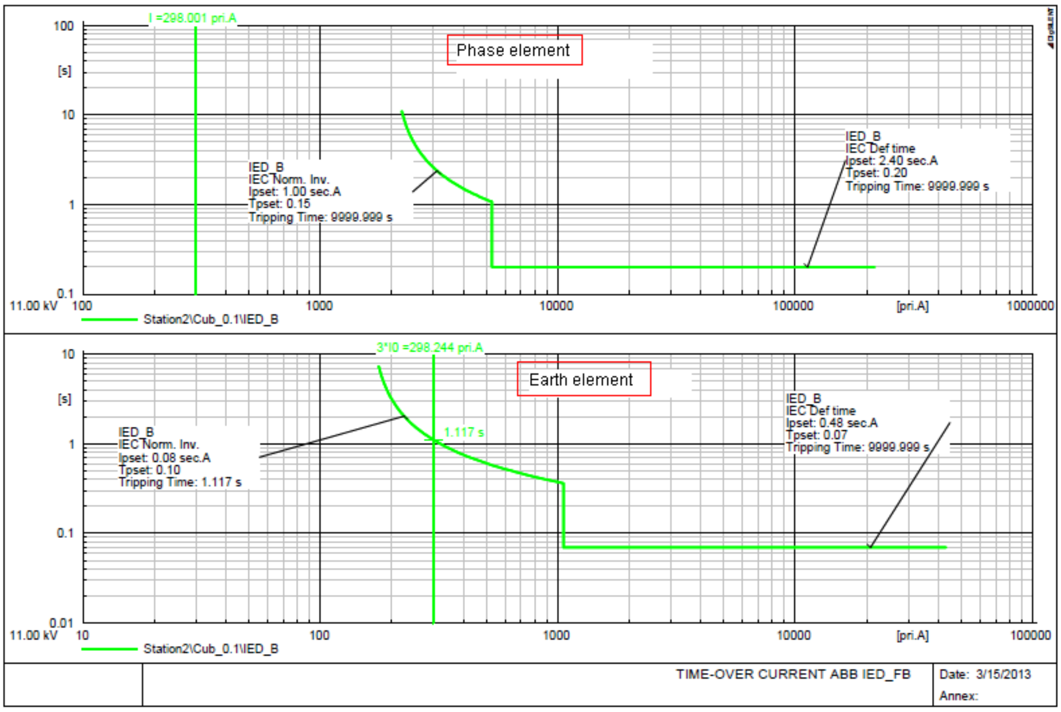


Figure 4.38: IED B protection response for the single phase to the ground fault with a clearing time of 1.117 seconds

Table 4.34: The result for the IED B protection response for the single phase to ground fault

Relays Tripping Times							
Short-Circuit Calculation according to IEC60909			Single Phase to Ground	/ Min. Short-Circuit Currents			
IED B	B2	/ Station2					1.117 s
51P-1(1)	(IEC: I>t	ANSI: 51)	Currents	A :	0.149 sec.A	298.00 pri.A	9999.999 s
				B :	0.000 sec.A	0.19 pri.A	
				C :	0.000 sec.A	0.19 pri.A	
51P-1(2)	(IEC: I>t	ANSI: 51)	Currents	A :	0.149 sec.A	298.00 pri.A	9999.999 s
				B :	0.000 sec.A	0.19 pri.A	
				C :	0.000 sec.A	0.19 pri.A	
51N-1(1)	(IEC: IE>t	ANSI: 51N)	Currents		0.149 sec.A	298.24 pri.A	1.117 s
51N-1(2)	(IEC: I>t	ANSI: 51N)	Currents		0.149 sec.A	298.24 pri.A	9999.999 s

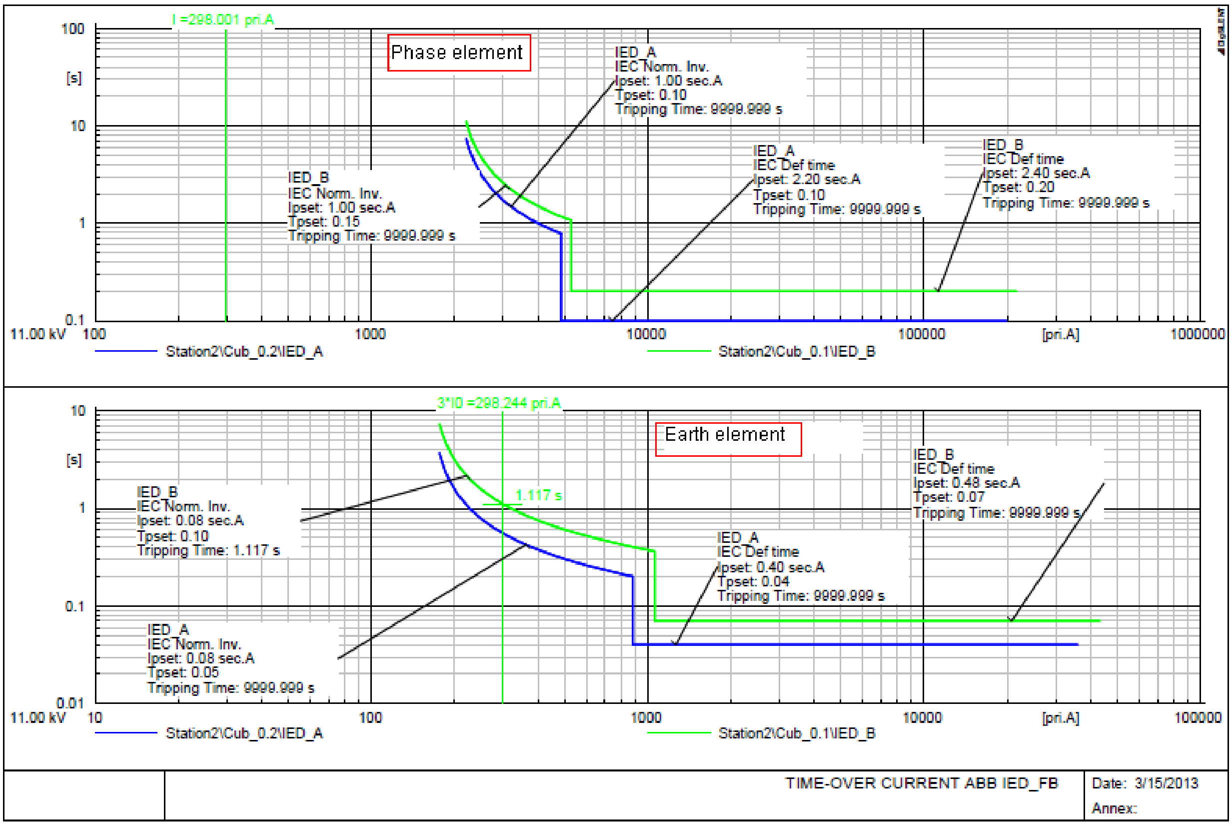


Figure 4.39: Protection responses to the single phase to the ground fault for the IEDs A and B from outgoing feeders

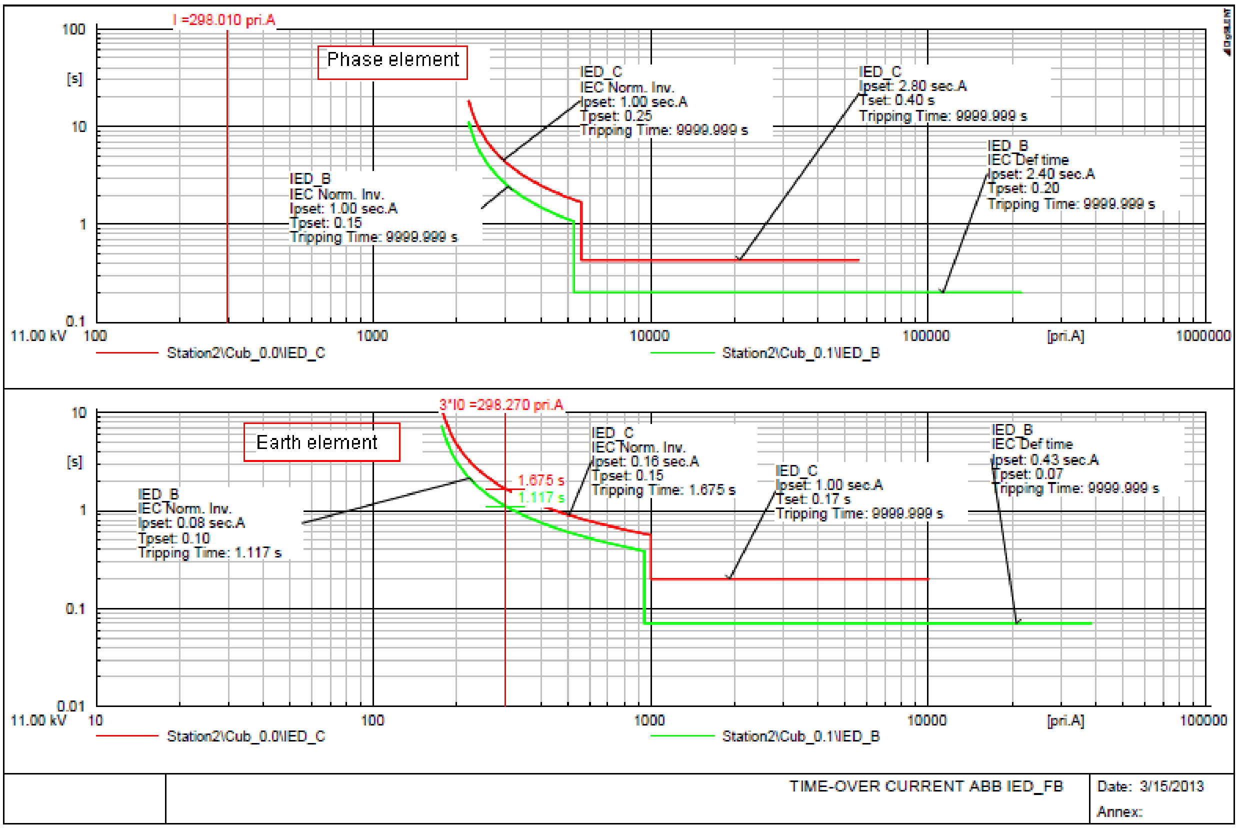


Figure 4.40: IED B time-overcurrent response of 1.117 seconds and IED C acting as back-up protection with time response of 1.675 seconds for the single phase to the ground fault

4.6.2.4 Three phase fault type on line (B2 to B3) for the IED B

For a fault shown in Figure 4.22, the results for the IED B are shown in Figures 4.41, 4.42 and 4.43 below. Table 4.35 shows the results for the three phase faults where the phase time overcurrent element 51P-1(1) tripping time response is 0.495 seconds and 51P-1(2) is 0.200 seconds.

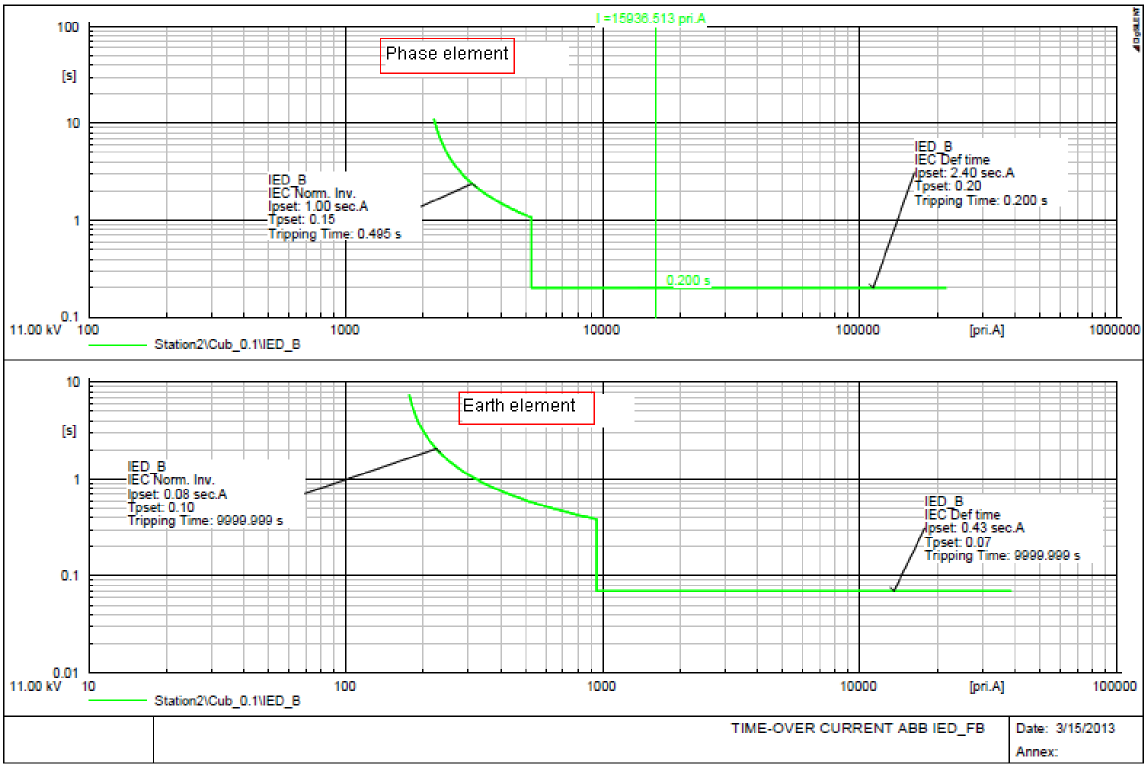


Figure 4.41: **IED B protection response for the three phase fault with a clearing time of 0.200 seconds for the DT and 0.495 seconds for the IDMT elements respectively**

Table 4.35: **The result for the IED B protection response for the three phase fault**

Relays Tripping Times						
Short-Circuit Calculation according to IEC60909		3-Phase Short-Circuit	/ Max. Short-Circuit Currents			
IED B	B2 / Station2					0.200 s
51P-1(1)	(IEC: I>t ANSI: 51)	Currents A :	7.968 sec.A	15936.51 pri.A		0.495 s
		B :	7.968 sec.A	15936.51 pri.A		
		C :	7.968 sec.A	15936.51 pri.A		
51P-1(2)	(IEC: I>t ANSI: 51)	Currents A :	7.968 sec.A	15936.51 pri.A		0.200 s
		B :	7.968 sec.A	15936.51 pri.A		
		C :	7.968 sec.A	15936.51 pri.A		
51N-1(1)	(IEC: IE>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A		9999.999 s
51N-1(2)	(IEC: I>t ANSI: 51N)	Currents	0.000 sec.A	0.00 pri.A		9999.999 s

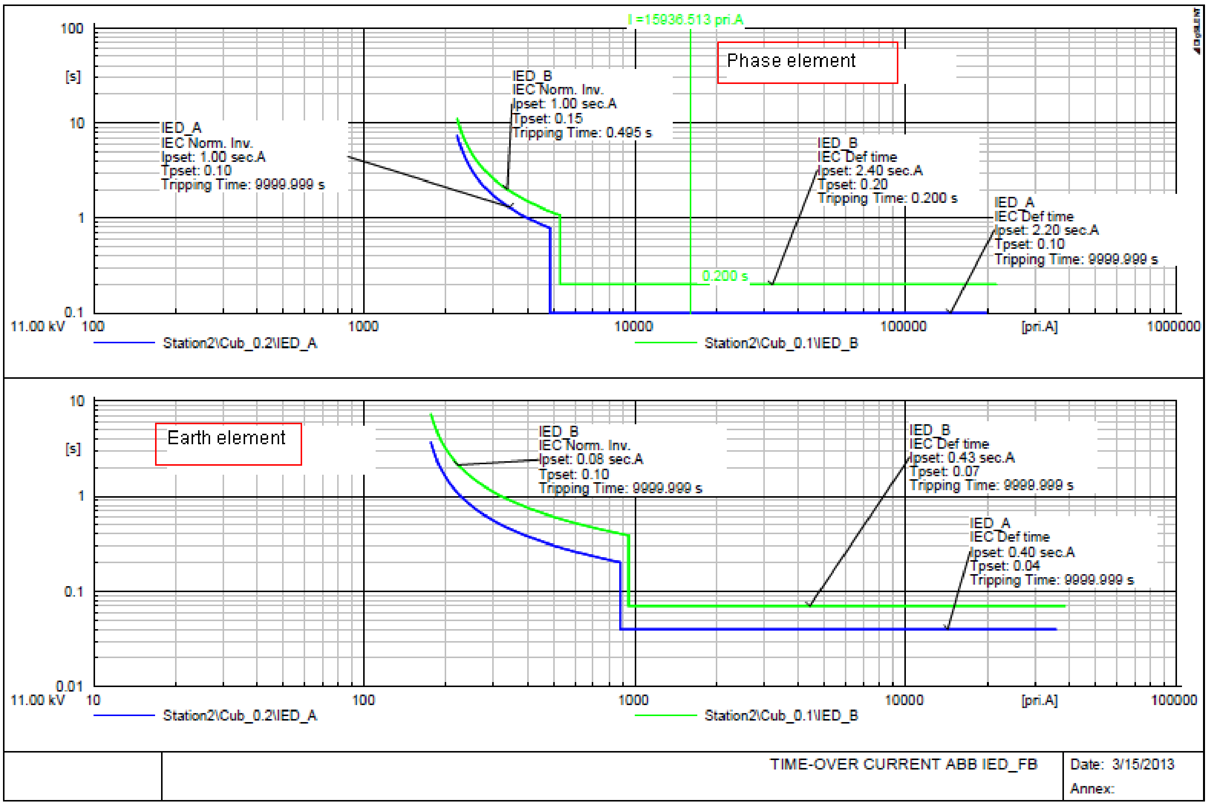


Figure 4.42: Protection response to the three phase fault for the IEDs A and B from the outgoing feeders

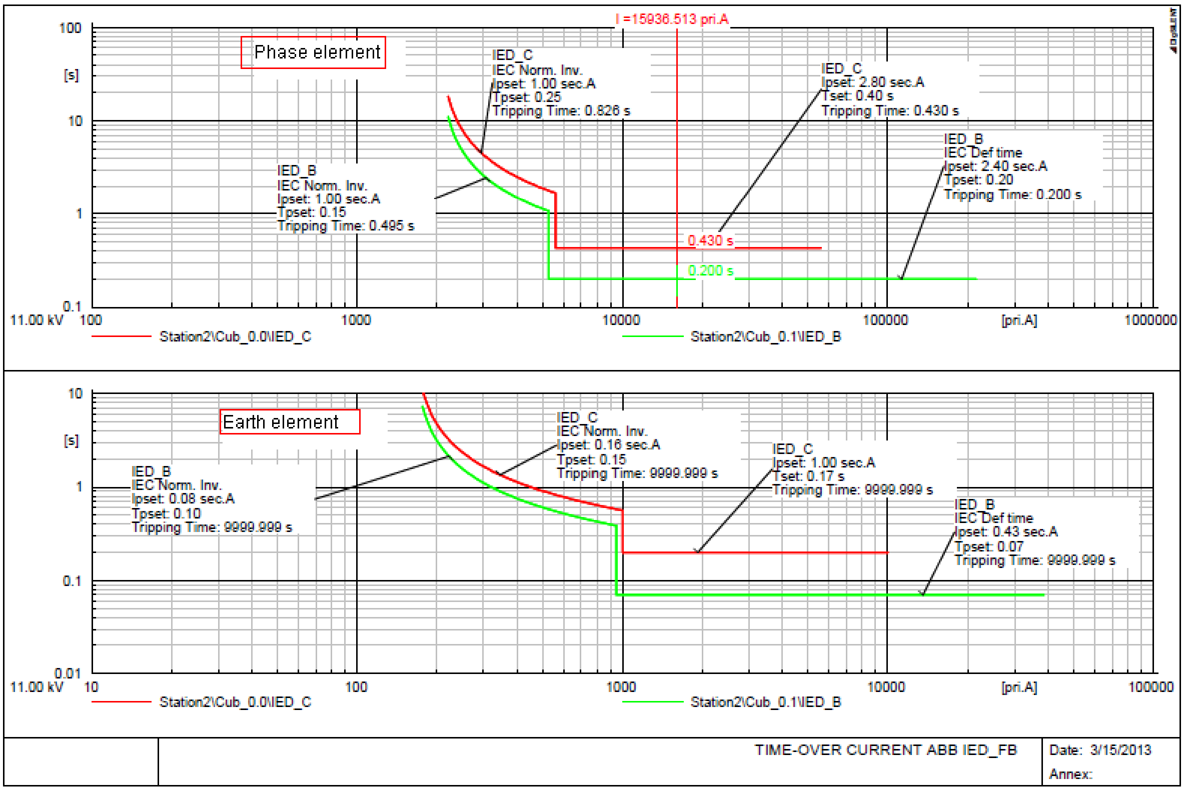


Figure 4.43: IED B time-overcurrent response of 0.20 seconds for the DT and 0.495 seconds for the IDMT element respectively and IED C acting as back-up protection with time response of 0.430 seconds for the DT and 0.826 seconds for the IDMT elements respectively for the three phase fault

4.6.2.5 Single phase to ground fault on the busbar B2 for the IED C

For the fault shown in Figure 4.26, the results for the IED C are shown in Figures 4.44 and 4.45 below. Table 4.36 below shows the results for IED C tripping time. Since the fault is the single phase to the ground only the Ground Time Overcurrent Element (51N) trips at 1.523 seconds.

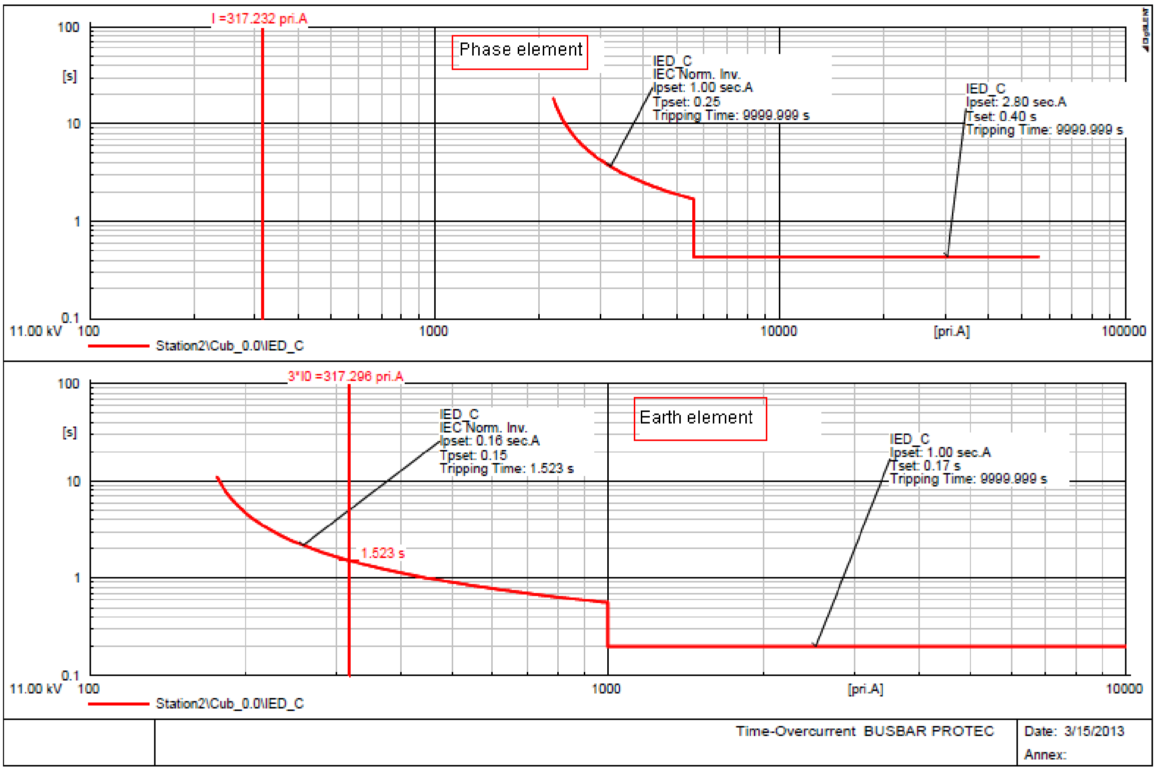


Figure 4.44: **IED C protection response to the minimum single phase to ground fault with a clearing time of 1.523 seconds**

Table 4.36: **The result for the IED C protection response for the single phase to the ground fault**

Relays Tripping Times
Short-Circuit Calculation according to IEC60909 Single Phase to Ground / Min. Short-Circuit Currents

IED C B2 / Station2							1.523 s
51P-1(1)	(IEC: I>t	ANSI: 51)	Currents	A :	0.159 sec.A	317.23 pri.A	9999.999 s
				B :	0.000 sec.A	0.03 pri.A	
				C :	0.000 sec.A	0.03 pri.A	
50P/51P(1)	(IEC: I>>	ANSI: 50)	Currents	A :	0.159 sec.A	317.23 pri.A	9999.999 s
				B :	0.000 sec.A	0.03 pri.A	
				C :	0.000 sec.A	0.03 pri.A	
Dir phase	(IEC: I->	ANSI: 67)	Angle U,I	A :	-178.83 deg	F: 9999.999 s	R: 9999.999 s
				B :	-176.32 deg	9999.999 s	9999.999 s
				C :	-176.32 deg	9999.999 s	9999.999 s
51N-1(1)	(IEC: IE>t	ANSI: 51N)	Currents		0.317 sec.A	317.30 pri.A	1.523 s
50N-51N	(IEC: I>>	ANSI: 50)	Currents		0.317 sec.A	317.30 pri.A	9999.999 s
Dir Earth	(IEC: I->	ANSI: 67N)	Angle Upol,I		-178.83 deg	F: 9999.999 s	R: 9999.999 s

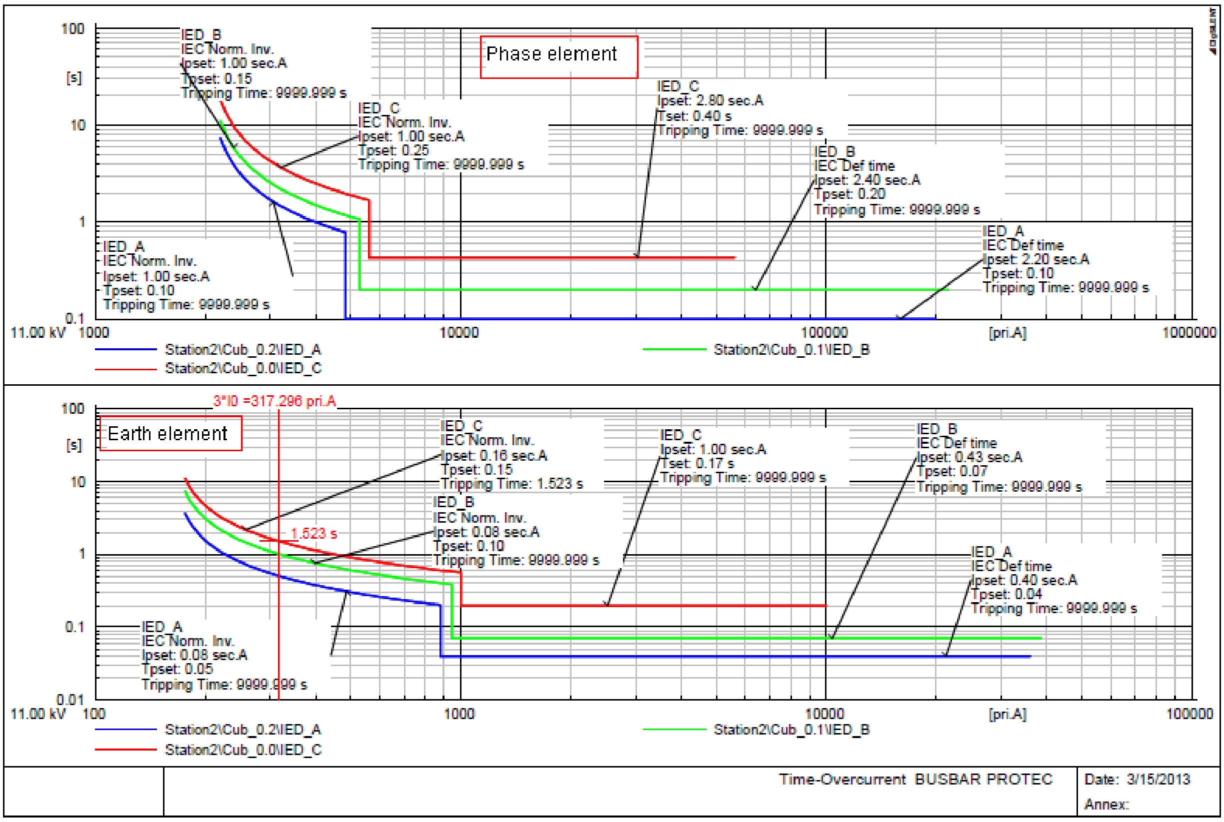


Figure 4.45: IEDs A, B and C protection responses to the minimum single phase to the ground fault applied on the busbar B2.

4.6.2.6 Three phase fault on the busbar B2 for the IED C consideration

For the fault shown in Figure 4.29, the results for the IED C are shown in Figures 4.46 and 4.47 below. Table 4.37 shows the results for the three phase faults where the phase instantaneous overcurrent element (50P) tripping time response is 0.430 seconds and the time overcurrent element (51P) tripping time response is 0.800 seconds

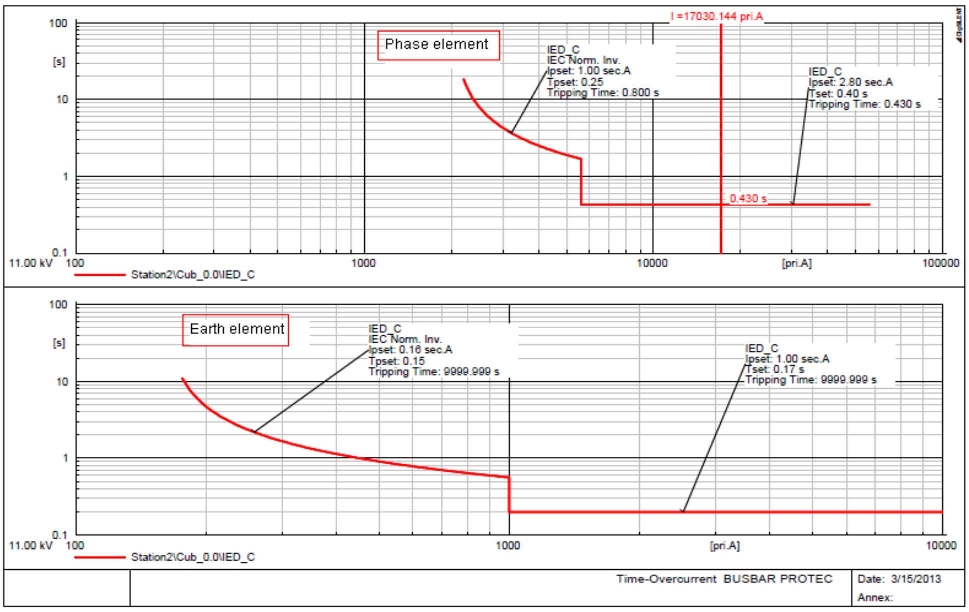


Figure 4.46: IED C protection response to the three phase fault

Table 4.37: The result for the IED C protection response for the three phase fault

```
Relays Tripping Times
Short-Circuit Calculation according to IEC60909                  3-Phase Short-Circuit   / Max. Short-Circuit Currents

IED C                                    B2           / Station2                                                     0.430 s
  51P-1(1)           (IEC: I>t   ANSI: 51  )          Currents A :     8.515 sec.A    17030.14 pri.A    0.800 s
                                                               B :     8.515 sec.A    17030.14 pri.A
                                                               C :     8.515 sec.A    17030.14 pri.A
  50P/51P(1)         (IEC: I>>   ANSI: 50  )          Currents A :     8.515 sec.A    17030.14 pri.A    0.430 s
                                                               B :     8.515 sec.A    17030.14 pri.A
                                                               C :     8.515 sec.A    17030.14 pri.A
  Dir phase          (IEC: I->   ANSI: 67  )          Angle  U,I A :  -92.42 deg  F:  9999.999 s    R:   9999.999 s
                                                               B :   27.58 deg       9999.999 s         9999.999 s
                                                               C :  147.58 deg       9999.999 s         9999.999 s
  51N-1(1)           (IEC: IE>t  ANSI: 51N )          Currents         0.000 sec.A        0.00 pri.A   9999.999 s
  50N-51N            (IEC: I>>   ANSI: 50  )          Currents         0.000 sec.A        0.00 pri.A   9999.999 s
  Dir Earth          (IEC: I->   ANSI: 67N )          Angle  Upol,I  -180.00 deg  F:  9999.999 s    R:   9999.999 s
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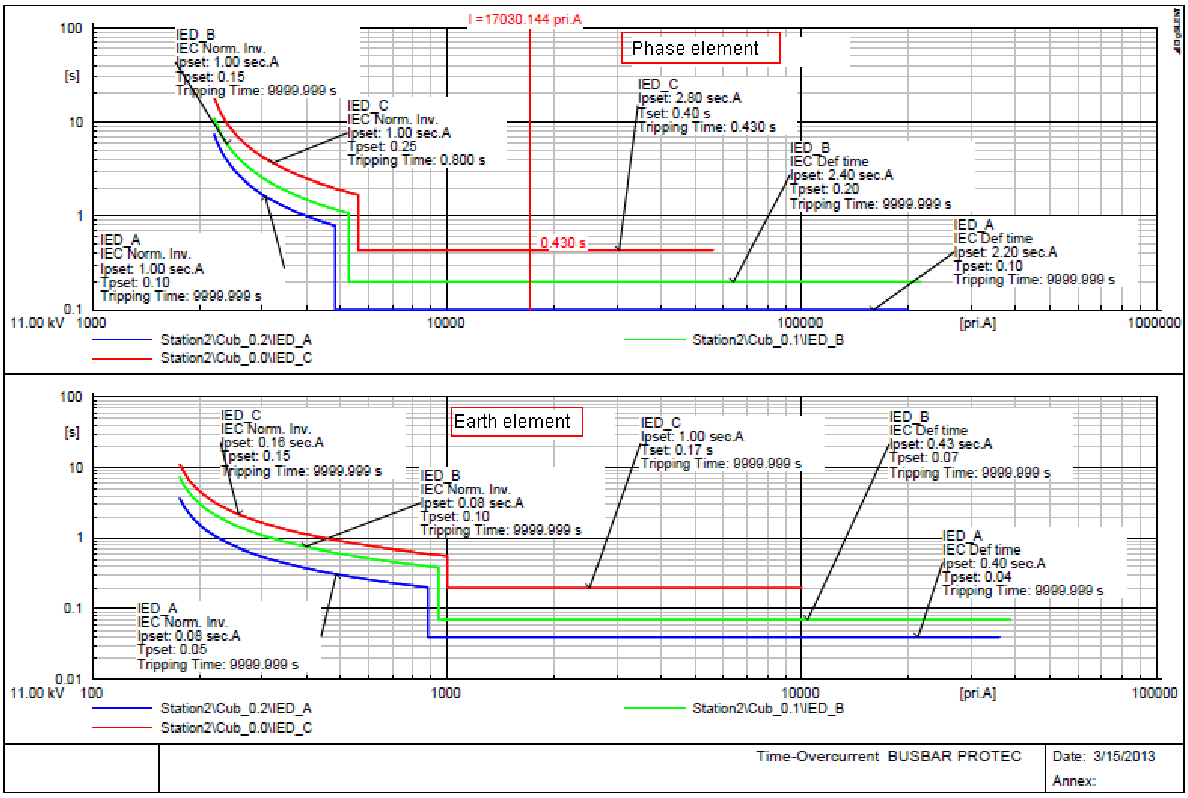

Figure 4.47: IEDs A, B and C protection responses to the three phase fault applied to the busbar B2

4.6.2.8 Case study two results

The results for case study two are all combined as show in Table 4.38

Table 4.38 Combined results for the different faults in the distribution network used in a case study two

Protection Device	Fault Location	Fault Type	Protection function	Short circuit power (S_k'') in MVA	Initial symmetrical short current (I_k'') in kA	Peak short circuit current (I_p) in kA	Tripping Time in seconds
IED A	Line (B2toB4)	Single phase to ground fault	51N (IN>)	1.96	0.309	0.821	0.527
IED A	Line (B2toB4)	Three phase Fault	51P(3I>)	315.97	16.584	44.089	0.100
IED B	Line (B2toB3)	Single phase to ground fault	51N (IN>)	1.89	0.298	0.752	1.117
IED B	Line (B2toB3)	Three phase Fault	51P(3I>)	303.63	15.937	40.986	0.200
IED C	Station2/ B2	Single phase to ground fault	51N (IN>)	2.01	0.317	0.845	1.523
IED C	Station2/ B2	Three phase Fault	51P(3I>)	324.47	17.030	45.354	0.430

4.7 Comparison and discussion of results

A comparison between case study one and two is done. The results for case study one where the conventional relays are simulated is in Table 4.31. The results for case study two where the IEDs are used are in Table 4.38. Based on the results in Table 4.31 and Table 4.38 can be seen that the performance for both protection case studies is the same. The reason for this that the simulation environment of DIgSILENT uses the same models of the protection elements for both conventional and the IEC 61850 standard-based protective devices.

Implementation of the protective scheme using real protective and a conventional or IEC 61850 standard-based approaches for exchange of data signals between the relays is expected to bring differences in these time responses. The implementation of the two variant of the reverse blocking protection scheme is described in chapter six.

4.8 Conclusion

This chapter has addressed the overcurrent protection by implementing a reverse blocking scheme for a distribution network. The model of the distribution network was introduced and simulated using DIgSILENT software package. Load flow was simulated. The short circuit currents were calculated for different faults locations on the distribution network.

The protection used was based on ABB protection devices that implement time-current characteristics. Discrimination has been achieved between the protection devices. This was achieved by making use of a combination of both current and time discrimination characteristics. This chapter investigated two case studies. Case study one was based on simulating the performance of the protection scheme for the distributed network using conventional relays that are not complained to the IEC 61850 standard. The case study two used IEDs that are compliant to the standard. The same parameters for both case studies were used to configure the protection devices. The protection device settings for the network have been carried out. The results obtained in this chapter were recorded and analysed and presented accordingly. A comparison of the results obtained from the two case studies show that the type of communication between the protection devices does not influence the protection response in the condition of simulation, as the protection algorithms and settings are the same. The differences can only be seen from the real-time implementation of the protection schemes. It was also discovered that the relays had limited protection elements compared to the IEDs. When it came to flexibility the relays had major disadvantages when compared to the IEDs. The objectives of this chapter were achieved by introducing IEDs which is the most important aspects of the modern electrical and protection systems. The next step in this thesis is to configure the IEDs. The reason for this exercise is to improve the communication and provide better performance than normal conventional relays, regarding their level of functionality. The configuration of the IEDs is based on two software tools, namely IED engineering is done using the PCM600 software tool and IED GOOSE configuration making use of CCT600 software tool. The application of these tools is presented in Appendix A.

The next chapter explains the importance of process engineering and the basic aspects of the IEC 61850 standard utilized by the ABB 670 IEDs. It also considers the effect of using the Ethernet networks and the IEC 61850 protocol for protection, integration, automation. The use of IEC 61850 GOOSE messages to communicate high-speed information between the IED’s is described shortly

CHAPTER FIVE

PROCESS ENGINNERING FOR THE IEC61850 STANDARD-BASED ABB 670 SERIES INTELLIGENT ELECTRONIC DEVICES (IEDs)

5.1 Introduction

IEC 61850 is the global standard for communication between the Intelligent Electronic Devices (IEDs) in the substation. This standard was developed to provide interoperability between all functions used for protection, monitoring, control and automation that are implemented by different vendors in substation (Krishnan and Palki, 2006). The standard creates the possibility of free allocation of functions that provides a path for a huge range of possible solutions for protection and substation automation systems (De Mesmaeker et al., 2005). When IEC 61850 standard is implemented it allows a major reduction of copper wire creating a better system and it is easy to diagnose the equipment in the substations. This new approach provides stability and overall reliability of the system (Andersson et al., 2003).

This chapter explains the importance of process engineering and some basic aspects of the IEC 61850 standard utilized by the ABB 670 IEDs. The effect of using Ethernet networks and IEC 61850 protocol for protection, integration, automation, and communication of high-speed information between ABB 670 IED's is described. The points that are covered in the chapter are: Part 5.2 describes the objective of IEC 61850 standard, part 5.3 details the application of the IEC 61850 standard on the ABB's new IED 670 series, part 5.4 shows the protection, control and monitoring functions for the ABB IED 670 series and part 5.5 gives the Conclusion.

5.2 Trends in the field of substation automation systems

In the substations, the protection, control and monitoring functions were managed separately by dedicated pieces of devices. This resulted in a division among the substation departments based on their supplier as well as the responsibilities. When microprocessor based equipment and serial communication were introduced to the substation, a platform for a basic common protocol known as IEC 60870-5-103 was developed. The serial communication on the other hand provided a numerical multi-functioning of the devices. This protocol was utilized as an information interface for the protection equipment. This development created a new approach to the substation automation by using fewer devices with more functions integrated in them. The new approach created a path for different functions such as control, protection and monitoring to be integrated into one common device. Since then the trend of developments over time in substation automation led to the raise of need for exchange of information as shown in Figure 5.1 below. Therefore it involved all substation automation specialists increasing pressure for common communication protocol. The trends were combined by the different specialists and the new standard IEC 61850 for common communication between different vendors within the substation systems was developed (De Mesmaeker et al., 2005).

Yesterday	Today	Tomorrow	Future
SA conventional MMI / Control Board	SA with interbay bus	SA with interbay and Process bus	Direct Access for Network Control

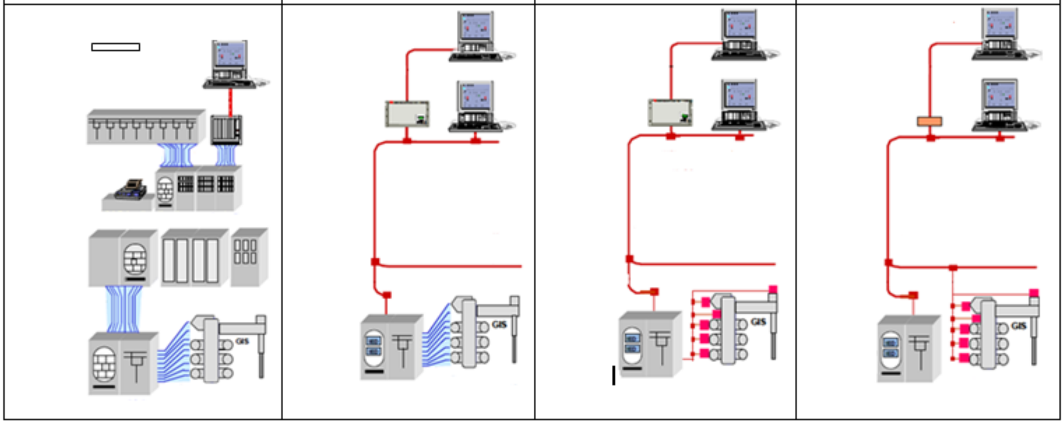

Figure 5.1: **Developments of Substation Automation over time (De Mesmaeker et al., 2005).**

5.3 Future architecture of substation automation systems (SAS)

When the new technologies were introduced, it created a platform where the architecture of SAS could be decentralized. This algorithm helped with the reduction of copper wires in substations. The architecture in Figure 5.2 shows the present structure of SASs. The conventional current transformers (CTs) and voltage transformers (VTs) at the station bus were hardwired to the relays of the process level (Andersson et al., 2003).

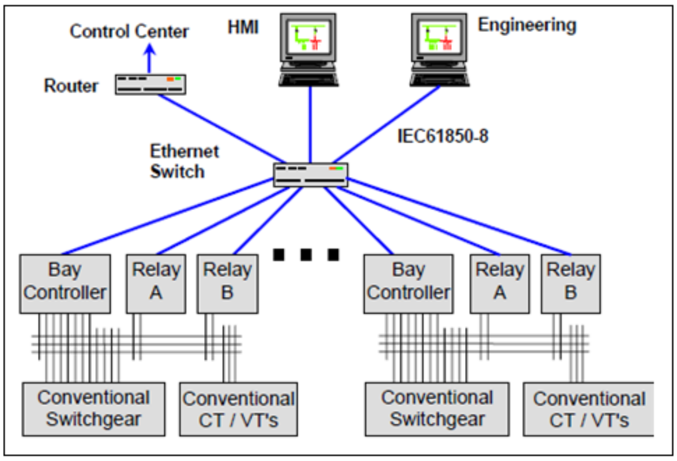

Figure 5.2: **Station Bus and conventional wiring to the process (Andersson et al., 2003).**

As time progresses the non-conventional instrument transformers such as galvanic or optical ones were developed as shown in Figure 5.3. The non-conventional instruments are connected to the relay via serial point to point communication as specified in the standard IEC 61850-9 part (Andersson et al., 2003).

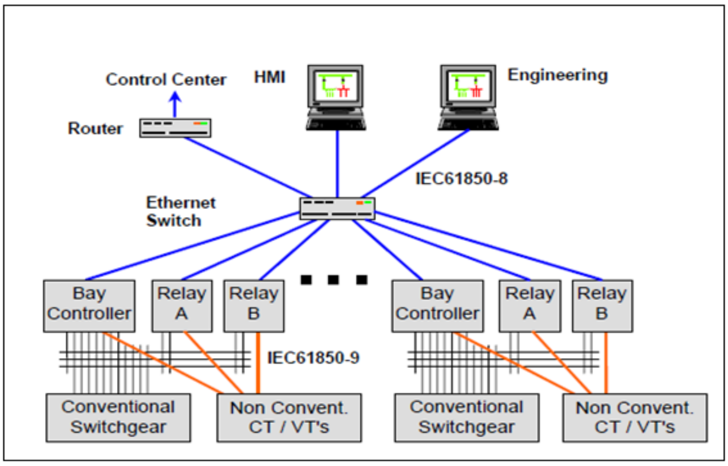

Figure 5.3: IEC 61850-8 station bus and IEC 61850- 9 links to non-conventional instrument transformers (Andersson et al., 2003).

The next phase was the introduction of modern switchgear fitted with communication interface drivers creating a communication network with IEC61850-8 part of the standard as shown in Figure 5.4 below. This method reduced the copper wiring between the process and the bay level, simplifying the connection algorithm (Andersson et al., 2003).

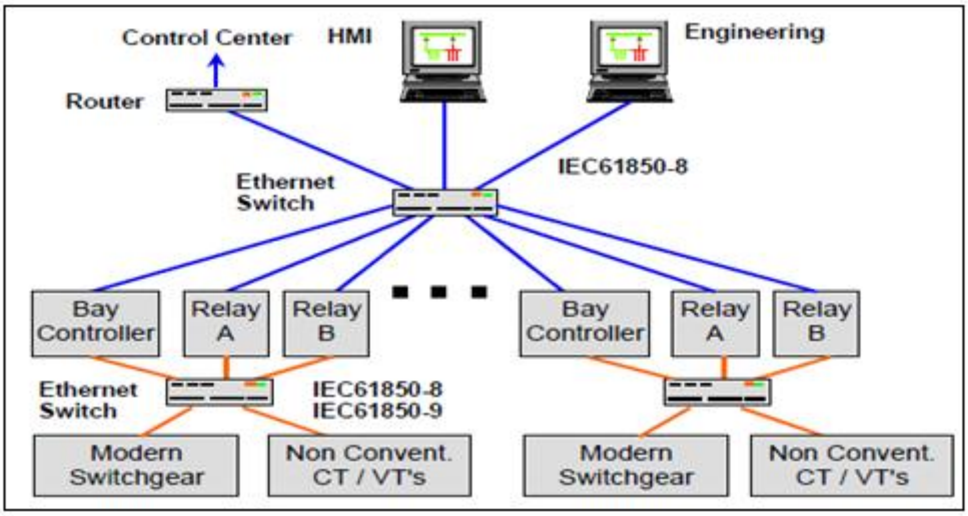

Figure 5.4: Hierarchical communication networks with IEC 61850-8 part as a station bus and a process bus using both IEC 61850-8 and IEC 61850-9 (Andersson et al., 2003).

The communication network was now fully developed within the substation. The substation communication network reaches a point where the system can use both IEC 61850-8 and IEC61850-9 station wide as shown in Figure 5.5 below .This algorithm permitted data to be easily transferred within the substation (Andersson et al., 2003).

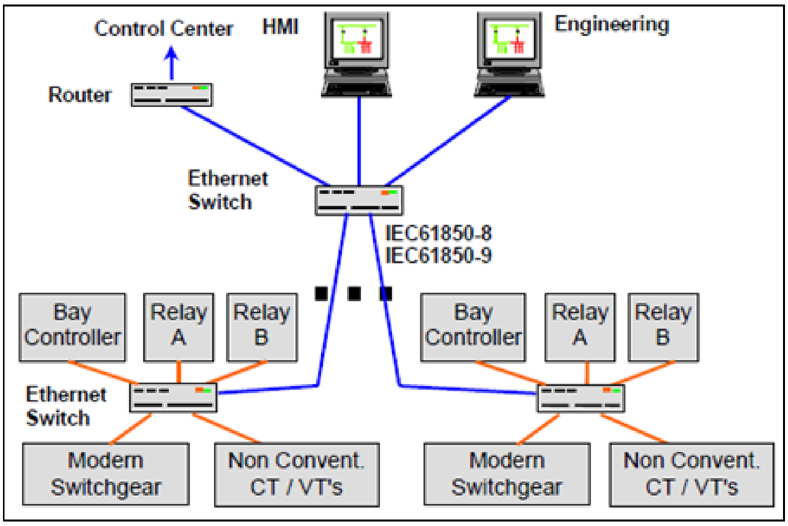

Figure 5.5: **One Single, Station wide communication network using both IEC 61850-8 and IEC 61850-9 part of the IEC 61850 standard (Andersson et al., 2003).**

5.4 The advantage of using IEC 61850 standard

5.4.1 Investment for future

Introducing the standard IEC 61850 as a solution creates a platform to guarantee a future proof system. This is achieved by documenting the system engineering done with the assistance of substation configuration description language (SCL) which is found in part six of the standard. This means that the developed solutions have capabilities of being re-used when the system requires extension.

5.4.2 Higher flexibility

The free allocation of functions in the IEC 61850 architecture creates flexibilities for the client to utilize them according to their needs. The IEC 61850 standard architecture does not enforce restrictions to the user. The high flexibility of the IEC 61850 standard application is in its interoperability.

5.4.3 Higher integration

The IEC 61850 standard permits a complete integration of a third party device that is IEC 61850 compliant in the substation system. Introducing communication between the station and bay level and also between the bay and the process levels the standard permits the next step of integration by connection of the sensors and actuators. This therefore increases the level of integration and reduces the cost of cabling.

5.4.4 Common naming for common understanding

The IEC 61850 standard is accepted all over the world and Part 7 of the standard explains all the data models in the substation using a global language.

5.5 The objectives of using the IEC 61850 standard

The main objective of using IEC 61850 standard is to develop a communication system that permits interoperability between IEDs (physical devices) from different vendors, conforming to the identical functional and operational requirements. In order to achieve this requirement the substation functions are divided into sub-functions (Logical Nodes) which are core component of the data model. These LNs are the basic data that are used for exchanging information within the substation automation (Andersson et al., 2003). In Figure 5.6 below an example of protection function is shown. The example used consists of four LNs namely:

- Distance protection function (PDIS)
- Current transformer (TCTR)
- Voltage transformer (TVTR)
- Circuit breaker (XCBR)

The standard introduces a system that consists of a collection of LNs which are situated in the logical devices (LDs). These LDs are found at the physical device (PD). The system is designed in such a manner that one PD can contain a number of different LDs. The LNs (TCTR and TVTR) are used to sense faults and map them into the LN (PDIS). LN (PDIS) is to supply a general or per phase trip signal to the LN (XCBR) (Andersson et al., 2003).

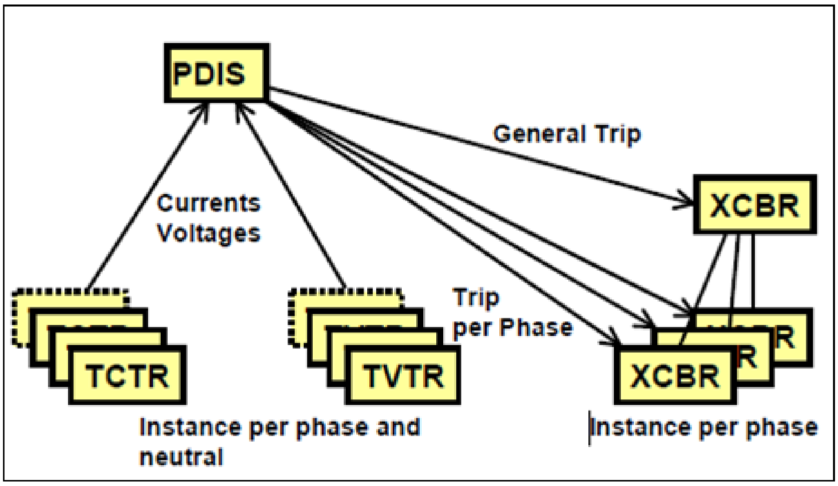

Figure 5.6: **Example of Logical Nodes used for protection functions (Andersson et al., 2003).**

5.6 The application of the IEC 61850 standard on ABB's new IED 670 (Intelligent Electronic Device)

The implementation of the reverse blocking protection scheme designed in Chapter four is implemented using the IEC 61850 standard compliant ABB IED 670 series protection device. This part of the chapter describes now the IEC 61850 standard is implemented on these devices.

In the substation automation system all protection related activities are influenced or changed by introduction of the IEC61850 standard. The main idea is for the user to understand how to implement the standard in practice (De Mesmaeker et al., 2005). It is also important to have a system that is cost effective when designing SAS to ensure faster returns on investment. The system must comprise devices that can supply a wide range of communication capabilities and interfaces compliant to IEC 61850 standard. It also requires a device that ensures maximum performance in protection, control and monitoring. The ABB's new IED 670 series is capable of meeting the above requirements (Lundqvist et al., 2007).

5.6.1 IEC 61850 requirements for the ABB IED 670 series

5.6.1.1 Computing and memory capacity

ABB IED 670 series has adopted new algorithm for numerical calculation module. The new alternative Central Processing Unit (CPU) model design consists of the main controller/CPU type IBM 3200, power computer 750FX 600MHz, and internal 100 Mbit/s communication bus components. The memory capacity is 128 Mb FLASH. It permits performance of one millisecond for differential protection functions, three milliseconds for other protection functions, and for the logic operations it takes between three to hundred milliseconds depending on the application. (Lundqvist et al. 2007).

5.6.1.2 Communication facilities

The IEC 61850 standard communications for ABB IED 670 is established on Ethernet network with a speed of ten to hundred megabits per second. When the IED 670 series processes information it utilizes IEC61850-8-1 part of the standard for low and medium speed and IEC61850-9-2 part for high speed. The IEC communication set up is designed in a network system and each IED must have a specific internet protocol (IP) address (Lundqvist et al., 2007). The communication network is used to transport data into different environments within the substation. The substation consists of a number of components at the different levels. Through the network these levels are required to communicate with each other, as shown Figure 5.7 below (Andersson et al., 2003). The levels are: process (where data acquisition, sensors and actuators are found); bay (where protection, monitoring and control task are found), and station where the SCADA operations are performed. The communication that occurs between the levels makes use of IEC61850 standard. (Lundqvist et al., 2007).

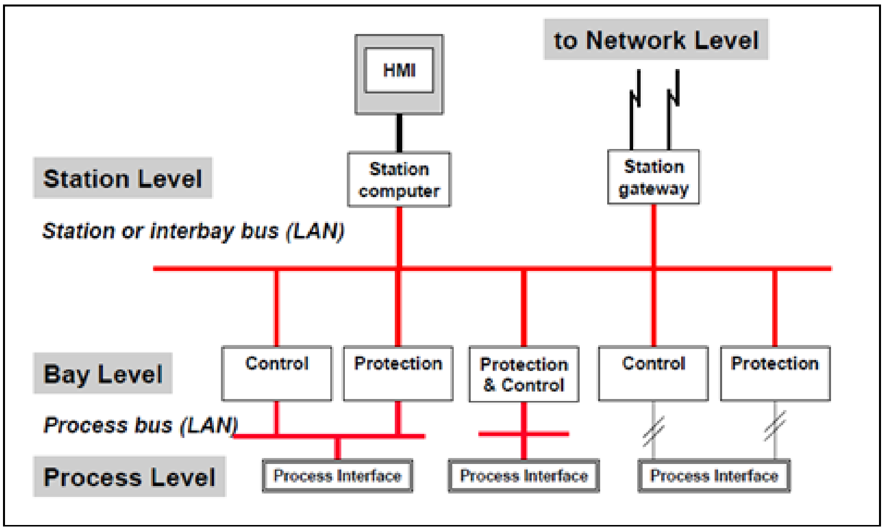

Figure 5.7: **Example of the Substation Automation system architecture (Andersson et al., 2003).**

5.6.2 Ethernet link communication interface for ABB IED 670 series

The ABB IED 670 series can use the following communication protocols:

- IEC61850-8-1 for peer-to-peer communication with GOOSE based on Ethernet
- IEC60870-5-103 is a serial protocol based on Ethernet
- Strömberg protection acquisition (SPA) is a serial protocol based on Ethernet
- Local operating network (LON) is a serial protocol based on Ethernet
- Distributed Network Protocol (DNP) 3.0 use a both Ethernet and serial ports.

5.6.3 Use of the IEC 61850-8-1 part standard protocol for peer to peer communication

The ABB IED 670 series is fitted with a double optical Ethernet rear ports and a front Ethernet port that are used for IEC61850-8-1 station bus communication. IEC 61850-8-1 communication protocol provides the IEDs to exchange information coming from different vendors. The communication is also used for simplifying the engineering system. The IEC 61850-8-1 communication protocol for ABB IED 670 series consist of two generic communications Input / output functions namely SPGGIO and MVGGIO. Generic communication I/O SPGGIO is used to transport one single logical signal to other systems or devices in the substation. Generic communication I/O MVGGIO function is used to generate the instantaneous value of an analog output to other systems or devices in the substations (EM 670 series, 2012). The IEC 61850-8-

1 protocol is used in this thesis for peer to peer communication, based on the GOOSE been received function block.

5.7 Protection, control and monitoring functions for the ABB IED 670 series

For network communication in the substations the IEC61850 has become the main standard that supports all communication tasks for protection, control and monitoring. The ABB IED 670 series relays are physical device models that are compliant with the IEC 61850 standard. The device model consists of logical groupings as shown in Figure 5.8. These groups provide logical nodes that are hardware independent and with future proof implementation. The IED 670 allows the tools for engineering solution to be used and specifies all the required file formats for substation configuration (Lundqvist et al., 2007).

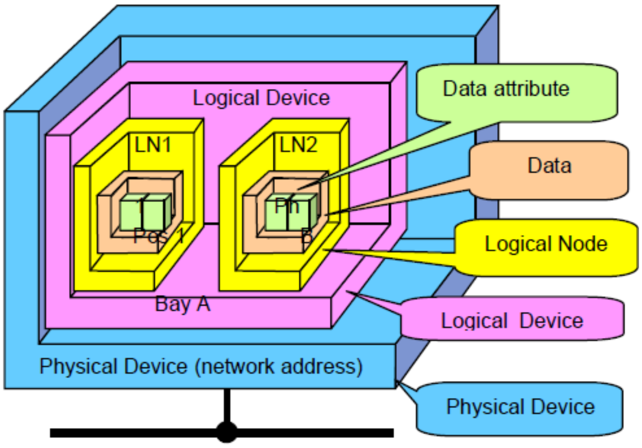

Figure 5.8: **The physical device that consists of logical groupings (Lundqvist et al., 2007).**

5.7.1 Substation Configuration Language

Substation Configuration Language (SCL) is a language used to describe configuration of the IEDs in the electrical substation and is specified in IEC61850-6-1 part. The SCL according to the IEC 61850-5 part is also used for the communication system description that is based on Extensible Markup Language (XML). The XML files represent a hierarchy files for SCL of the system.When it comes to station engineering two tools and four file types are defined by the 61850 standard. The relationships between these files are shown in Figure 5.9 below. An ideal engineering process starting from top to bottom with the utilization of the tools and the SCL files consist of the followings: (Engineering guide IEC61850, 2006):

- System Configurator tool
- IED Configurator tool
- System Specification Description file

- IED Capability Description file
- Station Configuration Description file
- Configured IED Description file

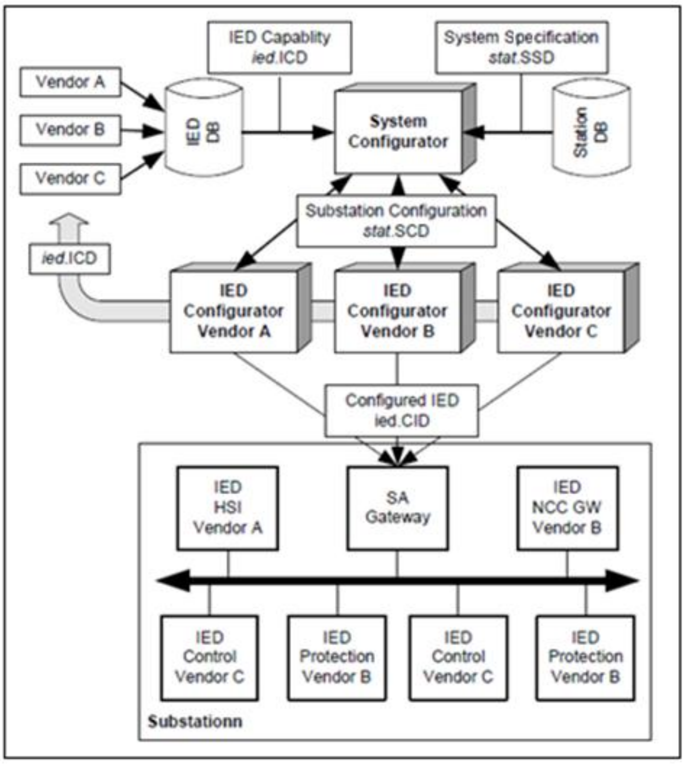

Figure 5.9: The Engineering process for substation configuration (Engineering guide IEC61850, 2006)

Various possibilities are available for engineering process when utilizing the tools and files. This is done for protection and control IEDs at a bay level. This bay level is where logic nodes are configured in large volumes. The system has a concept that permits IEDs to import and export files. These files can add or delete various signals in the station and it is required that the tools should support the system. The files are constructed using the same algorithm but with a different focus depending on the demands. (Kasztenny et al., 2006).

5.7.2 The principal structure of the SCL XML files for the ABB IED 670 series

It is not necessary or required to know the details of the XML file in order to configure the ABB 670 IEDs. The important part is to understand and organize the information provided by the SCL files such as IEDs ICD or station SCD. It is also important to acknowledge where the engineering additions such as Datasets and Control Blocks belong to when configuring the SCL file. The SCL XML file is based on specification in IEC 61850-6 part, clause 9. It is defined in five sections as shown in Figure 5.10 below. These sections are as follow (Engineering Guide IEC61850, 2006):

- Header
- Substation description
- Communication description
- IED description
- Data Type Templates

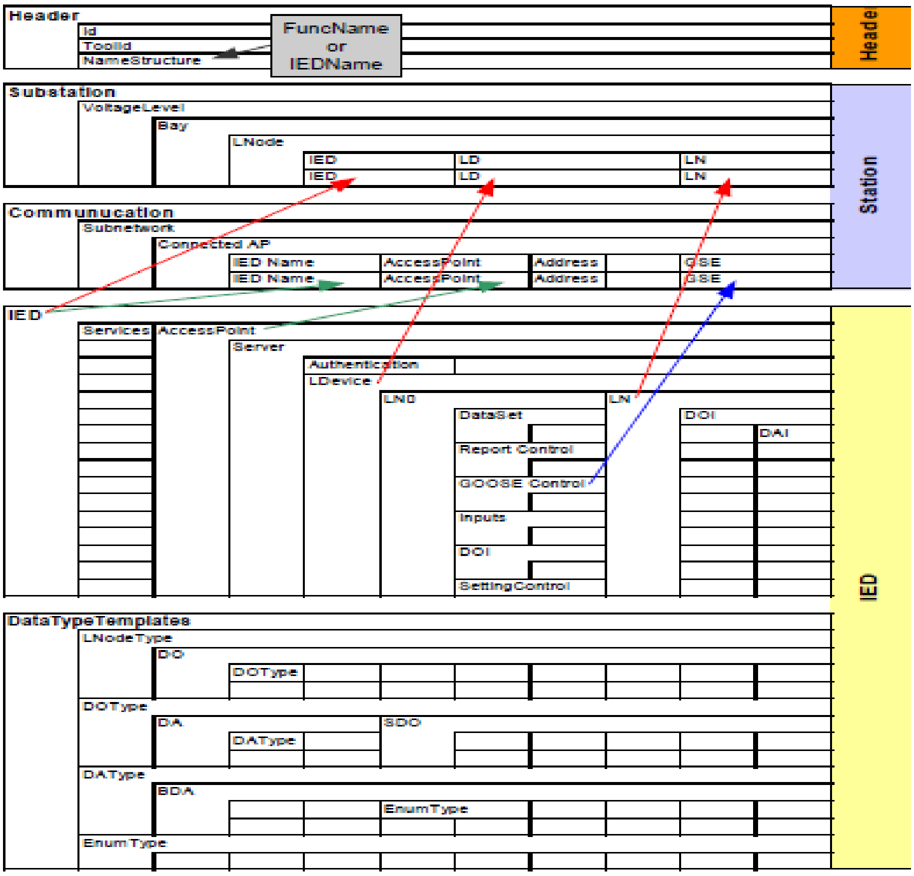

Figure 5.10: **Principle structure of the SCL XML file (Engineering Guide IEC61850, 2006).**

The arrows in the Figure 5.10 below show the connection between the different sections. The header is used to identify SCL configuration file and its version. The substation description sections are utilized for organizing and establishing the IEDs communication within the substation. This job is assigned by a protection and control IED manager tool (PCM600).The PCM600 tool is also used to link the logical nodes which are part of the IED to the substation section. A communication configuration tool (CCT600) is used for routing the engineering signals. These signals then are configured and imported to PCM600 tool where the communication section is organized and completed (Engineering Guide IEC61850, 2006).

The IED description section is where Datasets and Control Blocks are situated as part of the Logical nodes. CCT600 software tool is used to configure these logical nodes and it requires a communication section where Generic Object Oriented Substation Event (GOOSE) engineering is developed. Data type template in Figure 5.10 is used to supply correct message description and information of each Logical node type to the client. When it comes to these logical node types are define differently depending on the vendors of the IEDs. (Engineering Guide IEC61850, 2006)

5.7.3 Object and signal designation

When modeling the SCL file there are two kinds of object designations that need to be taken into consideration, namely the technical key and the user oriented textual designation. The technical key contains an attribute name which is use as the object identifier. It is also for engineering signal identifier and referencing in the SCL. When configuring the ABB 670 IEDs, PCM600 software tool produces a SCL technical key is not affected on the identification of the project. This technical key generated by the PCM600 tool is based on the IEC 61346 standard that is used electrical substations. The user for oriented textual description contains an attribute desc. The attribute is not required to hold carriage return. It is also not require tab characters. It is required that the meaning of the desc must be in the hierarchy of the object. (Engineering Guide IEC61850, 2006)

5.7.4 Signal identification in the communication system

When it comes to signal identification in the communication system of the IEC61850 standard there are rules that need to be followed. These rules are described in part 7-2 clause 19.2 of the standard. The components of the signal identification as defined in IEC 61850–7–2 are shown in Figure 5.11 below. The signal identification is made up of four parts, namely (Engineering Guide IEC61850, 2006):

- A user defined part identifying the Logical device LD in the process (LDName)
- A function related part to distinguish several LNs of the same class within the same LD/IED (LN-Prefix)
- The standardized LN class name and the LN instance number, which distinguishes several LNs of the same class and prefix within the same LD/IED
- A signal identification inside a LN consisting of data and attribute name as defined in IEC 61850–7–3 and IEC 61850–7–4 parts.

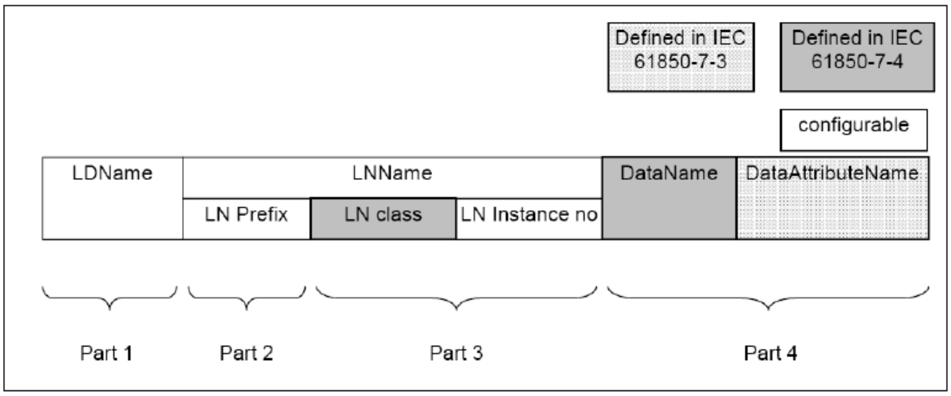

Figure 5.11: The components of the signal identification as defined in IEC 61850–7–2 (Engineering Guide IEC61850, 2006).

Part one and two in the above Figure can be defined using two options namely Function with which the SCL header is identified as FuncName and Product with which the SCL header is identified as IEDName when it comes to related naming. When IED is configured, the part one is used to describe the name of the physical object of the substation section and this is where the LNs are attached. In the parts two and three combined the LN name is created and the different LN representatives within the same LD of the IED are described. Part four in the Figure is used for DataName and Data Attribute Name which are configurable.

5.7.5 The substation section for the ABB IED 670 series

The substation section is used to explain the functional structure of the substation and this is where the primary equipment is found. At the substation section the LNs are attached to the primary elements on the basis of their functionalities

5.7.6 IED section for the ABB IED 670 series

This is where the IED communication is described. It also has part called data type template and this is where the IED ICD file is found. The ICD file includes LN descriptions and its support services. The IED section also has of a communication structure that is define by the IEC61850 standard. There are two IED types that are utilized in the substation system. They are station level IEDs and bay level IEDs. The station IEDs are found at the station level and they deal with transmitting information from and to the bay IEDs. The station IEDs are known as client IEDs. Bay level IEDs are found at the bay level in the substation and this is where signal configuration engineering is done. The bay level IEDs are known as the server IEDs shown in Figure 5.13a (Engineering Guide IEC61850, 2006).

5.7.7 The communication section for the ABB IED 670 series

The communication network of the physical IEDs is dependent on the organization of the substation structure as is shown in Figure 5.12 below. According to the IEC 61850 standard the communication system is defined without any existence relation to the protocols and media. The mapping of the existing media and protocols use Ethernet as its medium Manufacturing Message Specification (MMS). For more communication ABB IED 670 series such as Abstract Communication Service Interface (ACSI) is described in the IEC 61850-7-2 part. The specification of mapping the ACSI into the existing MMS is described in the IEC 61850-8-1part (Engineering Guide IEC61850, 2006).

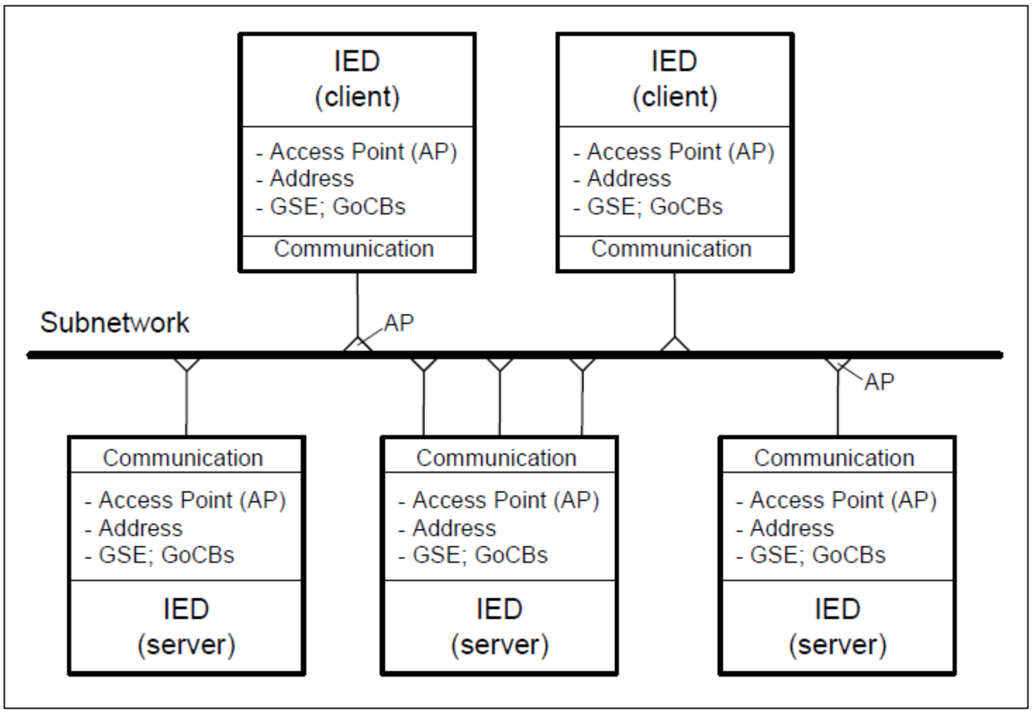

Figure 5.12: **Communication network used by the IEC61850 standard (Engineering Guide IEC61850, 2006).**

The communication section in the SCL file must consist of components that need to be identified in order to send information between the IEDs used in the project as shown in the Figure 5.12 above. These components are as follows: (Engineering Guide IEC61850, 2006):

- Used sub networks
- IEDs connected to the different sub networks
- Access points per IED to the sub networks
- the IP address of the LAN network
- The link to the GOOSE Control Block (GoCB) message in transmission direction.

When using the ABB IED 670 series the communication link to the IEDs are developed by using PCM600 software tool. This process is implemented when the IED is linked and established to the sub-network. There are various algorithms that can be used to structure the communication network. The most typical set-up is shown in Figure 5.13a and Figure 5.13b below.

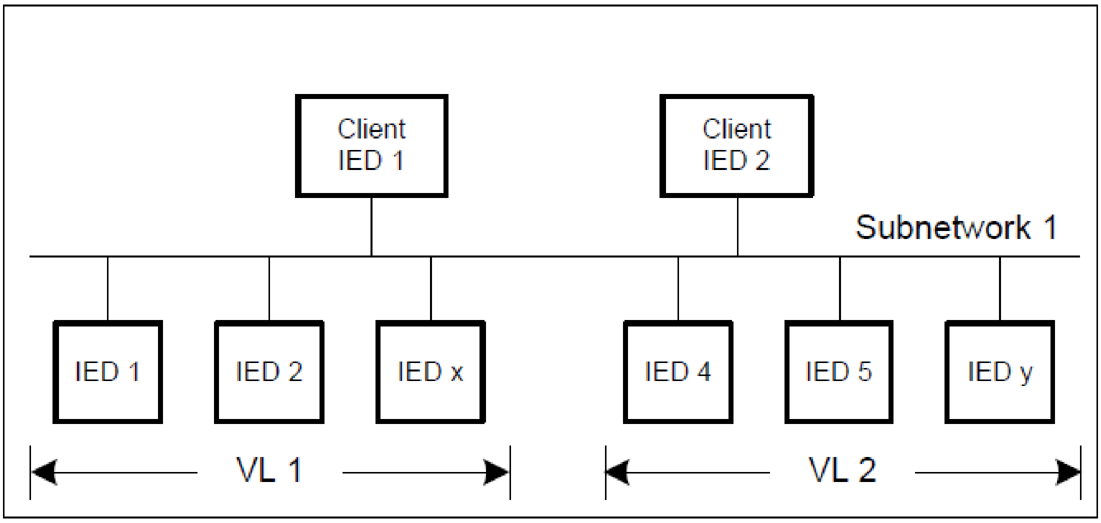

Figure 5.13a: **Communication sections: Possible network configuration (Engineering Guide IEC61850, 2006).**

The Figure 5.13a above shows a network configuration that uses one Sub network that links all IEDs for line voltages, one and two. Figure 5.13b as shown below makes use of two Sub networks where sub network one connects IED one, two and three together and sub network two connects IED four, five and six together.

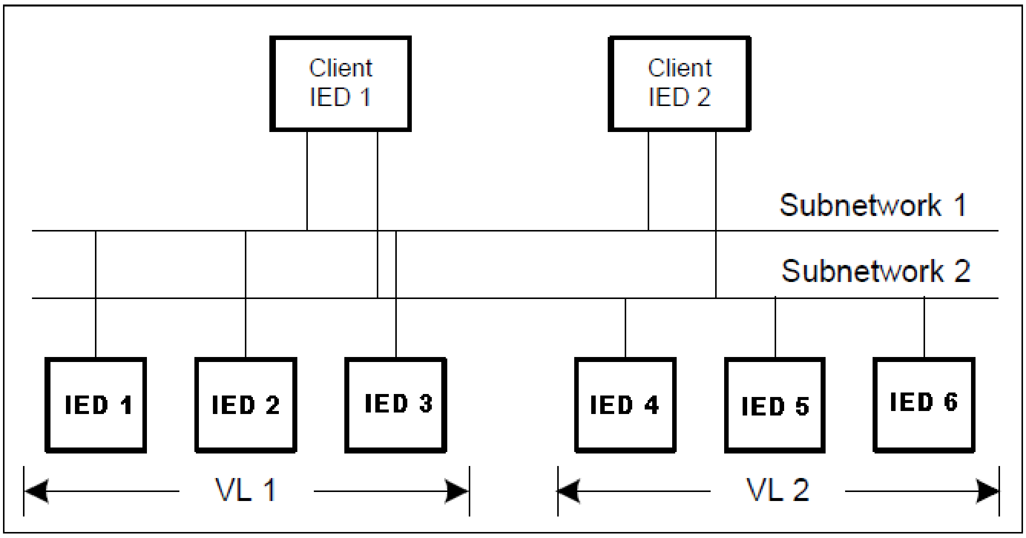

Figure 5.13b: **Communication sections: Possible network configuration (Engineering Guide IEC61850, 2006).**

Both network configurations satisfy the requirements for performance. The advantage of the network configuration shown in Figure 5.13b is that when one of the sub networks fails only one voltage level in the station will be lost.

5.7.8 Organization of the Logical Devices, Logical Nodes, Data Objects and Data Attributes in an IED

In a basic substation automation there is a server that represents communication interface to the sub network via an Ethernet or fiber optic cable. A one or more logical devices are connected to a server as shown in Figure 5.14 below. A logical device is linked into a server that contains a group of logical nodes. The logical device contains a special logical node known as logical node zero (LLN0). It contains the Datasets which can be used for various control block inputs. In each logical device there is also another special logical node known as physical logical device (LPHD) and it contains data objects that are used to describe the status of the physical device. The logical nodes contain a number of data objects that represent the data attributes (Engineering Guide IEC61850, 2006).

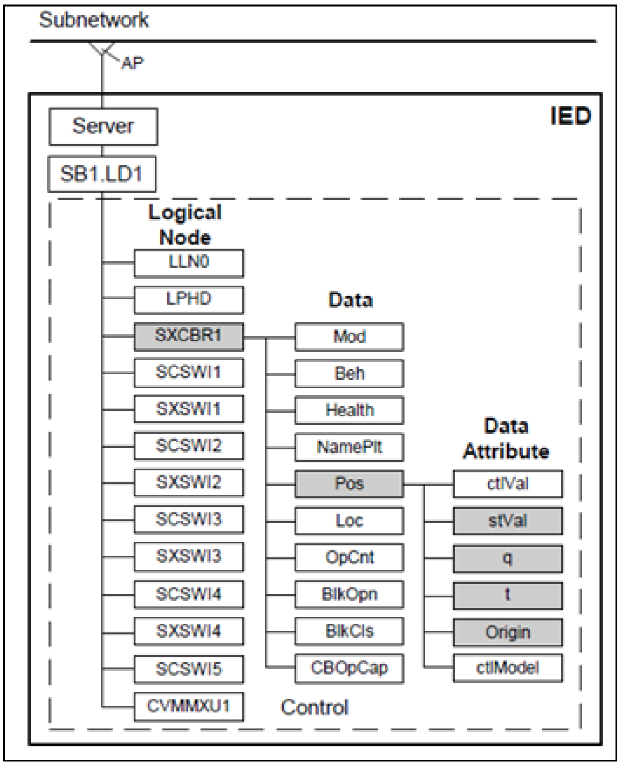

Figure 5.14: **Organization of Logic Devices, Logic Nodes, Data Objects and Data Attributes in an IED (Engineering Guide IEC61850, 2006).**

5.7.9 Signal engineering

Information signals are represented by data objects which are mapped to the station level IEDs. The signal engineering is used for requesting signals from data objects and connecting them to the client IEDs. The client IEDs are defined as receivers. The data object package includes control services which are used to manage control and monitoring commands. When utilizing ABB 670 IEDs the organizing and configuration of the logic devices down to the data attributes are implemented by the CCT600 tool. When configuring the IED the logic node type used will determine the number of data objects and data attributes per data object (Engineering Guide IEC61850, 2006)

5.7.10 DataSets

Report control blocks and data sets for transporting and monitoring signal are determined by IEC 61850 standard. These are for GOOSE messages. When it comes to horizontal path communication datasets also utilizes GOOSE messages. The datasets contain data attributes and data objects with no specified functions. Figure 5.15 below shows the information were Dataset are all positioned

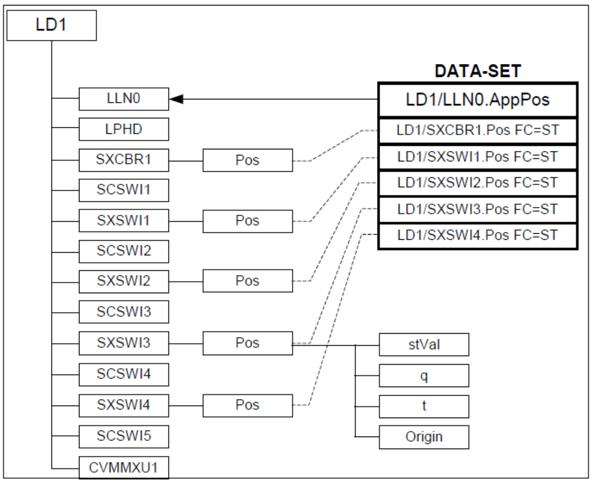

Figure 5.15: **IEC 61850–7–2 part: Example of Datasets (Engineering Guide IEC61850, 2006).**

The ABB 670 IED features datasets which are predefined by defaults. They are always available for the users. The only thing that needs to be done is to be able to link the datasets to the client IEDs. The ABB 670 IED has capability to state when datasets need to be modified according to the needs of the project.

5.7.11 Buffered Report Control Block

In order to be capable to transport the configured signals in the dataset, the Buffered Report Control Block (BRCB) has to be configured. The BRCB is used to handle and specify how the events are transported to the client. In the IEC6 1850-7-2 part clause 14 there is a table that lists all the contents of BRCB. The BRCB holds the attributes which deals with the communication between the client and the server. (Engineering Guide IEC61850, 2006).

5.7.12 Trigger Options

There are five different trigger options defined by the IEC 61850 standard. Three of the trigger alternatives belong to the data attributes. The other two trigger options belong to the control block configuration. The five trigger alternatives are as follows: (Engineering Guide IEC61850, 2006):

- Data-change (dchg) - This trigger option is active when the process value changes and the transmission is done.
- Quality change (qchg) - This trigger option looks at quality type of data attributes and if anyone changes in the quality description, it will be transmitted.
- Data value update (dupd) - This trigger option is used to define if transmission should be done based on a state which can be contained by the application.
- Integrity - This trigger option is used to force the transmission of all process values that are defined in the Dataset when a timer value expires
- General interrogation- This trigger option is requested when the IEDs (client and server) need to start or restart a session.

5.7.13 Connection of the Buffered Report Control Block to a Client Logical Node

The first requirement is for the buffered report control block to find out where the events must be send to. In the IEC 61850-6 part the standard specifies that signal routing engineering steps, is when the logical node of the client IED is linked into the Report Block Enabled option as shown in Figure 5.16. The chosen IED will be the client with its matching logical nodes. The logical nodes will become the part of the SCL structure that will show a report control description of the IED. When using ABB670 IEDs a CCT600 software tool links the client logical node to the field of buffered report control block by utilizing the drag and drop algorithm (Engineering Guide IEC61850, 2006).

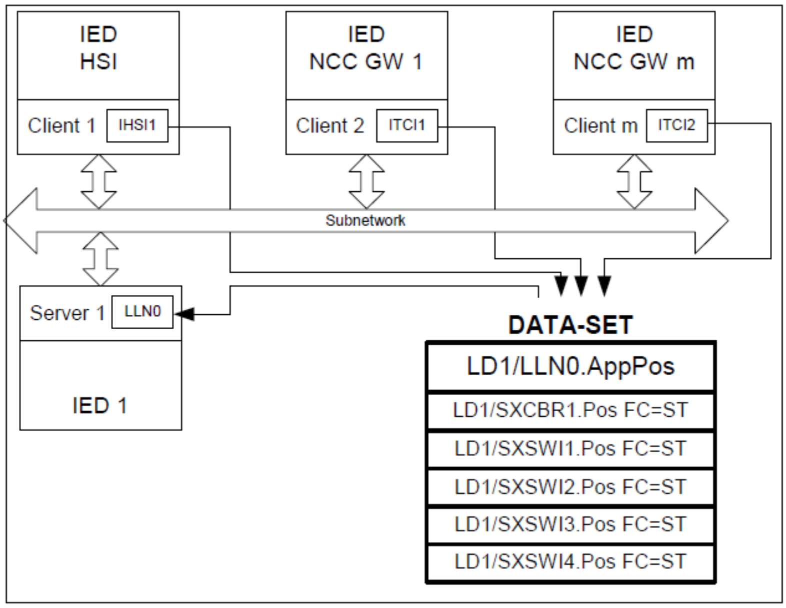

Figure 5.16: **Mapping of the BRCB to the client LN (Engineering Guide IEC61850, 2006).**

5.7.14 Principle operation of the Generic Object Oriented Substation Event (GOOSE) messages

The GOOSE class model is utilized to transfer data values between IEDs by means of multicast services. This function is used on the bay level. The GOOSE message is capable transporting data from a publisher to subscribers bypassing the server. GOOSE messages are only allowed to be sent in one direction. This means that subscriber of the GOOSE message can also send GOOSE messages back to the publisher in order to close communication loop. This method is depended on the application. A GOOSE concept example is shown in Figure 5.17 where three IEDs are utilized for exchanging GOOSE messages among each other (Engineering Guide IEC61850, 2006).

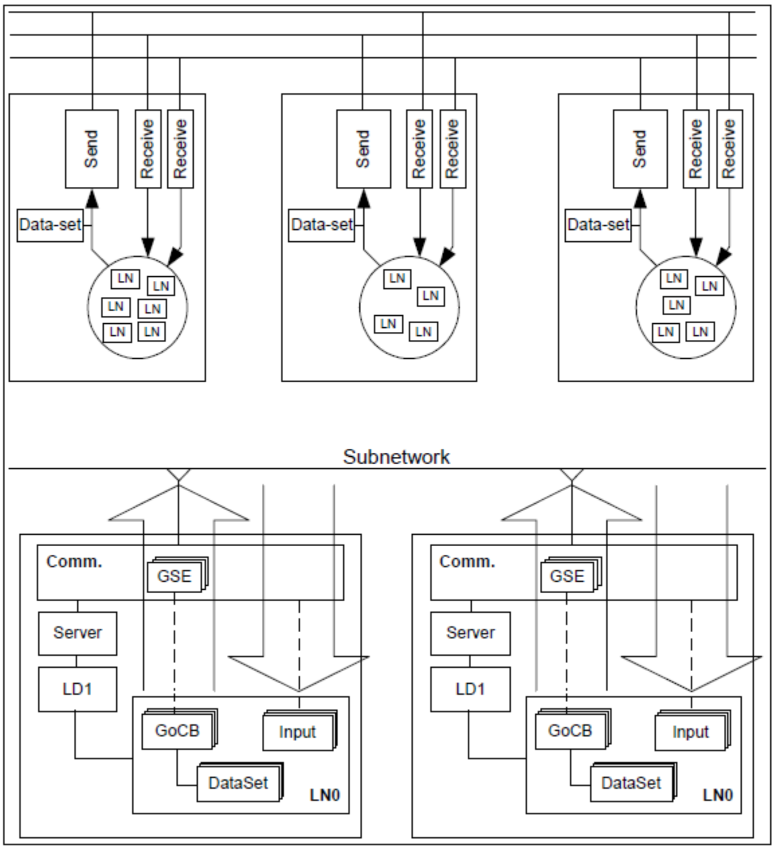

Figure 5.17: **IEC 61850 Principle operation of GOOSE messages (Engineering Guide IEC61850, 2006).**

5.7.15 How to send GOOSE messages

In order to be able to send GOOSE messages there are rules that need to be followed. Firstly a GOOSE Control Block (GoCB) needs to be defined. The GoCB must consist of Datasets that contain data objects of data attributes as shown in the Figure 5.17 above. When the data attribute trigger changes, GOOSE messages will be forced to be transported. Then all the data sets will be replicated into the buffer that is going to be sent. The buffer will also contain the actual value and will then be sent as a message. The subscriber will then receive GOOSE messages (Engineering Guide IEC61850, 2006).

5.8 Conclusion

This chapter describes the basics of how the IEC 61850 standard is implemented in the ABB IED 670 series. It also describes that IEC 61850 standard is straightforward at a user's level and it is the best solution for communication following today and future requirements. The IEC 61850 standard also guarantees the economical maintenance in substation automation. The chapter also explains in detail how the SCL describes the model utilized in the substations. The ABB 670 series IEDs functions and how the IEC 61850 standard is implemented. A basic description of how the IEC 61850 standard works and the different standard components utilized is shown. The Engineering process between the publisher and the subscriber is discussed in detail. Based on the literature review it can be concluded that using the GOOSE messages between the IEDs can improve the speed of data transmission.

The next chapter describes the performance between hard-wiring and GOOSE communication by development of laboratory test bench that is build using the ABB IEDs 670 series protection device. The next chapter also presents a proof of the above statement for the speed of the GOOSE messages on the basic of performance evaluation of the implementation and operation of the two case studies simulated in Chapter four. A laboratory test bench is built for this purpose using the ABB IED 670 series devices.

CHAPTER SIX
DISTRIBUTION BUSBAR PROTECTION IMPLEMENTATION AND EXPERIMENTATION

6.1 Introduction

Traditionally protection and control devices used hardwire as a path to distribute signals between each other. This method of communication creates time delay in transmitting the signal from the sending device to the receiving devices. The delay came from the time taken by the auxiliary relays from switching on and off when the signal had to be sent from the binary output of the sending device to the binary input of the receiving device. Utilization of the new digital technology allows the traditional reverse blocking schemes to be considerably improved in terms of operational speed. The new digital protection also offers an increase of flexibility and operational reliability. This chapter focuses on improving the operational speed and stability of the reverse blocking scheme used in distribution busbar protection. This is achieved by introducing Ethernet communication network using GOOSE messages between the IEDs. This method allows the blocking signals to be sent directly from one IED to another IED without any additional delay created by the auxiliary relays. A laboratory test bench is developed to investigate and compare conventional hard-wired blocking signal and the GOOSE communication. This test bench is utilized to improve the performance and reliability of the busbar reverse interlocking scheme. The same power network and its data used in Chapter four are used in this chapter to implement the practical studies.

The parts that are covered in this chapter are as follows: Part 6.2 introduces the IEC 61850 standard based operation of the protection scheme. The phases in the process of development of the laboratory test bench are described in part 6.3. The implementation of the technical experiment in the test bench is explained in part 6.4. Part 6.5 describes establishment of the communication between the IEDs and the PC with PCM600 engineering Pro software. The development configuration for the IED_C as used for protection of the incoming feeder is explained in part 6.6. Part 6.7 describes the operation of the hardwired protection scheme. The GOOSE engineering is done in part 6.8. Part 6.9 explains the operation of the GOOSE based protection scheme. The obtained results from the experiments are given in part 6.10 and their discussion is given in part 6.11. Part 6.12 concludes the chapter.

6.2 IEC 61850 standard based operation of the busbar protection scheme

For this protection system the incoming feeder IED and the outgoing feeder IEDs communicate using IEC 61850 GOOSE messages. When a fault occurs at one of the outgoing feeders a multifunctional IED will trip the feeder breaker and send a GOOSE message to block at once all the incoming IEDs that are not involved. The operational reliability of the protection scheme is based on GOOSE messaging. For this application, the ABB IED's and their software are used for protection. A laboratory test bench had to be developed as a platform where the practical experiments are exercised. The main aim of the experiments is to test and compare the communication performance between the IED's using both hard-wire systems for transfer of data signals as shown in Figure 6.1a and GOOSE messages based on the IEC61850 principles, as shown in Figure 6.1b.

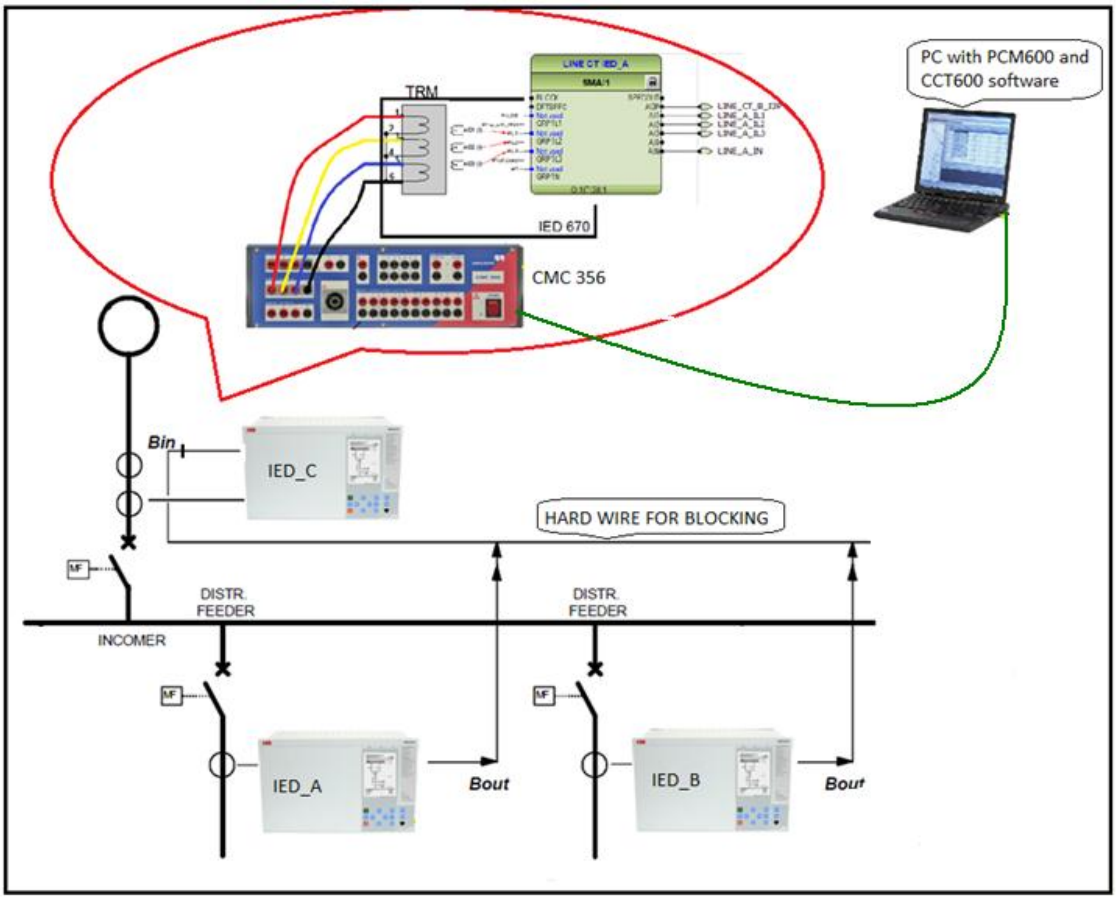

Figure 6.1a: **A busbar reverse blocking scheme using a hard-wired system**

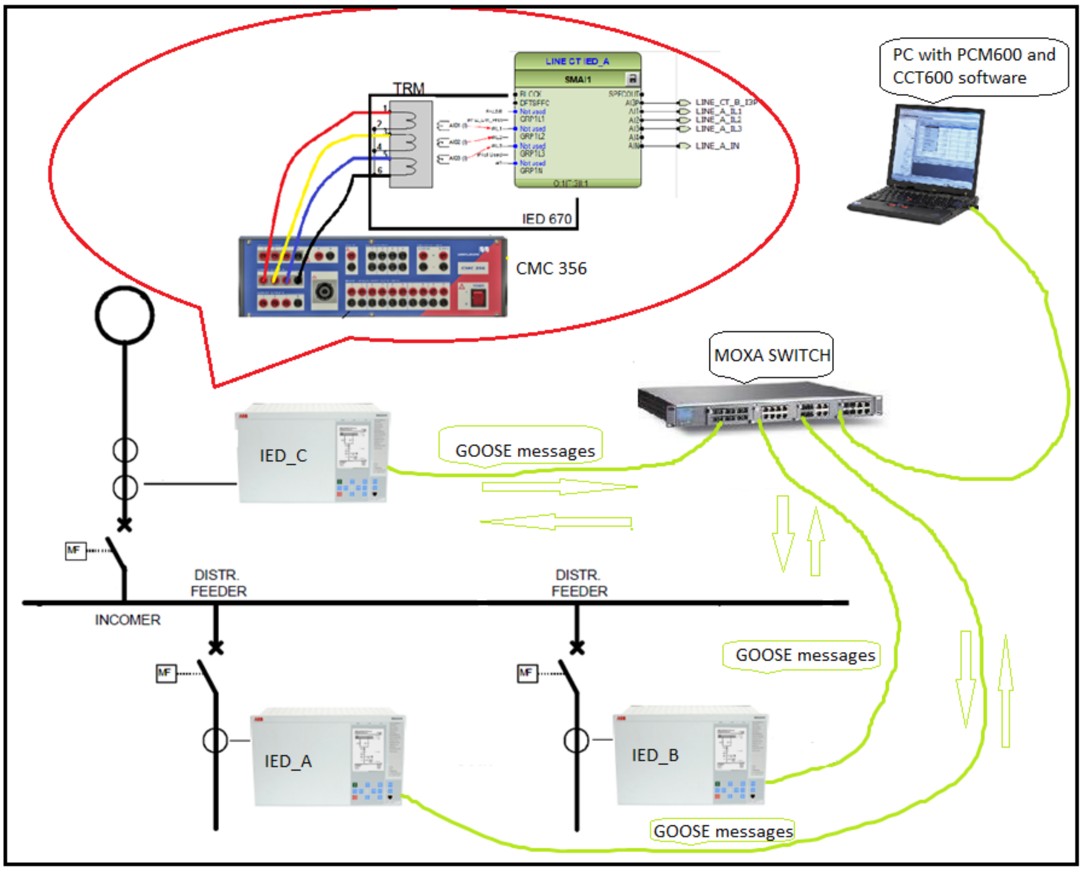

Figure 6.1b: **A busbar reverse blocking scheme using IEC61850 standard-based communication**

Figure 6.2 shows a distribution network that is used for building the lab test bench as simulated in DigSILENT in Chapter four.

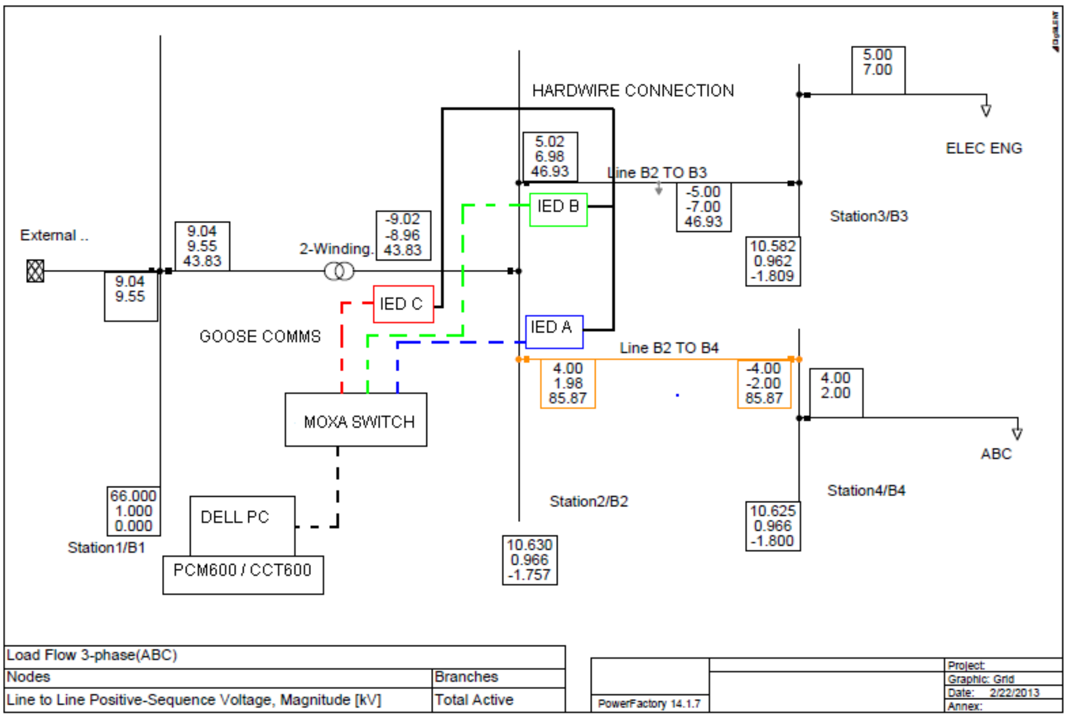

Figure 6.2: **The main DigSILENT distribution network used for building of the lab test bench**

6.3 The development of the laboratory test bench

A laboratory test bench is developed in order to be able to implement the designed busbar protection scheme known as a reverse blocking scheme. The IEC 61850 standard is implemented on the scheme and it is investigated how it influences the busbar protection scheme performance. All experiments in this chapter are developed using this test bench. The experiments repeat the investigations from Chapter four but in the hard-wired and in the software environment of the ABB IED 670 IEC 61850 standard compliant protection devices. The build test bench is shown in Figure 6.3

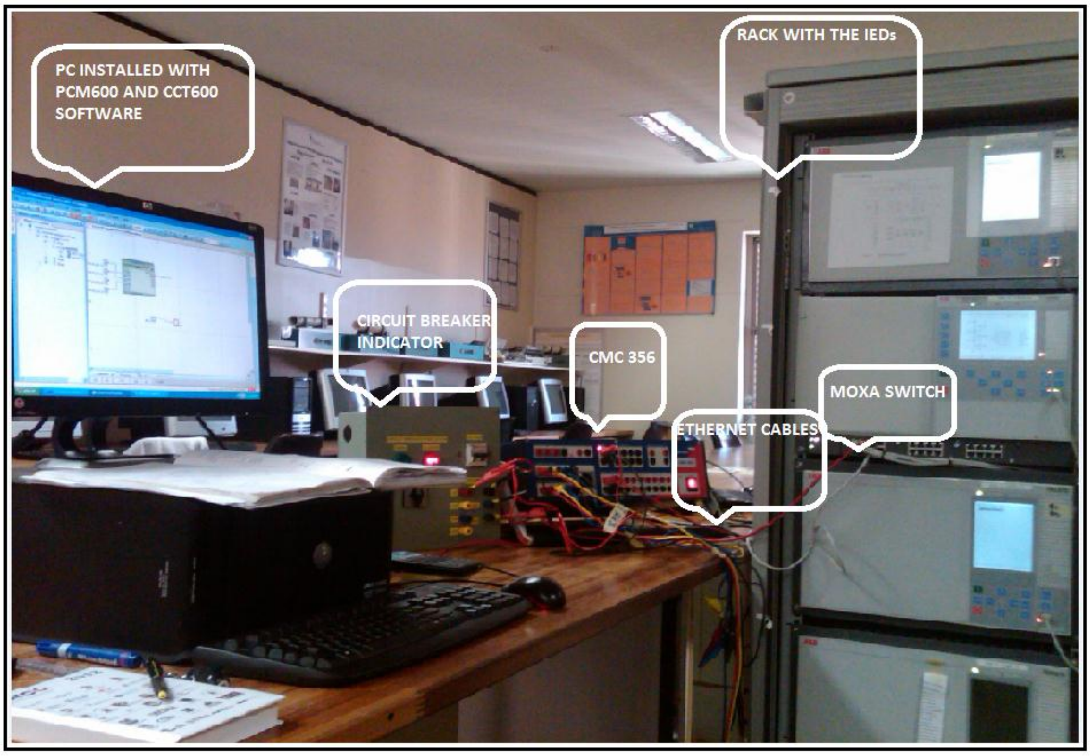

Figure 6.3: **The lab test bench that is developed for case studies**

The Laboratory test bench consists of the following components:

- ABB RED 670 IED (IED_C)
- ABB REL 670 IED (IED_B)
- ABB REB 670 IED (IED_A)
- PCM 600 configuration software tool
- CCT600 communication software tool
- CMC356
- MOXA switch
- DELL computer
- Auxiliary power supply

6.3.1 ABB 670 Series IEDs internal structure

The ABB 670 series IEDs are used for protection, control and monitoring and are all compliant to IEC 61850 standard. These IEDs consist of various modules namely:

- Combined Backplane Module (CBM) - This module is used to transport all internal signals between other modules in an IED. Transformer Input Module (TRM) is the only module that is not connected to CBM.
- Universal Backplane Module (UBM) - This module forms part of the IED backplane with connectors for TRM
- Power Supply Module (PSM) - This module is a regulated DC power that supplies auxiliary voltage to all static circuits.
- Numerical module (NUM) - This module is utilized for controlling all application information such as configuration, setting and communication. Local Human Machine Interface (LHMI) - This module is used to connect a Personal Computer (PC) to the IED by means of an Ethernet connector and consist of a push button keyboard, Light Emitting Diodes (LEDs) and Liquid Crystal Display (LCD) screen.
- Transformer input module (TRM) - This module is utilized to divide the internal circuits from the VT and CT circuits and it has twelve analog inputs.
- Analog Digital Conversion Module (ADM) - This module is used to convert analog inputs to digital ones. It also has Binary Input Module (BIM), Binary Output Module (BOM) and Binary I/O Module (IOM).
- Line Data Communication Modules (LDCM) - This module is utilized for digital communication to a remote terminal.
- Serial SPA/LON/IEC 60870-5-103 communication module (SLM) - This module is utilized for SPA/LON/IEC 60870-5-103 communication.
- Optical Ethernet Module (OEM)-This module is used for IEC 61850 based communication.
- GPS Time Synchronization Module (GSM)- This module is utilized to supply the IED with the GPS time to synchronize the IED operation with this time

6.3.2 Utilization of PCM600 and CCT600 software tools

PCM 600 software tool is used for engineering the IEDs as discussed in Appendix A. CCT600 is a tool utilized to configure the ABB IEDs to perform IEC 61850 horizontal (peer to peer) communication. It is also used to edit client and event reporting properties. CCT600 tool behaves as a system tool which is employed to define and share the 61850 based parameters as follows: communication addresses, horizontal communication data and client/server (system level/IED) connections

6.3.3 Moxa PowerTrans PT-7728 Switch

The PowerTrans PT-7728 is a switch certified to be utilized in substation automation systems (IEC 61850-3, IEEE 1613).It can be utilized for Fast Ethernet backbones and it is also capable to subscribe to redundant ring topologies. It has dual power inputs with a range of 24 VDC to 48 VDC or 110/220 VDC/VAC to gain the communication reliability. The front panel layout consists of system status LEDs, interface module LEDs, a push button switch for interface module selection, Ethernet interface module, Gigabit and Ethernet interface module. The rear panel has a serial console port and a ten pin terminal block. The PT-7728 accommodates a modular design that permits easy network planning allowing larger flexibility.

6.3.4 DELL Personal computer with PCM 600 and CCT600 on board

The personal computer accommodates the operating set up and other related software needed for local area network operations.

6.3.5 Ethernet cable with RJ 45 connector

This cable has a standard RJ-45 connector that was used to connect the IEDs together via the Moxa switch.

6.3.6 CMC 356 Omicron test device

The CMC 356 is a state-of-the-art hardware utilized for testing different kinds of protection devices. This device has six current outputs, four voltage outputs, generator combination socket, four binary outputs, DC power supply, DC measuring inputs, and ten multifunctional, and binary (dry/wet) inputs that are on the front panel. The rear panel of the device contains two counter inputs, four binary outputs (transistor), and interface for CMGPS or CMIRIG-B synchronization, low level voltage or currents outputs, and two Ethernet interfaces. This device has a unit capable of testing high burden electromechanical relays. It has also functions that are utilized to perform wiring and plausibility checks of CTs. This CMC 356 Omicron test device can be configured, by the software called Test Universe which is installed on a computer. This software offers flexibility and ability for different testing applications.

6.3.7 Power supply

An auxiliary supply is used to provide an auxiliary voltage to energize the ABB IEDs.This power supply has a switching circuit with rating a 220VAC input and 110VDC output.

6.4 Implementation of the practical experiment

Figure 6.4 shows a modified compact flow chart that is used as a guide for the practical. The IED configuring is done using PCM600 software. As explained in the Appendix A PCM600 software is the innovation tool for the operation and configuration of all the ABB 670 series protection devices (IED's). This software can be used to parameterize the device, view process data and evaluate fault that is recorded. With this type of service the information for different events can be speedily transmitted between IEDs

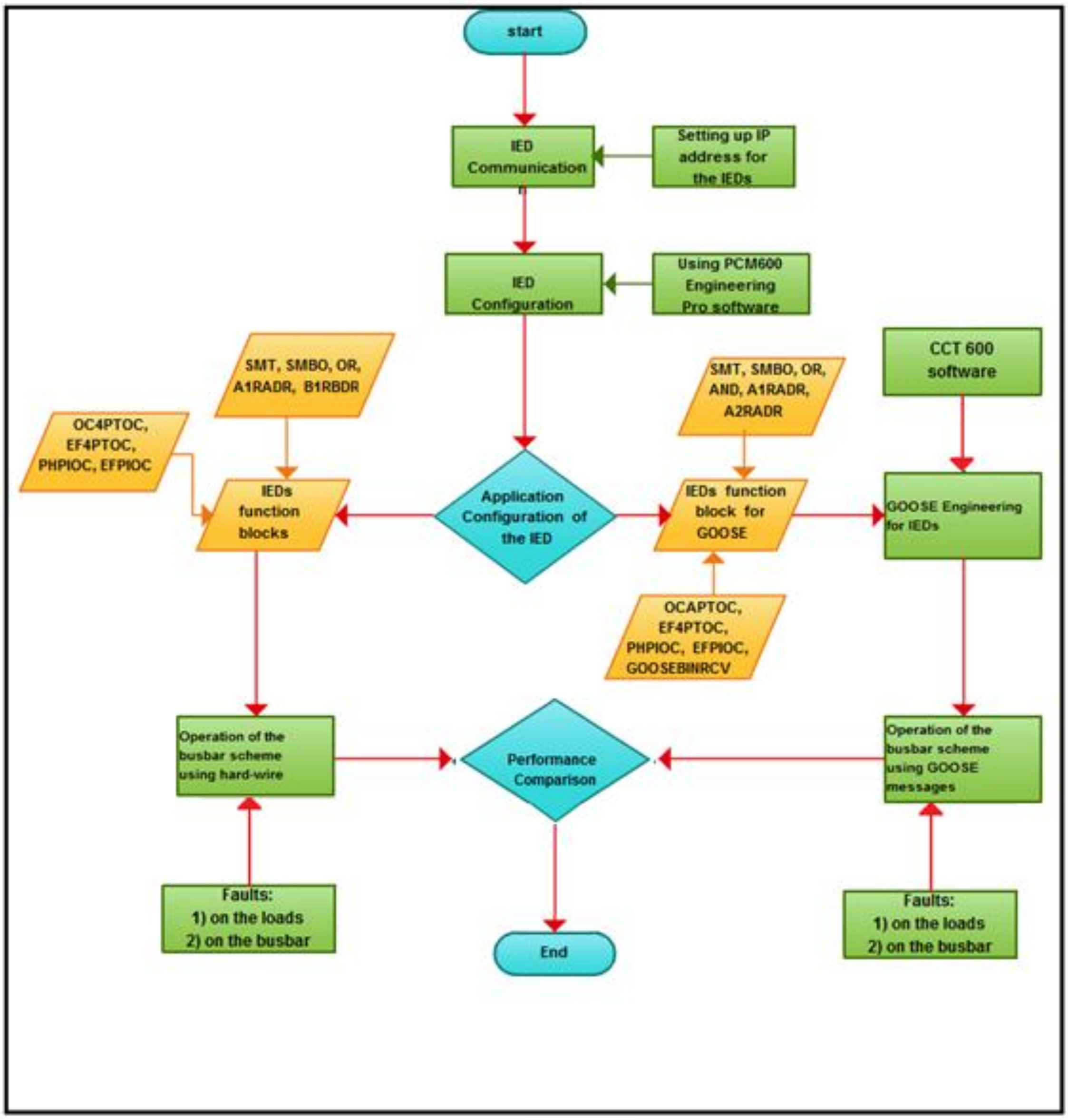

Figure 6.4: **The flow chart for the practical experiment**

Figure 6.4 shows that communication of IEDs needs to be first configured. The next step is to configure the IED application using various function blocks. This application is done into two ways namely: the busbar protection scheme using hard-wires between the IEDs and the busbar protection scheme using GOOSE messages between the IEDs. The results are recorded and compared. The abbreviations for the function blocks included ing Figure 6.4 is described in the thesis glossary.

6.5 Communication establishment between PCM600 software and the IED's

The used communication protocol within the substation is dependent on the communication between the IED and the PCM600 software. The IEDs have an Ethernet interface port situated on the front panel which is used for communication with PCM600 software. These IEDs also have Fibre Optic ports situated at the rear panel but the developed lab test bench only focuses on utilizing the Ethernet interface port. When this internet interface port is used for communication the TCP/IP protocol is employed. There are two variants that are needed to be taken into consideration for the communication between the IEDs and the PCM600 software. The two variant used for communication are explained below:

- A direct point to point connection between the IED Ethernet interface port and the PCM600 from the PC. The IED Ethernet interface port on the front panel is used as a service port.
- Indirect linking through the station LAN or from a remote end through a network.

In the lab test bench both variants are implemented separately. When it comes to the physical connection for both variants the IP address of the IED needed to be configured in order to enable these communications. The procedures to set up the communication for both variants are as follow:

- IP addresses need to be set on the physical IEDs.
- Set up the PC for a direct link or LAN/WAN network connection.
- The IEDs IP addresses need to be configured using PCM600 software and it is done for all IEDs.

6.5.1 Setting up IP addresses for the IEDs used

The corresponding mask and IP address for each IED are configured via the LHMI available in Ethernet interface port. Each Ethernet interface port has a factory default IP address that comes with the IED. The factory default IP address for the front port is 10.1.150.3 and its corresponding sub network mask is 255.255.255.0.The factory default IP address for the rear port is 192.168.1.10 and its corresponding sub network mask is 255.255.0.0.These corresponding masks and IP addresses for each IED are configured via the HMI on the IED. The block diagram shown in Figure 6.5 below was followed to change the IP addresses for each IED. This block diagram presents the algorithm developed to change the default IP address of the IEDs using their front panel HMIs.

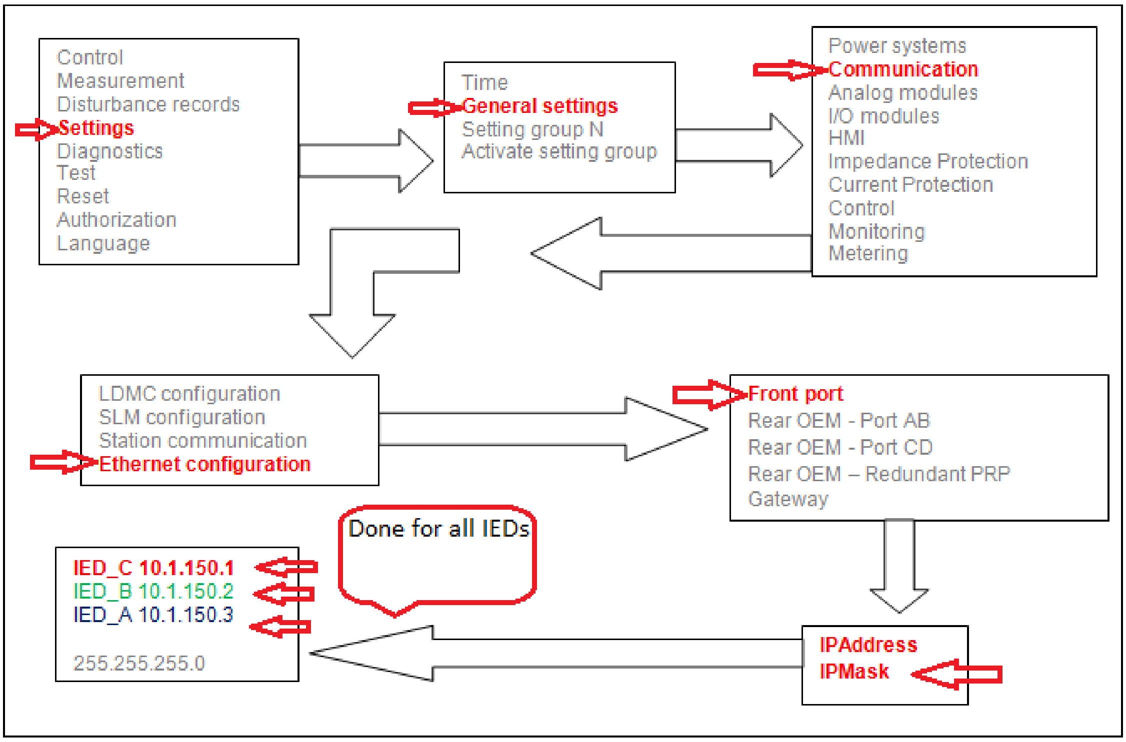

Figure 6.5: **Block diagram for IED IP Configuration using the local HMI panel**

The text in red in Figure 6.5 shows the navigation of the selections. When the IED is energized its front panel HMI displays a home page with a main menu. From this menu the setting function is required to be selected and then the algorithm navigates as follows: General settings>>Communication>>Ethernet configuration>>Front port>>IP address>>IP mask>>Values. The user can select the rear port that uses fiber optic cable or the front port which uses the Ethernet cable. For this project only the front port is utilized.

It is required that the front IP address must not be in the same subnet with the rear IP address to avoid communication failure.. For the first development of the lab test bench a direct point to point connection between the IED Ethernet interface port and PCM600 from the PC is implemented. The IED Ethernet interface port in front panel was used as a service port.

6.5.2 Setting up the PC for point to point communication using the front port of the IED

This method utilizes an algorithm that does not require a hub, router, bridge or switch to connect two physical Ethernet interfaces together. In order to apply this method a special cable is requested. This algorithm requires RJ-45 cable for connection as showed in Figure 6.6. It is recommended that the cable should be longer than two meters.

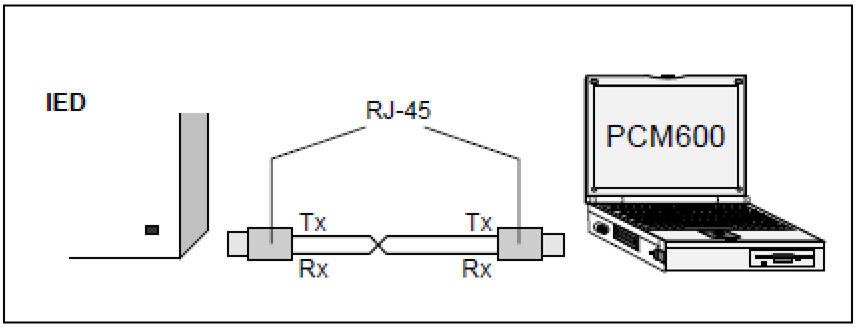

Figure 6.6: **Point to point Ethernet link between the IED and the PC with PCM600 software**

Once the physical connection between the IED and PC (with PCM600) using the null-modem cable is completed the network connection from the PC has to be configured and the procedure is as follows:

Select start on the PC screen and navigate to Network connection in the PC as shown in Figure 6.7

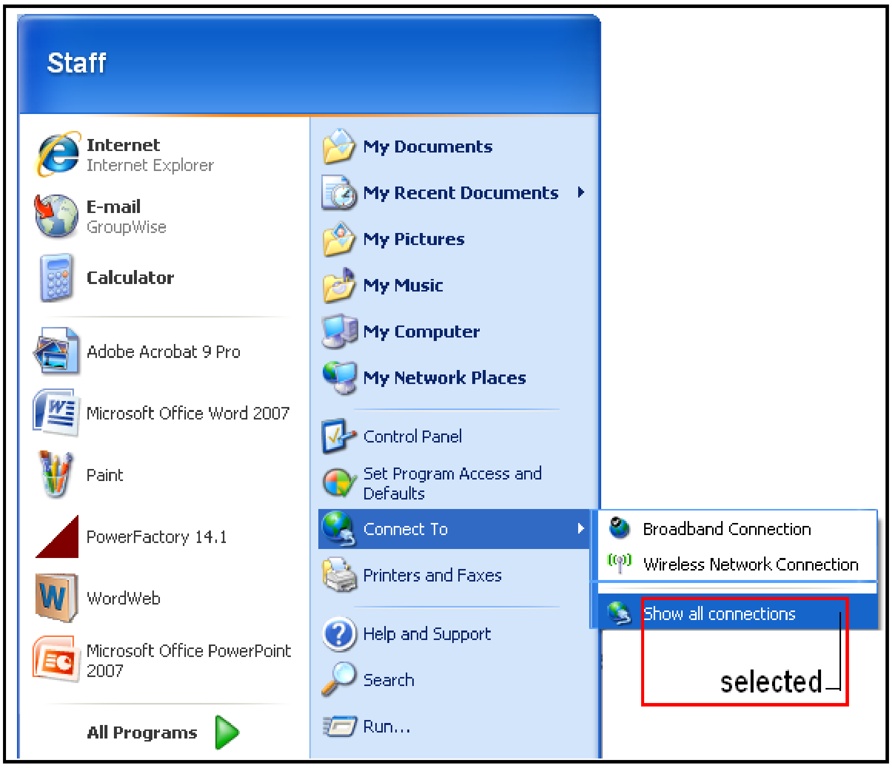

Figure 6.7 **Selected Network connections**

At the network connection menu a Local Area Connection the Properties are selected and a window is shown in Figure 6.8

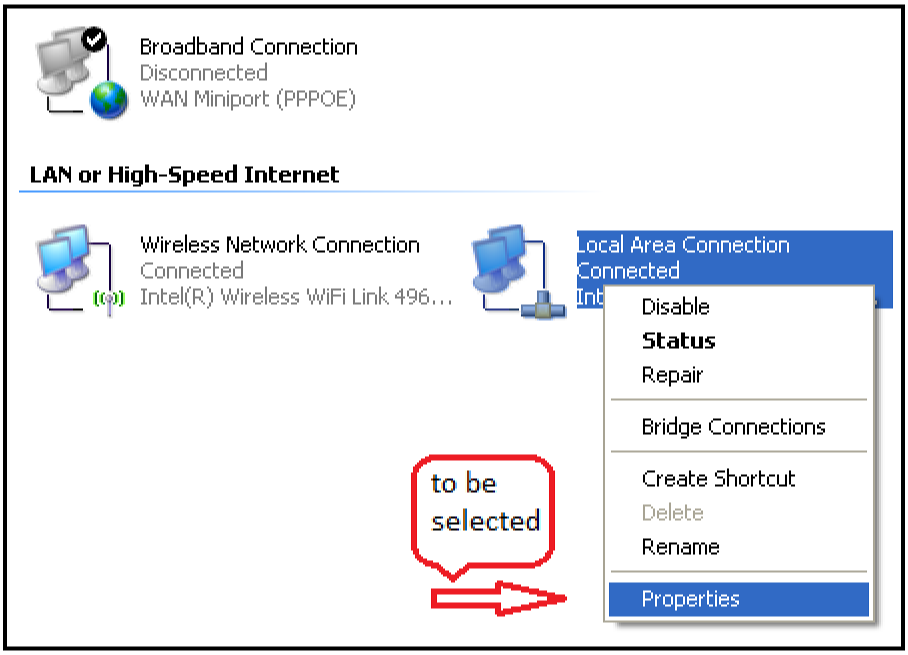

Figure 6.8: The local area connection

The properties of the local area connections are selected. There are various options of networks that can be chosen. The next step was to select internet protocol (TCP/IP) as shown in Figure 6.9.

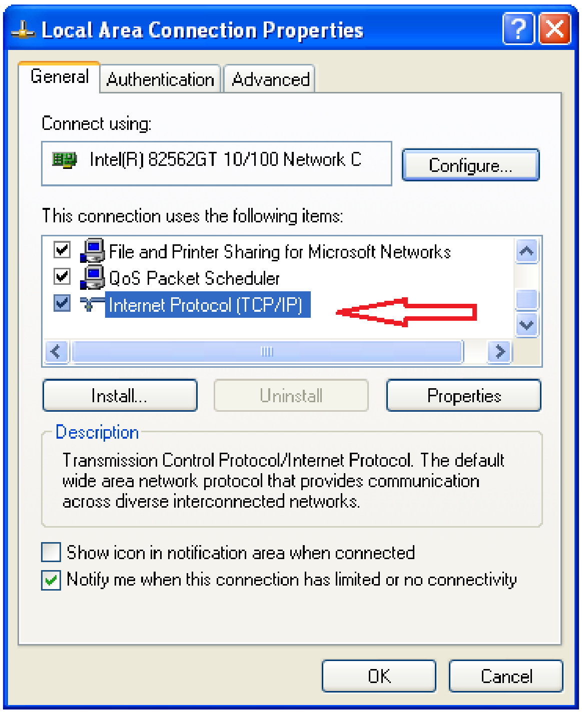

Figure 6.9: The internet protocol (TCP/IP) selection

In order to achieve the connection between the PC and the IED_C the properties of the internet protocol (TCP/IP) had to be completed as shown below in the Figure 6.10a.Figure 6.10a shows slots for the PC IP address and Subnet mask that needed to be defined. It is required that the IP address must not be the same as the IED IP address. In this case the PC IP address is 10.1.150.4 and the IED_C IP address is left as the factory default. The Subnet mask was selected as 255.255.255.0 as shown in Figure 6.10b.

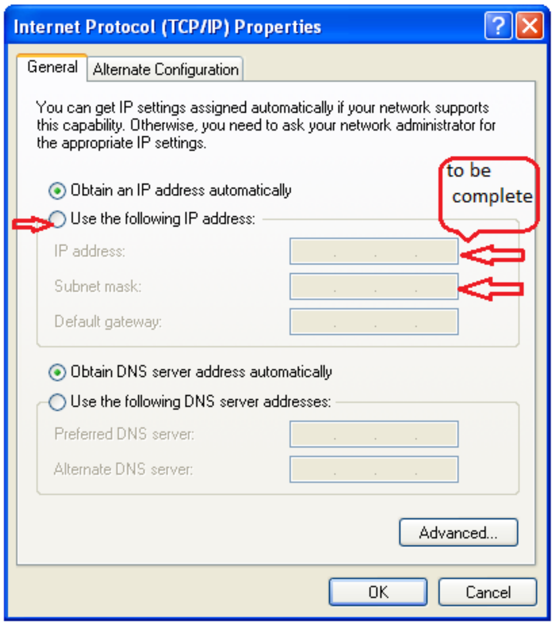

Figure 6.10a: **The Internet protocol (TCP/IP) properties**

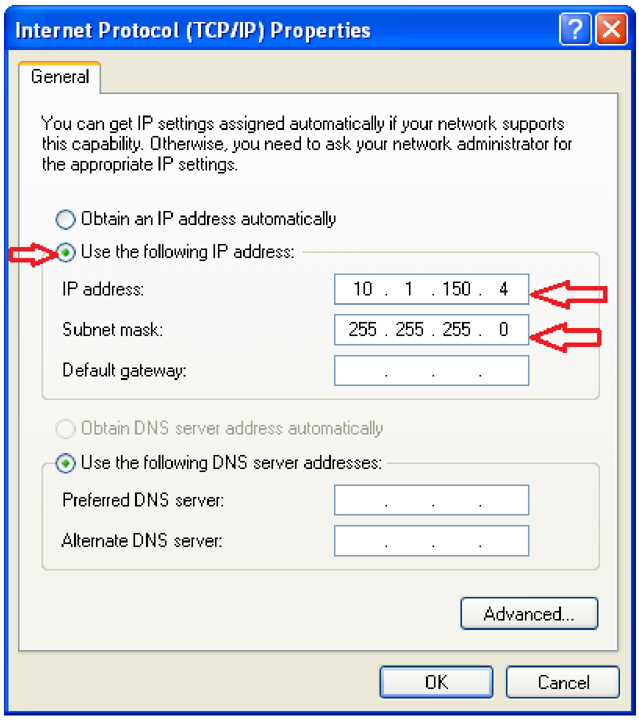

Figure 6.10b: The Internet protocol (TCP/IP) with completed properties

When the selection Figure 6.10b is completed the next step is to use a ***ping*** command in order to verify connectivity with the IED_C. The results as shown in

Figure 6.11 are that the connection between the IED_C and the PC with PCM600 software is achieved.

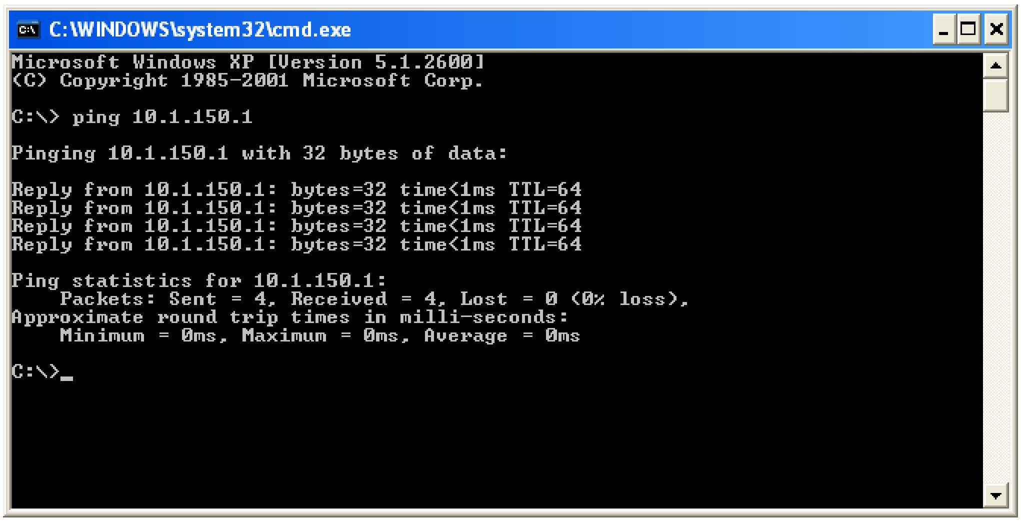

Figure 6.11: **Ping command for checking of the connection between the IED_C and the PC with PCM600 software**

6.5.3 Setting up the PC to access more than one IED via a switch

This setting algorithm is also implemented as a second possibility when developing the lab test bench. It makes use of an indirect connection through a station LAN. Once the physical connection between the IEDs and the switch is completed, a physical link via a switch and the PC has to be added as well. When all the physical links between IEDs and a PC via a switch are done, the network connection from the PC had to be configured using the same procedure for the direct point to point connection. Since the three IEDs are now linked to the PC via a MOXA switch as shown in Figure 6.12 their IP addresses are changed and the corresponding sub network mask is not necessary to be changed.

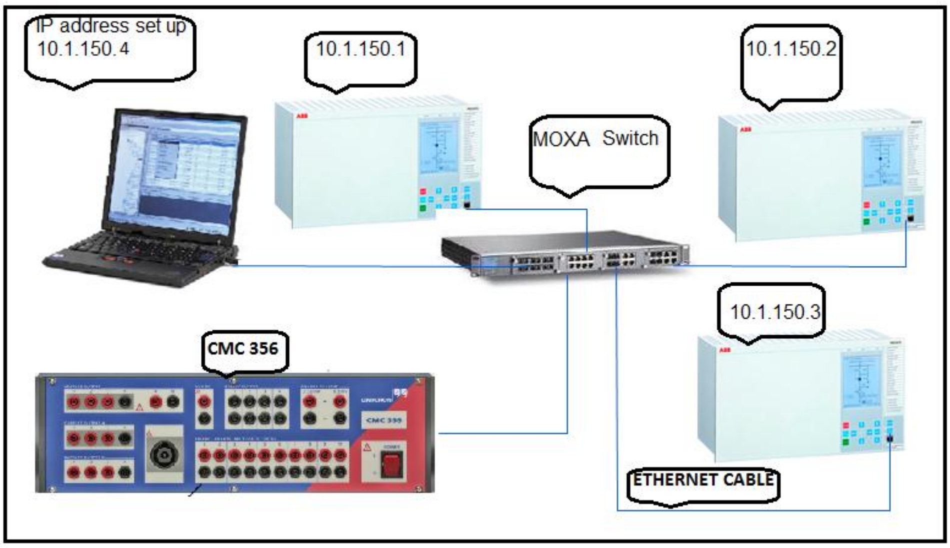

Figure 6.12: **Setting up the PC to access more than one IED via a MOXA switch**

The IP address for the IED_C is left as 10.1.150.1 which is by default, for IED_B is changed to 10.1.150.2 and for the IED_A is changed to 10.1.150.3 while the corresponding sub network mask is kept as 255.255.255.0. Once this step was completed a ***ping*** command is utilized to verify connectivity between the PC and the three IEDs via a MOXA switch. The results are shown in Figure 6.13.

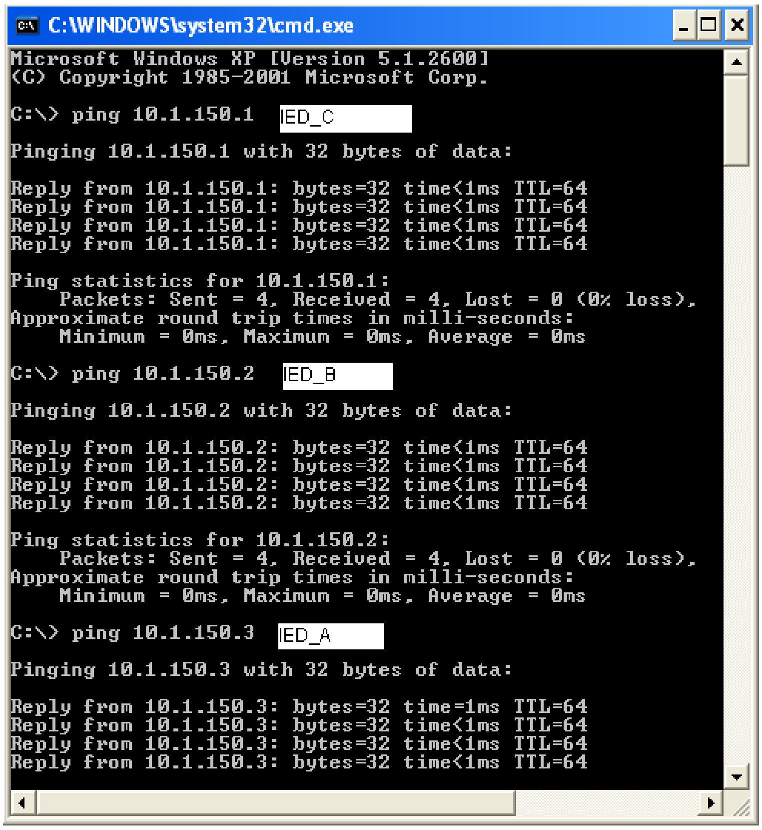

Figure 6.13: **Ping command results for the connection between the IED_C, IED_B, IED_A, and the PC with PCM600 via a MOXA switch**

From the results shown in Figure 6.13 can be seen that connection between the PC and the three IEDs via switch is achieved. This means that the IEDs can now be seen by the PCM600 software installed on the PC. This tool is used for engineering and managing the IEDs. The next step is to set up the project utilizing PCM600 software tool.

6.5.4 Setting up a project in PCM600 software tool

This software carries a plant structure window which includes one or sometimes more IED objects. More than one project can be developed and managed by the PCM600 software, but one project must be active at a time. It is also required to install the connectivity packages in the PC before PCM 600 software is used as referred to Appendix A. When installing this connectivity package it is required to use the latest version of a tool package or protocol. The connectivity packages consist of the following:

- Generic IEC 61850 IED connectivity Package
- IEC 61850 Connectivity Package
- LON Connectivity Package
- IED 670 Connectivity Package
- SPA Connectivity Package

This connectivity packages have a connectivity package manager used for managing all the different packages for the different IED types. Once these connectivity packages are installed, the PCM600 software recognizes it during its start-up and the corresponding IED types are available in the PCM600 software.

6.5.5 Engineering configuration of the IEDs using PCM600 engineering Pro software

The project is created and structured using the PCM600 engineering Pro software tool. At the PCM600 menu there is a window known as a plant structure. This is where the project is created and at the same time the project name is defined. In this case the project is named “Distribution Network” as shown in Figure 6.14 below

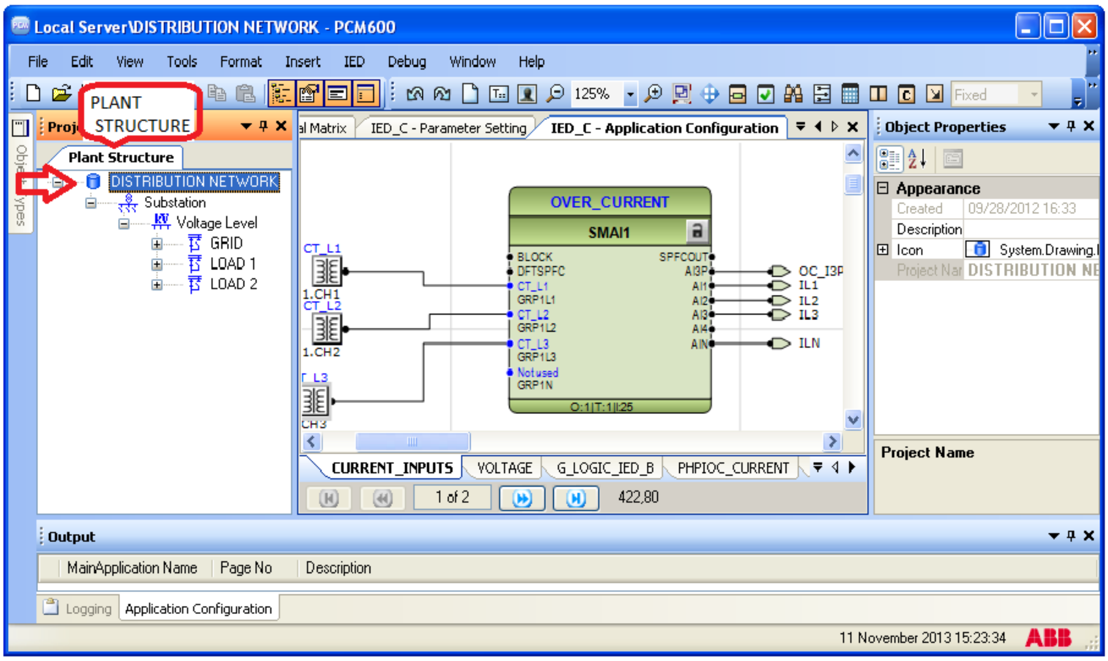

Figure 6.14: **The plant structure of the Distribution network**

The plant structure is used to recognize each IED and where it is situated at the substation. A geographical image of all the primary equipment that creates a bay is viewed in the plant structure window. The plant structure of the IEDs differs based on primary equipment within substation. The building of the plant for the considered case study is organized by a hierarchical structure that consists of five levels, namely:

- Project - Center
- Substation
- Voltage Level
- Bay level
- IED

The ABB devices are added to the plant structure topology by right clicking the bay folder and following the instructions shown in Figure 6.15 below. From the device catalog, the IED's can then be inserted by selecting the IED that is going to be used.

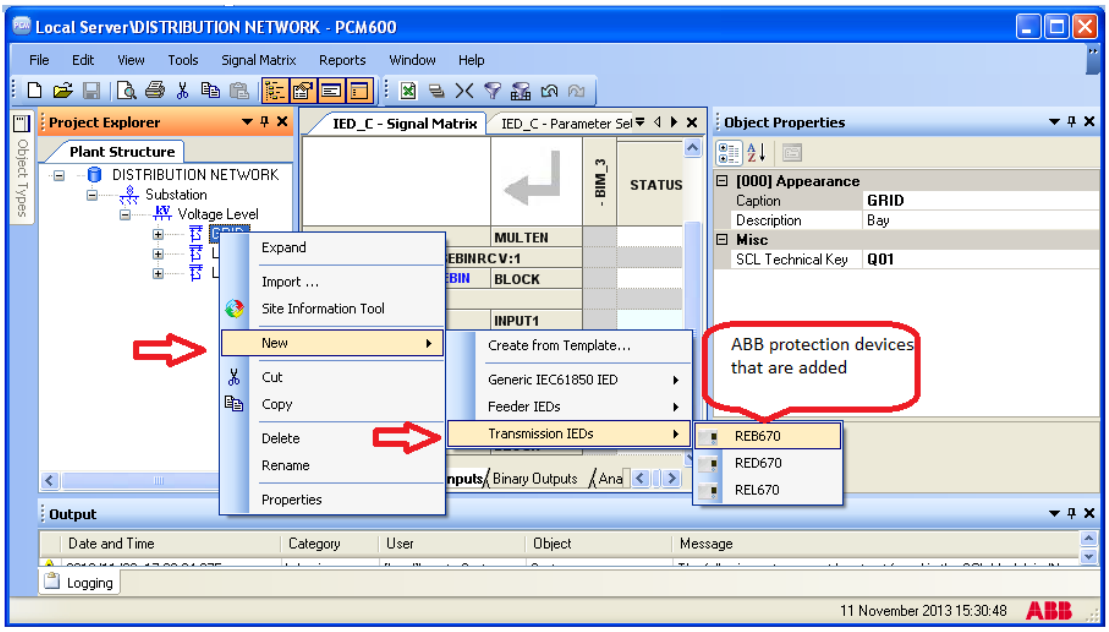

Figure 6.15: **Inserting ABB device into a project**

When it comes to inserting IEDs there are two types of options that can be chosen from namely:

- Online mode
- Offline mode.

Online mode is when IED is already connected to the PC with PCM600 software and the communication is established. This allows the PCM600 software tool to read the data straight from the IED. Offline mode is when PC with the PCM600 software is not physically connected to the IED. In this case the engineering procedures are done without the IED.

Working in offline mode is much more beneficial compared to online mode. Configuration preparation can be done even though IED is not available. Configuring an IED in an offline mode is similar to that of an online mode. The difference is that with offline mode it is not required to type the correct IP addresses in the Communication port because there is no physical connection between the PC and the IED.

Once all the three IEDs are inserted in their bays under the voltage levels as shown in Figure 6.16 the next step that needs to be completed is the application configuration for the IEDs. The application configuration of the IEDs consists of protection and control engineering.

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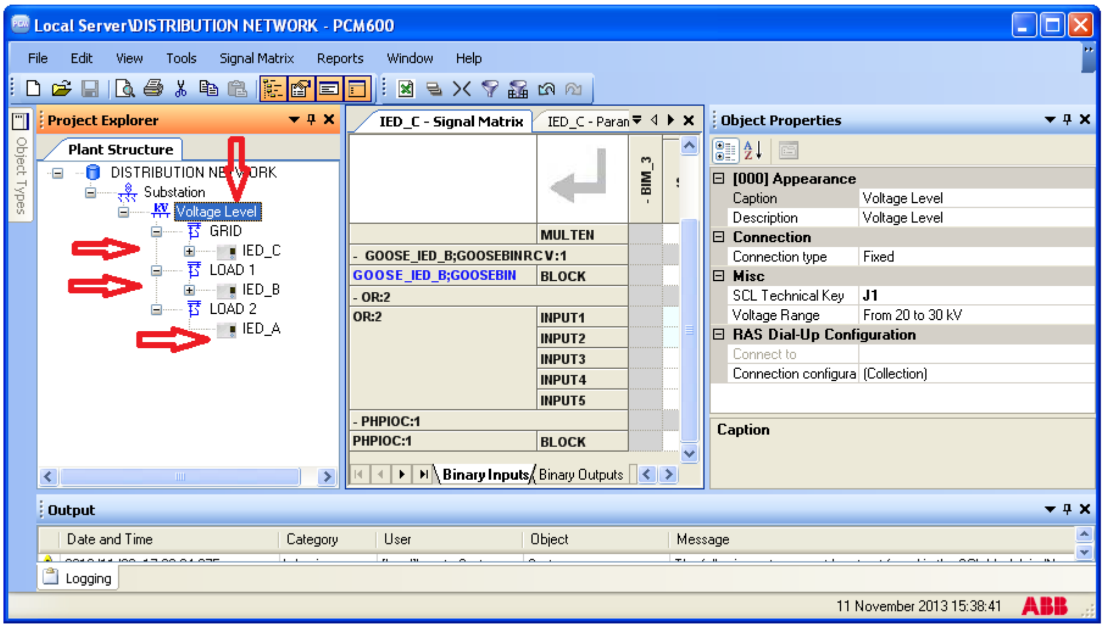

Figure 6.16: **Inserting of IEDs in the plant structure**

6.5.6 Application Configuration for the IEDs

Application Configuration Tool (ACT) is a platform where the application configurations for these IEDs are implemented.PCM600 engineering Pro software offers powerful ways to develop, accommodate, and modify application configurations for the ABB IEDs. This is where the whole signal flow from input to output is represented. These configurations are developed by using function blocks. The function blocks have different functions and dedicated operation. They are organized and designed in group types for a various functions. These function blocks belongs to five groups namely:

- Pre-processing blocks
- Control related functions
- Protection related functions
- Monitoring functions

- Communication functions

These function blocks are used for mapping the signals. The different function block types are viewed in the object type's window as shown in Figure 6.17 below.

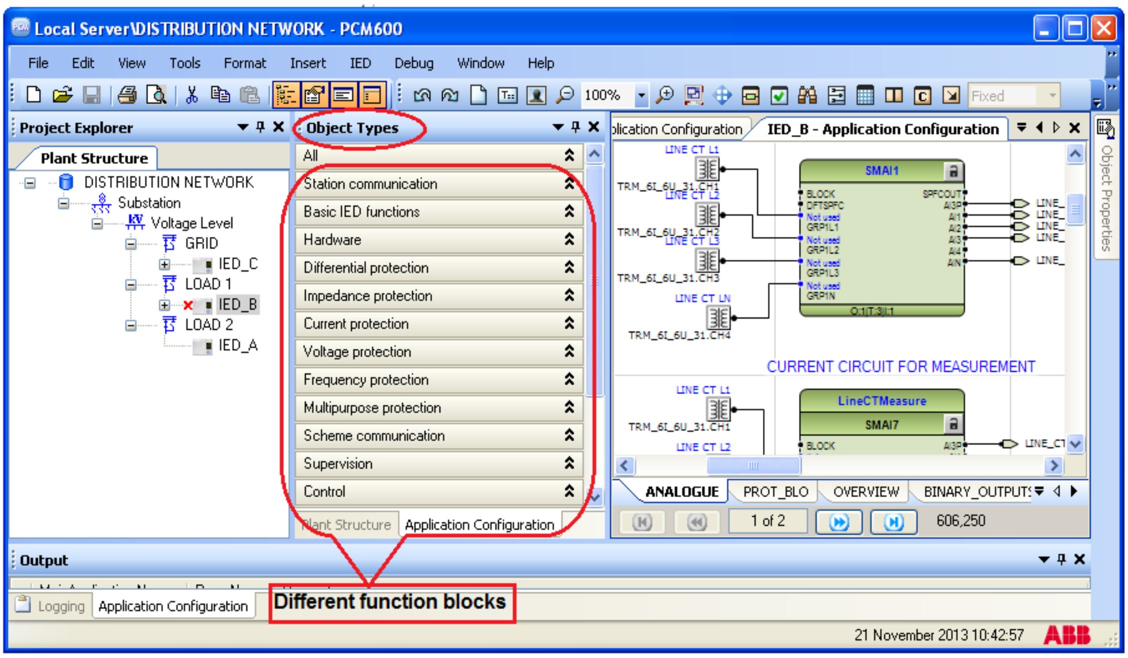

Figure 6.17: **The object type window that shows different function blocks**

6.5.7 The function blocks for analog data used in the IEDs for the outgoing feeders

Figure 6.18 below shows the pre-processing function known as Signal Matrix Analog Input (SMAI) for IEDs. It delivers processed analog data to all functions in ACT as discussed in Appendix A. It represents the Root Mean Square (RMS), Discrete Fourier Transform (DFT) and sampled data values. The data are accessible through the group signal output AI3P on the SMAI blocks. All other signals from A1 to AN produce only sampled values and they can be connected to a disturbance recorder. The parameter setting for this SMAI is shown in Appendix B. The current signals from the CTs of the outgoing feeder IEDs are shown in Figure 6.18. They are connected at the input TRM_6I_6U_3I channel 1 for the line 1; TRM_6I_6U_3I channel 2 for the line 2 and TRM_6I_6U_3I channel 3 for the line 3 of the SMAI1 .The same input signals are connected to SMAI7 block for measurements.

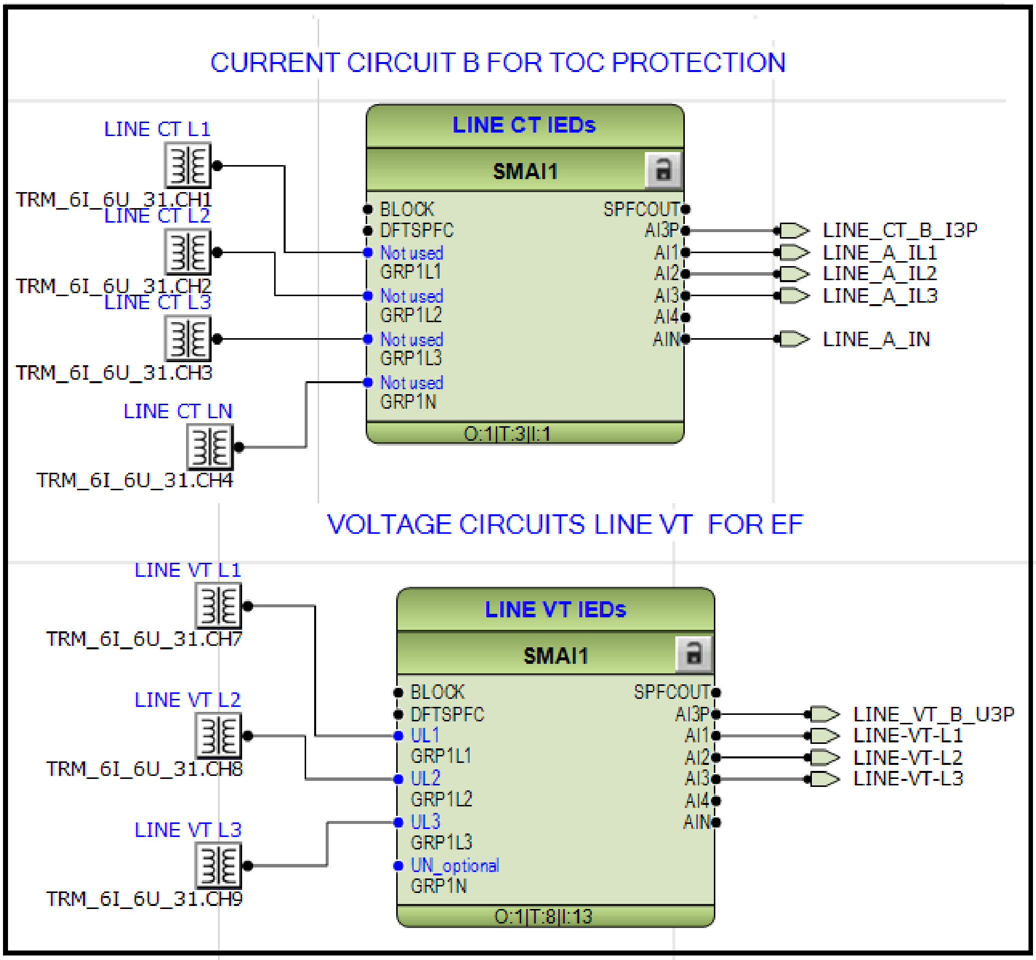

Figure 6.18: Signal Matrix Analog Input for currents and voltages

6.5.8 Function blocks for overcurrent protection used in the IEDs for the outgoing feeders

The principal operation for this overcurrent protection function block shown in Figure 6.19 is explained in Appendix A. The output AI3P of SMAI1 (currents) in Figure 6.18 is connected to the input I3P of the protection function block shown in Figure 6.19. The same method is implemented for the output AI3P of SMAI1 (voltages). It is connected to the input U3P.

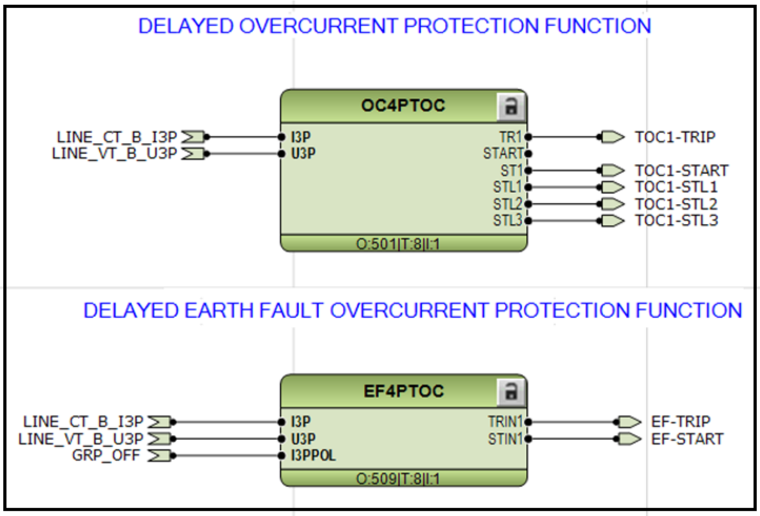

Figure 6.19: **The overcurrent protection function blocks for the IED_A**

6.5.9 Function blocks for the signal matrix of binary outputs used in the IEDs for outgoing feeders

The basic principal operation of this function block is discussed in Appendix A.The outputs of protection functions in Figure 6.19 are all connected to the inputs function block for binary outputs shown in Figure 6.20.This function block outputs link the signal with the physical binary output modules of the IEDs for the outgoing feeders

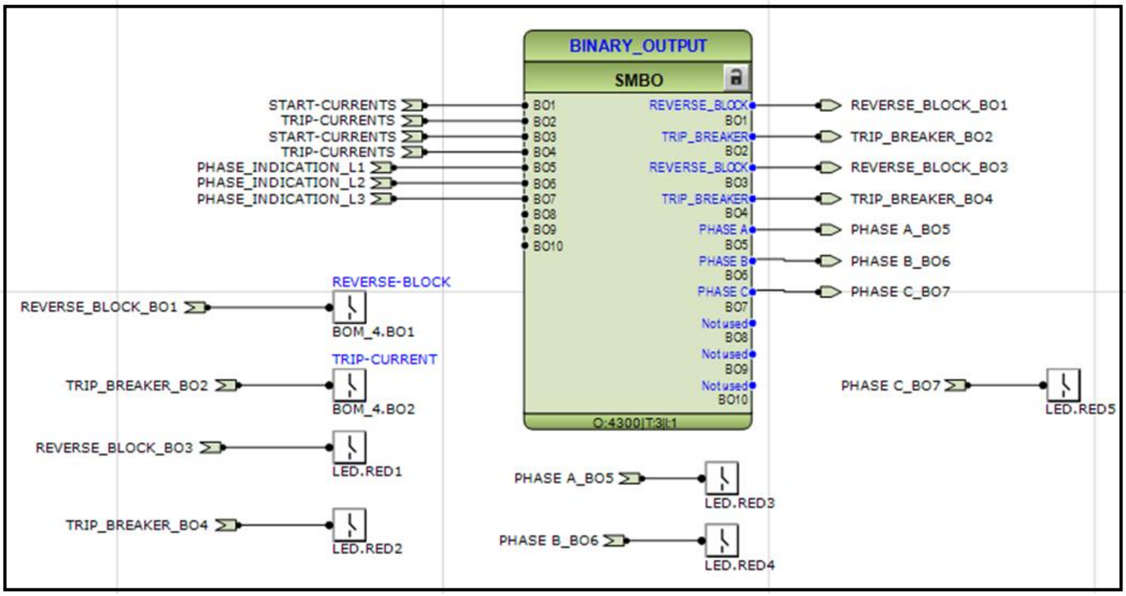

Figure 6.20: **The function blocks of the signal matrix for the binary outputs**

6.5.10. Function blocks for logic signals used in the IEDs for the outgoing feeders

The logic signals are divided into two groups. One group is for current protection for all three phases and the other group is for per phase protection as shown in Figure 6.21.This gives the user an option to see what type of fault has occured.

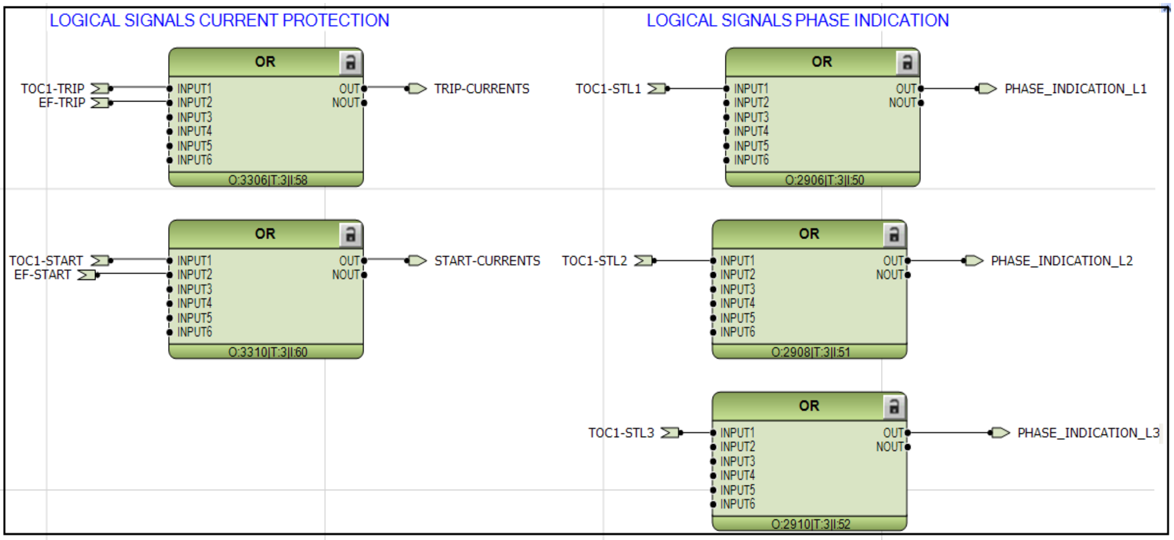

Figure 6.21: **The function blocks for the logic signals**

6.5.11. Function blocks for measurement of power, current and voltage used in the IEDs for the outgoing feeders

The basic principal operation of these function blocks are discussed in Appendix A.The outputs SMAI are all fed to the inputs of the meaurements blocks shown in Figure 6.22.This is done in order to be able to measure power,current and voltage for a future analysis.

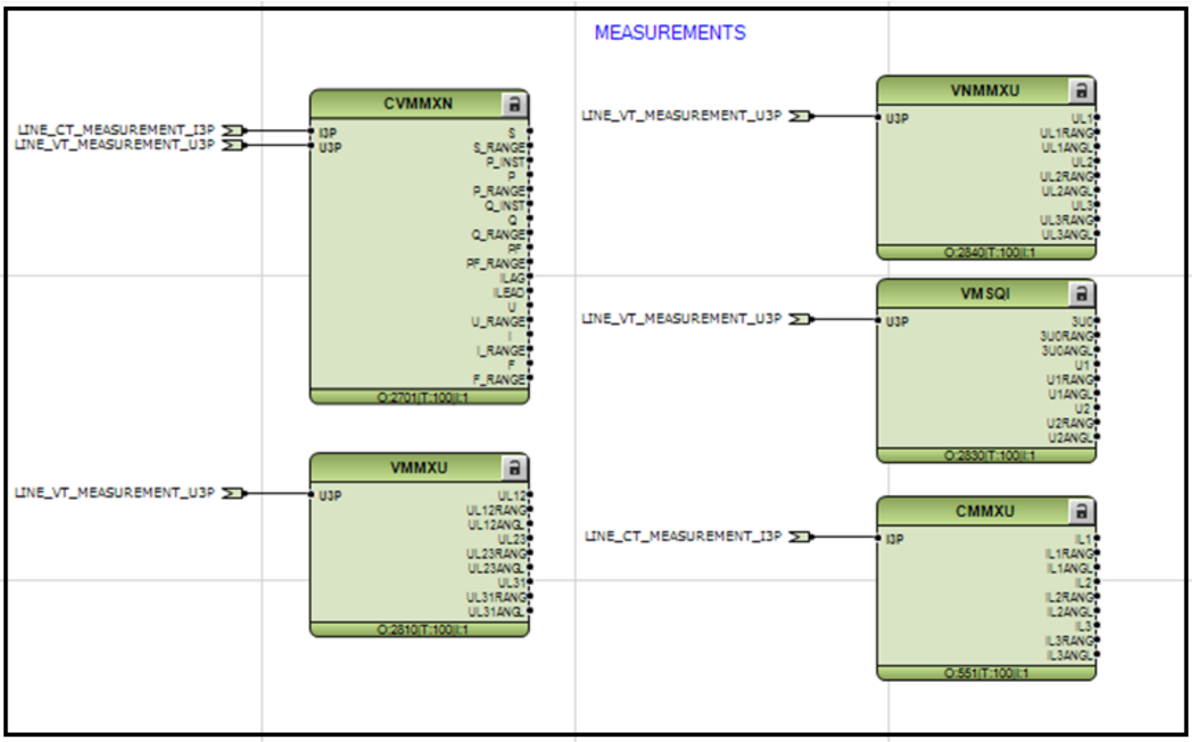

Figure 6.22: **The function blocks for measurements of power, current and voltage**

6.5.12. Function blocks for disturbance report of analog and binary signals used in the IEDs for the outgoing feeders

The basic principal operation of these function block is discussed in Appendix A. Two types of disturbance reports are recorded for the IED_A, namely A1RADR and A2RADR. These are for the analog currents and voltages recieved from the SMAI The binary disturbance recording function block B1RBDR is used for all the binary signals as shown in Figure 6.23 below.

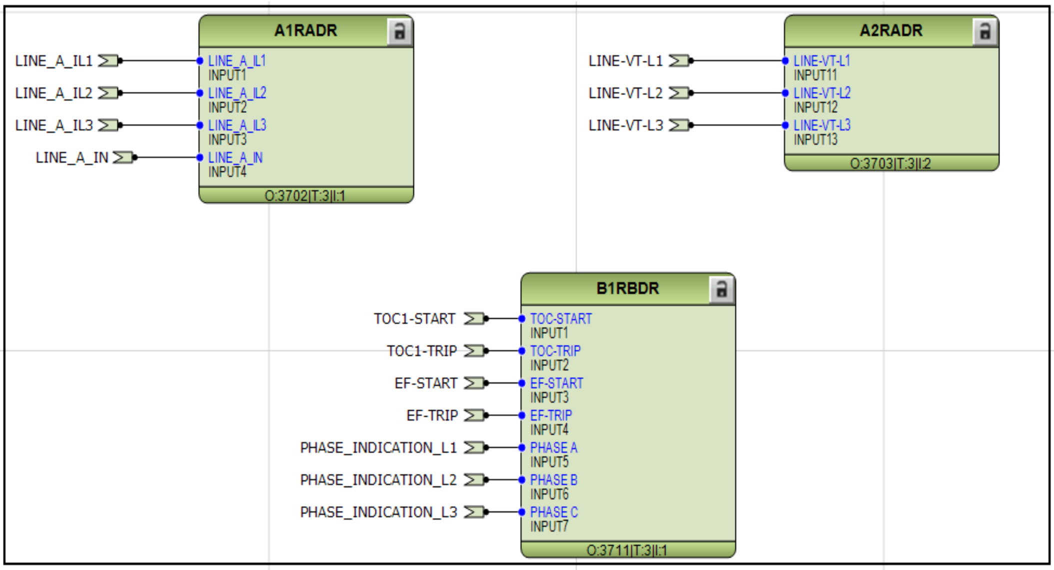

Figure 6.23: **The function blocks for a disturbance report of analog and binary signals**

6.6 Application Configuration for the IED_C used for protection in the incoming feeder

The IED_C is the most important IED to be configured. Both IED_A and IED_B have to communicate with IED_C. Detail of the IED_C configuration is explained further. The system is divided into sections so that it is easy to be understood.

6.6.1 Function blocks for analog input data in IED_C for protection in the incoming feeder

The use of this block shown in Figure 6.24 is the same as for the SMAI in Figure 6.18. The only difference is that's its input signals for the SMAI are fed from the CT on the incomer feeder.

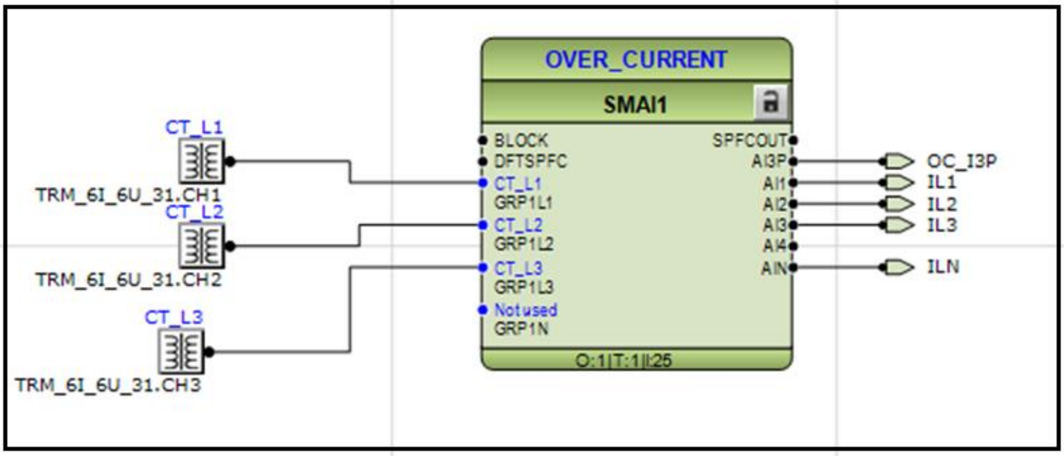

Figure 6.24: **The signal matrix of the analog inputs for currents of the IED_C**

6.6.2 Function blocks for protection in IED_C

The basic principles for this protection function block is discussed in Appendix A. The output AI3P in Figure 6.24 is then connected to the input protection function I3P for PHPIOC and I3P for EFPIOC respectively as shown in Figure 6.25a and EF4PTOC and OC4PTOC in Figure 6.25b as back up protection.

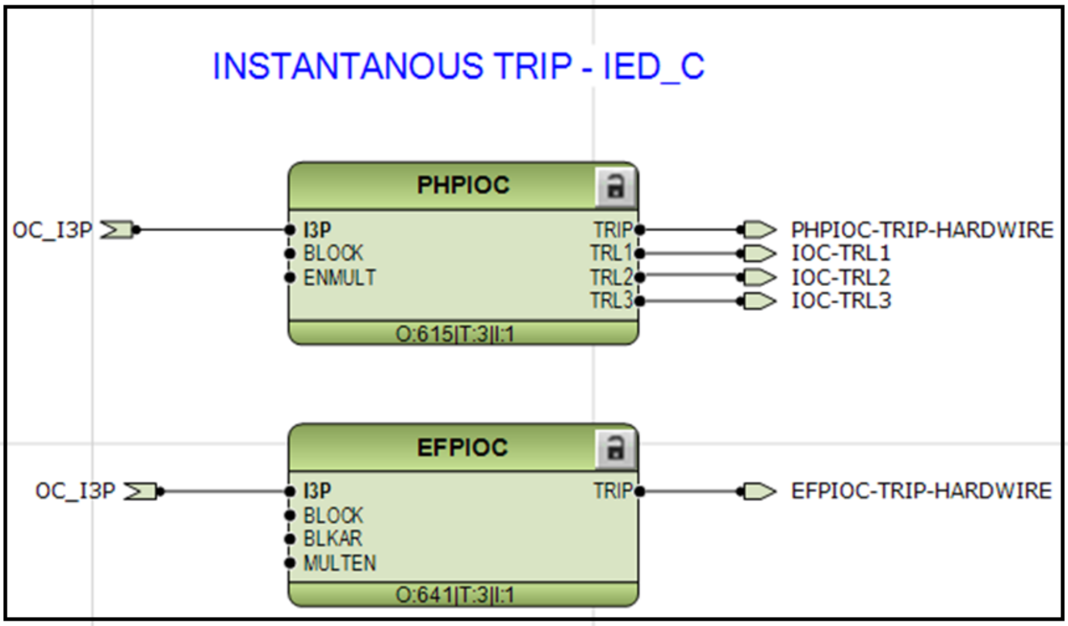

Figure 6.25a: **The protection function blocks for instantaneous tripping for internal fault**

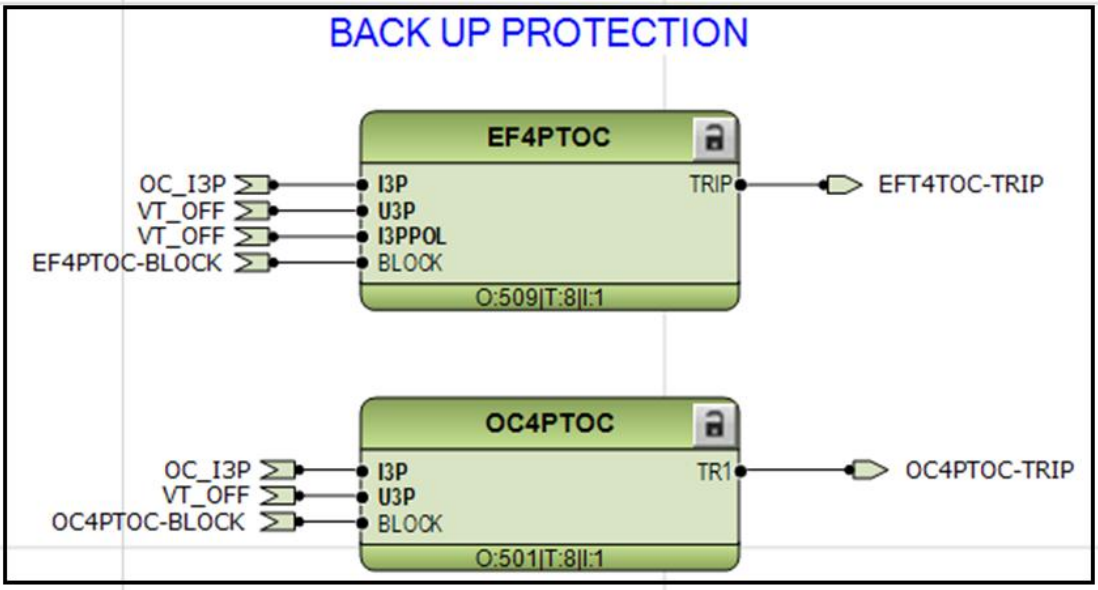

Figure 6.25b: The protection function blocks used for back-up protection

6.6.3 Function blocks for the signal matrix of the binary outputs in the IED_C

The outputs of protection functions in Figure 6.25a are all connected to the inputs BO2 and BO3 of the function block SMBO respectively as shown in Figure 6.26 below.This function block outputs link the signal with the physical binary output modules of the IED_C and also to the the LEDs that are displayed at the front panel of the IED.This is the basic operation when the fault is at the busbar.

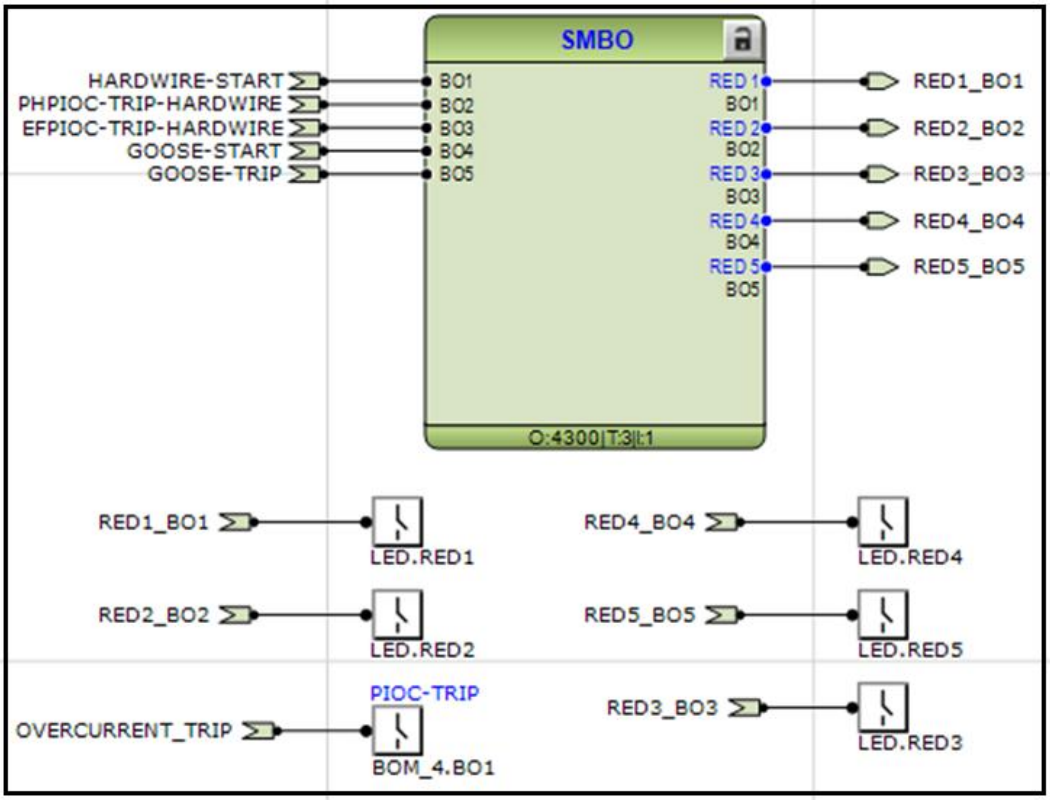

Figure 6.26: The function block for the signal matrix of the binary outputs

6.6.4 Function blocks for logic signals in the IED_C

For the considered busbar protection scheme developed for the laboratory test bench IED_C plays a most important role.It is where all the decissions are constructed and made.This critical part is done by the logic function blocks. Figure 6.27 shown two sets of logic gates and they are both OR type.The first OR gate is used for linking the hardwire connection from the IED_A and the IED_B.The binary output module (BOM_4.BO1) of the IED_A in Figure 6.20 is connected to the binary input module (BIM_3.BI3) of the IED_C via a copper cable.This also is done for IED_B and this is to transport signals for reverse blocking. When a signal from the IED_A or IED_B is sent to this logic block it will then become active and will send its output to blocks ether PHPIOC or EFPIOC for tripping depending on the type of the fault.

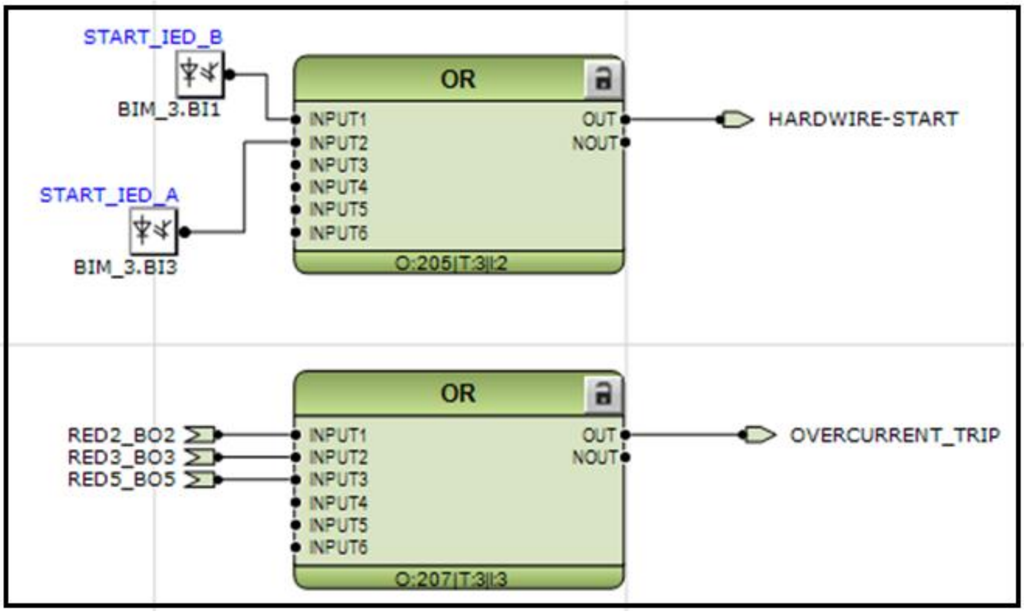

Figure 6.27: The logic block of OR gates utilized for sending the tripping signals to the physical circuit breaker

The second OR gate in Figure 6.27 is used for sending the tripping signal to the phisical circuit breaker.Three different inputs are connected to this OR gate.Input one represents the PHPIOC-TRIP signal displayed by the red led two,the input two represents EFPIOC-TRIP signal displayed by the red led three, and the input three represents GOOSE-TRIP signal displayed by the red led five.

6.6.5 Goose binary receive function block (GOOSEBINRCV)

The GOOSEBINRCV functions for IED_A and IED_B are installed in IED_C as shown in Figure 6.28.This function block is to receive signals to and from other IEDs via the interbay bus. The GOOSEBINRCV function blocks have 16 outputs that can be used. These outputs have configuration logic circuits that can be used for control purposes within the IED via binary outputs. The GOOSEBINRCV function block is used to communicate with the other IEDs. In the considered case the project makes use of four outputs per IED. Binary output one (TOC-GOOSE-ST) and valid data on the binary output one for IED_A are connected to an AND gate one in Figure 6.29 below. The reason for having valid data on binary output is to make sure that a full package GOOSE message is true. The same connection procedure is done for the outputs two up to four. The only difference is that output two is (TOC-GOOSE-TR), output three is (EF-GOOSE-START) and output four is (EF-GOOSE-TRIP). Same method is applied for IED_B.

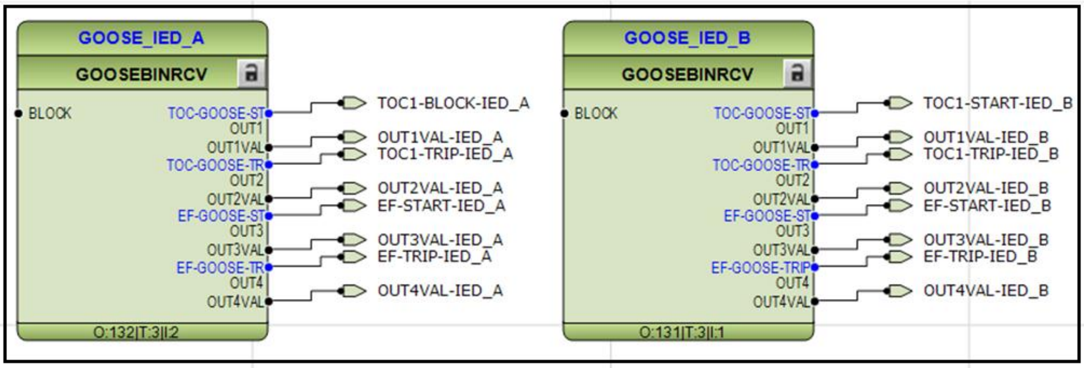

Figure 6.28: **The GOOSEBINRCV function block for the IED_A and IED_B installed in the IED_C**

6.6.6 A logic AND gate function blocks in IED_C

The outputs TOC1-START-IED_A and OUTIVAL1-IED_A from GOOSEBINRCV Figure 6.28 are connected into input logic AND gate as shown in Figure 6.29 below.This is done for OC4PTOC and EF4PTOC for both IED_A and IED_B.

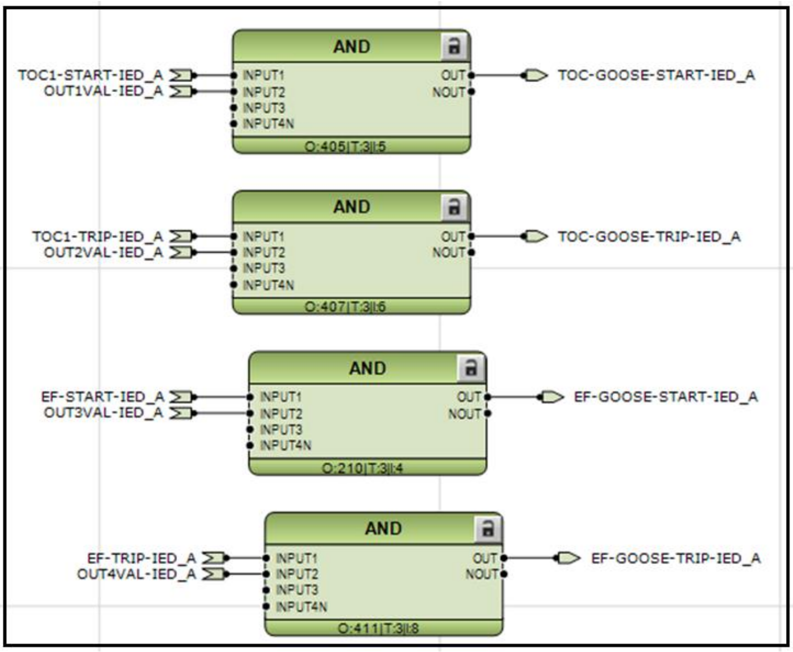

Figure 6.29: **GOOSE logical AND gates for the IED_A**

6.6.7 A logic OR gate function blocks in IED_C

The outputs of the AND gate function blocks in Figure 6.29 are connected into the inputs of the OR gates in Figure 6.30a. The output of the OR gates in Figure 6.30a are connected into the inputs of the OR gate in Figure 6.30b

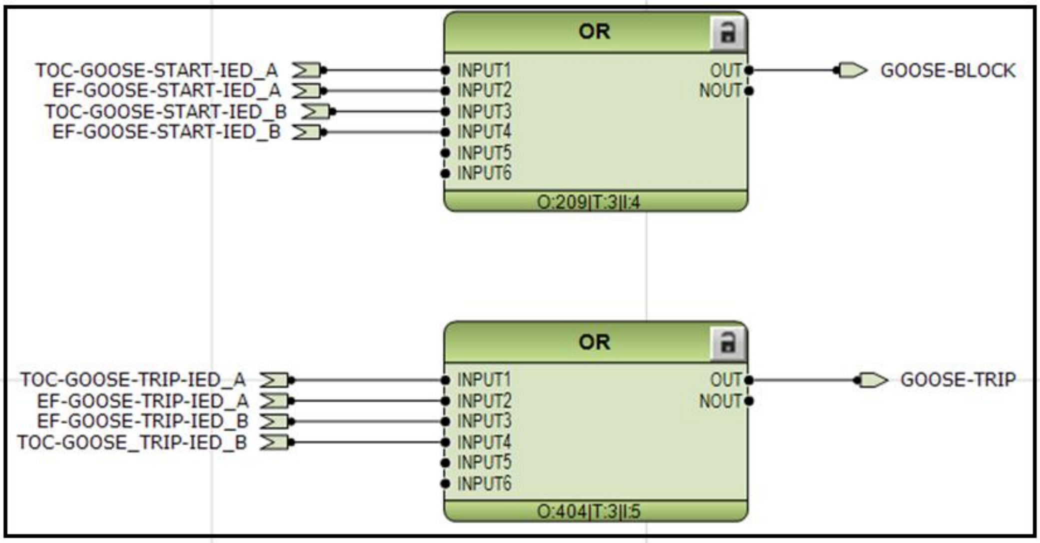

Figure 6.30a: **Logic OR gates for the reverse blocking signals**

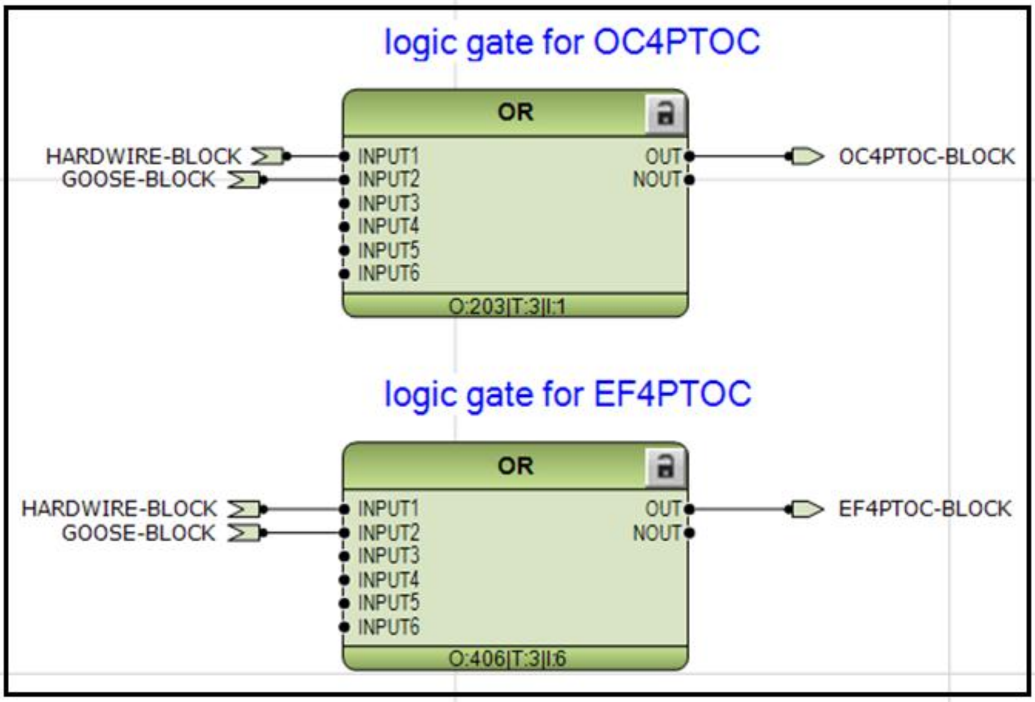

Figure 6.30b: **GOOSE logical OR gates for the IED_A and IED_B**

A complete algorithm developed for the engineering configuration of the reverse blocking protection scheme are given in the Figures below, where Figure i represents the hard-wires based operation and Figure ii represents the GOOSE messages based operation of the reverse blocking scheme. This algorithms are implemented in laboratory test bench to run the experiements.

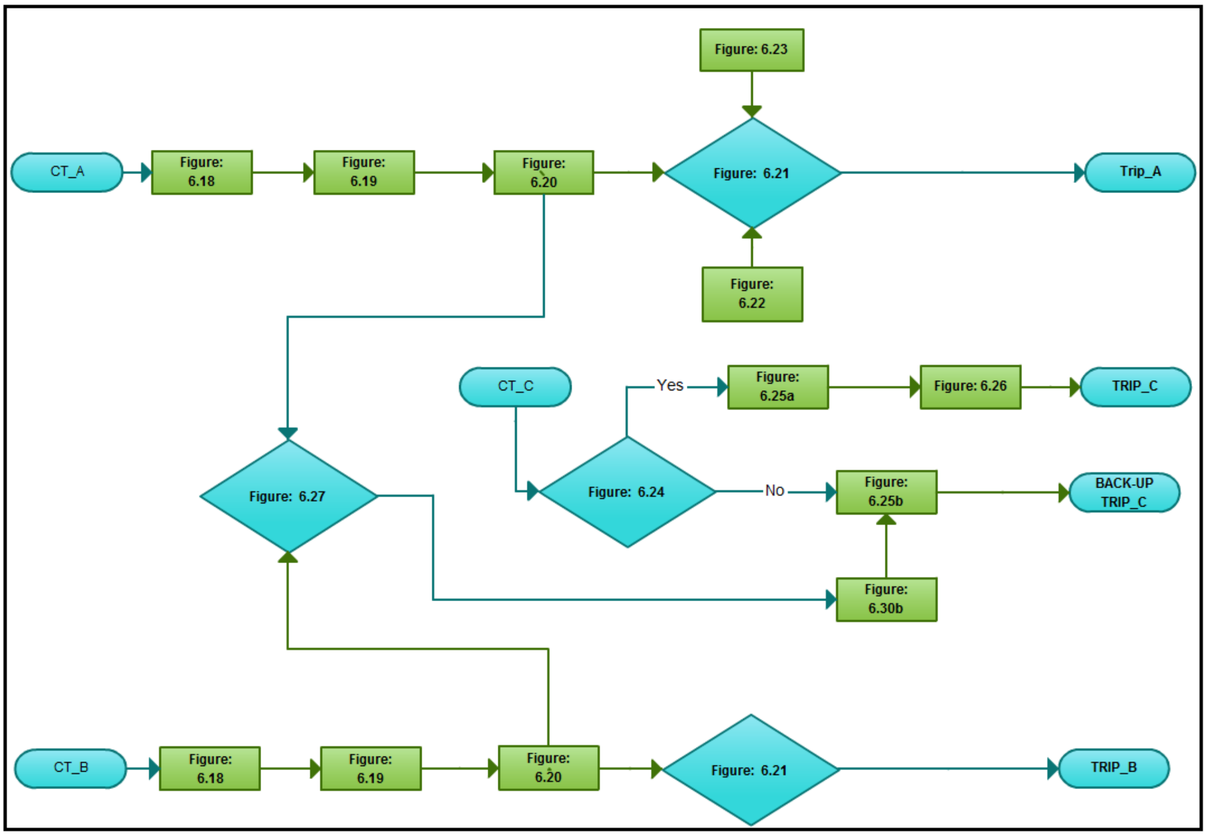

Figure i: Hard-wires based reverse blocking scheme

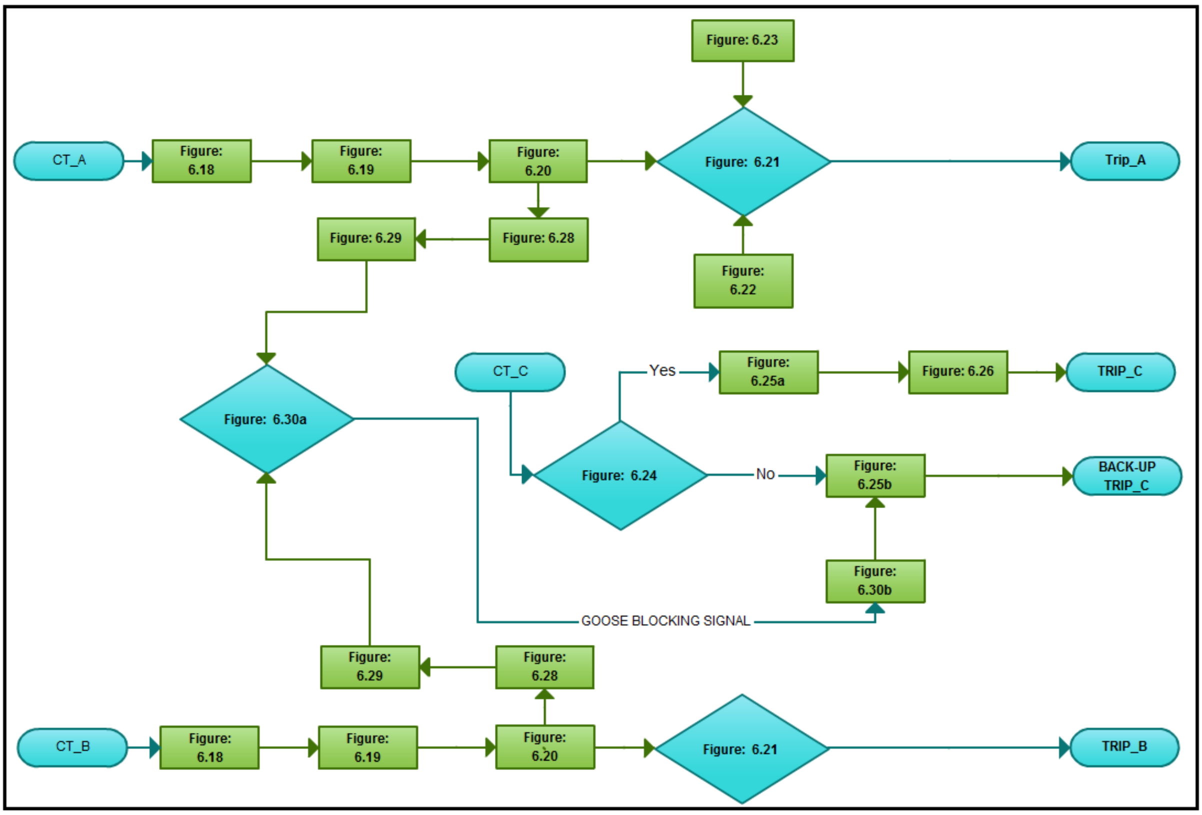

Figure ii: GOOSE messages based reverse blocking scheme

6.7 Operation of the busbar protection scheme using hard wire system

The basic operation of this scheme is discussed in Chapter two. A CMC 356 is used to inject the simulated fault currents. This hardware is controlled by software called OMICRON Test universe that is installed in a PC. This software features all the necessary components that are used for testing protection devices. In this case overcurrent features are used. The overcurrent test module and the hardware configuration are done for the distribution network with three protection devices. The overcurrent module that is configured for the practical and non-directional overcurrent protection functions with IDMT for low currents and DMT for high currents tripping characteristics is shown in Figure 6.31 below. Two types of faults are simulated in this network namely the external fault when the fault is at feeder and the internal fault when the fault is at the busbar. Three IEDs used namely: the ABB REL670 and the REB670 on the two outgoing feeders and the RED670 for the incoming feeder.

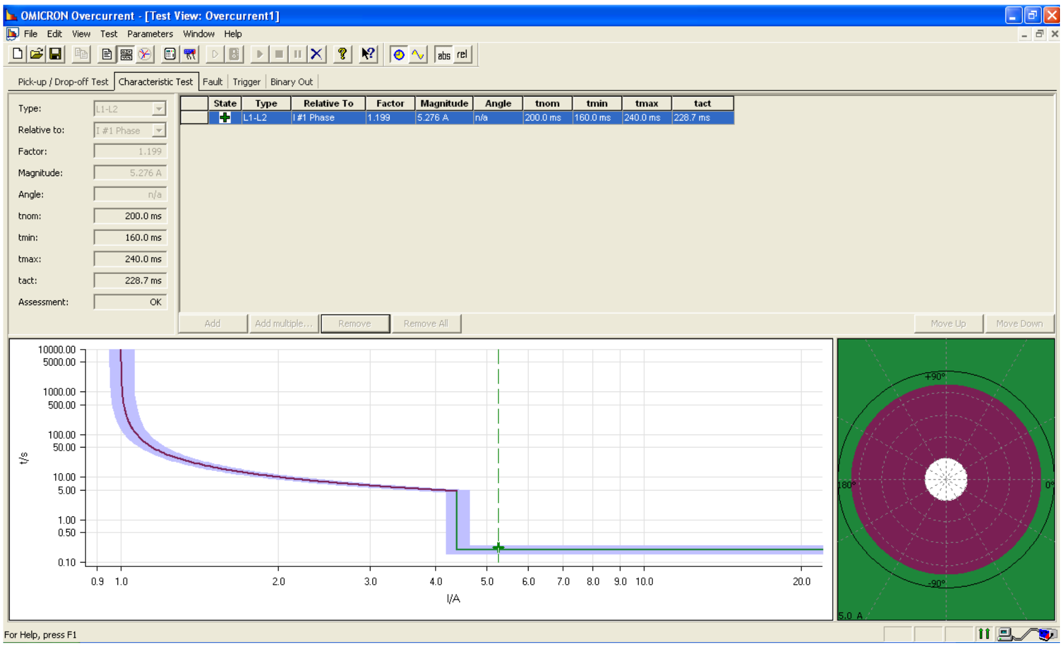

Figure 6.31: **The Overcurrent characteristic programmed in the Omicron software**

6.7.1 Fault on the two outgoing feeders making use of hard wires for communication

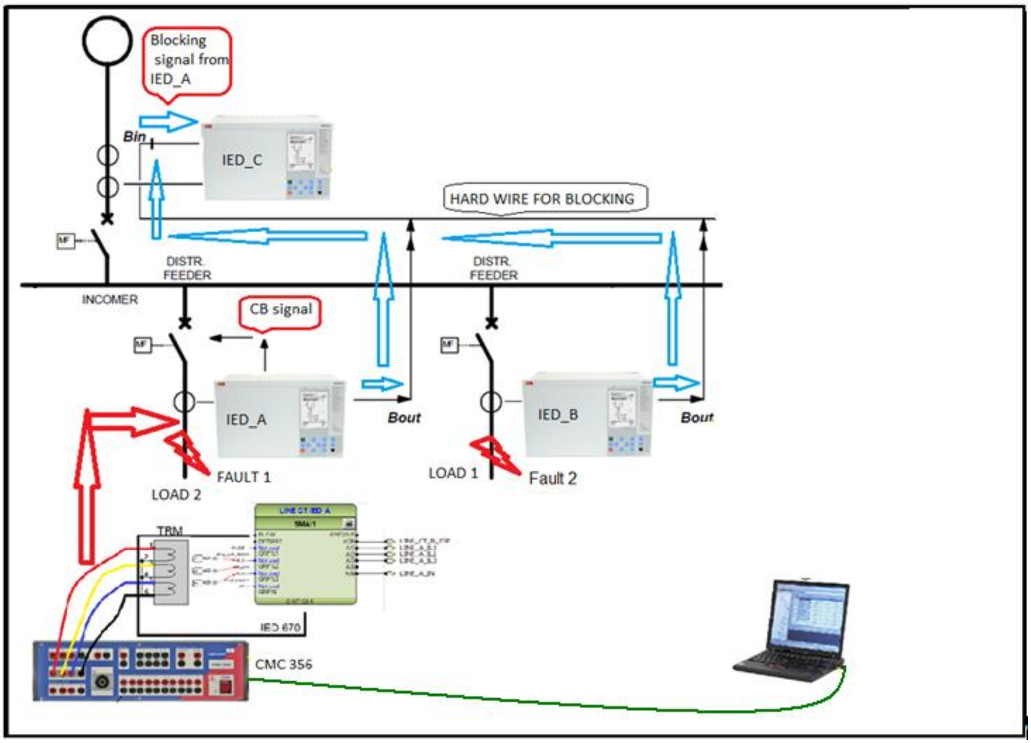

Figure 6.32: **The busbar reverse blocking scheme when the fault 1 is on the line that feeds load 2**

When fault 1 is in the line that feeds load 2 shown in Figure 6.32, the protection function block OC4PTOC in the IED_A and IED_C become active at the same time.The time delays for both protection functions are set differently as shown in Chapter four under Table 6.16 for IED_A and Table 4.25 for the IED_C. The combined output signals LINE_CT_B_I3P of SMAI1 in Figure 6.18 are sent to the input signal I3P of four step phase overcurrent protection (OC4PTOC) function block in Figure 6.19. Then the output signal ST1 of OC4PTOC is active and at the same time activating the protection function of the IED_C shown in Figure 6.25b A signal TOC 1-START is then sent to block the protection block of the IED_C via signal matrix for binary output one (BO1) that is linked to the physical binary output module (BOM_4.BO1) of the IED_A as shown in Figure 6.20. After some time delay based on DMT characteristics the output TR1 in Figure 6.19 is active and sends the signal TOC1-TRIP via the signal matrix for the binary output two (BO2) of Figure 6.20 to physical binary output module (BOM_4.BO2) of the IED_A tripping the breaker open.The next step is to inject the fault 2 on the line that feeds load1 as shown in Figure 6.32 and the same technique as for the fault 1 in load 2 is folowed.

6.7.2 Fault occurs on the busbar B2 making use of hardwires for communication

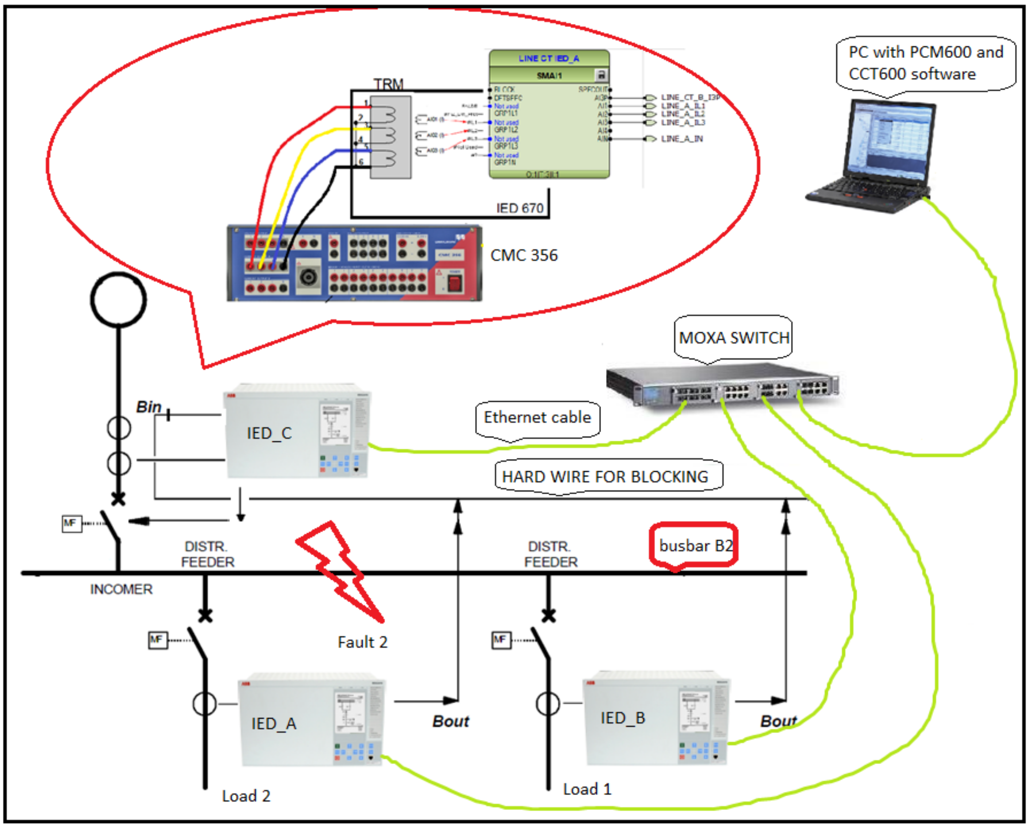

Figure 6.33: **The busbar reverse blocking scheme when the fault 2 is in the busbar B2**

When a fault occures on the busbar B2 in Figure 6.33 an instantanaous tripping is required.In this case output AI3P signals from Figure 6.24 are sent to the inputs of the protection function block on Figure 6.25a. Depending of the type of the fault whether it is a phase fault or earth fault it is sent to PHPIOC or EFPIOC respectively. When it is a three phase fault the signal is sent to instantaneous phase overcurrent protection (PHPIOC) and when a single phase to ground fault the signal is sent to Instantaneous earth overcurrent protection (EFPIOC). Then the signal is processed in these function blocks. The parameter settings are shown in Appendix B. The output TRIP of these protection function blocks are sent to the input of the SMBO block for binary output shown in Figure 6.26.

The next procedure is to develop the GOOSE engineering for that same scheme and later compare the results.

6.8 GOOSE engineering of the laboratory test bench

Once the IEDs configuration is completed in the PCM600 software the next step is to export the project at the substation level of the plant structure as SCD file. This file contains all communication and substation configuration of the IEDs. This file is then imported to the CCT600 software tool to create the IEC 61850 GOOSE messages communication. This software tool is utilized to configure GOOSE communication and is used as a platform for mapping of all the data that is needed for the project. When this GOOSE engineering is completed in the CCT600 software it is again required to export the SCD file from the CCT600 software and to import it back to the PCM600 software .When this is complete GOOSE connection between the used IEDS is required to be done at the signal matrix tool that is found in the PCM600 software. Once this procedure is completed the configuration is written to the three IEDs. The algorithm for this procedure is shown in Figure 6.34 below.

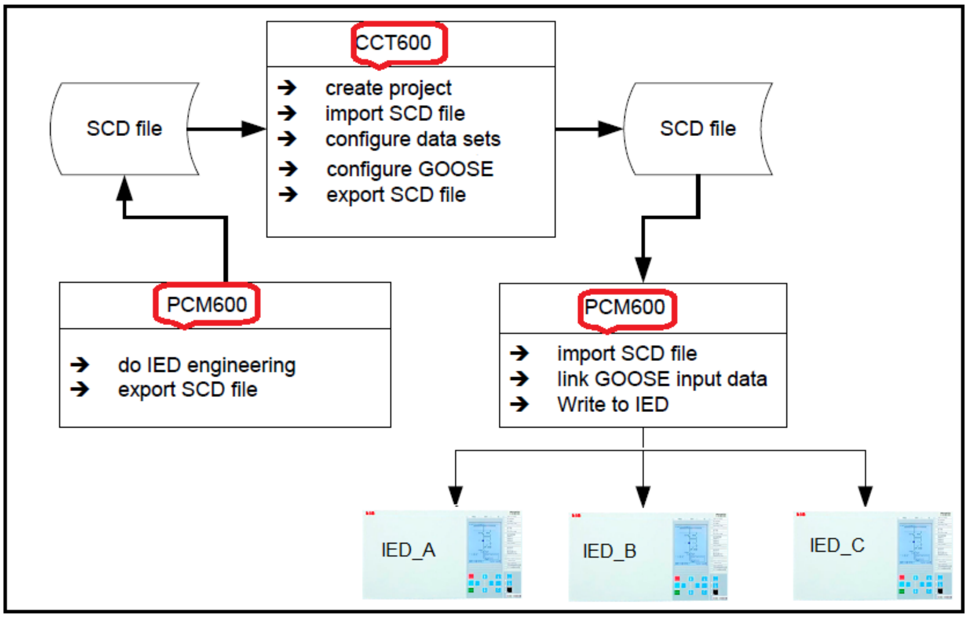

Figure 6.34: **The flow chart algorithm for GOOSE engineering of the laboratory test bench**

6.8.1 GOOSE engineering using CCT600 software tool

After the SCD file is exported from the PCM600 software it is then imported into the CCT600 software. Once the SCD file is imported to the CCT600 software tool the IEDs can be viewed at the project navigator window. At the communication section the IED_C is represented with a technical key AA1J1QO1A1, the IED_B is represented with a technical key AA1QO2A1 and the IED_A is represented with a technical key AA1QO3A1 respectively as shown in Figure 6.35 below

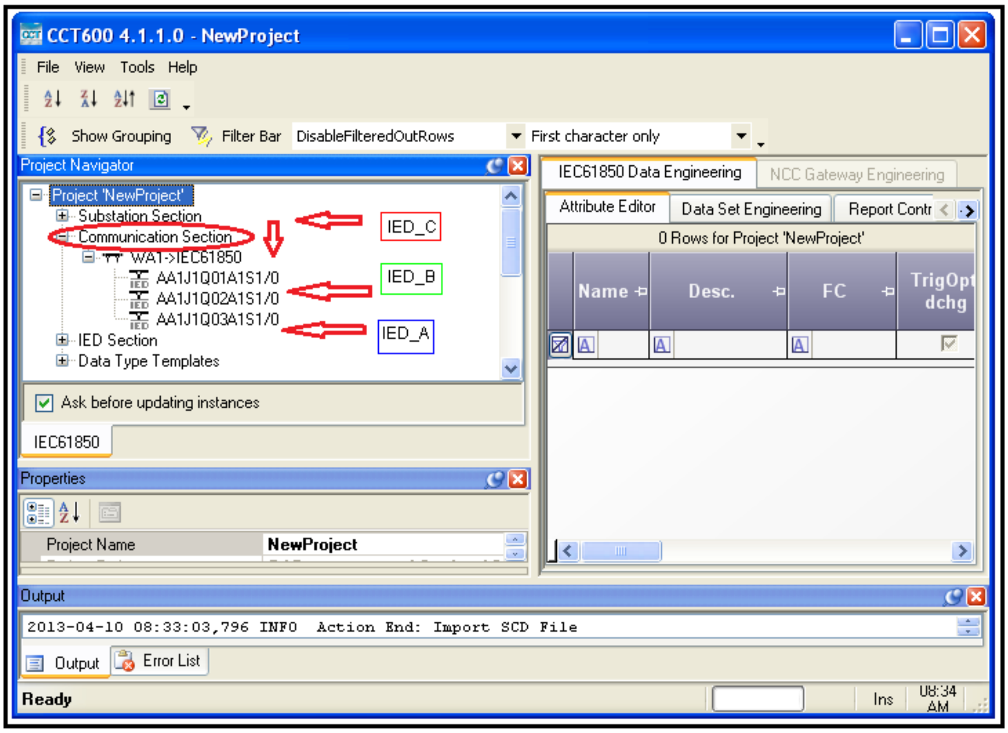

Figure 6.35: The identification of IEDs in the CCT600 software tool

Once all IEDs are identified the next step is to create the data sets under the IEC61850 Data Engineering window that are going to be sent as GOOSE messages by the IEDs. The IED section window as shown in Figure 6.36 is used for housing all the devices that are going to be used.

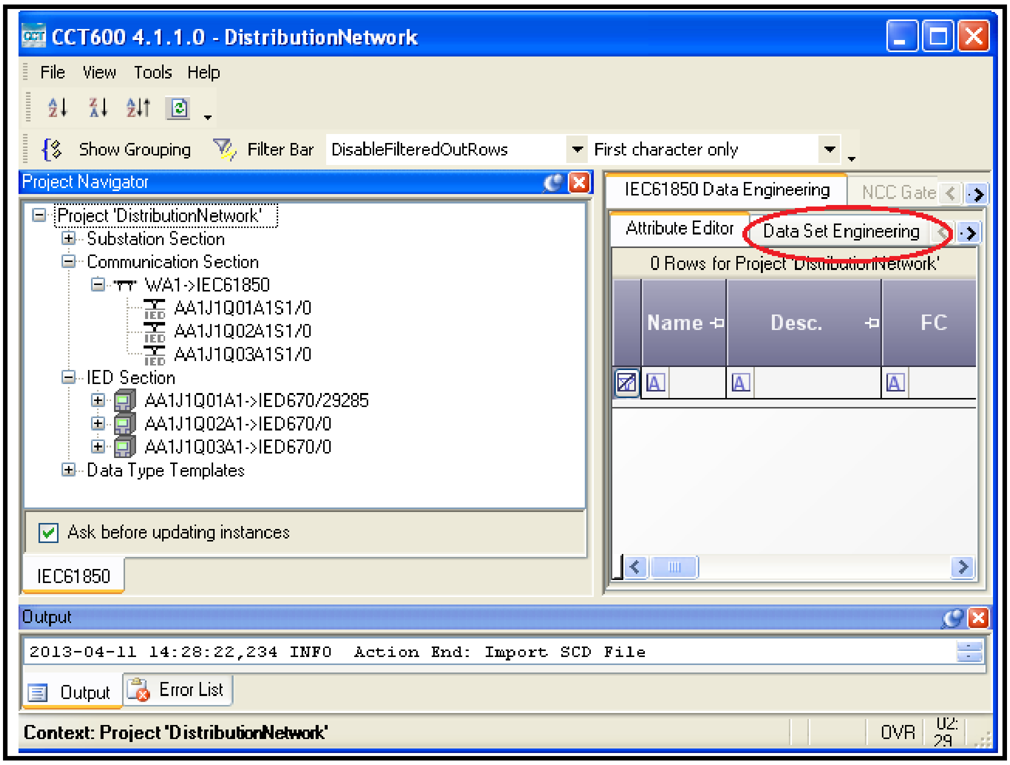

Figure 6.36: The IED section in the CCT600 software tool

The next step is to organize the Logical Devices, Logical Nodes, Data Objects and Data Attributes for the IEDs that are used. This communication section is found under Logical Device (LD) at the Logical Node Zero (LNLLNO). The LN LLN0 is a special LN per LD that contains the DataSets and the various control block inputs coming from the GOOSE messages. The basic mapping and signal engineering is explained in Chapter five. At the IEC61850 Data Engineering window when data set engineering is selected the following columns are completed:

- IED data model
- Data set entries
- Data sets

According to the IEC61850 standard, the information is presented based on a complete path with the following syntax:

- Logical Device (LD)
- Logical Node (LN)
- Data Object (DO)

Each Logical node represents a function and consists of a number of data objects. Each data object is made up by a number of data attributes as shown in Figure 6.37 below. These data objects are staging information signals that are mapped to the station level IEDs. Signal engineering is assigned to choose the requested data objects and link them to the client IED_C as a receiver in this case. Under the LDO there is LLNO/ABBIED670 that is chosen and it does consist of EF4_1EF4PTOC1 that is selected from the IED Data Model.

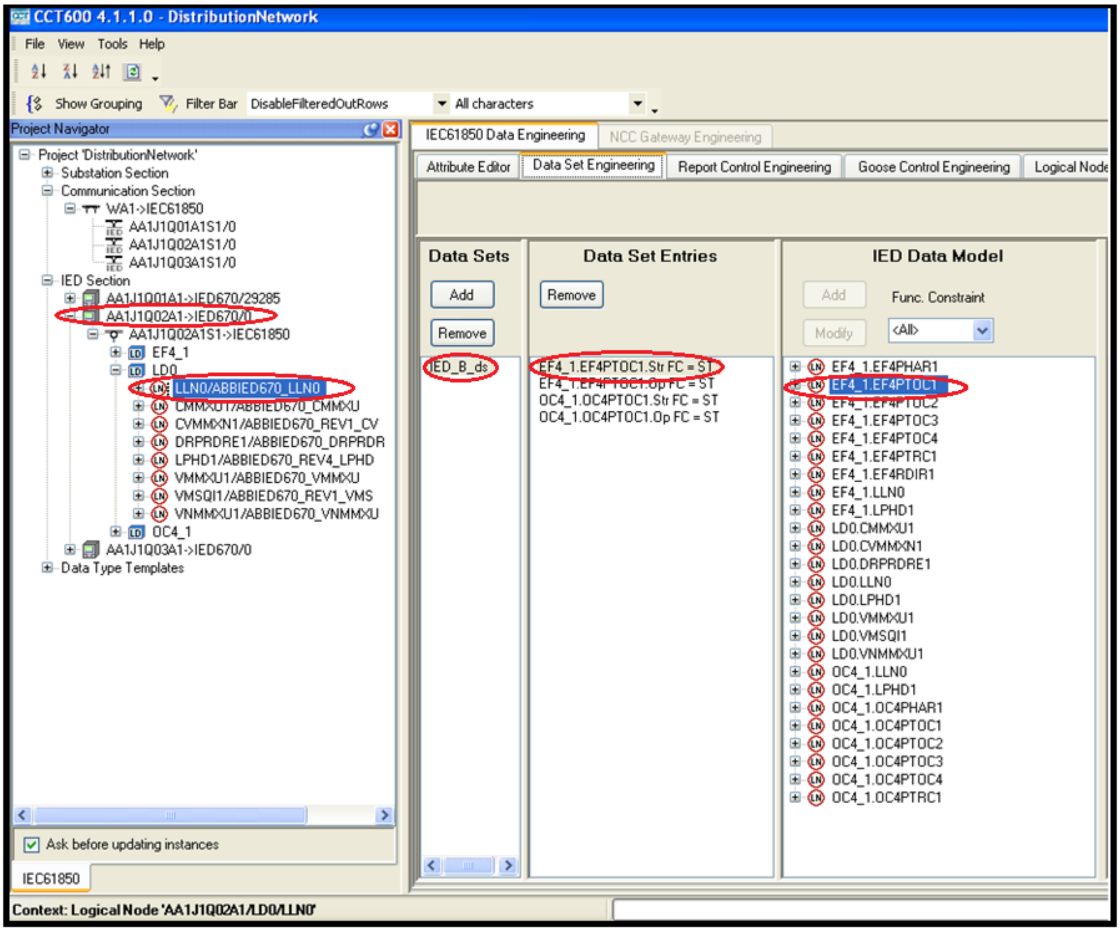

Figure 6.37: The IEC61850 Data sets Engineering for the IED_B

Once the data sets are configured the next step is to do GOOSE control engineering. In order to be able to send GOOSE messages from the IED_A and IED_B to the IED_C, the GOOSE Control Block (GoCB) is defined for the IED_A and IED_B as shown in Figure 6.38 below. This GoCB contains Datasets that carry data objects of data attributes shown in the Figure 6.37 above. When the data attribute triggers changes as a result of a fault, GOOSE messages will be published and IED_C at the incoming feeder is subscribed to them. Therefore all the data sets that are configured for the IED_A will be replicated into the buffer that is going to be sent. The buffer will also contain the actual value and will then be sent as a message. The subscriber which is IED_C will then receive the GOOSE messages including their sequence numbers. Once this configuration of the GOOSE control engineering is completed routing of Information between the IEDs and the GoCB is done.

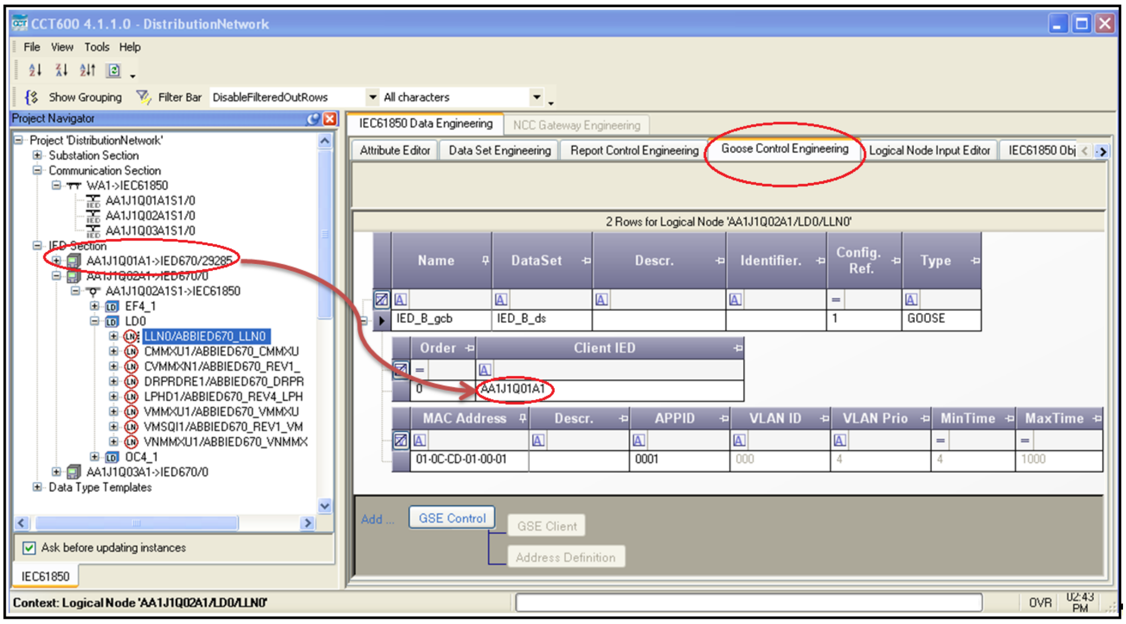

Figure 6.38: The mapping of GOOSE control engineering

The IED_C which should receive the GOOSE message is recognized. This IED has to be described in the engineering state as one that will receive GOOSE messages. It is defined at the LN0 under the structure of the LD in the receiving IED which in this case it is IED_B. This IED is identified as the input. This link is done by drag-and-drop method of the IED icon to the GoCB shown in Figure 6.38.

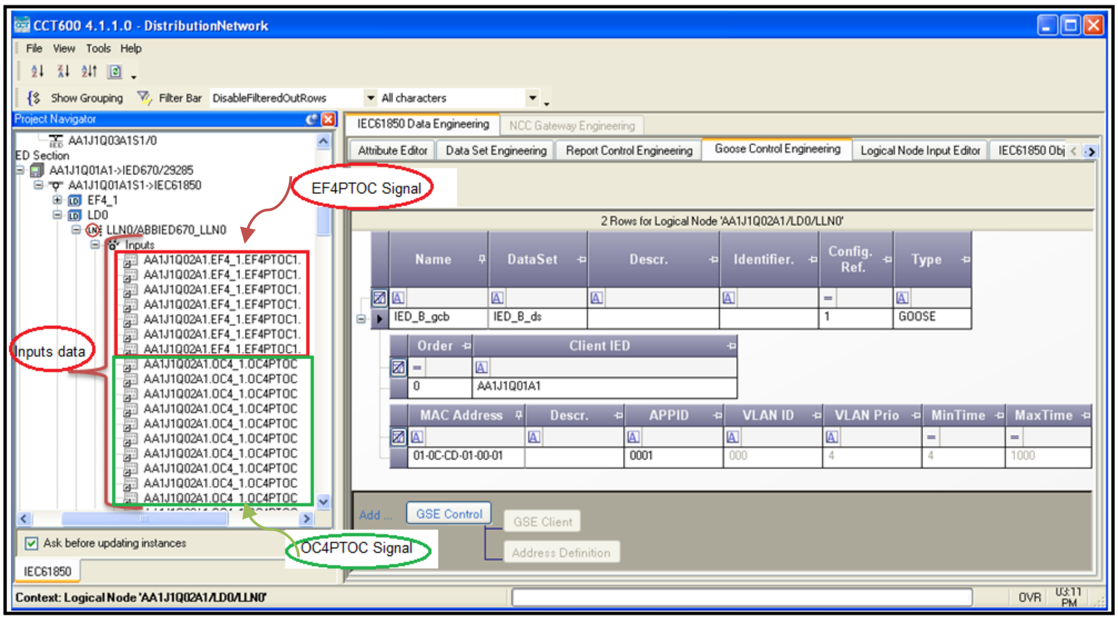

Figure 6.39: The updated data flow inputs

When the linking of GoCB to an IED is completed the next step is to update the dataflow and the output results are shown in Figure 6.39 above. The recorded result shows that the IED_A and IED_B are linked to the IED_C. The next procedure is to export the SCD file from the CCT600 software as shown in Figure 6.40 and then to import it back to the PCM600 software so that the signal matrix for the GOOSE communication is completed.

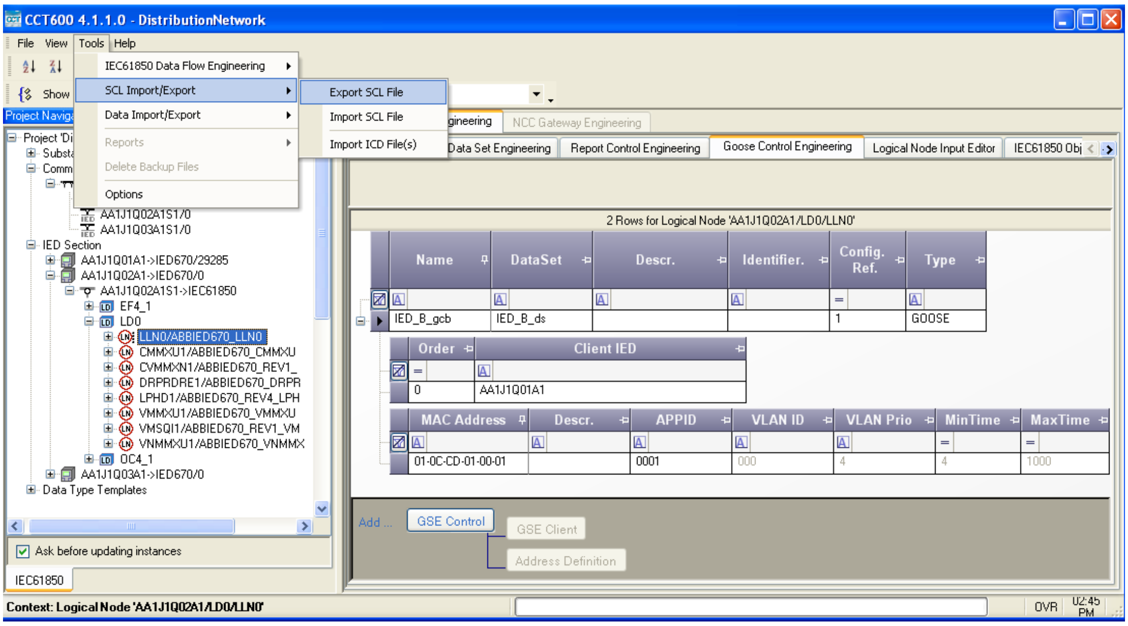

Figure 6.40: **The exporting of the SCD file from the CCT600 software tool**

6.8.2 Signal Matrix Tool (SMT) in PCM600 software used for making GOOSE connection

The SCD file from the CCT600 software is imported to the PCM600 software tool in order to make GOOSE connection. This configuration is done using SMT. When the SCD file is imported to the PCM600 software under SMT a new page is automatically created and it is called GOOSE receive. In this case the page shown in Figure 6.41 represents the GOOSE connection between the IED_C and the IED_B. The output of EF4PTOC function block (START and TRIP) and also OC4PTOC function block (START and TRIP) are sent via GOOSE messages to the IED_C. The same method is used for connection between the IED_C and the IED_A. The configuration is completed and the next step is to send the data to the IEDs.

The two configurations: IED configuration using PCM600 software tool and IED GOOSE engineering using CCT600 software tool are now implemented. The next step is to run the reverse busbar blocking scheme using the laboratory test bench and to record the results.

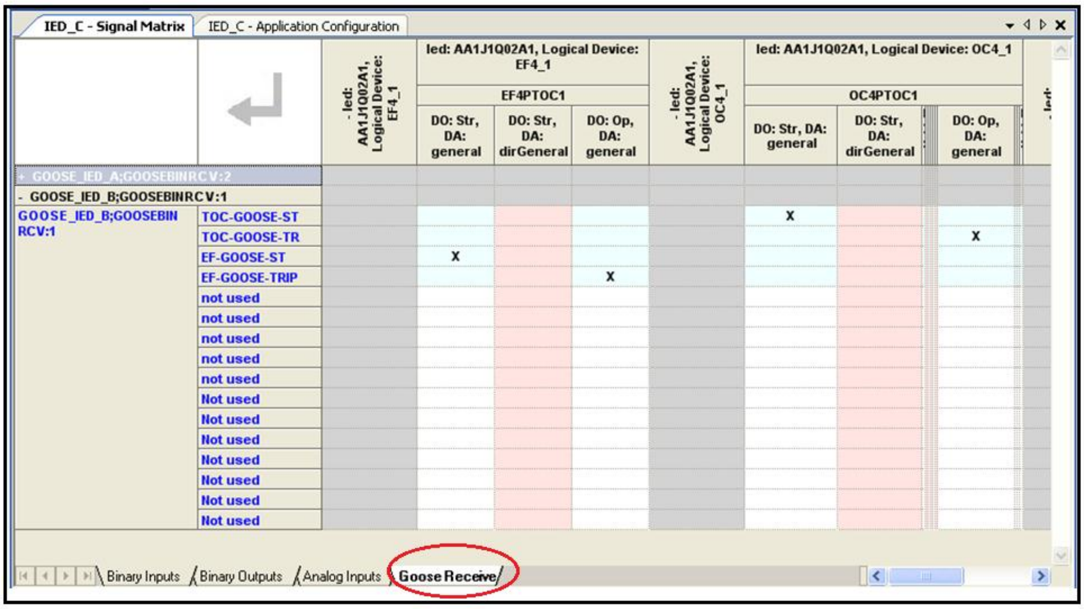

Figure 6.41: The representation of the signal matrix tool in PCM600 software

6.9 The operation of the protection scheme based on GOOSE communication

6.9.1 Fault on one of the two outgoing feeders where the IED_A and the IED_B are used for protection

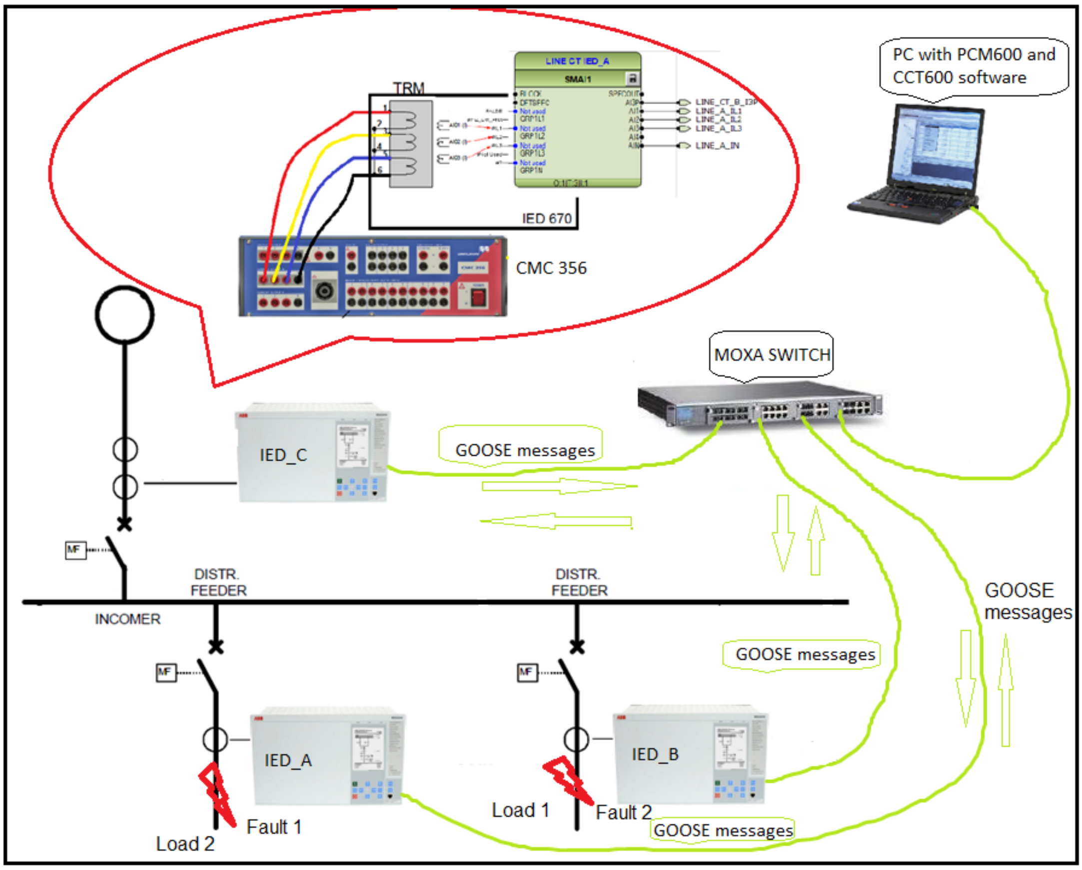

Figure 6.42: The simulated faults in one of the two outgoing feeders

In a case where a three phase fault occures on the line that feeds load 2 in Figure 6.42 the protection function blocks OC4PTOC at the IED_C and IED_A become active at the same time. The time delays for both protection functions are set differently.The parameters for the time setting are shown in Chapter four under Table 6.16 for IED_A and Table 4.25 for the IED_C. A TOC1-START signal of the IED_A from Figure 6.19 is sent to the input of the GOOSEBINRCV function block in Figure 6.28. Then this fuction block generates an output signals TOC1-START-IED_A and OUTIVAL1-IED_A that is sent to a logic AND gate as shown in Figure 6.29.This logic block then generates an output signal TOC-GOOSE-START-IED_A and sends it to the logic OR gate shown in Figure 6.30a for reverse blocking.This logic gate then generates an output signal called GOOSE-BLOCK and sends it to the input of the logic gate for OC4PTOC as shown if Figure 6.30b.This logic OR gates generates OC4PTOC-BLOCK signal sending it to the input of the protection function OC4PTOC shown in Figure 6.25b in order to stop it from operating. After the chosen delayed time from the OC4PTOC in Figure 6.19 a signal TOC-TRIP is genetated via the signal matrix for the binary output two (BO2) to the physical binary output module (BOM_4.BO2) of the IED_A tripping the breaker open. When the single phase to the ground fault occurs the same algorthims as for the three phase fault is used. The only difference is that the EF4PTOC is used for protection. If the OC4PTOC block in Figure 6.19 does not operate or clear the fault at the given time the OC4PTOC block in Figure 6.25b will sent a trip signal to open the breaker at the incoming feeder shown in Figure 6.42.The same algorithm is implemented when the fault occurs on line that feeds load 1 where the IED_B is installed. The results shown later are only focusing on the IED_B.

6.9.2 Fault at the busbar B2 where the IED_C is used for protection

When a three phase fault is issued at the busbar a selectivity scheme configured for the IED_C in the incoming bay provides high-speed protection making use of the fast instantaneous tripping element. In this case none of the IEDs on the outgoing feeder picks up or sees this fault. Therefore no blocking signal will be issued as shown in Figure 6.43. The results are recorded and analyzed for this experiment

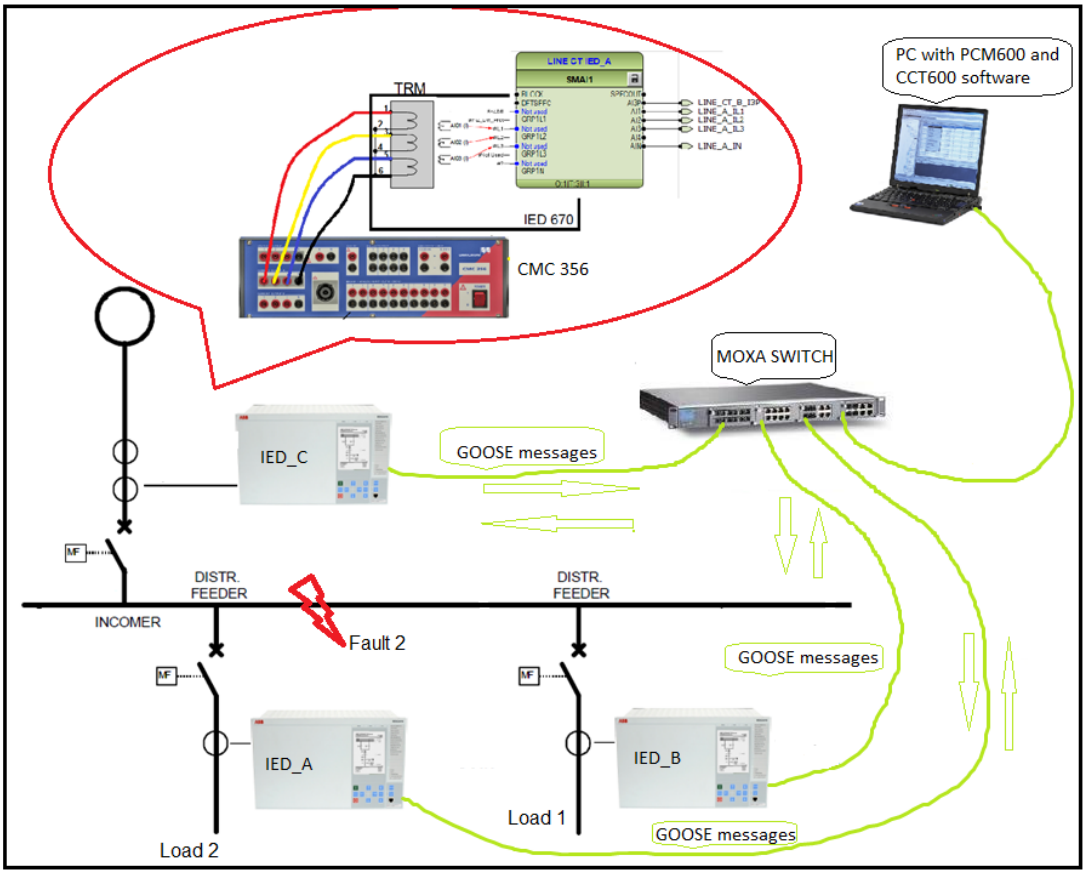

Figure 6.43: The simulated fault on the main intake busbar

6.10 Practical experiment results

6.10.1 Results for the fault at the outgoing feeder

For this lab-scale implementation a three phase fault current of 15717.25A is injected to the outgoing feeder where IED_B is installed with settings shown in Appendix B. The IED_B with the DMT characteristics parameters as explained in Chapter four START and sends block signal to the incoming IED_C with a delay of 0.2 seconds for a TRIP signal to open the breaker that is sitting in the outgoing feeder shown in Figure 6.44 below. The IED_C sitting at the incomer bay is blocked until the operation of the IED_B is complete. In a case where the IED_B does not trip the IED_C will trip the breaker that is situated on the incomer bay.

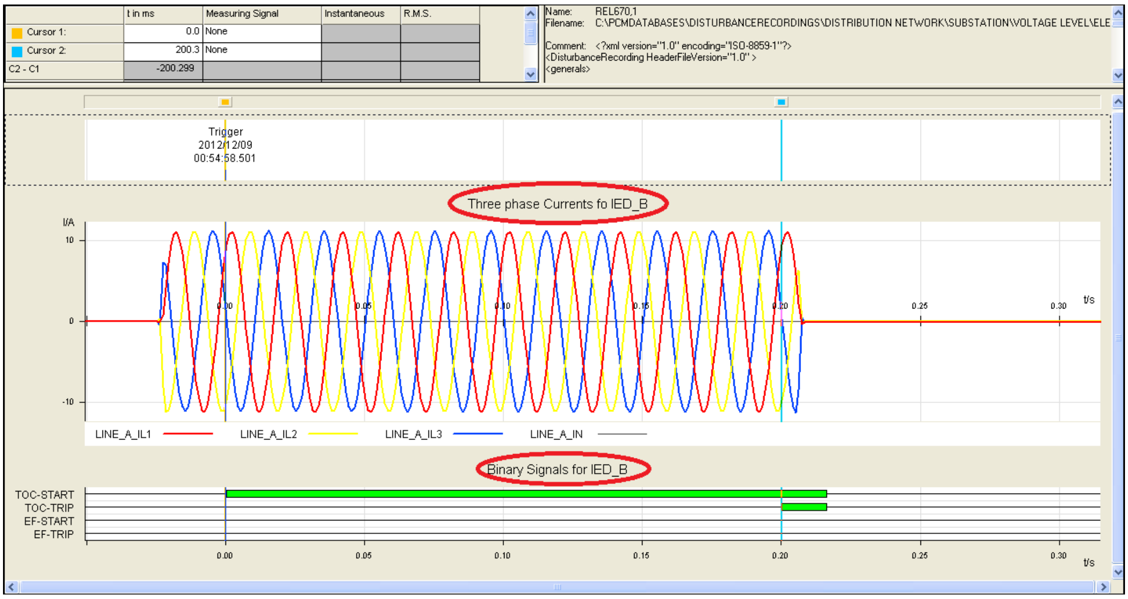

Figure 6.44: **The three phase fault at the outgoing feeder where the IED_B is installed**

6.10.2 GOOSE communication vs Hard-Wired (HW) connection

There are two types of tests implemented. One is that the IED_C is linked with the IED_B and the IED_A via hard wire (the normal traditional method) and the second one where IED_C is linked with the IED_B and the IED_A via an Ethernet cable using a GOOSE based method where GOOSE messages are used to block the fast overcurrent element of the IED_C from operating. The objective for this task is to measure how fast the IED_C protection overcurrent element can be blocked in the event where a fault occurs on the outgoing feeders. In order to achieve this objective a minimum operating time for the high-set overcurrent protection for the IED_C needs to be set properly. The results shown in Figure 6.45 is the time taken by the blocking signal that is sent by the IED_B sitting on the outgoing feeder to the IED_C sitting on the incomer feeder. From the moment the IED_B is triggered the GOOSE BLOCK signal represented in blue in Figure 6.45 is sent to the IED_C with no time delay and the hard wired BLOCK signal, represented in red, is delayed by 24.2 ms as shown below.

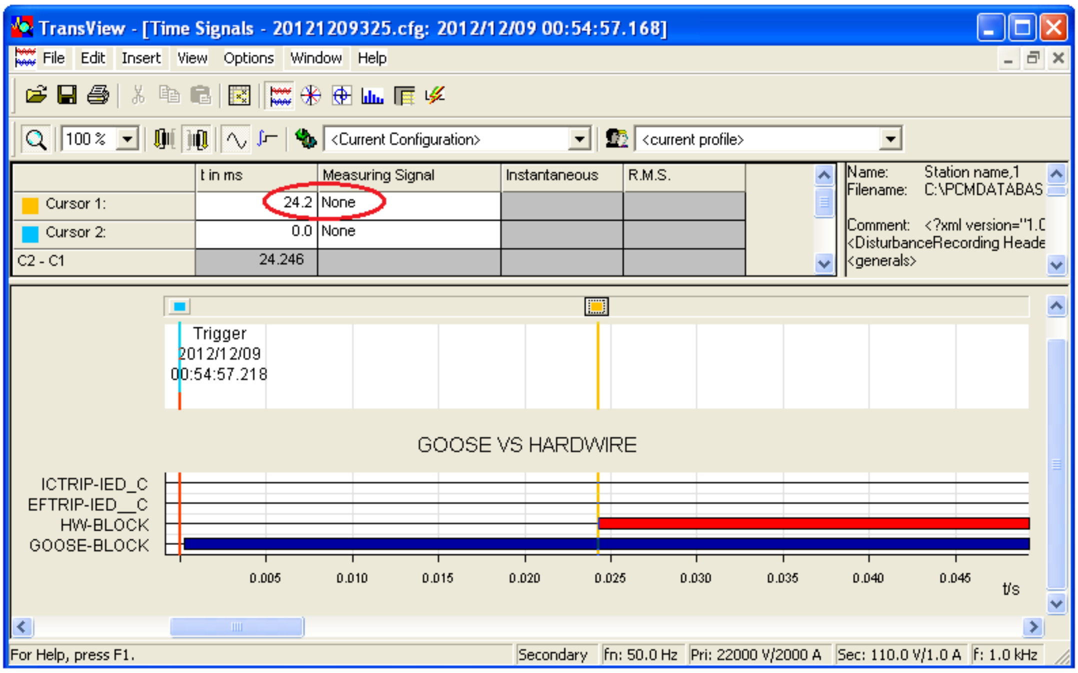

Figure 6.45: The results for Ethernet cable using GOOSE messages and hardwired connection between IEDs

The results recorded when both blocking signals were already sent to IED_C are shown in Figure 6.46. In this case the GOOSE BLOCK represented in blue shows the binary signal measured to see how long it took before the TRIP signal is issued by IED_B at the outgoing feeder. It can be seen that the GOOSE message took 216 ms delay from time when IED_B was triggered which is correct base on the DMT characteristic that was selected for the IED_B.

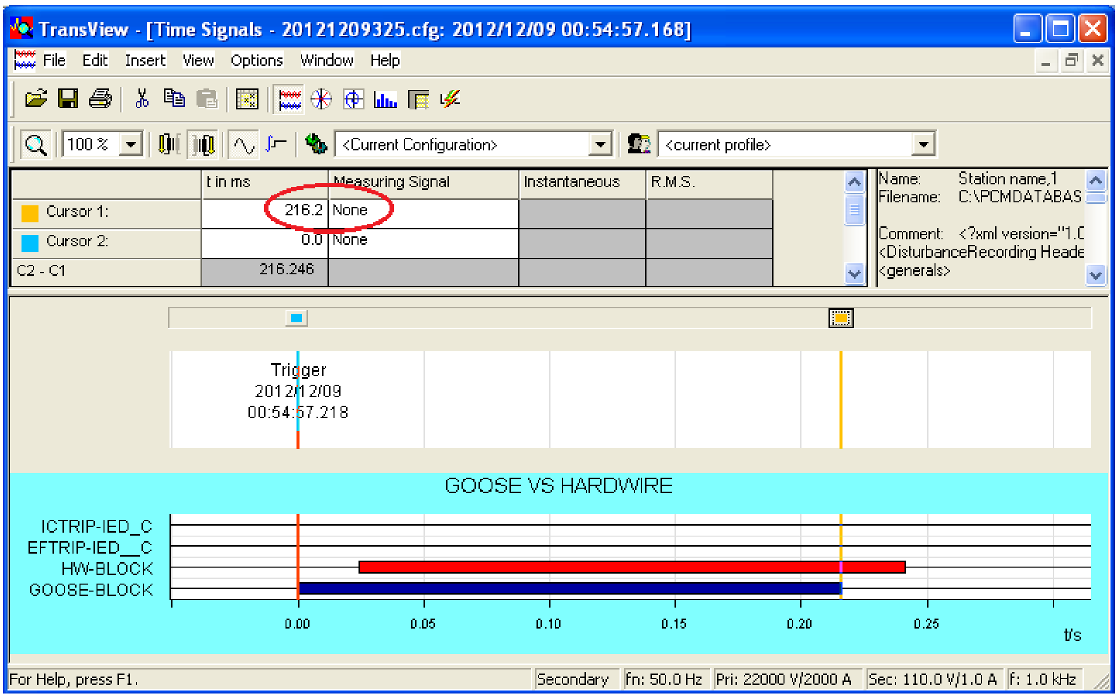

Figure 6.46: The results for the time measurement taken by the GOOSE BLOCKING binary signal.

In Figure 6.47 the HW BLOCK represented in red shows the binary signal measured to see how long it took before the trip signal is issued by the IED_B at the outgoing feeder. The result shows that the HW BLOCK signal took 240.8 ms time delay and based on the DMT characteristic set for the IED_B the time delay is increased by 40 ms. In a case where the fault is at the feeder where the IED_A is installed the same procedure is implemented. Therefore the practical results are not documented.

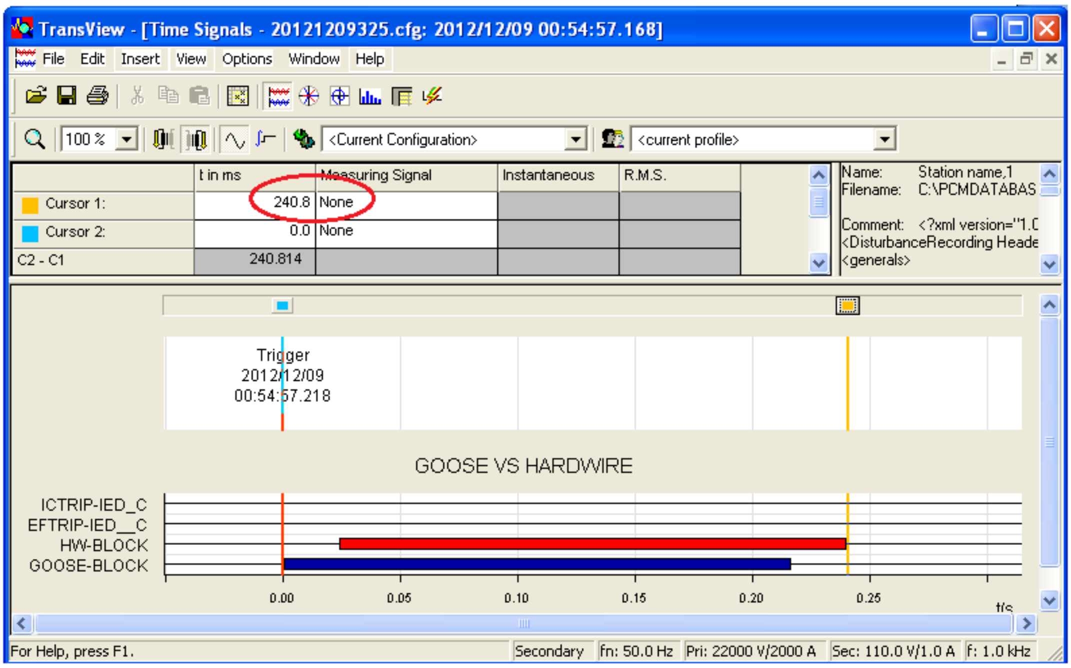

Figure 6.47: **The results for the time measurement taken by the the WH BLOCKING binary signal**

6.10.3 Performances of the hardwired and GOOSE solution for a fault in the outgoing feeder

There are three main issues that create time delay when the hardwired protection communication is performed, namely:

- The output circuitry delay
- The input handling and filtering time
- The application cycle time

GOOSE has more advantages when it comes to signal time delay. It also simplifies the wiring of the system. By mean of horizontal communication the response time from a device to a device is improved. These factors shown above were taken into consideration when hardwire was implemented and the details of the results are discussed later in the chapter.

The Figure 6.48 shows the behavior of a three phase analog currents when a fault is applied at the busbar B2. The fault current of 17194.22 A is injected into the busbar and the instantaneous tripping element configured in the IED_C took 24 ms to trip. In this case the IED_C is only used for tripping for the fault on the busbar B2 also known as internal fault.

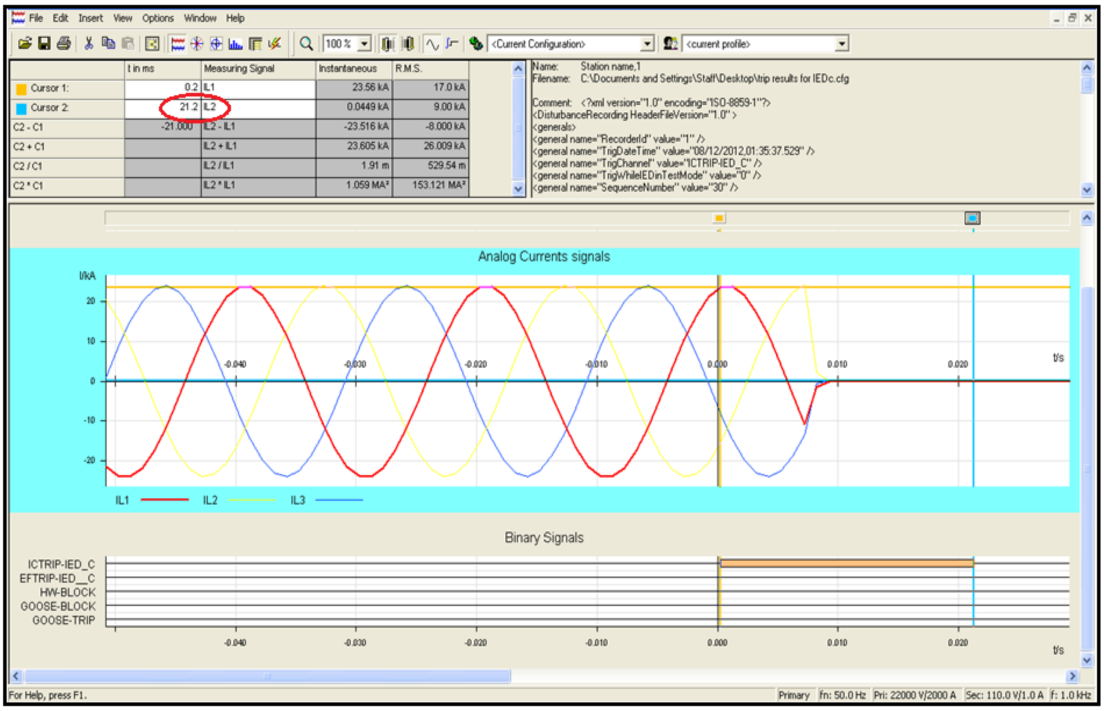

Figure 6.48: **The results obtained for three phase fault on the busbar B2**

6.11 Discussion of the obtained results

The results obtained in Chapter four which were done by a DigSILENT software simulation have been proven in this chapter practically. Although there were few factors that introduce constrains example the software simulation had built in circuit breakers and therefore it was simpler to get the accurate operating time for the full complete scheme. On the other side in the DigSILENT software based simulation the GOOSE communication could not be implemented. The communication between devices via GOOSE was only done on the practical implementation of the busbar protection scheme. The communication system between the protection devices is successfully configured and desired results are obtained. The traditional protection scheme for the busbar where hardwire is used to link the protection devices is investigated and the three factors that create constrains and time delays in the scheme operation are evaluated. The first factor is the delay made by the auxiliary power supply energising the path for signalling. This delays it typically 24 ms in this case. The second delay is the time taken for filtering and handling the input signal coming from another IED. Usually when the power is connected to the contactors an electromagnetic disturbance creates a spark and therefore an additional filter is needed and this creates another time delay. When the GOOSE messages are used for horizontal communication all these problems are solved. For a signal to be sent from one protection device to another one through the binary modules of the IEDs there is no need of auxiliary power supply and therefore no delay is created. This way of communication also simplifies the wiring and signalling of the system. The lab test bench developed for thesis is able to improve the speed and reliability of the protection scheme making use of GOOSE messages for communication.

6.2 Conclusion

The GOOSE services that are used reverse blocking in the busbar protection scheme are implemented. The effectiveness of using the IEC61850 standard for protection is discussed and analyzed. The IEDs configuration is successfully achieved with an assistance of the PCM600 software tool. The GOOSE engineering for the IEDs was also achieved successfully. The new approach of replacing the traditional conventional hard-wired blocking signals between the protection devices with an Ethernet LAN for GOOSE communication was proven to be successful. The operational speed was improved by using the GOOSE messages, when compared to the operational speed of the hardwired blocking signal for the busbar protection scheme. The reliability of the busbar protection system is also improved. The new method furthermore creates flexibility for future improvement of the protection schemes. It means that it provides the system to be easily extended and also reconfigurable for different network topologies. The test bench will be utilized for training of students and employees from utility companies that are in the protection field. It can be used as the platform to perform different schemes and to test the performance of GOOSE communication between the IEDs.

The next chapter focuses on conclusions, deliverables, and recommendations for the future work on busbar protection schemes at distribution levels.

CHAPTER SEVEN

CONCLUSION AND RECOMMENDATION

7.1 Introduction

Busbars are the most important components in the distribution networks. Faults on the busbar are uncommon, however an occurrence of a busbar fault can lead to a major loss of power. Busbars are the areas in a substation where the levels of current are high and therefore the protective relay application is very critical. Most circuits in the power system are connected to the busbars and therefore a sufficient protective system is required to protect their protection. In order for the protection scheme to be successful it is important to carry out the following specifications: Selectivity, Stability, Sensitivity, and Speed. To meet all of the above requirements protection must be reliable, meaning that the protection scheme must trip when called up to do so (dependability) and it must not trip when it's not supposed to (security).

The thesis focuses on the reverse blocking busbar protection scheme with aim to improve the speed of its operation and at the same time to increase operational reliability, flexibility and stability of the protection during external and internal faults by implementation of the extended functionality provided by the IEC61850 standard-based protective IEDs. The practical implementation of the scheme by the use of IEC 61850 standard communication protocol is investigated

The research analyzes in detail the reverse blocking busbar protection scheme that is used at the moment in the power systems and it develops an improved IEC 61850 based reverse blocking busbar protection scheme for distribution networks. The proposed scheme is modeled, set up as well as simulated using PCM600 and CCT600 softwares and implemented in a protection laboratory test bench environment.

This Chapter summarizes the results obtained the key findings and the thesis deliverables. The deliverables of the thesis are presented in part 7.2. Part 7.3 describes the possible academic, research and industry applications of the thesis deliverables. The future research work in the field of busbar protection for distribution systems is proposed part 7.4. Part 7.5 gives reference of the paper sent for publication.

7.2 Deliverables

In power systems the digital protection for the busbars in a distribution level has been neglected for a long time when compared to other protection. The need for digital protection for busbar has been discussed and solved by the implementation of the principles of the IEC 61850 standard in the thesis chapters. The deliverables of the thesis are as follows:

7.2.1 Literature review

The literature review presented in chapter two began its analysis on the various techniques used for the busbar protection. It also looked at the history of the busbar protection in power systems. Digital algorithms for busbar protection schemes in terms of speed, stability, security and dependability have been reviewed. A wide-range review of various works completed in the field of the busbar protection is also presented and different types of busbar protection schemes are analyzed. Traditional busbar protection using conventional protection devices has been also reviewed. The review also has focused on the development of the modern Intelligent Electronic Devices (IEDs) and more especially on the communication used in the substations.

7.2.2 Analysis of the busbar protection theory

The short description of the busbar theory developed for distribution networks is done in Chapter three paying attention to the protection schemes currently in use and to the overcurrent protection conventional and digital devices.

7.2.3 Construction of the distribution network

A model of a typical distribution network is developed and simulated. A radial distribution network was constructed for medium voltage (MV) and low voltage (LV) in Chapter four. This construction showed all buses, generation, transformer, network connections, cable interconnection, and loads. The distribution network was used for the load flow study. This load flow focused on determining voltage magnitude, voltage angles of the nodes, including the active and reactive power flow on all branches. For the load flow study a calculation methodology is applied in order to be able to specify fault ratings for the electrical devices that are used for protection.

7.2.4 Calculation of the short circuit impedance for all relevant components of the considered distribution network

Each component in the network was calculated for short circuit impedances using the collected parameters. The elements in the network were later represented by equivalent impedance for a balanced system

7.2.5 Reference of all impedances to the reference voltage

Since the network had the multiple voltage levels the impedances of the components that were calculated earlier were converted to a reference voltage. In Chapter four this was done in order for them to be implemented in a single equivalent circuit in the software environment of DigSILENT.

7.2.6 Short circuit calculations

The short circuit currents were calculated for all system parameters in Chapter four. The short circuit currents were applied to the network to check the rating of the equipment in the network during the planning stage. In this thesis the investigations focused on maximum expected currents and the minimum expected currents to manage the design for the protection scheme. For maximum currents a three phase fault was implemented on the network. For the minimum currents a single phase to ground fault were implemented in the network. The investigations were done by simulations in the DigSILENT software environment.

7.2.7 Design of the parameters and settings of the protection devices and the protection scheme investigation by simulation

The obtained short circuit currents were used to design the settings of three ABB conventional and three IEC 61850 standard compatible relays to be used for building of two study cases of the reverse blocking protection scheme in Chapter four. Operation performance of these schemes was investigated by simulation in DigSILENT for various types of faults. The results from simulation were analysed and compared. Conclusion was that the design and performance of the scheme is according to the requirements and the expectations.

7.2.8 Analysis of the application of the IEC 61850 standard to the process engineering of the ABB IED 670 series

ABB IED 670 series were selected for the implementation of the reverse blocking protection scheme Implementation of the various parts of the IEC 61850 standard in the ABB IED 670 series is described and analysed in Chapter five in order to be used further for the implementation of the reverse blocking protection scheme

7.2.9 Development of the Laboratory test bench

A laboratory test bench was developed and built to investigate and compare conventional hard-wired and GOOSE communication-based blocking signals. A distribution busbar reverse blocking scheme was designed and implemented for the laboratory test bench. This test bench was utilized to improve the performance and reliability of the busbar reverse blocking scheme at the distribution level. The same power network used in Chapter six is used for these practical studies.

A non-directional time overcurrent ABB IED 670 series were used for protection implementation. One relay was placed at the main incomer on the secondary side of the transformer, named (Relay C), another relay named (Relay A) was placed at the outgoing feeder A and the other relay named (Relay B) was placed on the outgoing feeder B. A CMC 356 Omicron test device to inject the fault currents, a MOXA PowerTrans PT-7728 switch to build the communication structure, a PC for setting up of the relays, and a DC power supply were used. All experiments were done using the laboratory test bench. Description of the trainer is given in Chapter six.

7.2.10 Design and implementation of the protection scheme

This thesis used PCM600 software tool for engineering configuration of the IED. This tool supplies functionalities that are useful for all IED control and protection applications. In the thesis it is utilized to manage protection and control of the ABB IEDs. For IEC 61850 standard communication CCT600 software is applied. The description on the block functions that were used to design the protection scheme is presented in Table 7.1

Table 7.1: **The block functions used for busbar reverse blocking scheme**

Function Blocks	Description
SMAI	Signal Matrix Analog Input is a preprocessed function block used for analog inputs signals that needs to be linked to the IED
SMBI	Signal matrix for binary inputs is a function block used for representing the path for the binary input signals into the intelligent electronic device (IED) for configuration
SMBO	Signal matrix for binary outputs is function block used for representing the path for binary outputs signals
PIOC	Instantaneous phase overcurrent protection is a function block having a discrete Fourier filter (DFT) system for pre-processed sampled phase currents
EFPIOC	Instantaneous residual overcurrent protection is function block have a DFT system for pre-processed sampled residual currents
OC4PTOC	Four step phase overcurrent protection block having four protection sub-functions with the same algorithm but working with different time and current values according to the measured current signal. It uses phase currents that are preprocessed in a DFT block This DFT block creates RMS values by using fundamental frequency of the phase currents.
EF4PTOC	Four step residual overcurrent protection block having four steps each with various protection characteristics It is used for phase-to-earth faults
CVMMXU	Measurement function used to calculates the quantities (P, Q, S, I, U and F)
CMMXU	A function block used for measuring phase current

VMMXU	This function block used for measuring the phase - phase voltages
A1DADR	This function blocks is used for disturbance report for analog signals
B1RBDR	This function blocks is used for disturbance report for binary signals
GOOSEBINRCV	Goose binary receive function block is use for receiving signals to and from the other IEDs via the interbay bus

The algorithms of the reverse blocking protection scheme based on hard-wires or Ethernet GOOSE communication given in Chapter six are shown in Figure i and Figure ii respectively.

7.2.11 Implementation of the reverse blocking protection scheme using hard wires for transfer of the blocking signals between the IEDs

The three used ABB IEDs were connected according to the scheme using copper wires for transfer of the blocking signals between the relays. The CMC 356 Omicron device was used to inject currents for the following faults:

- Single phase to ground fault on line (B2 to B4) for relay A
- Three phase fault in line (B2 to B4) for the relay A
- Single phase to ground fault in line (B2 to B3) for the relay B
- Three phase fault type at line (B2 to B3) for relay B
- Single phase to ground fault at the busbar B2 for the relay C
- Three phase fault on the busbar B2 for the relay C

The carried out activities for these faults were divided into two part namely internal fault where the fault is at the busbar and external fault where the fault is at the outgoing feeders. The fault response values were described in Chapter six. This method of communication created time delay in transmitting the signal from the sending device to the receiving devices. The delay came from the time taken by the auxiliary relays from picking up and dropping off when the signal had to be sent from the binary output of the sending device to the binary input of the receiving device.

7.2.12 Implementation of the reverse blocking protection scheme using Ethernet GOOSE communication

The reverse blocking busbar protection was implemented by introducing Ethernet communication between the IEDs. The same procedure of the experiments done for the hardwired communication between the IEDs in the busbar reverse blocking scheme was followed. The only difference is that internet cables were used instead of using copper wires. The fault response values were described in Chapter six. In this case the response times obtained are smaller.

7.2.13 Comparison of the operation of the hardwired and Ethernet communication based reverse blocking protection schemes

Speed operation of the two protection schemes were compared for the applied faults.

The new approach of replacing the traditional conventional hard-wired blocking signals between the protection devices with an Ethernet LAN for GOOSE communication was proven to be successful. The operational speed was improved by using the GOOSE messages, when compared to the operational speed of the hardwired blocking for busbar protection scheme. When it came to flexibility the relays had major disadvantages when compared to the IEDs.

Utilization of the new digital technology allowed the traditional reverse blocking schemes to be considerably improved in terms of operational speed. The new digital protection also offers an increase of flexibility and operational reliability. This is achieved by introducing Ethernet communication network using GOOSE messages between the IEDs. This method allowed the blocking signals to be sent directly from one IED to another IED without any additional delay created by the auxiliary relays.

7.3 Academic/Research and Industrial Application

The research work on the thesis leaded to development of a laboratory test bench where students can learn and understand the basics of protection principles. The test bench is developed in such a manner that it can be flexible for future protection applications. The researchers can also utilize this test bench for understanding the protection dynamics for distribution networks in power systems.

The test bench was used for demonstrations at the national seminar on the IEC 61850 standard developments and applications organized by the Centre for Substation Automation and Energy Management systems of the Department of Electrical Engineering. The test bench will be used in future for providing of hands-on courses for the engineers and technicians. Another application will be for testing and development of protection schemes for different industrial projects.

7.4 Future work

The project only focused on a network that has one incomer source and therefore non-directional method for overcurrent protection was used. For future research it would be interesting to investigate the performance of the protection scheme where a network consists of more than one incomer source. Another possibility for a future work is the comparison of the IEC 61850 standard-based differential protection scheme of a distribution network with the IEC 61850 standard-based reverse blocking scheme for the same network in terms of cost-effective and speed performances. In the industry the IEDs used in this project are mostly utilized for the transmission level protection in the power system network, although the protection elements are applicable at a distribution level. The ABB IED REF615 is produced for applications at the distribution level and another possibility is to implement the reverse blocking scheme using this IED.

The thesis focused more on the protection functions than on the control functions in the power system. Therefore for future research, the control of circuit breaker and other relevant component by having bay controller device from where all the control action are implement would be beneficial for the scheme operation.

Time synchronization for the lab scale system developed in this thesis used a method where the IED_C on the incomer is acting as a master NSTP-server and the other two IED_A and IED_B on the outgoing feeders are slaves synchronized with the master by completing the IED_C's IP address into them. In term of accuracy it is not as good as using GPS satellite clock. For future it will be beneficial to use the GPS satellite clock for time synchronization because of its accuracy.

The protection scheme developed in this project focussed only on ABB IEDs vendor and therefore interoperability is not implemented. Utilization of different vendors of IEDs for the scheme implementation would benefit the students to understand interoperability problems between the joint work of the different vendors IEDs.

7.5 Publication

Mnguni M, R. Tzoneva (2013) Comparison of the operational speed between conventional hard-wired and IEC 61850 standard-based implementation of the reverse blocking protection scheme for distribution networks, Sent to Journal of Electrical Engineering and Technology (JEET), December 2013.

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APPENDIX A

IED FUNCTIONS AND CONFIGURATION SOFTWARE TOOLS PCM600 AND CCT600

A.1 Introduction

The major concern for protection in the power systems is to assure continuous stability and reliability of the system operation. The ideal approach to understand protection in the power systems is by creating a lab test bench where simulation and emulation studies are implemented. In this Appendix A a detailed application description of the protection software tools and a list of function blocks, input and output signals as used in the test bench is done. The software tool package used for the IED configuration and all ABB 670 series function blocks that are used for the project are described. The blocks are presented grouped in different categories according to their functions.

A.2 Protection and control IED manager tool (PCM600)

The tool supplies functionalities that are useful for all IED control and protection applications. This tool is utilized to manage protection and control of ABB IEDs. It is also used for communication configuration, application and disturbance handling. The PCM600 tool consists of five main windows for viewing different functions as shown in Figure A.1 below

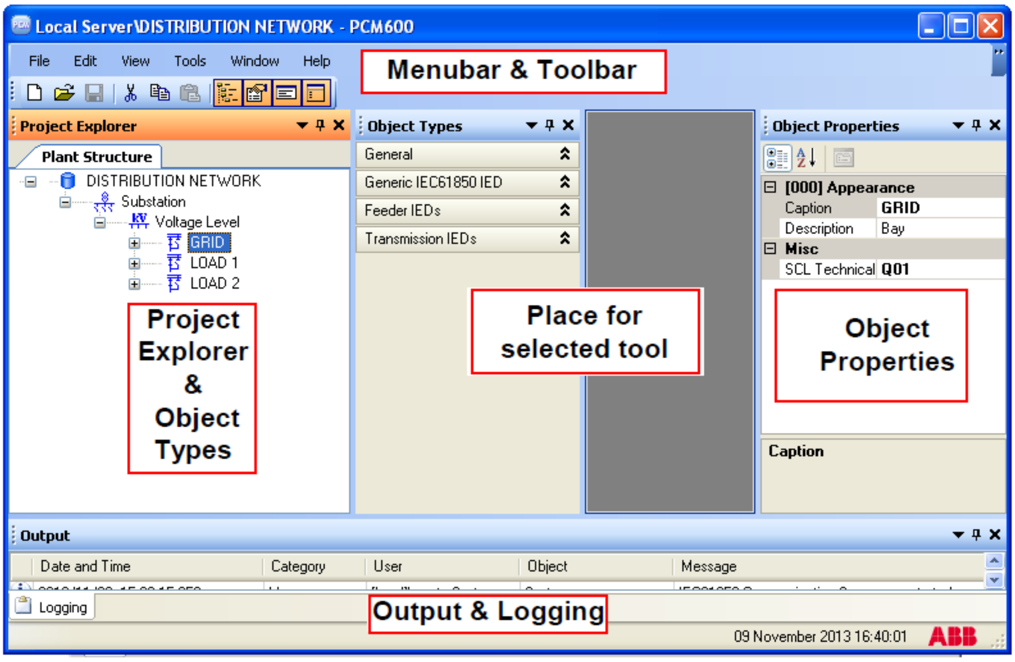


Figure A.1: A PCM600 viewer (Protection and control IED manager guide, 2012)

PCM600 tool is designed to communicate with IEDs via TCP/IP protocol that is incorporated with LAN or WAN. This fast and reliable connection is achieved through the communication port in front of the IED. The tool is capable of using a single command to write and read configuration, and setting data for the IED. PCM600 tool has the intelligence that assures the projects and data produced with earlier versions of the tool, to be edited which enables full backwards compatibility.PCM600 tool has the following functions / tools (Protection and control IED manager guide, 2012):

- Signal matrix
- Parameter setting
- Communication management
- Disturbance handling
- Signal monitoring
- Event viewer
- Creating/Handling projects
- IED user management
- XRIO parameter export/import
- Graphical display editor
- Hardware configuration
- User management
- Graphical application viewing
- Graphical application configuration
- IEC 61850 communication configuration

These functions are described shortly below

A.2.1 Signal matrix

Signal matrix viewer is a window of the PCM600 where current transformers (CTs), voltage transformers (VTs), binary input and binary output signals have permitted connection for configuration as shown in Figure A.2 below. The connection configuration changes are also done on this window. This tool is also utilized for GOOSE signal connection between IEDs (Protection and control IED manager guide, 2012).

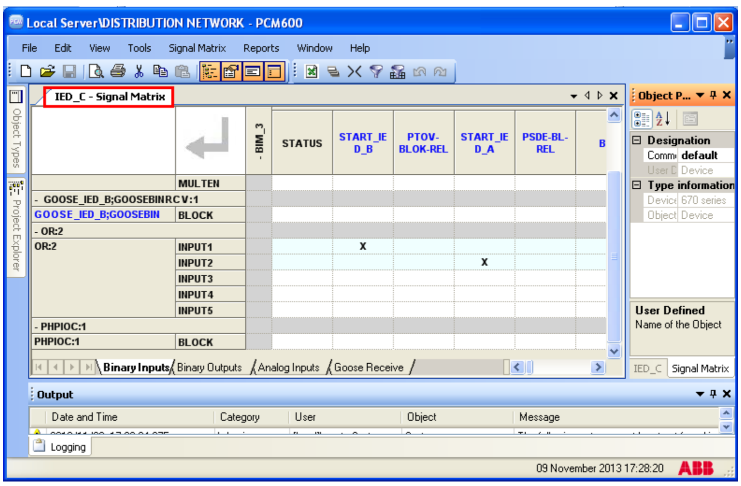


Figure A.2: **A signal matrix tool viewer (Protection and control IED manager guide, 2012)**

A.2.2 Parameter setting

PCM600 has a parameter setting tool where IEDs parameters are viewed as shown in Figure A. 3 below. This is where the setting of the IED is changed according to the requirements. This tool allows the parameters to be read from IED to PCM600 and vice versa. This tool can be utilized in two different modes namely normal mode and advance mode. The normal mode is used for viewing and changing the commonly utilized parameters. The advance mode is used to show all parameters that can be set (Protection and control IED manager guide, 2012).

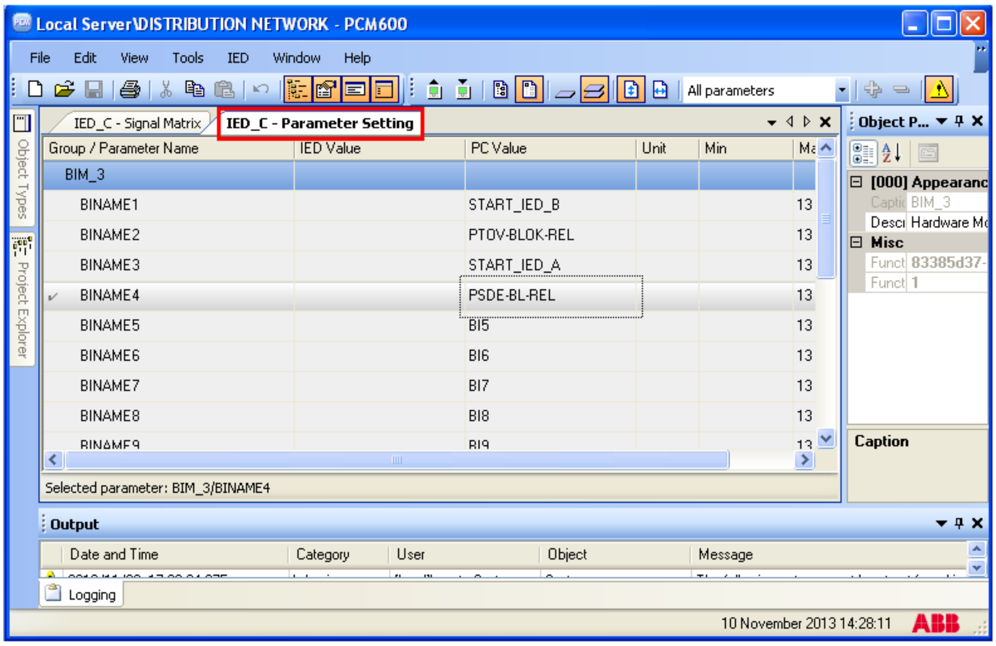


Figure A.3: **The Parameter setting viewer (Protection and control IED manager guide, 2012)**

A.2.3 Disturbance handling

PCM600 software tool provides well-organized handling and monitoring disturbance records for the IEDs. The disturbance recorded files are stored in the COMTRADE format (Standard format according to IEC 60255-24). This format grants the client to view the disturbance record making use of ABB Wavewin software (Protection and control IED manager guide, 2012).

A.2.4 Signal monitoring

The signal monitoring function is utilized for supplying online information of measured values and displays the status of binary input and output signals of an IED. It also helps with commissioning and testing of physical connections via the signal monitoring tool (Protection and control IED manager guide, 2012).

A.2.5 Event viewer

The event viewer window is used for viewing the sequence of events of the IEDs' information including timestamps. The event viewer assists with logging the information and facilitates detailed post-fault analyses of faults and disturbances (Protection and control IED manager guide, 2012).

A.2.6 Creating/handling projects

The project explorer viewer on the PCM600 is used to navigate different functions within the IED. Plant structure with a substation, voltage levels, bays and IEDs are created in the project explorer. New project can also be created by means of IED templates and this can provide the existing IED configuration to be reused by another IED. This entire configuration is viewed on the plant structure (Protection and control IED manager guide, 2012).

A.2.7 Graphical display editor

The graphical display editor is utilized for the display configuration of an IED as shown in Figure A.4 below. It consists of one or more pages used for displaying the drawing (Protection and control IED manager guide, 2010).

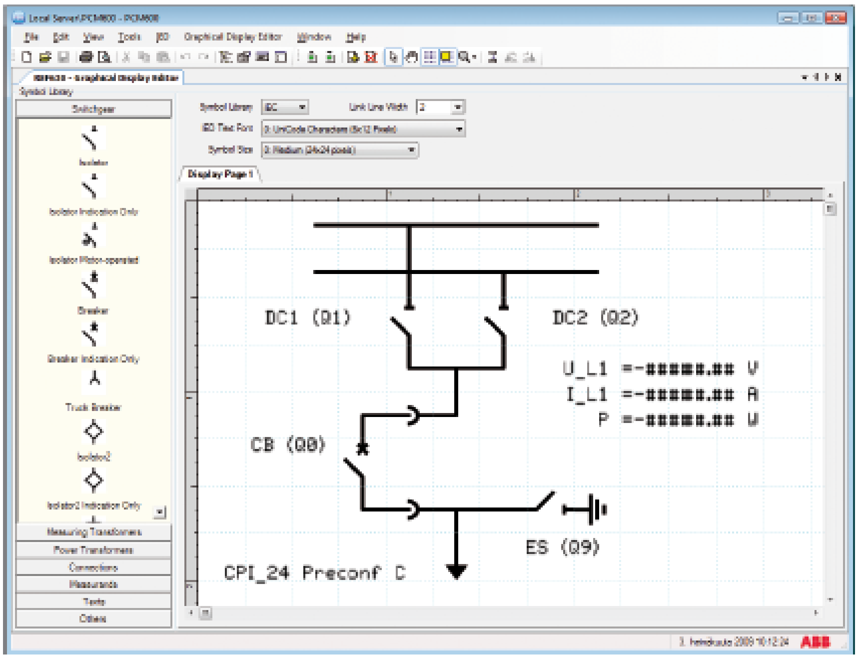


Figure A.4: **The Graphical display editor (Protection and control IED manager guide, 2012)**

A.2.8 Hardware configuration

This tool is used to sum-up the IED hardware module that includes the back and front panel. These panels they consists of a card with information and its slot position in the IED. It also has a function that is able to compare the hardware configuration used in the tool to the actual one in the IED (Protection and control IED manager guide, 2012).

A.2.9 User management

PCM600 tool management is done in both the software and the IED. This is where the administrator is capable of creating different account groups with different access rights and profiles. This tool assures the security and management of the IED (Protection and control IED manager guide, 2010).

A.2.10 Graphical application configuration and viewing

The graphical application configuration functionality is used to develop and modify application configurations which also can later be constructed as templates for re-use. This is where presentation function blocks used for configuration of the IED and the whole signal flow from the input to the output are viewed as shown in Figure A.5 below. The mapping of the function blocks is done on this window.

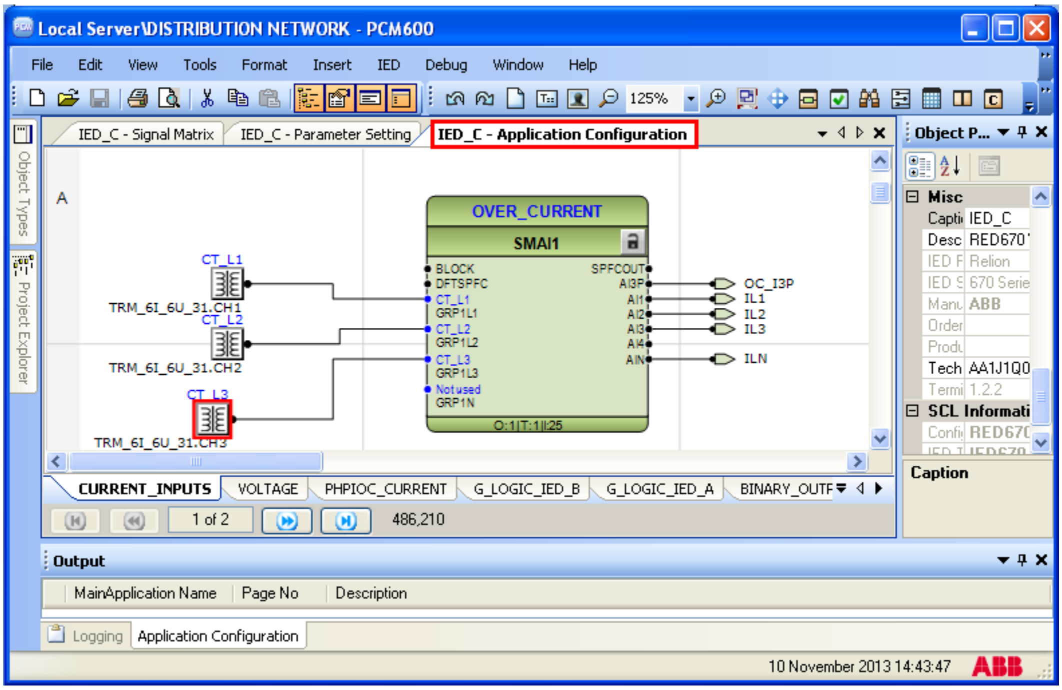


Figure A.5: **Application configuration and viewer (Protection and control IED manager guide, 2012)**

A.2.11 IEC 61850 communication configuration

The PCM600 software tool has two communication tools namely: communication management and communication configuration tools. The communication management tool is utilized for DNP3 and IED 60870-5-103 protocols of the IED. The communication configuration tool which is only available in PCM600 engineering Pro is utilized for IEC 61850 substation configurations including the inter-bay communication (Protection and control IED manager guide, 2012).

A.2.12 Tool variants

PCM600 tool has three variants namely PCM600, PCM600 Engineering and PCM600 Engineering Pro. The difference between the three variant are that PCM600 Engineering has additional graphical application configuration function, PCM600 Engineering Pro includes functionality such as graphical application and IEC 61850 communication configuration, PCM600 does not have this two additional functions as shown in Table A.1(Protection and control IED manager guide, 2012).

Table A.1: Supported functions per tool variant (Protection and control IED manager guide, 2012)

Function	PCM600	PCM600 Engineering	PCM600 Engineering Pro
Signal matrix	YES	YES	YES
Parameter setting	YES	YES	YES
Communication management	YES	YES	YES
Disturbance handling	YES	YES	YES
Signal monitoring	YES	YES	YES
Event viewer	YES	YES	YES
Creating/handling projects	YES	YES	YES
IED user management	YES	YES	YES
XRIO parameter export/import	YES	YES	YES
Graphical display editor	YES	YES	YES
Hardware configuration	YES	YES	YES
User management	YES	YES	YES
Graphical application viewing	YES	YES	YES
Graphical application configuration	NO	YES	YES
IEC 61850 communication configuration, including GOOSE	NO	NO	YES

A.2.1.3IED Connectivity packages

These packages is the software used for gathering material that is associated to a particular protection and control station It also provides the system with tools to connect and interact with the IED. These packages are utilized to produce configuration structures in PCM600. In order to define right connectivity package versions an Update Manager tool is utilized for assistance. It also includes products that support the connectivity concept (ABB 670 series application manual, 2012).

A.3 Analog input function block

Analog inputs channels are used as the path for measurements and protection signals. When power is measured it is important that the directions of all differential functions are properly defined. It is also required that a correct configuration is achieved by selecting and calculating correct quantities used in power systems. Therefore connection of CTs and VTs to the IED is important that is done properly. In ABB IED 670 series the measurement algorithms for protection are done at the primary side of the system, including set values. (ABB 670 series technical reference manual, 2012).

A.3.1 Signal matrix for analog inputs (SMAI) function block

It is preprocessed function block that is used for analog inputs signals that needs to be linked to the IED. It has five analog input signals namely phase one, phase two, phase three, neutral value and a block function as shown in Figure A.6. Voltage or current signals can be connected to inputs GRP1L1, 2 and 3 and neutral input signal is connected to GRP1N. AI3P is the output signal of all three phase signal information. The names and description of the signal matrix for analog inputs and the analog outputs are shown in Tables A.2 and A.3 below (ABB 670 series technical reference manual, 2012).

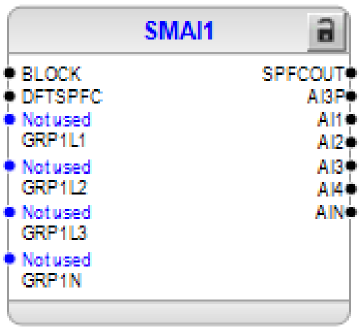


Figure A.6: **Signal matrix for the analog inputs (SMAI) function block(ABB 670 series technical reference manual, 2012).**

Table A.2: **Input signals for the SMAI function block (ABB 670 series technical reference manual, 2012).**

Signal	**Description**
BLOCK	Block group 1
DFTSPFC	Number of samples per fundamental cycle used for DFT calculation.
GRPNAME	Group name for GRP1 in SMT.
AI1NAME	Signal name for AI1 IN SMT.
AI2NAME	Signal name for AI2 IN SMT.
AI3NAME	Signal name for AI3 IN SMT.
AI4NAME	Signal name for AI4 IN SMT.

Table A.3: **Output signals for the SMAI function block (ABB 670 series technical reference manual, 2012).**

Signal	Description
SPFCOUT.	Number of samples per fundamental cycle from internal DFT
AI3P	Group 1 analog input three phase group.
AI1	Group 1 analog input 1.
AI2	Group 1 analog input 2.
AI3	Group 1 analog input 3.
AI4	Group 1 analog input 4.
AIN	Group 1 analog input residual of disturbance recorder.

A.3.2 Signal matrix for binary inputs (SMBI) function block

This function block is used for representing the path for the binary input signals into the intelligent electronic device (IED) for configuration. The inputs of SMBI as shown in Figure A.7 receive the physical binary inputs via the signal matrix tool. These input signals are then made available via the output BI1 up to BI 10 for configuration. . The names and description of the signal matrix for the binary inputs and outputs are shown in Tables A.4 and A.5 below (ABB 670 series technical reference manual, 2012).

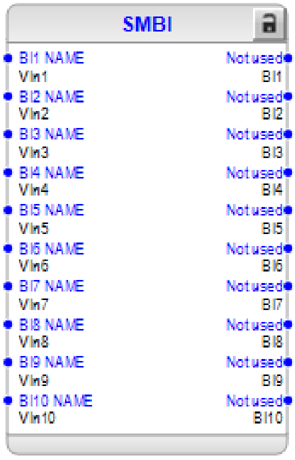


Figure A.7: **Signal matrix for binary inputs (SMBI) (ABB 670 series technical reference manual, 2012)**

Table A.4: **Input signals for the SMBI function block (ABB 670 series technical reference manual, 2012)**

Signal	Description
BI1NAME	Signal name for Binary Input 1 in SMT.
BI2NAME	Signal name for Binary Input 2 in SMT.
BI3NAME	Signal name for Binary Input 3 in SMT.
BI4NAME	Signal name for Binary Input 4 in SMT.
BI5NAME	Signal name for Binary Input 5 in SMT.
BI6NAME	Signal name for Binary Input 6 in SMT.
BI7NAME	Signal name for Binary Input 7 in SMT.
BI8NAME	Signal name for Binary Input 8 in SMT.
BI9NAME	Signal name for Binary Input 9 in SMT.
BI10NAME	Signal name for Binary Input 10 in SMT.

Table A.5: **Output signals for the SMBI function block (ABB 670 series technical reference manual, 2012).**

Signal	Description
BI1.	Binary input 1.
BI2.	Binary input 2.
BI3.	Binary input 3.
BI4.	Binary input 4.
BI5.	Binary input 5.
BI6.	Binary input 6.
BI7	Binary input 7.
BI8	Binary input 8.
BI9	Binary input 9.
BI10	Binary input 10.

A.4 Binary outputs function block

A.4.1 Signal matrix for binary outputs (SMBO) function block

This function block is used for representing the path for binary output signals. The input of the SMBO as shown in Figure A.8 receives signals from the physical binary outputs via the signal matrix tool. These signals are then made available via the outputs of the SMBO. The names and description of the signal matrix input and outputs for the binary outputs are shown in Tables A.6 and A.7 below. (ABB 670 series technical reference manual, 2012).

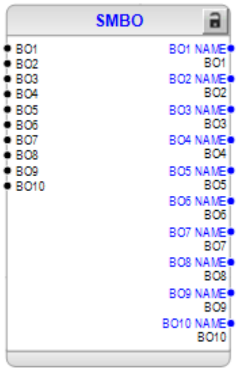


Figure A.8: **The SMBO function block (ABB 670 series technical reference manual, 2012).**

Table A.6: **Input signals for the SMBO function block (ABB 670 series technical reference manual, 2012).**

Signal	Description
BO1	Signal name for Binary Output 1 in SMT.
BO2	Signal name for Binary Output 2 in SMT.
BO3	Signal name for Binary Output 3 in SMT.
BO4	Signal name for Binary Output 4 in SMT.
BO5	Signal name for Binary Output 5 in SMT.
BO6	Signal name for Binary Output 6 in SMT.
BO7	Signal name for Binary Output 7 in SMT.
BO8	Signal name for Binary Output 8 in SMT.
BO9	Signal name for Binary Output 9 in SMT.
BO10	Signal name for Binary Output 10 in SMT.

Table A. 7: **The output signals for the SMBO function block (ABB 670 series technical reference manual, 2012).**

Signal	Description
BO1NAME	Signal name for Binary Output 1 in SMT.
BO2NAME	Signal name for Binary Output 2 in SMT.
BO3NAME	Signal name for Binary Output 3 in SMT.
BO4NAME	Signal name for Binary Output 4 in SMT.
BO5NAME	Signal name for Binary Output 5 in SMT.
BO6NAME	Signal name for Binary Output 6 in SMT.
BO7NAME	Signal name for Binary Output 7 in SMT.
BO8NAME	Signal name for Binary Output 8 in SMT.
BO9NAME	Signal name for Binary Output 9 in SMT.
BO10NAME	Signal name for Binary Output 10 in SMT.

A.5 Current protection function blocks

A.4.1 Instantaneous phase overcurrent protection (PIOC, 50)

This protection block contains a discrete Fourier filter (DFT) system with pre-processed sampled phase currents. It then creates the RMS values from the fundamental frequency per phase current. These phase current values are sent to the instantaneous over-current (IOC) function

Function description	IEC 61850 identification	IEC 60617 identification	ANS/IEEE C37.2 device number
Instantaneous phase overcurrent protection	PHPIOC	3I>>	50

The overcurrent function block consists of low transient overreach elements operating with short tripping time is used when high set short-circuits protection function is required. The short tripping time is trigged when eighty percent of the rated current of the power line at minimum source impedance is obtained. This function block has I3P, BLOCK and ENMULT inputs. It has TRIP, TRL1, TRL2, TRL3 outputs as shown in Figure 5.8. The names and description of the signal matrix for analog inputs are shown in Tables A.8 and A.9. (ABB 670 series technical reference manual, 2012).

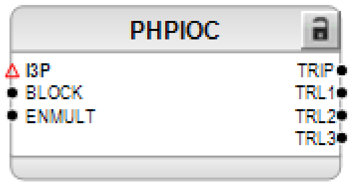


Figure A.9: **Instantaneous phase overcurrent function block (ABB 670 series technical reference manual, 2012).**

Table A.8: **Input signals for the PHPIOC function block (ABB 670 series technical reference manual, 2012)**

Signal	Description
I3P.	Group signal for current input.
BLOCK	Block of functions.
ENMULT.	Enable current start value multiplier.

Table A.9: **Output signals for the PHPIOC function block (ABB 670 series technical reference manual, 2012).**

Signal	Description
TRIP.	Trip signal from any phase.
TRL1.	Trip signal from phase L1.
TRL2.	Trip signal from phase L2.
TRL3.	Trip signal from phase L3.

A.4.1.1 Principle of operation for the PHPIOC

The RMS values are compared by a comparator with the operation current value (IP>>).If a phase current value is greater than the set operation current the comparator signal will set to be true. The signal in Figure A.9 will trigger the output signal TRLn (where n can be one, two or three) with no time delay sending a TRIP command to all three phases. (ABB 670 series technical reference manual, 2012).

A.4.2 Instantaneous residual overcurrent protection (EFPIOC)

This protection function block contains DFT system with sampled pre-processed phase currents. It then creates the RMS values from the fundamental frequency per phase current. These phase current values are sent to the instantaneous residual over-current (EFPIOC) function

Function description	IEC 61850 identification	IEC 60617 identification	ANS/IEEE C37.2 device number
Instantaneous residual overcurrent protection	EFPIOC	IN>>	50N

The overcurrent function block consists of low transient overreach elements operating with short tripping time is used when high set short-circuits protection function is required. The short tripping time is trigged when eighty percent of the rated current of the power line at minimum source impedance is obtained. This function block has I3P, BLOCK and ENMULT inputs. It also consists of TRIP, output as shown in Figure A.10 below. The names and description of the signal matrix for analog inputs and are shown in Table A.10 and A.11 (ABB 670 series technical reference manual, 2012).

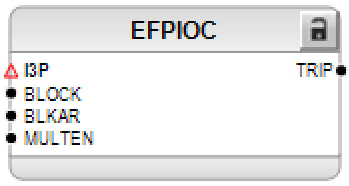


Figure A.10: **EFPIOC function block (ABB 670 series technical reference manual, 2012)**

Table A.10: **Input signals for the EFPIOC function block (ABB 670 series technical reference manual, 2012).**

Signal	type	Default	Description
I3P.	Group signal.		Three phase currents.
BLOCK.	Boolean.	zero	Block of function.
BLKAR.	Boolean.	zero	Block input for auto reclose.
MULTEN.	Boolean.	zero	Enable current multiplier.

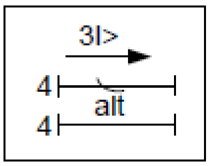
Table A.11: **Input signals for the EFPIOC function block (ABB 670 series technical reference manual, 2012).**

Signal	type	Description
TRIP.	Boolean.	Trips signal

A.4.2.1 Principle of operation for the EFPIOC

The RMS values are compared with a comparator to the setting of the operation current value (IN>>).If a phase current value is greater than the set operation current the comparator signal will set to true. The signal triggers the output TRIP without any delay for all three phases (ABB 670 series technical reference manual, 2012).

A.4.3 Four step phase overcurrent protection (OC4PTOC, 51_67) function block

Function description	IEC 61850 identification	IEC 60617 identification	ANS/IEEE C37.2 device number
Four step phase overcurrent protection	OC4PTOC		51/67

This protection block has four protection sub-functions with the same algorithm but working with different time and current values according to the measured current signal. These sub-functions are called steps and each of them can operate with inverse or definite time delay elements. The function element is either set as non-directional or directional depending on the protection scheme. This block has I3P, U3P, BLOCK, BLKTR, BLKST1,2,3,4 ,ENMULT1,2,3,4 inputs and TRIP, TRI-4, TRL1-3, TRL1 L1-3, TRL2 L1-3, TRL3 L1-3, TR4 L1-3, START, ST1-4, ST1 L1-3,

ST2 L1-3, ST3 L1-3, ST4 L1-3, 2NDHARM,DIRL1-3 outputs as shown in Figure A.11. This function block consists of four different sub-divisions when it comes to protection. These sub-divisions shown in Figure A.12 consist of the following (ABB 670 series technical reference manual, 2012):

- direction element
- harmonic restraint blocking function
- over current function
- mode selection

The names and description of the signal matrix for analog inputs are shown also in Table A.12 and A.13.

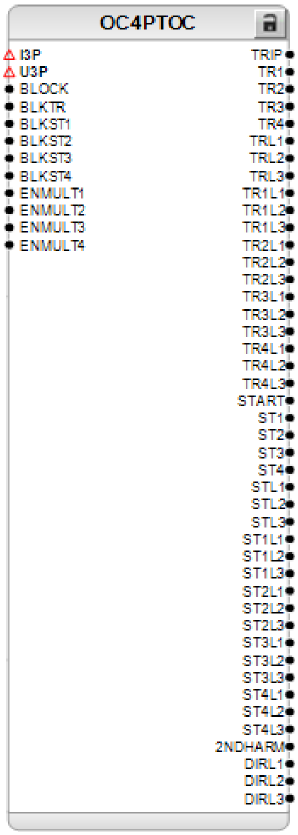


Figure A.11: **The OC4PIOC function block (ABB 670 series technical reference manual, 2012).**

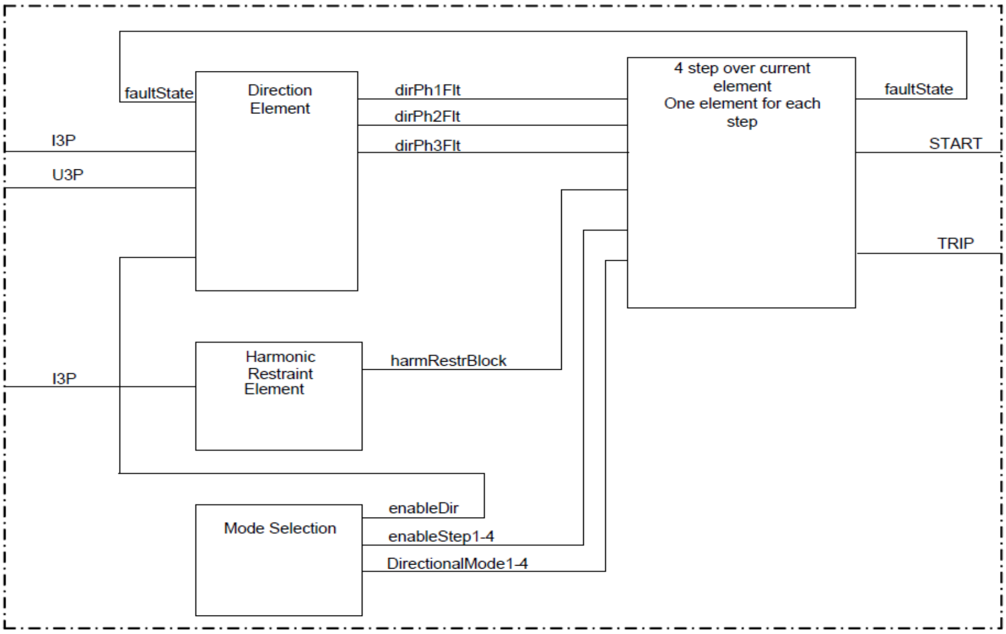


Figure A.12: The Functional overview of 0C4PTOC block (ABB 670 series technical reference manual, 2012)

Table A.12: The input signals for the OC4PTOC function block (ABB 670 series technical reference manual, 2012).

Signal	**Description**
I3P.	Group signal for current input.
U3P.	Group signal for voltage input.
BLOCK.	Block of function.
BLKTR.	Block of trip.
BLKST1.	Block of step 1.
BLKST2.	Block of step 2.
BLKST3.	Block of step 3.
BLKST4.	Block of step 4.
ENMULT1.	When activated the current amplifier is in use for step 1.
ENMULT2.	When activated the current amplifier is in use for step 2.
ENMULT3.	When activated the current amplifier is in use for step 3.
ENMULT4.	When activated the current amplifier is in use for step 4.

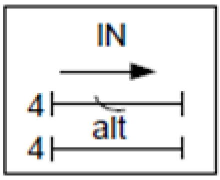
Table A.13: The Output signals for the OC4PTOC function block (ABB 670 series technical reference manual, 2012)

Signal	Description
TRIP	TRIP
TR1	Common trip signal from step 1
TR2	Common trip signal from step 2
TR3	Common trip signal from step 3
TR4	Common trip signal from step 4
TRL1	Trip signal from phase L1
TRL2	Trip signal from phase L2
TRL3	Trip signal from phase L3
TR1L1	Trip signal from step 1 phase L1
TR1L2	Trip signal from step 1 phase L2
TR1L3	Trip signal from step 1 phase L3

TR2L1	Trip signal from step 2 phase L1
TR2L2	Trip signal from step 2 phase L2
TR2L3	Trip signal from step 2 phase L3
TR3L1	Trip signal from step 3 phase L1
TR3L2	Trip signal from step 3 phase L2
TR3L3	Trip signal from step 3 phase L3
TR4L1	Trip signal from step 4 phase L1
TR4L2	Trip signal from step 4 phase L2
TR4L3	Trip signal from step 4 phase L3
START	General start signal
ST1	Common start signal from step 1
ST2	Common start signal from step 2
ST3	Common start signal from step 3
ST4	Common start signal from step 4
STL1	Start signal from phase L1
STL2	Start signal from phase L2
STL3	Start signal from phase L3
ST1L1	Start signal from step 1 phase L1
ST1L2	Start signal from step 1 phase L2
ST1L3	Start signal from step 1 phase L3
ST2L1	Start signal from step 2 phase L1
ST2L2	Start signal from step 2 phase L2
ST2L3	Start signal from step 2 phase L3
ST3L1	Start signal from step 3 phase L1
ST3L2	Start signal from step 3 phase L2
ST3L3	Start signal from step 3 phase L3
ST4L1	Start signal from step 4 phase L1
ST4L2	Start signal from step 4 phase L2
ST4L3	Start signal from step 4 phase L3
2NDHARM	Block from second harmonic detection
DIRL1	Direction for phase 1
DIRL2	Direction for phase 2
DIRL3	Direction for phase 3

The OCPTOC function block used phase currents that are preprocessed in a DFT block This DFT block creates RMS values by using fundamental frequency of the phase currents. This process suppresses the influence of high harmonic and DC current components. Then the current components derived by the RMS values are fed to the OC4PTOC where there is a comparator circuits that compares the each phase current. If it happens that one of the phases current is greater than the set operation current value a signal will be sent to active the output START without a delay. All four steps have a common output named START. If there are no blocking signals sent to the output START a signal will be sent to activate the timers in all steps. The timers have characteristic functions such as definite or inverse time delay. It will then send a signal to activate the output TRIP of the OC4PTOC after certain time (ABB 670 series technical reference manual, 2012).

A.4.4 Four step residual overcurrent protection (EF4PTOC) function block

Function description	IEC 61850 identification	IEC 60617 identification	ANS/IEEE C37.2 device number
Four step residual overcurrent protection	EF4PTOC		51N/67N

EF4PTOC consists of four steps each with various protection characteristics It is used for phase-to-earth faults. It has I3P, U3P, I3PPOL, BLOCK, BLKTR, BLKST1,2,3,4, ENMULT1,2,3,4, CBPOS, CLOSECB, OPENCB inputs and TRIP, TRINI-4, TRSTOF, START, STIN1-4, STSOTF, STFW, STRV, 2NDHARM outputs as shown in Figure A.13. EF4PTOC consists of four different sub-divisions when it comes to protection. These subdivisions are as follows (ABB 670 series technical reference manual, 2012):

- direction element
- harmonic restraint element
- blocking function
- over current function
- mode selection
- switch on to fault

An overview of the EF4PTOC block with the different parts is shown in Figure A.14. The names and description of the signal matrix for analog boolean inputs and boolean outputs are shown in Tables A.14 and A.15 (ABB 670 series technical reference manual, 2012).

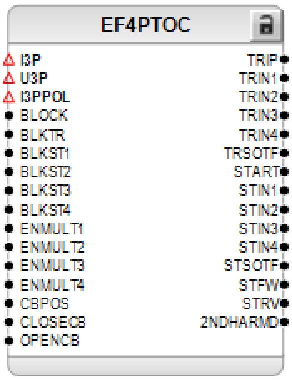


Figure A.13: **The EF4PTOC function block (ABB 670 series technical reference manual, 2012)**

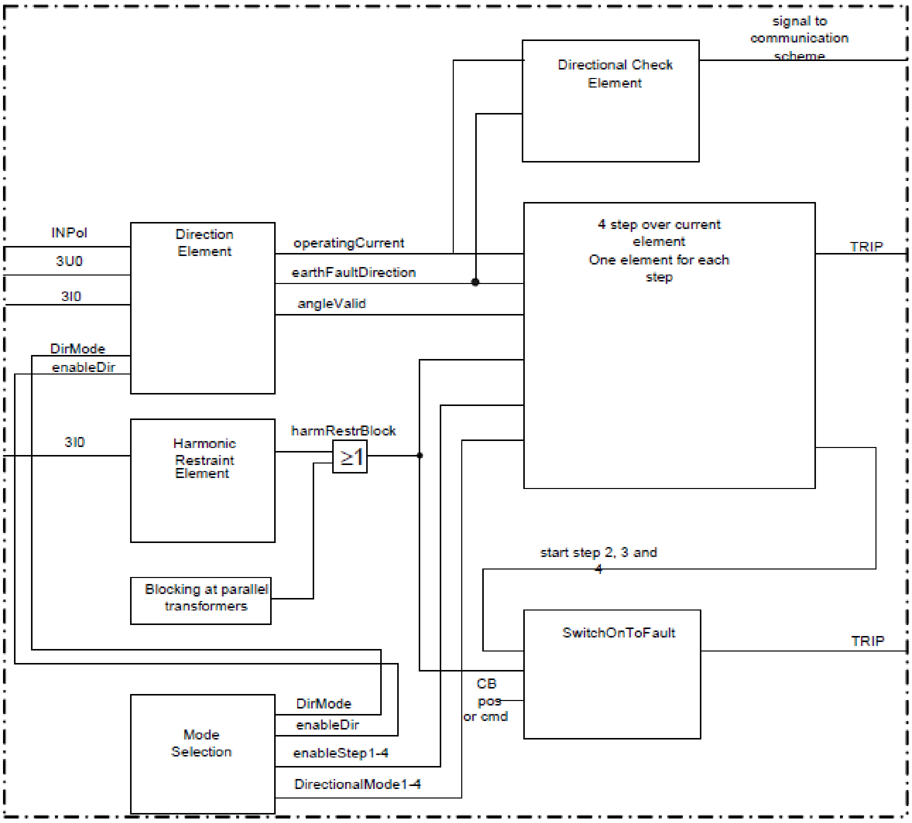


Figure A.14: The functional overview of the EF4PTOC block (ABB 670 series technical reference manual, 2012)

Table A.14: The input signals for the EF4PTOC function block (ABB 670 series technical reference manual, 2012)

BLKST1	BOOLEAN.	0	Block of step 1. (Start and trip)
BLKST2	BOOLEAN.	0	Block of step 2. (Start and trip)
BLKST3	BOOLEAN.	0	Block of step 3. (Start and trip)
BLKST4	BOOLEAN.	0	Block of step 4. (Start and trip)
ENMULT1	BOOLEAN.	0	When activated, the current multiplier is in use for step1.
ENMULT2	BOOLEAN.	0	When activated, the current multiplier is in use for step1.
ENMULT3	BOOLEAN.	0	When activated, the current multiplier is in use for step1.
ENMULT4	BOOLEAN.	0	When activated, the current multiplier is in use for step1.
CBPOS	BOOLEAN.	0	Breaker position.
CLOSECB	BOOLEAN.	0	Breaker close command.
OPENCB	BOOLEAN.	0	Breaker open command.

Table A.15: The Output signals for the EF4PTOC protection function block (ABB 670 series technical reference manual, 2012)

Name	Type	Description
TRIP.	BOOLEAN.	Trip.
TRIN1.	BOOLEAN.	Trip signal from step 1.
TRIN2.	BOOLEAN.	Trip signal from step 2.
TRIN3.	BOOLEAN.	Trip signal from step 3.

TRIN4.	BOOLEAN.	Trip signal from step 4.
TRSOTF.	BOOLEAN.	Trip signal from earth switch onto fault function.
START.	BOOLEAN.	General start signal.
STIN1.	BOOLEAN.	Start signal step 1.
STIN2.	BOOLEAN.	Start signal step 2.
STIN3.	BOOLEAN.	Start signal step 3.
STIN4.	BOOLEAN.	Start signal step 4.
STSOTF.	BOOLEAN.	Start signal from earth fault switch onto fault function.
STFW.	BOOLEAN.	Forward directional signal.
STRV.	BOOLEAN.	Reverse directional start signal.
2NDHARMD.	BOOLEAN.	2nd harmonic block signal.

The EF4PTOC function block used residual currents that are preprocessed in a DFT block. It then creates the RMS values from the fundamental frequency per residual current. These current components are fed to EF4PTOC function where there is a comparator circuits that compares the each phase current. If it happens that the residual current is greater than the set operation current value a signal will be sent to active the output STINx (x = step1-4) without a delay. All four steps have a common output named START. If there is no blocking signals sent to the output START a signal will be sent to activate the timers in all steps. If there is blocking signal send to the output START a signal will be sent to activate the timers in all steps. The timers have characteristics functions such as definite or inverse time delay It will then send a signal to activate the output TRIP in EF4PTOC function block (ABB 670 series technical reference manual, 2012).

A.5 Monitoring functions for ABB 670 IEDs

A.5.1 Measurement functions

This function is utilized for measurement, supervision, reporting to the local HMI and monitoring of power systems. It is a function that allows continuous monitoring the measured values of reactive power, active power, currents, voltages, power factor and frequency. This function is an important factor when it comes to efficient production, transmission and distribution for electrical energy. It offers fast and easy overview of the current status of the power system to the operator. This function block can also be utilized for testing and commissioning of protection IEDs. These measurement functions are based on periodic reporting namely CVMMXU, CMMXU, VMMXU, CMSQI and VMSQI functions. (ABB 670 series technical reference manual, 20012).

A.5.1.1 Measurement function (CVMMXU) function block

Function description	IEC 61850	IEC 60617 identification	ANSI/IEEE C37.2 device number
measurements	CVMMXU	P, Q, S, I, U, F	

The measurement function (CVMMXU) has I3P and U3P input and has the following as output quantities shown in Figure A.15 below. The names and description of the signal matrix for analog inputs is shown in Table A.16 and for the outputs in Table A.17 below where P, Q and S are three phase active, reactive and apparent power, PF represents power factor, U represents phase-to-phase voltage amplitude, I represents phase current amplitude, and F represents power system frequency

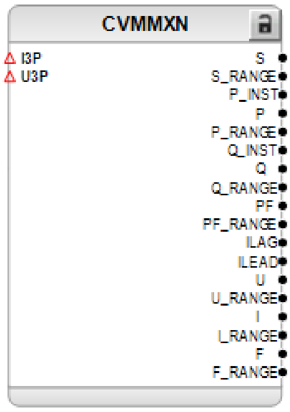


Figure A.15: The Measurement function block (CVMMXU) (ABB 670 series technical reference manual, 2012).

Table A.16: The Measurement function block (CVMMXU) input signals (ABB 670 series technical reference manual, 2012)

Name	type	Description
I3P	GROUP SIGNAL	Group signal for current input
U3P	GROUP SIGNAL	Group signal for voltage input

Table A.17: The Measurement function block (CVMMXU) output signals (ABB 670 series technical reference manual, 2012)

Name	type	Description
S	REAL	Apparent power magnitude of dead band value
S_RANGE	INTEGER	Apparent power range
P_INST	REAL	Active Power
P	REAL	Active Power magnitude of dead band value
P_RANGE	INTEGER	Active power range
Q_INST	REAL	Reactive power
Q	REAL	Active power magnitude of dead band value
Q_RANGE	INTEGER	Reactive Power range
PF	REAL	Power Factor magnitude of dead band value
PF_RANGE	INTEGER	Power Factor range
ILAG	BOOLEAN	Current is lagging voltage
ILEAD	BOOLEAN	Current is leading voltage
U	REAL	Calculate voltage magnitude of dead band value

U_RANGE	INTEGER	Calculated voltage range
I	REAL	Calculated current magnitude of dead band value
I_RANGE	INTEGER	Calculated current range
F	REAL	System frequency magnitude of dead band value
F_RANGE	INTEGER	System frequency range

A.5.1.2 Operation of the measurement (CVMMXU) function block

When three phase current and voltage are connected into the input I3P and U3P of the measurement function block (CVMMXU) a configuration tool groups the signal and calculates the quantities (P, Q, S, I, U and F) through nine different methods as shown in the Table A.18 below. Methods from one to two on the Table A.18 calculate three phase power. Methods from three to nine have a function that assumes that the power system is fully symmetrical when the three phase power is calculated. When calculating the complex apparent power then the quantities P, Q, S and PF make use of the following formulas for calculation (ABB 670 series technical reference manual, 2012):

$$P = Re(\overline{S}) \quad (5.1)$$

$$Q = Im(\overline{S}) \quad (5.2)$$

$$S = |\overline{S}| = \sqrt{P^2 + Q^2} \quad (5.3)$$

$$PF = \cos \emptyset = \frac{P}{S} \quad (5.4)$$

Table A.18: **The Different methods for calculation of three phase power systems (ABB 670 series technical reference manual, 2012)**

Set value for parameter "Mode "	Formula used for complex, three phase power calculation	Formula used for voltage and current magnitude calculation	comment
L1, L2, L3	$\overline{S} = \overline{U_{L1}} \cdot \overline{I^*_{L1}} + \overline{U_{L2}} \cdot \overline{I^*_{L2}} + \overline{U_{L3}} \cdot \overline{I^*_{L3}}$	$U = (\lvert\overline{U_{L1}}\rvert + \lvert\overline{U_{L2}}\rvert + \lvert\overline{U_{L3}}\rvert)/\sqrt{3}$ $I = (\lvert\overline{I_{L1}}\rvert + \lvert\overline{I_{L2}}\rvert + \lvert\overline{I_{L3}}\rvert)/3$	Used when three phase-to-earth voltages are available
Arone	$\overline{S} = \overline{U_{L1L2}} \cdot \overline{I^*_{L1}} - \overline{U_{L2L3}} \cdot \overline{I^*_{L3}}$	$U = (\lvert\overline{U_{L1L2}}\rvert + \lvert\overline{U_{L2L3}}\rvert)/\ 2$ $I = (\lvert\overline{I_{L1}}\rvert + \lvert\overline{I_{L3}}\rvert)/\ 2$	Used when three two phase-to-phase voltages are available
PosSeq	$\overline{S} = 3 \cdot \overline{U_{PosSeq}} \cdot \overline{I^*_{PosSeq}}$	$U = \sqrt{3} \cdot \lvert\overline{U_{PosSeq}}\rvert$ $I = \lvert\overline{I_{PosSeq}}\rvert$	Used when only symmetrical three phase power shall be measured
L1L2	$\overline{S} = \overline{U_{L1L2}} \cdot \left(\overline{I^*}_{L1} - \overline{I^*}_{L2}\right)$	$U = \lvert\overline{U_{L1L2}}\rvert$ $I = (\lvert\overline{I_{L1}}\rvert + \lvert\overline{I_{L2}}\rvert)/\ 2$	Used when only U_{L1L2} phase-to-phase voltage is available
L2L3	$\overline{S} = \overline{U_{L2L3}} \cdot \left(\overline{I^*}_{L2} - \overline{I^*}_{L3}\right)$	$U = \lvert\overline{U_{L2L3}}\rvert$ $I = (\lvert\overline{I_{L2}}\rvert + \lvert\overline{I_{L3}}\rvert)/\ 2$	Used when only U_{L2L3} phase-to-phase voltage is available
L3L1	$\overline{S} = \overline{U_{L3L1}} \cdot \left(\overline{I^*}_{L3} - \overline{I^*}_{L1}\right)$	$U = \lvert\overline{U_{L3L1}}\rvert$ $I = (\lvert\overline{I_{L3}}\rvert + \lvert\overline{I_{L1}}\rvert)/\ 2$	Used when only U_{L3L1} phase-to-phase voltage is available
L1	$\overline{S} = 3 \cdot \overline{U_{L1}} \cdot \overline{I^*_{L1}}$	$U = \sqrt{3} \cdot \lvert\overline{U_{L1}}\rvert$ $I = \lvert\overline{I_{L1}}\rvert$	Used when only U_{L1} phase-to-earth voltage is available
L2	$\overline{S} = 3 \cdot \overline{U_{L2}} \cdot \overline{I^*_{L2}}$	$U = \sqrt{3} \cdot \lvert\overline{U_{L2}}\rvert$ $I = \lvert\overline{I_{L2}}\rvert$	Used when only U_{L2} phase-to-earth voltage is available
L3	$\overline{S} = 3 \cdot \overline{U_{L3}} \cdot \overline{I^*_{L3}}$	$U = \sqrt{3} \cdot \lvert\overline{U_{L3}}\rvert$ $I = \lvert\overline{I_{L3}}\rvert$	Used when only U_{L3} phase-to-earth voltage is available

A.5.2 Phase current measurement (CMMXU) function block

Function description	IEC 61850	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase current measurements	CMMXU	$\boxed{I}$	-

The phase current measurement function (CMMXU) has I3P input and has the following output quantities as shown in Figure A.16. The names and description of the signal matrix for analog inputs are shown in Table A.19 and the outputs are shown in Table A.20 (ABB 670 series technical reference manual, 2012):

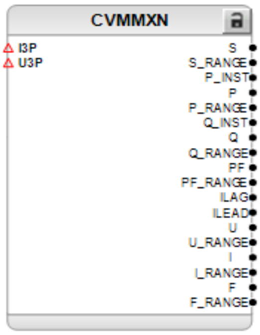


Figure A.16: **The Phase current measurement function block (CMMXU) (ABB 670 series technical reference manual, 2012)**

Table A.19: **The phase current measurement function block (CMMXU) inputs (ABB 670 series technical reference manual, 2012)**

Name	Type	Default	Description
I3P	GROUP SIGNAL	-	Group connection abstract block 1

Table A.20: **The phase current measurement function block (CMMXU) outputs (ABB 670 series technical reference manual, 2012)**

Name	**Type**	**Description**
IL 1	REAL	IL1 Amplitude, magnitude of reported value
IL 1 RANG	INTEGER	IL 1 Amplitude range
IL 1 ANGL	REAL	IL 1 Angle, magnitude of reported value
IL2	REAL	IL2 Amplitude, magnitude of reported value
IL 2RANG	INTEGER	IL 2 Amplitude range
IL2ANGL	REAL	IL 2 Angle, magnitude of reported value
IL3	REAL	IL3 Amplitude, magnitude of reported value
IL3RANG	INTEGER	IL 3 Amplitude range
IL3ANGL	REAL	IL3 Angle, magnitude of reported value

When three phase current is connected into the input I3P of the phase current measurement function block (CMMXU) a configuration tool handles the currents and calibrates them into measuring accuracy of better then class 0,5. This is managed by compensating amplitude and angle at five, thirty and hundred percent of the rated current. The currents that are compensated between five and hundred percent are constant as shown in Figure A.17 (ABB 670 series technical reference manual, 2007)

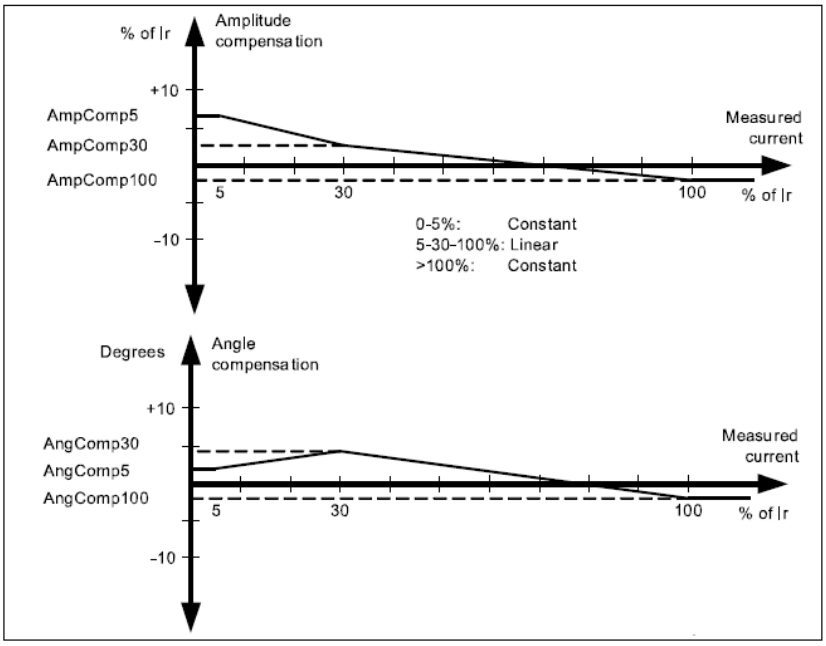


Figure A17: **Calibration curves (ABB 670 series technical reference manual, 2012)**

A.5.3 The Phase - phase voltage measurement (VMMXU) block

Function description	IEC 61850	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase-phase voltage measurement	VMMXU	$\boxed{U}$	-

The phase-phase voltage measurement function (VMMXU) has U3P input and has the following output quantities as shown in Figure A.18. The names and description of the signal matrix for analog inputs and outputs of this block are shown in Table A.21 and A.22 (ABB 670 series technical reference manual, 2012):

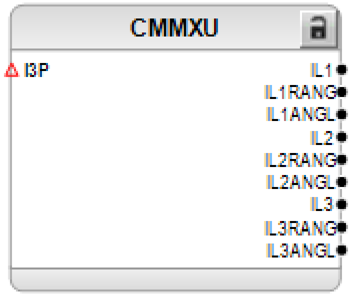


Figure A.18: The Phase-phase voltage measurement function (VMMXU) (ABB 670 series technical reference manual, 2012)

Table A.21: The Input signals for the voltage measurement function (VMMXU) (ABB 670 series technical reference manual, 2012)

Signal	Description
U3P	Group connection abstract block 2

Table A.22: The output signal for the voltage measurement function (VMMXU) (ABB 670 series technical reference manual, 2012)

Name	Description
UL 12	UL12 Amplitude, magnitude of reported value
UL 12 RANG	UL 12 Amplitude range
UL23	UL 23 Amplitude, magnitude of reported value
UL23RANG	UL23 Amplitude range
UL31	UL 31 Amplitude, magnitude of reported value
UL31RANG	UL 31 Amplitude range

When three phase voltage is connected into the input U3P of the phase-phase voltage measurement function block (VMMXU) a configuration tool handles the voltages and calibrates them into measuring accuracy of better then class 0,5. This is managed by compensating amplitude and angle at five, thirty and hundred percent of the rated voltage. The voltages compensated between five and hundred percent are constant (ABB 670 series technical reference manual, 2012).

A.5.4 Current sequence component measurement (CMSQI) function block

Function description	IEC 61850	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current sequence component measurement	CMSQI	$\boxed{I1, I2, I0}$	-

The Current sequence component measurement (CMSQI) has I3P input and has the following output quantities as shown in Figure A.19. The names and description of the signal matrix for analog inputs are shown in Table A.23 and for the outputs are shown in Table A.24 (ABB 670 series technical reference manual, 2012).

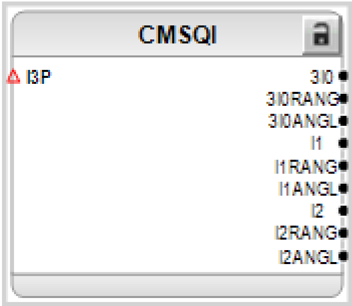


Figure A.19: **The current sequence component measurements (CMSQI) function block (ABB 670 series technical reference manual, 2012)**

Table A.23: **The Input signals for the current sequence component measurement (CMSQI) (ABB 670 series technical reference manual, 2012)**

Signal	Description
I3P	Group connection abstract block 3

Table A.24: **The Output signals for the current sequence component measurement (CMSQI) block (ABB 670 series technical reference manual, 2012)**

Name	Description
3I0	3I0 Amplitude, magnitude of reported value
3I0 RANG	3I0 Amplitude range
I1	I1 Amplitude, magnitude of reported value
I1RANG	I1 Amplitude range
I2	I2 Amplitude, magnitude of reported value
I2RANG	I2 Amplitude range

When three phase currents are connected into the input I3P of the current sequence component measurement function block (CMSQI), instant power quantities are produced. These quantities are calculated and transferred to their responding outputs which are positive, negative and zero sequence. Calculation of the quantities is done by means of utilizing the fundamental frequency phasors.

A.5.5 The Voltage sequence measurement (VMSQI) function block

Function description	IEC 61850	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage sequence component measurement	VMSQI	$\boxed{U1, U2, U0}$	-

The voltage sequence measurement (VMSQI) block has U3P input and has the following as output quantities as shown in Figure 5.19. The names and description of the signal matrices for analog inputs and the outputs are shown in Table A.25 and A.26 respectively (ABB 670 series technical reference manual, 2012).

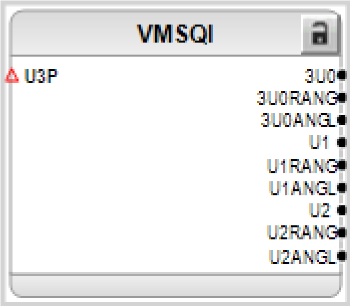


Figure A.20: **The voltage sequence measurement (VMSQI) block (ABB 670 series technical reference manual, 2012)**

Table A.25: **The Input signals for the Voltage sequence measurement (VMSQI) (ABB 670 series technical reference manual, 2012)**

Signal	Description
U3P	Group connection abstract block 4

Table A.26: **The output signals for the Voltage sequence measurement (VMSQI) block (ABB 670 series technical reference manual, 2012)**

Name	Description
3U0	3U0 Amplitude, magnitude of reported value
3U0 RANG	3U0 Amplitude range
U1	U1 Amplitude, magnitude of reported value
U1RANG	U1 Amplitude range
U2	U2 Amplitude, magnitude of reported value
U2RANG	U2 Amplitude range

When three phase voltages are connected into the input UI3P of the voltage sequence component measurement function block (VMSQI), instant power quantities are produced. These quantities are calculated and transferred to their responding outputs which are positive, negative and zero sequence. Calculation of the quantities is done by means of utilizing the fundamental frequency phasors.

A.6 Disturbance report function block

The disturbance report is a common name for a group of functions that produce information that is sufficient for engineers and operators to perform and analyze. The functions in the disturbance report block are as follows:

- General disturbance information
- Indications (IND)

- Event recorder (ER)
- Event list (EL)
- Trip values (phase values) (TVR)
- Disturbance recorder (DR)
- Fault locator (FL)

A combination of the above functions develops a structure for disturbance report as shown in Figure 5.20 below. The indication (IND) function is used for screening the status of all carefully chosen binary input that is linked into disturbance report function. The ER is utilized for logging the status of the selected binary signals when they change. This event happens when one of the triggering conditions is activated for the disturbance report. The event list (EL) function uses save input names, time and status to save them in the event list. The trip value recorder (TVR) function is used for calculating and presenting the fault and pre-fault values of the selected analogue input signals. This is achieved when the analogue inputs are connected into the disturbance report function. The disturbance recording (DR) function is utilized for recording analog and binary data during and after the fault. The fault locator (FL) function is used for measuring and indicates where the fault occurs (ABB 670 series technical reference manual, 2012).

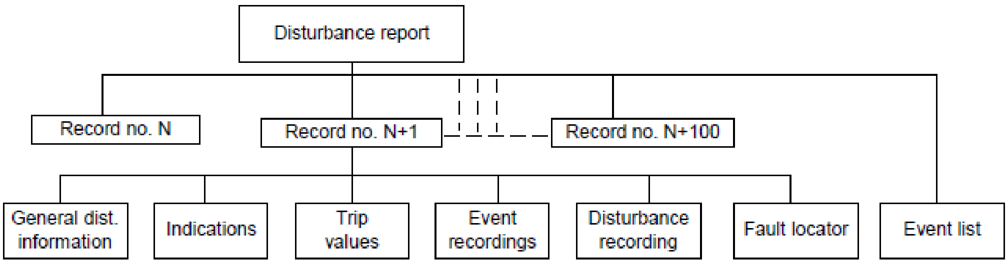


Figure A.21: The disturbance report structure (ABB 670 series technical reference manual, 2012).

A.7 Conclusion

This Appendix A has covered the protection functions of distribution network based on the ABB 670 series IEDs. It also explained the PCM600 software package and it different tools. The function blocks described in Appendix A are used to design the busbar reverse blocking scheme.

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APPENDIX B
THE PARAMETER SETTING FOR THE IED_B

B.1 Introduction

The IEDs that are used in the thesis has been configured and certain parameters had to be completed. Some of the parameters in the configuration are left in their default values. PCM600 has a parameter setting tool where IEDs parameters are viewed. Appendix B contains all the IEDs parameters that are completed and viewed. This is where the setting of the IED is changed according to the requirements. This tool allows the parameters to be read from IED to PCM600 and vice versa. This tool can be utilized in two different modes namely normal mode and advance mode. The normal mode is used for viewing and changing the commonly utilized parameters. The advance mode is used to show all parameters that can be set. Appendix B covers all the parameter settings of the IEDs that are used in the reverse busbar protection scheme. Since the setting for IED_A is similar to IED_B therefore IED_A setting is not covered (Protection and control IED manager guide, 2012).

B.1.2 The settings of binary input modules (BIM) used by IED_B

Table B.1 represents the BIM_3 and BIM_5 which are the hardware configuration of the input of IED_B .This is where all the income BIM signals are connected.

Table B.1: The settings of the binary input modules (BIM_3 and BIM_5) for IED_B

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
BIM_3					
BINAME1		BI1			13 character(s)
BINAME2		BI2			13 character(s)
BINAME3		BI3			13 character(s)
BINAME4		BI4			13 character(s)
BINAME5		BI5			13 character(s)
BINAME6		BI6			13 character(s)
BINAME7		BI7			13 character(s)
BINAME8		BI8			13 character(s)
BINAME9		BI9			13 character(s)
BINAME10		BI10			13 character(s)
BINAME11		BI11			13 character(s)
BINAME12		BI12			13 character(s)
BINAME13		BI13			13 character(s)
BINAME14		BI14			13 character(s)
BINAME15		BI15			13 character(s)
BINAME16		BI16			13 character(s)
Operation		On			
OscRelease		30	Hz	1	30
OscBlock		40	Hz	1	40

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
BIM_5					
BINAME1		BI1			13 character(s)
BINAME2		BI2			13 character(s)
BINAME3		BI3			13 character(s)
BINAME4		BI4			13 character(s)
BINAME5		BI5			13 character(s)
BINAME6		BI6			13 character(s)
BINAME7		BI7			13 character(s)
BINAME8		BI8			13 character(s)
BINAME9		BI9			13 character(s)
BINAME10		BI10			13 character(s)
BINAME11		BI11			13 character(s)
BINAME12		BI12			13 character(s)
BINAME13		BI13			13 character(s)
BINAME14		BI14			13 character(s)
BINAME15		BI15			13 character(s)
BINAME16		BI16			13 character(s)
Operation		On			
OscRelease		30	Hz	1	30
OscBlock		40	Hz	1	40

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B.1.3 The setting of the binary output module (BOM) for IED_B

The setting of the binary output signals (BOM_4) of IED_B are represented in Table B.2 below.

Table B.2: The setting of the binary output module (BOM_4) for IED_B.

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
BOM_4					
BONAME1		REVERSE-BLOCK			13 character(s)
BONAME2		TRIP-CURRENT			13 character(s)
BONAME3		REVERSE_BLOCK			13 character(s)
BONAME4		TRIP_SIGNAL			13 character(s)
BONAME5		BO5			13 character(s)
BONAME6		TVI-TRIP			13 character(s)
BONAME7		BO7			13 character(s)
BONAME8		BO8			13 character(s)
BONAME9		BO9			13 character(s)
BONAME10		BO10			13 character(s)
BONAME11		BO11			13 character(s)
BONAME12		BO12			13 character(s)
BONAME13		BO13			13 character(s)
BONAME14		BO14			13 character(s)
BONAME15		BO15			13 character(s)
BONAME16		BO16			13 character(s)
BONAME17		BO17			13 character(s)
BONAME18		BO18			13 character(s)
BONAME19		BO19			13 character(s)
BONAME20		BO20			13 character(s)
BONAME21		BO21			13 character(s)
BONAME22		BO22			13 character(s)
BONAME23		BO23			13 character(s)
BONAME24		BO24			13 character(s)
Operation		On			

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B.1.4 The setting of the transformer module unit (TRM) for IED_B

The setting for the TRM_6I_6U_31 where the line CTs and VTs signals are connected are represented in Table B.3a and Table B.3b below

Table B.3a: **The setting of the transformer module unit (TRM) for IED_B**

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
TRM_6I_6U_31					
NAMECH1		LINE CT L1			13 character(s)
ChannelType1		CurrentProtection			
RatedTrans1		1.0	A	0.1	300.0
CTStarPoint1		ToObject			
CTsec1		1	A	1	10
CTprim1		3000	A	1	99999
NAMECH2		LINE CT L2			13 character(s)
ChannelType2		CurrentProtection			
RatedTrans2		1.0	A	0.1	300.0
CTStarPoint2		ToObject			
CTsec2		1	A	1	10
CTprim2		3000	A	1	99999
NAMECH3		LINE CT L3			13 character(s)
ChannelType3		CurrentProtection			
RatedTrans3		1.0	A	0.1	300.0
CTStarPoint3		ToObject			
CTsec3		1	A	1	10
CTprim3		3000	A	1	99999
NAMECH4		LINE CT LN			13 character(s)
ChannelType4		CurrentProtection			
RatedTrans4		1.0	A	0.1	300.0
CTStarPoint4		ToObject			
CTsec4		1	A	1	10
CTprim4		3000	A	1	99999
NAMECH5		CH5			13 character(s)
ChannelType5		CurrentProtection			
RatedTrans5		1.0	A	0.1	300.0
CTStarPoint5		ToObject			
CTsec5		1	A	1	10
CTprim5		3000	A	1	99999
NAMECH6		CH6			13 character(s)
ChannelType6		CurrentProtection			
RatedTrans6		1.0	A	0.1	300.0
CTStarPoint6		ToObject			
CTsec6		1	A	1	10
CTprim6		3000	A	1	99999
NAMECH7		LINE VT L1			13 character(s)
ChannelType7		Voltage			
RatedTrans7		110.0	V	0.1	300.0
VTsec7		110.000	V	0.001	999.999
VTprim7		400.00	kV	0.05	2000.00
NAMECH8		LINE VT L2			13 character(s)
ChannelType8		Voltage			

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Table B.3b: The setting of the transformer module unit (TRM) for IED_B

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
RatedTrans8		110.0	V	0.1	300.0
VTsec8		110.000	V	0.001	999.999
VTprim8		400.00	kV	0.05	2000.00
NAMECH9		LINE VT L3			13 character(s)
ChannelType9		Voltage			
RatedTrans9		110.0	V	0.1	300.0
VTsec9		110.000	V	0.001	999.999
VTprim9		400.00	kV	0.05	2000.00
NAMECH10		BusA_1PhVT			13 character(s)
ChannelType10		Voltage			
RatedTrans10		110.0	V	0.1	300.0
VTsec10		110.000	V	0.001	999.999
VTprim10		400.00	kV	0.05	2000.00
NAMECH11		BusB_1PhVT			13 character(s)
ChannelType11		Voltage			
RatedTrans11		110.0	V	0.1	300.0
VTsec11		110.000	V	0.001	999.999
VTprim11		400.00	kV	0.05	2000.00
NAMECH12		CH12			13 character(s)
ChannelType12		Voltage			
RatedTrans12		110.0	V	0.1	300.0
VTsec12		110.000	V	0.001	999.999
VTprim12		400.00	kV	0.05	2000.00

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B.1.4 The communication setting for IED_B

IED_B use the IEC61850-8-1:1 for GOOSE messages. A front port is used for Ethernet communication with as IP Address 10.1.150.2. Activating the disturbance recording (DRPRDRE) for IED_B is also shown. SMAI9 is used for measurements. All the settings are represented in Table B4.

Table B.4: The communication / recording and measurement setting for IED_B

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
IEC61850-8-1: 1					
Operation		On			
IEDName		AA1J1Q02A1			18 character(s)
GOOSE		Front			

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
ETHFRNT: 1					
Front port					
General					
IPAddress		10.1.150.2			
IPMask		255.255.255.0			
Gateway					
General					
GWAddress		10.1.150.1			

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
DRPRDRE: 1					
Operation		On			
PreFaultRecT		0.05	s	0.05	9.90
PostFaultRecT		0.1	s	0.1	10.0
TimeLimit		1.0	s	0.5	10.0
PostRetrig		On			
ZeroAngleRef		1	Ch	1	30
OpModeTest		Off			

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
MeasurementVT; SMAI9: 21					
GRPNAME		MeasurementVT			13 character(s)
AI1NAME		UL1			13 character(s)
AI2NAME		UL2			13 character(s)
AI3NAME		UL3			13 character(s)
AI4NAME		Not used			13 character(s)
DFTReference		InternalDFTRef			
ConnectionType		Ph-N			
TYPE		1	Ch	1	2

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B.1.5 The setting of four step phase overcurrent protection (OC4PTOC) for IED_B

The setting of the OC4PTOC:1 for IED_B are represented in Table B.5 below

Table B.5: The setting of four step phase overcurrent protection (OC4PTOC) for IED_B

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
OC4PTOC: 1					
General					
General					
MeasType		DFT			
Setting Group1					
Operation		On			
IBase		8500	A	1	99999
UBase		400.00	kV	0.05	2000.00
AngleRCA		55	Deg	40	65
AngleROA		80	Deg	40	89
StartPhSel		1 out of 3			
Step 1					
Setting Group1					
DirMode1		Non-directional			
Characterist1		ANSI Def. Time			
I1>		185	%IB	1	2500
t1		0.008	s	0.000	60.000
k1		0.05		0.05	999.00
IMin1		17	%IB	1	10000
t1Min		0.000	s	0.000	60.000
I1Mult		2.0		1.0	10.0
Step 2					
Setting Group1					
DirMode2		Off			
Characterist2		ANSI Def. Time			
I2>		500	%IB	1	2500
t2		0.400	s	0.000	60.000
k2		0.05		0.05	999.00
IMin2		50	%IB	1	10000
t2Min		0.000	s	0.000	60.000
I2Mult		2.0		1.0	10.0
Step 3					
Setting Group1					
DirMode3		Off			
Characterist3		ANSI Def. Time			
I3>		250	%IB	1	2500
t3		0.800	s	0.000	60.000
k3		0.05		0.05	999.00
IMin3		33	%IB	1	10000
t3Min		0.000	s	0.000	60.000
I3Mult		2.0		1.0	10.0
Step 4					
Setting Group1					
DirMode4		Off			

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Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
Characterist4		ANSI Def. Time			
I4>		175	%IB	1	2500
t4		2.000	s	0.000	60.000
k4		0.05		0.05	999.00
IMin4		17	%IB	1	10000
t4Min		0.000	s	0.000	60.000
I4Mult		2.0		1.0	10.0

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B.1.6 The measurement function (CVMMXN) function block for IED_B

The settings of CVMMXN function block for IED_B are represented in Table B.6 below.

Table B.6: **The setting of measurement function (CVMMXN) function block for IED_B**

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
CVMMXN: 1					
General					
General					
Operation		On			
IBase		3000	A	1	99999
UBase		400.00	kV	0.05	2000.00
SBase		2080.00	MVA	0.05	200000.00
Mode		L1, L2, L3			
PowAmpFact		1.000		0.000	6.000
PowAngComp		0.0	Deg	-180.0	180.0
k		0.000		0.000	1.000
Apparent power S					
General					
SLowLim		80.0	%SB	0.0	2000.0
SLowLowLim		60.0	%SB	0.0	2000.0
SMin		50.0	%SB	0.0	2000.0
SMax		200.0	%SB	0.0	2000.0
SRepTyp		Cyclic			
Active power P					
General					
PMin		-200.0	%SB	-2000.0	2000.0
PMax		200.0	%SB	-2000.0	2000.0
PRepTyp		Cyclic			
Reactive power Q					
General					
QMin		-200.0	%SB	-2000.0	2000.0
QMax		200.0	%SB	-2000.0	2000.0
QRepTyp		Cyclic			
Power factor PF					
General					
PFMin		-1.000		-1.000	1.000
PFMax		1.000		-1.000	1.000
PFRepTyp		Cyclic			
Voltage U					
General					
UMin		50.0	%UB	0.0	200.0
UMax		200.0	%UB	0.0	200.0
URepTyp		Cyclic			
Current I					
General					
IMin		50.0	%IB	0.0	500.0
IMax		200.0	%IB	0.0	500.0
IRepTyp		Cyclic			
Frequency Fr					

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B.1.7 The measurement function (CMMXU) function block for IED_B

The settings of CMMXU function block for IED_B are represented in Table B.7 below.

Table B.7: The setting of measurement function (CMMXU) function block for IED_B

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
CMMXU: 1					
General					
General					
Operation		On			
IBase		3000	A	1	99999
IL1 Amplitude					
General					
IL1DbRepInt		10	Type	1	300
IL1Max		1000.000	A	0.000	10000000000.000
IL1RepTyp		Cyclic			
IL1 Angle					
General					
IL1AngDbRepInt		10	Type	1	300
IL2 Amplitude					
General					
IL2DbRepInt		10	Type	1	300
IL2Max		1000.000	A	0.000	10000000000.000
IL2RepTyp		Cyclic			
IL2 Angle					
General					
IL2AngDbRepInt		10	Type	1	300
IL3 Amplitude					
General					
IL3DbRepInt		10	Type	1	300
IL3Max		1000.000	A	0.000	10000000000.000
IL3RepTyp		Cyclic			
IL3 Angle					
General					
IL3AngDbRepInt		10	Type	1	300

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B.1.8 The measurement function (VMMXU) function block for IED_B

The settings of VMMXU function block for IED_B are represented in Table B.8 below.

Table B.8: The setting of measurement function (VMMXU) function block for IED_B

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
VMMXU: 1					
General					
General					
Operation		On			
UBase		400.00	kV	0.05	2000.00
UL12 Amplitude					
General					
UL12DbRepInt		10	Type	1	300
UL12Max		500000.000	V	0.000	10000000000.000
UL12RepTyp		Cyclic			
UL12 Angle					
General					
UL12AnDbRepInt		10	Type	1	300
UL23 Amplitude					
General					
UL23DbRepInt		10	Type	1	300
UL23Max		500000.000	V	0.000	10000000000.000
UL23RepTyp		Cyclic			
UL23 Angle					
General					
UL23AnDbRepInt		10	Type	1	300
UL31 Amplitude					
General					
UL31DbRepInt		10	Type	1	300
UL31Max		500000.000	V	0.000	10000000000.000
UL31RepTyp		Cyclic			
UL31 Angle					
General					
UL31AnDbRepInt		10	Type	1	300

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B.1.9 The measurement function (VMSQ1) function block for IED_B

The settings of VMSQI function block for IED_B are represented in Table B.9 below.

Table B.9: **The setting of measurement function (VMSQI) function block for IED_B**

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
VMSQI: 1					
General					
General					
Operation		On			
3U0 Amplitude					
General					
3U0DbRepInt		10	Type	1	300
3U0Min		0.000	V	0.000	10000000000.000
3U0Max		300000.000	V	0.000	10000000000.000
3U0RepTyp		Cyclic			
3U0LimHys		5.000	%	0.000	100.000
3U0 Angle					
General					
3U0AngDbRepInt		10	Type	1	300
3U0AngZeroDb		0	m%	0	100000
3U0AngMin		-180.000	Deg	-180.000	180.000
3U0AngMax		180.000	Deg	-180.000	180.000
3U0AngRepTyp		Cyclic			
U1 Amplitude					
General					
U1DbRepInt		10	Type	1	300
U1Min		0.000	V	0.000	10000000000.000
U1Max		300000.000	V	0.000	10000000000.000
U1RepTyp		Cyclic			
U1LimHys		5.000	%	0.000	100.000
U1 Angle					
General					
U1AngDbRepInt		10	Type	1	300
U2 Amplitude					
General					
U2DbRepInt		10	Type	1	300
U2Min		0.000	V	0.000	10000000000.000
U2Max		300000.000	V	0.000	10000000000.000
U2RepTyp		Cyclic			
U2LimHys		5.000	%	0.000	100.000
U2 Angle					
General					
U2AngDbRepInt		10	Type	1	300
U2AngMin		-180.000	Deg	-180.000	180.000
U2AngMax		180.000	Deg	-180.000	180.000
U2AngRepTyp		Cyclic			

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B.1.10 The disturbance recording for IED_B

The disturbance recording (DR) function is utilized for recording analog and binary data during and after the fault. .Table B.10a represents the settings for binary data (B1RBDR:1). Tables B.10b and B10c represents the settings for analong data A1RADR:1 and A2RADR:2 respectively.

Table B.10a: The settings for binary data (B1RBDR:1) of IED_B.

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
B1RBDR: 1					
Binary Signals Ch 1-16					
General					
NAME1		TOC-START			13 character(s)
Operation01		On			
TrigLevel01		Trig on 1			
IndicationMa01		Show			
SetLED01		On			
NAME2		TOC-TRIP			13 character(s)
Operation02		On			
TrigLevel02		Trig on 1			
IndicationMa02		Show			
SetLED02		On			
NAME3		EF-START			13 character(s)
Operation03		On			
TrigLevel03		Trig on 1			
IndicationMa03		Show			
SetLED03		On			
NAME4		EF-TRIP			13 character(s)
Operation04		On			
TrigLevel04		Trig on 1			
IndicationMa04		Show			
SetLED04		On			
NAME5		PHASE A			13 character(s)
Operation05		On			
TrigLevel05		Trig on 1			
IndicationMa05		Show			
SetLED05		On			
NAME6		PHASE B			13 character(s)
Operation06		On			
TrigLevel06		Trig on 1			
IndicationMa06		Show			
SetLED06		On			
NAME7		PHASE C			13 character(s)
Operation07		On			
TrigLevel07		Trig on 1			
IndicationMa07		Show			
SetLED07		On			
NAME8		DRB#-INPUT8			13 character(s)
Operation08		Off			
TrigLevel08		Trig on 1			
IndicationMa08		Hide			
SetLED08		Off			
NAME9		DRB#-INPUT9			13 character(s)

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Table B.10b: The settings for analog data (A1RADR:1) of IED_B.

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
A1RADR: 1					
NAME1		LINE_A_IL1			13 character(s)
Operation01		On			
NomValue01		0.0		0.0	999999.9
UnderTrigOp01		On			
UnderTrigLe01		50	%	0	200
OverTrigOp01		On			
OverTrigLe01		200	%	0	5000
NAME2		LINE_A_IL2			13 character(s)
Operation02		On			
NomValue02		0.0		0.0	999999.9
UnderTrigOp02		On			
UnderTrigLe02		50	%	0	200
OverTrigOp02		On			
OverTrigLe02		200	%	0	5000
NAME3		LINE_A_IL3			13 character(s)
Operation03		On			
NomValue03		0.0		0.0	999999.9
UnderTrigOp03		On			
UnderTrigLe03		50	%	0	200
OverTrigOp03		On			
OverTrigLe03		200	%	0	5000
NAME4		LINE_A_IN			13 character(s)
Operation04		On			
NomValue04		0.0		0.0	999999.9
UnderTrigOp04		Off			
UnderTrigLe04		50	%	0	200
OverTrigOp04		Off			
OverTrigLe04		200	%	0	5000
NAME5		LINE_UL1			13 character(s)
Operation05		On			
NomValue05		0.0		0.0	999999.9
UnderTrigOp05		Off			
UnderTrigLe05		50	%	0	200
OverTrigOp05		Off			
OverTrigLe05		200	%	0	5000
NAME6		LINE_UL2			13 character(s)
Operation06		On			
NomValue06		0.0		0.0	999999.9
UnderTrigOp06		Off			
UnderTrigLe06		50	%	0	200
OverTrigOp06		Off			
OverTrigLe06		200	%	0	5000
NAME7		LINE_UL3			13 character(s)

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					DISTRIBUTION NETWORK	ABB Ltd.			AA1J1Q02A1
				Repla...	DISTRIBUTION NETWORK.Substation.Voltage Level.LOAD 1	ABB	Created by / Approved by	Title: IED_B	Document id. / Rev. 0 / Rel. date 11/21/2013 / Lan en / 1 / 2

Table B.10c: The settings for analog data (A2RADR:2) of IED_B.

Settings

Group / Parameter Name	IED Value [SG1/Common]	PC Value [SG1/Common]	Unit	Min	Max
A2RADR: 2					
NAME11		LINE-VT-L1			13 character(s)
Operation11		On			
NomValue11		0.0		0.0	999999.9
UnderTrigOp11		On			
UnderTrigLe11		50	%	0	200
OverTrigOp11		On			
OverTrigLe11		200	%	0	5000
NAME12		LINE-VT-L2			13 character(s)
Operation12		On			
NomValue12		0.0		0.0	999999.9
UnderTrigOp12		On			
UnderTrigLe12		50	%	0	200
OverTrigOp12		On			
OverTrigLe12		200	%	0	5000
NAME13		LINE-VT-L3			13 character(s)
Operation13		On			
NomValue13		0.0		0.0	999999.9
UnderTrigOp13		On			
UnderTrigLe13		50	%	0	200
OverTrigOp13		On			
OverTrigLe13		200	%	0	5000
NAME14		DRA#-INPUT14			13 character(s)
Operation14		Off			
NomValue14		0.0		0.0	999999.9
UnderTrigOp14		Off			
UnderTrigLe14		50	%	0	200
OverTrigOp14		Off			
OverTrigLe14		200	%	0	5000
NAME15		DRA#-INPUT15			13 character(s)
Operation15		Off			
NomValue15		0.0		0.0	999999.9
UnderTrigOp15		Off			
UnderTrigLe15		50	%	0	200
OverTrigOp15		Off			
OverTrigLe15		200	%	0	5000
NAME16		DRA#-INPUT16			13 character(s)
Operation16		Off			
NomValue16		0.0		0.0	999999.9
UnderTrigOp16		Off			
UnderTrigLe16		50	%	0	200
OverTrigOp16		Off			
OverTrigLe16		200	%	0	5000
NAME17		DRA#-INPUT17			13 character(s)

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Re	Modification	Rel. d...	Creat...	Base...	Approved by	Rev.: 0	Rel. date: 11/21/2013	Lan: en	1 / 2

APPENDIX B

THE PARAMETER SETTING FOR THE IED_C

B.2.1 The settings of binary input modules (BIM) used by IED_C

Tables B.11 represents the BIM_3 which are the hardware configuration of the input of IED_C .This is where all the income BIM signals are connected.

Table B.11: The settings of the binary input module (BIM_3) for IED_C

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
BIM_3					
BINAME1		START_IED_B			13 character(s)
BINAME2		PTOV-BLOK-REL			13 character(s)
BINAME3		START_IED_A			13 character(s)
BINAME4		PSDE-BL-REL			13 character(s)
BINAME5		BI5			13 character(s)
BINAME6		BI6			13 character(s)
BINAME7		BI7			13 character(s)
BINAME8		BI8			13 character(s)
BINAME9		BI9			13 character(s)
BINAME10		BI10			13 character(s)
BINAME11		BI11			13 character(s)
BINAME12		BI12			13 character(s)
BINAME13		BI13			13 character(s)
BINAME14		BI14			13 character(s)
BINAME15		BI15			13 character(s)
BINAME16		BI16			13 character(s)
Operation		On			
OscRelease		30	Hz	1	30
OscBlock		40	Hz	1	40

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					Project: DISTRIBUTION NETWORK	ABB Ltd.	Technical ref...	Document kind	AA1J1Q01A1
				Repla...	DISTRIBUTION NETWORK.Substation.Voltage Level.GRID	ABB	Created by / Approved by	Title: IED_C	Document id. / Rev. 0 / Rel. date 11/21/2013 / Lan en / 1 / 1

B.2.2 The settings of binary output module (BOM) used by IED_C

Tables B.12 represents the BOM_4 which are the hardware configuration of the output of IED_C .This is the path used for all the outgoing signals

Table B.12: The settings of the binary output module (BOM_4) for IED_C

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
BOM_4					
BONAME1		PIOC-TRIP			13 character(s)
BONAME2		PTOC-TRIP			13 character(s)
BONAME3		GOOSE-C-TRIP			13 character(s)
BONAME4		GOOSE-V-TRIP			13 character(s)
BONAME5		PTOV-TRIP			13 character(s)
BONAME6		BO6			13 character(s)
BONAME7		BO7			13 character(s)
BONAME8		BO8			13 character(s)
BONAME9		BO9			13 character(s)
BONAME10		BO10			13 character(s)
BONAME11		BO11			13 character(s)
BONAME12		BO12			13 character(s)
BONAME13		BO13			13 character(s)
BONAME14		BO14			13 character(s)
BONAME15		BO15			13 character(s)
BONAME16		BO16			13 character(s)
BONAME17		BO17			13 character(s)
BONAME18		BO18			13 character(s)
BONAME19		BO19			13 character(s)
BONAME20		BO20			13 character(s)
BONAME21		BO21			13 character(s)
BONAME22		BO22			13 character(s)
BONAME23		BO23			13 character(s)
BONAME24		BO24			13 character(s)
Operation		On			

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B.2.3 The setting of the transformer module unit (TRM) for IED_C

The setting for the TRM_6I_6U_31 where the line CTs and VTs signals are connected are represented in Table B.13 below

Table B.13: The setting of the transformer module unit (TRM) for IED_C

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
TRM_6I_6U_31					
NAMECH1		CT_L1			13 character(s)
ChannelType1		CurrentProtection			
RatedTrans1		1.0	A	0.1	300.0
CTStarPoint1		ToObject			
CTsec1		1	A	1	10
CTprim1		2000	A	1	99999
NAMECH2		CT_L2			13 character(s)
ChannelType2		CurrentProtection			
RatedTrans2		1.0	A	0.1	300.0
CTStarPoint2		ToObject			
CTsec2		1	A	1	10
CTprim2		2000	A	1	99999
NAMECH3		CT_L3			13 character(s)
ChannelType3		CurrentProtection			
RatedTrans3		1.0	A	0.1	300.0
CTStarPoint3		ToObject			
CTsec3		1	A	1	10
CTprim3		2000	A	1	99999
NAMECH4		CH4			13 character(s)
ChannelType4		CurrentProtection			
RatedTrans4		1.0	A	0.1	300.0
CTStarPoint4		ToObject			
CTsec4		1	A	1	10
CTprim4		2000	A	1	99999
NAMECH5		CH5			13 character(s)
ChannelType5		CurrentProtection			
RatedTrans5		1.0	A	0.1	300.0
CTStarPoint5		ToObject			
CTsec5		1	A	1	10
CTprim5		2000	A	1	99999
NAMECH6		CH6			13 character(s)
ChannelType6		CurrentProtection			
RatedTrans6		1.0	A	0.1	300.0
CTStarPoint6		ToObject			
CTsec6		1	A	1	10
CTprim6		2000	A	1	99999
NAMECH7		CH7			13 character(s)
ChannelType7		Voltage			
RatedTrans7		110.0	V	0.1	300.0
VTsec7		110.000	V	0.001	999.999
VTprim7		22.00	kV	0.05	2000.00
NAMECH8		CH8			13 character(s)
ChannelType8		Voltage			

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						DISTRIBUTION NETWORK	ABB Ltd.	Created by	Title IED_C	AA1J1Q01A1
						DISTRIBUTION NETWORK.Substation.Voltage Level.GRID	ABB	Approved by		Document id. Rev. 0 Rel. date 11/21/2013 Lan en 1 / 2

B.2.4 The communication and Instantaneous phase overcurrent protection (PHPIOC, 50) setting for IED_C

IED_B use the IEC61850-8-1:1 for GOOSE messages. A front port is used for Ethernet communication with as IP Address 10.1.150.1. SMAI9 is used for current measurements. All the setting including the PHPIOC function block is represented in Table B14.

Table B.14: The communication / recording and measurement setting for IED_C

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
IEC61850-8-1: 1					
Operation		On			
IEDName		AA1J1Q01A1			18 character(s)
GOOSE		Front			

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
OVER_CURRENT; SMAI1: 25					
GRPNAME		OVER_CURRENT			13 character(s)
AI1NAME		CT_L1			13 character(s)
AI2NAME		CT_L2			13 character(s)
AI3NAME		CT_L3			13 character(s)
AI4NAME		Not used			13 character(s)
DFTRefExtOut		InternalDFTRef			
DFTReference		InternalDFTRef			
ConnectionType		Ph-N			
Negation		Off			
MinValFreqMeas		10	%	5	200
UBase		400.00	kV	0.05	2000.00
TYPE		1	Ch	1	2

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
PHPIOC: 1					
Setting Group1					
Operation		On			
IBase		8500	A	1	99999
OpMode		1 out of 3			
IP>>		200	%IB	1	2500
StValMult		1.0		0.5	5.0

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			Repla...	DISTRIBUTION NETWORK.Substation.Voltage Level.GRID		Created by Approved by	Title IED_C	Document id. Rev. 0 Rel. date 11/21/2013 Lan en	1 / 1
Re	Modification	Rel. d...	Creat...	Base...					

B.2.5 The setting of four step phase overcurrent protection (OC4PTOC) for IED_C

The setting of the OC4PTOC:1 for IED_C are represented in Table B.15 below

Table B.15: The setting of four step phase overcurrent protection (OC4PTOC) for IED_C

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
OC4PTOC: 1					
General					
General					
MeasType		DFT			
Setting Group1					
Operation		Off			
IBase		3000	A	1	99999
UBase		400.00	kV	0.05	2000.00
AngleRCA		55	Deg	40	65
AngleROA		80	Deg	40	89
StartPhSel		1 out of 3			
IMinOpPhSel		7	%IB	1	100
2ndHarmStab		20	%IB	5	100
Step 1					
Setting Group1					
DirMode1		Non-directional			
Characterist1		ANSI Def. Time			
I1>		1000	%IB	1	2500
t1		0.000	s	0.000	60.000
k1		0.05		0.05	999.00
IMin1		100	%IB	1	10000
t1Min		0.000	s	0.000	60.000
I1Mult		2.0		1.0	10.0
ResetTypeCrv1		Instantaneous			
tReset1		0.020	s	0.000	60.000
tPCrv1		1.000		0.005	3.000
tACrv1		13.500		0.005	200.000
tBCrv1		0.00		0.00	20.00
tCCrv1		1.0		0.1	10.0
tPRCrv1		0.500		0.005	3.000
tTRCrv1		13.500		0.005	100.000
tCRCrv1		1.0		0.1	10.0
HarmRestrain1		Off			
Step 2					
Setting Group1					
DirMode2		Non-directional			
Characterist2		ANSI Def. Time			
I2>		500	%IB	1	2500
t2		0.400	s	0.000	60.000
k2		0.05		0.05	999.00
IMin2		50	%IB	1	10000
t2Min		0.000	s	0.000	60.000
I2Mult		2.0		1.0	10.0
ResetTypeCrv2		Instantaneous			

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Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
tReset2		0.020	s	0.000	60.000
tPCrv2		1.000		0.005	3.000
tACrv2		13.500		0.005	200.000
tBCrv2		0.00		0.00	20.00
tCCrv2		1.0		0.1	10.0
tPRCrv2		0.500		0.005	3.000
tTRCrv2		13.500		0.005	100.000
tCRCrv2		1.0		0.1	10.0
HarmRestrain2		Off			
Step 3					
Setting Group1					
DirMode3		Non-directional			
Characterist3		ANSI Def. Time			
I3>		250	%IB	1	2500
t3		0.800	s	0.000	60.000
k3		0.05		0.05	999.00
IMin3		33	%IB	1	10000
t3Min		0.000	s	0.000	60.000
I3Mult		2.0		1.0	10.0
ResetTypeCrv3		Instantaneous			
tReset3		0.020	s	0.000	60.000
tPCrv3		1.000		0.005	3.000
tACrv3		13.500		0.005	200.000
tBCrv3		0.00		0.00	20.00
tCCrv3		1.0		0.1	10.0
tPRCrv3		0.500		0.005	3.000
tTRCrv3		13.500		0.005	100.000
tCRCrv3		1.0		0.1	10.0
HarmRestrain3		Off			
Step 4					
Setting Group1					
DirMode4		Non-directional			
Characterist4		ANSI Def. Time			
I4>		175	%IB	1	2500
t4		2.000	s	0.000	60.000
k4		0.05		0.05	999.00
IMin4		17	%IB	1	10000
t4Min		0.000	s	0.000	60.000
I4Mult		2.0		1.0	10.0
ResetTypeCrv4		Instantaneous			
tReset4		0.020	s	0.000	60.000
tPCrv4		1.000		0.005	3.000
tACrv4		13.500		0.005	200.000
tBCrv4		0.00		0.00	20.00
tCCrv4		1.0		0.1	10.0

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B.2.6 The disturbance recording for IED_C

Table B.15a represents the settings for binary data (B1RBDR:1). Tables B.15b represents the settings for analong data A1RADR:1

Table B.15a: The settings for binary data (B1RBDR:1) of IED_C.

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
B1RBDR: 1					
Binary Signals Ch 1-16					
General					
NAME1		DRB#-INPUT1			13 character(s)
Operation01		On			
TrigLevel01		Trig on 1			
IndicationMa01		Show			
SetLED01		On			
NAME2		DRB#-INPUT2			13 character(s)
Operation02		On			
TrigLevel02		Trig on 1			
IndicationMa02		Show			
SetLED02		On			
NAME3		DRB#-INPUT3			13 character(s)
Operation03		On			
TrigLevel03		Trig on 1			
IndicationMa03		Show			
SetLED03		On			
NAME4		DRB#-INPUT4			13 character(s)
Operation04		On			
TrigLevel04		Trig on 1			
IndicationMa04		Show			
SetLED04		On			
NAME5		DRB#-INPUT5			13 character(s)
Operation05		On			
TrigLevel05		Trig on 1			
IndicationMa05		Show			
SetLED05		On			
NAME6		DRB#-INPUT6			13 character(s)
Operation06		Off			
TrigLevel06		Trig on 1			
IndicationMa06		Hide			
SetLED06		Off			
NAME7		DRB#-INPUT7			13 character(s)
Operation07		Off			
TrigLevel07		Trig on 1			
IndicationMa07		Hide			
SetLED07		Off			
NAME8		DRB#-INPUT8			13 character(s)
Operation08		Off			
TrigLevel08		Trig on 1			
IndicationMa08		Hide			
SetLED08		Off			
NAME9		DRB#-INPUT9			13 character(s)
Operation09		Off			

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Table B.15b: The settings for analog data (A1RADR:1) of IED_C.

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
A1RADR: 1					
NAME1		IL1			13 character(s)
Operation01		On			
NomValue01		0.0		0.0	999999.9
UnderTrigOp01		On			
UnderTrigLe01		50	%	0	200
OverTrigOp01		On			
OverTrigLe01		200	%	0	5000
NAME2		IL2			13 character(s)
Operation02		On			
NomValue02		0.0		0.0	999999.9
UnderTrigOp02		On			
UnderTrigLe02		50	%	0	200
OverTrigOp02		On			
OverTrigLe02		200	%	0	5000
NAME3		IL3			13 character(s)
Operation03		On			
NomValue03		0.0		0.0	999999.9
UnderTrigOp03		On			
UnderTrigLe03		50	%	0	200
OverTrigOp03		On			
OverTrigLe03		200	%	0	5000
NAME4		ILN			13 character(s)
Operation04		On			
NomValue04		0.0		0.0	999999.9
UnderTrigOp04		Off			
UnderTrigLe04		50	%	0	200
OverTrigOp04		Off			
OverTrigLe04		200	%	0	5000
NAME5		UL1			13 character(s)
Operation05		On			
NomValue05		0.0		0.0	999999.9
UnderTrigOp05		Off			
UnderTrigLe05		50	%	0	200
OverTrigOp05		Off			
OverTrigLe05		200	%	0	5000
NAME6		UL2			13 character(s)
Operation06		On			
NomValue06		0.0		0.0	999999.9
UnderTrigOp06		Off			
UnderTrigLe06		50	%	0	200
OverTrigOp06		Off			
OverTrigLe06		200	%	0	5000
NAME7		UL3			13 character(s)

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				Repla...	DISTRIBUTION NETWORK.Substation.Voltage Level.GRID	ABB	Created by / Approved by	Title: IED_C	Document id.
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B.2.7 Goose binary receive function block (GOOSEBINRCV)

The GOOSEBINRCV functions for IED_A and IED_B are installed in IED_C.These function block are to receive signals to and from other IEDs via the interbay bus. Table B.16 represents the settings for GOOSE_IED_A: GOOSEBINRCV: 1 and GOOSE_IED_A: GOOSEBINRCV: 2 respectively.

. **Table B.16**: **The settings for Goose binary receive function block (GOOSEBINRCV)**

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
GOOSE_IED_A; GOOSEBINRCV: 2					
Operation		On			

Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
GOOSE_IED_B; GOOSEBINRCV: 1					
Operation		On			

					Project DISTRIBUTION NETWORK	Responsible department ABB Ltd.	Technical ref...	Document kind	Doc. designation AA1J1Q01A1
				Repla...	DISTRIBUTION NETWORK.Substation.Voltage Level.GRID	ABB	Created by Approved by	Title IED_C	Document id. Rev. 0 Rel. date 11/21/2013 Lan en 1 / 1
Re	Modification	Rel. d...	Creat...	Base...					