Cape Peninsula
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INVESTIGATION INTO ALTERNATIVE PROTECTION SOLUTIONS FOR DISTRIBUTION NETWORKS

by

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DECLARATION

I, Fessor Mbango, 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.

Signed **Date**

ABSTRACT

Recently, due to concerns about the liberalization of electricity supply, deregulation and global impact on the environment, securing a reliable power supply has become an important social need worldwide. To ensure this need is fulfilled, detailed investigations and developments are in progress on power distribution systems protection and the monitoring of apparatus which is part of the thesis.

The main objective of a protection schemes is mainly to keep the power system stable by isolating only the affected components or the section of the electricity network in which the fault has developed while allowing the rest of the network to continue operating. It is important to note that the protection equipment does not prevent faults from occurring, but it limits the damaging effect of the fault and protects other healthy equipment. This is only achieved if the protection system of the electrical network involved complies with the requirements and purpose of the electrical protection standards. These requirements include the Operational speed, Reliability, Security and Sensitivity. In conventional substations that are still existing within the utilities networks, a number of long cables are then used to complete the links between substation equipment in order for them to communicate (hardwired). This method is uneconomical and is being phased out completely in the near future. Over the last few years a new standard for substation automation communication has been developed within the International Electrotechnical Commission (IEC), the IEC 61850.

This standard defines the integration requirements of multi-vendor compliant relays and other IED's for multiple protection schemes as well as control and automation techniques. In this particular thesis, Distribution protection is the area of interest, particularly the application of Time and Overcurrent protection schemes. A look into different protection alternatives and the application of new technologies for Electrical Power Distribution Systems that unify protection and control units so that they can be incorporated into Intelligent Substation as opposed to the most existing (conventional substation) is analyzed. The proposed algorithm has been verified through simulations of the CPUT and Eureka three phase power distribution systems. A testing Lab is also part of this thesis and is meant for experiments as well as simulation performance in order to gain knowledge and skills for designing and engineer substations with IEC 61850 standards equipments. The results indicate that the reduction of copper wiring cable has increased and the communication speed has improved and simplified.

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Terms/Acronyms/Abbreviations	Definitions/Explanation
AC	Alternating current
ADC	Analogue to Digital Converter
ALF	Accuracy limit factor
ANSI	American National Standard Institute
ARP	Address Resolution Protocol, A Transmission Control Protocol/Internet Protocol (TCP/IP) process that maps an IP address to Ethernet address, required by TCP/IP for use with Ethernet.
BS	British Standard
CFC	Continuous Function Chart
CID	Configured IED Description
CPU	Central Processing Unit
CT	Current Transformer, Used to convert current from one current to an acceptable magnitude for measurement and protection purposes.
CVT	Capacitor voltage transformers
DASC	Distribution Automation System Computer
DC	Direct current
DO	Data Object
DOC	Directional Over-current Protection
DSP	Digital signal processor
E	Phase-to-neutral voltage of the equivalent single-phase diagram
EEPROM	Electrically Erasable Programmable Read Only Memory
EHV	Extra high-voltage
EMC	Electromagnetic compatibility
EMI	Electromagnetic interference
EPROM	Electrically Programmable Read Only Memory

f	Power frequency
FIFO	First in first out
GOOSE	Generic Object Orientated Substation Event. A high speed multicast peer-to-peer message used in substations to replace conventional hard wiring.
GPS	Geographical positioning system
HMI	Human Machine Interface
HV	High Voltage, 66kV or 132kV
ICD	IED Capability Description
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device, Can be a metering, protection, control or monitoring unit.
IEE	Institution of Electrical Engineers
IEEE	Institute of Electrical and Electronic Engineers
IMD	Insulation monitoring device
Ioc	Instantaneous Overcurrent
IOU	Input/Output Units
IP	Internet Protocol
IRIG	Inter-Range Instrumentation Group
ISO	International Standards Organization
Km	Kilometer
LAN	Local area network
LPCT	Low-Power Current Transducer
LV	Low Voltage
MCB	Miniature circuit breaker
MCCB	Moduled-case Circuit Breakers
MU	Merging Unit, Used to publish Sampled Values for currents and or voltages. May incorporate digital Inputs and Outputs (I/O) that can be published or be subscribed to on the substation LAN.
MV	Medium Voltage
MVA	Mega Volt Ampere

NCC	Network Control Centre. The hub of any electrical distribution network. Central place where all operations are controlled and documented.
NCIT	Non Conventional Instrument Transformers, Instrument transformers that are not based on iron wound cores like conventional Current Transformers and Voltage Transformers.
NMD	Notified maximum demand
NPAG	Network Protection and Application Guide
NPC	Neutral point coil
NTP	Network Time Protocol
Op	Operate
OSI	Open Systems Interconnection
P	Protection
PC	Personal computers
PSA	Protection System Automation
PSD	Power System Design
PSM	Plug Setting Multiplier
PU	Per unit
PWM	Pulse width modulation
RALF	Rated accuracy limit factor
RAM	Random access memory
RAS	Remedial Action Schemes
RCT	Winding resistance in a current transformer
RFC	Request for comments
RN	Neutral-point earthing resistance
ROM	Read only memory
RTU	Remote Terminal Unit, the intermediate device used to communicate all the information required by the NCC
SA	Substation Automation
SCADA	Supervisory Control and Data Acquisition
SCD	Substation Configuration Description
SCL	Substation Configuration Language

SCSM	Specific Communication Services Mappings
SRAM	Static Read Only Memory
SSD	System Specification Description
T	Tripping time delay
TCP/IP	Transmission Control Protocol/Internet Protocol
TMS	Time multiplier setting
Toc	Time Overcurrent
UCA2	Utility Communications Architecture 2.0
UTP	Unshielded twisted pair
VD	Vector Diagram
VLAN	Virtual Local Area Network
VT	Voltage Transformer, Used to convert voltage from one magnitude to another. Used in substations to reduce the primary voltage to an acceptable magnitude for measurement and protection purposes

MATHEMATICAL NOTATION

Symbols/Letters	Definition/Explanation
S_b	The base MVA
S_{max}	Maximum short-circuit power
S_{max}	Maximum short circuit power
S_{rated}	Rated short circuit power
T_c	Breaking time of the downstream circuit breaker, which includes the breaker response time and the arcing time,
Z_b	The base impedance in ohms
$Z_{pu(GB)}$	The *per unit impedance given base*
$Z_{pu(NB)}$	The per unit impedance new base
c_{max}	Maximum voltage correction factor
i_p	The instantaneous value of the secondary current

i_p	Peak short-circuit current
i_p	The instantaneous value or the primary current
$i_{1[a-c]}$	Primary side currents
$i_{2[a-c]}$	Secondary side currents
$\emptyset$	Secondary burden
Es	Secondary induced e.m.f
I	Applied current
I	CT, and relay, secondary rating (5 A assumed)
I	Value of applied current
I/I_s	Multiple of setting current
Ie	Exciting current
Is	Secondary current
IV	Setting voltage
Vkp	CT knee point voltage
Vs	Secondary output voltage
$X\%$	Internal Reactance of Transformer in %
X/R	Reactance to resistance ratio of the power system
$Z\%$	Rated % transformer impedance
Zb	The burden impedance
Zs	The self-impedance
a	Rotates a vector anti-clockwise through 120°, extensively used in symmetrical component analysis
dT	Time delay tolerances,
j	Rotates a vector anti-clockwise through 90°
kV	Transformer secondary voltage in kV
m	Safety margin
q	Auxiliary factor depend on the minimum breaker tripping time and the rated power per pole pair of the machine
t	Theoretical operating time
tr	Upstream protection unit overshoot time,
α	Constants

β	Constants
θ	Phase angle error
κ	Auxiliary factor to consider the maximum asymmetric short circuit current
μ	Permeability of the medium
μ	Auxiliary factor to consider the breaking current for asynchronous machines
μo	Permeability of free space = $4\pi 10^{-7}$
μr	*Relative permeability of the specific medium*
φ	Flux

CHAPTER 1
GENERAL INTRODUTION

This chapter provides the general information that lays the basis of the thesis. It further gives a brief presentation on the distribution network protection, the concept for the substation automation system and the relays basic functional characteristics that are required in terms of protection.

1.1 INTRODUCTION

As the electrical national grid expands, the number of distribution networks has increased tremendously in the past few years. For an electrical distribution network to function in a stable and reliable way, it should be protected. This is only achieved if the protection system of the electrical network involved complies with the requirements and purpose of the electrical protection standards. These requirements include the Operational speed, Reliability, Security and Sensitivity **(Pathirana, 2004)**. The main objective of a protection scheme is mainly to keep the power system stable by isolating only the affected components or the section of the electricity network in which the fault has developed while allowing the rest of the network to continue operating. It is important to note that the protection equipment does not prevent faults from occurring, but it limits the damaging effect of the fault and protects other healthy equipment **(Soudi & Tomsovic, 1999)**. A large amount of the distribution network data must be logged and interpreted accurately. This will assist the protection engineers to select and ensure that the correct protection equipment is used for the correct application. Distribution network protection involves interaction with human operators in the control centres and in the field, thus the effects on the distribution network must be understood to ensure that the safe and effective protection of the network is not compromised. Additionally system checks and safety checks must be performed to ensure equipment ratings are not exceeded and personal safety is not compromised in order to increase reliability in a complex distribution network.

Protection engineers therefore spend more time on studying the power system networks and use different protection equipments to find the most cost effective as well as technically viable ways to protect the power system networks. These engineers frequently make decisions that involve tradeoffs among alternatives. The best solution is often not clear due to the fact that no single alternative will satisfy all objectives. Most questions that rise during this process are whether the protection scheme should learn toward greater dependability or greater security, as to whether the fast clearing times are necessary or whether cheap protection schemes are acceptable? It is therefore impossible to apply a single protective relaying scheme that is suitable for each attribute, making tradeoffs necessary. The number of alternatives available, the complexity of the attributes that each alternative is to be rated against and any uncertainties in meeting these attributes, all contribute to the degree of difficulty in making decision. Here the engineering decision analysis technique is being implemented, therefore serving as a guiding and helping tool **(Larson, 2007:1).**

Recently, due to concerns about the liberalization of electricity supply, deregulation and global impact on the environment, securing a reliable power supply has become an important social need worldwide. To ensure this need is fulfilled, detailed investigations and developments are in progress on power distribution systems and the monitoring of apparatus, **(Hiroshi et al, 2002)**. Part of these are the demands for future intelligent control of substations, protection, monitoring, and communication systems that have advantages in terms of high performance, functional distribution and integrated power distribution management. By promoting and exercising these developments, an intelligent substation can be built and a reduction in costs involved and profitable saving for the reliable power system can be expected.

The electrical power network is made up of three key sections. These sections include the generation, transmission and distribution section. Distribution section is responsible for the transfer of high voltage electricity through a localized distribution network, which reduces the voltage and provides a connection to the premises of the end customer including most Municipalities. This distribution network consists of overhead lines in rural areas, underground cables in urban areas, and a number of substations operating at successively lower voltages. Since electrical utilities invest millions of rand in electrical network in order to distribute electricity, it is therefore essential for any company to effectively protect its investment against damage. This is achieved by the installation of protection relays on the network.

In this particular research project, distribution network protection is the area of interest. An investigation of different protection alternative and the implementation of new technologies for Electrical Power Distribution Systems (EPDS) that combine protection and control units so that they can be incorporated into an intelligent substation as opposed to the most existing (conventional substation) is the main objective and is exercised in the thesis.

1.2 SUBSTATION AUTOMATION SYSTEM

Substation Automation (SA) system can be defined as a system for monitoring, managing, controlling and protecting a power system. This is accomplished by obtaining real-time information from the power system, having powerful remote and local control applications as well as advanced electrical protection. The core ingredients of a Substation Automation system are data communication, local intelligence, and supervisory control and monitoring. The term Substation Automation is too restrictive and may be misleading at times. This is in the sense that it refers specifically to substations only. The concepts encompassed in the definition have a broad application than being limited to substations only since it is applicable to electrical power networks at large, from High Voltage transmission networks, via Medium Voltage distribution networks, to Low Voltage reticulation networks. The Substation Automation is gradually developing and most of the equipment that forms the core of such a system is located in an electrical substation or switch room. The modern, intelligent devices ensure that the need for human intervention or presence in substation is minimal **(IDC Engineers pocket guide, 2003: 30-31)**.

Note: *The term "substation" is used throughout the research to describe mainly buildings housing electrical switchgear, but it may also include switchgear housed in some sort of enclosure, for example a stand-alone Ring Main Unit, etc.*

1.2.1 Functional Structure of Substation Automation system

Substation Automation system, by definition, consists of the following main functional components:

- Measurement
- Monitoring
- Data Communication
- Electrical Protection
- Control

1.2.2 Measurement

A wealth of real-time information about a substation or switchgear panel is collected. The data are typically displayed in a central control room and/or stored in a central database. Measurement consists of:

- Electrical measurements (including metering) - voltages, currents, power, power factor, harmonics, etc.
- Analogue measurements, e.g. transformer and motor temperatures
- Disturbance recordings for fault analysis

This makes it unnecessary for personnel to go to a substation to collect information, again creating a safer work environment and cutting down on personnel workloads. The amount of real-time information collected can assist in doing network studies such as load flow analysis, planning and the prevention of major disturbances in the power network that cause production losses.

Note: *The term 'measurement' refers to current, voltage and frequency, while 'metering' refers to power, reactive power, and energy (kWh). These different terms originated due to the fact that different instruments were historically used for metering and measurement. Nowadays the two mentioned functions are integrated in modern devices, with no real distinction between them, hence the terms 'measurement' and 'metering' are used interchangeably in this research.*

1.2.3 Monitoring

The monitoring functions include:

- Sequence-of-Event Recordings
- Status and condition monitoring, including maintenance information, relay settings, etc.

This information is handy since they can assist in fault analysis, to determine what happened where, when and in what sequence. The above mentioned can effectively improve the efficiency of the power system and the protection thereof.

1.2.4 Data Communication

Data communication forms the core of any Substation Automation system, and is virtually the glue that holds the system together. Without communications, the functions of the local control and electrical protection will continue, but there is no complete Substation Automation system functioning. The form of communications will depend on the used architecture, while the architecture may in turn depend on the form of protocol chosen.

1.2.5 Electrical Protection

Electrical Protection is still one of the most important components of any electrical switchgear panel, in order to protect the equipment and personnel and to limit damage in case of an electrical fault. Electrical protection is a local function and must be able to function independently of the Substation Automation system if required, although it is an integral part of this system under normal conditions. The functions of electrical protection should never be compromised or restricted in any Substation Automation system **[Strauss, 2003].**

1.2.6 Control

Control function includes local and remote control. The automatic control functions allow the risk of human error to be greatly reduced. Local control should continue to function with or without the support of the rest of the Substation Automation system. Relay settings can be altered via the system, and requests for certain information can be initiated from the remote SCADA station. This has eliminated the need for personnel to go on site to perform switching operations, as switching actions can be performed much faster remotely, which is a major advantage in emergency situations. In addition, the operator at the SCADA terminal has a clear overview of what is happening in the power network throughout the plant, and this improves the quality of decision-making.

1.3 MODERN SUBSTATION COMMUNICATION ARCHITECTURE

Different communication architectures exist today by implementing components of Substation Automation system in different practice. The most advanced systems nowadays are developing more and more towards a common basic architecture and this is illustrated in Figure 1.1. The modern systems consist of three main divisions: **(IDC Engineers pocket guide, 2003: 34-37)**.

1.3.1 Object Division

The object division of the Substation Automation system consists of Intelligent Electronic Devices (IEDs), modem, and 3rd generation microprocessor based relays including Remote Terminal Units (RTUs). The component division consists of the process and the bay level.

1.3.2 The Communications Network

The Communications Network is virtually the nervous system of the Substation Automation system. The communication network ensures that raw data, processed information and commands are relayed quickly, effectively and error-free among the various field instruments, IEDs and the SCADA system. The physical medium is fiber-optic cables in modern networks, although some copper wiring still exists between the various devices inside a substation. The communication network needs to be an 'intelligent' subsystem in its own right to perform the functions required of it, and is not merely a network of fiber-optic and copper wiring. The communication networks serve as the interface between the bay level and the SCADA station, which might be a SCADA master station in the substation itself, or placed remotely in a central control room.

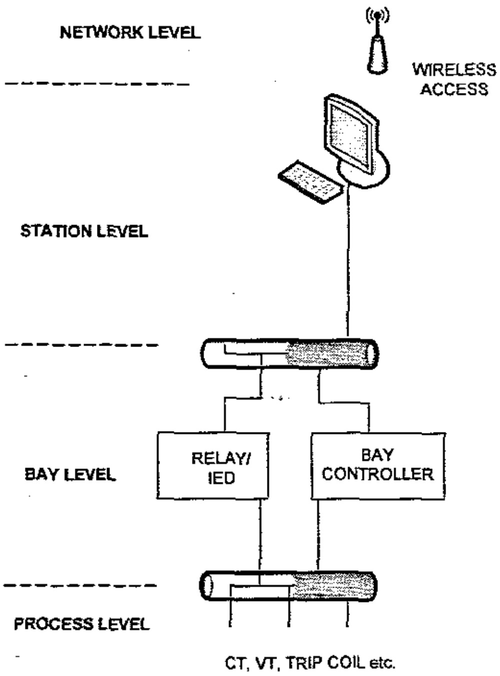

Figure 1.1: *Typical Substation Automation system's structure*

1.3.3 SCADA Master

The SCADA (Supervisory Control and Data Acquisition) master station forms the virtual brain of the Substation Automation system. It receives data and information from the field, and then decides what to do with it **(Lohmann, 2000).** Nowadays, it simply consists of an advanced, reliable PC or workstation with its peripheral and support hardware and a SCADA software package.

The system structure can be implemented using historically developed generations of relays, types of communications, protocols and so on. The considerations in the thesis are based on the use of the new IES 61850 standards for substation automation and their implementation through the new types of relays – the Intelligent Electronic Devices (IEDs) capable to communicate using Ethernet networks.

1.4 POWER SYSTEM PROTECTION

As noted above, the protective system encompasses more than just the protective relays themselves. The type of protective scheme and the type of communication channel will also affect the performance and security of the overall protective system. For this reason, the technology and philosophies utilized in protection schemes should be up to date and well-established because they must be very reliable. Protection systems usually comprise of five components:

- Current and voltage transformers to step down the high voltages and currents of the electrical power system to convenient levels for the relays to deal with.
- Relays to sense the fault and initiate a trip, or disconnection, order.
- Circuit breakers to open/close the system based on relay and auto-recloser commands.
- Batteries to provide power in case of power disconnection in the system.
- Communication channels to allow analysis of current and voltage at remote terminals of a line and to allow remote tripping of equipment.

Failures that may occur could be, such as fallen or broken transmission lines, insulation failure, incorrect operation of circuit breakers, short circuits and open circuits. Protection devices are installed with the aims of assets protection as well to ensure continuity of supply **(Moore, 2009).** The three classes of the used protective devices are:

- Protective relays that control the tripping of the circuit breakers surrounding the faulted part of the network
- Devices with automatic operation, such as auto-reclosing or system restart devices
- Monitoring equipment which collects data on the system for post event analysis

While the operating quality of these devices, and especially of the protective relays, is always critical, different strategies are considered for protecting the different parts of the system. Completely redundant and independent protective systems can be applied to the important gear.

1.4.1 Functionality and operational sequence

Imagine crossing a busy street. As you walk you become aware of an approaching vehicle by means of your senses (hearing). You look (sight) in the direction of the car and based on your experience (memory) your brain makes a decision on what your body should do to protect yourself. The brain takes action and commands the body to run out of the way. During the above scenario three distinct phases can be distinguished. The first one is called the awareness phase. The second is making decision and the third is taking action **(Jacobs, 2006).**

The protection system operates in exactly the same way. Electrical quantities (voltage, current, frequency, etc.) are fed into (awareness) the protection relay and based on its program / internal configuration, the protection relay makes a decision on what to do and causes a circuit breaker to trip (action), see Figure 1.2 for the flow sequence.

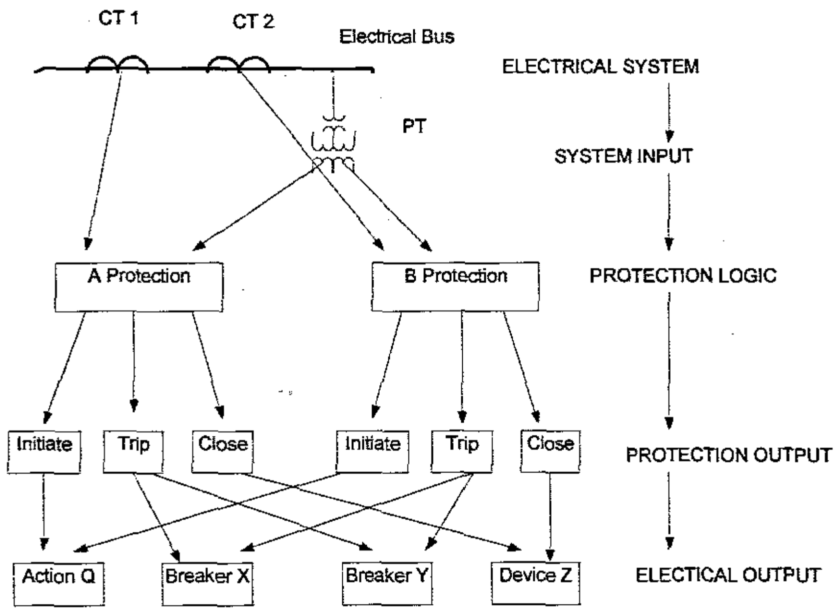

Figure 1.2: Block diagram of protection operation

1.4.2 Types of Protection

Medium voltage distribution network - Protection on the distribution network serves two important functions such as: Protection of the plant and that of the public (including employees). At a basic level, protection looks to disconnecting equipment which experiences an overload or a connection to earth. Some of the items found in substations such as transformers may require additional protection based on temperature or gassing among others.

- **Overload** - Overload protection requires current transformer which only measures the current in a circuit. If the current exceeds a pre-determined level, the circuit breaker or fuse should operate.
- **Earth fault** - Earth fault protection again requires current transformers that sense an imbalance in a three phase circuit. In general a three phase circuit is in balance, therefore if a single (or multiple) phases are connected to earth, a current imbalance is detected. The circuit breaker will therefore operates should the imbalance exceeds the predetermined value.
- **Distance** - Distance protection detects both the current and voltage. A fault on the circuit will normally creates a sag in the voltage level. If this voltage falls below the pre-determined level while the current is above a certain level the circuit breaker will operate. This is useful on long lines where if a fault was experienced at the end of the line the impedance of the line may inhibit the rise in current. Since voltage sag is required to trigger the protection.

- **Back-up** - At all times the objective of protection is to remove only the affected portion of plant and nothing else. Sometimes this does not occur for various reasons which can include:
    - Mechanical failure of a circuit breaker to operate
    - *Incorrect protection setting*
    - Relay failures

  A failure of primary protection will usually result in the operation of back-up protection which will generally remove both the affected and unaffected items of plant to remove the fault.

Low voltage distribution networks - The low voltage network generally relies on fuses or low voltage circuit breakers for the removal of both the overload as well as earth faults.

1.4.3 Protective Relays

A protective relay is a device, which operates to disconnect a faulty part of the system, thereby protecting the remainder of the system from further damage. The relay detects the abnormal conditions in the electrical circuits by constantly measuring the electrical quantities which are different under normal and fault condition. The electrical quantities that may change under fault conditions are voltage, current, frequency and phase angle. Through the changes in one of these quantities, the faults signal their presence, type and location to the protective relays. Having detected the fault, the relay will then operate to close the trip circuit of the breaker, resulting in the breaker opening and disconnecting the faulty circuit. In effect, power protection has the following five most important aims as its levels of control and functionality, as shown in order of priority below **(IDC Engineers pocket Guide, 2003: 14).**

- To minimize damage
- To safeguard the entire system
- To ensure safety of personnel
- To reduce resultant repair costs
- To ensure continuity of supply

All of these requirements make it necessary to ensure early detection, localization, and rapid isolation of electrical faults and additionally prompt a safe removal of faulty equipment from service. Very important specifications of the relays are their time of operation and the principles of their operation determined by the function needed to be implemented, as follows:

1.4.3.1 Relay Timing

Time of operation is one of the characteristics that are important in terms of protection relays. Operating time means the time taken from the instant when the actuating element is energized to the time when the relay contact is closed. This time is controllable by applying different settings that are ideal or applicable to a certain application and in general the relays are provided with controls to cater for operation time adjustment.

1.4.3.2 Functional relay types

Relays are generally classified according to the functions they are called upon to perform in the protection of electric power system. An example is given in terms of a relay that recognizes over current in a circuit and initiates corrective measures; this relay is termed an overcurrent relay. In order to understand the above the following examples are shown below as follows:

- **Overcurrent relay (non directional):** This type of relay initiates corrective measures when the circuit current exceeds the predetermined value. In this regard the actuating source is the current in the circuit supplied to the relay by the current transformer. These types of relays are applied in alternating current (A.C.) circuits only and can operate for fault current flowing in either direction and for a directional relay; the operation will only take place for a specific direction.
- **Distance or impedance relay:** So far the operation of the relays mentioned above depends upon the magnitude of current in the protected circuit. However there is another group of relays in which the operation is governed by the ratio of the applied voltage to current in the protected circuit. These relays are called distance or impedance relays and they operate when the detected impedance is less than the predetermined value.
- **Differential relay:** This is a relay that operates when the phasor difference of two or more identical electrical quantities exceeds a pre-determined value. Therefore in terms of current, the differential relay perform on a basis of Kirchhoff's law that states that the sum of current entering a node is equal to the sum of current leaving that same node. This condition changes as soon as the fault occurs in the system.

1.4.4 Instrument Transformer

Current and voltage transformers are required to transform high currents and voltages into more manageable quantities for measurement, protection and control. Most of the relays used in power systems operate by virtue of the current and/or voltage supplied by current and voltage transformers connected in various combinations to the system element that is to be protected.

The three main tasks of instrument transformers are :**(Hewitson et al, 2004: 44).**

- To transform currents or voltages from a usually high value to a value easy to handle for relays and instruments.
- To insulate the relays, metering and instruments from the primary high voltage system.
- To provide possibilities to standardize relays and instruments to few rated currents and voltages.

1.4.4.1 Current Transformer

A current transformer is used to transform a primary current quantity in terms of its magnitude and phase to a secondary value such that in normal conditions the secondary value is substantially proportional to the primary value. In terms of protective purposes the knee point can be used to define current transformer specifications. This is the voltage applied to the secondary side of the CT with all other windings open circuited, which, when increased by ten percent, causes the increase in exciting of 50% (Bayliss & Hardy, 2006).

1.4.4.2 Voltage Transformers

There are two types of voltage transformers used for protection equipment, the purely electro-magnetic type (commonly referred to as a VT) and the Capacitor type (referred to as a CVT). Electromagnetic VT's are also referred to as inductive voltage transformers and are fundamentally similar in principle to power transformers but with rated outputs in VA rather than kVA or MVA. It is however normal to use this type of voltage transformer up to the system rated voltages of 36kV. Above this voltage level, the capacitor VTs become more cost effective and are frequently implemented.

1.4.5 Electrical Faults

Electrical faults usually occur due to breakdown of the insulating media between live conductors or between a live conductor and earth. This breakdown may be caused by any of these factors, e.g. overheating, mechanical damage, ionization of air, voltage surges (caused by lightning or switching), ingress of a conducting medium, and deterioration of the insulating media due to an unfriendly environment or old age, and misuse of equipment. Fault currents release a vast amount of thermal energy, and, may cause fire hazards, major destruction to equipment and risk to human life if not cleared quickly.

Switchgear should be rated correctly to withstand and break the worst possible fault current, which is a solid three-phase short-circuit close to the switchgear. The different faults that mainly occur on the power system are indicated in Figure 1.3 below. From Figure 1.3 it is evident that there are balanced and unbalanced faults. A balanced fault is where the current magnitudes in all three phases are equal. High currents (magnitudes higher than the load current) flow during fault conditions and the magnitude of the fault is dependent on the fault location and the equivalent impedance between the fault and the generation sources.

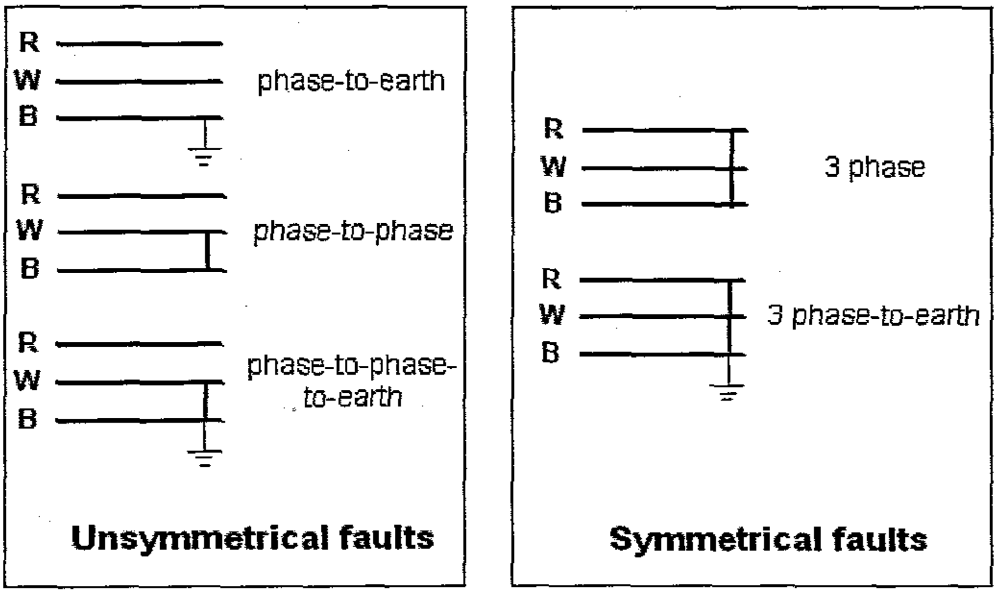

Figure 1.3: *Different power system faults*

Transient faults are faults that do not damage the insulation permanently and as such allow the circuit to be safely re-energized after a short period of time. A typical example in this case could be an insulator flashover following a lightning strike, which could be successfully cleared by opening of a circuit breaker, which could then be automatically reclosed. Transient faults occur mostly on outdoor equipments where the main insulating medium is air. Permanent faults, as the name implies, are the consequence of permanent damage to the insulation of either the transmission medium or any associated equipment that is attached to it **(Hewitson et al, 2005).**

1.4.6 Calculation of short circuit currents

Accurate fault current calculations are normally carried out using an analysis method called "Symmetrical Components." This method involves the use of higher mathematics and is based on the principal that any unbalanced set of vectors can be represented by a set of 3 balanced systems, namely; positive, negative and zero sequence vectors. However, for practical purposes, it is possible to attain a good approximation of three phase short circuit currents using some very simplified methods **(De Kock, 2004).**

1.4.7 Fuses

This is probably the oldest, simplest, cheapest used type of protection device. The operation of a fuse is very straightforward in that: The thermal energy of the excessive current causes the fuse-element to melt and the current path is interrupted. Through technological developments fuses are more predictable, safer and faster (not to explode).A common misconception about fuses, is that they will blow as soon as the current exceeds the rated value. This is contentious. A typical fuse has an inverse time-current characteristic, much similar to an IDMT relay. The pick-up value starts approximately at twice the rated value and the higher the current, the faster the fuse blowing action. By nature, fuses can only detect faults that are associated with excess current. Therefore, a fuse does not offer the required adequate earth fault protection **(Strauss, 2003)** *and they are not considered in the thesis.*

1.5. PROTECTION FUNCTIONAL CHARACTERISTICS

Before any further discussion, it is very important to view and understand the purpose of the protection system and the required basic functional characteristics that protective relays should satisfy in order to perform their function properly. These basic functional characteristics include: **sensitivity, selectivity, speed dependability, security and reliability.**

1.5.1 Sensitivity

Sensitivity applies to the ability of the relay to operate reliably under the actual condition that produces the least operating tendency, e.g. the time-overcurrent relay is expected to operate *under the minimum* set fault current condition. In the normal operation of a power system, generation is switched in and out to give the most economical power generation for different loads which can change at various times of the day and various seasons of the year. The relay on a distribution feeder must be sensitive enough to operate under the condition of minimum generation when a short circuit at a given point to be protected draws a minimum current through the relay. *NOTE: On many distribution systems, the fault-current magnitude does not differ very much for minimum and maximum generation conditions because most of the system impedance is in the transformer and lines rather than the sources themselves* ***(Burke, 1994).***

1.5.2 Selectivity

Selectivity is the ability of the relay to differentiate between those conditions for which immediate action is required and those for which no action or a time-delayed operation is required. The relays must be able to recognize faults on their own protected equipment and ignore, in certain cases, all faults outside their protective area **[James, 1994]**. It is the responsibility of the relay to be selective in the sense that, for a given fault condition, the minimum number of devices should operate to isolate the fault and interrupt service to the fewest customers possible. An example of an inherently selective scheme is differential relaying; other types, which operate with time delay for faults outside the protected zones, are said to be relatively selective. If protective devices are of different operating characteristics, it is especially important that selectivity be established over the full range of short-circuit current magnitudes.

1.5.3 Speed

Speed is the ability of the relay to operate in the required time period. Speed is important in clearing a fault since it has a direct bearing on the damage done by the short-circuit current; thus, the ultimate goal of the protective equipment is to disconnect the faulty equipment as quickly as possible. Critical clearing times for a transmission line are often used to determine the required operating speed for the transmission line protection. These critical clearing times are usually based on close in three phase faults. It is obvious that a three phase fault at one of the line terminals of the system would prevent the transfer of any power and thus must be cleared in high speed **(Alexander & Andrichak, 2004).**

For lower source to line impedance rations (Zs/ZL), as the fault is moved towards the centre of the line, more power can be transferred during the fault, thus permitting longer operating times. Similarly, a phase to ground fault, even at one of the line terminals, has much less effect on the power transfer capability of the system. In fact, the system may be able to transfer more power during a single line to ground fault than after the breakers have been opened to clear the fault. In terms of system stability it is critical to trip the breaker near the fault in high speed for close-in faults to minimize the effect of the fault on the power transfer capability. Once the near end clears, the fault appears as a high impedance fault to the remote terminal and power transfer capability is increased thus helping to maintain stability. Consequently, it is not so critical to trip as fast at the end of the line remote from the fault **(Andrichak, 2005).**

1.5.4 Reliability

A basic requirement of protective relaying equipment is that it be reliable. Reliability refers to the ability of the relay system to perform correctly. It denotes the certainty of correct operation together with the assurance against incorrect operation from all extraneous causes. The proper application of protective relaying equipment involves the correct choice not only of relaying equipment but also of the associated apparatus. For example, lack of suitable sources of current and voltage for energizing the relay may compromise, if not jeopardize, the protection.

1.5.5 Dependability

Dependability is considered to be one of the most important requirements for any protective relay system since the non-operation of the protective relaying equipment can result in the destruction of a power system component and the collapse of the power system. In this document, the term "protective relay system" refers to more than a set of relays.

The protective relay system consists of the complete complement of protective elements covering a zone of protection (including backup relaying), any associated communications equipment and power system components such as current and potential transformers. There are a number of factors that affect dependability directly. Perhaps the most important factor is the design of the relays and schemes used for protection. The relay measuring elements and schemes should have the characteristics and sensitivity to detect all faults up to the limitations imposed by system and fault conditions **(Andrichak & Wilkinson, 2003).**

Every relay system has limitations; for example, each relay has a current level (sensitivity) below which it cannot respond. Thus, for some low level faults on the line, the protection cannot be expected to operate. Another contributing feature is the availability of the protective gear. If the equipment is not available to perform its function at the time it is needed, then the dependability of the protective system is reduced. Maintenance and hardware reliability are factors which affect availability. Equipment which requires periodic adjustments, cleaning of contacts, etc. will not be available for protection during the maintenance period, thus reducing dependability **(Madhava, 1980).** The higher reliability of digital relays, along with their self test features, improves their availability, and therefore the dependability of the protective system.

1.5.6 Security

The security of the relay system is at least as important as its dependability because an incorrect operation of a protective system reduces the overall reliability of the power system. In fact, a review of major system disturbances, such as blackouts, will show that the disturbance is more likely to be caused by the malfunction of a protective system rather than the non-operation of a system. The malfunctions may be of the sympathetic trip nature, where a protective system on a non fault line operates for an external fault; or it may be caused by a miss-set relay that operates due to a short term increase in load caused by the opening of another line in the system. In addition, the security of a protective relay system can be adversely affected by system transients, current and voltage transformer transients, and series capacitor transients, surges produced by switching on the high voltage system or in the dc control circuit, and by radio frequency interference. The overall security of a protective system can be greatly improved through the use of relay equipments that are properly designed to perform correctly in the harsh substation environment **(Andrichak & Wilkinson, 2003).**

The considered performance characteristics depend on the technology of relay producing, the structure of the substation automation system, the type of communication channels and protocols used between the levels of the system and between the protection devices. The thesis is investigating the possibilities for improvement of the relays functional characteristics as a result of development of IEC 61850 standard based substation automation systems by development of:

- lab-scale systems for testing of the protection functions, and
- protection systems for two types of distribution networks: CPUT reticulation and EUREKA networks.

1.6 SUMMARY OF CHAPTERS

The thesis contains seven chapters that explain the perceptions, developments and the results of the research.

Chapter 1 gives the general information that lays the basis of the thesis. It further gives a brief presentation on the distribution network protection, the concept for the substation automation system and the relays basic functional characteristics that are required in terms of protection.

Chapter 2 presents the background, main research question, problem statement, aim and objectives of the thesis. It further identifies the types of software's; the research methods used and lay the groundwork of the thesis.

Chapter 3 briefly presents the thesis literature review. A brief look at the IEC61850 standard, its benefits and challenges associated with it is covered. Analysis of the papers presenting different topics in protection in the environment of the standard based substation automation system is done in the table form. Some remarks and recommendations are given at the end of the chapter.

Chapter 4 presents the main types of faults that occur in electrical power systems. The generation and development stages of protective relays are presented. The chapter further describes in some details the concepts of relay input sources. The protection functions and applications of protective relays and multifunctional devices (IED's) in a distribution environment are carried out.

Chapter 5 covers the modelling and protection design, simulation studies and analysis of the CPUT and Eureka distribution network using DIgSILENT.

Chapter 6 analyzed the effect of using Ethernet networks and IEC 61850 protocols for protection, integration and automation. It describes the use of IEC 61850 GOOSE messages to communicate high speed information between IED's on a local area network.

Chapter 7 *summarizes the main results obtained in the thesis. It provides general conclusions* and discussions on the findings, suggestions and recommendations.

1.7 CONCLUSION

In conclusion this chapter gives a brief presentation on the distribution network protection and the basic functional characteristics that are required in terms of protection. The six basic functional characteristics are well explained to address instability which is the greatest danger to a healthy power system that results from faults that are not cleared on time. The chapter further provides the general information that lays the basis of the thesis. The background, main research question, problem statement, aim and objectives of the thesis will be covered in chapter 2.

CHAPTER 2

BACKGROUND, PROBLEM STATEMENT, AIM, AND OBJECTIVES

This chapter presents the background, main research question, problem statement, aim and objectives of the thesis. It further identifies the types of software's; the research methods used and lay the groundwork of the thesis.

2.1 BACKGROUND

Due to the growing demand of power and a higher efficiency of power distribution, protection of power systems has become a backbone of any power network. The complexities of the power networks and the low stability margin at which they are currently operating have a dramatic increase in the occurrence of catastrophic failures in electric power systems **(Pathirana, 2004).** In conventional substations that still exist within the power network, substation equipment such as switchgear and transformer, control, protection, and monitoring apparatus are independent of every other device. A number of long cables are then used to complete the links between these devices in order for them to communicate (hardwired). This method is uneconomical and it is therefore very important to refrain from these old protection systems and embark on the application of new technology (the IEC61850 compliant equipments) that will reduce the wiring within substations, improve communication among protection equipments using Generic Object Oriented Substation Event (GOOSE) messages over Ethernet, and simplify the complexity of substation within power systems. The applications of the IEC61850 standard will also contribute to the stability of the power systems. A successful protection, control and substation automation require a protection engineer to identify and implement the most appropriate technical and financial solution for the newer substations as well as for the upgrading of existing substations. Over the last few years the new standard for substation automation communication, IEC 61850 has been developed by the International Electrotechnical Commission (IEC). This is basically one of the factors that brought about the term substation protection, control and automation hence the IEC 61850 is more than just a new standard for communication within substation **(McDonald, 2004).** Beside introducing data models for all major substation components and defining services to allow for mapping on the mainstream communication stacks, this new standard is also designed to fulfil the following requirements:

- **Interoperability**
  Intelligent Electronic Devices (IEDs) from various manufacturers are able to exchange and use the information for their own functions
- **Future proof**
  Here the basis for the standard is the data models that relate to the basic functionality of the substation, which changes less rapidly than communication or automation technology.
- **Flexible design**
  The new standard users have the flexibility to freely allocate the various functionalities to the devices that form the substation automation system (SAS).

When a complete set of the IEC 61850 products is available, the new standard applications will result in an integrated system of all the substation equipment (non-conventional). This integrated system includes instrument transformers, protective relays, control systems as well as *high voltage (HV) switchgear that is controlled and supervised using the IEC 61850 process* and station bus. Based on this standard integration, specification, implementation, testing and maintenance of an IEC 61850 based system can no longer be handled by communication specialists only but will require coordination between various disciplines and knowledge areas ,such as:

- Protection and protection systems
- Protection relays functional testing
- Substation control and automation
- SCADA and distribution automation
- Communication technology
- Protocol testing etc

This standard defines the integration requirements of multi-vendor compliant relays and other IEDs for multiple protection schemes as well as control and automation techniques. All these are managed under a hierarchical supervisory control and data acquisition system (SCADA). Since Protection System Design (PSD) and Power System Automation (PSA) require the art of professional workmanship, engagement in technical discussions with distribution network engineers and operators as well as with national and international experts is required to ensure that the actual implementation follows the standards and its regulation. Application of the standard worldwide is still limited and implemented very often according to the vendor's interpretation of the standard requirements.

2.2 STATEMENT OF THE PROBLEM

The capital investment involved in the distribution of electrical power is so high that proper precautions have to be taken to ensure that the equipment not only operate at high efficiency but are also protected from possible faults. The existence percentage of conventional substations in which the substation equipment such as switch gear and transformer, control, protection and monitoring equipment is independent from one another while the connection is being provided by the interconnected signal cables is still high. If protection equipment fails to operate or discriminate correctly under fault conditions, this can have serious implications for the power system through system damage and risks to personnel **(Mc Dowell & Uddin, 2005)**.On the other hand the economic penalties associated with such events is now important since the end users relies heavily on the availability of stable and quality power supply. Although a complete resistance from such disastrous failures is not easily achievable, new development in the distribution protection environment is promising and power outages can be minimized and alleviated. At the same time the application of substation automation standards-based solutions is still limited. There are not consistent studies of the benefits from the new technology solutions for different protection cases in distribution network. Therefore investigation of the application of the IEC61850 standard will be of benefit as opposed to the existing conventional systems.

The research work of the thesis is in the field of investigation of the capabilities of the new compliant with the requirements of IEC61850 standard IEDs of different vendors to operate in integration, providing innovative solutions of the protection problems in distribution network and in this way to improve the functional characteristics of the conventional relay and the stability and cost effectiveness of the power system. Based on the above mentioned, the main research question of the project can be formulated as follows:

How to apply the new compliant IEC 61850 standard multi-vendors IEDs' data models, functions, capabilities for communication by GOOSE messages, software and hardware in order to achieve innovative and better than conventional (according to the functional characteristics) solutions of the protection problems in distribution networks. Can the application of the IEC61850 compliant IED's contribute to the integration of substation equipment in order to address the conversion of conventional substations into non-conventional substations and minimize instability in power systems?

To answer of the above research question the following problem is stated to be solved in the thesis:

Problem statement: To analyze the application of the IEC 61850 standard, to develop and investigate alternative standards-based protection solutions for CPUT and Eureka distribution networks and to investigate their functional characteristics by simulation and real-time implementation in a lab-scale test system.

2.2.1 Sub-Problems

2.2.1.1 Site survey and data collection

A site survey of the CPUT and Eureka networks to be conducted in order to collect the protection data using a well established methodology tailored to the site layout. This survey includes a visit to all major switch rooms. Protection forms are used for collecting the information either directly from site equipments or from existing site records.

2.2.1.2 Existing Network analysis

In the case of existing network, the research starts with comprehensive protection audit. A protection audit provides an effective assessment of a power distribution system without a commitment to a full scale power system study. This minimizes the impact that failures could have on the network by reviewing the protection co-ordination of the power system.

2.2.1.3 New Network analysis

A protection philosophy is developed based on the system requirements. This philosophy is used to derive the specifications and design of protection schemes. Relay settings are calculated in order to provide optimum protection for the network and that of the maintenance personnel. If the protective devices are already specified, then verification of their application efficiency and setting issued should be verified.

2.2.1.4 Identify the components/equipments for reliable protection

A reliable protection scheme is essential for the safe and economical protection of any power system. Protection equipment that fails to operate or discriminate correctly under fault conditions can have serious implication for the power system through increased disruption, system damage and pose risk to human.

2.2.1.5 Calculation of relay setting

Relay settings are calculated in order to provide optimum protection for the network 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 correspond to the characteristics required.

2.2.1.6 Fault analysis using simulation

Different types of fault are applied in different sections within the network using DigSilent software in order to assist in the analysis of the suitable protection methods and equipments selection.

2.2.1.7 Real time implementation on different software and hardware platforms

For real time implementation the project uses different software and hardware platforms as follows:

- **DIGSI4/SIGRA4** for modelling and system simulation, the software consists of the test system hardware, the basic software (including the device database) and the VD monitor (Vector Diagram Monitor).This equipment enables operation of all the test system's functions. In addition to the VD monitor, other test monitors are available which serve to simplify, automate and thus to speed up tests for various types of relay (Inverse time overcurrent and earth fault relays, distance protection relays, etc.)
- **Dig Silent** for power systems modelling and protection co-ordination
- **DIGSI4** for simulation, set up and programming of the IED's
- ***OMICRON*** *for fault injection, testing of relays and GOOSE configuration*
- **IED's** for tripping and fault clearance

2.2.1.8 Operating and control results comparison

The operating and control result are compared and validated. The analyses are based on the elements response results, accuracy, modern control theories and compatibility.

2.2.1.9 Analysis of the protection report

Protection coordination studies are conducted using DIgSILENT software. Here the calculation for the main and unit protection devices applied on busbar, transformer and feeders of distribution network, are carried out. These calculations are carried out in accordance with the international electro technical commission (IEC) standards in order to validate the existing settings as well as providing settings for new networks. The protection studies for the new network or existing network is fully documented in the report with the following:

- Protection philosophy

- Site survey record
- Network diagram for each section studied
- Existing and proposed protection grading curves
- Methodology and setting calculations for unit protections
- Methodology and settings for system control (e.g. Auto reclosing on distribution system)
- Existing and proposed relay setting schedules

2.3 RESEARCH AIM AND OBJECTIVES

The aim of this project is to develop and investigate correct and improved distribution networks protection technique using the IEC61850 standard in order to protect, integrate and automate the substation operations in a profitable, safe, responsible and environmentally friendly way and to apply the developed methods to the CPUT distribution network. Cape Peninsula University of Technology (CPUT) always consider and take responsibility for the long term academic, economic, social and environmental implications. Therefore the decision to approve this research was not only made to benefit the institution but also to address the education and training deprivation that affect many of the students and communities at large.

2.3.1 Main objectives of the research

Theoretically and technically the research aim is to acquire a highly sophisticated protection and integrated substation control system through acceptable IEC 61850 instruments as well as to provide smart solutions in distribution operations. The objectives are:

- To analyze the IEC 61850 technology available on the market
- To determine the need for the IEC 61850 equipments in substations
- To identify the protection system of existing network
- To identify and study various protection schemes used in distribution systems
- To use simulation package to study the efficiency, speed, sensitivity and reliability of recommended protection instruments and verify their operation
- To develop a test LAB for experimental purposes in order to gain extensive knowledge to design and engineer substation with IEC 61850 tools and equipment
- To test multi-vendor IED's for interoperability
- To estimate the benefits of the standards-based protection solutions on the basis of their applications to CPUT and Eureka networks

2.4 HYPOTHESIS

The research work on the thesis will prove that:

By implementing a new protection algorithm that is based on the IEC61850 protocol, it is possible to improve distribution substation protections schemes and provide smart solutions in distribution operations.

2.5 ASSUMPTIONS

In order to alleviate the complexity of system modelling and the simulation burden, the following assumptions are considered in the thesis protection studies:

- The site survey and data collection implementation give a clear understanding of the existing network.
- A protection audit provides an effective assessment of a power distribution system without a commitment to a full scale power system study.
- A protection philosophy is developed based on the system requirements.
- The used IEDs are compatible with the IEC61850 standard requirements and had a conformance test to prove it.

2.6 DELIMITATION OF THE RESEARCH

The proposed research focuses only into alternative protection solutions aimed for distribution networks using protection relays that are IEC61850 compatible. The main protection types that are part of this research are as follows: Feeder protection, Zone protection, Transformer protection, and Bus protection. The protection schemes under the above mentioned types are analyzed in details. The proposed schemes are modelled, set up and simulated using DIGSI4, DIgSILENT and OMICRON Test Universe V2.3 software in a protection testing Lab environment and thereafter should be implemented on the Cape Peninsula University of Technology (CPUT) and Eureka distribution networks. The study solutions are universal to cater for any existing or new distribution network.

2.7 MOTIVATION FOR THE RESEARCH PROJECT

As distribution systems become more complex, the opportunities to increase reliability multiply. Electric consumers are more often affected by distribution systems disturbances, than by transmission line disturbances. This is due to the closer proximity of the distribution system to trees, human activity, and plus the load itself. A utility can take advantage of multiple alternate sources to increase reliability. However it is not practical to require human dispatchers to perform all the necessary checks and operations. Most distribution protection, monitoring and control had remained relatively unchanged for years. Utilities are now starting to upgrade the protection, monitoring and control capabilities for their distribution systems with the new distribution automation technologies and SCADA **(Allen, 2008: 1-2)**.

Moreover the project poses a challenge in that, reliable protection, control and automation of power system is highly required as the electrical networks expand on daily basis. This is necessary for the safe and economical operation of power systems. Such challenging aspects are the author's motivation and inspiration for the project in question (i.e. Investigation into alternative protection solutions for a distribution network) using the IEC61850 standard.

2.8 RESEARCH DESIGN AND METHODOLOGY

The action plan implemented in this regard includes a thorough gathering of information on both the existing and developing networks. Since the research aim is to explore different protection phenomena and understand them fully, the following are the methods used to meet the *objectives of the research.*

2.8.1 Analysis of the selected method/scheme

Remedial Action Schemes (RAS) are designed to monitor and protect electrical systems by automatically performing switching operations in response to adverse network conditions to ensure the integrity of the electrical system and avoid network collapse. Therefore the methods and scheme chosen are analyzed by modelling all protection component of the network in a one line diagram using the simulation software. The system utilizes a number of different Intelligent Electronic Devices (IEDs) interconnected using a common networking and communication protocol to form an integrated scheme capable of performing automated protection of loads and communications to avoid collapse of the distributed electrical network. The analysis has outlined the design of the system, started with comprehensive system studies to examine and determine the requirements of the RAS. The analysis of the system is discussed including the architecture of the system as well as the selection of IEDs used and the role each plays in the overall scheme. Finally, the methods employed in the commissioning of the schemes are provided.

2.8.2 Simulation and test lab-scale system building

Substation protection relay has many uses and offers considerable value to utility operation, maintenance, planning, engineering, and protection of the system. New technology offers several alternatives to protect, collect, store, and distribute this information in an efficient and economical manner. These IEDs perform instrumentation and analysis of power system equipment based on specific vendor algorithms. Therefore the effects of all equipment in the system are studied, and the mathematical model of each is implemented. After the selection of IEDs to be used and the role each should play in the overall scheme, the complete network is therefore simulated using DIgSILENT software. The test LAB in conjunction with DIGSI 4, SIGRA4 and Test Universe V2.3 software is built for simulation and hands on practical operation. A testing Lab is also part of this research and is meant for experiments as well as simulation performance in order to gain knowledge and skills for designing and engineer substations with IEC 61850 equipments.

2.8.3 Site survey and Data collection

A site survey is conducted in order to collect the protection data using a well established methodology tailored to the site layout. This survey includes a visit to all major switch rooms. Protection forms are used for collecting the information either directly from site equipments or from existing site records. The collected data provided an effective assessment of the distribution system that leads to a reliable protection system that is essential for the safe and economical operation of the power system in question.

2.8.4 Documentation method

The documentation is theoretically split into three sections, of which the first have outlined the theory of the existing protection and proposed protection. It has further view and analyzes the application of multi-vendor IED's in terms of interoperability and outline the application, advantage and disadvantage of similar and that of different vendor combination. The protection system analysis and the mathematical modelling of all instruments are documented. The efficiency comparison of the protection systems before and after being upgraded is outlined. The second and third section has compiled a case study of the CPUT and Eureka distribution systems, where simulation, testing and emulation are performed.

2.9 CONCLUSION

In conclusion this chapter presents the thesis aim and objectives and the terms and concepts used throughout the thesis. The problem statement of the research and the analysis of steps taken in order to accomplish the research objectives are given. Different software's that are required for simulation and real-time implementation are identified. The thesis is aimed at investigating the alternative protection solutions for distribution networks that are in line with the integrated substation network architectures (the IEC61850 standard), taking the cost/benefit analysis into account.

Literature review of the existing standards-based substation automation and protection solutions is given in Chapter 3.

CHAPTER
3
LITERATURE REVIEW

This chapter presents the thesis literature review. A brief look at the IEC61850 standard, its benefits and challenges associated with it is covered. Analysis of the papers presenting different topics in protection in the environment of the standard based substation automation system is done in the table form. Some remarks and recommendations are given at the end of the chapter.

3.1 INTRODUCTION

As highlighted in chapter one and two, the study emerge from the concerns regarding the implementation of the IED's that are IEC61850 compatible and the level of competence of engineers and technician in South Africa. In order to understand the study (substation automation) a need to examine various aspects that are related to the study is required. The analysis of this chapter includes general views considering different aspects of protection in the area of distribution networks substation automation systems.

The general theory is explored pertaining to the changes in substation automation through the application of IEC61850 and with reference to the work of **Apostolov, et al., (2006)** as this writers have placed the issue on the theoretical platform, the theory underpinning the substation automation reform. The literature review incorporates the main problems of the existing conventional protection systems, needs for changes towards the new standard approach, benefits from application of the new standard based approach, type and methods of protection applied to be used with the new equipment, applications in power systems of the new standard based approach, what equipment is used from vendors point of view, problems existing in application of the new standard based approach, stability, faults and other characteristics achieved, using the new equipment etc.

3.2 GENARAL VIEW OF SUBSTATION AUTOMATION AND THE IEC61850 STANDARD

Traditionally protective relays have been electromechanical devices whose purpose was only to protect electrical power systems against system failures. Application of microprocessors to power system relaying has increased the functionality of protective relays and brought new concepts, which considers control, protection and monitoring functions integrated together. Since there are numerous methods and schemes for protection, a detailed research is done to access all the available methods and select the one that is more appropriate for this project since a modern power system needs precise and high quality control with protection functions as primary due to the top priority safety reasons. All the required information is gathered by reading related books, journals that are recently published, internet and research done in this field.

3.2.1 Definition of substation automation and the IEC 61850

In order to understand and implement the IEC61850 standard, it is important to first look at the definition of the concept of IEC61850 and substation automation. According to **Dolezilek and Udren, (2006), Vicente, et al., (2009)** the IEC 61850 can be described as the one solution for substation communications. The IEC 61850 standard, communications networks and systems in substations, provides an internationally recognized method of local and wide area data communications for substation and system protective relaying, integration, control, monitoring, metering, and testing. It has built-in capabilities for high-speed control and data sharing over communications network, eliminating most dedicated control wiring.

The reason why IEC 61850 is seen as the one solution is because it fulfils all the needs for communications within substations. The standard also provides the necessary tools for engineering the one solution. The standard defines all the required file formats to configure the substation and eventually configure the individual Intelligent Electronic Devices (IEDs).

Another definition as cited in **(Brand, et al., 2004),** the standard IEC 61850 Communication Networks and Systems in Substations provides interoperability between the electronic devices (IEDs) for protection, monitoring, metering, control and automation in substations. Interoperability and free allocation of functions opens up a vast range of possible solutions. It is important for both utilities and Substation Automation system providers to understand this process.

According to **Apostolov (2006),** IEC 61850 is a new approved international standard for substation communications that already has a significant impact on the development of different devices or systems used in the substation. He further describes that all major substation protection and control equipment manufacturers have products that implement different forms of IEC 61850 communications to simplify integration in substation automation systems and improve the functionality of the system, while at the same time reduce the overall system cost. New protection solutions are being developed in order to take full advantage of the functionality supported in the standard.

In addition **Brand and Janssen (2005),** describe the new communication standard IEC 61850 as the Substation Automation communication replacing almost all traditional wires by serial communication. They further stated that based on mainstream communication means like Ethernet, it provides a high flexibility regarding communication architectures. Due to its flexibility utilities are concerned about the process of specifying an IEC 61850 based Substation Automation systems.

Brunner (2005), Lohmann (2001), Mackiewicz (2005) recognize the IEC61850 as an international standard for substation automation that was introduced in 2003/2004. It is the first global standard for the utility industry and in the future the IEC 61850 will replace the mainly vendor specific protocols that have been used in the past with a standardized protocol. They also acknowledge that the standard is more than just another communication protocol. Besides introducing commercial communication technology in the sub-station automation system, IEC 61850 incorporates more features not available so far in substation automation.

For **Andersson, et al., (2001)**, the IEC61850 is the new substation automation standard that allows by its flexible approach to separate functionality from physical architecture and by so doing allows choosing architecture optimized according to needed reliability and functionality. The standard supports all communication tasks like control, protection and monitoring. It covers communication between all IED's from the process level over the bay level up to the station level.

3.3 THEORETICAL FRAMEWORKS AND TECHNOLOGY BEHIND THE STANDARD

In order to understand the IEC61850 and substation automation principles better it is important to assess the theory from different points of view. It is also important to know that the way to approach substation automation today has changed considerably due to the rapid change of technology. Therefore, when utilizing the IEC 61850 standard, there are many questions that need to be answered and this includes the following. Can acceptable results be achieved when using this standard compared to conventional, proven methods? This is of special interest to timing of high speed peer-to-peer commands compared to hard wired techniques currently used as well as the ability of multiple vendors to exchange information on a common medium without any protocol converters.

3.3.1 Communication Medium

Ethernet is the physical communication medium specified by IEC 61850. The data throughput of modern Ethernet is much higher than that of token ring or master-slave systems. 100Mbit/s is now the commonly adopted base data rate. Ethernet components suitable for substation applications are readily available **(Herrmann, et al., 2006)**, **(Van Zyl , 2008)**, **(Skendzik et al., 2007)**.

Brand, et al., (2004) stress the same idea indicating that: IEC61850 is based on Ethernet, and Ethernet allows different physical variants. Since the standard and Ethernet is supporting both client-server relations and peer-to-peer communication, any communication topology connecting all related IEDs fulfils the functional requirements. Therefore, the final determination of the communication topology is strongly influenced by constraints, i.e. by non-functional requirements like performance.

Furthermore **Tibbals and Silgardo (2008)**, **Hou and Dolezilek (2008)**, **and Madren (2004)** suggested that Ethernet with fiber cabling has many benefits for power utility substations. Fiber is highly noise-resistant and easier to work with in high-voltage environments. It is also better adaptable to the industry's requirement for transmission over relatively long distances, and offers the most cost-effective upgrade path to higher bandwidths as they become necessary. Given the changing cost structures of fiber connectivity as well as increasing demands for bandwidth as utilities adopt more sophisticated and bandwidth-hungry applications, fiber and Ethernet is the best solution and will therefore dominate the substation communications mix.

Hahnloser (2007) stated that IEC 61850 Specifies the use of Ethernet technology in the areas of power generation and distribution, therefore all vendor specific buses within substation will be replaced.

3.3.2 The peer-to-peer communications methods

The peer-to-peer communications mechanisms allow protection engineers to revolutionize traditional protection and control schemes, reducing the costs of system design, installation, commissioning, operating, and maintenance, and at the same time, increase the reliability of the system. The IEC 61850 standard includes two real-time, peer-to-peer communication methods that are particularly useful to protection engineers: Generic Substation Event (GSE) messaging and Sampled Values (SV) messaging. The two types of GSE messages, Generic Object-Oriented Substation Event (GOOSE) and Generic Substation State Event (GSSE), can coexist but are not compatible. GSSE is an older, binary-only message type, and all new systems use the more flexible GOOSE, which conveys both binary and analogue data (**Hou and Dolezilek, 2008**).

In terms of speed, the testing of GOOSE message between two is fairly simple, the mechanism for doing this type of verification on many communicating devices is fairly complicated. From a user's point of view, the mechanism must be at least as reliable with minimal latencies under real-world conditions. The IEC 61850 specification helps in this area by defining "test" modes within the protocol, but good testing tools that take advantage of this capability are still missing, (**Muschlitz, 2006**), (**Zhang, et al., 2005**), (**Horak and Hrabliuk, 2002**).

3.3.4 Systems configuration

To configure an automation system, a unique IP-address is firstly assigned to each network device. These devices are typically the protection devices, bay devices, station controller and the time server. By means of the system configurator of the engineering tool, the logical communications between devices are established according to the IED Configuration Description (ICD) files. The system configurator of the engineering tool links the data objects of the devices and creates a System Configuration Description (SCD) file. The information of this file is written into the devices to complete the configuration (**Herrmann, et al., 2006**).

As stated by **Caetano and Pernes (2007)**, the configuration language, substation configuration language (SCL), is defined in the standard. The use of this language permits that different tools, from different vendors, can understand the information contained inside any IED. Enabling data exchange, it also avoids misunderstandings, and facilitates the integration between vendors. All the engineering is stored in these SCL files, which facilitates its reuse in the next projects. Also the project documentation is produced from these files, which makes it to use the standard between project developers and vendors.

3.3.5 Interoperability

Interoperability is one of the most important aspects of the standard. The ability to maintain a certain level of freedom allowing the use of specific vendor functions is also one of the major advantages, as it allows different philosophies from each supplier and still leaves a certain space for creativity. It is also considered as a future-proof standard, because it takes in consideration the evolution of the technology in the future. It is based on the mainstream Ethernet communication and contains definitions for the communication to the process-bus, expecting that in the future the products will start supporting communication in the lowest level of the process, **(Caetano and Pernes, 2007), (Andersson, et al., 2003).**

3.3.6 IEC 61850 application in protection and control

Some protection and control schemes require information exchange between IEDs within a substation. These are typical applications where the GOOSE protection and control messages replace hardwires and provide the same communication through an Ethernet LAN. The fast bus tripping scheme typically applies to radial distribution systems to achieve a clearance time for bus faults that is close to a bus differential scheme. This scheme is also referred to as reverse interlocking. *Reclosing control-modern* IEDs typically incorporate both protection and control functions like breaker reclosing. For breaker failure protection, local breaker failure backup protection is common for high-voltage applications **(Hou and Dolezilek, 2006), (Kruger, 2006), (Apostolov, 2008).**

According to the view from **BRENT, et al., (2007)** protection function characteristics are nothing new. They were defined by IEEE Standards based on the characteristics of induction disk relays. The microprocessor based device only emulates the physical behaviour of the historical relay. The development of "universal" distribution system protection relays has brought challenges. Multiple protective functions must be specified into one package to meet various users' applications within the power distribution system.

3.4 IEC61850 BENEFITS

The first benefit from applying the IEC61850 to SA systems is clearly the installation of interoperability between IEDs of different brands. 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 **(Caetano and Pernes, 2007), (Kulkarni and Mannazhi , 2003)**.

As cited in **Andersson, et al., (2003)**, the new process close technology and the new standard *IEC61850 offer several benefits for the design of a substation. The number of copper wires will* be significantly reduced. This will also reduce the amount of manual work involved in assembling and testing these wires. The number of non-supervised functions will be reduced to almost zero. This reduces the time until an error will be detected and increases the availability of the system. With the introduction of the new technology, a true redundancy is possible at *reasonable cost for all functions of the substation.*

Another study by **Hahnloser (2007)** reveals that the benefit of the IEC61850 standard includes the following:

- 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

3.5 CHALLENGES AND PROBLEMS ASSOCIATED WITH IEC61850

According to the literature consulted, the following factors were regarded as challenges and problem associated with the IEC61850 standard for substation automation. One study by **(Apostolov, 2008)** emphasizes that it is important to focus on the problems of IEC61850 standard that could be associated with the utilities because they are the main implementers of the standards.

Caetano and Pernes (2007) discovered that in a first approach, the feeling among the utilities engineering teams about a totally new system brings a certain part of fear and a certain part of reluctance for abandoning a totally proved system, where the workflow was clearly controlled.

The most urgent issue regarding engineering teams when a project is gained and has to be delivered consists in training. All the programmers that will be involved have to be trained immediate and efficiently, otherwise a normal delivery time will not be enough for system development and error corrections. For **Apostolov (2009)** the problem of the IEC61850 standard that could be associated with utilities involves their skills in setting up the IED's as well as their attitude toward the standard. To date it is still evident that there is a wide gap between utilities and suppliers in terms of knowledge and understanding of the standard which is slowing down the implementation of the IEC61850 standard.

The present scope of IEC 61850 is limited to communications within a substation. Work is underway to extend the IEC 61850 standard to cover inter-substation communications requirements **(Apostolov, 2008), (Zaherdoust, 2008), (Hsu and Gauci, 2008).**

Another challenge of IEC 61850 is the time synchronization mechanism. The creators of the standard wisely chose an existing standard, the Simple Network Time Protocol (SNTP), rather than inventing a new protocol for the purpose. However, SNTP does not define any accuracy requirements. It merely states that the client should use the "best" time source available. In contrast, IEC 61850 Part 5 defines the time synchronization accuracy required for various IEDs according to differing "classes" of time requirements. Some of these accuracy requirements stretch the limits of being able to determine the time itself in a device, much less being able to compare it against the time on another device. IEC 61850 conformance testing millisecond-level accuracy is relatively easy to verify, for instance, but sub-microsecond accuracies are very hard to confirm. The best means of comparing time synchronization is to have two devices measure and timestamp the same electrical pulse after having their clocks synchronized, and then compare the timestamps as shown in **(Muschlitz, 2006), (Holbach et al., 2009), (Vararaksit and Spuntupong, 2008)** .

According to **Caetano and Pernes (2007),** time synchronization is totally independent from the other services inside the system. It is therefore possible to use different services for different synchronization accuracy classes, but currently what defined is the **SNTP** (Simple Network Time Protocol) that assures a 1ms accuracy class. Each IED connected will stay as a time client, fetching the time from a time server that can be a GPS clock or any other SNTP server running in a computer connected to the network. The 1ms accuracy is implemented via a mechanism of calculation and correction of the transmission delays between clients and server.

Herrmann, et al., (2006), point out that the certification of devices compliant with IEC 61850 is an important milestone towards the creation of an environment in which equipment from different manufacturers work smoothly together. The conformity tests specified in IEC 61850 were carried out on one representative device of the manufacturer. KEMA, an independent test institute approved by the UCA International Users Group, was responsible for the first set of tests in March 2005. The certification process involves checking the documents of manufacturers and confirming that actual implementation matches what is written in the standard-document. This is what most vendors do not have although claiming that their products are IEC61850 compliant. The utilities are therefore experiencing problem with the manufacturers due to the certification issue since untested product represents too high risk to the rest of their system. For this project the IED's used are compliant and a certificate is received from SIEMENS.

Finally is the support services because if support service to end user, in this case the utilities and academic institution, are lacking then it may be one of the contributing factors that hamper with proper implementation of the IEC61850 for substation automation. Therefore it is very important for vendors and suppliers to understand the role of support services and its importance in the engineering industry.

3.6 COMPARISON OF THE EXISTING PAPERS ON THE ANALYSIS OF POWER SYSTEM PROTECTION

The survey and comparison of the papers was carried out using the following criteria.

- Statement of the problem
- Project objective
- Approach of solution (model)
- Constraints and drawbacks experienced, and
- Findings

Table3.1 *Comparison of methods used for power system protection*

PAPER	PROBLEM STATEMENT	OBJECTIVE	MODEL	CONSTRAINTS	FINDINGS
Brand, Brunner, Wimmer (2004) *"Design of IEC61850 based substation automation systems according to customer requirement"*	*Communication* is the backbone of substation automation and, therefore, IEC 61850 is the most important key for designing systems	To analyze the effect of IEC61850 features in designing optimized systems.	A model of the real environment is used in order to implement the designing parameters as issued by the	Some boundary conditions like the topology of the substation, the interfaces to auxiliary power supply system, to the switchgear and	With IEC61850, different solutions are possible. Optimized Substation Automation

	since interoperability and free allocation of functions opens up a vast range of possible solutions		customer	to network control centers etc.	systems can be designed, which are not expensive and with un-maintainable solutions.
Schwarz (2007) *"Impact of IEC61850 on system engineering, tools, people-ware and the role of system integrator"*	To analyze the basics of IEC 61850 through the engineering of substations and IEDs application	To understand and to define the role of the system integrator for IEC 61850 based systems.	Lab tests, pilot projects, and other projects are used to train users, to gain the needed expertise	Vendors, users, and system integrators have to go through a learning curve	The knowledge of IEC61850 is still minimal within utility companies
Baxevanos, Labridis (2007) *"A multi-agent system for power distribution network protection and restoration: Designing concepts and an application prototype"*	Power Distribution network is a physically distributed system that depends on a proper functionality and interoperability of several heterogeneous components.	To autonomously perform effective fault management on medium voltage (MV) power distribution network.	A model of the real environment is used in order to define the designing parameters of a multi agent system (MAS).	Experimenting with fault management systems has proven to be a complicated procedure	The need for protection and control systems which exhibit self organizing, coordinating and collaborative behaviour is imperative
Taisne (2006) *"Intelligent alarm processor based on chronicle for transmision and distribution system"*	The application of intelligent alarm processor based on an innovative method which provide a fast and deterministic analysis of events	To minimise the alarm overload in Energy or distribution management system dispatcher	An intelligent alarm processor based (IAP) is implemented	Formalism from symtom to diagnosis knowledge is lacking. The methods remain too complex regarding the need to configure and to maintain the knowledge base.	Dspite numerous researchers no reliable and industrial solution seemed to satisfy the requirement of IAP for energy management systems and distribution management system
Abyaneh, Karegar, Zahedi, Ahmadi (2004) *"Constraints Reduction of the optimal coordination of overcurrent Relays"*	The optimal coordination constraint between the primary relay and the backup relays	To analyze an effective method to reduce the number of constrain that limit the benefit of the optimal programming	A performance of the proposed method was evaluated by its application to an 8-Bus of an industrial power network	Approaches to coordinate protective devices in power systems are a tedious and time consuming job and the graphical and analytical methods cannot obtain optimal settings	Using geometry of the optimal OC coordination problem can reduce the number of constraints and increase the speed of processing time
Candy, Taisne (2007) *"Advanced alarm processing facilities installed on Eskom'sEnergy*	To find a solution to information overload on SCADA system by applying a new	To address the data cognitive and overload problems experienced by	The implemented functionality uses a model based parten	To identify what network state must be exist for the chronicle to be recognised and	The energy management system used by Eskom can improve the

management system"	energy management system known as TEMSE.	control staff at Eskom's	recognition algorithm provided by AREVA's intelligent Alarm processing application	triggered. Justification of mandatory, forbidden and group events and the what happen analysis	alarms and historical trends of scada systems
Charles, McDaniel, Dood (2007) *"Protection, Control and Automation system for a multi station looped distribution system"*	Development of the protection, control and automation systems for distributing system	To upgrade the protection scheme and design a supervisory control and data acquisition system	A one line diagram method was implemented	Product selection due to the flexibility and analogue logic availability that is required	The use of IEC 61850 IED's and SCADA is a solution to a reliable and cost effective protection system
Skendzic, Ender, Zweigle (2007) *"IEC 61850-9-2 Process Bus and Its Impact on Power System Protection and Control Reliability"*	*Analysis of the IEC 61850-9-2 Process Bus and its Impact on Power System Protection and Control Reliability*	To analyze the Sampled Value (SV) Process Bus concept that is introduced by the IEC 61850-9-2 standard.	A simulation model is used to illustrate the application and difference between conventional and non conventional VT's and CT's, merging units etc.		Process Bus technology described in IEC 61850-9-2 offers a variety of new and exciting possibilities in designing the Ethernet-based protection and control systems.
Larson (2007) *"Decision Analysis Applied to Protective Relaying"*	Decision analysis methods use rigorous techniques to determine the best alternative that solve a problem with multiple competing objectives	To analyze and present a customized methodology for relays system selection	Decision analysis technique has been applied	The complexity of the attributes that each alternative is to be rated against and any uncertainties in meeting these attributes all contribute to the degree of difficulty in making a decision	Individual decision makers can be risk adverse, risk seekers or risk neutral
Kashiwazaki, Wakida, Sato (2002) *"New technologies for electric power distribution systems"*	The construction of intelligent substation in the power distribution systems as well as protection/control unified equipment as examples of the new technology	To unify protection/control units so they can be incorporated into intelligent substation for the benefit of high performance and integrated power distribution management	The method used was the implementation of digital technology and IT related technology aimed at reducing costs and enhance reliability	Slower development and release of products that have compatibility and are low in cost in terms of demand from clients	Stability of power supply and improved maintenance at a reduced cost by promoting these developments
Schweitzer, Scheer, Feltis (1992) *"A fresh look at distribution protection"*	Most digital distribution relays provide traditional phase and ground	To analyze, discuss and implement the additional	A typical distribution system arrangement	Changing traditional protection schemes requires purchasing and installation of	Advanced digital distribution relays improve

	overcurrent protection, reclosing functions and limited metering and event recording	features of more advanced digital distribution relays	equipped with digital distribution relays was used	additional equipment	distribution protection and reduce utility capital, operational and maintenance costs
Soudi, Tomsovic (2000) *"Optimal distribution protection design: Quality of solution and computational analysis"*	The fundamental goal of an electric utility is to use various reliability indices to evaluate the service reliability and prioritize capital and maintenance expenditures	To evaluate the practicality of such design optimization techniques through comparison of the acquired solutions to existing utility practices and analysis of the computational complexity of the algorithms	A typical distribution circuit from a major utility is selected to illustrate the proposed approached in terms of customer based indices such as SAIFI, SAIDI, and CAIDI	Limitations imposed by coordination, design, application and costs concerns	Preventive measures and appropriate remedial actions improves distribution reliability of any utility
Lohmann (2005) *"New strategies for substation control protection and access to information"*	The advantages of a substation oriented decentralized automated concept with regards to the acceleration and substantiation of the decision making process are obvious	To provide a five level functional structure for power system management via decentralized substation oriented automated concept	The substation information management unit that act as the data base convertor is used in conjunction with the wide area network	This method provide more data than can be processed and assimilated in the time available	The integration of protection and control is a way to minimize installation and maintenance complexity by reducing the number of EID's in a substation
Mui, Nwankapa, Yang, Madonna (2003) *"The development of a comprehensive Power distribution systems curriculum*	The restructuring of the electric utilities and the rapid installation of new automated component has created the need for engineers with formal knowledge about power distribution automation and control	To address the topic of power distribution systems in terms of classes and software laboratories at several universities	The development of power distribution systems curriculum centred around a reconfigurable distribution automation and control laboratories	Efforts towards integrating the laboratories into existing power distribution courses	The power distribution curriculum can be used in graduate curriculum as well
Hill, Behrendt (2008) *"Upgrading power system protection to improve safety, monitoring, protection and control*	The migration of conventional substation into intelligent substations through the use of microprocessor relays	To install microprocessor-based bus differential protection on medium voltage switch gear and selectively	A 5kV power plant one line diagram was used with simulation software	The method to improve selective coordination is crucial	Significant benefits to improve monitoring and control were also realized because of the installation of

		replacing electromechanical overcurrent relays with microprocessor relays			microprocessor devices
Allen (2008) *"Effects of wide area control on the protection and operation of distribution networks*	Wide area control systems may degrade the effectiveness of traditional protection practices	To examine the use of wide area automatic control systems in electric power distribution networks and understand its effects on the distribution network to ensure that the safe and effective operation of the network is not compromised	A one line diagram was used and different schemes were applied to a two feeder network	There is little doubt that sophisticated automatic control systems are and will continue to be important factors in the mission to deliver high quality, reliable power	HMI can play a critical role in determining how the control system is performing
Baxevanos, Labridis (2007) *"A multi-agent system for power distribution network protection and restoration: Designing concepts and an application prototype"*	Power Distribution network is a physically distributed system that depends on a proper functionality and interoperability of several heterogeneous components.	To autonomously perform effective fault management on medium voltage (MV) power distribution network.	A model of the real environment is used in order to define the designing parameters of a multi agent system (MAS).	Experimenting with fault management systems has proven to be a complicated procedure	The need for protection and control systems which exhibit self organizing, coordinating and collaborative behavior is imperative
Abyaneh, Karegar, Zahedi, Ahmadi (2004) *"Constraints Reduction of the optimal coordination of overcurrent Relays"*	The optimal coordination constraint between the primary relay and the backup relays	To analyze an effective method to reduce the number of constrain that limit the benefit of the optimal programming	A performance of the proposed method was evaluated by its application to an 8-Bus of an industrial power network	Approaches to coordinate protective devices in power systems are a tedious and time consuming job and the graphical and analytical methods cannot obtain optimal settings	Using geometry of the optimal OC coordination problem can reduce the number of constraints and increase the speed of processing time
Charles, McDaniel, Dood (2007) *"Protection, Control and Automation system for a multi station looped distribution system"*	Development of the protection, control and automation systems for distributing system	To upgrade the protection scheme and design a supervisory control and data acquisition system	A one line diagram method was implemented	Product selection due to the flexibility and analogue logic availability that is required	The use of IEC 61850 IED's and SCADA is a solution to a reliable and cost effective protection system
Larson (2007) *"Decision Analysis*	Decision analysis methods use	To analyze and present a	Decision analysis	The complexity of the attributes that	Individual decision

Applied to Protective Relaying"	rigorous techniques to determine the best alternative that solve a problem with multiple competing objectives	customized methodology for relays system selection	technique has been applied	each alternative is to be rated against and any uncertainties in meeting these attributes all contribute to the degree of difficulty in making a decision	makers can be risk adverse, risk seekers or risk neutral
Kashiwazaki, Wakida, Sato (2002) *"New technologies for electric power distribution systems"*	The construction of intelligent substation in the power distribution systems as well as protection/control unified equipment as examples of the new technology	To unify protection/control units so they can be incorporated into intelligent substation for the benefit of high performance and integrated power distribution management	The method used was the implementation of digital technology and IT related technology aimed at reducing costs and enhance reliability	Slower development and release of products that have compatibility and are low in cost in terms of demand from clients	Stability of power supply and improved maintenance at a reduced cost by promoting these developments
Schweitzer, Scheer, Feltis (1992) *"A fresh look at distribution protection"*	Most digital distribution relays provide traditional phase and ground overcurrent protection, reclosing functions and limited metering and event recording	To analyze, discuss and implement the additional features of more advanced digital distribution relays	A typical distribution system arrangement equipped with digital distribution relays was used	Changing traditional protection schemes requires purchasing and installation of additional equipment	Advanced digital distribution relays improve distribution protection and reduce utility capital, operational and maintenance costs
Soudi, Tomsovic (2000) *"Optimal distribution protection design: Quality of solution and computational analysis"*	The fundamental goal of an electric utility is to use various reliability indices to evaluate the service reliability and prioritize capital and maintenance expenditures	To evaluate the practicality of such design optimization techniques through comparison of the acquired solutions to existing utility practices and analysis of the computational complexity of the algorithms	A typical distribution circuit from a major utility is selected to illustrate the proposed approached in terms of customer based indices such as SAIFI, SAIDI, and CAIDI	Limitations imposed by coordination, design, application and costs concerns	Preventive measures and appropriate remedial actions improves distribution reliability of any utility
Lohmann (2005) *"New strategies for substation control protection and access to information"*	The advantages of a substation oriented decentralized automated concept with regards to the acceleration and substantiation of	To provide a five level functional structure for power system management via decentralized substation oriented automated	The substation information management unit that act as the data base convertor is used in conjunction with the wide area	This method provide more data than can be processed and assimilated in the time available	The integration of protection and control is a way to minimize installation and maintenance

	the decision making process are obvious	concept	network		complexity by reducing the number of EID's in a substation
Mui, Nwankapa, Yang, Madonna (2003) *"The development of a comprehensive Power distribution systems curriculum*	The restructuring of the electric utilities and the rapid installation of new automated component has created the need for engineers with formal knowledge about power distribution automation and control	To address the topic of power distribution systems in terms of classes and software laboratories at several universities	The development of power distribution systems curriculum centred around a reconfigurable distribution automation and control laboratories	Efforts towards integrating the laboratories into existing power distribution courses	The power distribution curriculum can be used in graduate curriculum as well
Hill, Behrendt (2008) *"Upgrading power system protection to improve safety, monitoring, protection and control*	The migration of conventional substation into intelligent substations through the use of microprocessor relays	To install microprocessor-based bus differential protection on medium voltage switch gear and selectively replacing electromechanical overcurrent relays with microprocessor relays	A 5kV power plant one line diagram was used with simulation software	The method to improve selective coordination is crucial	Significant benefits to improve monitoring and control were also realized because of the installation of microprocessor devices
Allen (2008) *"Effects of wide area control on the protection and operation of distribution networks*	Wide area control systems may degrade the effectiveness of traditional protection practices	To examine the use of wide area automatic control systems in electric power distribution networks and understand its effects on the distribution network to ensure that the safe and effective operation of the network is not compromised	A one line diagram was used and different schemes were applied to a two feeder network	There is little doubt that sophisticated automatic control systems are and will continue to be important factors in the mission to deliver high quality, reliable power	HMI can play a critical role in determining how the control system is performing

3.4.1 Findings from the literatures comparison

In view of the researched papers, there are a number of approaches in terms of distribution network protection that are in line with the IEC 61850 substation protection, automation and control system although the goal is common, Table 3.1. The evaluation of protection schemes in

terms of speed, security and dependability has place a huge burden and responsibility among the IED's vendor since a reliable protection system required the products that complies with the standard and conformance certificates are required at all times. The IEC 61850 standard has been defined in cooperation with manufacturers and users to create a uniform, future-proof basis for the protection, communication and control of substations.
According to **Lundqvist (2001)** the technological history in Protection and Station Automation can be shown by comparing space requirements between modern and old equipment. One numerical terminal can replace up two five panels with electromechanical relays or two panels with static relays. This is a major advantage since space is so difficult to own nowadays. Self-supervision and communication are additional features of numerical terminals.

Labuschagne and van der Merwe, (2005) indicate that numerical relays have revolutionized protection, control, metering, and communication in power systems. Functional integration, new methods of communication, reduced physical size, and an enormous amount of available information are benefits of this revolution. Having made the initial conceptual adjustment of relating objects from electromechanical technology such as rotating discs and moving armatures to such electronic technology as analog-to digital converters and comparators, protection practitioners must then deal with programming the relays. Initially, programming was no more than selecting values for relay settings. Further advancement in digital technology, however, has made possible advanced and sophisticated programming of logical functions and analog quantities.

In terms of protection **Hadjicostis and Verghese (2007)** suggested that it is possible to detect and identify failures in power systems lines by analyzing binary status information from relays and circuit breakers. The approach, which is based on Petri net models, requires very simple calculations (linear checks) during execution time and allows for concurrent/incremental processing of the information as it arrives at the control center.

Mozina,Murty and Yalla (1996) indicated that self diagnostics is one of the most important features of digital relays. It was not available in either electromechanical or static relays design. One of the major benefits of relays self diagnostics is its impact on periodic maintenance. With conventional electromechanical relays and solid state electronic relays the user has to verify that the relay is operating by periodically injecting current and voltages.

Dolezilek et al, (2007) reveals that the multifunction protective relays and other intelligent electronic devices (IEDs) create two unique and independent remedial action scheme (RAS) systems with redundant functionality thus referred to as dual-primary, while also supporting SCADA monitoring requirements. These dual-primary RAS systems work simultaneously or individually as operational and testing situations require. Further discussion includes design and implementation of integrated digital communications of data to add RAS and SCADA functionality to mission-critical IEDs. Innovative, real-time communication quality measurements demonstrate that the performance and reliability meet or exceed the requirements.

Skendzic, et al., (2007) analyze the Sampled Value (SV) Process Bus concept that was recently introduced by the IEC61850-9-2 standard. This standard proposes that the Current and Voltage Transformer (CT, PT) outputs that are presently hardwired to various devices (relays, meters, IED, and SCADA) be digitized at the source and then communicated to those devices using an Ethernet-Based Local Area Network (LAN). The approach is especially interesting for modern optical CT/PT devices that possess high quality information about the primary voltage/current waveforms, but are often forced to degrade output signal accuracy in order to meet traditional analog interface requirements (5 A/120 V). While very promising, the SV-based process bus brings along a distinct set of issues regarding the overall reliability of the new Ethernet communications-based protection and control system.

Focusing on the EID's sources **Tholomier and Chatrefou (2008)** emphasize that non-conventional instrument transformers with digital interface based on IEC 61850-9-2 process bus eliminate some of the issues related to differences in protection and metering requirements. The data can be processed by any device to perform different protection, automation and control functions as opposed to conventional CT's and VT's.

Tholomier and Chatrefou (2008) noted that successful implementation of non-conventional instrument transformers (NCIT) in various applications automatic identification system and geographical identification system (AIS and GIS) requires the availability of a full range of products. Laboratory type tests and field experiments have been running for more than 15 years and successfully show the technical feasibility of sensors and their implementation in high voltage networks within the ruling specifications. All configurations require one unique secondary electronic rack, the so-called Merging-Unit (MU). This is a device that includes sensor electronics and different kinds of interface, compatible with protection and metering devices.

According to **Charles, et al., (2007)** opinion a condensed set of criteria for a new IEC61850 protection and SCADA system are based on the following statements:

- Simplify the protection and control schemes by eliminating a multiplicity of discrete relays and components with one device that can be used to satisfy all required applications
- Improve the manual operations of the system.
- Improve the coordination of the system to eliminate ongoing over-tripping that was being experienced with conventional relays.
- Provide the capability to obtain fault event recorder information and sequential event recorder data from anywhere on the SCADA communication network without requiring travel to the relay location.

According to **Allen (2007)** applying the IEC61850 IED's and automating the distribution network is that more data become available to the control center. Information that was previously islanded in standalone recloser controls becomes accessible via the SCADA interface. This is a great benefit because it adds to the dispatcher's situational awareness. However, it can also have a negative effect if the data are not organized. Some systems forward large amounts of unorganized data to the control center. In the end, this approach is not sustainable because operators become frustrated. The negative impact of large amounts of unorganized data becomes more pronounced as more feeders become automated.

According to **Candy and Taisne (2007), Taisne (2006,2007)** such problems are solved and improved by applying an energy management system that implements the functionality that uses a model based pattern recognition algorithm provided by AREVA's intelligent alarm processing application (IAP) software. In so doing, the data overloading will be reduced and this will address the data and cognitive overload problems that can be experienced by control centres.

According to the literature survey the IEC 61850 has gain an excellent track record as the established communication standard on the worldwide market for the automation of substations. Its main advantages are:

- **Simple substation structure:** No more interface problems. With IEC 61850, protocol diversity and integration problems are a thing of the past.
- **Everything is simpler:** From engineering to implementation, from operation to service. Save time and costs on configuration, commissioning and maintenance.
- **Reduction of costs:** IEC 61850 replaces wiring between feeders, control switches, and signaling devices.

- **More reliability:** Only one communication channel is used for all data –in real time, synchronized via Ethernet.

3.5 REMARKS

Different researchers have looked at the theory of (Upgrading Power System Protection to Improve Safety, Monitoring, Protection, and Control) from different angles but the main objective is to reach a common goal. In general protection is a wide subject, different protection schemes have been handled separately in different categories, that if put together, will make up a complete protection system for any distribution power system. As indicated by different authors, through the analysis of their research, the goals of the protection system is still to strive and obtain a power system protection service that ensures an optimum performance of power system protection schemes. The application of Intelligent Electronics Devices (IED's) that complies 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 conventional hard wired solutions. It reliably supports interoperability between protective relays and control devices from different manufacturers in the substation which is a necessity in order to achieve substation level interlocking, protection and control functions and improve the efficiency of microprocessor based relays applications.

Most researchers have outlined that this standard has gained fast attention and wide application; therefore it is certainly here to stay for the foreseeable future in power substation integration, automation, and control. Applied to substation protection and control, the new standard brings the benefits of cost savings in engineering design, installation, commissioning tests, operation, and maintenance. Power protection engineers should learn the new technology, since the modelling of IEC 61850 based multifunctional distance protective relays requires good understanding of their functional hierarchy, as well as the modelling principles defined in the standard. These engineers should work even closer with engineers from communications and/or information technology departments, to be able to provide protection and control specifications under the new communications environment, and be able to strike the best compromise between protection/control performance and communications network complexity.

In this research project a complete IEC61850 protection Lab is implemented. The main goal will be to achieve communication between the IED's using the Ethernet communication protocol as recommended by the standard. In addition interoperability will be proven by exercising the application of System Configuration Language. Some protection automation and interlocking functions, and the application of overcurrent protection will be implemented.

3.6 CONCLUSION

In conclusion this chapter presents a brief summary of the literature survey related to the topic of investigation. The role of the IEC61850 standard and the theory that underpin the standard were also discussed. .The challenges that the utilities are facing were also highlighted. The theoretical aspect of protection will be covered in chapter 4.

CHAPTER 4

THEORETICAL ASPECTS OF PROTECTION

This chapter briefly presents the main types of faults that occur in electrical power systems. It further outlines the steps used in calculating the most common faults that leads to protection analysis study. The generation and development stages of protective relays are presented. The chapter further describes in some details the concepts of relay input sources analysis. The types of instruments and different methods used to measure voltages and currents that are fed into protection relays and IED's in order for them to detect abnormal condition and to make responsible decision in power systems are presented. The protection functions and applications of protective relays and multifunctional devices (IED's) in a distribution environment are carried out.

4.1 THEORY OF POWER SYSTEMS FAULT

4.1.1 Introduction

In order to apply protection relays, it is usually necessary to know the limiting values of current and voltage, and their relative phase displacement at the relay location, for various types of short circuits and their position in the system. These, normally require some system analysis for faults occurring at various points in the system. In general, power systems are subjected to different kinds of faults. The most common types are three phase ones with and without earth connection, phase to phase, single phase to earth and double phase to earth. These disturbances, if allowed to persist, may damage plant and interrupt the supply of electric energy. Therefore, the analysis of load and fault conditions provides useful information that includes the following:

- The choice of power system arrangement
- The required braking capacity of switch gear and fuse gear
- The application of protection and control equipment
- The required load and short circuit rating of the system
- System operation, security of supply and economics and
- The investigation of unsatisfactory power system performance

4.1.2 Types of faults on a three-phase system

Mostly, the power distribution is globally a three-phase distribution especially from power sources. The types of faults that can occur on a three-phase AC system are shown in Figure 4.1.

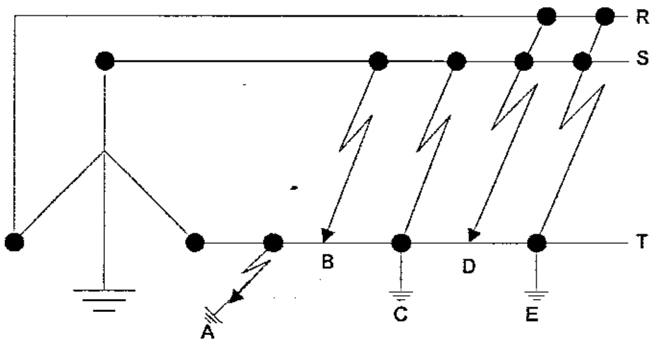

Figure 4.1 *Types of faults on a three-phase system*

Where:

(A) =Phase-to-earth fault
(B) =Phase-to-phase fault
(C) =Phase-to phase-to-earth fault
(D) =Three-phase fault
(E) =Three-phase-to-earth fault

It should be noted that for a phase-to-phase fault, the currents will be high, for the reason that the fault current is only limited by the inherent (natural) series impedance of the power system up to the point of fault (Ohm's law).

4.1.3 Transient and permanent faults

Transient faults are classified as faults, which do not damage the insulation permanently and allow the circuit to be safely re-energized after a short period. A typical example would be an insulator flashover, following a lightning strike, which would be successfully cleared by opening the circuit breaker, which could then be closed automatically. Transient faults occur mostly on outdoor equipment where air is the main insulating medium. Permanent faults are the result of permanent damage to the insulation, as the name implies. In such cases, the equipment has to be repaired and recharging must not be entertained before repair/restoration.

4.1.4 Symmetrical and asymmetrical faults

A symmetrical fault is a balanced fault with the sinusoidal waves being equal about their axes, and represents a steady-state condition. An asymmetrical fault displays a DC offset, transient in nature and decaying to the steady state of the symmetrical fault after a period of time, as shown in Figure 4.2. In a balanced three phase system, each of the three phases should have currents and voltages which are equal and 120° phase shifted with respect to one another. In addition the impedance in each line should be identical. These faults can be analyzed by using a single phase representation. However these types of faults are very seldom.

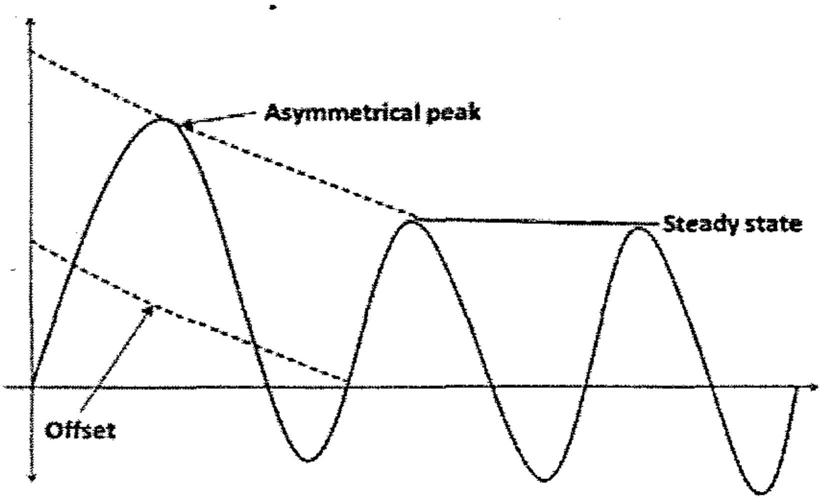

Figure 4.2 *An asymmetrical fault*

During unbalanced faults, the system symmetry disappears completely and the single phase representation used for three phase balanced faults no longer applies. The majority of these faults occurs between one single phase and earth or between two phases and earth and are termed asymmetrical or unbalanced fault. These faults arise from lightning discharges, mechanical causes and other over voltages that initiate flashovers and power arcs. Another type of asymmetrical faults which are of interest is the open circuit faults which result from broken conductor, mal-operation of fuses and single phase switchgears.

4.1.5 Per-unit system

Power plant like transformers and generator impedance data is normally expressed as a percentage (%) or in per unit (pu) on the nameplate. Any pu value is expressed as a ratio between the actual and the base value **(Alstom APPS, 2006)**. Therefore the pu value is unit less or dimensionless.

$$X_{pu} = \frac{X_{actual}}{X_{base}} \tag{4.1}$$

$$X_{\%} = X_{pu} \times 100 \tag{4.2}$$

The actual value could be the voltage, current, power or impedance. The reference value is regarded as 1 pu or 100%. All the network theorems like Ohm's law still apply. For a single phase system the formulas are as follows:

$$I_b = \frac{S_b}{V_b} \tag{4.3}$$

$$Z_b = \frac{V_b}{I_b} \tag{4.4}$$

$$Z_b = \frac{V_b^2}{S_b} \tag{4.5}$$

Where:
$I_{b=}$ the base current in kA
Z_b = the base impedance in ohms
V_b = the base voltage in kV
S_b = the base MVA

The rated values of voltage and power can be used to calculate the actual impedance of the equipment by using the following formula:

$$Z_{actual} = \frac{Z_{pu} \times V_b^2}{S_b} \tag{4.6}$$

Converting to a new base:

$$Z_{pu(NB)} = Z_{pu(GB)} \times \frac{S_{NB \times V_{GB}^2}}{V_{GB} \times V_{NB}^2} \tag{4.7}$$

Where:

$Z_{pu(NB)}$ = the per unit impedance new base
$Z_{pu(GB)}$ = the per unit impedance given base

For the three phase system, the base current and impedance formula are as follows:

$$I_b = \frac{S_b}{\sqrt{3}\, V_b} \tag{4.8}$$

$$Z_b = \frac{V_b^2}{S_b} \tag{4.9}$$

4.1.6 Methods for calculating short circuit currents

A symmetrical fault, which is three-phase fault and three phase to earth fault with symmetrical impedances to the fault, leaves the electrical system balanced and therefore can be calculated from the single-phase impedance diagram. This symmetry is lost during asymmetrical faults such as: line to earth, line to line and line to line to earth.

4.1.6.1 Calculation of short circuit currents

Accurate fault current calculations are normally carried out using an analysis method called "Symmetrical Components." This method involves the use of higher mathematics and is based on the principal that any unbalanced set of vectors can be represented by a set of 3 balanced systems, namely; positive, negative and zero sequence vectors **(Preve, 2006:81-84)**. However, for practical purposes, it is possible to attain a good approximation of three phase short circuit currents using some very simplified methods, which are discussed below. The short circuit current close to the transformer and at the secondary side of the transformer can be quickly calculated, using the following formula:

Short-circuit MVA = $\frac{100P}{X\%}$ and (4.10)

Short - circuit current, $I_{kA} = \frac{MVA}{kV\sqrt{3}}$ (4.11)

Where:

P = Transformer rating in MVA
$X\%$ = Internal Reactance of Transformer in %
IkA = Short-circuit current in kA
kV = Transformer secondary voltage in kV

Normally, the percentage (%) reactance value of the transformer can be obtained from the nameplate, or if not, from the transformer data sheets. If a length of cable (more than 100m) exists between the transformer and the fault, the impedance of the cable has to be taken into account to arrive at a realistic value for the worst-case fault current. This is done by calculating the source impedance and then adding the cable impedance, as follows:

Source Impedance, $Z = \frac{kV}{kA\sqrt{3}}$ (4.12)

Fault Current, $kA = \frac{kV}{Z_{source}+Z_{cable}}$ (4.13)

Z_{cable} can be obtained from the manufacturer's cable data sheets. However the above calculation is another approximation, as Z_{source} and Z_{cable} are not necessarily in phase and complex algebra should be used. This is accurate enough in most practical applications. When considering a three phase system, each vector quantity of current or voltage is replaced by three components, therefore a total of nine vectors will uniquely represent the value of the three phases. The balanced phasors of a three phase system are designated as follows:

- Positive sequence components which consist of three phasors that are equal in magnitude but 120° apart and are rotating in the same direction as the phasors in the power system (e.g. in the positive direction).
- Negative sequence components, which consist of three phasors of equal magnitude but spaced at 120° apart and are rotating in the same direction as the positive sequence phasors, but in a reverse sequence.
- Zero sequence components, which consist of three phasors that are equal in magnitude and in phase with each other, rotating in the same direction as the positive sequence phasors **(Saha, et al., 2005)**. With this kind of arrangement, voltage values of any three phase system V_a, V_b and V_c can be represented. These will be covered in the next topic.

4.1.6.2 Symmetrical component analysis of the three phase network

Any Protection Engineer will always be interested in a wider variety of faults than just a three-phase fault. The most common fault is a single-phase to earth fault, which, in Low Voltage (LV) systems, can produce a higher fault current than a three phase fault. Similarly, because protection is expected to function correctly for all types of faults, it may be essential to consider the fault currents due to many different types of fault. Since the three-phase fault is unique in being a balanced fault, a method of analysis that is applicable to unbalanced faults is required **(Driesen and Van Craenbroeck, 2002:1-3)**. It can be shown that, by applying the 'Principle of Superposition', any general three-phase system of vectors may be replaced by three sets of balanced (symmetrical) vectors; (two sets of three-phase but having opposite phase rotation and one set is co-phasal). As mentioned earlier these vector sets are described as the positive, negative and zero sequence sets respectively **(Labuschagne and Fischer, 2005:9)**. These vectors are applied in conjunction with the following operators:

$j = 1\angle 90^{\circ}$ rotates a vector anti-clockwise through 90°

$a = 1\angle 120^{\circ}$ rotates a vector anti-clockwise through 120° extensively used in symmetrical component analysis

$a^2 = 1\angle 240^{\circ}$, $a^2 + a + 1 = 0$

Fortescue (1999) has discovered the unbalanced phasors property and then introduced the method of symmetrical components (three unbalanced phasors of a three phase system can be resolved into three balanced systems of phasors). The *n* phasors may be resolved into ***(n-1)*** sets of balanced n-phase systems of different phase sequence and one set of zero phase sequence (uni-directional phasor system). The equations between phase and sequence voltages are given below **(Acevedo, 2000:1-18).**

$$V_a = V_{a0} + V_{a1} + V_{a2}$$

$$V_b = V_{b0} + V_{b1} + V_{b2}$$

$$V_c = V_{c0} + V_{c1} + V_{c2} \qquad (4.14)$$

Where:

V_{a1} , V_{b1} etc. = the phasors of the first set of balanced n-phase systems. It should be noted that phasors are single spaced (positive sequence components).

V_{a2}, V_{b2} etc. = the phasors of the second set of balanced n-phase systems. In this case the phasors are double spaced (negative sequence components).

V_{a0}, V_{b0}, etc. = the zero sequence phasors

V_a,V_b and V_c = original phasors and they are a sum of their components

The graphical representation of symmetrical sequence components relations is shown, Figure4.3

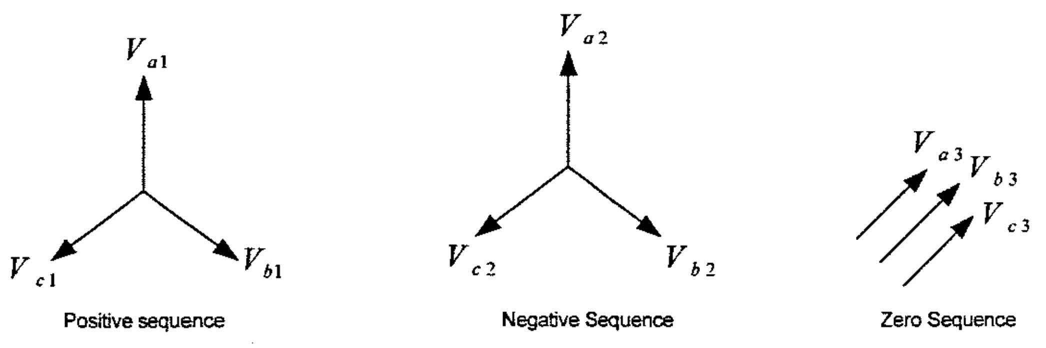

Figure 4.3: *Symmetrical components relations*

4.1.7 Discussion and conclusions

A good understanding and working knowledge of system fault analysis is very important for the protection personnel as they are required to know how the systems operate and behave under load and fault conditions. In addition this is important as it assists engineers in the selection of relays that are suitable or match the parameters for the protected system **(Alstom, 2006)**.

In conclusion the content of this section will contribute towards the faults and protection simulation of electrical networks. System analysis is covered in details because in order to apply protection relays or to perform any protection study, it is usually necessary to know the limiting values of current and voltage, and their relative phase displacement at the relay location, for various types of short circuits and their position in the system. This is due to the fact that a clear understanding of network faults and network behavior under fault or load condition is a requirement for any protection engineer.

4.2 THEORY OF RELAY INPUT SOURCES

4.2.1 Introduction

Protective relays and measuring devices are triggered by data (current and voltage) supplied from current (CT's) and voltage (VT's) transformers. Due to technical, economic and safety reasons, this data cannot be obtained directly from the high-voltage power supply of the equipment, and this is where the CT's and VT's came into play. The standards of application for most of these items are available and most of them are obvious and will be further explained at a later stage in this section, as these directly affect the accuracy and performance of protective relays **(WU, 1985:793)**.

4.2.2 Main principles of CT's and VT's

The voltage transformers and current transformers continuously measure the voltages and currents of electrical systems and are responsible to give feedback signals to protective relays to enable them to detect abnormal conditions. Instrument transformers are unique versions of transformers with respect to measurement of current and voltages. The theories behind instrument transformers are the same as those for normal transformers in general **(Hewitson et al., 2004:45)**.The main tasks that are required from instrument transformers are:

- To transform currents and voltages from usually a high value to a value easy to handle for relays and instruments.
- To isolate the relays, metering and instruments from the primary high-voltage system.
- To provide possible methods of standardizing the relays and instruments, etc. to a few rated currents and voltages.

4.2.3 Non conventional instruments transformers (NCIT)

The earlier types of instrument transformers have all been based on electromagnetic principles using magnetic cores. There are now several new methods of transforming the measured quantity using optical and mass state methods available **(Rahmatian, et al., 2001:1-2)**. In conjunction with the development of complete substation automation systems, future trends include optical data communication to 'optical' CTs and VTs. The IEC standard 61858 covers the optical communication from the process side **(NPAG, 2002:92)**. As previously pointed out, classical magnetic CTs are subject to various problems for certain conditions. These problems require unique attention when such CTs are applied. According to **(Rahmatian, et al., 2001)**, an alternative that has been receiving increased attention within Europe in recent years is the use of optical CTs. These devices reduce most of the serious problems that are associated with iron-core magnetic CTs **(Kezunovic et al, 2006:1)**.

The bulk sensors make use of a block of glass machined to direct light around the conductor. Such sensors are limited in ability to adapt to various sizes and shapes **(Rahmatian and Ortega, 2006:1-2)**. Besides, the advantages associated with accuracy and freedom from saturation, the basic characteristics of such measuring systems can be changed by simple programming in the associated software **(Horak and Hrabliuk, 2003).** Therefore, the availability of the measured quantities in digital form can serve to simplify any tasks related to design, testing, and diagnostics. Optically based measuring devices have the potential to revolutionize the manner in which measurements are currently made in power systems.

4.2.4 IEC 61850 merging unit (MU)

The IEC 61850 has also defined the application of another type of devices that are related to protection or non-protection functions. This includes the Merging Unit (MU). The merging unit is an interface unit that allows multiple analogues CT/VT's, binary inputs and is capable of producing multiple time-synchronized serial unidirectional multi-drop digital point to point outputs in order to provide data communication via the logical interfaces. In addition, it allows the replacement of copper control cables with fibre which leads to functionality improvements and reduction of commissioning, engineering and maintenance costs **(Apostolov and Van Diver, 2007:2)**. The existing Merging Units encompass the following functionality:

- Signal processing of all the sensors – (conventional or non-conventional)
- Synchronization of all the measurements – (3 currents and 3 voltages)
- Analogue interface – (high and low level signals)
- Digital interface – (IEC 60044-8 or IEC 61850-9-2)

In 2007 **Apostolov, et al.,** recommended that it is essential to be able to interface with both the conventional and non-conventional sensors in order to permit the implementation of the system within different substation environments. A simplified diagram with the communications architecture of an IEC 61850 based substation automation system is shown in Figure 4.4.

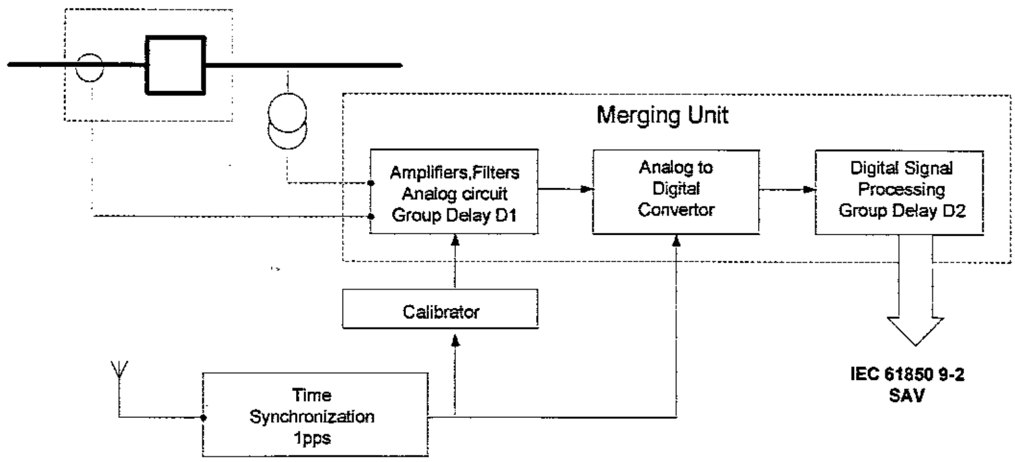

Figure 4.4: *Block diagram of the simplified Merging Unit*

The IEC 61850-7-2 standard classifies a set of theoretical information exchange models called the abstract communication service interface (ACSI). The model for the transmission of sampled values is of significance due to the interface between the protection and instrument transformers. The IEC 61850-9-2 therefore supports the complete flexibility of the abstract model defined by the IEC 61850-7-2 standard. The IEC 60044-8 is the product standard for the electronic current transformers. The standard specifies, among others, the digital outputs for both the electronic current and voltage transformers. The IEC 61850-9-2 does not necessarily require the merging unit but with the digital interface according to the IEC 60044-8, the merging unit is mandatory. According to the IEC 61850-9-2 standard, the secondary converter can directly have an output. However, systems consideration like the necessity of synchronized sampling and the existence of the synchronization network makes the use of the merging units to be suitable in a first step. The concept of the merging unit is also instrumental in terms of integrating conventional instrument transformers with digital interface systems of the IEDs. For that matter, the link between the instrument transformers and the merging units would be a high-energy analogue signal **(Bruner et al, 2005:1-5)**.

4.2.4.1 The process close Architecture Details

As stated earlier, at the process level there is a merging unit (MU) that is connecting the voltage and current transformers with the protection and control devices. The most important task of the merging unit is to merge the current and voltage data of the three phases. The interface between the MU and instrument transformers is technology specific. The output is standardized according to the IEC61850-9. Part of the MUs that are currently available on the market allows the connection of both the conventional CTs/VT's and nonconventional CTs/VT's or a mix of both instrument transformers.

4.2.4.2 Non-conventional instrument transformers and CB monitoring

In order to maintain reliability and correct operation, it is recommended that the sampled analogue values from the MU must be time coherent at all time. This could be achieved either by having each sample time tagged or by synchronous sampling of all the analogue values throughout the entire substation. In addition a reference local or global common time is compulsory in the system. Different process close architectures do exist and they are depending on which signals of the switchgear are connected using conventional wires and which one are connected by means of an IEC61850 network. As illustrated in Figure 4.5, non-conventional instrument transformers are connected to the protection and control equipment through the MU. The connection from the sensor to the MU is a proprietary serial link, while the link from the MU to the protection and control equipment is standardized according to the IEC61850-9. The IEC6850-9 connection can be of several point-to-point links or a network using a switch.

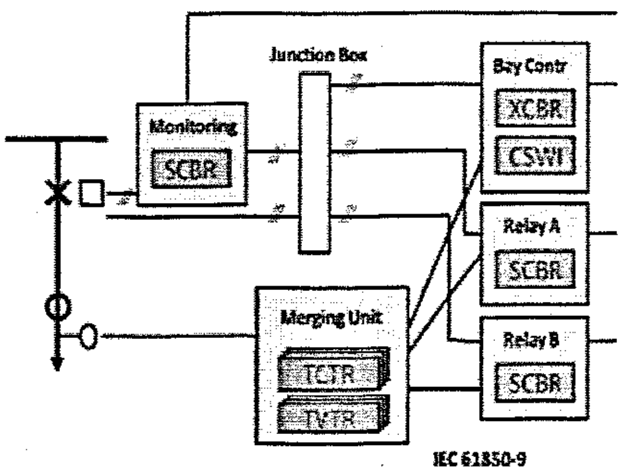

Figure 4.5: Non-conventional instrument transformers and CB monitoring

In addition to the non-conventional sensor, a monitoring unit (SCBR) that is used to monitor the circuit breaker drive is implemented **(Andersson, et al., 2002:3-5)**. There are conventional connections from the monitoring unit to the existing protection and control equipment for alarms and operational signalling as well as an IEC61850-8 connection to the station level for detailed monitoring data. In this configuration, all trip commands and positioning signals between circuit breaker and protection and control equipment are still conventionally connected with wires.

4.2.4.3 Non-conventional instrument transformers and intelligent CB drive

Figure 4.6 shows the fully intelligent switchgear with the nonconventional instrument transformers including a breaker and the breaker monitor (SCBR).

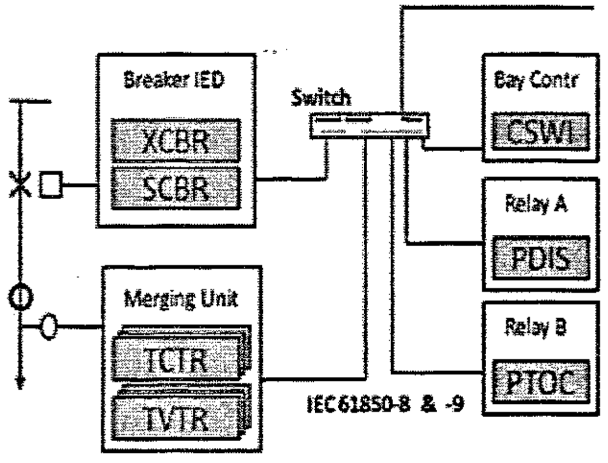

Figure 4.6: Non-conventional instrument transformers and intelligent CB drive

In this arrangement, the merging unit and the monitoring device are connected to the protection and control equipment by means of a process bus using both the IEC61850-8 and IEC61850-9. In addition the process bus is used for the complete exchange of information between the process level and the bay level. As a result, there are no conventional wire connections between the switchgear and equipment on bay level, to any further extent.

4.2.4.4 Function Integration

At bay level protection, control and at times monitoring functions are applied in separate physical devices. As the name implies, function integration is the method used to reduce the number of physical devices that are required in a system. This reduction of devices contributes to the increase in system stability and reliability. Currently, the traditional function allocation is that all protection, control and monitoring functionalities are allocated to the bay and/or the station levels, Figure 4.7.

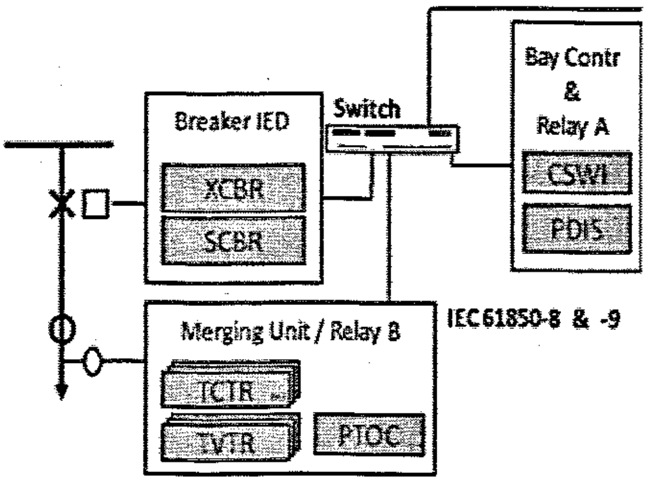

Figure 4.7: The function integration at process and bay level

To date, some of the functionality that has been integrated and have proven a reduction in the number of physical devices required on the bay level includes:

- the disturbance recorder integrated in the protection device and,
- the protection and control integrated in one physical device

Recently **Andersson, et al., 2002** noted that, with the introduction of non-conventional sensors and actuators, electronic devices are introduced further below the bay level. This increases the total number of electronic devices within the system. However, the good news is that it offers additional opportunities for function integration. An example of the function integration is given in Figure 4.7. The functional setup is the same as in Figure 4.6 but now the protection functions are integrated in the merging unit and in the bay controller respectively.

4.2.5 Conclusions

The concepts of relay input sources are clearly defined in this section. The section has explained the CT's and VT's generation from the conventional type to the "All optical sensing type" and the challenges involved. The development of fibre-optic CT's and VT's and their practical applications in high and medium voltage substations have made significant progress in recent years. It is therefore noticeable that the new technology has brought important contribution and advantages over conventional instruments, hence as parts of this project the non-conventional instrument transformers are proposed to be applied in conjunction with the IED's.

4.3 THE THEORY OF RELAYS TECHNOLOGY

4.3.1 Introduction

Protection relays are devices that sense or monitor any change in the signal received, normally from a current or voltage source. Should the magnitude of the incoming signal be outside the preset range, then the relay will operate. This operation is generally to open or close the electrical contacts to initiate further operation such as tripping of the circuit breaker.The fundamental parameters of the three-phase electrical system include voltage, current, frequency and power. The above mentioned have pre-determined values and sequence under healthy conditions. Any change from this normal behavior could be the result of a fault condition either at the load end or at the source end **(Hewitson et al, 2004:96)**. The huge number of electromechanical and static relays are still giving dependable service within most power systems today, therefore a brief descriptions on these technologies is necessary although the purpose of the project is to focus on modern protection relay practice.

4.3.2 Electromechanical (IDMTL) relays

As the name implies, this relay monitors the current, and have an inverse characteristics with respect to the currents being monitored. The electromechanical relay has been one of the most popular relays used on medium- and low-voltage systems for many years, and modern digital relays' characteristics are still mainly based on the torque characteristic of this type of relay **(Hewitson et al, 2004:96-98)**. For this reason, it is worthwhile studying the operation of this relay in detail to understand the characteristics adopted in the digital relays.

4.3.3 Static relays

Static relays are relays in which the designed response is developed by electronic or magnetic means without any mechanical motion **(NPAG, 2002:101)**. This means, that the name 'static relay' covers the electronic relays of both the digital and analog designs. The analog relays refer to electronic circuits with discrete devices like diodes, transistors, etc., which were adopted in the initial stages.

4.3.4 Numerical relays

The difference between digital and numerical relay rests on points of fine technical details, and is seldom found in areas other than Protection. They can be viewed as normal developments of digital relays as a result of progress in technology. Normally, they use a specialized digital signal processor (DSP) as the computational hardware, together with the related software tools. **(NPAG, 2002:102-105)**.

4.3.5 Protection relaying philosophy

The main Function of Protective Relaying is to cause a prompt removal from service of any element of the power system when it suffers from short circuit or when it starts to operate in any abnormal manner that might cause damage or interference with the effective operation of the rest of the system. The relaying equipment is assisted in this task by circuit breakers that are capable of disconnecting the faulty element when instructed to do so by the relaying equipment **(Aptransco technical reference book, 2004:5-7)**. The theoretical characteristic as defined in IEC 60255-3 standard is based on the formula **(Bayliss and Hardy, 2007:278)**.

$$t = \frac{\beta}{\left(\frac{I}{I_n}\right)^{\alpha} - 1} \qquad (4.16)$$

Where:

t = theoretical operating time

I =value of applied current

I_n = basic value of current setting

β and α, are constants

The characteristic curve of the relay(s) can be chosen from general standard shapes:

- Definite time.
- Standard inverse time.
- Very inverse time
- Extremely inverse time.

4.3.6 Relays burden on current transformer

The burden is the normal continuous load imposed on the current transformers by the relay, normally expressed in VA as well as in ohms sometimes. With static relays, almost any primary setting is made possible. This means that on a distribution network that is equipped with static relays, the relay coordination is still possible at high fault levels even for a very low relay current setting and low CT ratios. Modern static relays have a very low burden of less than 0.02 Ω for 5 A inputs and 0.10 Ω for 1 A input, which is independent of the setting **(Hewitson, et al., 2004:116)**. For electromechanical relays, this is usually stated as 3 VA nominal. The modern electronic relays present a very lower figure, which is one of their major advantages. However, for the electromechanical relays, the selection of the plug setting does have an effect on the burden. Therefore the lower setting results in the higher burden on the CTs. Hence,

$VA = I^2R$, therefore

$$R = \frac{VA}{I^2} \tag{4.17}$$

Where:

$R =$ resistance or impedance

$VA =$ burden

$I^2 =$ current function

As indicated above, the lower tap therefore, places a higher burden on the CTs and they should have sufficient performance to meet such demands.

4.3.7 Conclusions

This section focuses on the evolution of relays as well as their operating philosophy since they are being classified in accordance with the functions that they carry out. The factors that influences the relays settings,, the impact that the relays impose on the instrument transformers as well as the operating environmental factors, to ensure all relays comply with the EMC requirement are all covered in this section.

4.4 THEORY OF IED'S APPLICATION AND PROTECTION FUNCTION

4.4.1 Introduction

The protection relays operate only after an abnormal condition has occurred, with adequate indication to allow their operation. As a result, protection does not imply prevention, but rather, minimizing the fault period and limiting the damaging effect, outage period, as well as associated problems that might result otherwise **(Blackburn and Domin, 2006: 48-54).**

4.4.2 Review of literature on relays application

Many power systems of different sizes are protected by thousands of relays. Different relays exist for different application and each relay is assigned to protect a piece of equipment from being damaged. The basic philosophy within protection system design is that, any equipment that is threatened by a sustained fault should be automatically taken out of service before being damaged. Amongst the phenomenon that create disturbances in power systems are various types of system instability, overloads, and power system cascading **(Horowitz and Phadke,**

1992); (Elmore, 1994); (Blackburn, 1987); (Phadke and Thorp, 1988); (Anderson, 1999). In general faults occur as random events, and faults are usually an act of nature. In power systems a fault usually means a short circuit, although more generally refers to some abnormal condition within a system **(Begovic, 2001)**. The basic system equipments that require protection includes generators, transformers, transmission lines and systems nodes (buses).

4.4.2.1 Relay application

The basic application of relays in power systems is protection. For any power system, the power network is divided into a number of zones. Therefore a zone of protection refers to a section in a power system with a defined set of equipments. A protection system consisting of one or a number of relays is therefore made responsible for all faults occurring within the zone of protection.

4.4.2.2 Protection of transmission lines

In transmission lines overcurrent relays can be used as a mean of protection. The overcurrent relay activation value is set between the maximum load current and the minimum fault current that is expected on the line. When distance calculation is involved, the impedance is calculated and used as the activating or "pickup" quantity. When high speed protection of the entire line is desirable, pilot relaying is therefore used to protect the line. Although tie lines are generally protected by impedance relays, overfrequency means of protection can be an option, as relays must deal with a number of possible faults. It is therefore expected of the protection system to be able to compete and challenge all possible faults combinations. The advanced measurement and communication technology in wide area monitoring and control are expected to provide new, faster, and better ways to detect and control an emergency **(Begovic, 2001).**

4.4.2.3 Transformer protection

Transformers with the MVA ratings below 2.5MVA are regarded as small transformers and are generally protected by means of fuses or overcurrent relays. Large transformers with the MVA rating of 2.5 MVA and above are protected by circuit breakers. These beakers are operated by percentage current differential relays, overcurrent relays, temperature and pressure sensing devices.

4.4.2.4 Busbar protection

Busbar protection is designed to protect substations during fault conditions. Differential relaying is the most common primary tool.

4.4.2.5 Arc protection

An arc protection relay is a device used to maximize the safety of personnel, while at the same time minimizing the damage effect on equipments and material in substations installation during hazardous power system fault situations. For any installation, the arc protection system detects an arc and measures the fault current. Should any fault detection occur the arc protection relay will immediately trips the concerned circuit breaker(s) to ensure the fault is isolated. Advanced arc protection system operates much faster than conventional protection relays thus keeping arc short circuit damages to a minimum level. Time is very crucial in terms of detecting and minimizing the effects of an arc. Therefore an arc fault that last for about 500 ms may cause severe damage to an installation. However, if the arc fault lasts for less than 100 ms then the damage is often minor, but if an arc is eliminated in less than 35 ms then the damage is almost unnoticed and this is one of the advantage that the IED's offers.

4.4.2.6 Other relay application

In power system, the IED's are part of the relays that offer control functions as opposed to protection functions or a combination of both. An example of control functions could be, controlled islanding schemes, load shedding on overfrequency, and so forth. In most power systems, undervoltage relaying application is commonly used on critical busses to protect against voltage collapse. In general when the magnitude of the bus voltage drops below a certain amount, the undervoltage relays signals a predetermined load shedding operation.

4.4.2.7 Coordination of Relay Protection

The coordination of relay protection is performed to ensure that only the equipment that is threatened with damage is taken out of service. The settings of the relay serve as a control mechanism, when a relay issues a control signal to a circuit breaker. Therefore, the relay coordination is the sequencing of the relays communication and operations across all relays in the power system. For instance, with a fault on a transmission line, coordination imply that the relay closest to the fault should operate before the upstream one does, thus reducing the amount of outaged equipment to be small as possible. The coordination of relay protection functions is a difficult art, thus determining all relay settings and whether or not each of them operates correctly is a time consuming and difficult process **(Thorp, 2003:4)**.

4.4.3 Development of IEC61850 intelligent electronic devices (IED's)

The modern microprocessor relays are no longer just protection devices in power systems but have advanced to perform much other functionality that facilitate effective operation of power systems. In addition, modern microprocessor relays include protection, metering, automation, digital fault recording (DFR), control and reporting etc. The term 'intelligent electronic device' (IED) is not a straightforward definition, as oppose to the term 'protection relay' on the other hand. Generally speaking, any electronic device that possesses some kind of local intelligence can be called an IED. However, concerning specifically the protection and electrical industry, this term actually came into existence to explain a device that has versatile electrical protection functions, advanced local control intelligence, monitoring abilities and the means of extensive communications directly to a SCADA system. Because of these capabilities, it is now more accurate to refer to these microprocessor devices as intelligent electronic devices (IED's). As the IED's prevail in today's power substations, they are performing more system automation and control functions and as a result the amount of data available from substations increases exponentially. Once the IED's are networked together, they will provide almost all the information required by the system operators and more. These substation IED networks are also able to provide data at a much faster speed and reduce or eliminate additional transducers, input and output contacts and even RTUs within distribution power systems. **(Hou and Dolezilek, 2008:1).**

4.4.3.1 The functions of an IED

The functions of a typical IED can be classified into five main categories namely, protection, control, monitoring, metering and communications. Some IEDs may be more advanced than others, and some may give emphasis to certain functional aspects over others, but these main functionalities should be incorporated to a greater or lesser degree **(Flores, et al., 2007:2).** ***Note:*** *An IED could be either IEC61850 compliant or not depending on the Manufacture and the certificate of compliance should always be made available to the client as proof.*

4.4.3.2 Protection function of an IED

The characteristics of the protection function are nothing new. They are defined by the IEEE Standards that are based on the induction disk relays characteristics. The IED's only emulates the physical behaviour of the historical electromechanical relay. In addition, one of the difference between the IED's and the traditional relays is that, the multiple protection functions are specified and integrated into one package to meet various users' applications within the power distribution system. **(Duncan, et al., 2002:3). Hewitson, et al.**, (2004:127) stated that, the protection functions of the IED are developed from the basic overcurrent and earth fault protection functions of the feeder protection relay (thus certain manufacturers named their IED's 'feeder terminals'). This is due to the reason that the feeder protection relay is used on almost all compartments of a typical distribution switchboard, and the fact that more demanding protection functions are not required to enable the relay's microprocessor to be used for control functions. The IED is also meant to be as adaptable as possible, and is not intended to be a specialized protection relay, for example motor protection. This also makes it more affordable. The protection functions are normally provided in separate function blocks, which are activated and programmed independently.

4.4.3.3 Control functions

Additionally to traditional protection theories and applications, new terms such as data rate, mirrored bits communications, and protocols that are related to microprocessor devices became regular in the protection environment. With the new components of IEC 61850 aimed at real-time controls and protection, a good knowledge and understanding of computer and communication networking is required in order to achieve the full benefit of the IEC61850 standard. In this section, the traditional protection schemes are grouped into two different categories in terms of their communication requirements as well as the distances involved and data volume **(Hou and Dolezilek, 2008: 8-10)**. The distance referred to, could be within a particular substation or between a numbers of substations while the data volume is binary or continuous analogue data.

4.4.3.4 Inter-IED Message exchange within a substation

The control and protection schemes that require information exchange between the IEDs within a substation are described in the following subsections below. These are the typical applications that illustrate how the Generic Object-Oriented Substation Event GOOSE control and protection messages replace the hard wires in substations and provide the similar communication via Ethernet LAN. This is one of the contributing factors the standard has brought about.

4.4.3.5 Fast bus tripping control

The fast bus tripping scheme normally applies to radial power distribution systems in order to achieve the minimum clearance time for bus faults that are close to the bus differential scheme. This scheme can also be referred to as the reverse interlocking scheme. From Figure 4.8, should the fault occur, the IED for the bus high-side breaker communicates with the feeder IED's about the location of a fault.

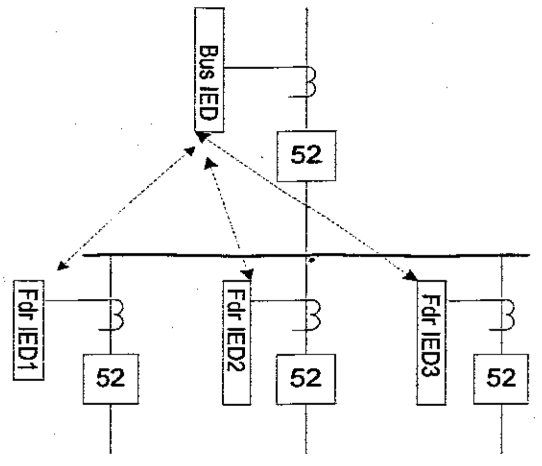

Figure 4.8: *Fast bus tripping scheme for distribution substations with radial feeders*

If the fault occurs on a feeder, one of the feeder IED's will sense the fault and immediately issue a signal to block the fast tripping element of the bus IED. On the other hand, should the fault occurs on the bus, then no feeder IED's detect the fault and block the bus IED, therefore the bus IED should trip the bus using the fast overcurrent elements.

4.4.3.6 Reclosing control

The modern IED's generally incorporate both control and protection functions like breaker reclosing. Most sophisticated IED's have control schemes for two breakers to be used in the breaker-and-a-half and ring bus arrangements. However, many utilities use dedicated IED to carry out breaker failure protection, reclosing, and other functions for a specific breaker bay.

4.4.3.7 Breaker failure protection control

The local breaker failure backup protection control is popular for high-voltage applications. Like in the case of reclosing control, today's IED's normally have in-built breaker failure protection, additionally to complete protection functions. Once the IED issues a trip signal, it simultaneously starts a timer and monitors the breaker current. If the monitored current does not disappear in a preset time, the IED will then issues a re-trip signal or trips the closest breakers in order to isolate the faulted one. However, if the user is required to treat the breaker as a bay with the purpose to perform the bay controls and protection functions, then a dedicated IED could be used for breaker failure protection. The same IED could be used to monitor additional breaker should the fault occur, the IED for the bus high-side breaker communicates with the feeder IED's about the location of a fault.

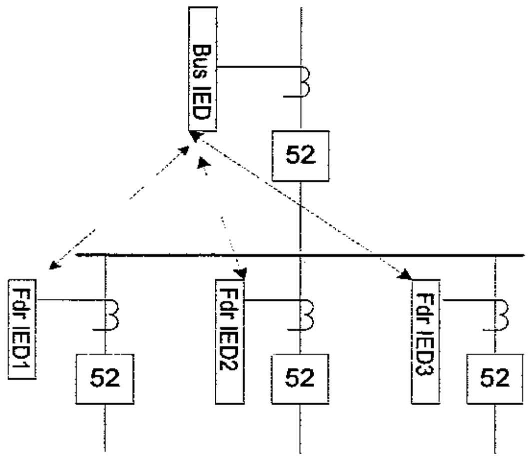

Figure 4.8: Fast bus tripping scheme for distribution substations with radial feeders

If the fault occurs on a feeder, one of the feeder IED's will sense the fault and immediately issue a signal to block the fast tripping element of the bus IED. On the other hand, should the fault occurs on the bus, then no feeder IED's detect the fault and block the bus IED, therefore the bus IED should trip the bus using the fast overcurrent elements.

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4.4.3.8 Monitoring functions

Monitoring functions include Self-Monitoring and External Circuit Monitoring. During the early days of microprocessor-based devices, most users had a very major concern about reliability. They were concerned about losing all protected equipment, should an all-in-one electronic box (IED) malfunction. On the other hand, since IED's use numerical (digital) technology, that reduces internal analogue components, while including added functions, and provides advanced self-monitoring technology, these concerns are overcome **(Johnson, 2002: 1688).** The IED's self-monitoring programs can identify up to 98% of all IED-internal hardware and software problems, such as microprocessor failure, memory failure, and state of the power supply. Additionally, monitoring of external inputs, outputs, condition of dc power supply and circuit breaker components, further extends the scope of monitoring and protection. External circuit monitoring with circuit breaker coil monitoring can be used to detect an interrupt in both the trip and close paths while the VTs and CTs connection failures can be indicated using voltage and current symmetry analysis, something that most normal relay cannot do. Therefore, one multifunction device which reports all information about its condition could be more reliable and secure than a number of devices that have no way of warning "on line" that they are faulty (**Duncan, et al., 2002: 4**).

4.4.3.9 Metering functions

The IED's, provide current and voltage metering, voltage based functions as well as calculated energy metering at an accuracy that is appropriate for in-plant metering. Therefore, this eliminates the necessity for separate meters, resulting in significant cost savings and simplification of panel wiring. The metering function serves a number of purposes:

- Metered values that are mainly used for commissioning and testing purposes
- Load profile information
- Energy allocation through interconnected circuit / process
- Continuous metering

The rms values that can be measured include positive, negative, zero sequence currents and voltages, and phase shift between measured values. These data (power information) as provided by the IED's are very handy in terms of system planning, resource planning and cost analysis. However, the energy metering might not be as accurate as revenue metering, that uses CTs and meters of high accuracy, but it is useful for internal cost allocation purposes. Hence, by combining the internal programmable logic controller (PLC) capability and metering functions within the IED, more unique system requirements can be achieved. One of the examples is that, a maximum demand penalty can be avoided by setting the kVA and kW demand alarm levels that will initiate shedding of selected loads or switching of capacitor banks **(Duncan et al, 2002:4)**.

4.4.3.10 Communication functions

The ability of communication of an IED is one of the most significant aspects of modern electrical and protection systems and is one of the aspects that clearly separate the different manufacturers' devices from one another regarding their level of functionality as shown in Figure 4.9 below. In order to accommodate new, increasingly popular IED network functions, substations communication infrastructure has experience dramatic changes. Substation IED network communications are gradually migrating to Ethernet. In the past, substation integration systems were mostly based on relay networks built using EIA-232 point-to-point and EIA-485 multi-drop communication ports within the relays. These ports communicate at a speed of +/- 38.4 kilobits per second (Kbps).

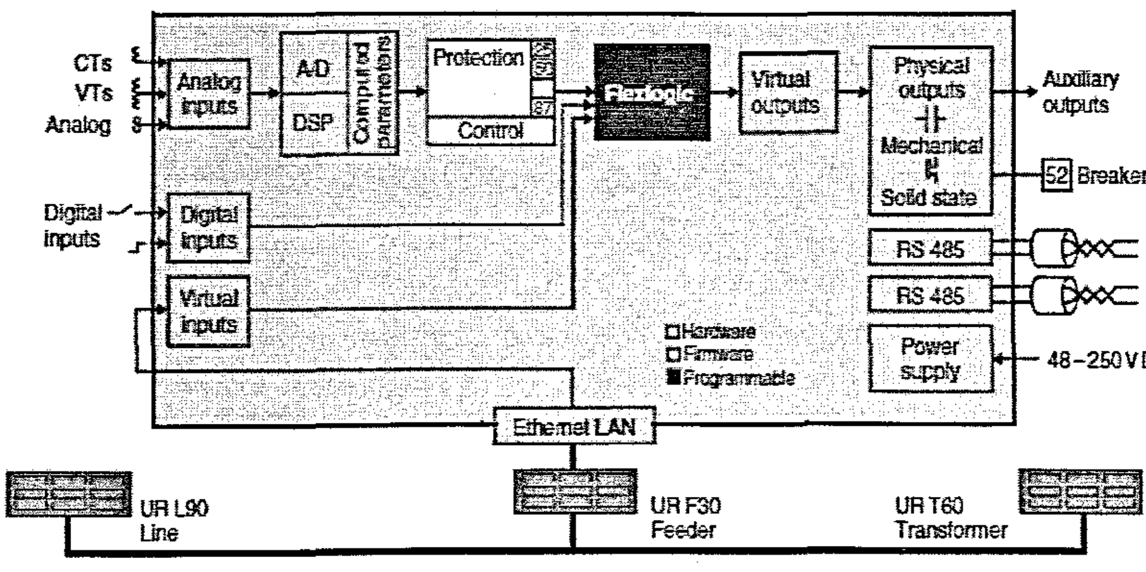

Figure 4.9: *Typical IED internal configuration (courtesy of GE Multilin)*

With this scenario, the information exchange is carried out using address-based protocols such as Distributed Network *Protocol* (DNP3), Mod-bus and Profibus. With the new IEC 61850 standards, the entire picture of substation communications have changed due to the popularity of the Ethernet networks. Therefore, many current substation integration and automation projects built, are demonstrating the benefits of the standard (**Hou and Dolezilek, 2008:1**).

4.4.3.11 IEC 61850 GOOSE applications within a substation

The IEC 61850 standard was initially designed for communications within a substation. Rather than just replacing the hard wires within substations, the Generic Object-Oriented Substation Event (GOOSE) messages can also monitor the health status of the virtual wires. This is similar to the self-test functions that are performed by microprocessor IED's, to avoid circumstances where a failed or faulted device is not identified until it is called upon to protect the power equipment. The retransmission of GOOSE messages is one mechanism to ensure that the status of a channel to the receiving end of the channel is periodically known. Without any changes in the event, the prior GOOSE message is published every 1 second in the steady state. When a state change occurs in a GOOSE message, the IED will immediately publish this state change. It will continue to publish this state change using a repetition strategy, until the "time to live" period is reached. Once the "time to live" period has been reached, publishing of the GOOSE message will return to a cyclic repetition method. The subscribing IED monitors this message and publishes a GOOSE message alarm, notifying SCADA, modifies its internal logic, activates an alarm LED and description on the front panel. This IED can also send email message to the protection technical team if the message is not received within a prescribed time frame as appropriate. However, a channel can still fail between a new event and the time that the last message was received. The possibility of the unchecked failure is proportional to the period, which is typically one second **(Skendzic and Guzmán, 2005:2-4).** A dropped Ethernet packet or frame can be another possible failure mode. This could be due to a high volume of Ethernet traffic or interference from control and power cabling that could be sharing a cable tray with the Ethernet cable. Therefore, for time-critical applications like breaker failure, the timing requirements need to be clearly specified so that the network traffic is sized correctly to ensure the success rate of the first GOOSE message reception. The IEC 61850 standard has classified application types that are based on how fast the messages are required to be transmitted between networked IED's. The standard has also specifies the performance of each type of application, based on time duration of message transmission.

4.4.4 Substation automation and advanced technology

Substation automation is not an easy goal to achieve in existing substations. Automation in a substation is measured as provision of new generation intelligent electronic devices (IEDs), and computers to monitor and communicate. It is simple and convenient to incorporate these components in new substations at a design stage as no crucial modification will be required. But in an existing substation, which is already implementing some old type's relays, automation is a question of what can be done to trim down the operating expenses and improve customer service, from practical and economical perspective.

4.4.5 Computer application in substation environment

At the end of the day a computer is the most useful addition to record all the information about the various systems and feeders. A substation computer is an important system element in that it allows intelligence to be moved downward to the substation. This intelligence reduces the amount of data that must be communicated between substations as well as the master station and plays a vital role in terms of fault finding. An example is that, information can be retrieved when required from databases maintained at the substation computer This provides a way to conquer the need for a standard protocol in terms of communication. In the case where the optional monitor is employed along with a keyboard, the computer can also serve as the human–machine interface (HMI) for information and control in the substation. The following are the additional capabilities added by including a computer in the substation:

- Maintains databases at substation
- Mathematical operations on the data
- Flexibility
- Human–machine interface in the substation

4.4.6 Existing substations

Substations contain amongst other systems, as well as subsystems specific to control and protection. These are: control panels, relay panels, communication, and RTU panels. Conventionally all this equipment gets interconnected through miles of cabling, which results in lengthy engineering and testing processes during the substation installation and commissioning stage. This view is shown in Figure 4.10, below.

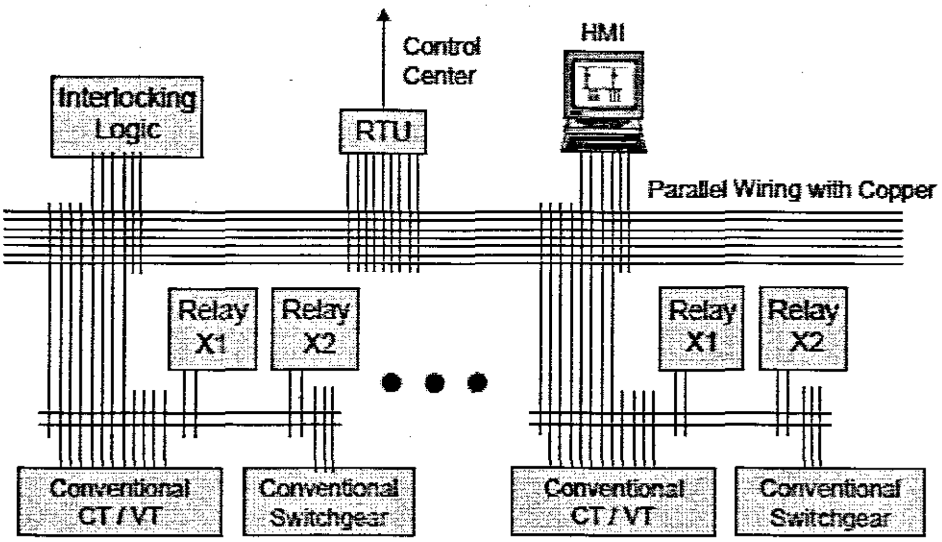

Figure 4.10: *Conventional substation (courtesy of Hirschmann automation and control)*

4.4.7 Substation upgrading and IED's application

A typical scheme is shown in Figure 4.11, for providing just those functions required, reducing expense and improving customer service. It helps to reduce capital expenditures and helps operators to minimize trips to substations and reduce out-age time. Existing relays, modules are replaced with more advance ones, as a result parallel copper wirings are replaced with serial communication and the feeder automation elements are added on each feeder panel as shown in the diagram below. This is referred to as a distributed architecture, since the feeder automation elements are installed next to the input/output wiring sources.

The feeder automation components are available as add-on components to the existing feeders. Feeder current and bus voltage are given as inputs for each feeder automation unit, additionally to the status inputs like the reclose status, breaker status and output from trip current relays. Some outputs are required from the automation unit for tripping, closing, and enabling/disabling of the recloser **(Andersson, Bruner & Engler, 2002: 2)**. The feeder automation elements generate the relay target information from the trip current relay inputs. Trip current relays that could be mounted directly on the studs of relay cases are available. This allows them to be mounted without rewiring the tripping circuit. In modern substations new technology (using the IEC 61850 standard) has been implemented to increase the reliability of the installation as well as the reduction of its size and cost. To date, a large amount of integration has taken place in the abovementioned systems and products, shrinking the footprint and reducing the overall complexity of the systems.

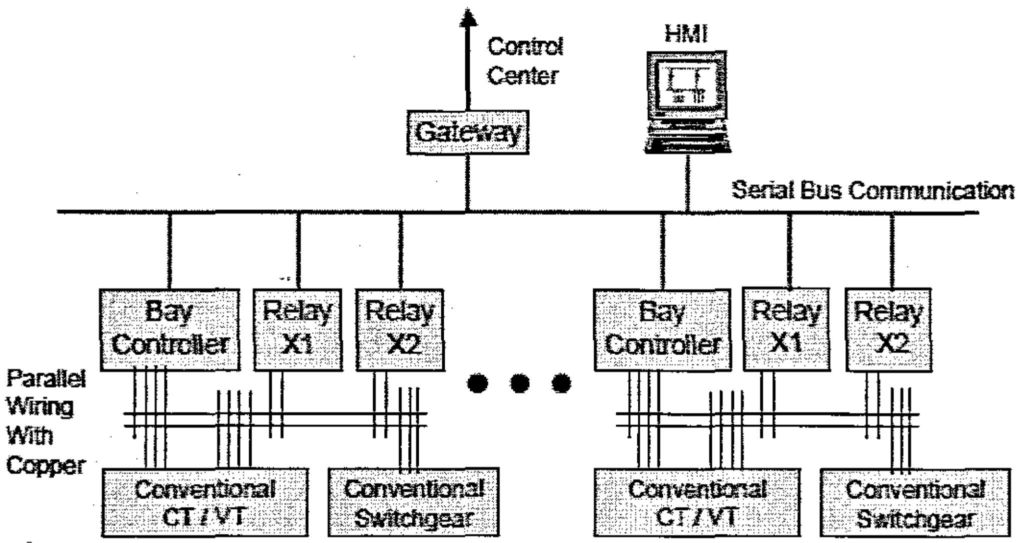

Figure 4.11: Overview of the station Bus (courtesy of Hirschmann automation and control)

The changes, improvements and development due to the advancement of new technology and the application of numeric relays is shown below in Figure 4.12, where the station bus has been implemented.

4.4.8 The future of protection in distribution systems

As already mentioned earlier, protection relays has become more advanced, versatile and flexible with the introduction of microprocessor-based relays. The very first communication capabilities of relays were mainly intended to facilitate with commissioning. With technology developments, PLC functionality were incorporated into relays, and with the development of small RTUs, it was soon realized that relays could be much more than just protection devices.

The questions and approaches of equipping protection relays with advanced control functions and the addition of protection functions to a bay controller are raised. Both of these approaches have been followed, with different manufacturers adopting different approaches to the question of protection, control and communications **(Hahnloser, 2007:7)**. These resulted in a wide range of devices on the market, some more onto control, some stronger on protection, and therefore the term protection relay was too restrictive to describe these devices. Therefore, integration has resulted in the terms such as relays, interface panel, control panels, etc. being replaced with the term Intelligent Electronic Device (IED) as well as Substation Automation (SA) systems as shown in Figure 4.12 below.

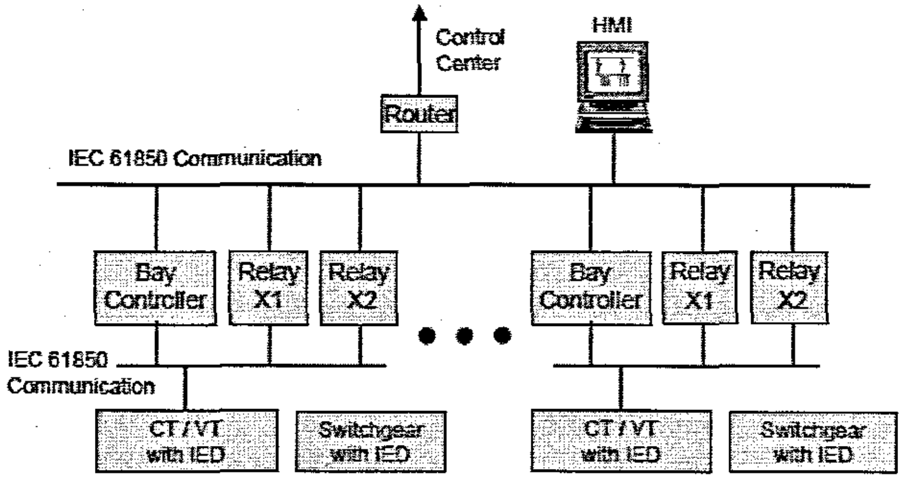

Figure 4.12: *Overview of IEC 61850 –Station and Process Bus (courtesy of Hirschmann automation and control)*

A substation engineered on this basis would have one or more of such IEDs per Medium Voltage (MV) bay, connected to the process (CT, VT, CB, and isolator) on one side, and communicating by means of an optic digital Ethernet bus to a computerized control & monitoring (SA) system on the other side. The control system will also communicate upwards to the SCADA system at the control centre through fibre optic or other channels. In some installations, the security and operational reasons order the isolation of control from protection. Today an IED is a compact cost effective product that could cover protection, local control, recording, monitoring and communication all in one box. Communication standards such as IEC 61850 guarantee that the communication protocol and set-up is standardized across various vendors paving the way towards IED inter-operability and, IED inter-changeability is to be hoped, in the future. All of these reduce the number of panels as well as the wiring. In addition, the IED is 'multi-function' and it is not unusual to have a large number (20–30 or more) of protection functions in one device due to its high processing capability. Watchdog and self-supervision functions ensure high availability for such devices. Some of these IEDs, with unique functions such as line differential, are even provided with built-in geographical positioning system (GPS) cards to achieve extremely reliable microsecond accuracy time stamps of internal signals at source. This is a requirement for accurate and reliable line differential protection and advanced monitoring applications. In the future such systems will incorporate optical data communication to 'optical' CT's and VT's, intelligent breakers, etc. with the final result of moving towards a substation with 'copper less' controls and protection.

4.4.9 Time Synchronization as per IEC61850

Time synchronization is an important factor in distribution network protection because it is best to have as much synchronized data as possible to assist in data analysis and event correlation during catastrophic events. The IED's that are time synchronized compatible, are synchronized using the most accurate method that is supported by each IED **(Preuss and Pellegrini, 2007:5)**. One of the areas that the emerging IEC61850 standard is addressing is the movement of data associated with sampling and digitization of both current and voltage measurements inside a substation. In protection, the IED's make their decisions based on current and voltage samples that are measured by other IED's. Therefore, the sample data must be moved and synchronized within few milliseconds in order to guarantee proper decisions making, and therefore ensuring proper relay and power switching operations. Within any substation, a number of IED's will be transmitting time-critical sample data at a high rate. This data can be handled reliably within a single common network by a 100Mb full-duplex multi-cast Ethernet over fibre media, probably with multiple VLAN segments in the case of larger substations **(Madren, 2004:6)**.The IEC61850-5 Type-6 time Synchronization messages maximum permissible delay times are shown below, Table 4.1. In 2008 **Hou, et al.**, stated that the IEC 61850 communications standard is continuously evolving to include new technologies and practices to serve additional functions as they gain popularity.

Table 4.1: *IEC61850-5 Type-6 time Synchronization messages maximum permissible delay times*

T1	**+/- 1mS**	Event time tagging on bay level
T2	**+/- 0.1mS**	Control and protection: Time tagging of zero crossings and of data for the distributed synchronization check. Time tags to support point on wave switching.
T3	**+/- 25µS**	Synchronized sampling and advanced function

Although the application of GPS-based time synchronization is more popular, the Simple Network Time Protocol (SNTP) method will also be discussed as they are both part of the IEC61850 standard. However, the existing SNTP method can only provide 1-millisecond accuracy at best and this is only on Ethernet networks that are carefully designed. This is not acceptable for protection purposes and many other applications because the time stamp assigned to data changes has microsecond resolution while the SNTP provide only 1-millisecond accuracy. At present, protection class time-stamp accuracy is only available through

GPS methods like IRIG-B. A separate IRIG-B network is recommended since it has additional advantage of maintaining time synchronization during Ethernet network failure. The IEEE is working on the IEEE 1588 time synchronization method's profile, which will provide high accuracy by capturing the time each message is received, over Ethernet networks. Most vendor proprietary modifications of SNTP methods could function in a similar way but are not recommended, since they are not standardized or widely available for that matter. Nowadays the use of IRIG-B time-synchronization methods is in demand while the Protection engineers are watching the evolution of the IEEE 1588 **(Hou, et al., 2008:2)**.The IED network data are more helpful and important when all the IEDs in a system are synchronized. In addition, the utility of existing systems, such as SCADA and asset management, are improved when the state of the incoming data is improved. Time synchronization is therefore valuable, because measurements taken at the same instant are presented to the user **(Dolezilek and Schweitzer, 2009:6)**.

4.4.10 Benefits of IEC 61850 application

The new generations of microprocessor multifunctional protective relays, the EID's and the IEC61850 standard are offering the integrated flow of rich information for operations and management, as well as improved performance of system protection and security. These benefits are obtained through the following achievements **(Hahnloser, 2007:8)**.

- Object-oriented architecture
- Lower communication infrastructure costs
- Reduces effort in commissioning
- Lower installation and maintenance costs
- Reduce wiring costs
- Provides a full set of services
- Enable interoperability without gateways / routers

A general comparison between different generation of protection relays is summarized and shown as tabulated below in Table 4.3. As clearly shown by the graph, it is evident that there is no way one can achieve benefits without any costs involved, Figure 4.13. A true reflection of a complete view of cost justification of IEC61850 devices does not just depend on the price of the device **(Mackiewicz, 2004: 9-10)**. It should be noted that benefit are received as systems are used and not only when they are purchased. Therefore the initial cost of the IEDs are high but does not rise excessively due to their benefits that includes, the reduction of operation and maintenance costs as well as improved service quality and the overall availability of power system **(Lohmann, 2000:1)**.

Table 4.3: Overview of protection relays generation and their capabilities.

	IED	NUMERICAL	SOLID STATE	ELECTROMAGNETIC
Self checking & reliability	✓	✓	✓	X
System integration & digital environment	✓	✓	x	X
Functional flexibility & adaptive Relaying	✓	✓	x	X
Complete Substation Automation	✓	x	x	X
Functional capability	high	medium	low	Very low

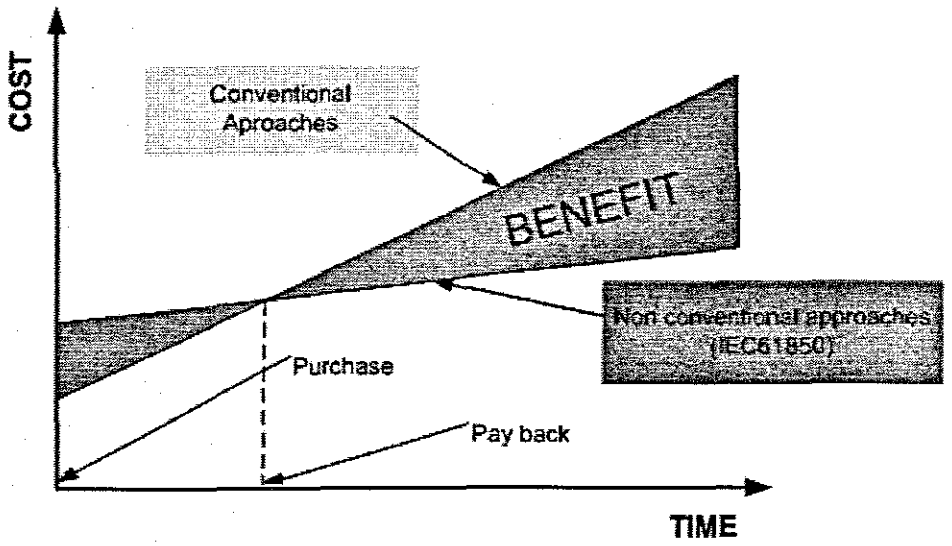

Figure 4.13: Graphical representation of cost justification

4.4.11 Conclusions

In this section the importance of protection functions and applications of protective IED's in a distribution environment are discussed. The ability, advantage and disadvantages between the IED's and other relays plus the factors that affect the protection system, as well as the importance of the protected equipments are analyzed. As a whole the chapter has covered the theoretical aspects that require understanding in order to perform protection studies using the IED's. The theory in this chapter will be used to perform the content of chapter 5 and 6.

CHAPTER 5

PROTECTION SIMULATION STUDIES AND DISTRIBUTION NETWORK ANALYSIS

It is widely accepted that power system protection is an important aspect in designing and upgrading of electrical power systems. This chapter covers the modeling and analysis of the fault level and protection settings of the CPUT and Eureka Distribution Networks using DIgSILENT software package. Different types of phase faults are applied and simulated at different locations, to analyze their effect and impact on the above mentioned systems as well as the critical clearing times while maintaining the stability of the networks. The IED's settings, grading and co-ordination is carefully analyzed and applied in order to protect the distribution feeders, busbars, transformers, conductors and insulators, as it is the objective that the faulted part should be isolated rapidly from the rest of the system so as to increase stability margin and therefore decrease damage to the equipments. This chapter therefore presents the details of the power systems configurations that were chosen, the simulation studies carried out as well as discussion of the simulation results obtained.

5.1 INTRODUCTION

The protection of power system has been and continues to be of major concern in terms of stability and reliability in system operation. The ideal approach to study the protection phenomena in a power system is by simulating the power system using suitable protection program such as DIgSILENT. The DIgSILENT program currently available on the market represents the power system components with genuine realistic models. These models generally match and represent the characteristics of the components while keeping the complexity of the models to a minimum .Beside presenting a convenient way to generate the required signals and parameters to analyse power systems feature (in this case the protection schemes), DIgSILENT also allows the users to study the worst case scenarios that are unlikely to occur in real life, making it possible to cater for faults that are rare. In order to validate the concept of the IED's discussed in the previous chapters, the simulations are carried out using DIgSILENT and the models are based on the real networks. A power network can be protected using a variety of different relay configurations. In this thesis the main focus and objective was to select the more practical system protection configurations and apply them on the real and existing networks in order to identify the feasibility of the proposed protection IED's. In network protection studies, the frequent considered faults are the short circuits of different types such as: single line-to-ground fault, line-to-line fault, double line-to ground fault, and three-phase fault **(Kimbark, 1948).** Although the efficiency of the IED's is being tested, the objective is still the same, which is: Isolation of the problems with a minimum service disruption based on the protective devices' Time-Current characteristics. The information that is required in order to accomplish the protection study in this project is shown below **(Acevedo, 2000: 67).**

- Protection device manufacturer and type
- Protection device ratings
- Power transformers data
- Voltage level at each bus in the system
- Full load current of all loads within the system
- Short circuit current available at each bus
- Instrument transformers ratios
- Trip settings and ratings

5.2 NETWORKS CONFIGURATION

Since the study is based on medium voltage (MV) distribution network protection, two networks were chosen (CPUT and EUREKA network) as mentioned earlier in this chapter. The voltage range that is applicable to the 3-phase power networks simulated model is 66kV that is scaled down through 11kV to 400V. The full load current at these voltages within the system is also presented in the simulation. Since very high currents in power systems generally occur as a result of faults on the system, these currents are then used to determine the presence of faults in the protected power systems. The overcurrent IED's that form the basis of this chapter, are the most common form of protection that has been implemented to deal with excessive currents on the simulated model of the two power networks. Although the overcurrent protection IED's are mainly intended to operate under fault conditions only, it is important to ensure that the settings associated with the relays are of a compromise in order to cater for both overload and overcurrent conditions. The fuses, moduled-case circuit breakers (MCCBs) and thermo-magnetic switches lender a simple operating arrangement and will be mainly applied in the protection of the low voltage equipments.

5.2.1 Overcurrent IED's characteristics

The overcurrent IED's can be classified into three main groups and this is based on their operating characteristics. The three main groups (definite current, definite time and inverse time) are clearly illustrated in Figure 6.2 a, b and c below **(Gers & Holmes, 1998:66-70)**, where *t* is the time and *A* is the current.

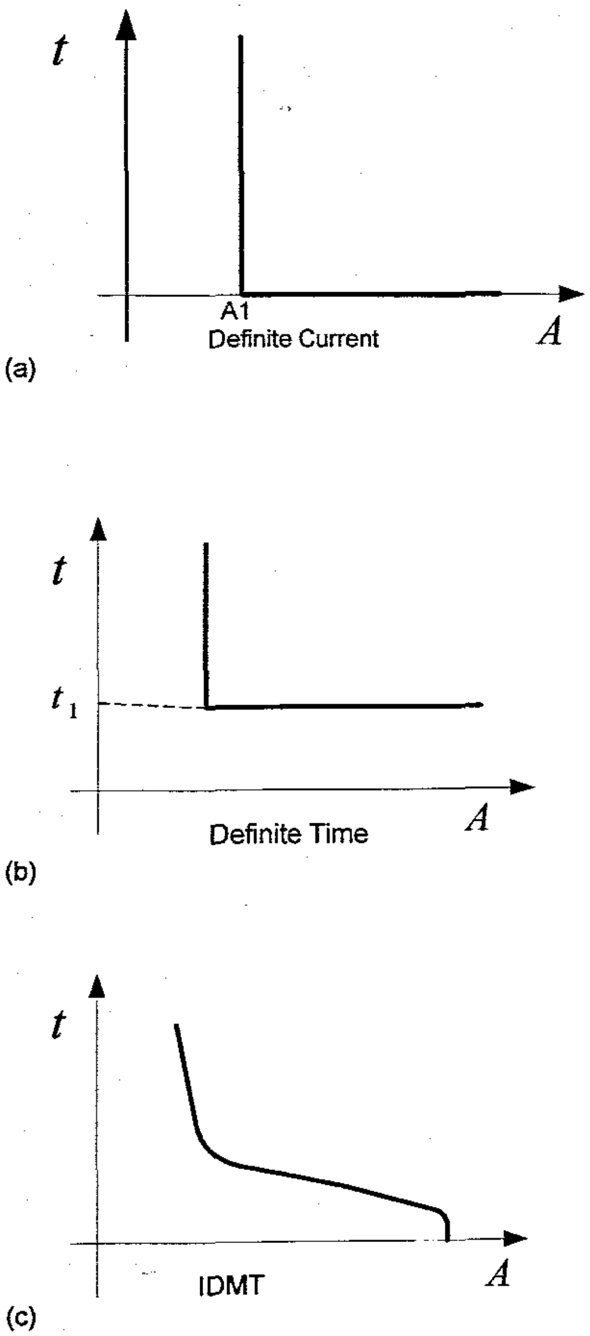

Figure 5.2: *Time-current operating characteristics of overcurrent relays*

5.2.1.1 Definite current characteristics

These types of characteristics allow the IED's to operate instantaneously when the measured current reaches the predetermined value. The settings are chosen in such a way that at the substation furthest away from the source, the IED will operate for a low current value and the operating currents will then gradually increase at each substation in the direction of the source. Therefore the IED with the settings that are lower operates first and disconnects the loads at the point closest to the fault. This type of protection do poses some drawbacks and one of them is in the sense that it has little selectivity at high values of short-circuit current.

5.2.1.2 Definite time-current characteristics

The types of IED's with these characteristics enable the settings to be varied in order to cope with different levels of currents by making use of different operating times. The settings can be adjusted in a manner that the breaker closest to the fault is tripped in a shortest period, while the remaining breakers are tripped in succession, using longer time delays moving backwards in the direction of the source. It should be noted that the difference between the tripping times for the same current is called the discrimination time. The only main disadvantage with this type of discrimination is the fact that faults that are close to the source and are subjected to higher currents may be cleared in a relatively long period. In order to set the settings, the current tap is used to define the value at which the IED will start to operate, while the dial is used to select the exact timing of the IED's operation. It should be taken into account that the time delay setting is independent of the value of the over-current that is required to operate the relay.

5.2.1.3 Inverse-time characteristics

The basic property of inverse-time characteristics is that it allows the IED's to operate in a time which is inversely proportional to the fault current. The inverse-time characteristic's advantage over the definite time is that, for very high currents much shorter tripping times can be achieved without risking the protection selectivity.

5.3 MODELING OF THE CPUT NETWORK

Cape Peninsula University of Technology is currently being supplied by the City of Cape Town (CoCT) at 11kV with a notified maximum demand (NMD) of 2000kVA. The CPUT intake feeder is supplied from a 66/11kV, 40MVA, and 10% impedance transformer. The said reticulation network is made up of the 11kV (MV) switchgear at the intake substation, power transformers and Low Voltage (LV) switchgears as the network goes down streams. There are a total number of thirteen substations, each containing one or a combination of the abovementioned equipments. The assessment of the existing 11kV CPUT reticulation network is carried out, in order to identify and evaluate the shortcomings of this power system as well as to upgrade the substations that are currently running on obsolete protection equipments (for the application of substation automation according to the IEC 61850 standard).

The main protection schemes used in this network is the overload, overcurrent and earth protection. This is applied at the intake substation only. The SIEMENS 7SJ80 is used in the thesis to replace the CDG36 IDMT mechanical relays that were used to perform the protection functions. Due to financial constraints and, technical reason, fuse protection is also implemented to protect lines and distribution transformers in the downstream substations. The campus power network schematic is shown below in Figure 5.1.

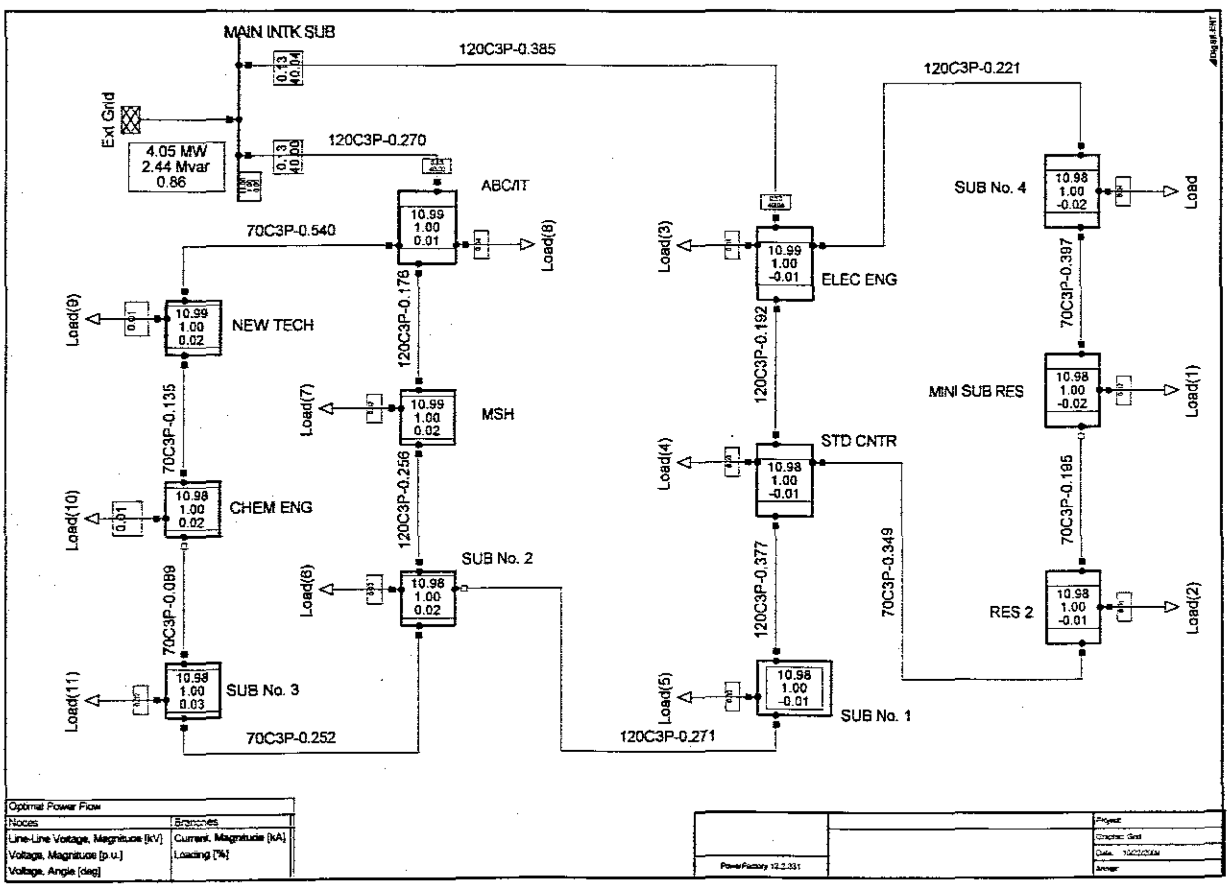

Figure 5.1: CPUT network one line diagram

5.3.2 Protection device settings (over-current IED)

The 7SJ80 over-current IED's are normally supplied with the instantaneous and a time delay element within the same unit. Unlike the old relays, the microprocessor based protection IED has a three phase over-current and an earth fault units housed in the same case. Setting up of this overcurrent IED involves selecting the parameters which characterize the required time-current characteristics of both the time delay unit and instantaneous units. However this process has to be carried out twice, firstly for the phase relays and secondly repeated for the earth-fault relays. Even though these two processes are identical, the three phase short circuit currents are used for setting up the phase relays, while the phase to earth fault current is used for setting up the earth-fault relays.

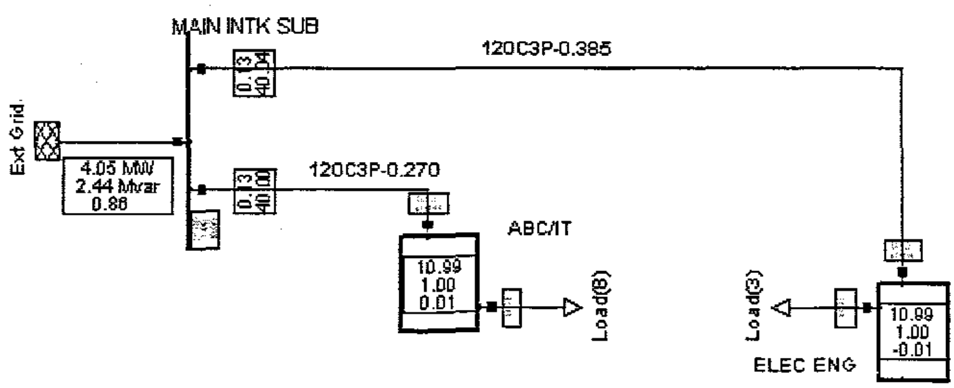

Figure 5.2: CPUT main-intake substation

The 7SJ80 protection IED's are applied on the medium voltage at the intake substation to protect the incoming and the outgoing feeders, Figure 5.2. The IED's settings are of the inverse time characteristics. These settings are chosen in order to allow discrimination with the rest of the circuit protection since fuse protection is used on the low voltage network down streams.

5.3.3 Calculation of fault level

If not given, the maximum and minimum fault level on both sides of the transformer should be calculated based on the available information of the transformer. The maximum and minimum impedance ratio should also be determined. This information is very important in order to achieve high accuracy of the model being simulated. The maximum and minimum parameters at the intake are indicated in Figure 5.3 and the formula for calculating the max fault level is shown as follows:

$$S_{max} = \frac{S_{rated}}{Z\%} \tag{5.1}$$

Where:

S_{max} = maximum short circuit power
S_{rated} = rated short circuit power
$Z\%$ = rated % transformer impedance

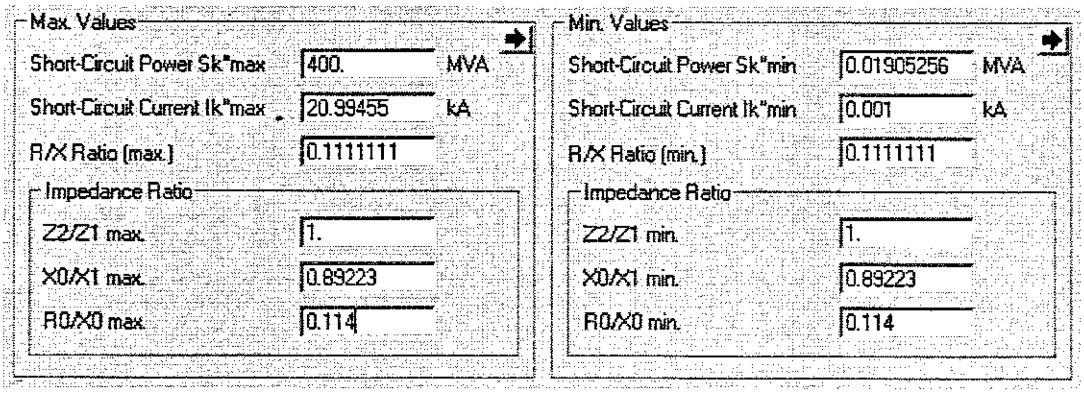

Figure 5.3: *Intake grid parameters*

Table 5.1 indicates the maximum short-circuit power that was obtained at different substations within the network at a rated voltage of 11 kV upon which the profile in Figure 5.4 is drawn.

Table 5.1: *Substations maximum Short-circuit power*

SUBSTATION	Rated Voltage rtd V.(kV)	Correction Factor	Max. Short-circuit power Sk"(MVA)
MAININTK SUB	11.00	1.10	400.00
NEW TECH	11.00	1.10	287.76
CHEM ENG	11.00	1.10	270.65
SUB No. 3	11.00	1.10	285.04
ABC/IT	11.00	1.10	366.71
MSH	11.00	1.10	346.11
SUB No. 2	11.00	1.10	318.34
ELEC ENG	11.00	1.10	353.13
STD CNTR	11.00	1.10	331.56
SUB No. 1	11.00	1.10	293.75
SUB No. 4	11.00	1.10	328.43
MINI SUB RES	11.00	1.10	275.60
RES 2	11.00	1.10	284.12

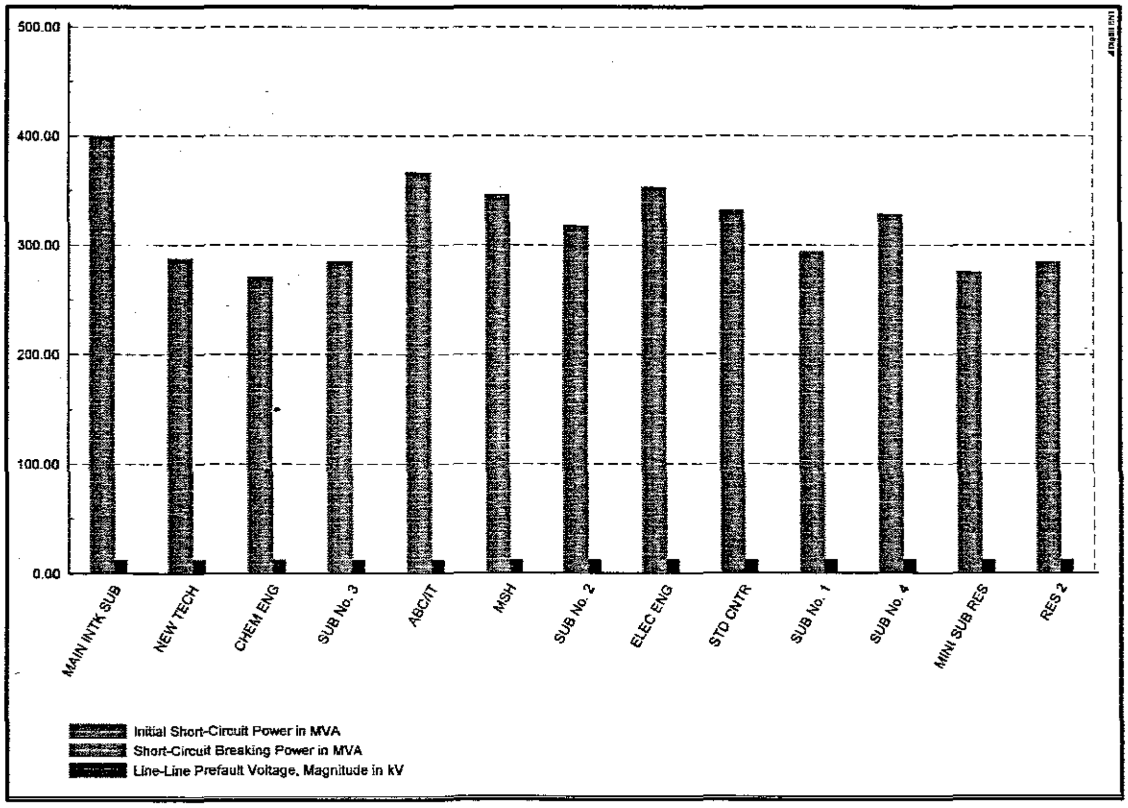

Figure 5.4: *Maximum Fault level profile at different substations*

5.3.2 Calculation of three-phase short-circuit current levels

Apart from load flow calculation, short circuit analysis is the most calculation function frequently used when dealing with electrical networks. It is commonly used in system planning (e.g. co-ordination of protection equipment) as well as in system operations (e.g. determining protection relay settings as well as fuse sizing).

The use of DIgSILENT simulation software to determine the short circuit currents in planning and operation applications when the conditions are not yet known can be based on the nominal and/or the calculated dimensions of the operating network and uses correction factors for voltages and impedances in order to push the results toward the safe side **(DIgSILENT BUYISA course manual, 2007)**. On the other hand, for short-circuit calculations in a system operation environment, the accurate network operating conditions are all well known. It should be noted that all the models are simulated using the IEC60909 standard. The three-phase short-circuit levels are illustrated in Figure 5.5 and Table 5.2.

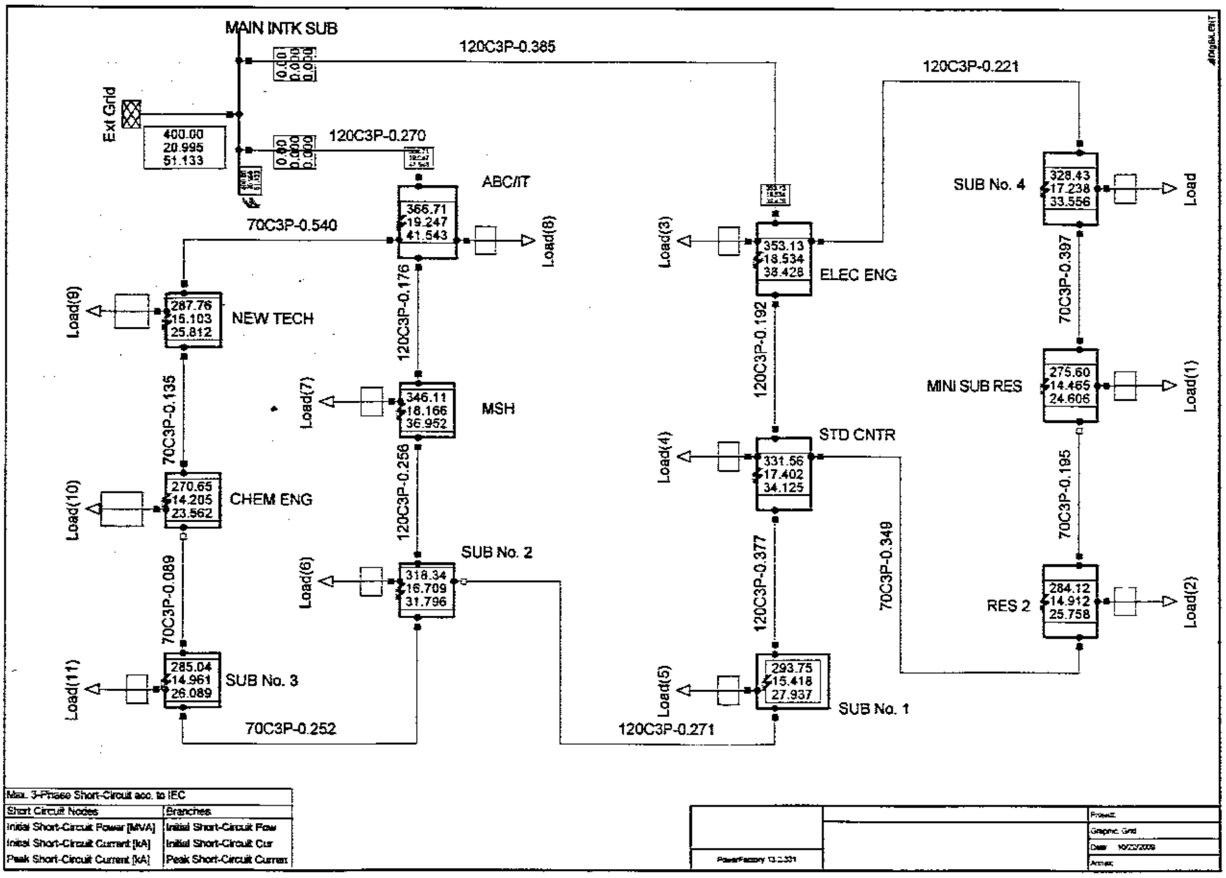

Figure 5.5: CPUT network 3-phase maximum short circuit currents (fault location with feeders)

A maximum short-circuit power of 400MVA, together with the Initial symmetrical (sub-transient) short-circuit current of 20.995kA and a peak short-circuit current of 51.133kA is recorded at the source. The above parameters are applicable to the rest of the substations and can be viewed in Figure 5.5 and Table 5.2 respectively. In order to determine the parameters of the network, the system information needs to be entered into the DIgSILENT program. DIgSILENT software is equipped with the data base that contains most if not all the necessary components to build and model any electrical network,(in this case a distribution network).The formula for the maximum short circuit current is as follows:

$$I_{fmax} = \frac{S_{max}}{(\sqrt{3} \times V_b)} \qquad (5.2)$$

Where:

$I_{fmax} =$ muximum short-circuit current

$S_{max} =$ maximum short-circuit power

$V_b =$ base voltage

Table 5.2: Short circuit calculations results according to IEC

SUBSTATION	Ik" [kA/kA]	ip [kA/kA]	Ib [kA]	Ik [kA]	I th [kA]
Main Intake	20.99	51.13	20.99	20.99	21.31
ABC/ IT	19.25	41.54	19.25	19.25	19.40
ELEC. ENG	18.53	38.43	18.53	18.53	18.66
NEW –TECH	15.10	25.81	15.10	15.10	15.15
CHEM-ENG	14.21	23.56	14.21	14.21	14.25
SUB No. 3	14.96	26.09	14.96	14.96	15.01
MSH	18.17	36.95	18.17	18.17	18.28
SUB No. 2	16.71	31.80	16.71	16.71	16.79
STD CNTR	17.40	34.13	17.40	17.40	17.49
SUB No. 1	15.42	27.94	15.42	15.42	15.48
SUB No. 4	17.24	33.56	17.24	17.24	17.33
Mini-SUB RES	14.47	24.61	14.47	14.47	14.51
RES No. 2	14.91	25.76	14.91	14.91	14.96

Where:

$I_k^{"}$ = Initial symmetrical (sub-transient) short-circuit current
i_p = peak short-circuit current
I_b = symmetrical short circuit breaking current
I_k = steady state short-circuit current
I_{th} = thermal equivalent short-circuit current

The formulae for the above parameters according to the IEC 60909 are shown as follows:

$$I_{k,max}^{"} = \frac{c_{max} U_n^2}{\sqrt{3}} \cdot \frac{1}{\underline{Z}_k} \tag{6.3}$$

$$i_p = \kappa . \sqrt{2} . I_k^{"} \tag{6.4}$$

$$I_b = \mu . q . I_k^{"} \tag{6.5}$$

$$I_k = I_k^{"} \tag{6.6}$$

$$I_{th} = \sqrt{\frac{\int_0^{Tk} i^2 dt}{T_k}} \tag{6.7}$$

Where:

c_{max} = maximum voltage correction factor
U_n = nominal voltage
κ = auxiliary factor to consider the maximum asymmetric short circuit current
μ = auxiliary factor to consider the breaking current for asynchronous machines

q = auxiliary factor depending on the minimum breaker tripping time and the rated power per pole pair of the machine

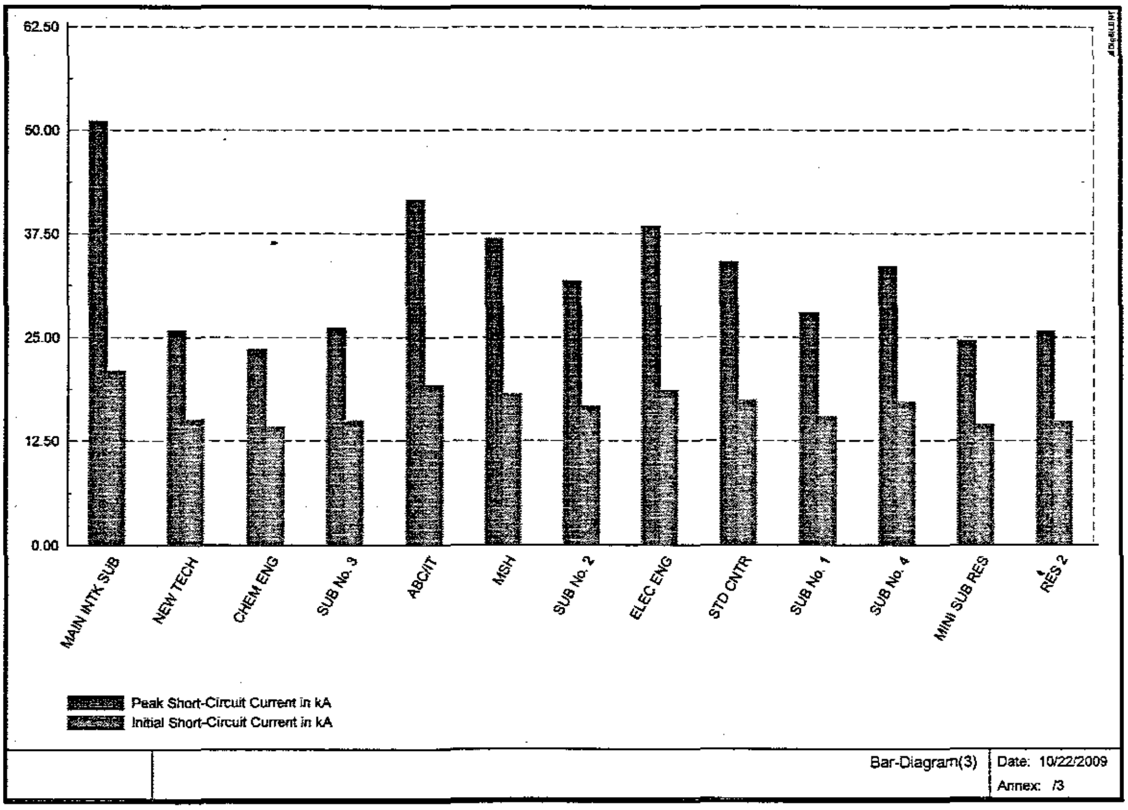

Figure 5.6: *Short circuit currents profile at each substation*

Figure 5.6 and 5.7 illustrate the short-circuit currents that are recorded within the entire CPUT power network. These parameters serve a very important role in terms of setting up the protection system. If the accuracy of the calculated results according to the IEC 60909 is not sufficient enough, the other way of verifying these results is by making use of the superposition method.

This method calculates the expected short circuit currents in the network based on the network operating condition (by using the results from the preceding load flow). If the system models are correct, the results of these two methods are always more or less the same **(DIgSILENT basic training notes V13.2, 2007:1-2)**.

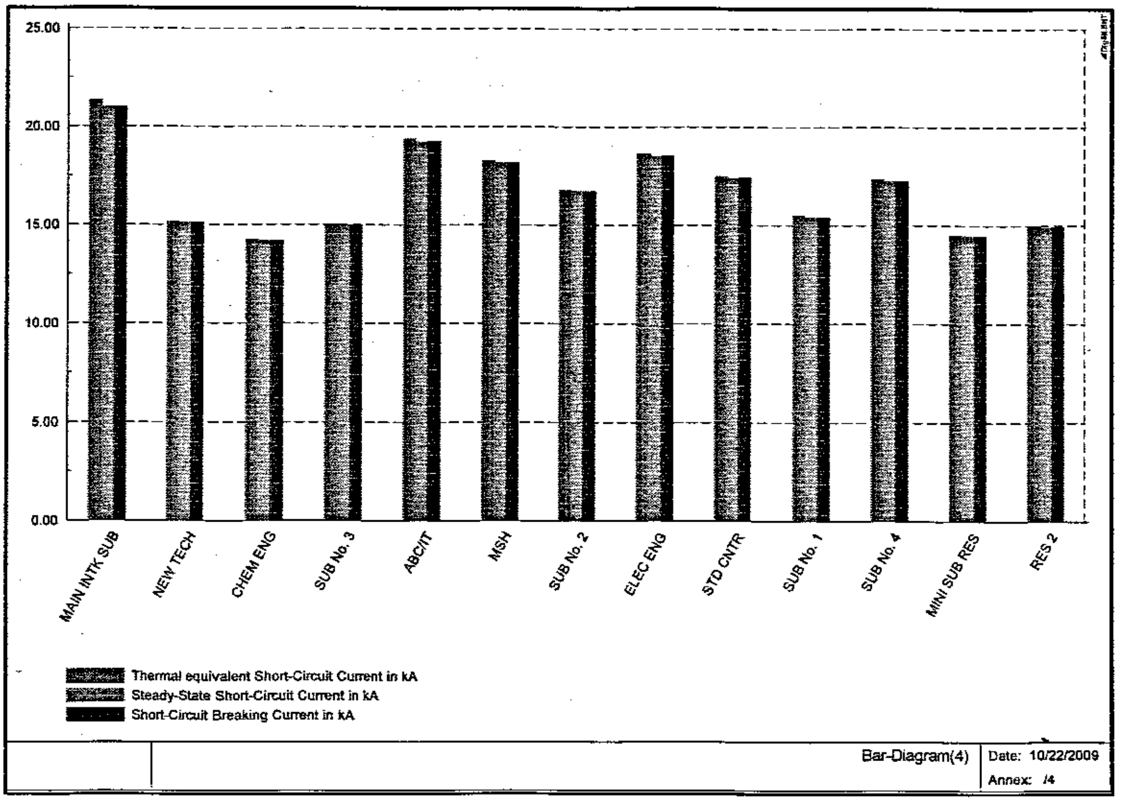

Figure 5.7: *Thermal, steady-state, and breaking short circuit currents profile.*

5.3.3 The selection of CT transformer ratio

The nominal and short circuit current (I_{sc}) of the power network plays a vital role in terms of CT transformer ratio choice. The CT's transformation ratio is determined by the magnitude of the nominal and short circuit current, provided no saturation is recorded. It is therefore that $I_{sc}(5/X) \leq 100(A)$ so that $X \geq (5/100).I_{sc}$, where *X* is the current constant **(Gers & Holmes, 1998: 81)**.This is illustrated in Table 5.3.

Table 5.3: *CT ratio Selection*

I_{sc} (A)	(5/100)I_{sc} (A)	CT Ratio
6640	332.0	400/5
14714.0	735.7	800/5
16714.0	835.7	1200/5
16714.0	835.7	1600/5

The CT ratio can also be determined by looking at the rated currents of the type of cable and transformer that has been used for a certain application. **Note:** *For the CPUT network the ratio of **2000/1** is chosen on the transformer secondary side.*

- **Long time inverse** – This characteristic is used for protection of neutral earthing resistors.

$$t = \frac{120}{\left(\frac{I}{I_s}-1\right)} \tag{5.11}$$

5.3.4.2 Analysis of the IED's setting parameter

The operating time of an overcurrent IED can be delayed in order to ensure that the IED does not trip before any other protection devices closest to the fault operate, when subjected to fault conditions. Definite time and inverse time characteristics of the relays can be adjusted by the selection of two parameters.

These include the TAP and DIAL settings. The DIAL setting represents the time delay prior to the IED operation, each time the fault current reaches a value equal to or above the IED setting. If the setting of the DIAL is smaller than this means that the operating time will be shorter. On the other hand, the TAP is the value which defines the pick-up current of the IED's **(Gers & Holmes, 1998:73-74).** The TAP value is determined by allowing the overload margin above the nominal current as expressed by the formula below. Note: TAP setting, Plug setting, Current settings is the same thing and they all determine the pick-up current of the relay, where as DIAL and TMS are also referring to the same thing and they all determine the operating time of the relay.

5.3.4.3 Current setting

In general the current setting of the relay is normally described as either a percentage or multiple of the CT's primary or secondary rating. If the current transformer's primary rating is the same as the normal full load current of the circuit, then the percentage settings will refer directly to the primary system. The choice of current setting therefore depends on the CT ratio and the load current and is normally above the maximum load current, typically by 10%, assuming the circuit is capable of carrying the maximum projected load **(Hindle et al, 2006)**. Therefore, the relay pick-up current (I_s) can be calculated by first obtaining the transformer full load current and by allowing the 10% overload and taking into account the fact that the relay resets at 95% of setting.

$$I_s = 1.1 \times \frac{I_{FL}}{0.95} \tag{5.12}$$

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$$I_s = 1.1 \times \frac{I_{FL}}{0.95} \tag{5.12}$$

Where:

$I_s =$ current setting
$I_{FL} =$ full load current

In terms of CT ratio, the I_s for CPUT network can be chosen using either $400A$ or $2000A$
Hence:

- $I_s = 5.0 => 400A$ can be selected or
- $I_s = 1.0 => 2000A$

5.3.4.4 Grading Margin

In order to achieve a correct discrimination in protection, it is important to have a time interval between the operations of two adjacent IED's. The grading margin depends upon the following factors:

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

It is common practice to use a value of $50 - 100ms$ for a circuit breaker overall interrupting time but should the switch gear be slower than this time, then it must be taken into account. It should be noted that the CT errors does not affect the definite time overcurrent relays. In the past a fixed margin of *0.4 sec* was considered enough for correct discrimination.

e.g.:

Breaker operating time	0.1
Relay overshoot	0.05
Allowing of errors	0.15
Safety margin	0.1
Total	**0.4 sec**

With modern faster switchgear and lower overshoot times the figure of $0.3sec$ may be feasible and can be used under best possible conditions. In this project a grading of 0.3 and $0.4sec$ has been used.

5.3.4.5 Time Multiplier Settings

The time multiplier setting is taken as the means of adjusting the operating time of the inverse type characteristics. It should be noted that it is not a time setting but a multiplier (**Wright,**

2006:7).In order to calculate the required time multiplier settings (TMS), the operating time of the closest downstream protection device at maximum fault level should be known. This operating time should be calculated with a TMS equals to 1, using a formula for the standard inverse characteristics.

$$Required\ TMS = \frac{Required\ operating\ time}{Operating\ time\ for\ TMS=1} \qquad (5.13)$$

5.3.5 Earth fault protection

The most frequent type of faults that occur in power systems are the earth faults. The phase overcurrent protection units are used to detect this fault. However, it is possible to obtain more sensitive protection by using IED's that respond to residual current that can appear in the system. The residual current could be detected by either connecting the CT in an available neutral to earth connection or by connecting line CT's in parallel. It should be noted that on a low voltage 4-wire distribution system, 4 CT's are required to ensure stability under all load conditions. The inclusion of the fourth CT (being placed in a neutral connection) is recommended at all time because the degree of the system unbalance is not normally known.

5.3.6 Plotting of relays characteristics

The non-directional time overcurrent IED's are used at the CPUT intake substation for protection. These IED's allows the selection of one of the current-time (I-t) curves characteristics as earlier discussed. The I-t curves are further specified by the time dial and the pick-up current. The time dial settings scale the I-t curve in the Time vs. PSM plot as per curve definition. The pick-up current defines the nominal I_p value which is used when calculating the tripping time.

The lower currents will not trip the IED (infinite tripping time) and the higher currents will on the other hand not decrease the tripping time further beyond the minimum tripping time. If the IED does not see the fault, it will not trip and a tripping time of $9999.99\,sec$ will be indicated **(DIgSILENT GmbH, 2009:31)**. Therefore, varying the pick-up current will not change the I-t curve, but will scale the measured current to different per unit values. This is illustrated as follows:

- Assume the minimum current defined by the I-t curve is $Imin = 1.1\ I/Ip$.
- Assume the measurement unit defines $Inom = 4.0$ rel.A.
- Assume pickup current $Ipset$=1.5 p.u.
  relay will not trip for $I < 1.1x1.5x4.0$ rel.A = 6.6 rel.A

- Assume pickup current $Ipset = 8.0$ rel.A
  relay will not trip for $I < 1.1x8.0$ rel.A = 8.8 rel.A

5.3.6.1 Main intake - Electrical Engineering feeder and busbar protection settings and characteristics.

On the basis of the above calculation, the main protection IED settings are defined as given in Table 5.4,

where:

T_{oc} = time over-current element
I_{oc} =instantaneous over-current element
T_{oce} = time over-current earth-element
I_{oce} = instantaneous over-current earth-element

Table 5.4: Main protection IED settings

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.5	
Time Dial	0.15		0.15	
Pick-up Current		8.0		0.1
Time Setting		0.2		0.0

The IED's with time overcurrent characteristics allows the following setting to be applied:

- The time overcurrent characteristic
- The pickup current
- The time dial

As indicated in Table 5.4, these settings (time and instantaneous phase and earth-fault settings) are limited by the relay model and only the characteristics available for specific type of relay can be selected and on the other hand not all possible values for the pickup current and time dial may be entered. In this case the calculated setting values that are suitable for this project application are shown in Table 5.4.

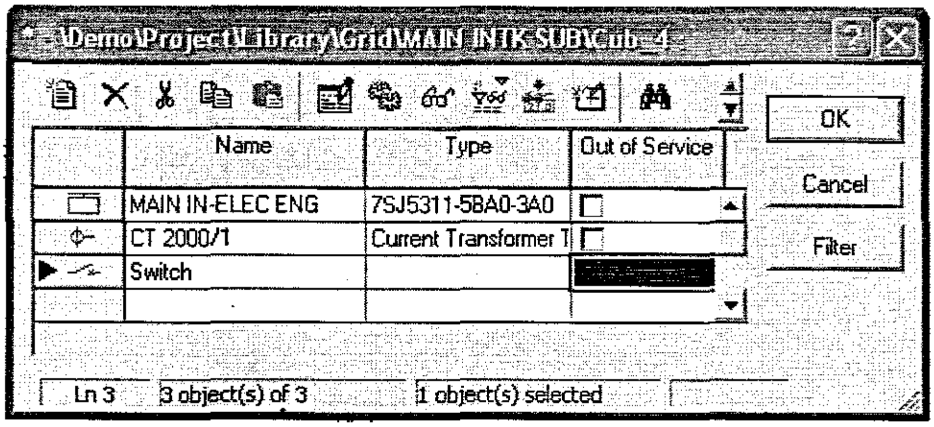


Figure 5.8: *Protection devices of Main Intake and Electrical Engineering cubicle*

As a standard, protection devices are generally stored in the object which they act upon, but they can be stored elsewhere, if need be. This is illustrated in Figure 5.8, where the IED, the CT's and the switch reside in cubicle 4. As recommended in DIgSILENT, and by default, the following applies **(DIgSILENT basic training notes, 2007:115)**:

- The protection devices which act upon a single switch are stored within the cubicle which contains that switch and this is highly recommended.
- The protection devices which act upon a number of switches connected to the same busbar are stored in that specific busbar.
- On the other hand, protection devices which act upon a number of switches connected to the same busbar system are stored in the same station containing that busbar system.
- Therefore, protection devices which act upon switches linked to more than one busbar system are stored in the same station containing those busbar systems, or they can be stored in the power system grid folder should more than one station be involved.

As a rule, the IED's or relay is best stored in the same folder as the voltage and/or current transformers which it uses and this will be observed as the chapter continuous. The protection devices of cubicle 4 protect the feeder between the Main Intake and the Electrical Engineering substations. With the three phase fault as indicated in Figure 5.9, the maximum fault level of 376.10MVA, a short-circuit current of 19.740kA and the peak current of 43.928kA is recorded.

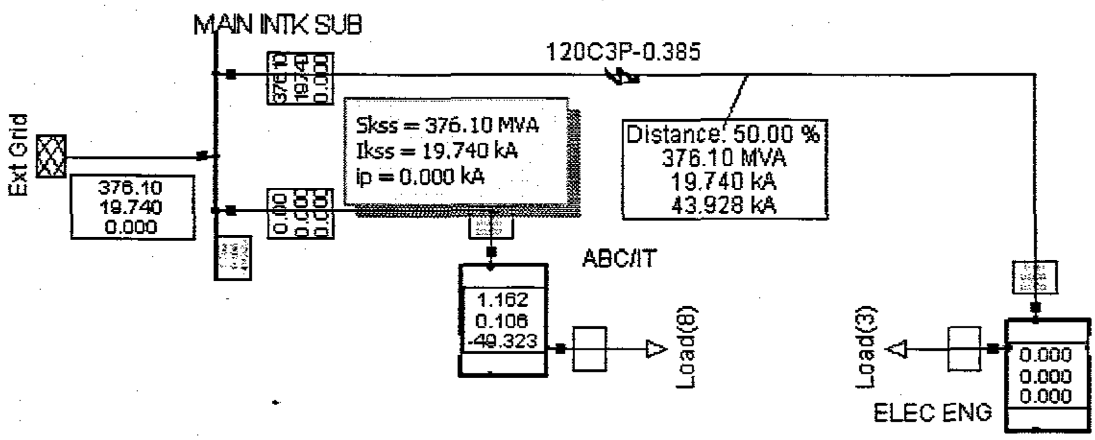


Figure 5.9: Three phase fault between Main Intake and Electrical Engineering substation

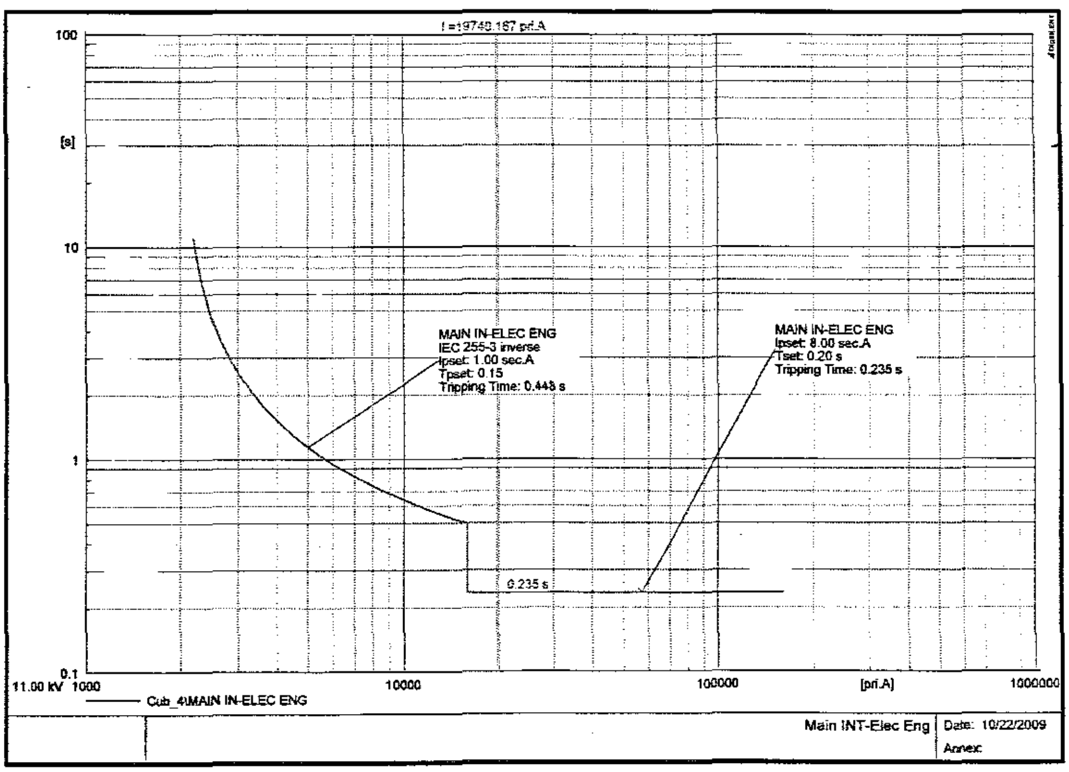


Figure 5.10: Main protection response with a clearing time of 0.448 and 0.235sec.

From the relay model, the time-overcurrent and instantaneous overcurrent characteristics are chosen. The relay with the time-overcurrent facilities allows for the selection of one of the I-t curves ("characteristic") which are available for the selected relay type. In this case the IEC 255-3 inverse characteristic is chosen. The I-t curve is further specified by the pickup current and the time dial as demonstrated in Table 5.4. Both these values should be in the range specified by the I-t curve definition.

According to the curve definition, the time dial settings scales the I-t curve in the Time vs. I/Ip plot. Hence, the pickup current defines the nominal value (Ip) which is used to calculate the tripping time. These settings can be viewed in Figure 5.10. The protection response to the fault in Figure 5.9 is shown in Figure 5.10.This fault is on the feeder between the Main-Intake and Electrical Engineering substation and the response is from the relay that is closer to the fault. For the initial short circuit of 19.740kA and a maximum fault level of 376.10 MVA, the relay has responded with the instantaneous tripping of 0.235 sec and the inverse definite minimum time (IDMT) response of 0.448 sec.

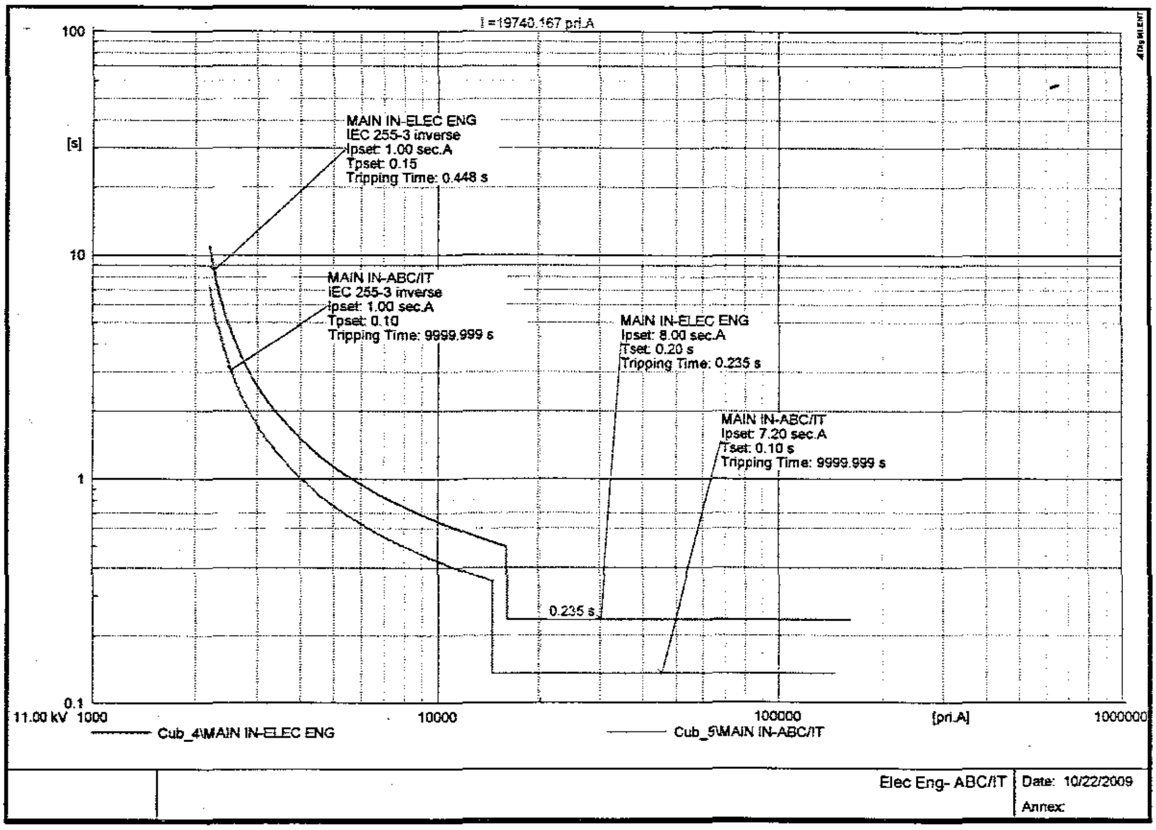


Figure 5.11: Main protection response for the outgoing feeders

The main intake busbar has two outgoing feeders that feed the electrical engineering and ABC/IT substations. Just like the electrical engineering feeder is protected, the ABC/IT feeder is also protected. Figure 5.11 illustrates the tripping characteristics of the two feeders. The relay on the line that feeds the ABC/IT substation does not see the fault that is on the Main Intake-Electrical Engineering feeder, therefore a tripping time of 9999.999 sec for both the Toc and the Ioc is recorded. This ensures correct settings of devices and no false tripping or unwanted tripping will be experienced.

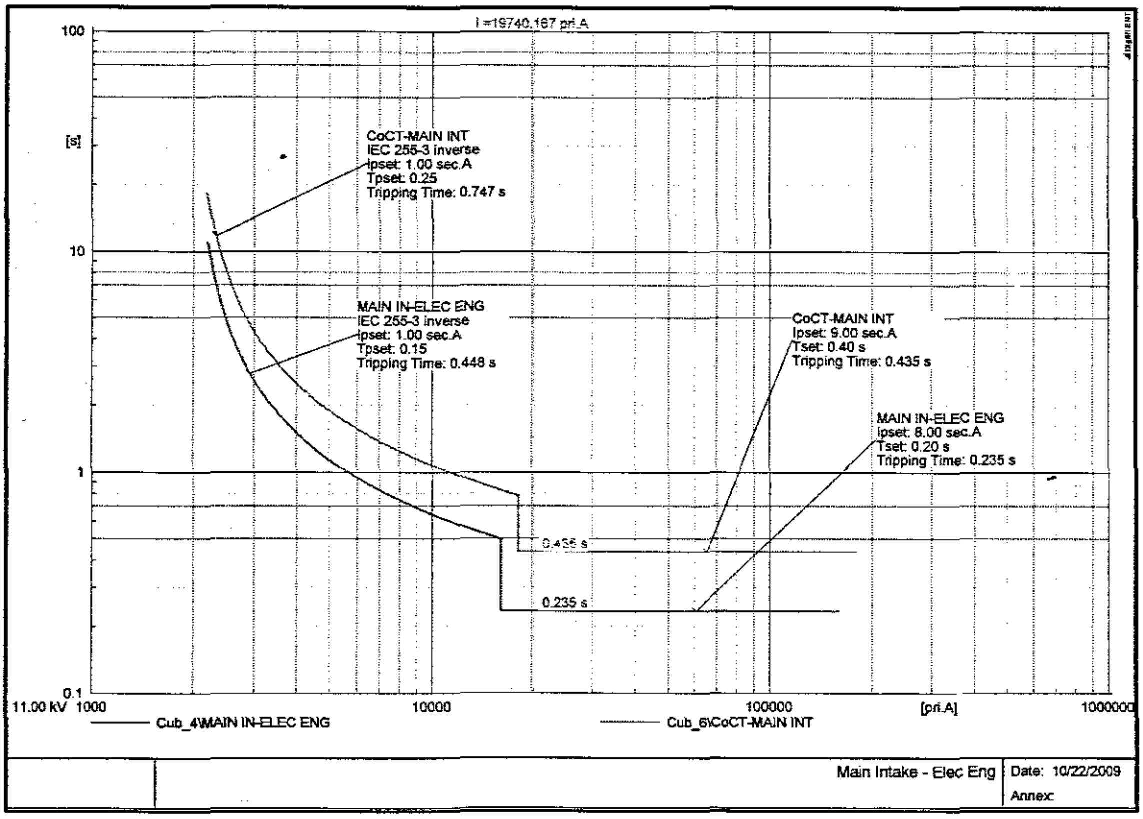


Figure 5.12: *Main and back-up protection time-overcurrent response*

The fault indicated by Figure 5.9 is picked-up by two protection devices. In terms of IDMT, a sequence tripping response of 0.448 and 0.748 sec is recorded as indicated by Figure 5.12.The IED close to the fault has responded in 0.448 sec while the immediate up-stream IED followed with a delayed response at 0.748sec.This indicates that should the main IED fail to operate then the next up-stream will operate in 0.748 sec. The instantaneous characteristic of the two protection devices have responded in 0.235 and 0.435 sec respectively.

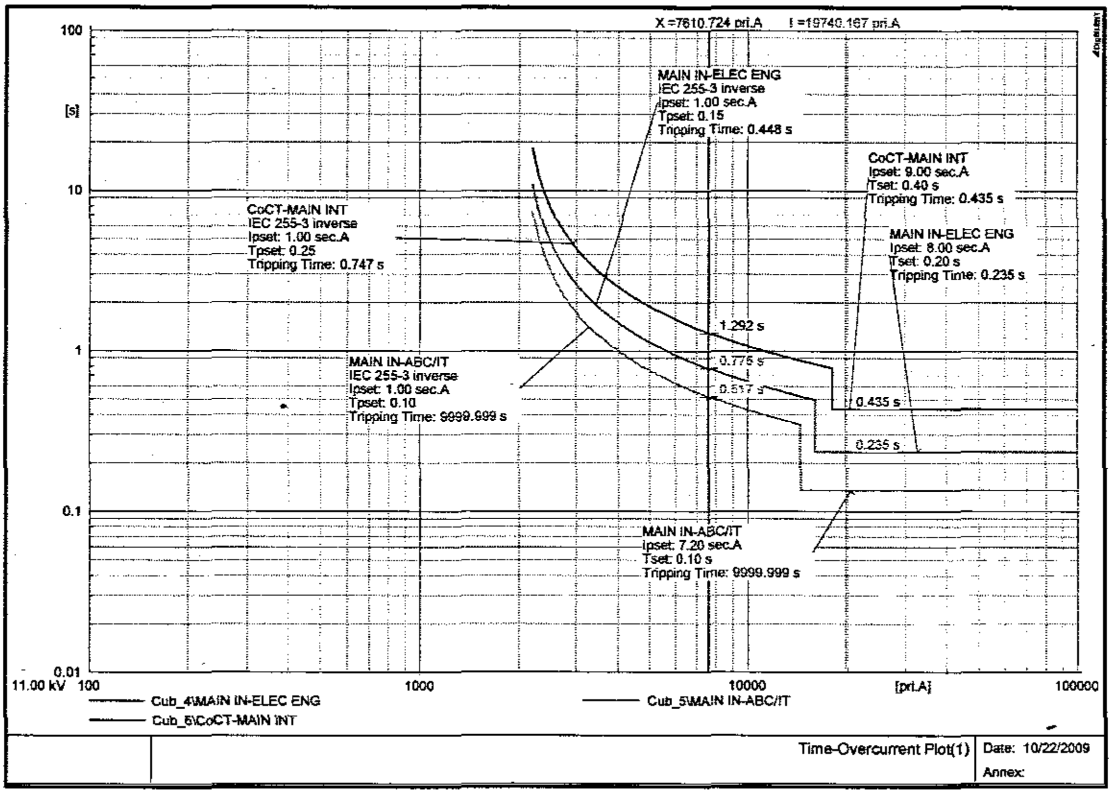


Figure 5.13: *Time overcurrent for the incoming and two outgoing feeder*

The time-overcurrent plot in Figure 5.13 shows the results of the short-circuit fault (19740.167A) as a vertical 'x-value' line across the graph. This allows the intersection of the calculated current with the time-overcurrent characteristic to be labelled with the tripping time. Since the currents for each particular relay could be different, a current line for each relay can be drawn. This option has been demonstrated in Figure 5.13. The relay on the Main Intake ABC/IT feeder did not respond to the fault recorded on the adjacent feeder. It is very important to make sure that the settings are done accordingly to prevent the tripping of wrong equipment.

5.3.6.2 Main intake-ABC/IT feeder protection settings and characteristics

Table 5.5: *Main protection IED settings*

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.5	
Time Dial	0.10		0.10	
Pick-up Current		7.2		0.1
Time Setting		0.1		0.0

The settings for the relay that protect the feeder between the Main Intake and the ABC/IT substation are shown in Table 5.5. Since the settings are made up of a combination of instantaneous overcurrent (direct overcurrent) and an optional time delay, the pickup time (Ts) which is the minimum time needed for the relay to react is set at 0.1 and 0.0. Additionally, a time dial ($Tset$) of 0.10 is specified. The pick-up current for the instantaneous current is set to 7.2 and 0.1 while the current settings for the time over-current is set at 1.0 and 0.5 respectively. Therefore, the relay will not trip unless the current exceeds the pickup current ($Tsetr$) for at least $Ts + Tset$.

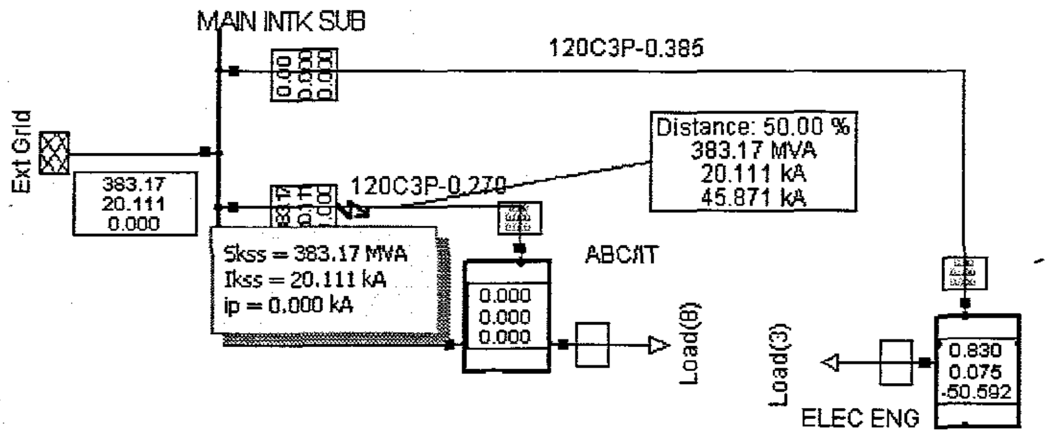


Figure 5.14: *Three phase fault between Main Intake and ABC/IT*

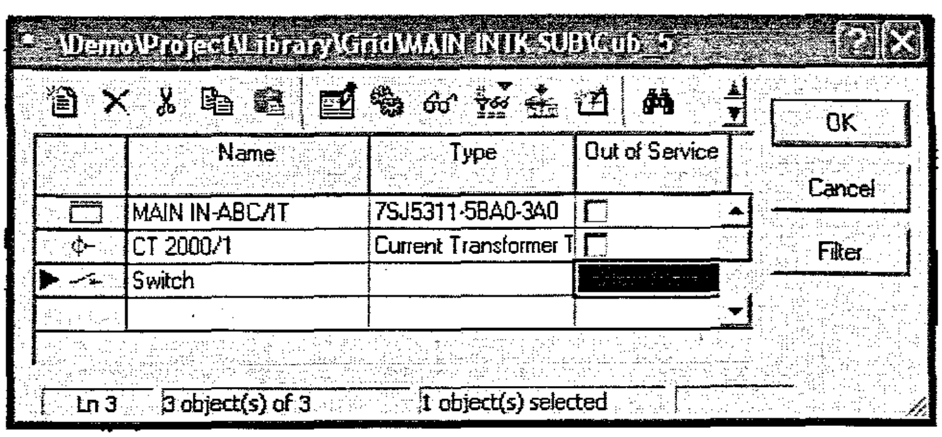


Figure 5.15: *Protection devices of Main Intake and ABC/IT cubicle*

The three phase fault between the Main Intake and ABC/IT substation is shown in Figure 5.14.

The short circuit current of 20.111kA at a maximum fault level of 383.17MVA is recorded. Figure 5.15 indicates that cubicle 5 which is on line 3 have three objects and one of the objects is selected. This is therefore a clear indication that the devices responsible for the protection of line 3, which are the feeder between the Main Intake and ABC/IT substation, as earlier stated, are grouped in cubicle 5 and not scattered all over.

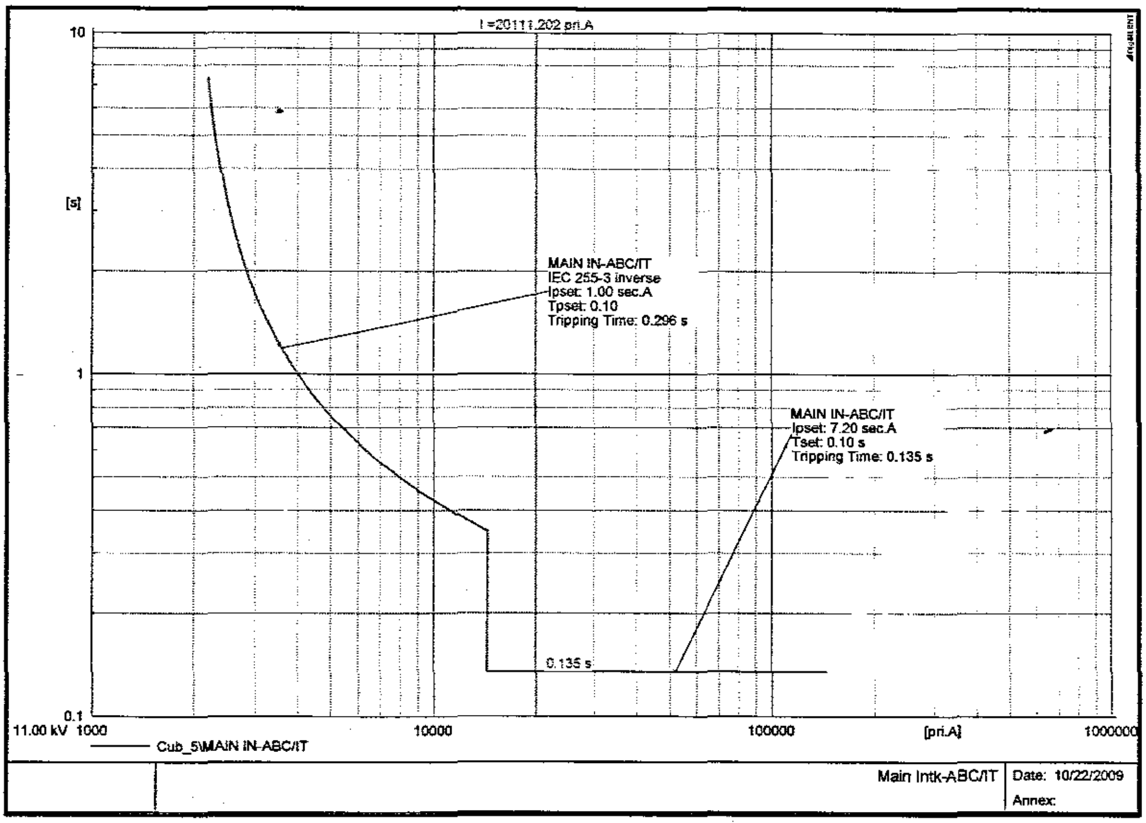


Figure 5.16: *Cubicle 5 protection devices response characteristics*

The response characteristics of the protection device at cubicle 5 are shown in Figure 5.16. Here a combination of two characteristics (Toc *and* Ioc) is shown. With a short circuit current of 20.111kA as indicated by the vertical line, the protection device has responded with an instantaneous tripping time of 0.135sec. For the inverse definite minimum time the normal characteristic (the IEC 255-3 inverse) is used and has responded with a tripping time of 0.296 sec.

Figure 5.17 shows the tripping characteristics of the protection devices at both out going feeders that feeds the Electrical Engineering and the ABC/IT substation. Again the fault is on the ABC/IT feeder as indicated by Figure 5.14. The relay responsible for the protection of the line feeding the Electrical Engineering substation did not pick-up the fault; hence no tripping signal was issued. A tripping time of 9999.999 sec is therefore recorded as shown in Figure 5.17. The relay in cubicle 5, which is responsible for the faulty line has pick-up the fault and the tripping time can be viewed below in Figure 5.17.

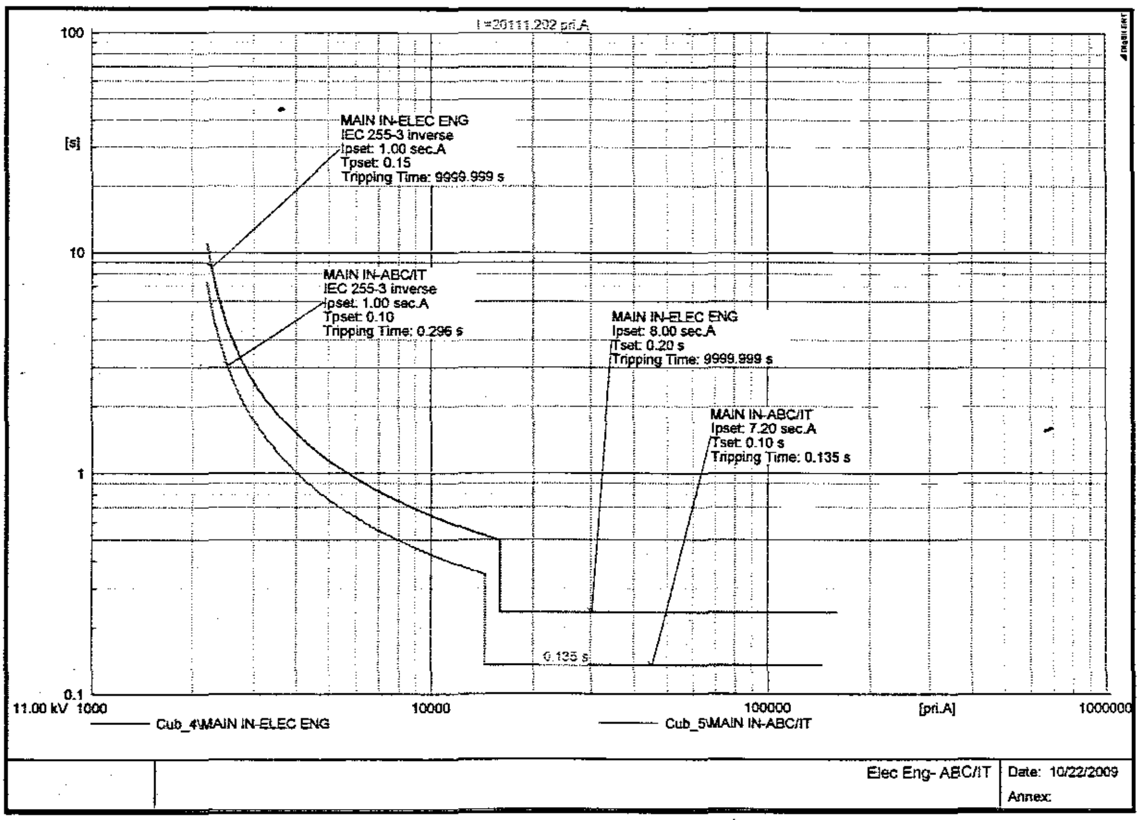


Figure 5.17: *Outgoing feeders' protection response with a fault on ABC/IT feeder.*

Any fault that is not cleared on time will stress the source which will result in black-out if it is not attended to. Beside the black-out, the equipment involved will also be damaged due to high current that could be experienced as a result of high short circuit fault. In protection the relays are always placed in such a way that they protect from the source downstream towards the loads. The fault indicated by Figure 5.14 is picked-up by two protection devices and a sequence tripping response of 0.135 and 0.296 sec for the relay closer to the fault and 0.435 and 0.741sec for the next upstream relay is recorded as indicated by Figure 5.18.The IED close to the fault has responded with an instantaneous tripping of 0.135 sec while the immediate upstream IED followed with a delayed response at 0.435sec.This indicates that should the main IED fail to operate then the next up-stream will operate in 0.435 sec to clear the fault.

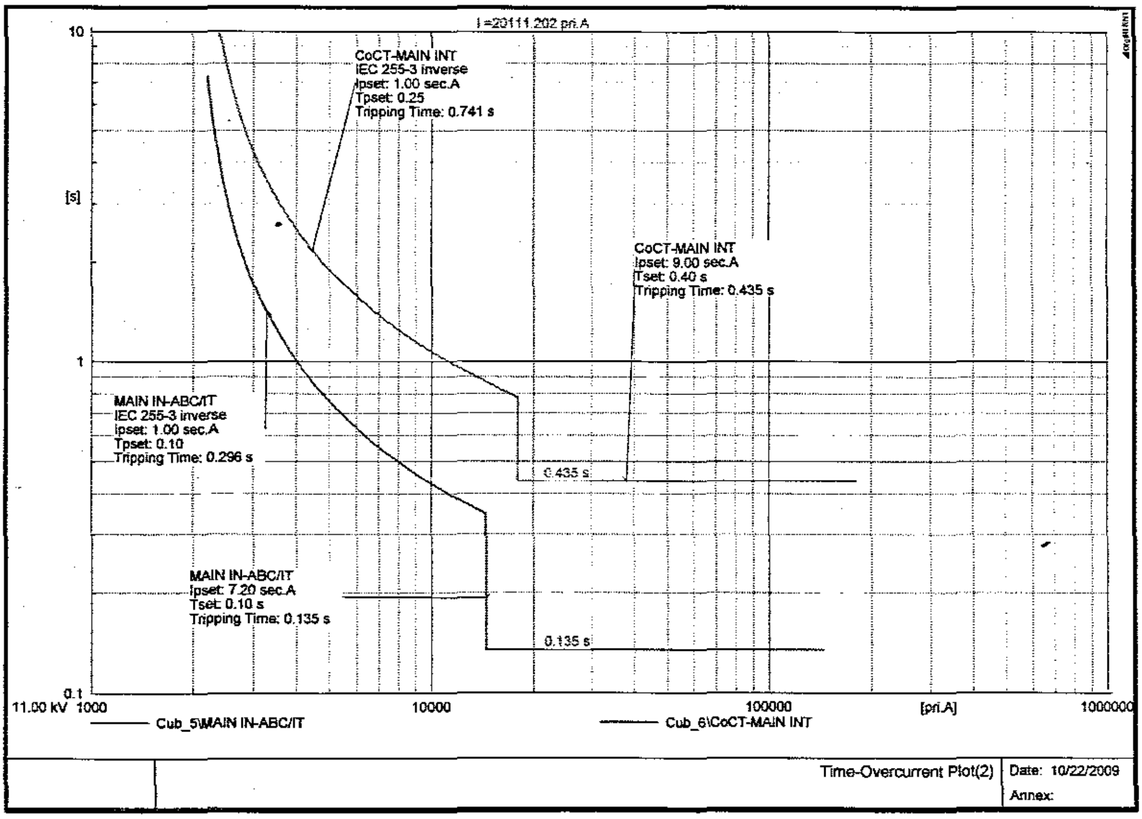


Figure 5.18: Main and upstream protection response for the short-circuit fault of 20.111kA.

Three tripping characteristics are shown in Figure 5.19. These characteristics represent the tripping response for the three relays that protect the incoming and two outgoing feeders. The name of the feeders in which the relays cubicle resides is shown in the single line graphic and the tripping times are made visible. For the relays that did not trip a tripping time of 9999.999 sec is shown. The fault on which the relays have acted upon is shown in Figure 5.14. The settings of all the relays and their tripping characteristics can be viewed in Figure 5.19. The use of the Intelligent Electronic Devices enables the busbar protection and the back-up protection to be combined in the same unit. With reference to Figure 5.14, a typical overcurrent IED would be time coordinated in a normal manner providing overcurrent and earth fault protection for the system. The instantaneous element in the incomer IED can be prevented from operating by the overcurrent IED's on the outgoing feeders. Therefore, upon detection of a feeder fault the associated feeder IED would operate a start contact. This contact information is carried to the incomer IED via GOOSE massages, which upon energized would block the instantaneous element of the incomer IED.

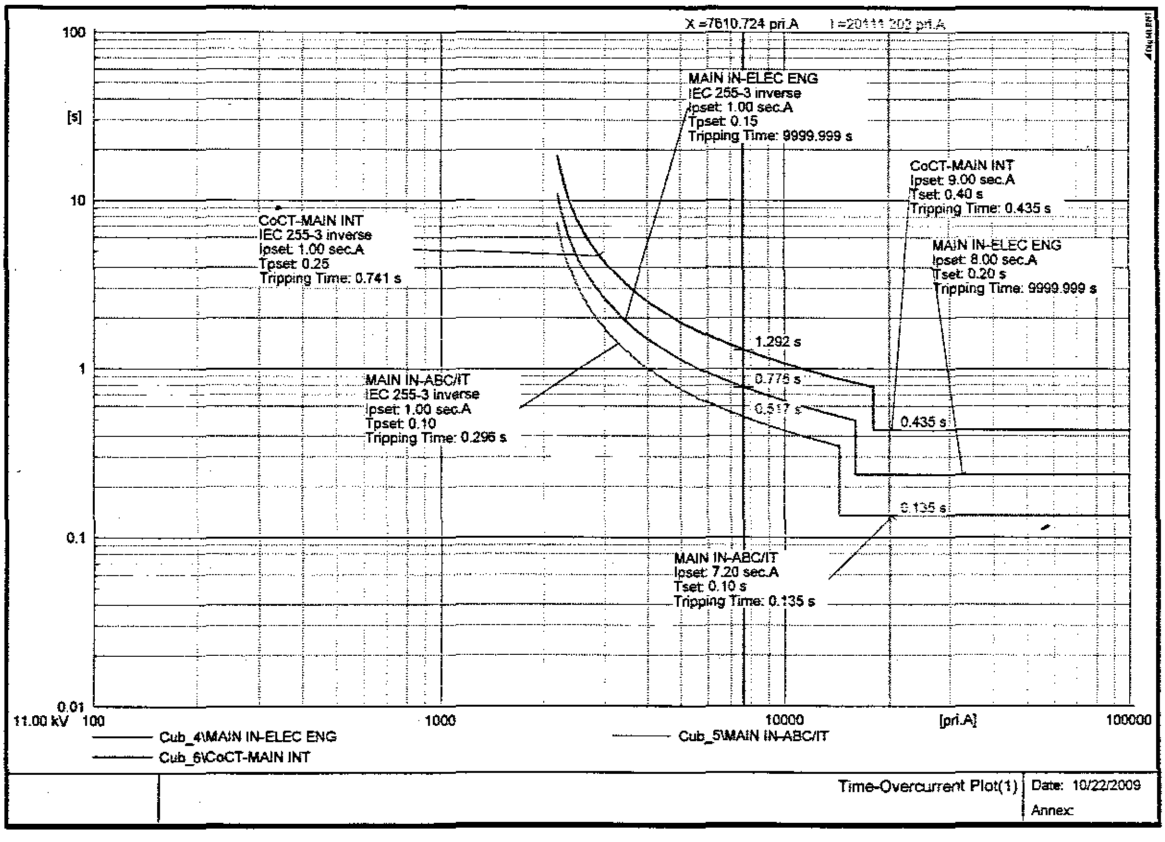


Figure 5.19: Main and upstream protection response for a fault on the ABC/IT feeder with a short circuit current of 20.111kA.

6.3.6.3 CoCT-Main intake busbar and feeder protection settings and characteristics

The busbars form a very important part of the power system. In order to maintain system stability and minimize damage to equipment due to high fault levels, huge time delayed tripping is not acceptable for busbar faults. It is therefore recommended to detect busbar faults selectively with a unit form of system protection. The basic requirements that should be known when setting up the busbar protection schemes are as follows:

- Since the protection could only be called to operate once or twice in the life time of the switch gear's installation, it must be fully reliable and failure to operate under fault conditions is unacceptable.

- It must be totally stable under all through fault conditions since this will help to prevent unnecessary widespread interruption of supply.
- It must possess the capability of complete discrimination between sections of the busbar to guarantee that a minimum number of breakers are tripped to isolate the fault.
- It must have a reliable operation speed to minimize damage and maintain system stability.

Table 5.6: *Busbar protection IED settings*

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.5	
Time Dial	0.25		0.25	
Pick-up Current		9.0		0.1
Time Setting		0.4		0.0

The settings for the busbar protection IED at the Main Intake substation is shown in Table 5.6. For the phase faults, the time overcurrent characteristic is set with a current setting of 1.0 and a time dial of 0.25 while the instantaneous characteristics is set at 9.0 for the pick-up current and a time setting of 0.4. For the earth faults, the time overcurrent characteristic is set with a current setting of 0.5 and a time dial of 0.25 while the instantaneous elements are set at 0.1 for the pick-up current and a time setting of 0.0.

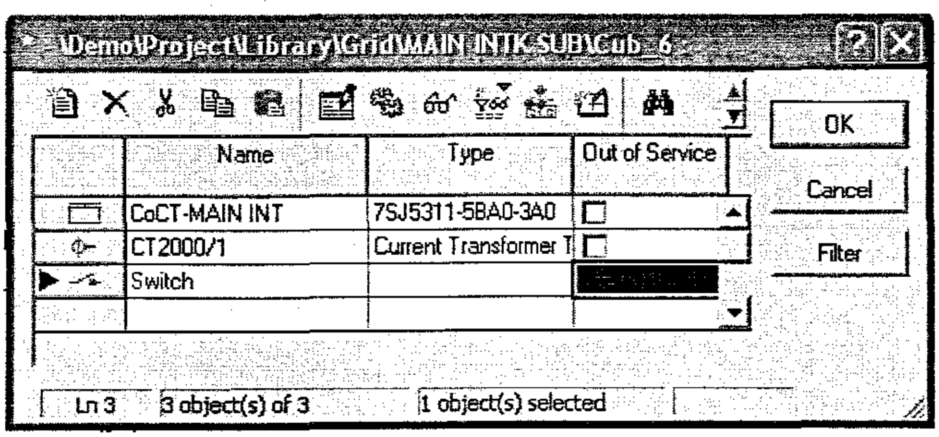


Figure 5.20: *Protection devices of CoCT-Main intake cubicle*

The protection devices for the busbar at the Main Intake substation are grouped in cubicle 6 as illustrated in Figure 5.20. Three items that are responsible for the protection of the busbar include the relay, a current transformer and a breaker. A current transformer with a CT ratio of 2000/1 is used.

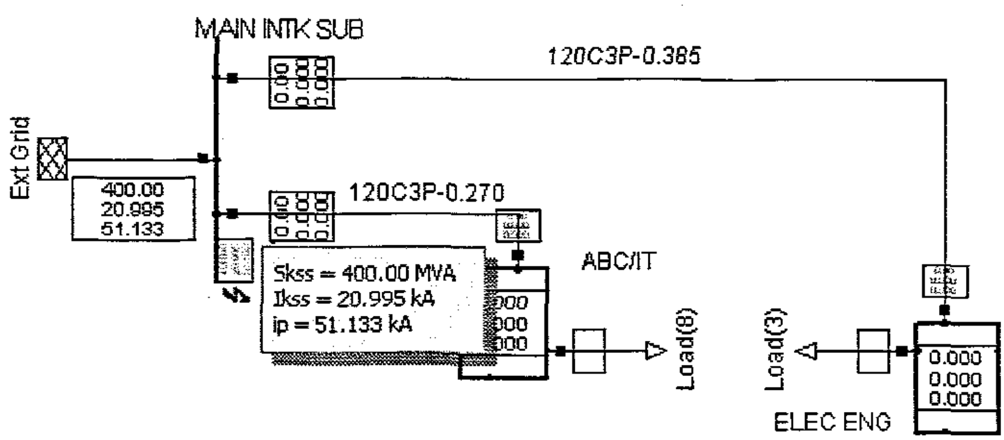


Figure 5.21: *Three phase fault on the Main Intake busbar*

In Figure 5.21 the three phase fault has been introduced on the busbar. This fault is sitting between three relays, the one on the incoming feeder and the ones on the two outgoing feeders. A maximum fault level of 400.00 MVA, a maximum short circuit current of 20.995 kA and a peak current of 51.133 kA is recorded. These value correspond with the calculated values that have been shown earlier in Figure 5.3.

At the end of the incoming feeder there is a protection device that looks at the busbar status and monitor if the rated parameters are not being exceeded. With a fault as indicated in Figure 5.21, the bus protection device has responded with an instantaneous tripping of 0.435 sec and a normal inverse tripping of 0.727 sec. The response characteristic of the bus protection device is illustrated in Figure 5.22. As the name implies, the busbar serve as a node where the electrical nodes are connected to. Although the outgoing feeder that feed the ABC/IT substation is being fed by the Main intake busbar, its protection did not see the fault that is on the busbar hence, a tripping time of 9999.999 sec was recorded. This response is correct in a sense that the fault recorded is upstream with reference to the feeder protection and only the protections behind it are expected to trip. The tripping times, primary current and relays settings can be viewed as shown in Figure 5.23.

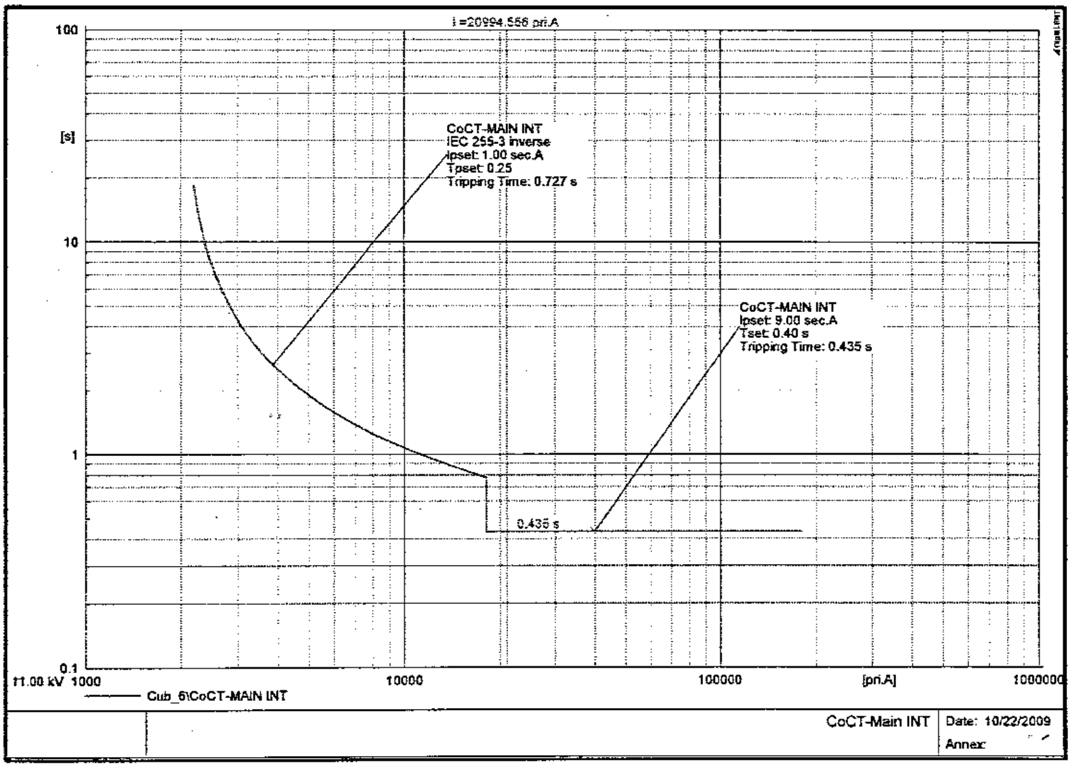


Figure 5.22: Bus protection response characteristics.

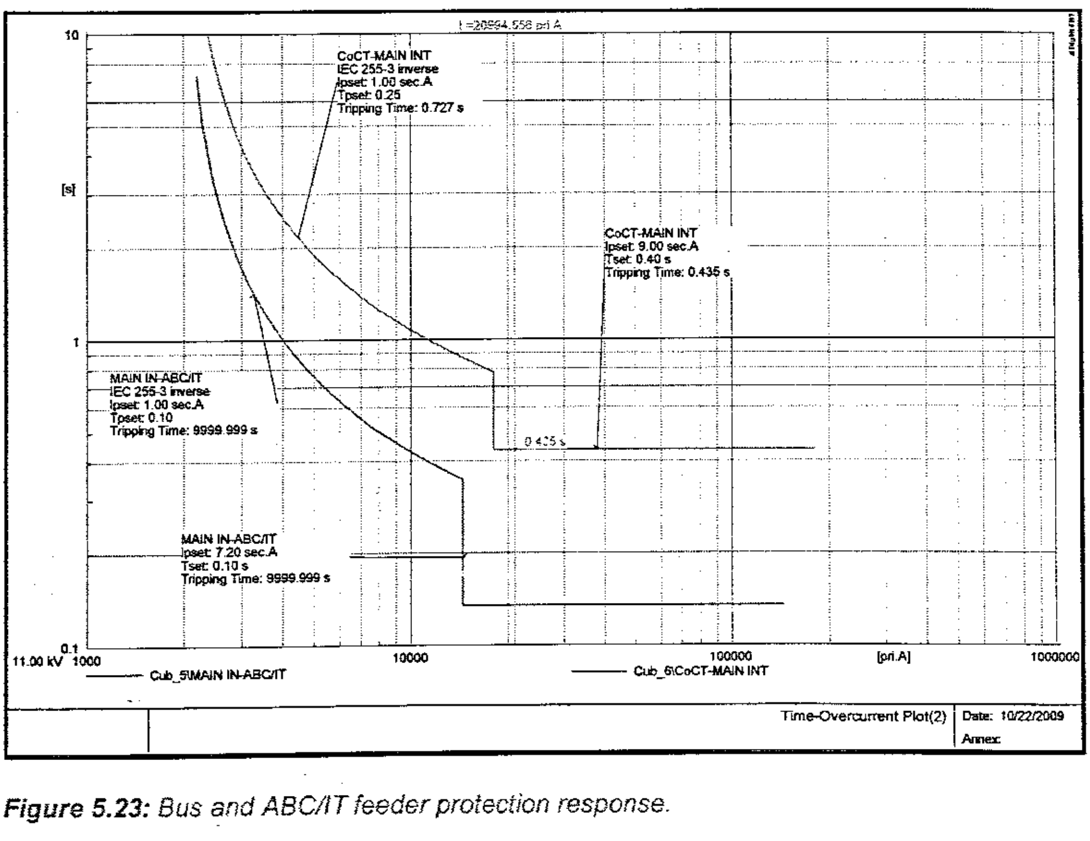


Figure 5.23: Bus and ABC/IT feeder protection response.

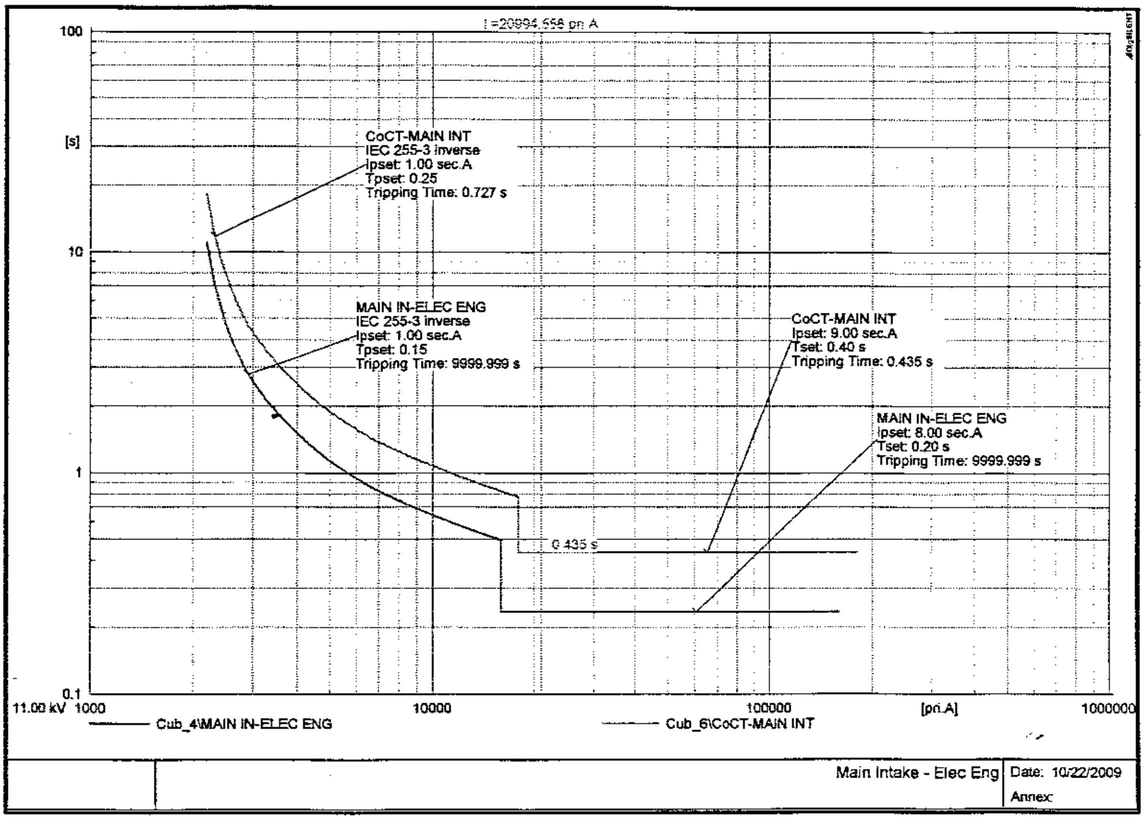


Figure 5.24: *Bus and Electrical Engineering feeder protection response.*

For economy reason, basic medium-voltage switchgear with one incoming feeder does not really require special busbar protection. In such a case, busbar protection is provided by the time overcurrent relay of the incoming feeder as shown in Figure 5.22 & 5.24. As can be seen in Figure 5.24, the tripping time of the time-overcurrent protection for the incoming feeder occurs with a tripping time greater than that of the outgoing feeders. Therefore the busbar protection serves as a backup protection for the two outgoing feeder protections.

In terms of single busbars with one defined incoming feeder and defined outgoing feeders, high-speed busbar protection can be provided with less additional effort by means of reverse interlocking. Such busbar configurations are commonly used in medium-voltage systems networks. The time-overcurrent relays available for feeder protection are used, as shown in Figure 5.21. An additional benefit is that all the relays used are equipped with at least two definite-time current stages($I >$ & $I >>$), which can be blocked individually. Therefore, the expiry of time (t = 0.435s) as recorded on the bus protection response can be blocked via the binary input (BI1) of the protection device.

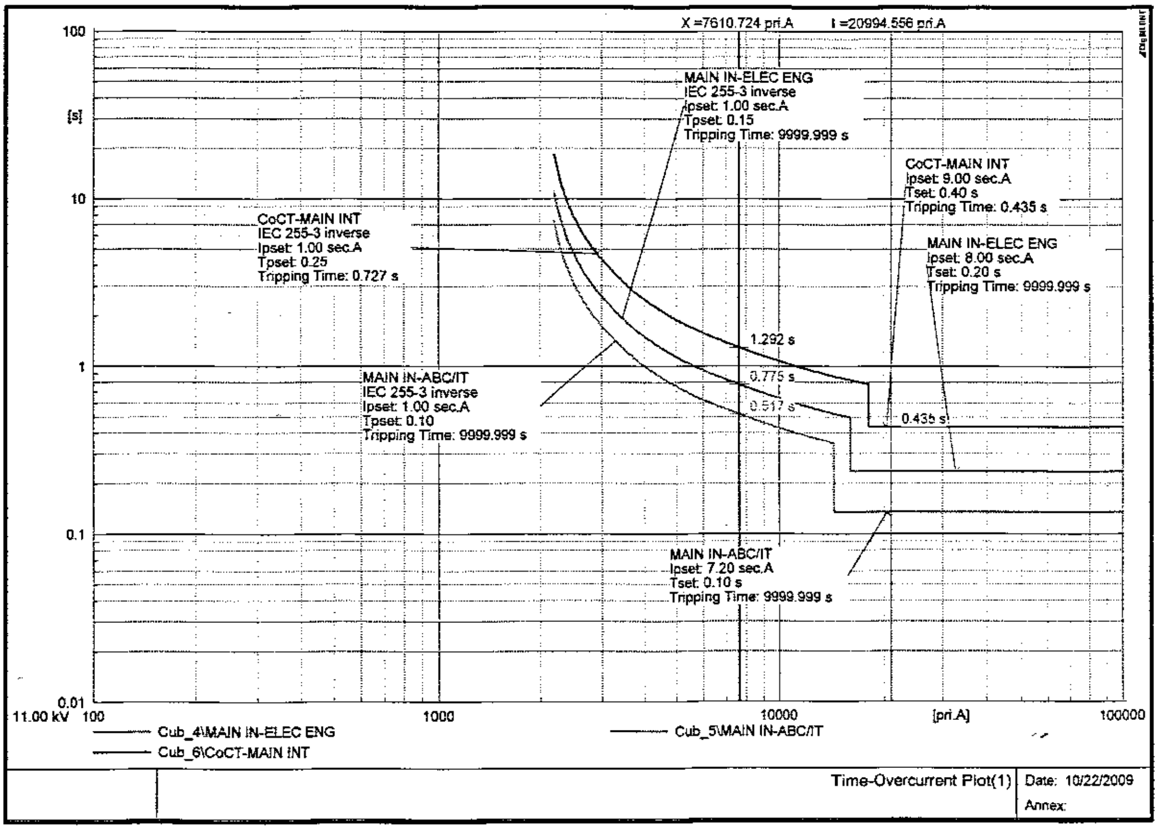


Figure 5.25: *Bus and feeder protection with reverse interlocking.*

With a fault on the busbar as indicated in Figure 5.21, no infeed is recorded from the outgoing feeder onto the fault, hence, no response has been recorded on the protection devices that are located at the two outgoing feeders and consequently there is no blocking signal. The protection device at the incoming feeder that feeds the busbar has responded with a tripping time of 0.435sec in order to isolate the affected busbar. This is illustrated in Figure 5.25. The busbar fault is then disconnected within a short period and the extent of the fault is limited.

With the fault further downstream on the feeder between ABC/IT and NEW TECH substations, the parameters are shown in Figure 5.26. The stress that it imposes on different busbars is also highlighted. Please note that any white square block on the feeder indicates an open breaker.

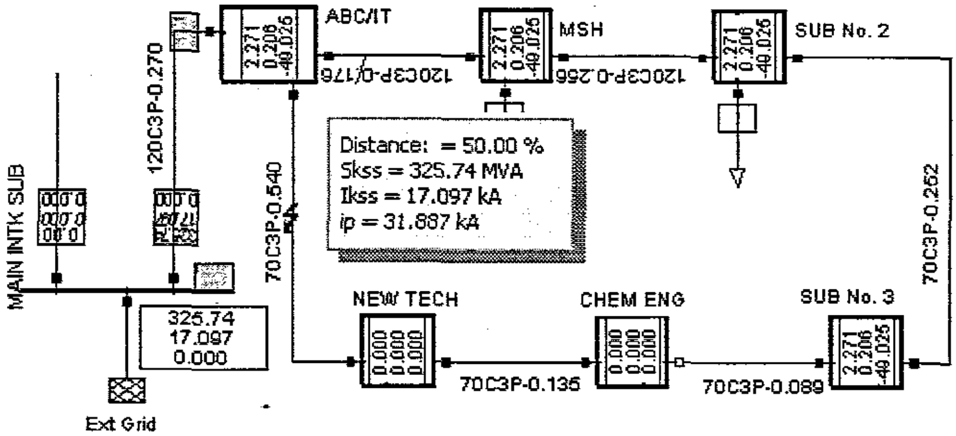


Figure 5.26: Three phase fault on the ABC/IT-NEW TECH feeder.

The tripping characteristics of the three phase fault as shown in Figure 5.26 are illustrated in Figure 5.27. As can be seen the very same relays at the Main Intake are used to issue the tripping signals.

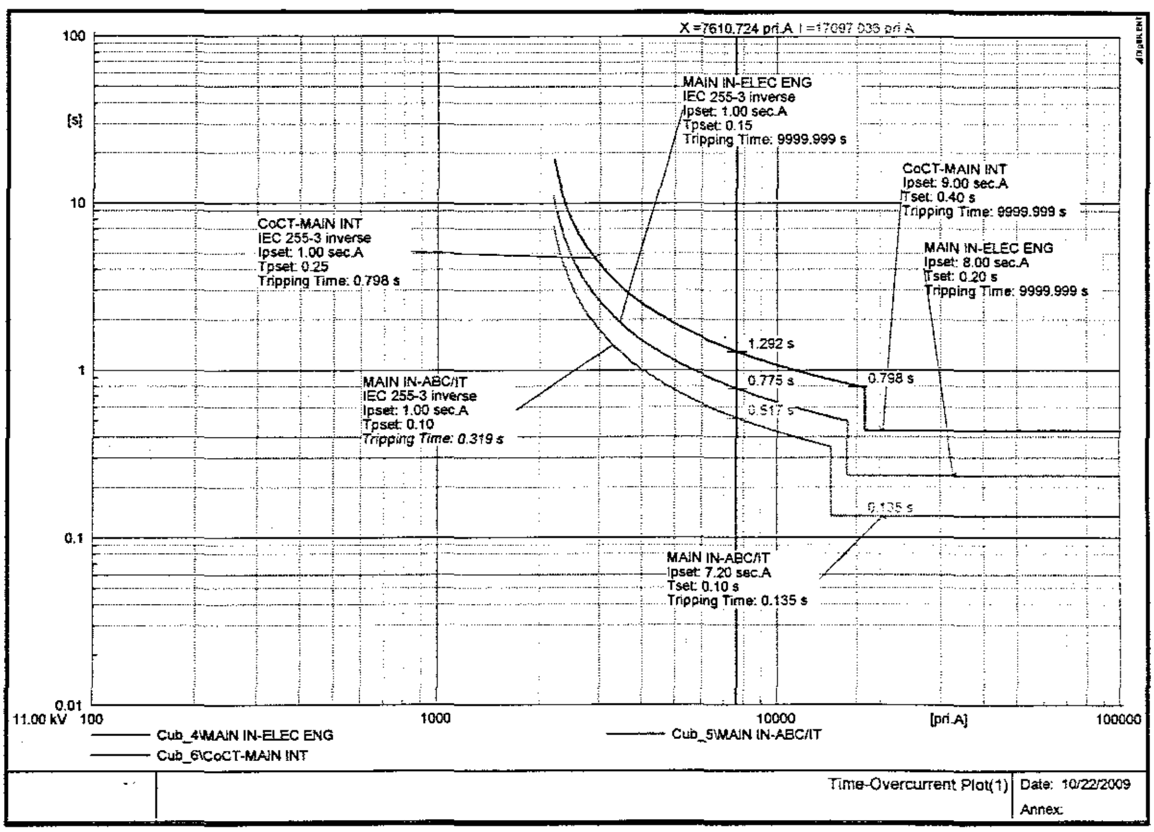


Figure 5.27: Protection response to the fault on the ABC/IT-NEW TECH feeder.

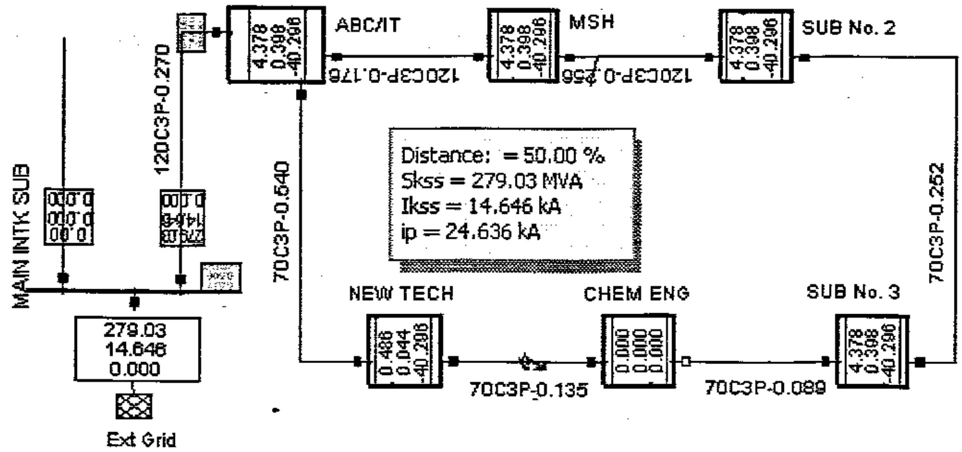


Figure 5.28: *Three phase fault on the NEW TECH- CHEM ENG feeder.*

With the fault as indicated in Figure 5.28, the corresponding tripping characteristics as shown in Figure 5.29 indicate that the definite tripping time of the back-up relay did not respond to the fault, as a result a tripping time of 9999.999 sec is shown.

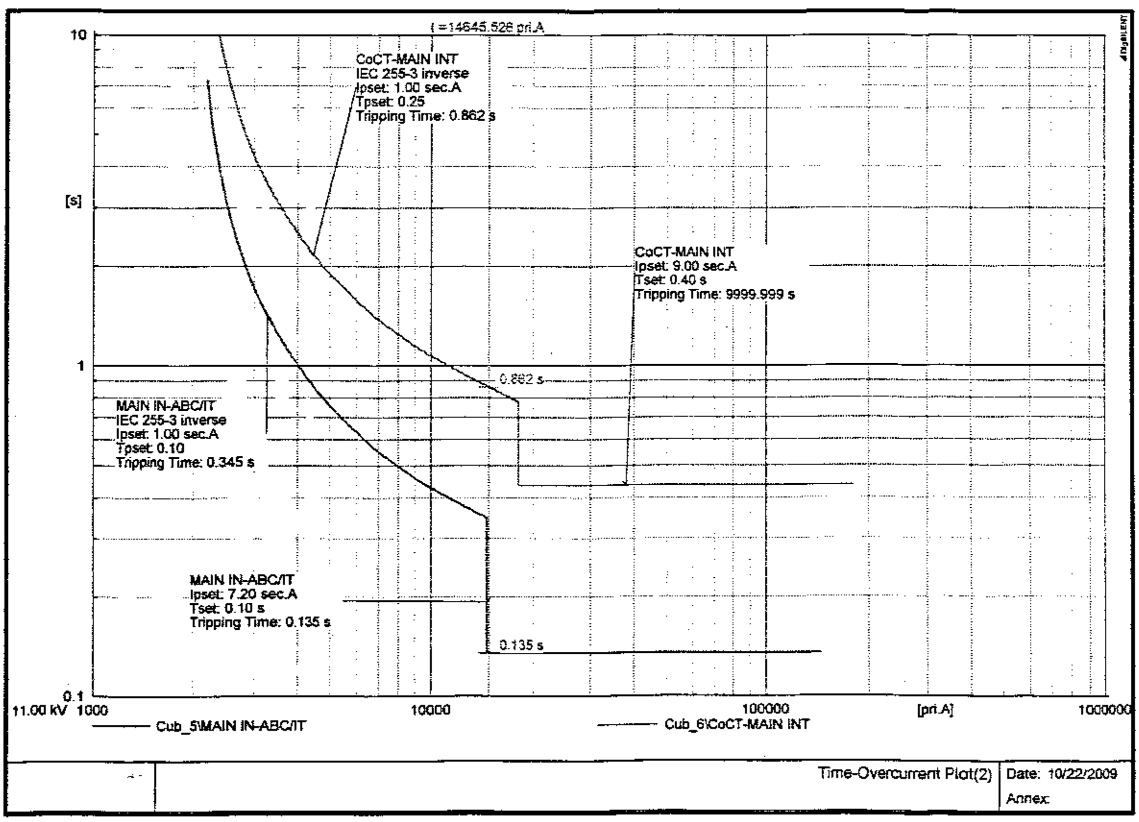


Figure 5.29: *Main and back-up protection response for the fault between NEW TECH & CHEM ENG.*

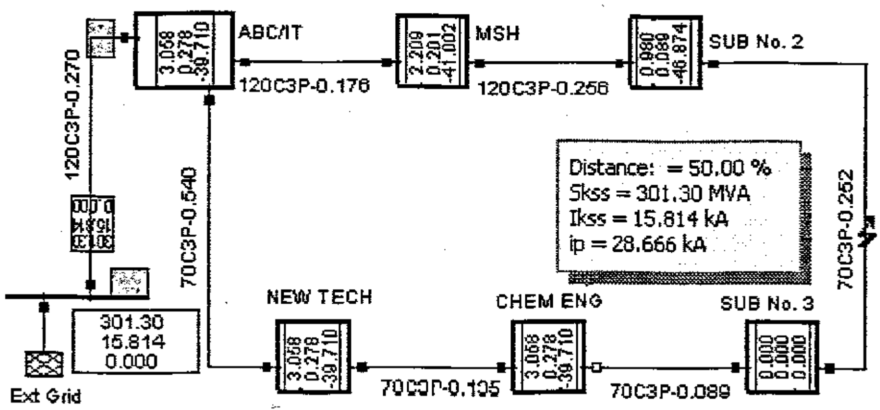


Figure 5.30: *Three phase fault on the feeder between SUB No.2 & 3.*

Figure 5.31 shows a single stage definite time overcurrent characteristics. In terms of selectivity the relay closest to the fault has issued a tripping signal 0.135 sec. The fault parameters are shown in Figure 5.30.

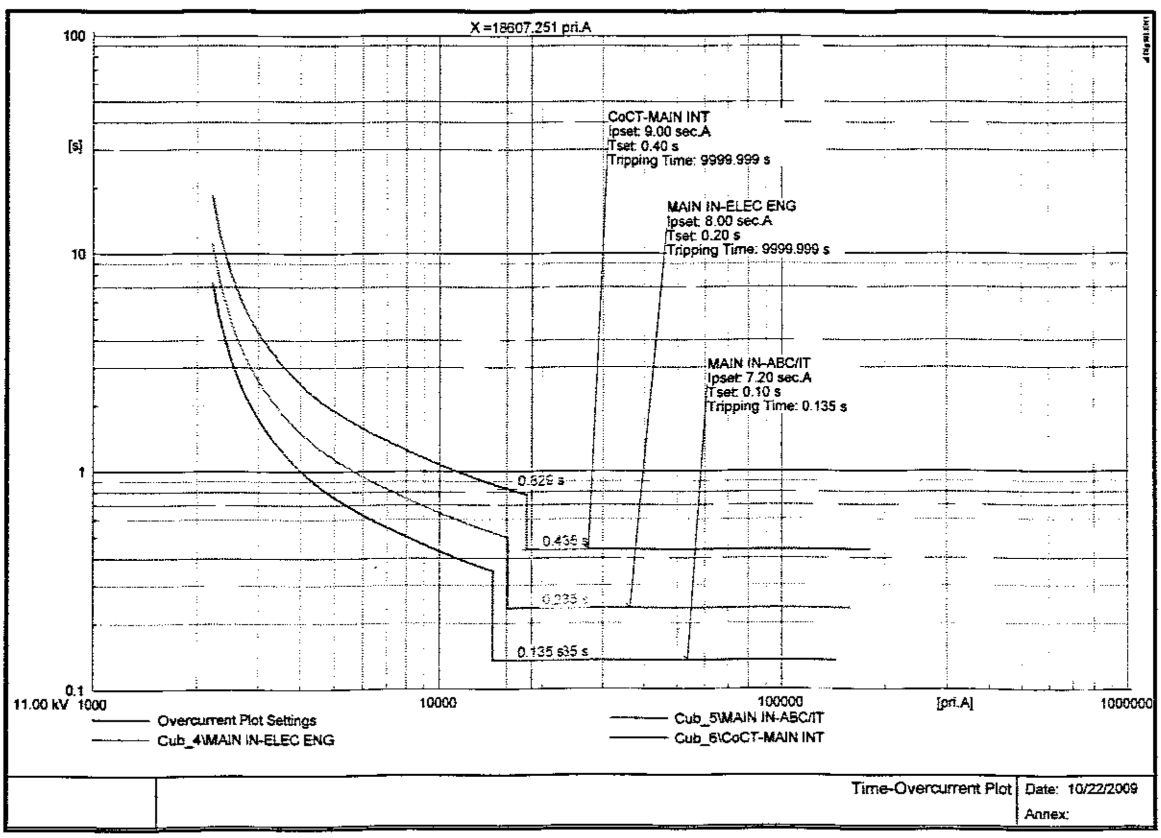


Figure 5.31: *Protection response of the fault on the feeder between SUB No.2 & 3.*

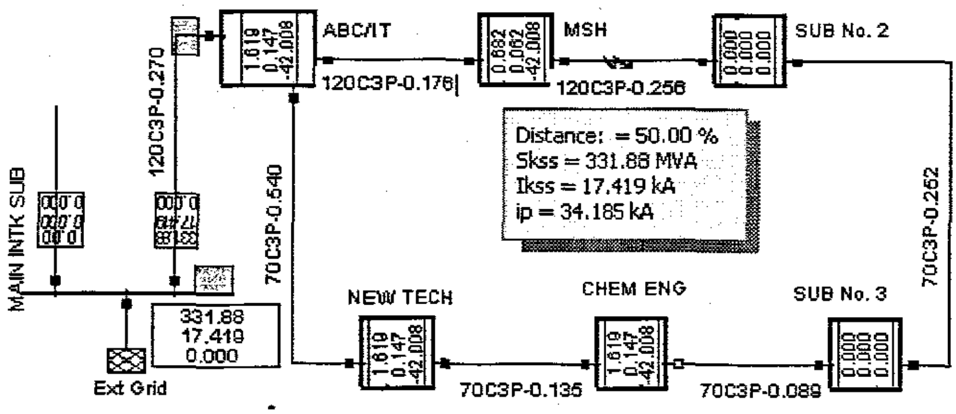


__Figure 5.32:__ Three phase fault on the feeder between MSH &SUB No.2.

A short-circuit current of 17.419kA is recorded on the CT's primary when the fault is between the MSH and SUB No. 2 as shown in Figure 5.32. The overcurrent settings are defined by the grading coordination of the network. From Figure 5.33 it can be seen that the definite tripping for the back-up relay did not respond to the fault.

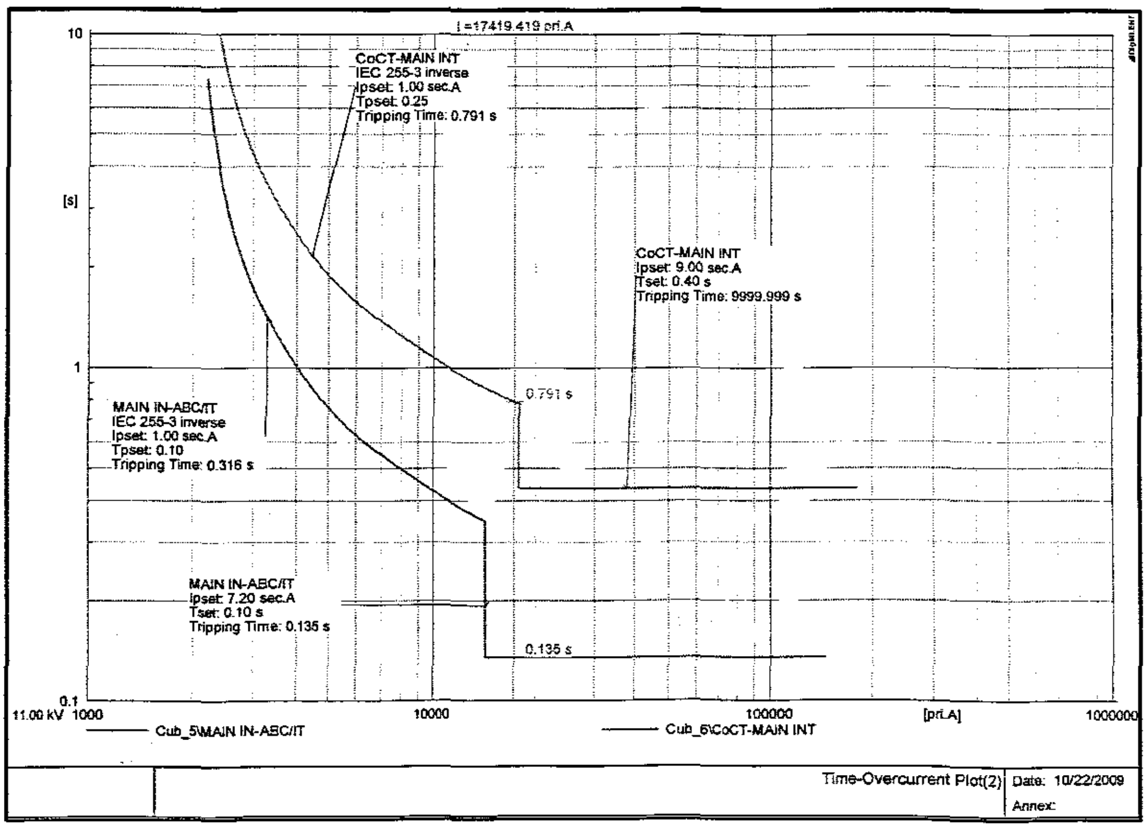


__Figure 5.33:__ Protection response of the fault on the feeder between MSH &SUB No.2.

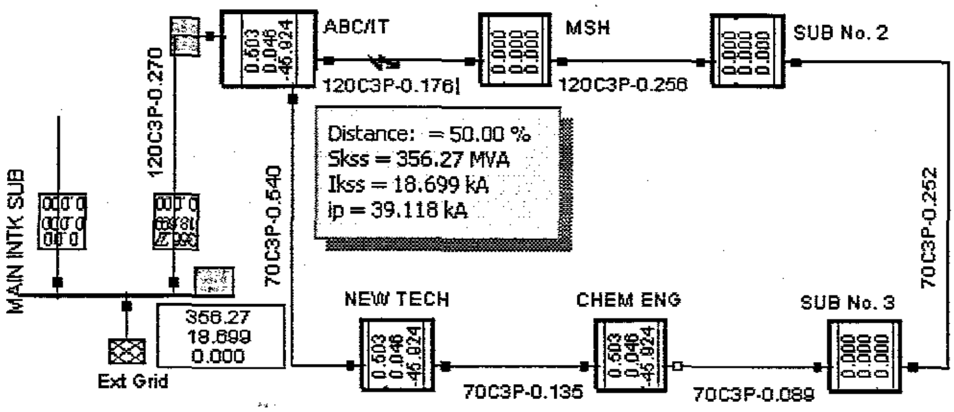


Figure 5.34: *Three phase fault on the feeder between ABC/IT & MSH.*

The phase overcurrent protection is used to clear the fault as shown in Figure 5.34. The definite time and time delayed overcurrent protection is set to provide discrimination and to clear the fault with a high degree of accuracy. Two relays have picked-up the fault and responded accordingly while the relay on the adjacent feeder did not pick-up the fault and therefore, not responding. This operation is correct and the tripping response is shown in Figure 5.35.

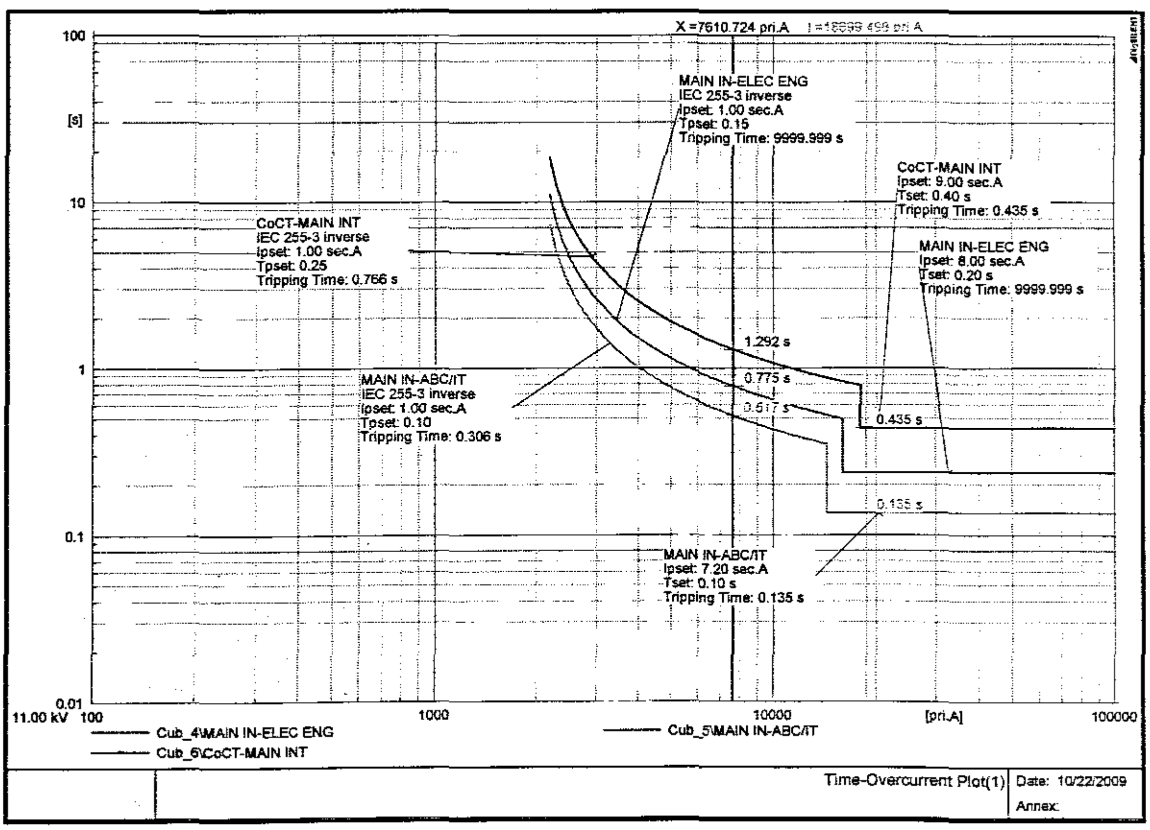


Figure 5.35: *Protection response of the fault on the feeder between ABC/IT & MSH*

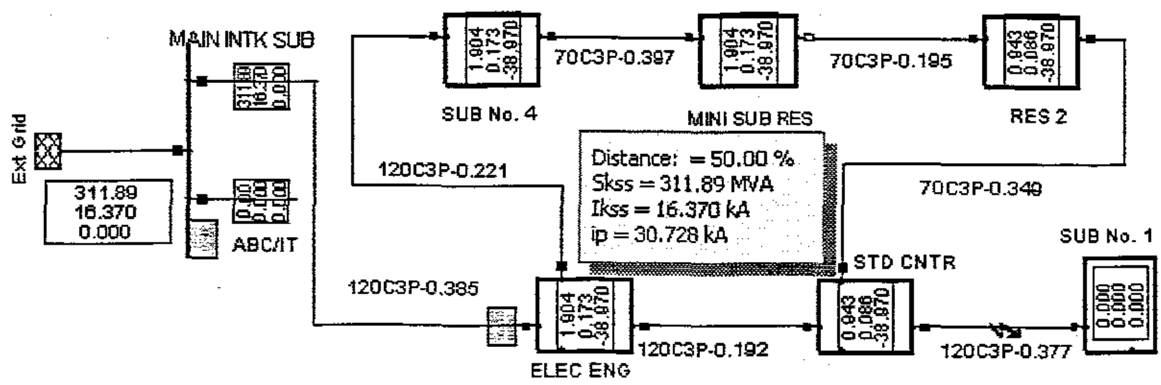


Figure 5.36: *Three phase fault on the feeder between STD CNTR &SUB No.1.*

The criteria for setting the inverse time element and the instantaneous element varies depending on the location and on the type of system element that is being protected, in this case the feeders and busbars. For the fault as shown in Figure 5.36, the settings and responses (tripping times) can be viewed in Figure 5.37

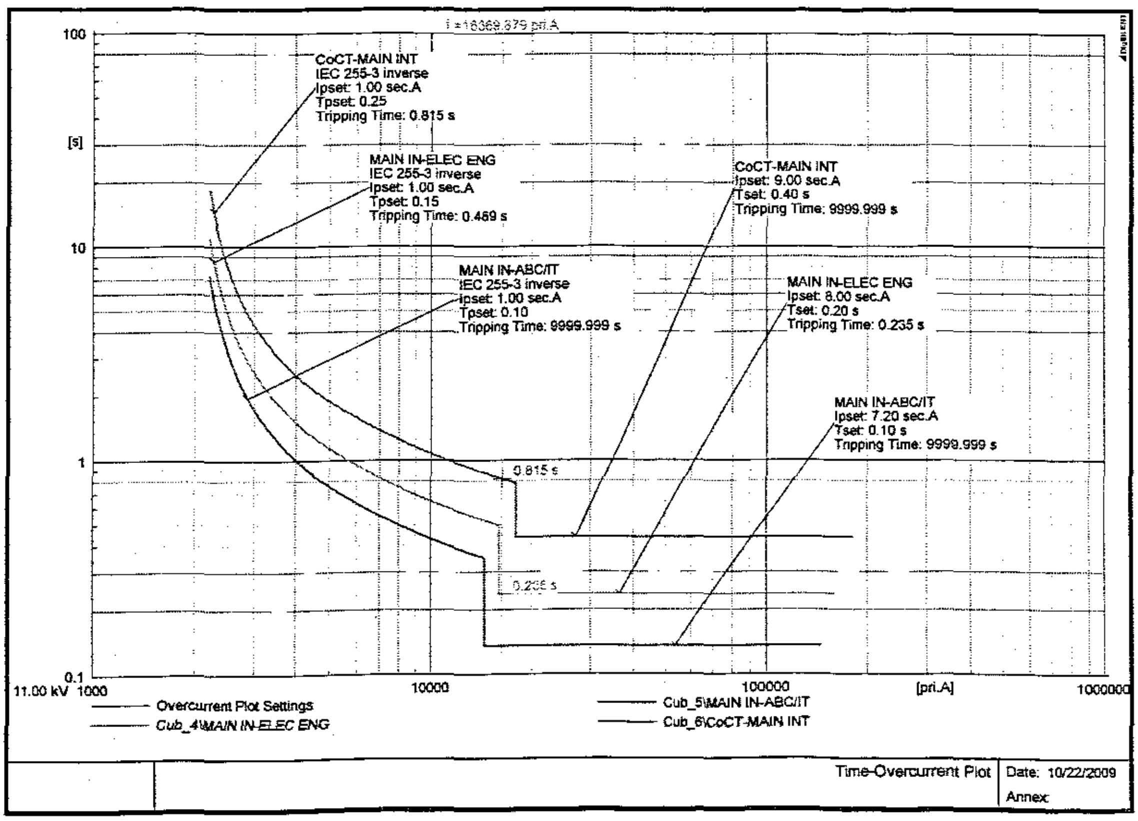


Figure 5.37: *Protection response of the fault on the feeder between STD CNTR &SUB No.1.*

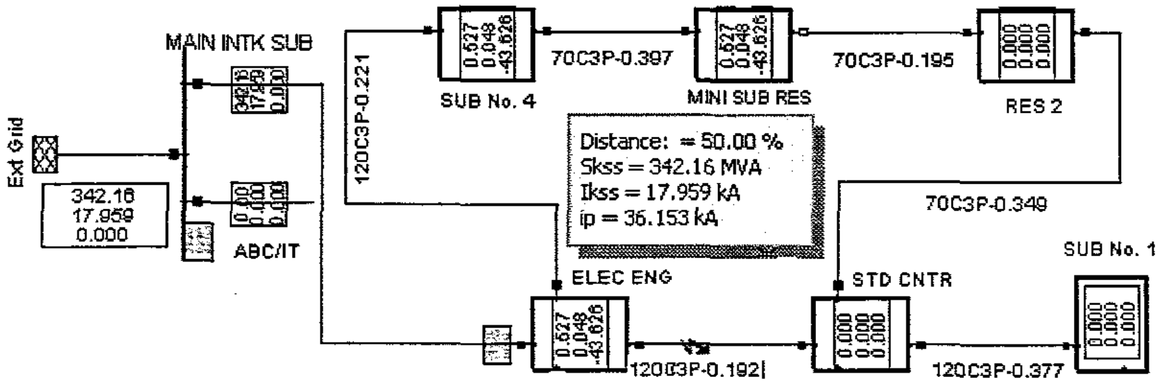


Figure 5.38: *Three phase fault on the feeder between ELEC ENG & STD CNTR.*

A short-circuit current of 17.959kA is recorded when the fault is between the ELEC ENG and STD CNTR substation as shown in Figure 5.38. The overcurrent settings are defined by the grading coordination of the network. From Figure 5.39, it can be seen that the definite tripping for the back-up relay did not respond to the fault.

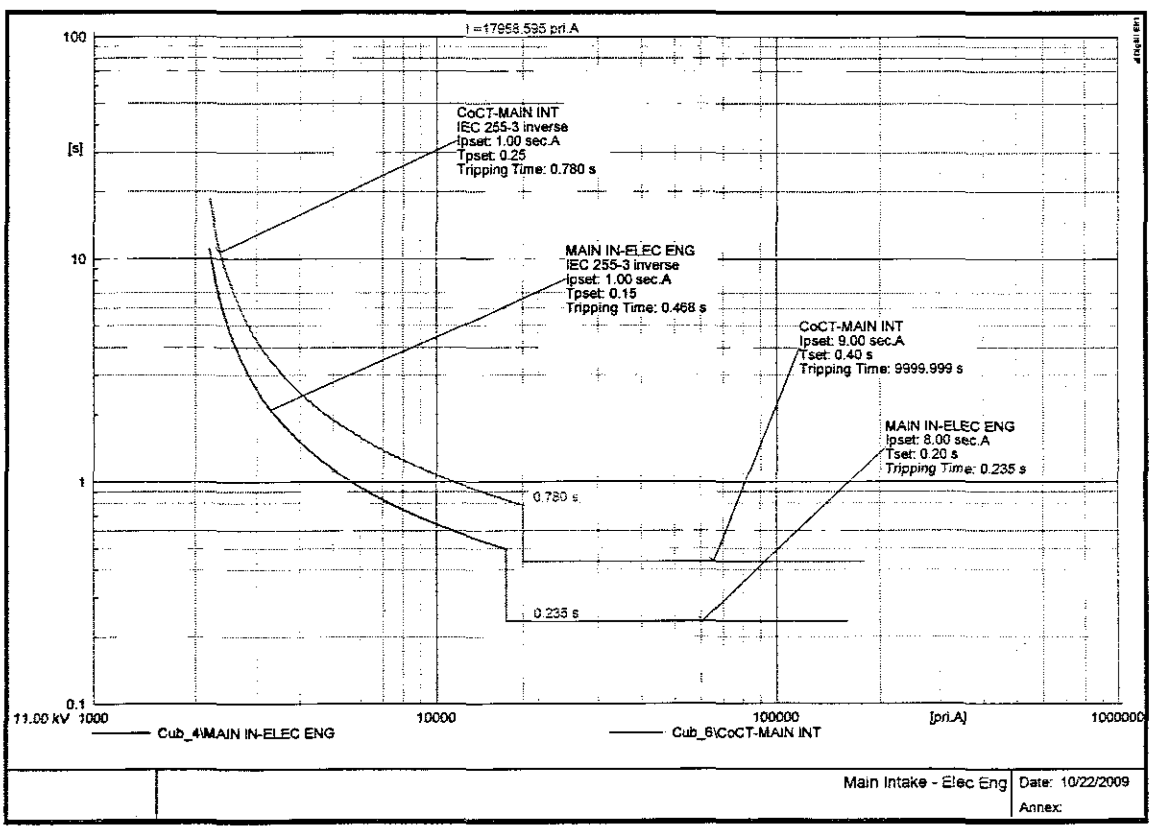


Figure 5.39: *Protection response of the fault on the feeder between ELEC ENG & STD CNTR.*

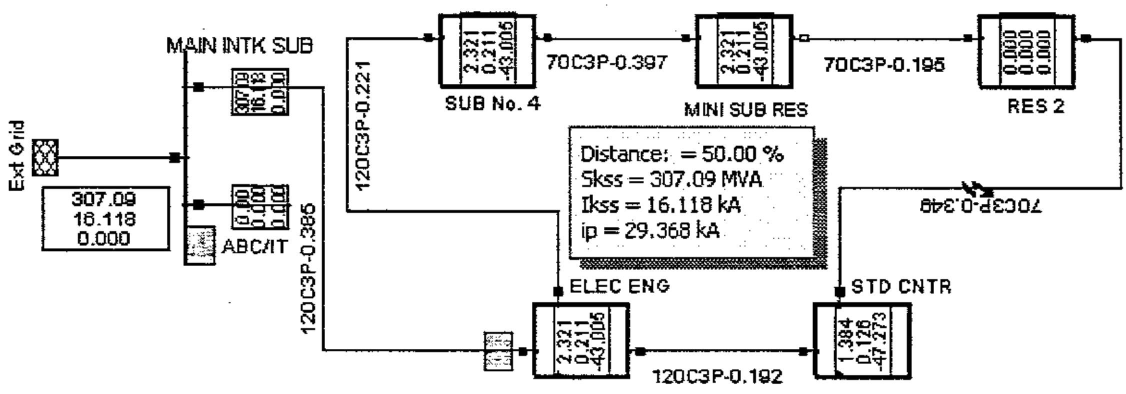


Figure 5.40: *Three phase fault on the feeder between RES2 & STD CNTR.*

With the fault as indicated in Figure 5.40, the corresponding tripping characteristics as shown in Figure 5.41 indicate that the definite tripping time of the back-up relay did not respond to the fault and as a result a tripping time of 9999.999 sec is shown. The fault is cleared in 0.235 sec by the relay closer to the fault.

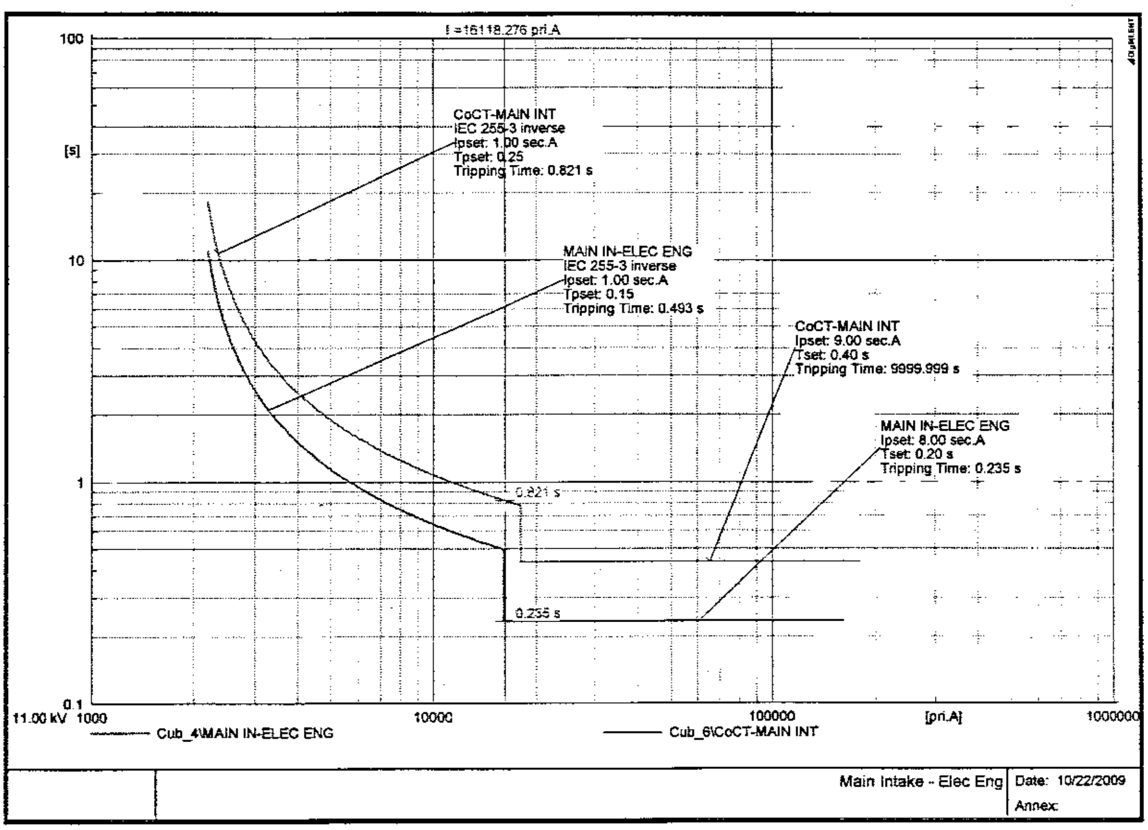


Figure 5.41: *Protection response of the fault on the feeder between RES2 & STD CNTR.*

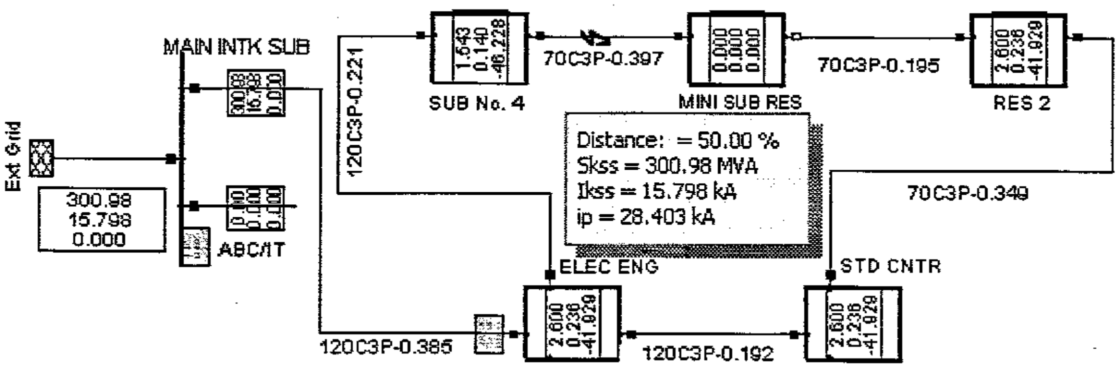


Figure 5.42: *Three phase fault on the feeder between SUB No.4 & MINI SUB RES.*

A maximum fault level of 300.98MVA and a short circuit of 15.798kA are logged as the fault was introduced as shown in Figure 5.42.The relay on the ABC/IT (adjacent) feeder did not response to the fault as it is not directly involved. The definite time characteristics for the main and back-up relays did not pick up the fault as it is not within their setting ranges (predetermined values).

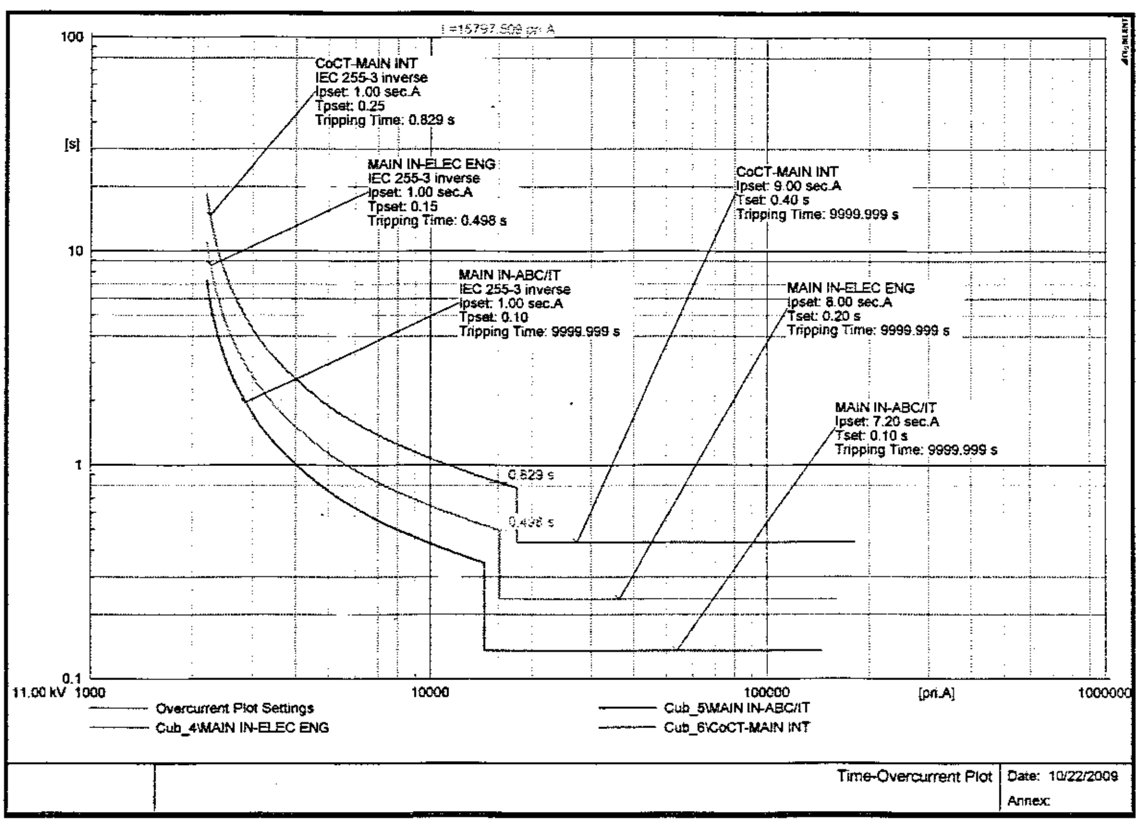


Figure 5.43: *Protection response of the fault on the feeder between SUB No.4 & MINI SUB RES.*

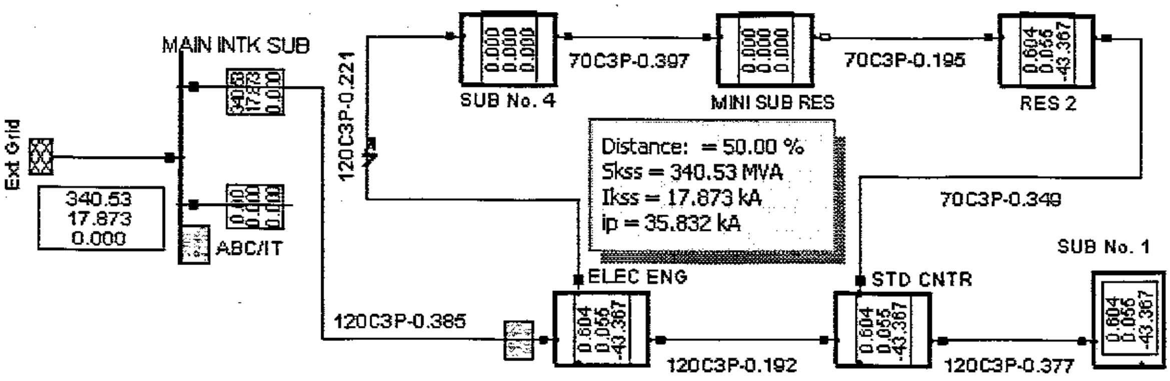


Figure 5.44: Three phase fault on the feeder between SUB No.4 & ELEC ENG.

For the fault as shown in Figure 5.44, the main and back-up protection has responded as shown in Figure 5.45. An instantaneous tripping of 0.235 sec has cleared the fault. With the inverse characteristic, the fault current is inversely proportional to the operating time of the relay hence, the lower the fault current the longer the tripping time.

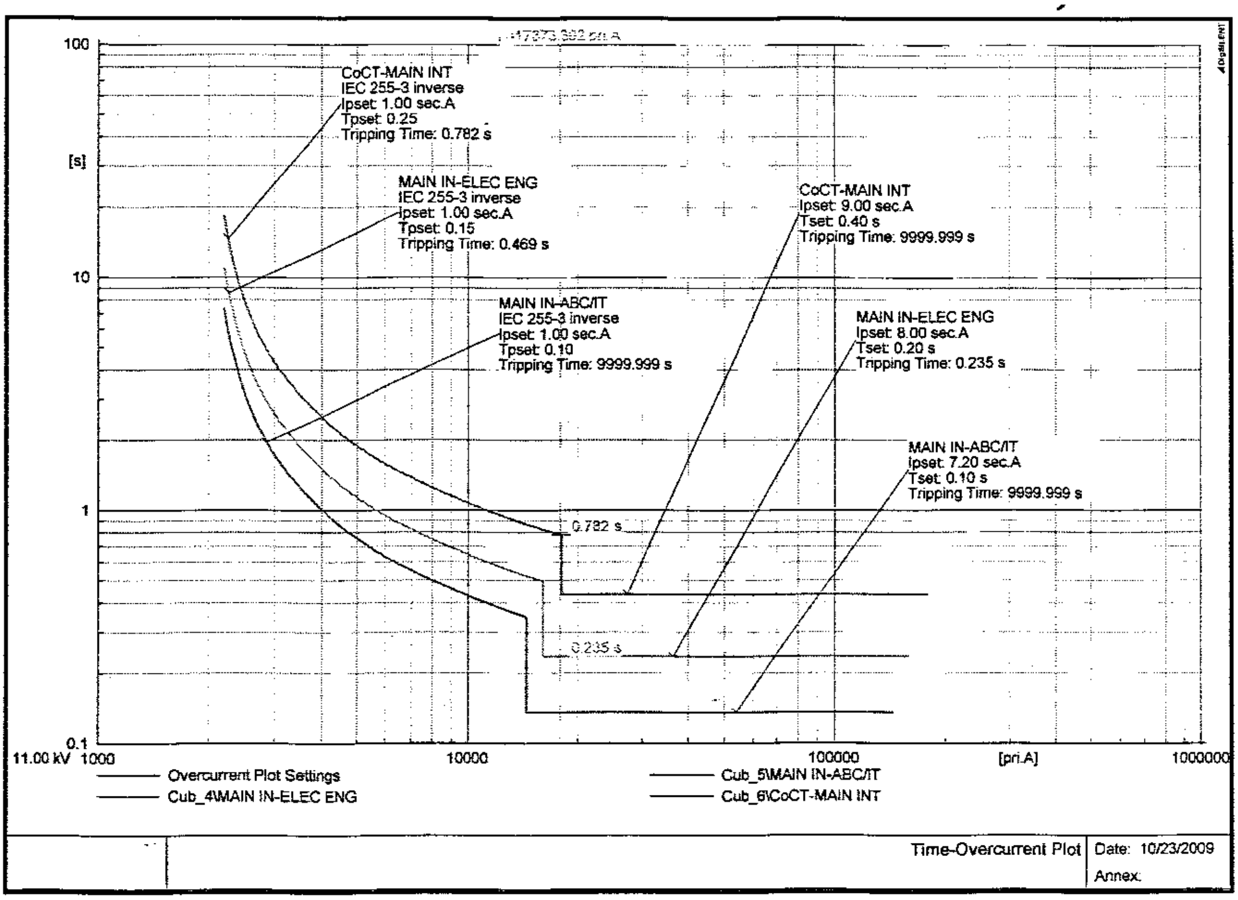


Figure 5.45: Protection response of the fault on the feeder between ABC/IT & MSH

Note: *A brief discussion of the results, findings and recommendation for the CPUT network can be viewed at the end of this chapter.*

5.4 MODELING OF THE EUREKA NETWORK

Eureka distribution network belongs to Eskom and it is supplied via two parallel transformers rated at 66/11kV, 40MVA and a percentage impedance of 10%. The 66kV is stepped down to 11kV through to Lower Voltages (LV) via a number of substations. The load flow results as obtained from historical trends are shown below in Table 5.7 and Figure 5.46.

Table 5.7: *Eureka network load flow results*

SUBSTATION	P (MW)	Q (MVAR)	CABLE LOADING (%)
Eureka - Matroosfontein	3.62	0.54	56.18
Matroosfontein - Bishop Lavis1	1.99	0.29	31.08
Eureka - Belvanie	4.02	0.58	62.23
Eureka - 18th Ave	5.25	0.91	81.72
18th Ave - 8th Ave	2.56	0.52	32
Eureka - Avonwood	3.34	0.68	52.25
Eureka - cojac	5.42	1.12	84.4
Cojac - Bishop Lavis3	3.96	0.8	62.33
Bishop Lavis3 - Heilbot	1.94	0.49	31
Eureka - Holloway	4.82	0.72	74.39
Eureka - Indian	1.2	0.3	18

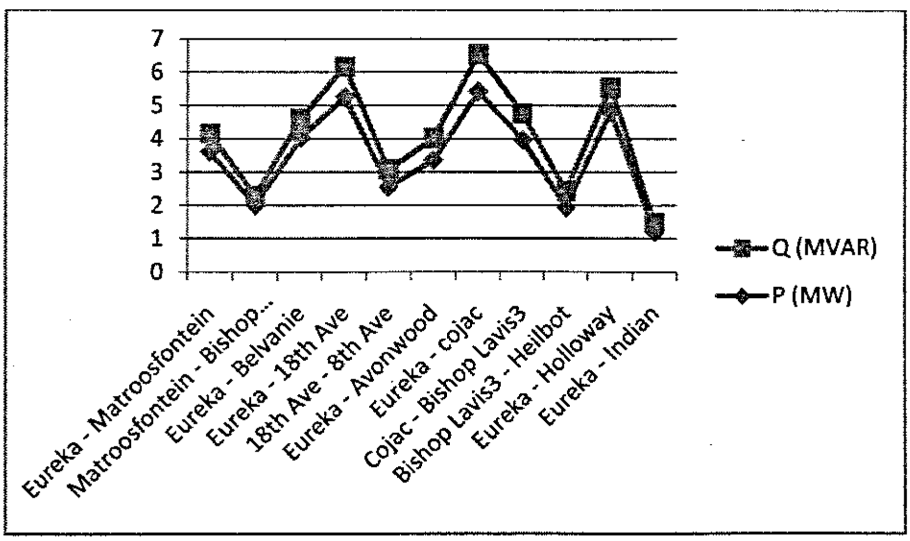


Figure 5.46: *Eureka network power profile*

The Eureka network with loadings and fault on busbars are shown in Figure 5.47 and 5.48.

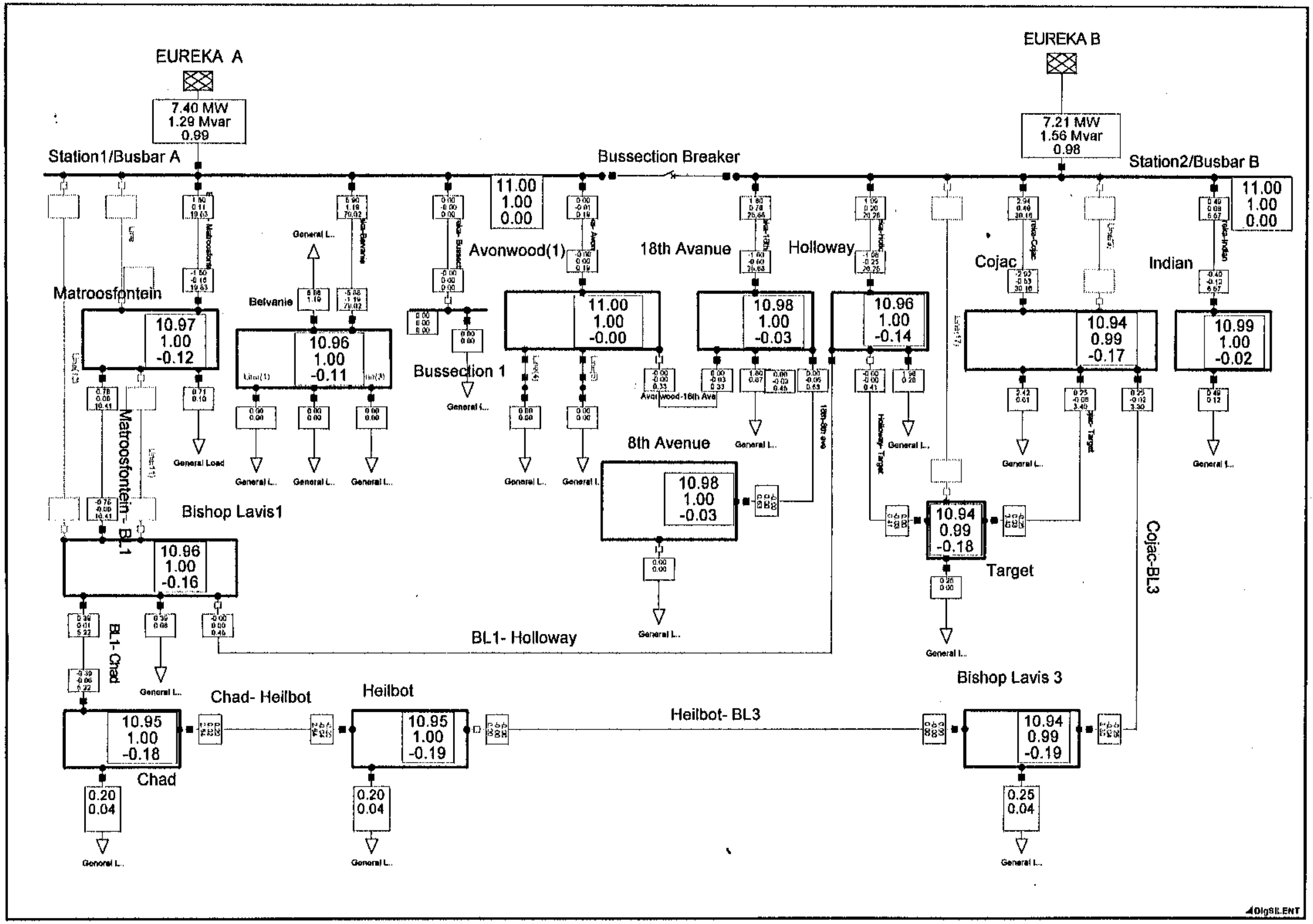


Figure 5.47: Overview of the Eureka network power flow results

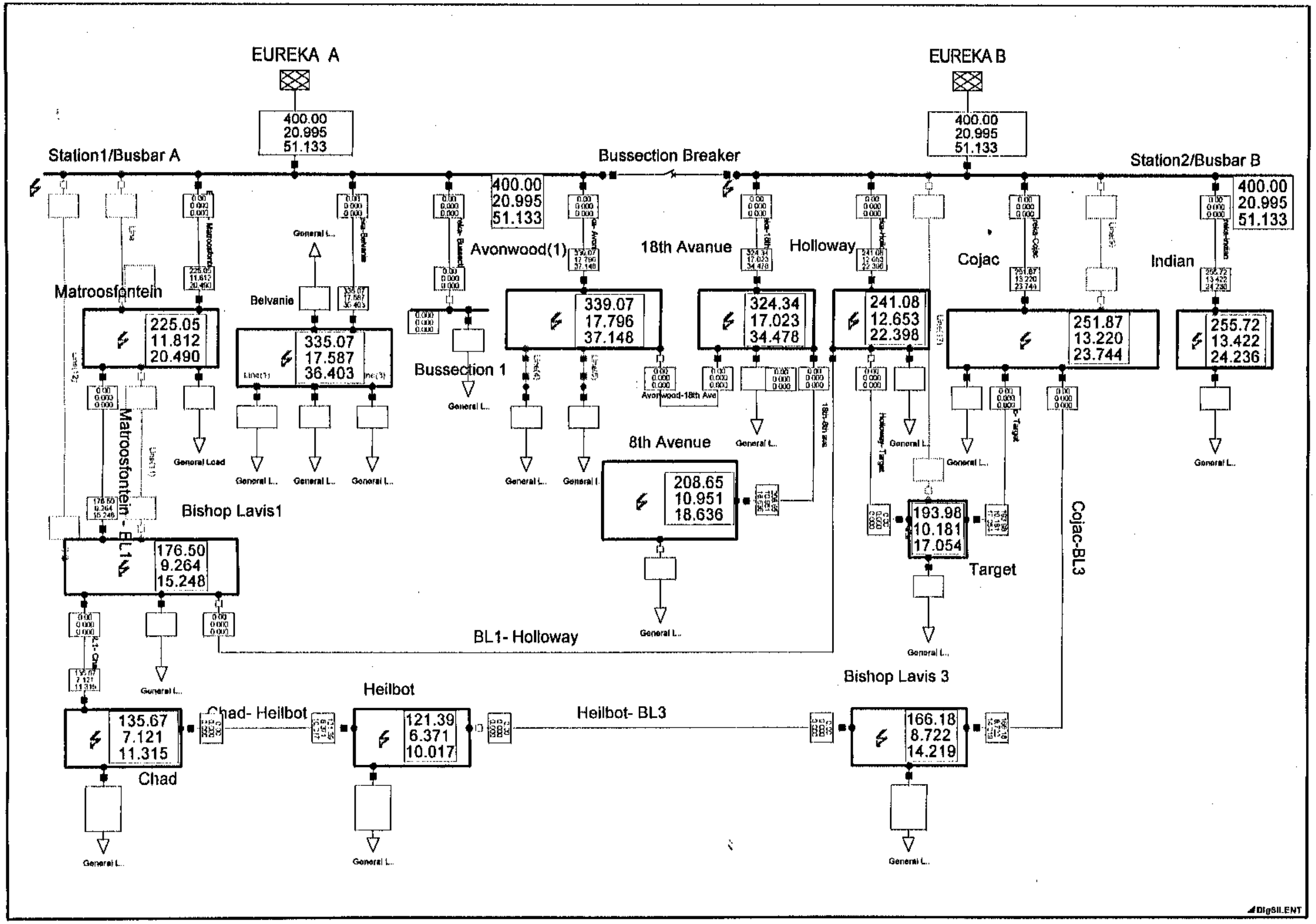


Figure 5.48: Overview of the Eureka network with faults on busbars

In this network, only the protected substations are considered for this project. The principle of co-ordination is applied and exercised on this network. This principle refers to the procedure of setting overcurrent IED's to ensure that the IED nearest to the fault operates first and all the other IED's have enough additional time to prevent them from operating. Therefore, if the co-ordination is done correctly and the IED closest to the fault fails to function, then the next up-stream IED should operate and so forth towards the source.

The maximum short-circuit power, correction factor and rated voltage obtained from the Eureka power system using DIgSILENT are shown in Table 5.8. The corresponding graph that indicates the profile of the above mentioned parameters as recorded using DIgSILENT is shown in Figure 5.49.

Table 5.8: *Substations max. Short-circuit power, correction factor and rated voltage*

SUBSTATION	**Rated Voltage rtd V.(kV)**	**Correction Factor**	**Max. Short-circuit power Sk"(MVA)**
Busbar A	11.00	1.10	400
Busbar B	11.00	1.10	400
18th Ave	11.00	1.10	324.34
8th Ave	11.00	1.10	208.65
Avonwood	11.00	1.10	339.07
Belvanie	11.00	1.10	335.07
Bishop Lavis1	11.00	1.10	166.18
Bishop Lavis 3	11.00	1.10	176.5
Chad	11.00	1.10	135.67
Cojac	11.00	1.10	251.87
Heilbot	11.00	1.10	121.39
Holloway	11.00	1.10	241.08
Indian	11.00	1.10	255.72
Matroosfontein	11.00	1.10	225.05
Target	11.00	1.10	193.98

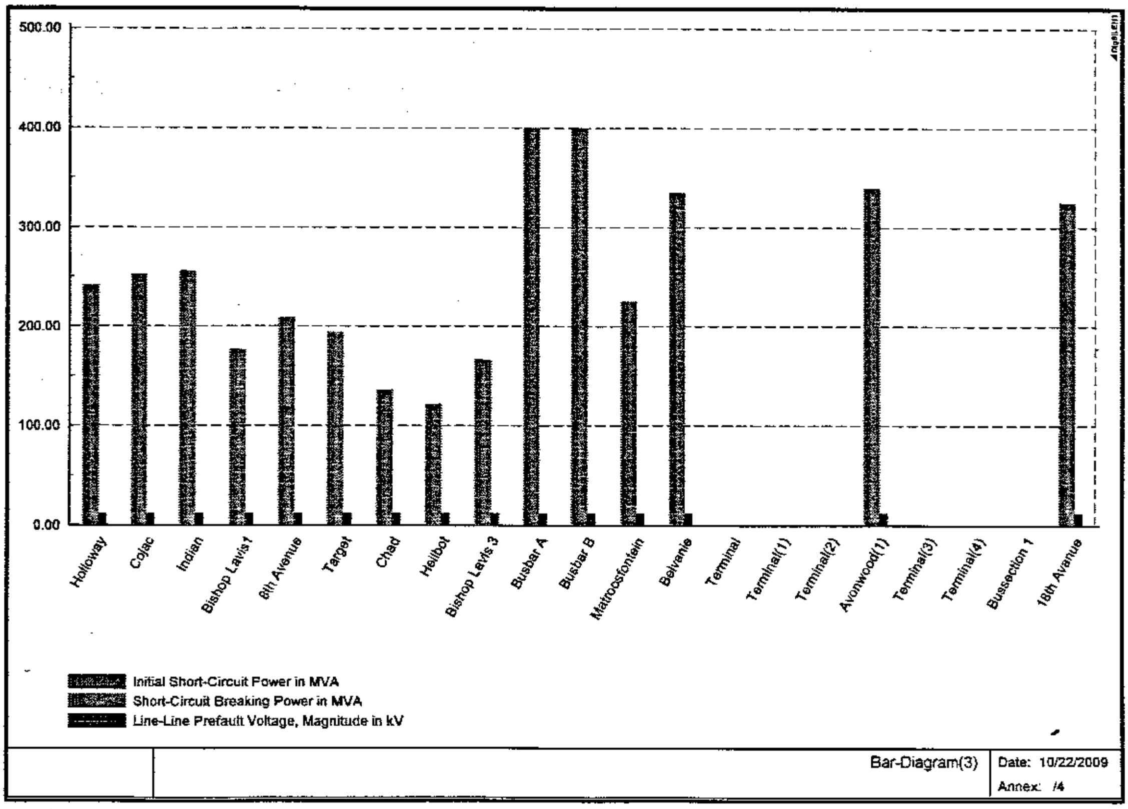


Figure 5.49: *Maximum Fault level profile at different substations*

Table 5.9 indicates various short circuit calculation results as obtained at different substations within the network according to the IEC60909 standard, upon which Figures 5.50 & 51 are plotted.

Table 5.9: *Short circuit calculations results according to IEC60909 standard*

SUBSTATION	Ik" [kA/kA]	Ip [kA/kA]	Ib [kA]	Ik [kA]	I th [kA]
Busbar A	20.99	51.13	20.99	20.99	21.31
Busbar B	20.99	51.13	20.99	20.99	21.31
18^{th} Ave	17.02	34.48	17.02	17.02	17.12
8^{th} Ave	10.95	18.64	10.95	10.95	10.99
Avonwood	17.8	37.15	17.8	17.8	17.92
Belvanie	17.59	36.4	17.59	17.59	17.7
Bishop Lavis1	8.72	14.22	8.72	8.72	8.75
Bishop Lavis 3	9.26	15.25	9.26	9.26	9.29
Chad	7.12	11.32	7.12	7.12	7.14
Cojac	13.22	23.74	13.22	13.22	13.27
Heilbot	6.37	10.02	6.37	6.37	6.39
Holloway	12.65	22.4	12.65	12.65	12.7
Indian	13.42	24.24	13.42	13.42	13.47
Matroosfontein	11.81	20.49	11.81	11.81	11.85
Target	10.18	17.05	10.18	10.18	10.21

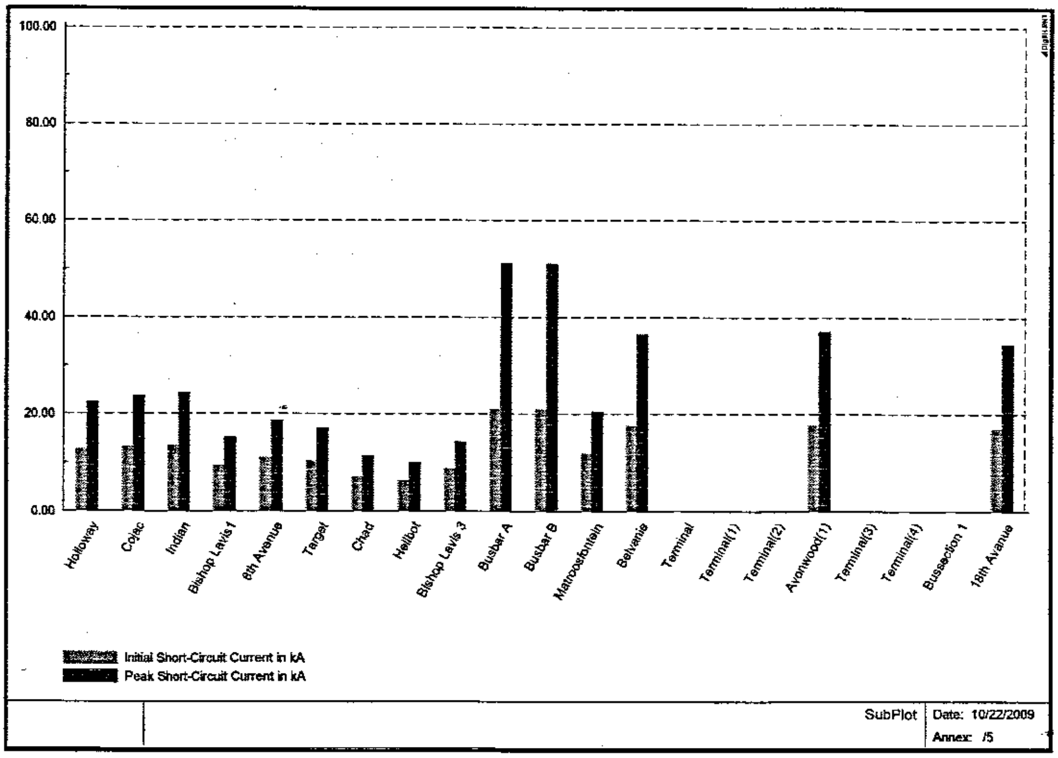


Figure 5.50: *Short circuit currents profile at each substation*

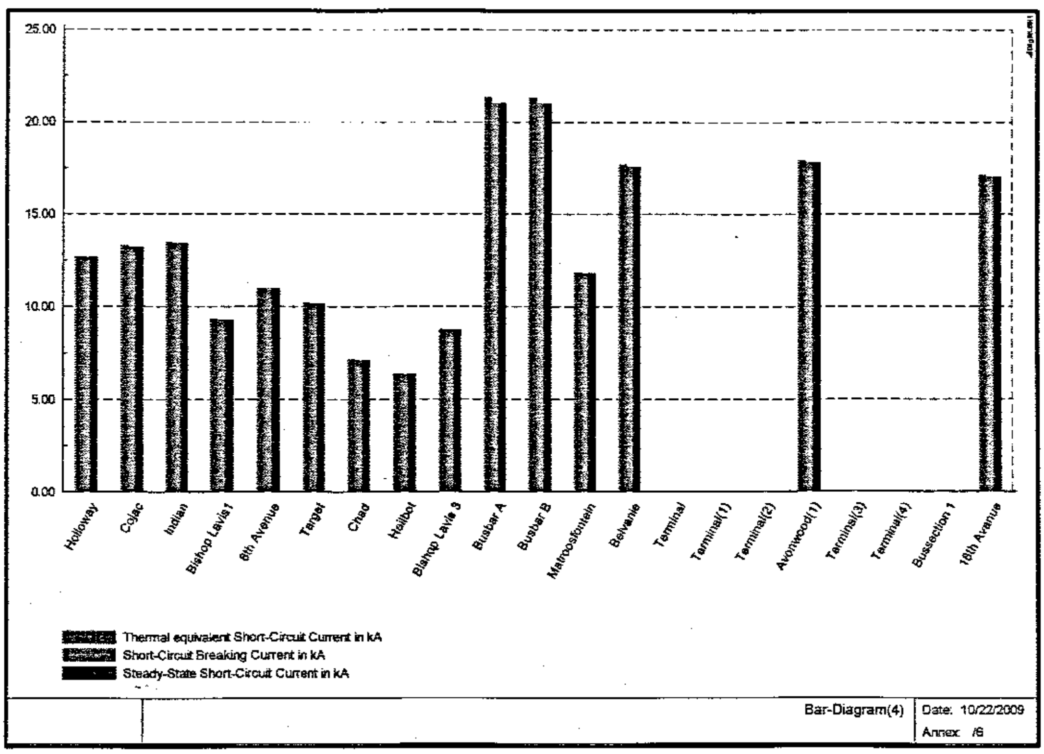


Figure 5.51: *Short circuit currents profile at each substation*

5.4.1 Heilbot-Bishop Lavis3 busbar and feeder protection settings and characteristics

Figure 5.52 indicates a three phase fault on the feeder between Bishop Lavis 3 (BL3) substation and Heilbot substation. The settings for the IED at BL3 are shown in Table 5.10

Table 5.10: *Protection IED settings (Heilbot-Bishop lavis3)*

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.1	
Time Dial	0.40		0.07	
Pick-up Current		15.8		.01
Time Setting		0.40		0.0

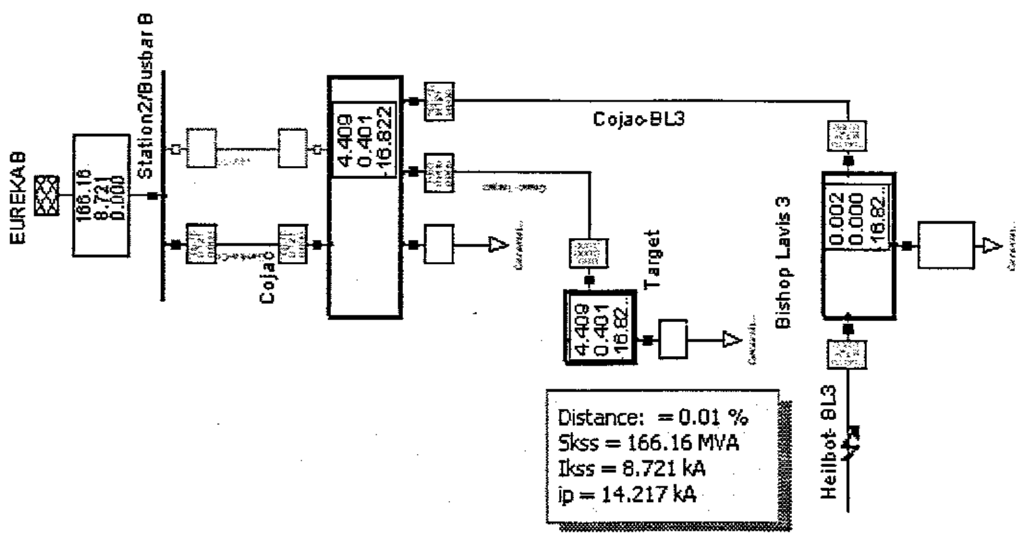


Figure 5.52: *Fault on the Bishop Lavis3 line*

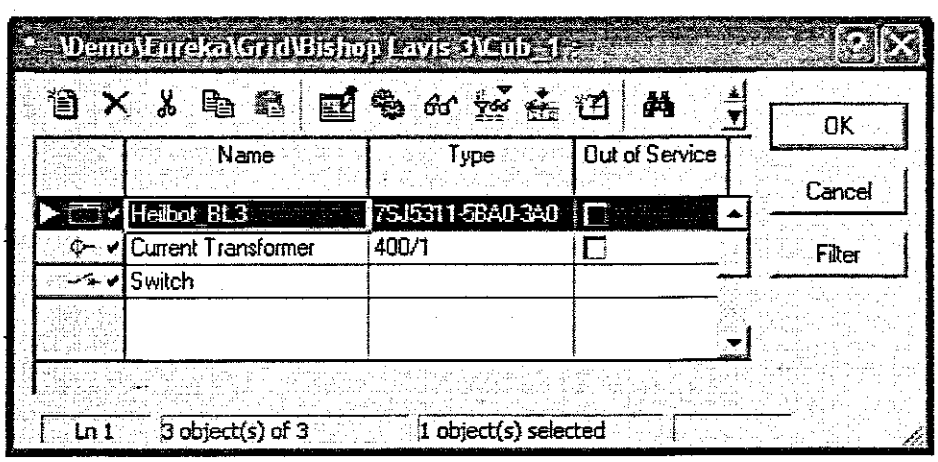


Figure 5.53: *Protection devices on the Bishop Lavis 3 (BL3) cubicle*

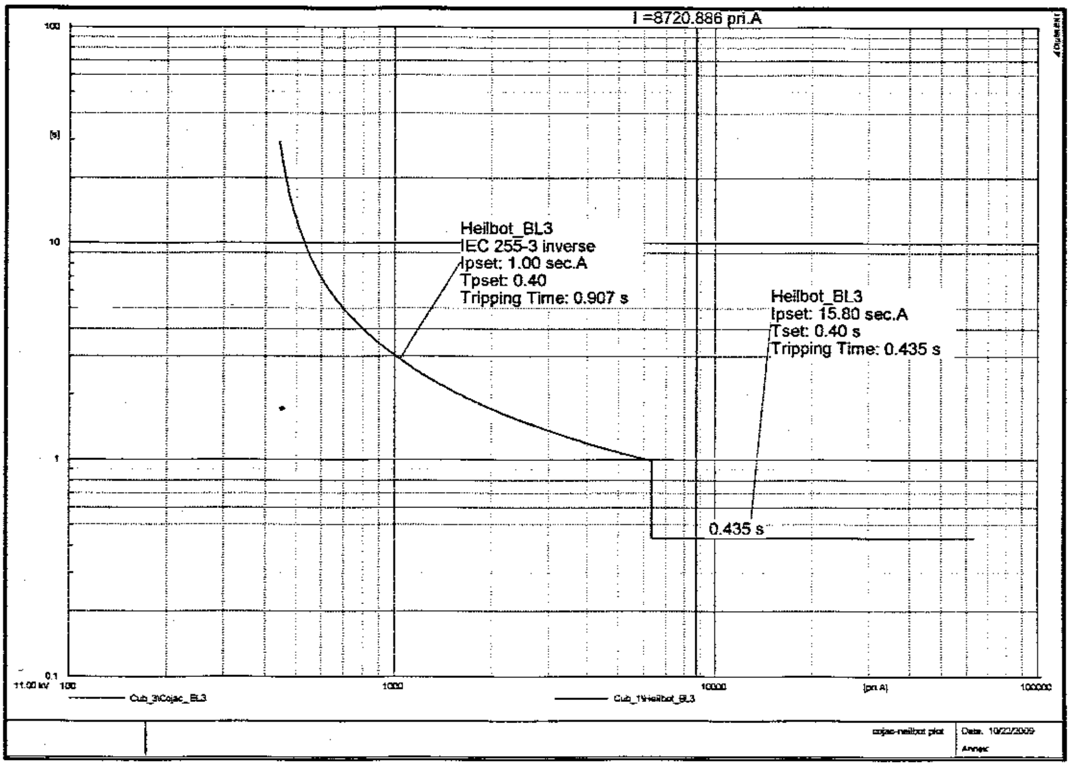


Figure 5.54: *Main protection response for the fault on the BL3 feeder*

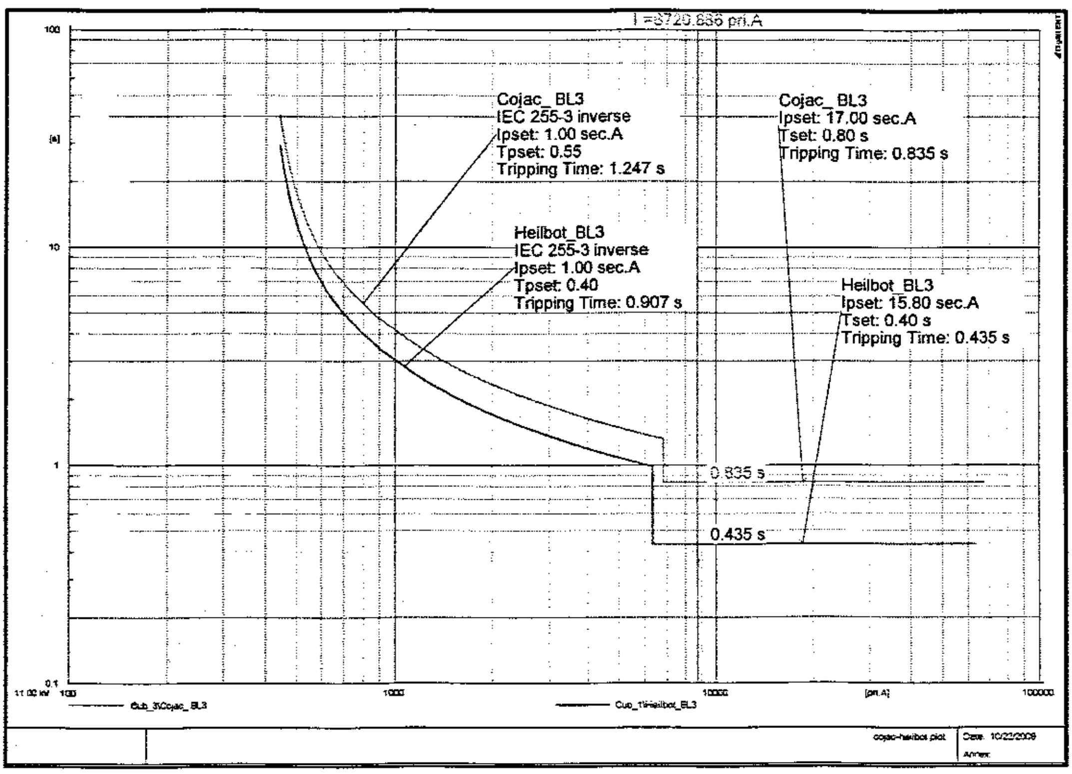


Figure 5.55: *Co-ordinated protection response for the fault on the BL3 feeder*

The main protection devices are grouped in cubicle 3 as shown in Figure 5.53. The main protection for the fault on BL3 has issued a definite tripping time of 0.435 sec and an inverse tripping time of 0.907 sec. The upstream relay has seen the fault but will not trip unless the main protection fails, then the tripping will occur as graded in sequence. This is illustrated in Figure 5.54 and 5.55 respectively.

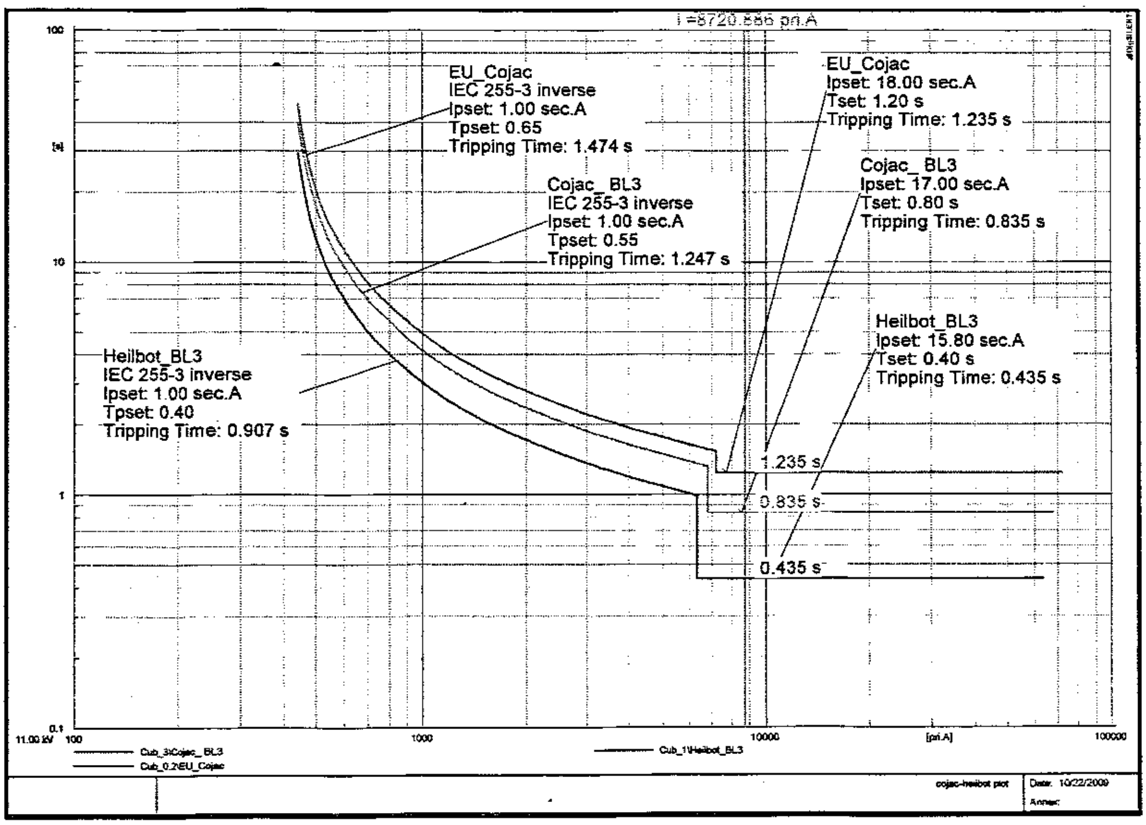


Figure 5.56: *Co-ordinated protection response for the fault on the BL3 feeder*

With a fault current of 8.721kA as recorded in Figure 5.52 above and a fault current 14.217kA, Figure 5.56 indicates the response characteristics of the co-ordinated protection devices. For the Instantaneous over-current (*Ioc*) response the sequence tripping time of 0.435, 0.835 and 1.235 sec from the nearest to the furthest up-stream protection devices is recorded. In the case of time overcurrent response (*Toc*) the sequence tripping time recorded is 0.907, 1.247, 1.474 sec. Correct co-ordination is achieved as no upstream IED's will trip before the down-stream devices.

5.4.2 Cojac-Bishop Lavis3 Busbar and feeder protection settings and characteristics

Figure 5.57 indicates that the fault has been shifted one step behind and it is now situated between Cojac and BL3 substation. The setting of the nearest protection device is indicated in Table 5.11 below. The list of cubicle 3 components that are responsible for the main protection of Cojac-BL3 feeder is shown in Figure 5.58.

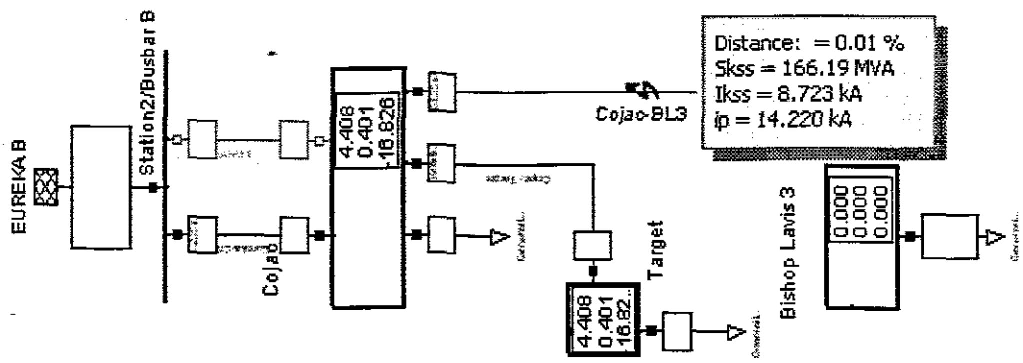


Figure 5.57: Fault between Cojac and BL3

Table 5.11: Main protection IED settings (cojac-BL3)

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.1	
Time Dial	0.55		0.11	
Pick-up Current		17.0		0.1
Time Setting		0.8		0.0

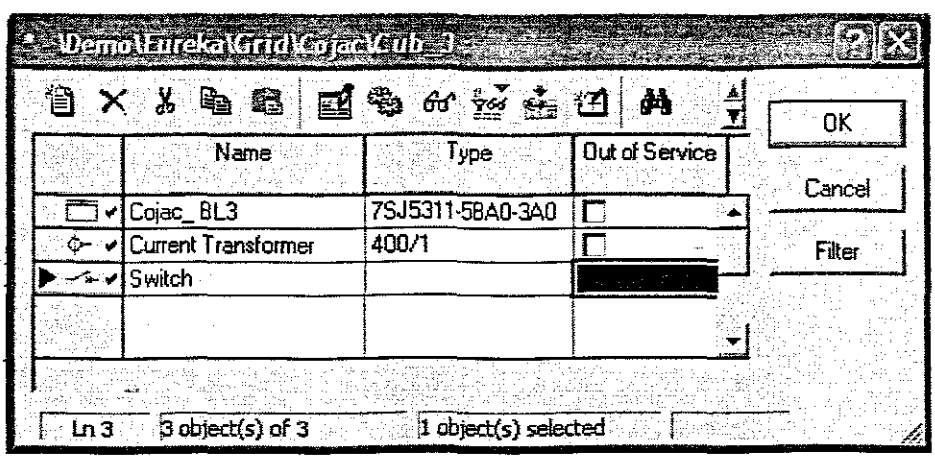


Figure 5.58: Protection devices on the Cojac cubicle

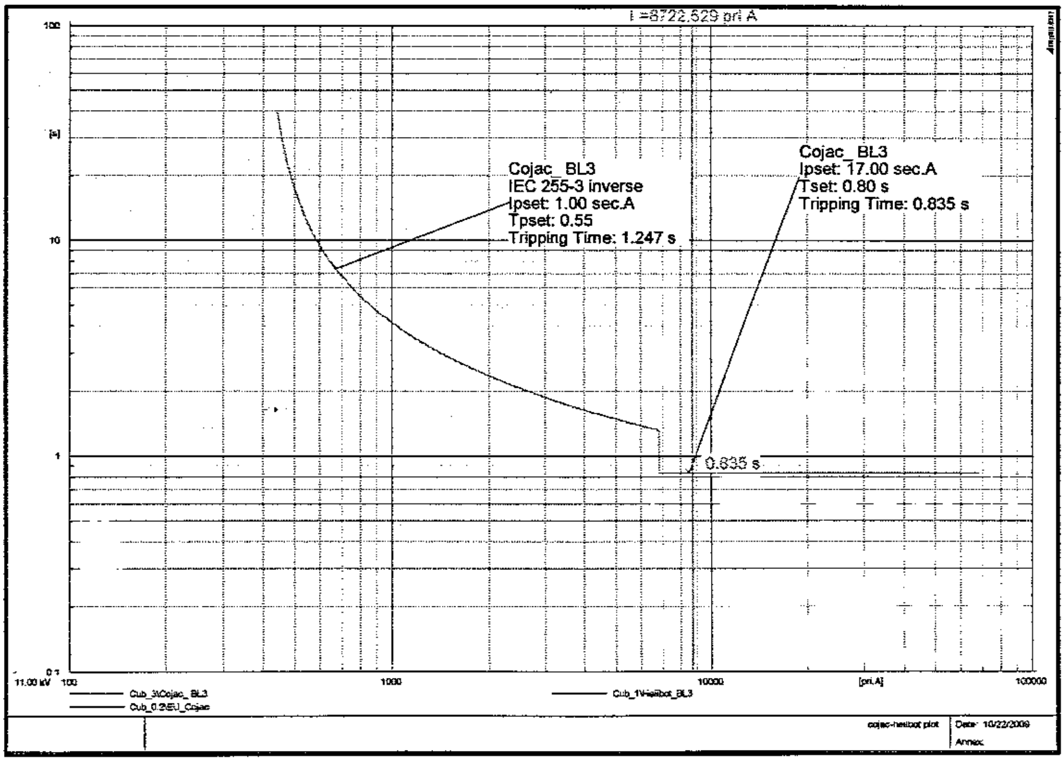


Figure 5.59: *Main protection response for the fault on the Cojac-BL3 feeder*

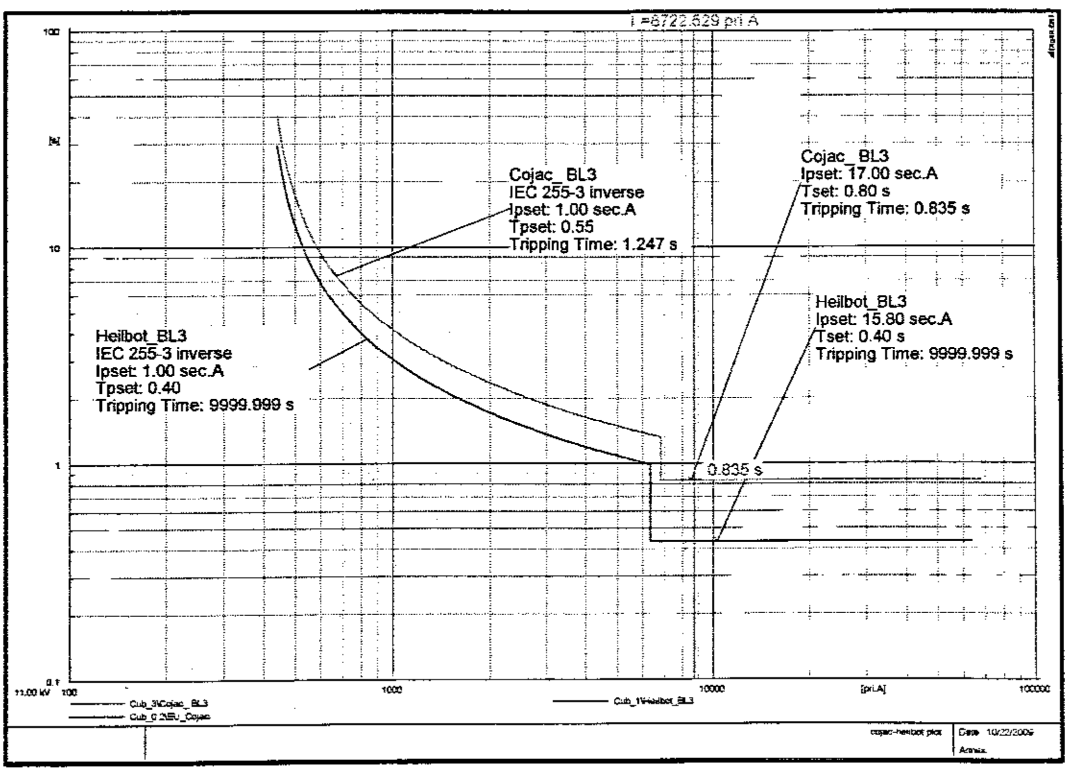


Figure 5.60: *Co-ordinated protection response for the fault on the BL3 feeder*

The protection response to the fault in Figure 5.57 is shown in Figure 5.59.This fault is on the feeder between the Cojac and Bishop Lavis 3 substation and the response is from the relay that is closer to the fault. For the initial short circuit of 8.723kA and a maximum fault level of 166.19 MVA, the relay has responded with the instantaneous tripping of 0.835 sec and the inverse definite minimum time (IDMT) response of 0.247 sec. Figure 5.60 illustrate a co-ordinated protection response and a response characteristic with a tripping time of 9999.999 sec is observed. For this characteristic, the relay is downstream with reference to the fault.

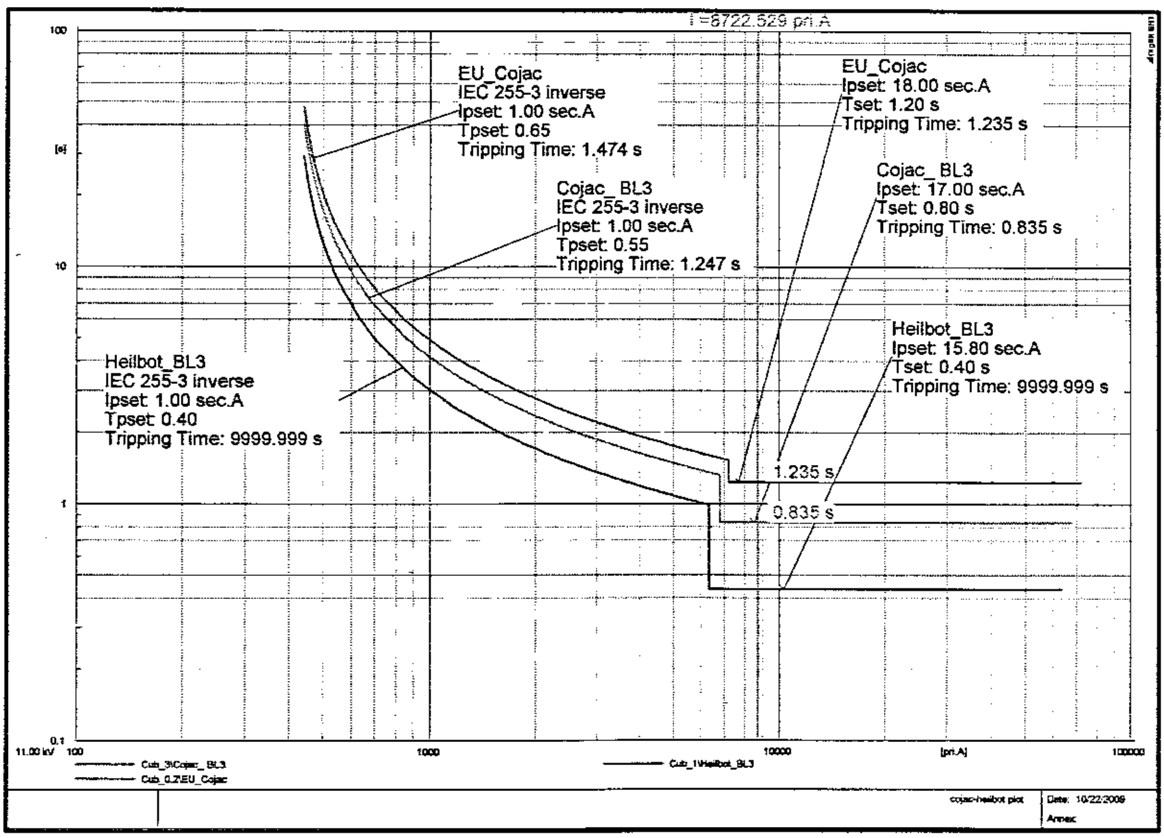


Figure 5.61: Co-ordinated protection response for the fault between Cojac and BL3

In Figure 5.61 above, it can be seen that the protection devices downstream with reference to the fault location did not see the fault and an indication of 9999.999 sec is recorded from the first response characteristic. The definite time characteristic responses are at 0.835 and 1.235 sec, followed by the inverse definite time characteristics with a tripping time of 1.247 and 1.474 sec. This is an indication that there is adequate additional time in between the IED's that is preventing the false or unwanted tripping.

5.4.3 Eureka-Cojac busbar and feeder protection settings and characteristics

Figure 5.62 indicates that the fault has been shifted one step behind again and it is now situated between Eureka and Cojac substation. The setting of the main protection device is indicated in Table 5.12 below. The components that are responsible for the main protection of Eureka-Cojac feeder are grouped in cubicle 0.2 as shown in Figure 5.63.

Table 5.12: *Protection IED settings (Eureka-Cojac)*

	Toc>	Ioc>	Toce>	Ioce>
Current Setting	1.0		0.1	
Time Dial	0.65		0.05	
Pick-up Current		18.0		0.1
Time Setting		1.2		0.0

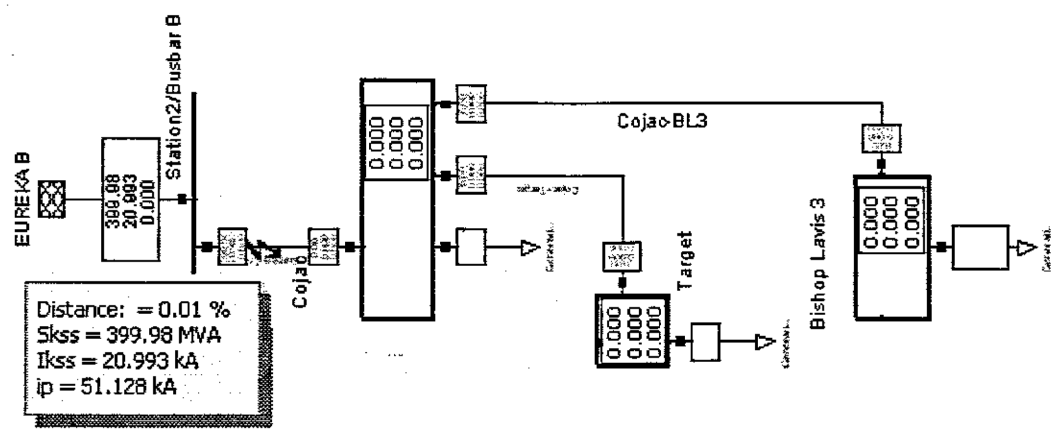


Figure 5.62: *Fault between Eureka and Cojac*

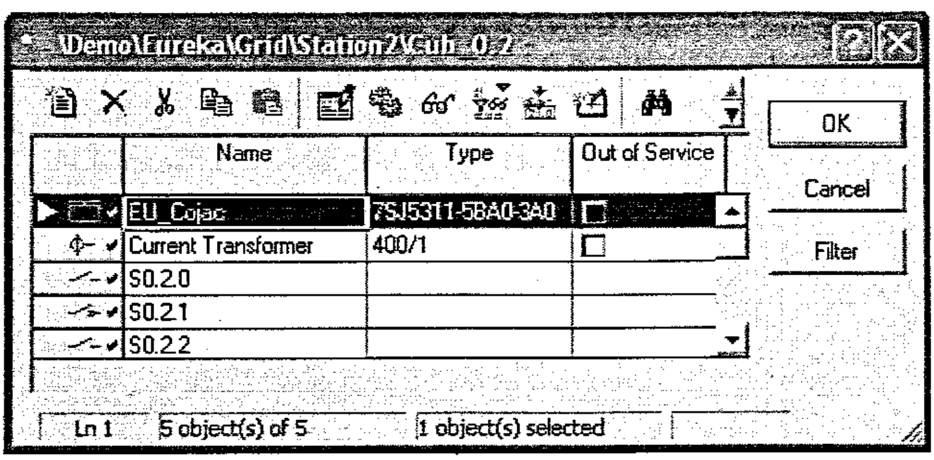


Figure 5.63: *Protection devices on the Eureka cubicle*

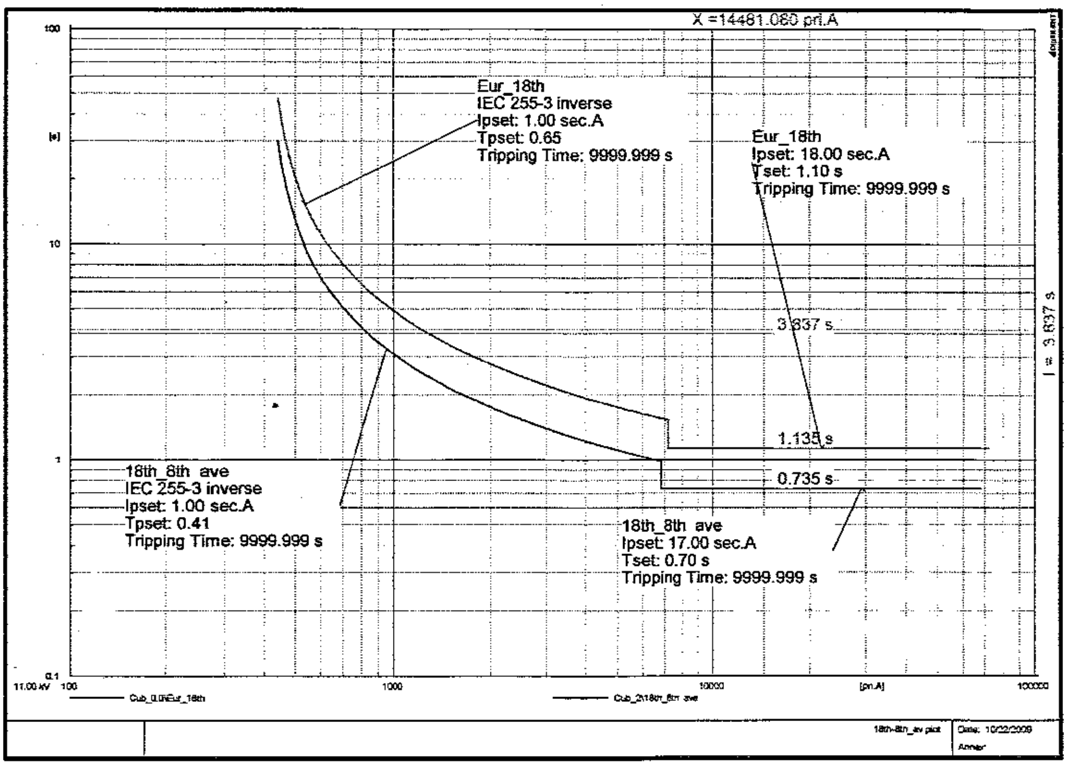


Figure 5.64: Co-ordinated protection response for the fault on the 18th & 8th feeder

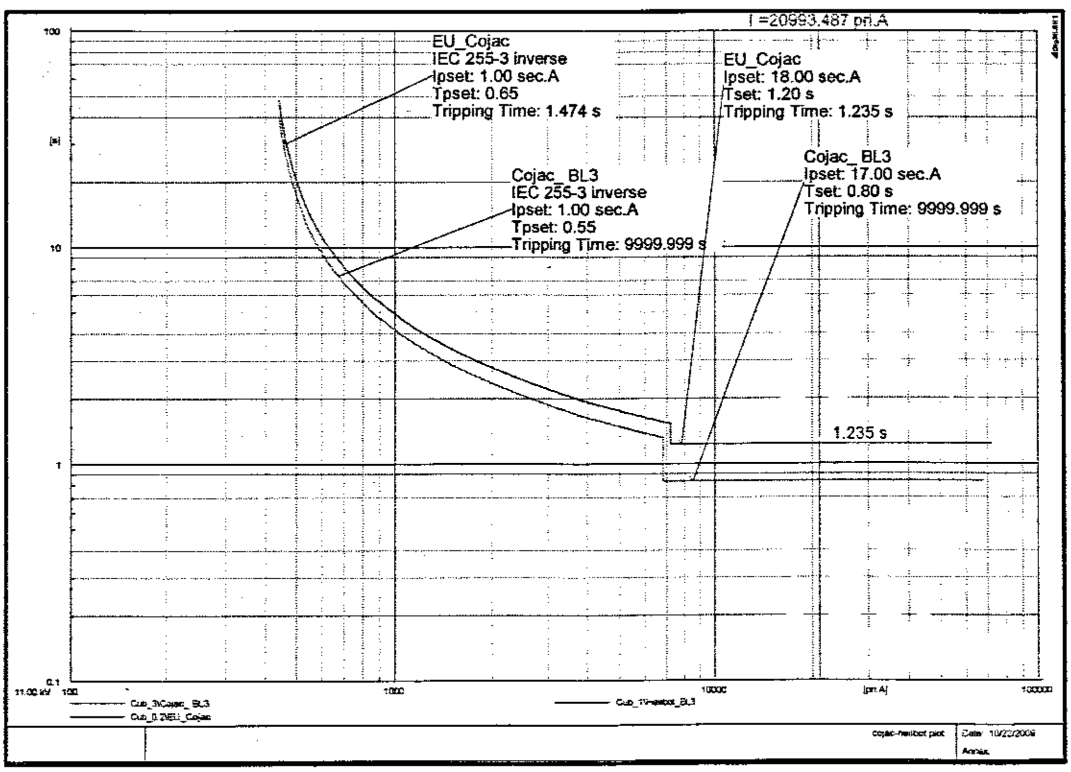


Figure 5.65: Co-ordinated protection response for the fault on the Eureka - Cojac feeder

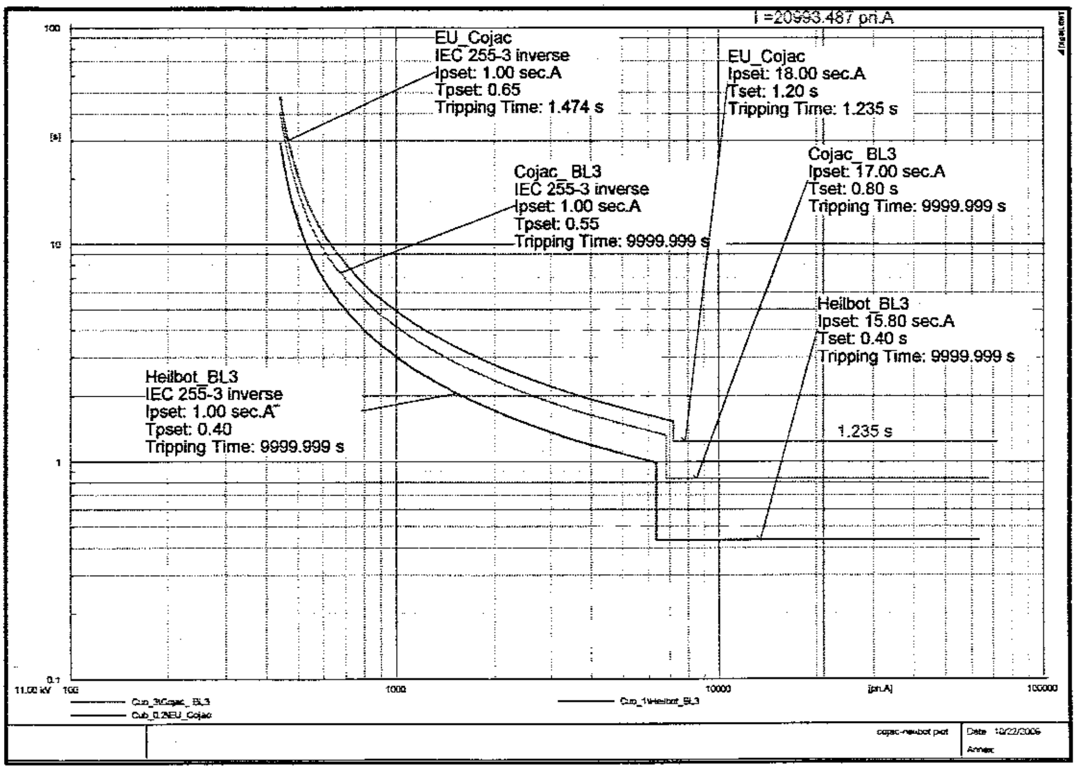


Figure 5.66: *Co-ordinated response for the fault between Eureka and Cojac*

Figure 5.64 illustrates that if two feeders are supplied by the same busbar and one feeder experiences a fault, then that does not necessarily mean that the protection of the adjacent feeder must pick-up the fault. Therefore the response of the 18th avenue feeder's protection devices indicated a tripping time of 9999.999 sec for the fault on the Eureka- Cojac feeder. With the fault between Eureka and Cojac as indicated in Figure 5.62, the downstream protection did not respond to the fault except for the immediate upstream relay that has cleared the fault in 1.235 sec as shown in Figure 5.65 and 5.66 above.

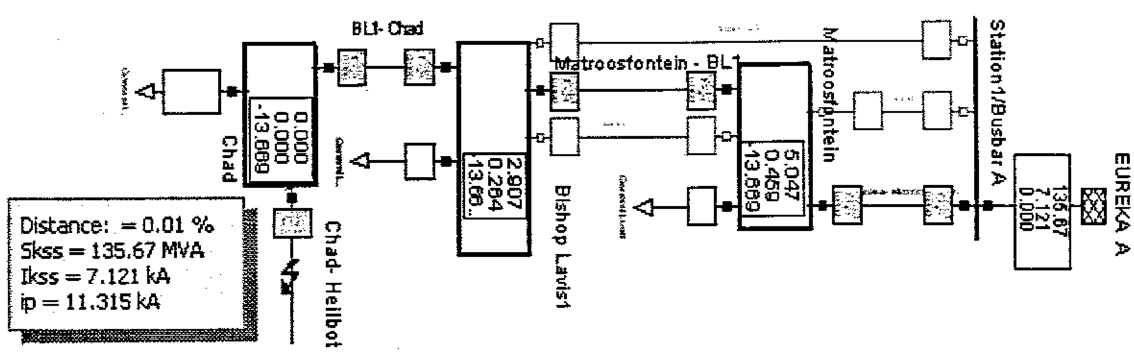


Figure 5.67: *Fault between Chad and Heilbot*

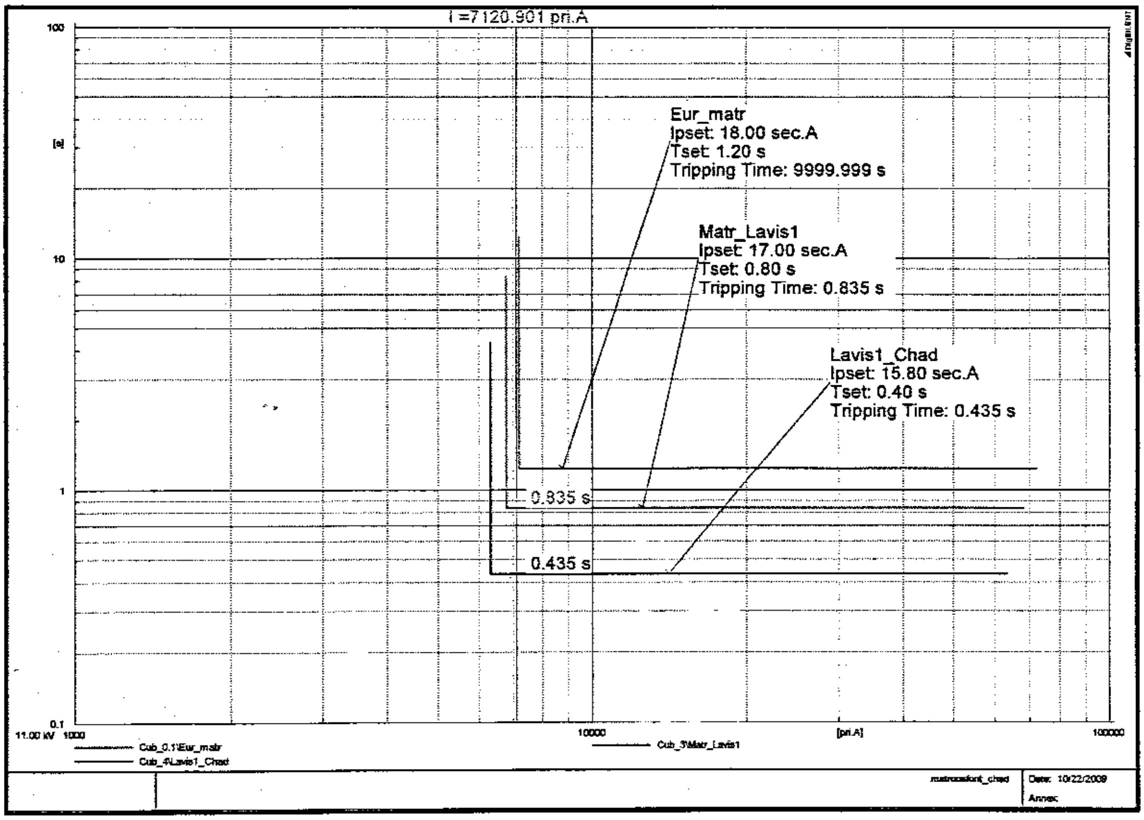


Figure 5.68: Co-ordinated protection response for the fault on the Chad - Heilbot feeder

The fault between Chad and Heilbot is shown in Figure 5.67. A maximum fault level of 135.67MVA, a short circuit current of 7.121kA and a peak current of 11.315kA are recorded during the fault. The co-ordinated protection response for this particular fault is shown in Figure 5.68. The definite tripping time is shown and a grading margin of 4sec is used. Two relays have picked-up the fault at different intervals. Although this two relays have seen the fault, only one relay will trip. A tripping time of 0.435 sec is issued by the first relay.

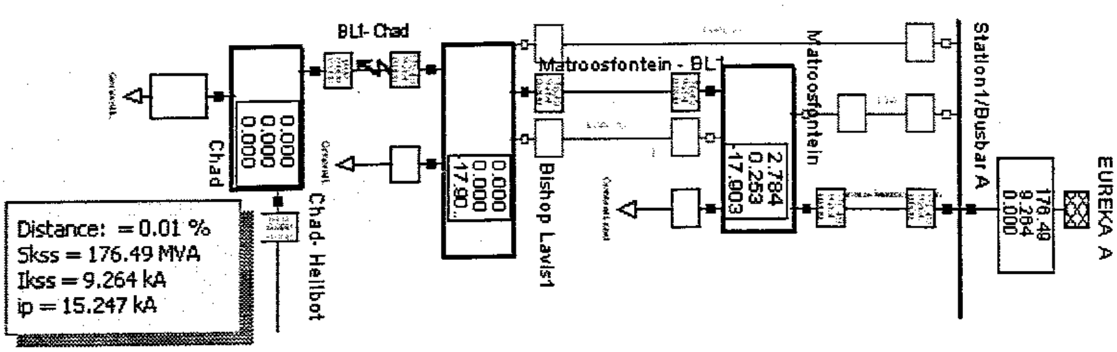


Figure 5.69: The fault on the BL3 feeder

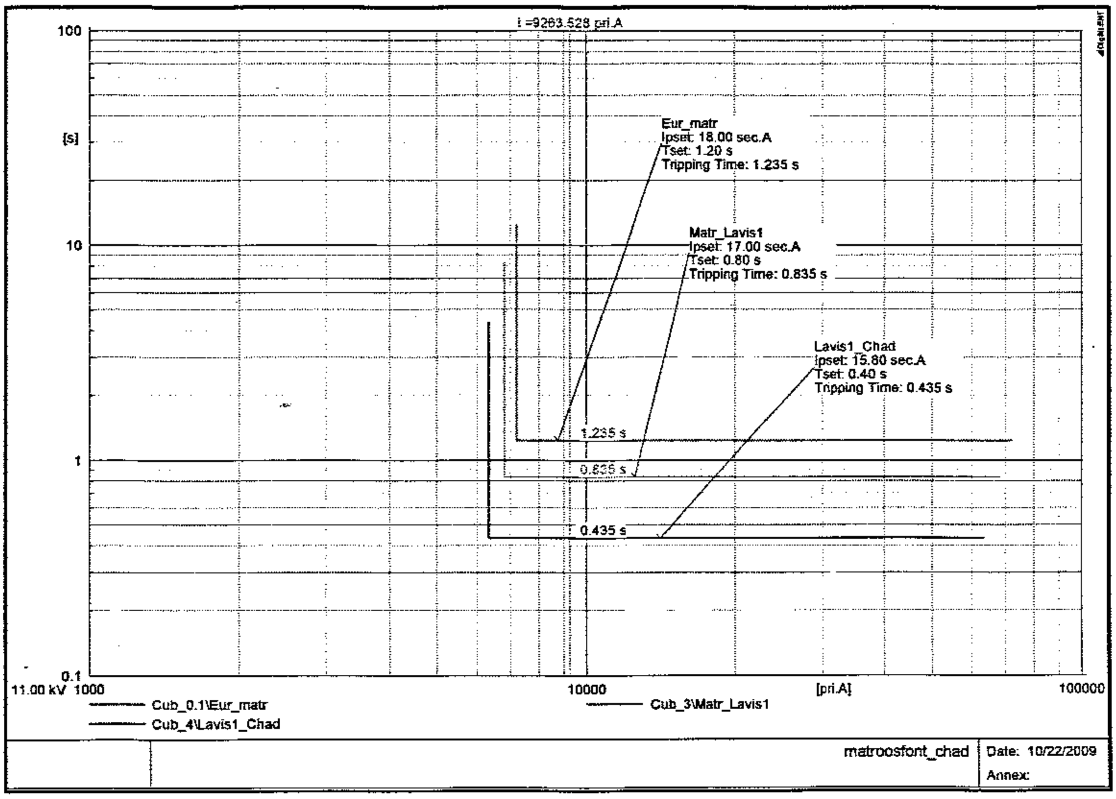


Figure 5.70: Co-ordinated protection response for the fault on the BL1- Chad feeder

The fault between BL1 and Chad is shown in Figure 5.69. A maximum fault level of 176.49MVA, a short circuit current of 9.264kA and a peak current of 15.247kA are recorded at the time of the fault. The co-ordinated protection response for this particular fault is shown in Figure 5.70. The definite tripping time is shown and a grading margin of 4sec is used. Three relays have picked-up the fault at different intervals (0.435, 0.835 and 1.235 sec). Although this three relays have seen the fault, only one relay will trip. A tripping time of 0.435 sec is issued by the first relay.

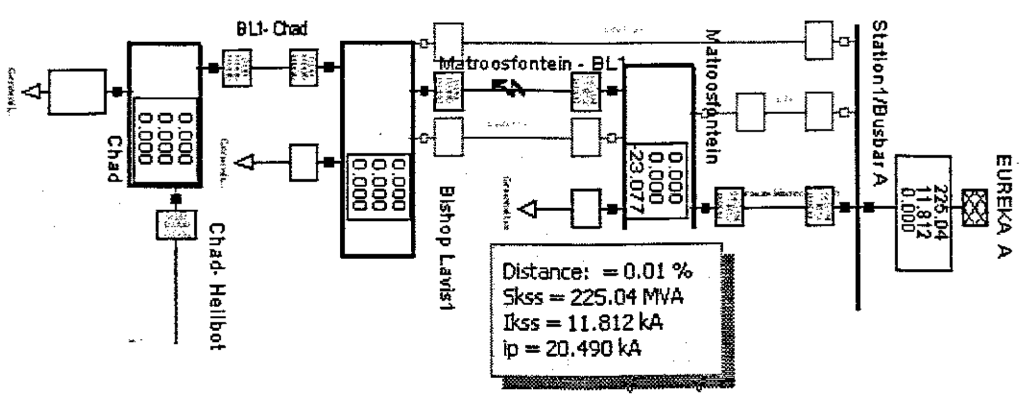


Figure 5.71: The fault on the Matroosfontein - BL1 feeder

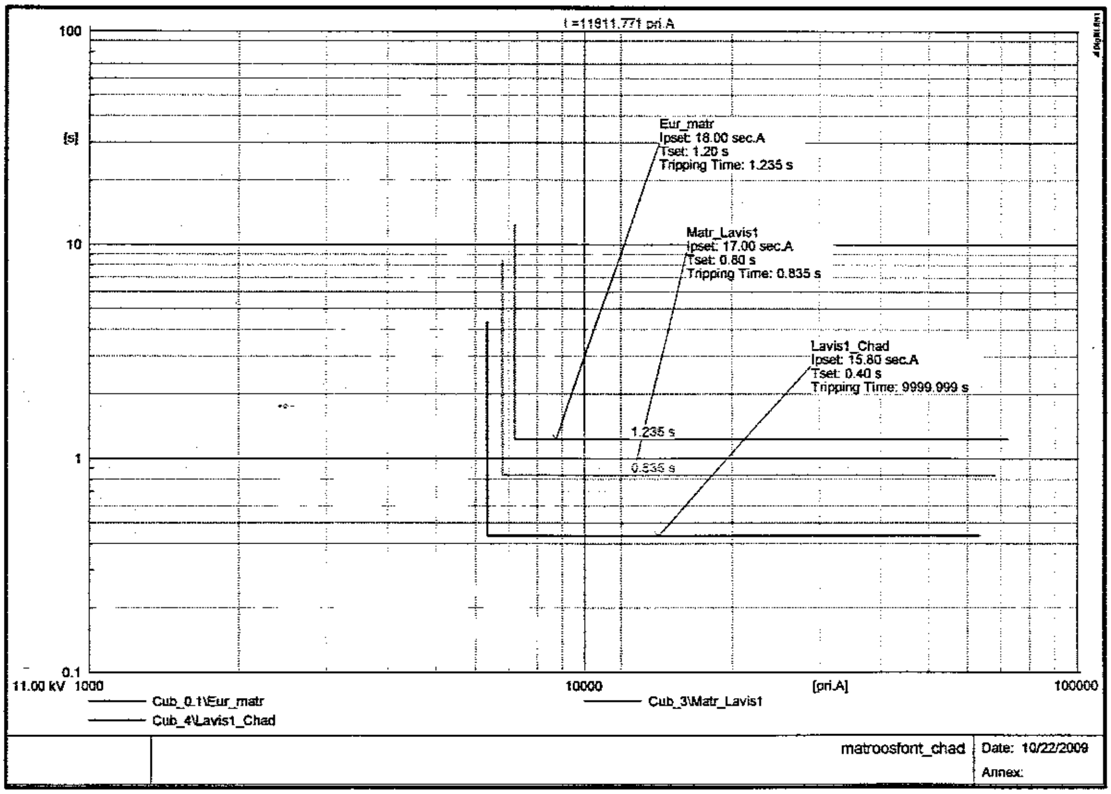


Figure 5.72: The fault on the Matroosfontein - BL1 feeder

When the fault is between Matroosfontein and BL1 feeder as shown in Figure 5.71, a maximum fault level of 225.04MVA, a short circuit current of 11.812kA and a peak current of 20.490kA are recorded during the fault. The co-ordinated protection response for this particular fault is shown in Figure 5.72. As the fault has shifted backward, the relay downstream the fault did not see the fault. Hence, two relays have picked-up the fault at different intervals (9999.999, 0.835 and 1.235 sec). Although this two relays have seen the fault, only one relay should trip.

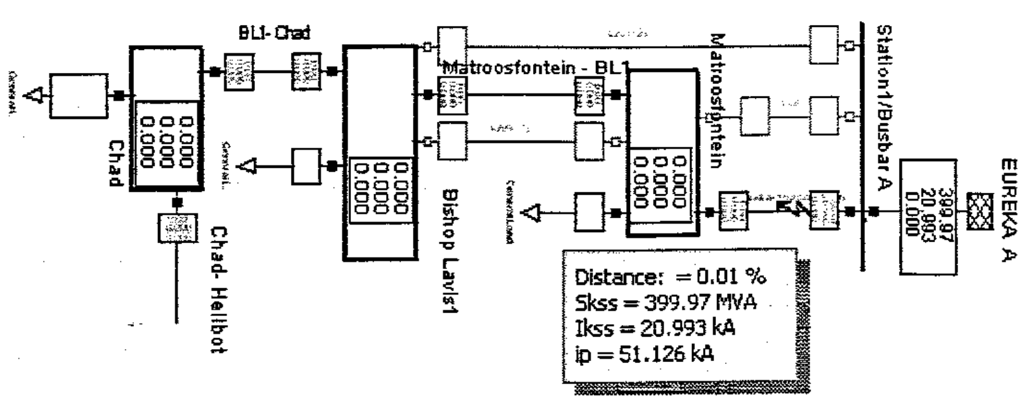


Figure 5.73: The fault on the Eureka - Matroosfontein feeder

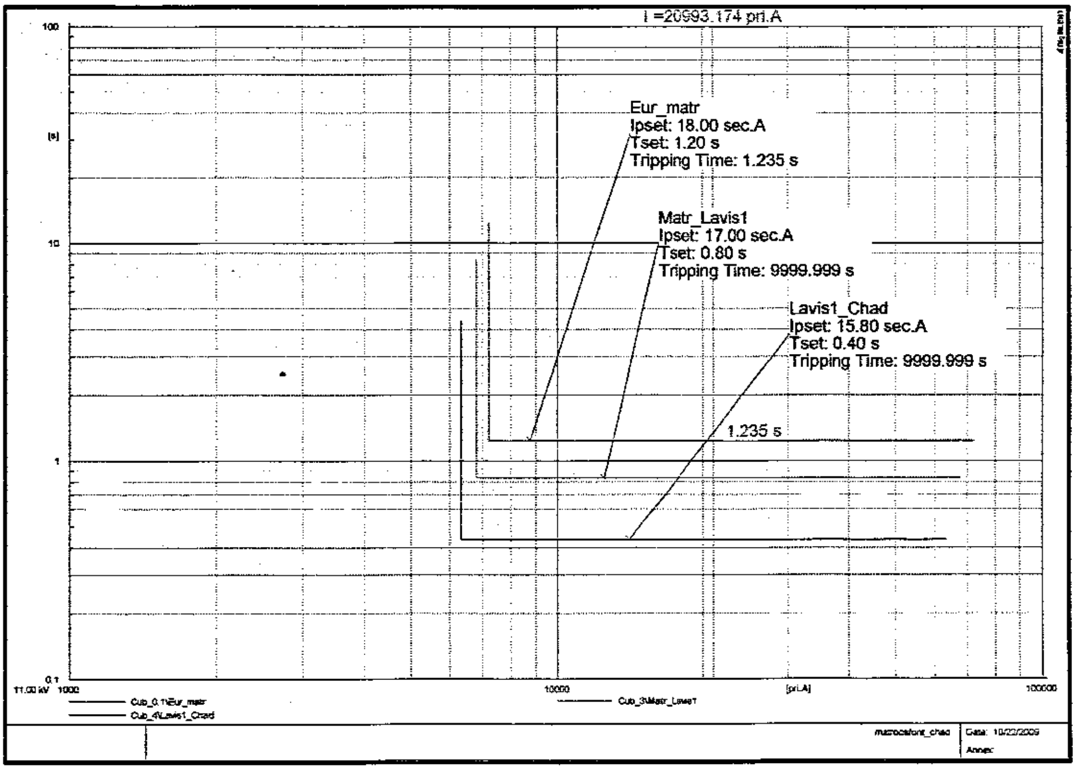


Figure 5.74: Co-ordinated protection response for the fault on the Eureka - Matroosfontein feeder

A maximum fault level of 399.97MVA, a short circuit current of 20.993kA and a peak current of 51.126kA are recorded when the fault is between Eureka and Matroosfontein feeder as shown in Figure 5.73. The co-ordinated protection response for this particular fault is shown in Figure 5.74. The definite time characteristic is shown and a grading margin of 4sec is used. Two relays did not pick-up the fault as they are ahead of it. A tripping time of 1.235 sec is issued by the relay that is looking into the fault.

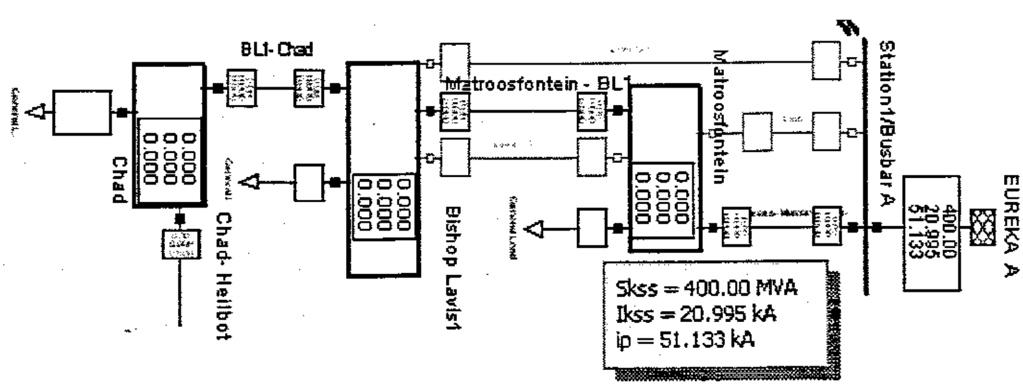


Figure 5.75: The fault on the Eureka busbar

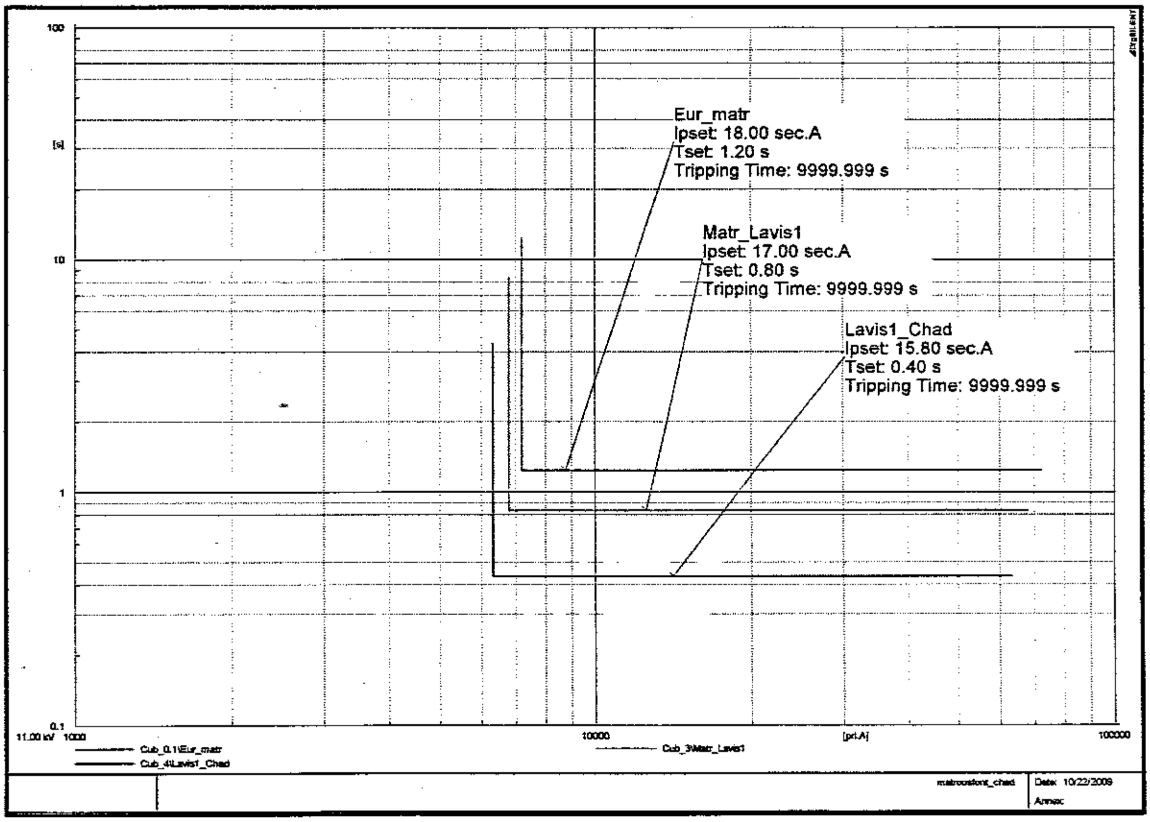


Figure 5.76: Co-ordinated protection response for the fault on the Eureka busbar

If the fault is on the Eureka busbar and the protection responsible for the busbar is taken out of service, there will be no protection and all the protection ahead of the fault will give a tripping time of 9999.999sec.This is illustrated in Figure 5.75 and 5.76 respectively.

5.5 MODELING OF THE PARALLEL TRANSFORMER FEEDER

A common design criterion for parallel transformer feeders is that, the system maximum load must be able to be carried by one feeder while the other feeder is out of service. If both feeders are in service and the above condition holds with no allowance for short-time overload capability, then the maximum pre-fault load current for individual feeder will be 50% of rated current. This indicates that the directional protection settings should be above 44% of rated current in order to offer a reliable security for the two parallel feeders. Directional overcurrent IED's are commonly used at the receiving ends of the parallel feeders or transformer feeders. The main purpose of the directional over-current protection (DOC) is to ensure full discrimination of the main or back-up over-current protection of a power system for faults near the receiving end of a feeder. Lower current settings can also be adopted with the application of modern IED's in relation to reverse load current at the receiving ends of the parallel feeders **(Hindle, Wright & Lloyd, 2001:1-2)**.

5.5.1 Overcurrent grading of the transformer feeder

The following calculations are done as per ALSTOM protection and control 2006 training manual **(ALSTOM Mini APPS course Manual, 2006)**.

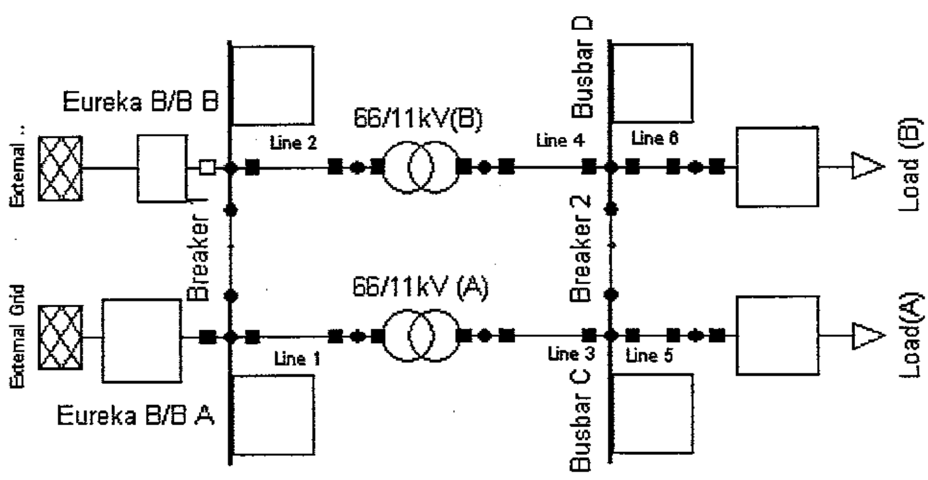


Figure 5.77: *Parallel transformer feeder*

Transformer information:

66/11kV,

40MVA,

10% impedance,

YnYn configuration

Task1: Fault level calculation

$$S_{maxLV} = \frac{S_{rated}}{Z_1} = \frac{40MVA}{0.1} = 400MVA$$

<u>HV fault current</u>

At 66kV the maximum fault current can be calculated as follows:

$$I_{faultHV} = \frac{400 \times 10^6}{(\sqrt{3} \times 66 \times 10^3)} = 3.5kA$$

LV fault current

The low-voltage side line current is:

$$I_{faultLV} = \frac{400 \times 10^6}{(\sqrt{3} \times 11 \times 10^3)} = 20.995kA$$

$$Z_{source} = \frac{66^2}{400} = 10.89\Omega$$

Applying a base MVA of 40MVA

$$Z_{base} = \frac{66^2}{40} = 108.9\Omega$$

Hence on a per unit basis

$$Z_{source} = \frac{10.89}{108.9} = 0.1pu$$

Calculation of maximum fault on the LV side is carried out as follows:

$$I_{fault\ LV} = \frac{1}{(Z_{source} + Z_{trfr})} = \frac{1}{(0.1 + 0.1)} = 5pu$$

At 66 kV the base current can be calculated:

$$I_{base\ 66kV} = \frac{40MVA}{(\sqrt{3} \times 66 \times 10^3)} = 350A$$

Therefore, the actual fault current;

$I_{fault\ LV} = 5 \times 350 = 1750A$ at 66kV

At 11 kV the base current can be obtained as follows:

$$I_{base\ 11\ kV} = \frac{40MVA}{(\sqrt{3} \times 11 \times 10^3)} = 2099A$$

Hence the actual fault current;

$$I_{fault\ LV} = 5 \times 2099 = 10497A$$

Task 2: LV relay setting

Relay pick-up current settings (I_s)

The transformer full load current is calculated as follows:

$$I_{full\ load} = \frac{40MVA}{(\sqrt{3} \times 11 \times 10^3)} = 2099A$$

Allowing a 10% overload and taking into account the fact that the relays reset at 95% of setting.

$$I_s = \frac{2099 \times 1.10}{0.95} = 2430A$$

In terms of CT ratio this is 2430/2000 = 1.215

Therefore select $I_s = 1.0 \;=>\; 2000A\, primary$

<u>Tripping characteristic selection</u>

Select a standard inverse characteristic

<u>Time multiplier settings</u>

Assume an operating time of 0.5sec at maximum fault current and calculate the operating time at the maximum fault level with a time multiplier setting (TMS =1) equals to one, using a formula *for the standard inverse characteristic.*

$$t = \frac{0.14 \times TMS}{\left[\frac{fault\ current}{set\ current}\right]^{0.02} - 1}$$

$$= \frac{0.14}{\left[\frac{10497}{2000}\right]^{0.02} - 1}$$

$$= 4.152sec$$

However, the operating time required is 0.5sec, and therefore;

$$Required\ TMS = \frac{Required\ operating\ time}{Operating\ time\ for\ TMS = 1}$$

$$= \frac{0.5}{4.152} = 0.12$$

Hence the operating time at 10497A will therefore be:

$t = 4.152 \times 0.12 = 0.5sec$

Task 3: HV relay settings

<u>Relay pick-up current settings (I_s)</u>

To ensure proper co-ordination, the pick –up current of the HV side relays must be set above that of the LV side relays.

The LV relay is set at $2000A => 405A$ at 66kV

Now set the HV relay 10% above the LV relay and this yield the following:

$I_s = 405 \times 1.1 = 446A$

In terms of CT ratio: $446/600 = 0.74$

Therefore:

$I_s = 0.7 \times 600 => 40primary$

Tripping characteristic selection

Select the standard inverse characteristic to grade with relation to LV relay.

Time multiplier settings

Calculate the relay operating time at a maximum LV fault current of 1750A with reference to HV side and a time multiplier of 1

$$t = \frac{0.14 \times TMS}{\left(\frac{I_{fault}}{I_{set}}\right)^{0.02} - 1}$$

$$= \frac{0.14}{\left(\frac{1750}{446}\right)^{0.02} - 1}$$

$$= 5.05sec$$

Remember to take a grading margin of 0.4 sec into account and then calculate the operating time of the LV fault level, thus;

$$0.866 \times 10497 = 9090A$$

Therefore

$$t = \frac{0.14 \times 0.12}{\left(\frac{9090}{2000}\right)^{0.02} - 1}$$

$$= 0.546sec$$

Therefore for the HV relays subjected to a fault current of 1750A, an operating time of at least 0.946 sec is required.

$$Required\ operating\ time = 0.546 + 0.4 = 0.946sec$$

Hence for the required TMS;

$$TMS = \frac{0.946}{5.05} = 0.187$$

Therefore select $TMS = 0.19$

With $TMS = 0.19$, the operating time can be achieved as follows:

$$Operating\ time = 0.19 \times 5.05 = 0.959sec$$

Hi set instantaneous element settings

For fast clearing times of faults on the transformer HV bushings and part of the way into the transformer, the Hi set can be set at 120% up to 130% of the maximum LV fault level in multiples of the IDMT setting current.

$$Hi\,set = \frac{120\% \times 1750}{446} = 4.7times$$

Therefore select a Hi set ofx 5 => $2230A$, (446x5)

Note: The Toc (current setting and time dial), and the Ioc (pick-up current and time setting) can be manipulated at any point in time using the tripping characteristic. This is more useful, when performing relays co-ordination. The co-ordination of directional and non-directional time-overcurrent protection is illustrated from Figure 5.78 up to Figure 5.96. When the fault is located on line 5 as illustrated in Figure 5.78, a maximum short circuit power of 193.46MVA with a short circuit current of 10.154kA and a peak current of 23.253kA is recorded. The main protection (relay 5(51)) responded with a tripping time of 0.212 sec to clear the fault as illustrated in Figure 5.79. The rest of the relays upstream with reference to the fault have picked-up the fault but did not trip. The relays at the receiving end of the transformer feeder (relay3 (51) & 3(67)) have different characteristics in the sense that, relay 3 (51) is non directional and relay 3 (67) is directional. Their settings and co-ordinated tripping characteristics are shown in Figure 5.80.

Figure 5.81 shows the combination of co-ordinated response characteristics for the fault as indicated in Figure 5.78 above. Relay 5 (51) responded with a tripping time of 0.212 sec to discriminate the fault. Relay 3 and 4 (51) recorded a tripping time of 0.968 sec while 1 and 2 (51) are trailing at 1.886 sec. A tripping time of 9999.999 sec is recorded on the relays that did not pick-up the fault. Should relay 3 (51) be used to open breaker 2, then the settings for relay 4 (51) should be changed.

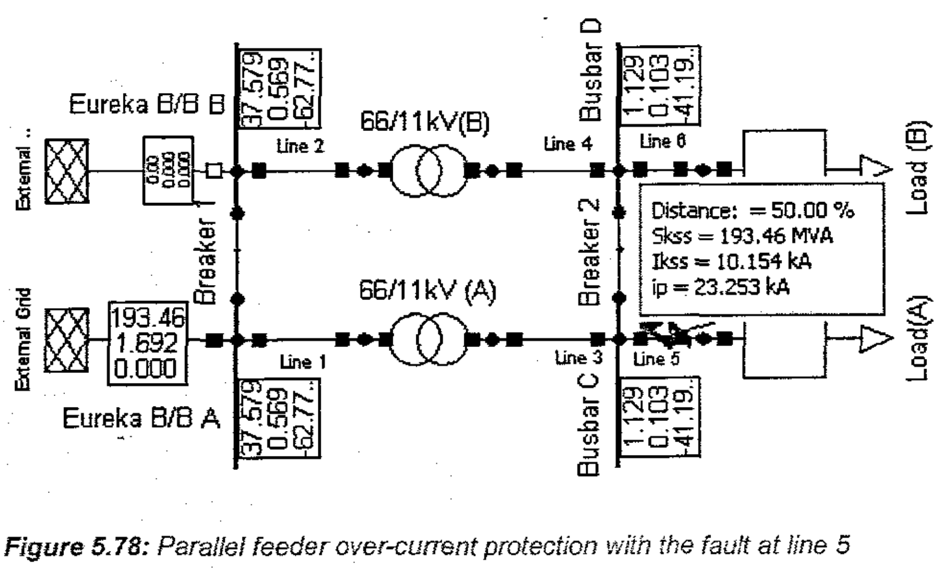


Figure 5.78: Parallel feeder over-current protection with the fault at line 5

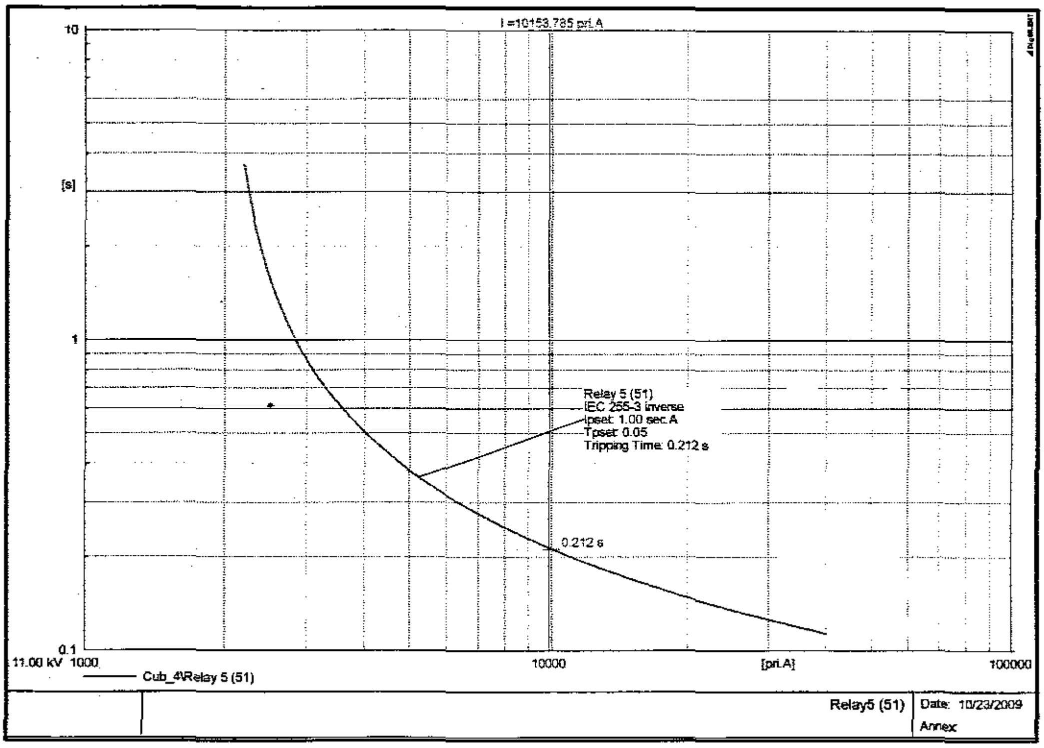


Figure 5.79: Main protection response for the fault on line 5

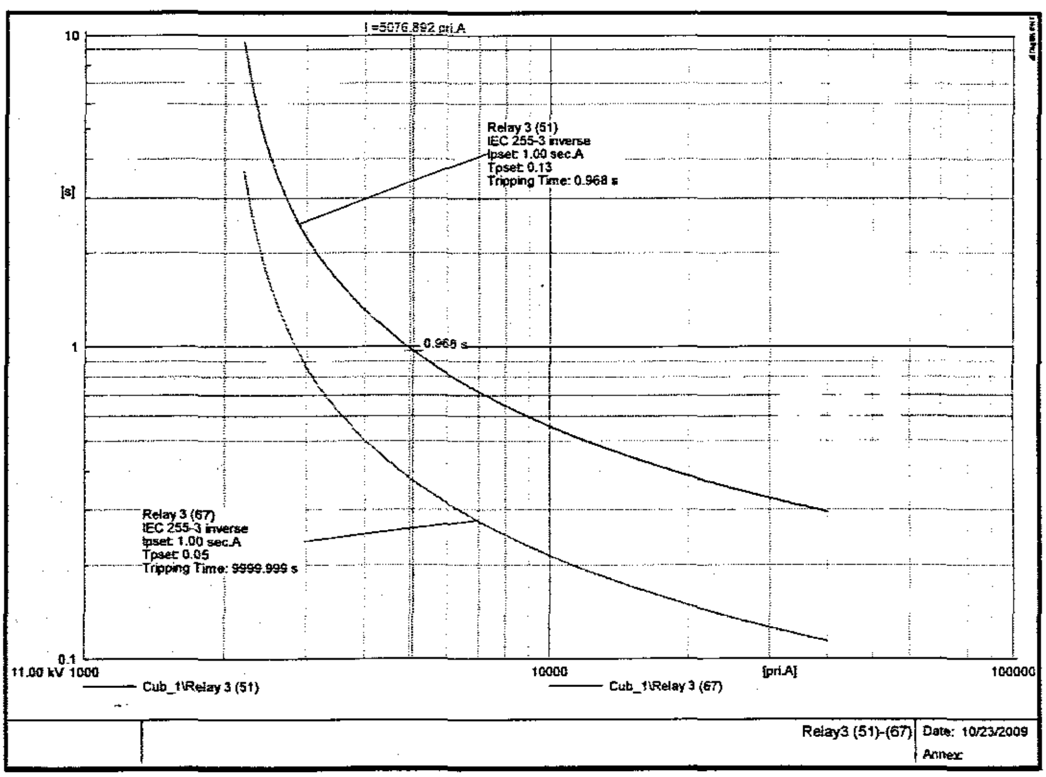


Figure 5.80: Co-ordinated protection response for the fault on line 5

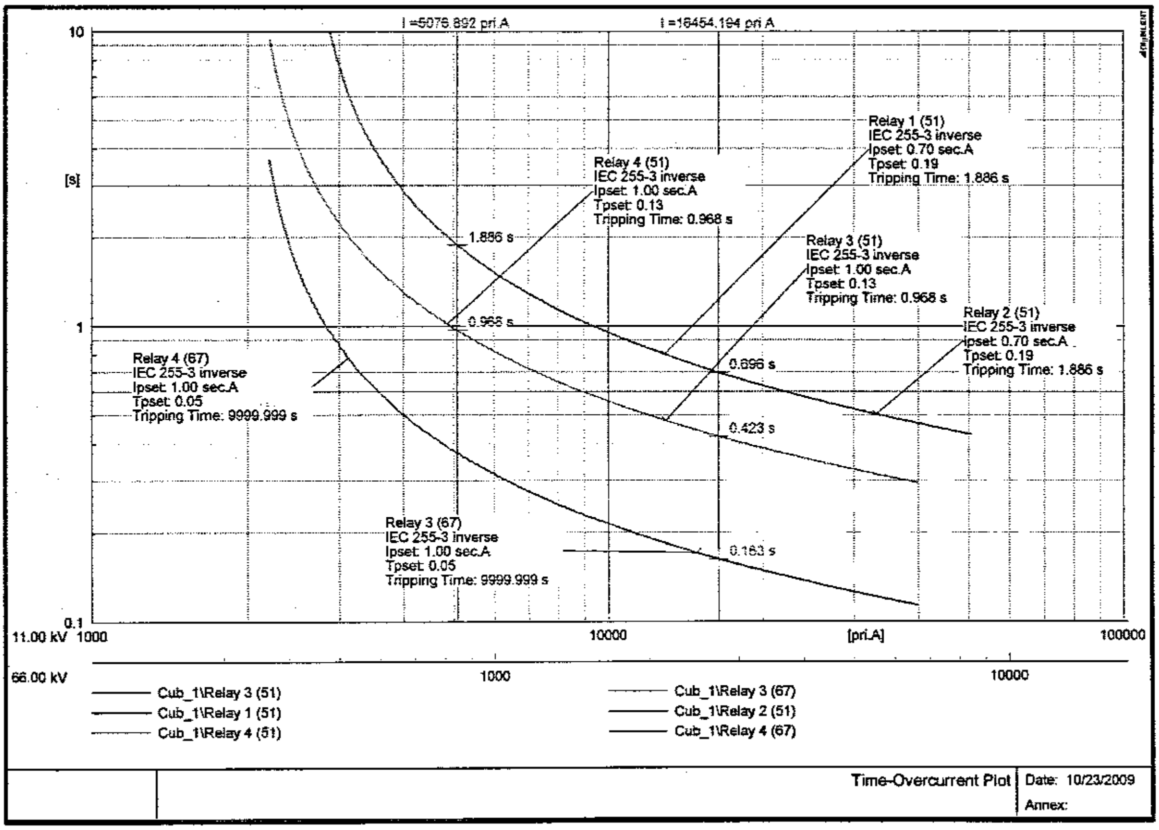


Figure 5.81: *Co-ordination of the time-overcurrent protection for fault on line 5*

Directional phase overcurrent relays are applied at the receiving end of the transformers' feeder (end of line 3 & 4). The purpose is to ensure full discrimination of main and back-up power system overcurrent protection for a fault close to the receiving end of one feeder. When the fault is located on line 3 as illustrated in Figure 5.82, the constraint imposed on the system includes a maximum short circuit power of 207.66MVA with a short circuit current of 10.900kA and a peak current of 27.095kA as recorded.

It is noticed that when the fault was on line 5, some of the relays at the receiving end of transformer A did not pick-up the fault. This is due to the fact that the relays at the receiving end of the transformer feeder (relay3 (51) & 3(67)) have different characteristics in the sense that, relay 3 (51) is non directional and relay 3 (67) is directional (looking in the direction of the transformer secondary). To ensure proper co-ordination of the time over-current protection for the fault condition as illustrated in Figure 5.83 and 5.84, the directional *Toc* relay 3 (67) has tripped in 0.361 sec. Relay 3 (67) is set to trip before any other non directional relays operate, that are on a healthy feeder.

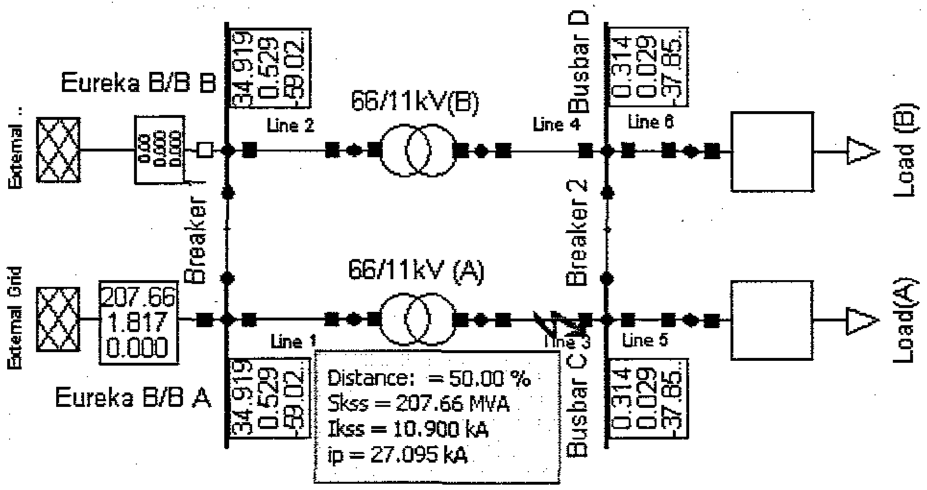


Figure 5.82: Parallel feeder over-current protection with the fault on line 3

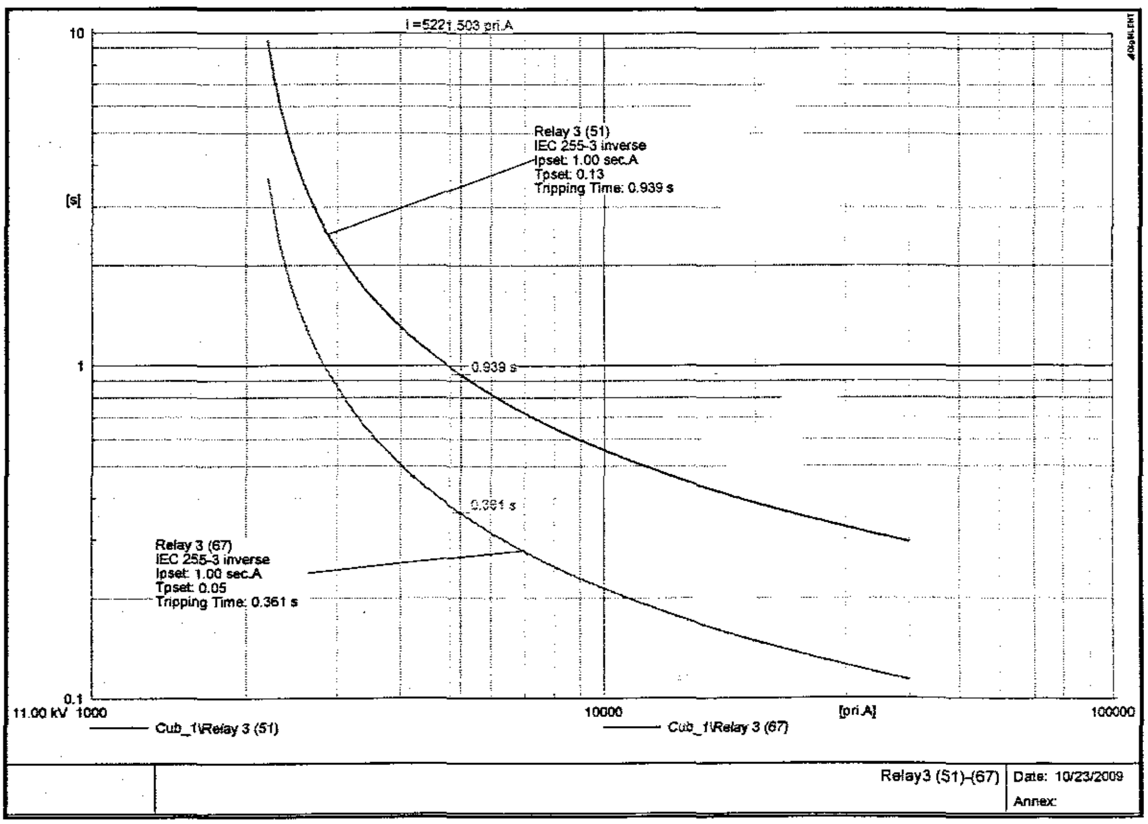


Figure 5.83: Co-ordinated protection response for the fault on line 3

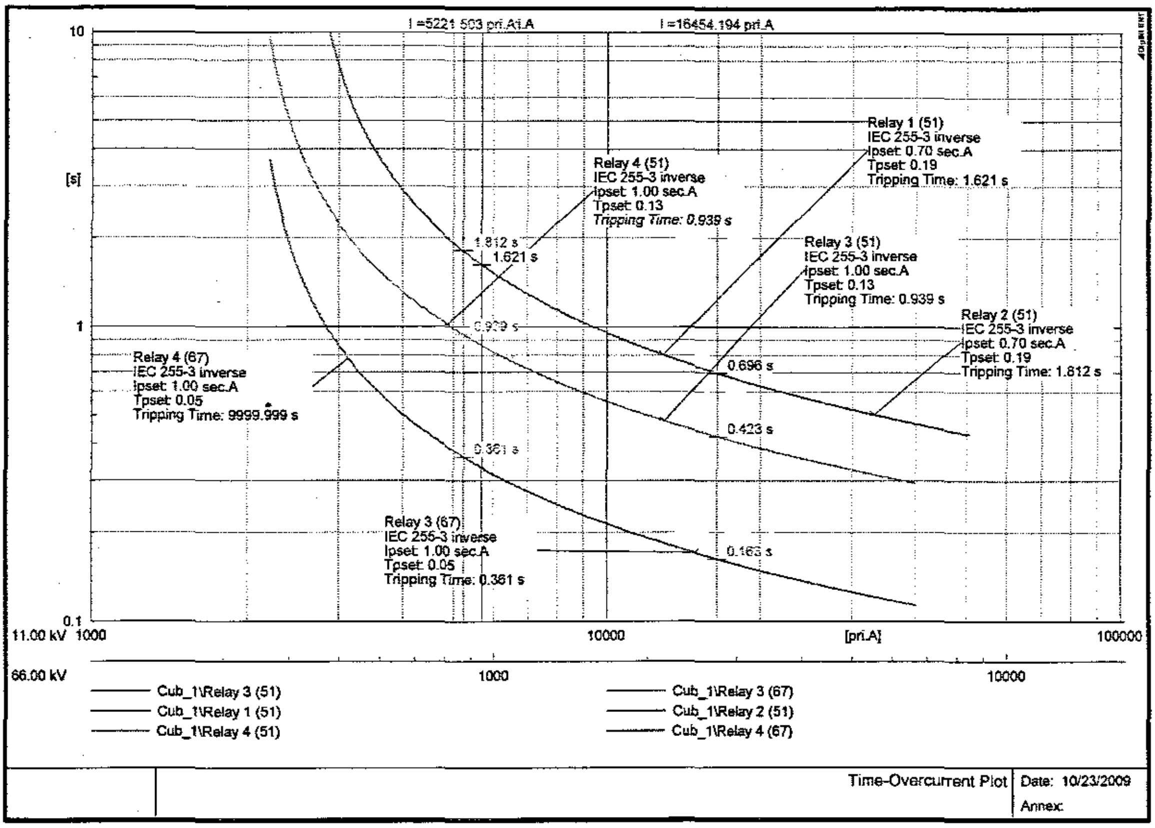


Figure 5.84: *Co-ordination of the time-overcurrent protection for fault on line 3*

As the fault shifts, the fault parameters change too. Therefore, each fault has its own unique parameters of which the relays handle differently. When the fault is located on line 1 as illustrated in Figure 5.85, a maximum short circuit power of 399.01 MVA with a short circuit current of 3.490 kA and a peak current of 8.498 kA is recorded.

Figure 5.86 illustrates the IEC 255-3 inverse characteristics for relay 1 (51) response. For the short circuit current of 3.490 kA as indicated in Figure 5.85, relay 1(51) responded with a tripping time of 0.615 sec. All other protection devices did not pick–up the fault; hence a tripping time of 9999.999 sec is recorded on all these relays as shown in the Figure 5.87.

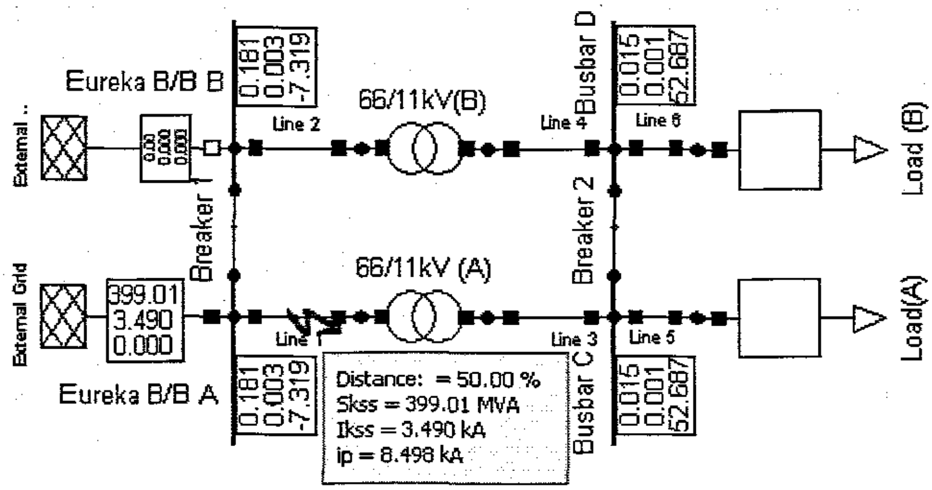


Figure 5.85: *Parallel feeder over-current protection with the fault on line 1*

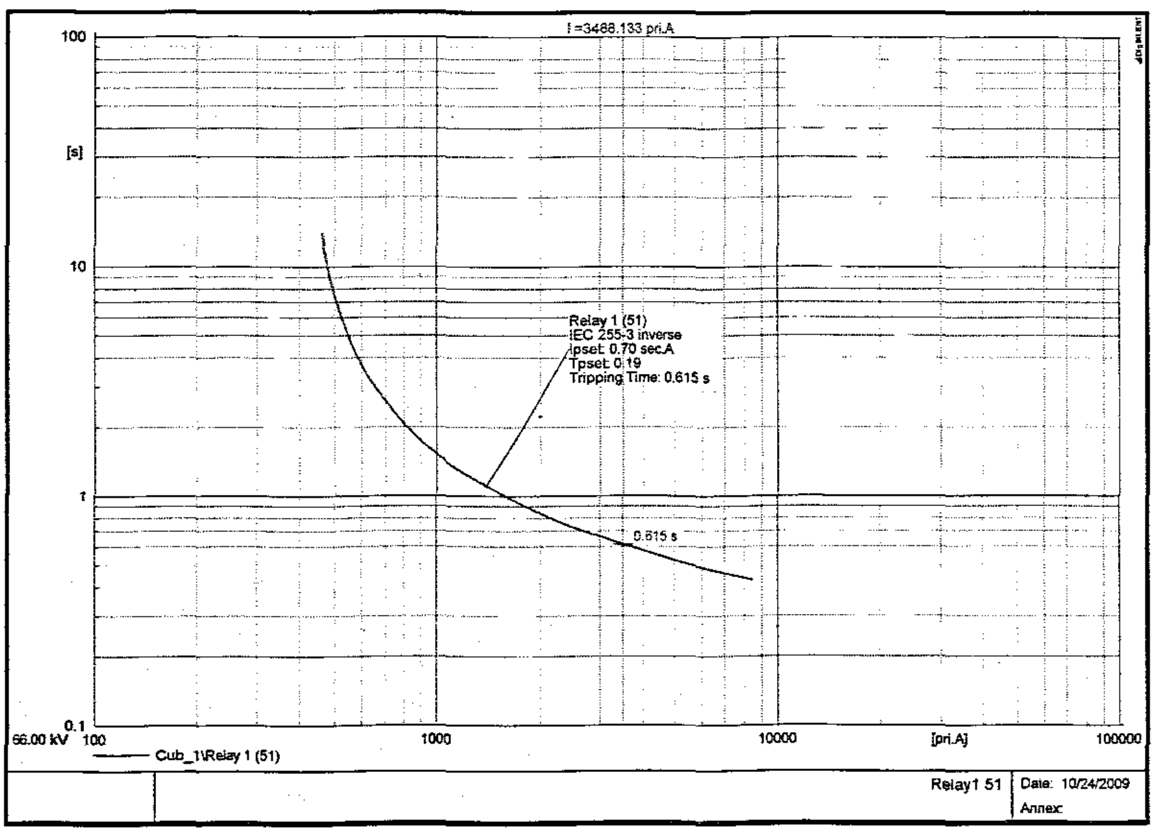


Figure 5.86: *Co-ordinated protection response for the fault on line 1*

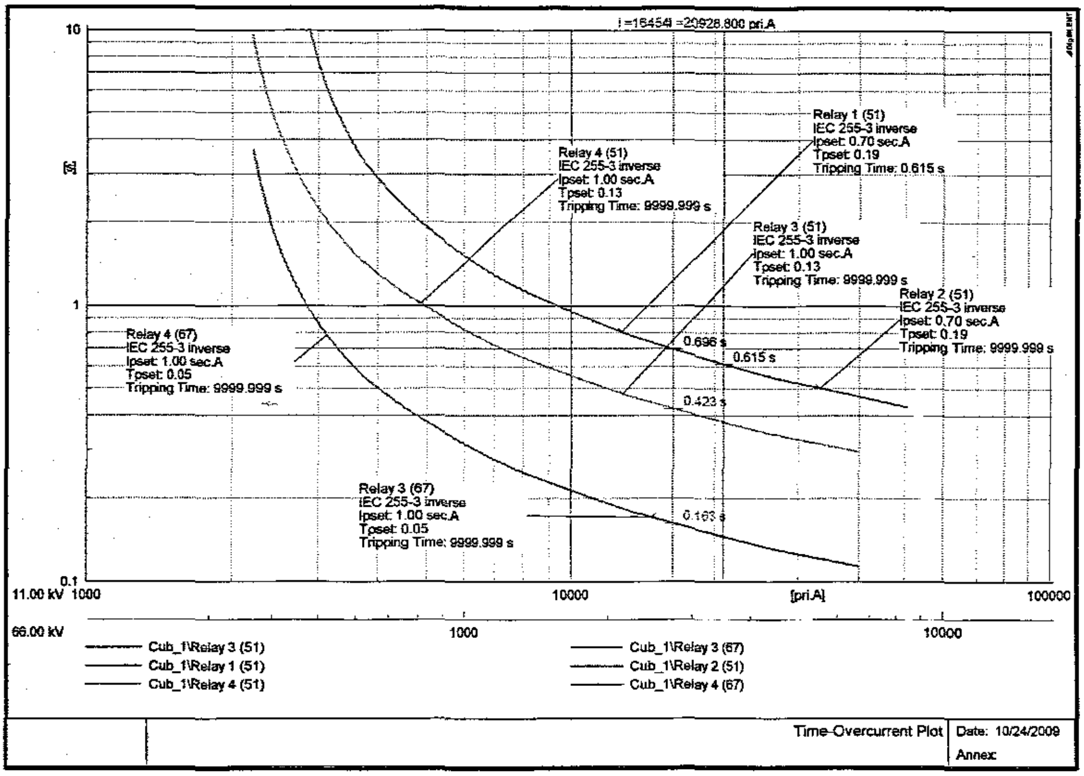


Figure 5.87: *Co-ordination of the time-overcurrent protection for fault on line 1*

Figure 5.88 shows a fault at line 2; relay 2 isolates the affected section from the rest of the network in order to prevent black-out. With this scenario the loads will be fed via one transformer, hence this type of this set up is more recommended. A tripping time of 0.615 sec is recorded as shown in Figure 5.89 and 5.90.

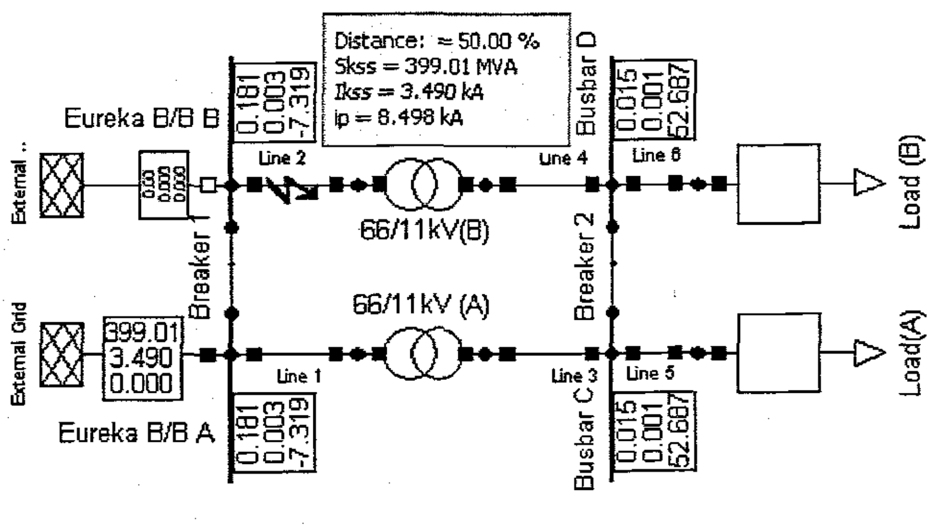


Figure 5.88: *Parallel feeder over-current protection with the fault on line 2*

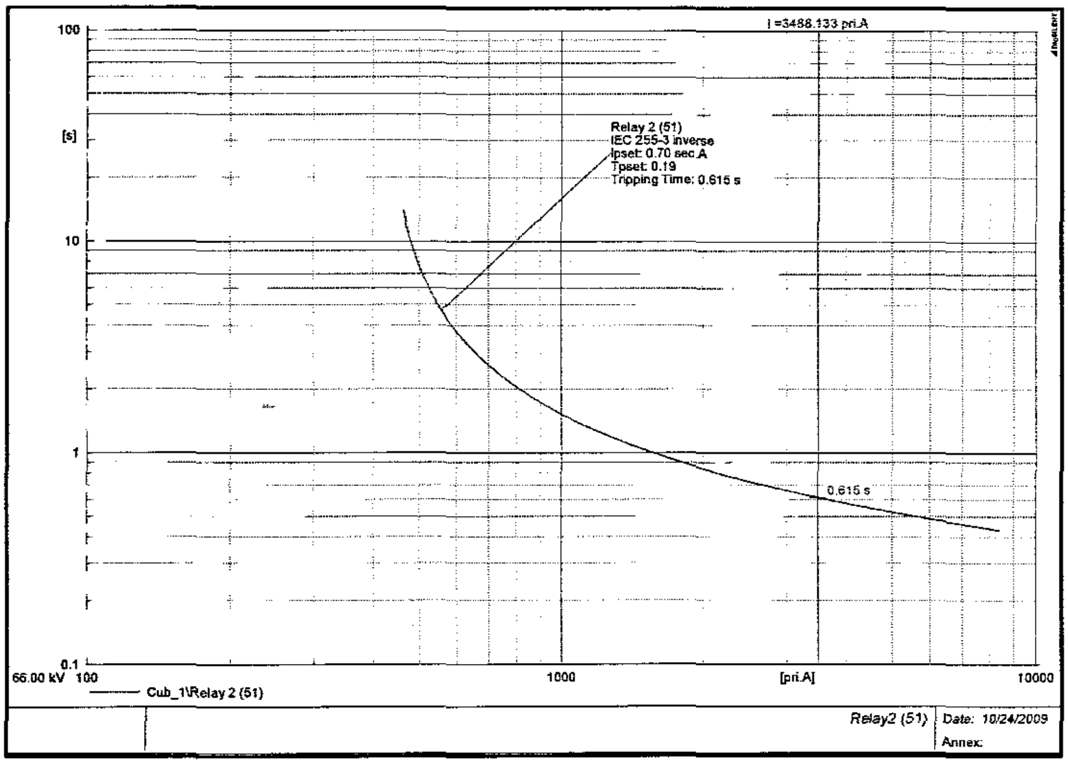


Figure 5.89: *Co-ordinated protection response for the fault on line 2*

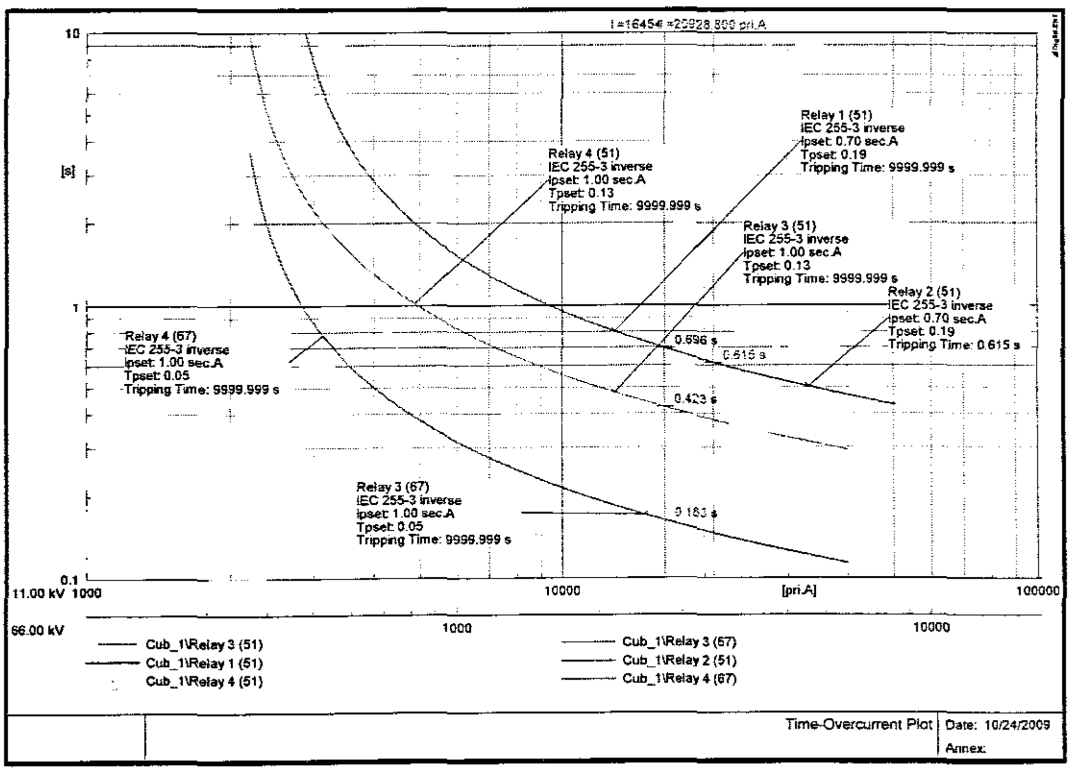


Figure 5.90: *Co-ordination of the time-overcurrent protection for fault on line 2*

Figure 5.91 indicates a short circuit current of 10.900kA. Although there are two relays at the receiving end [the directional 4(67) and non-directional relay 4(51)], the directional relay 4 (67) picks-up the fault first and issues a tripping time of 0.361 sec. It is a must that this relay responds first before any unwanted tripping arose from non-directional relays [1(51) or 3 (51)].This is illustrated in Figure 5.92 and 5.93.

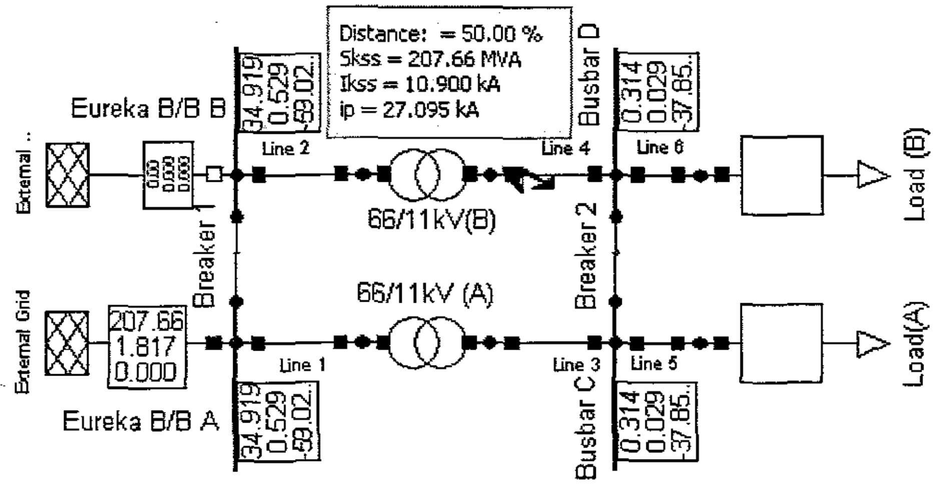


Figure 5.91: *Parallel feeder over-current protection with the fault on line 4*

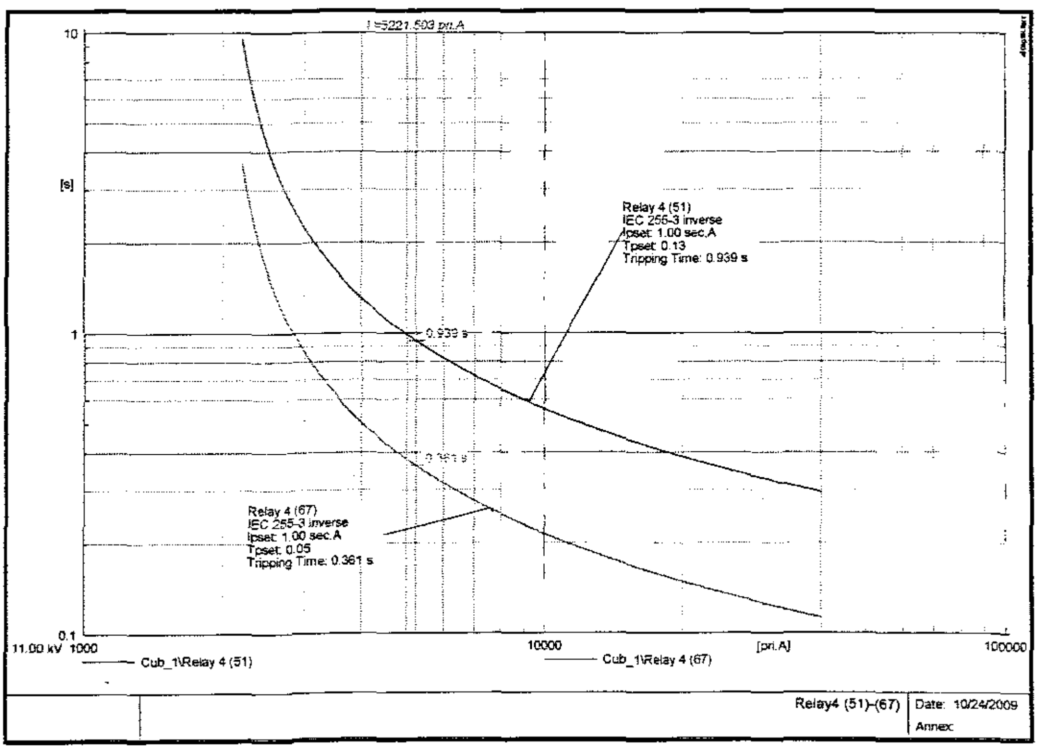


Figure 5.92: *Co-ordinated protection response for the fault on line 4*

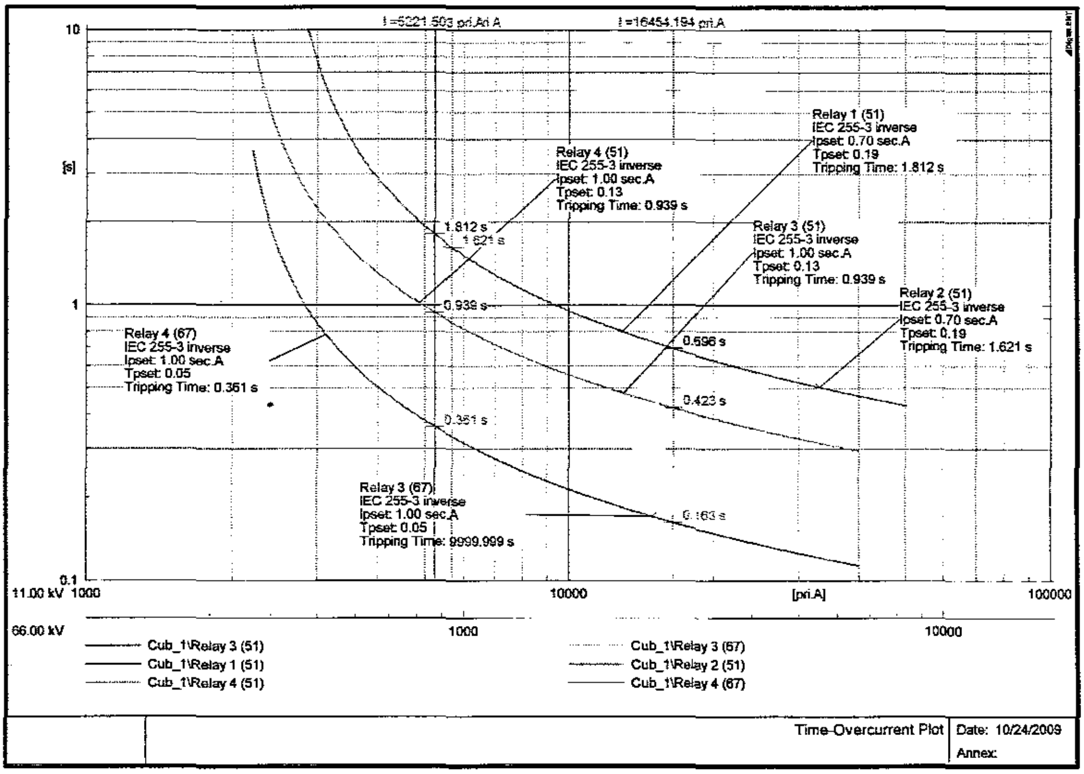


Figure 5.93: Co-ordination of the time-overcurrent protection for fault on line 4

When the fault is located on line 6 as illustrated in Figure 5.94, a maximum short circuit power of 193.46 MVA with a short circuit current of 10.154 kA and a peak current of 23.253 kA are recorded. The main protection (relay 6(51)) responded with a tripping time of 0.212 sec to clear the fault as illustrated in Figure 5.95.

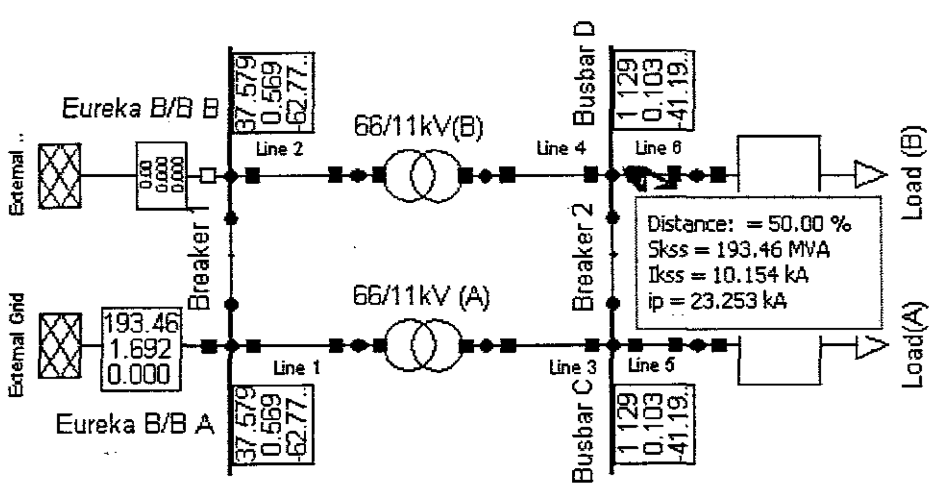


Figure 5.94: Parallel feeder over-current protection with the fault on line 6

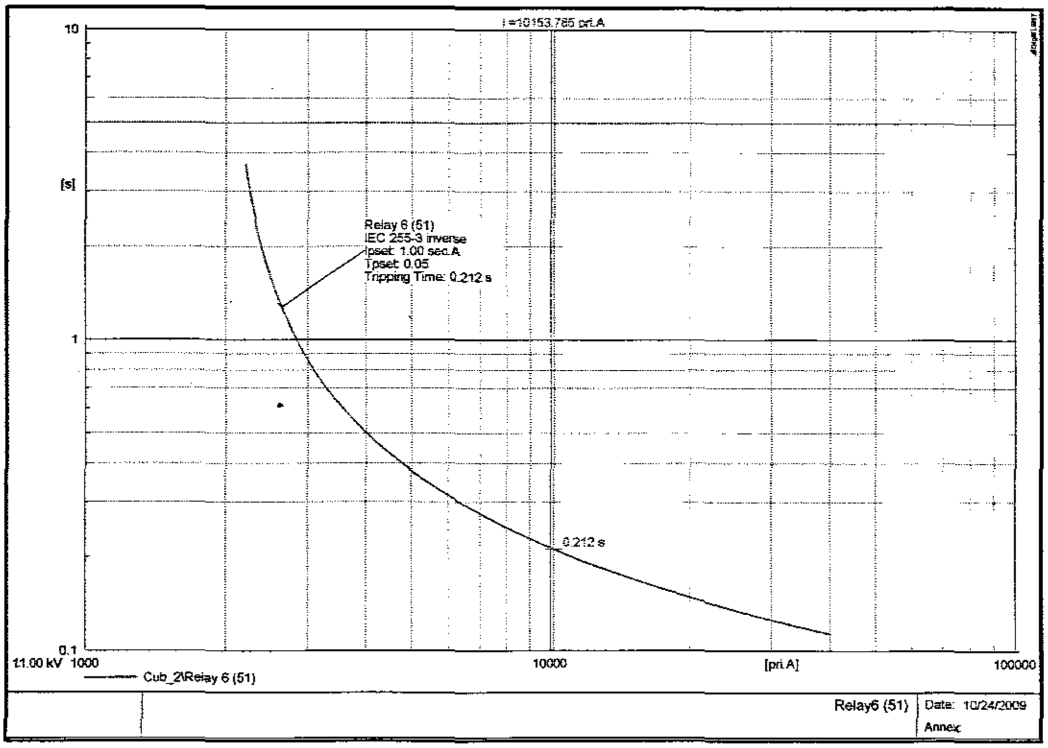


Figure 5.95: Co-ordinated protection response for the fault on line 6

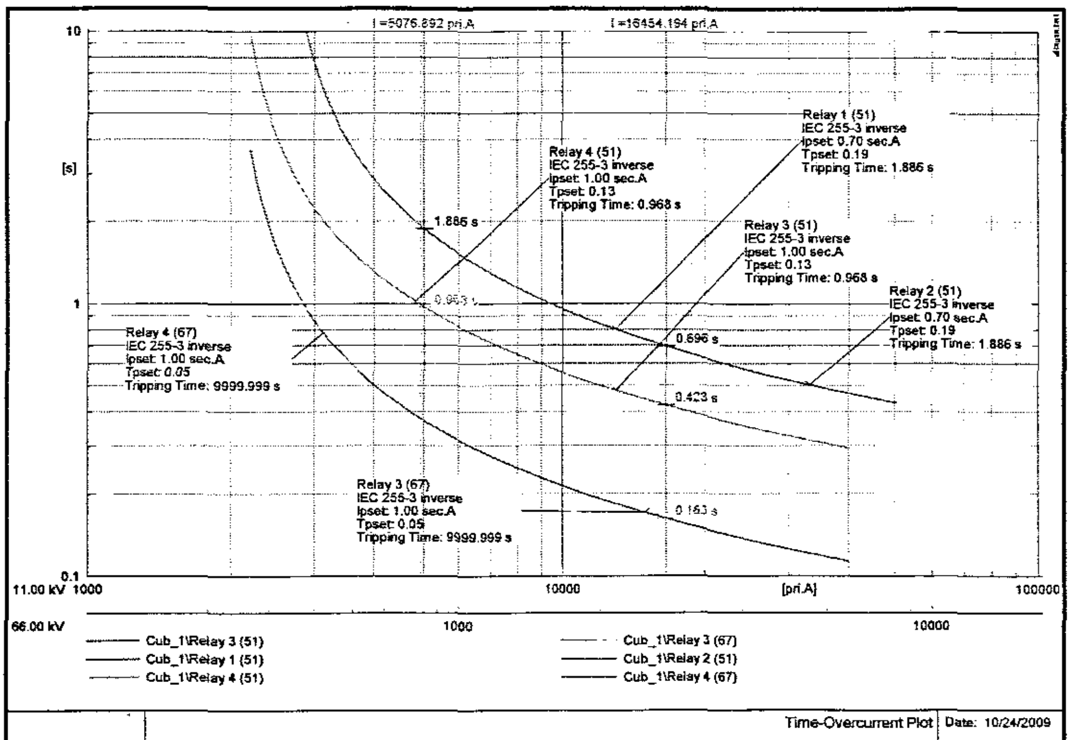


Figure 5.96: Co-ordination of the time-overcurrent protection for fault on line 6

The non directional relays upstream with reference to the fault have pick up the fault but will not trip. The relays at the receiving end of the transformer feeder [relay4 (51) & 4(67)] have different characteristics since, relay 4 (51) is non directional and relay 4 (67) is directional. Their settings and co-ordinated tripping characteristics are shown in Figure 5.96.

Figure 5.96 shows the combination of co-ordinated response characteristics for the fault as indicated in Figure 5.94 above. Relay 6 (51) responded with a tripping time of 0.212 sec to discriminate the fault. Relay 3 and 4 (51) recorded a tripping time of 0.968 sec while 1 and 2 (51) are trailing at 1.886 sec. A tripping time of 9999.999 sec is recorded on the relays that did *not pick-up the fault. Should relay 4 (51) be used to open breaker 2. then the settings for relay 3* (51) should be changed.

5.6 DISCUSSION OF RESULT

The results for the two modelled network (CPUT and Eureka) is briefly summarized as follows.

5.6.1 CPUT network

A site survey has been conducted and the network data has been collected. Based on this data, the load flow analysis for the campus reticulation network was successfully performed. Included in the survey was the network protection audit. The system was modelled using DIgSILENT and all the parameters required for protection study were obtained. Among the obtained parameters is the maximum short circuit power, rated short circuit power and the percentage impedance of the transformers. The fault currents and tripping time at various point on the network has been established and simulated. Discrimination has been achieved by overcurrent, time and by a combination of both overcurrent and time. Since discrimination by current relies upon the fact that the fault current varies with the position of the fault, this variation is due to the impedance of various impedances of the network such as cables and transformers between the source and the fault. Therefore accurate calculation was carried out in terms of transformer capacity, cable's current and impendence capacity. As a result accurate parameters where achieved in terms of real, reactive and apparent power as well as the maximum fault current and short circuit currents. Accurate results from the load flow analysis model were due to the calculated parameters. Therefore it is very important that the minimum and maximum parameters as shown in Figure 5.3 are calculated accurately and not thumb sucked values because they have a major impact on the accuracy of the network. The selection of current transformers and protection calculation are performed based on the load flow results. The ideal CT ratio that was chosen, based on the load flow result has made it possible for the correct current settings to be achieved. In order to obtain correct discrimination it is necessary to have a correct time interval between two adjacent relays. This time interval (grading margin) was obtained as the factors that influences it where correctly calculated. These factors include the circuit breaker interrupting time, relay overshoot time, errors and safety margin. Any fault on the system irrespective of the location can be cleared with a minimum period as correct discrimination and grading margin is used, refer to Appendix A. In this way unnecessary tripping of protective relays has been avoided. The calculated and simulated results correspond and no error was recorded. Slight differences occurs only in terms of decimal places Overcurrent protection, breaker failure protection and the grading of downstream versus upstream protection was part of the modelling process. These data is used in chapter 7 for the testing of the IED's.

5.6.2 Eureka network

Power flow analysis and protection analysis was conducted on this network. Protection calculations were carried out based on the obtained data. On this network discrimination is also carried out using both time and current and the following duties were carried out. This includes relays settings and configuration coordination, relay application coordination, coordination and control, refer to Appendix B. Both calculations have been carried out in a similar fashion as in subsection 5.6.1. Although the fault level does not tend to vary much in interconnected systems and sometimes it may be found impossible to obtain correct discrimination for all the faults, the system was looked at in details under maximum and minimum fault conditions and the best compromise was reached. Directional overcurrent protection was applied to help overcoming this problem. The calculated results were applied in DIgSILENT for simulation purposes and the principle of coordination was successfully obtained as calculated. The principle of coordination refers to the procedure of setting overcurrent relays to ensure that the relay nearest to the fault operates first and all other relays have enough additional time to prevent them from operating. An example is that if a relay that is closer to the fault fails to clear the fault within its zone of operation, the next upstream relay should operate provided the coordination is correct. The parallel transformer feeder scenario was modelled and a combination of directional and non directional relays has given good results in terms of operating time and coordination. The simulation results where compared with the calculated results and the deviation is minimal.

5.7 CONCLUSIONS

This chapter has covered the protection of distribution network based on the protection devices that posses the time current characteristics. Part of this chapter's content is the mathematical derivation of the systems maximum fault level, short circuit currents for both the MV and LV part of the network and the network impedances. The relays trip settings and calculation have been carried out, and this is the basic mathematical relation describing how the protection devices will behave when there is an imbalance between the preset calculated parameters and the system measured parameters. The results obtained in this chapter were achieved using the eight most important factors that should be known before attempting any protection study. The analysis and modelling of the two networks was carried out using DIgSILENT software package and the results obtained are presented accordingly.

The means of communication of an IED is one of the most significant aspects of modern electrical and protection systems and it is one of the aspects that clearly separate their differences with the normal relays, regarding their level of functionality. The IED's communication part is covered in chapter 6.

CHAPTER 6

PROTECTION SOLUTIONS BASED ON ETHERNET AND IEC61850 SUBSTATION COMMUNICATION

The purpose of this chapter is to analyze the effect of using Ethernet networks and IEC 61850 protocols for protection, integration, automation and the use of IEC 61850 GOOSE messages to communicate high-speed information between IED's or other devices on the local area network (LAN). The chapter also analyses the behaviour of GOOSE messaging when the fault occurs in the system. The CPUT network and topology is used to demonstrate the protection, control and interlocking using GOOSE messages. Siemens IED and software are used to carry out the analysis and for interoperability additional SEL421 IED is included. The study is performed using DIGSI4 software. The obtained results are evaluated and the optimal location of the IED's in the network is suggested. Various network architectures that can be implemented with Ethernet switches in substations and their performance that they can offer are also included.

6.1 INTRODUCTION

As earlier mentioned, the communications Network is virtually the nervous system of Substation Automation. The communication network ensures that raw data, processed information and commands are shared quickly, effectively and error-free among the various field instruments, and IED's. The physical medium will be fiber-optic cables in modern networks, although some copper wiring still exists between the various devices inside a substation. IEC 61850 is a global international standard for substation automation. The IEC 61850 approach has introduced a high-speed Ethernet communication for substations, providing a user-independent and expandable IT infrastructure for substation automation. In addition IEC 61850 models substation equipment, protection and control functions **(Etherden, 2007).** When building a network, the tasks and components can be overwhelming at times. The solution on how to build a computer network lies in the understanding of the network communications foundation. Again the key to building a complex network requires an understanding of the physical and logical components of a simple point-to-point network. To become proficient in networking, the knowledge of why networks are built and the protocol used in modern network design is required **(McQuerry, 2008).** Since this is what expected of any protection Engineer nowadays, this chapter briefly explores the basics of networking and provides a solid foundation on which to build a comprehensive knowledge of networking technology.

6.2 WHAT IS A NETWORK

A network is a connected collection of devices and end systems, such as computers and servers that can communicate with each other. Networks carry data in many types of environments, including substations, small businesses, and large enterprises. In a substation, a number of components in different levels are required to communicate with each other, and such levels can be described as follows: Figure 7.1

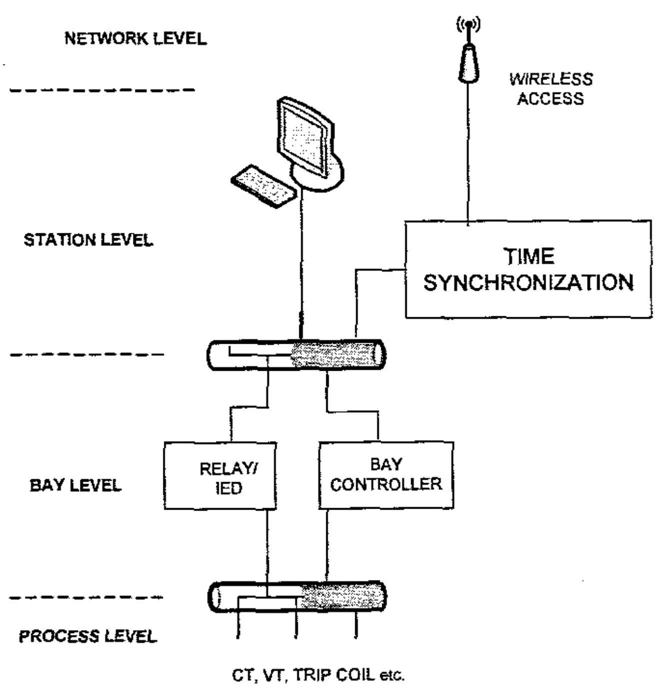


Figure 6.1: *Overview of the IEC61850 cross-level communication*

IEC 61850 is the first and only standard that covers all levels of a switchgear system. These levels include the process, bay and station level. Individual devices communicate within a level or between levels using the same protocol. The bus structure used for communication is flexible and can also be designed in different ways using different network topologies. By using

Transmission Control Protocol/Internet Protocol (TCP/IP), services such as web services for remote maintenance can also be transmitted through the same communication network simultaneously. At this point in time Ethernet is used as the communication path and has gain popularity of more than 90% in most commonly used connection type between computers and their peripherals in local networks. In this way, a 10-MBit network can easily be integrated into the usual 100-MBit network of today and in the 1 GBit network of tomorrow, on the other hand **(Ethernet & IEC61850 start-up, 2005).**

6.3 ETHERNET AND NETWORKING BASICS

Ethernet is not the only means to network embedded devices, but it is a very popular choice. This is because it is easy to put together and apply an Ethernet network without much knowledge about its inner workings. Hardware and software elements with the in-built Ethernet support (e.g. IED's) can shield the user from the details. But a little knowledge of Ethernet can help in selecting network components, writing of software that exchanges data over the network, and troubleshooting of network related problems.

6.3.1 Transmission Control Protocol/Internet Protocol (TCP/IP)

Transmission Control Protocol/Internet Protocol is a set of protocols that allow communication between Devices. Nowadays, network administrators can choose from numerous protocols, but the TCP/IP protocol is the most widely used protocol. Part of the contributing reason is that TCP/IP is the protocol of choice in terms of the Internet (the world's largest network). TCP/IP offers many advantages over other network protocols and protocol suites **(Blank, 2004:6-10)**. Below is a summary of some of the benefits on using the TCP/IP protocol suite:

6.3.1.1 A widely published, open standard

TCP/IP protocol is not a secret. It is neither proprietary nor owned by any corporation. Since it is a published protocol with no secrets, any computer engineer is able to improve or enhance the protocol by publishing a request for comments (RFC).

6.3.1.2 Compatibility with different computer systems

TCP/IP enables any device to communicate with any other devices. TCP/IP is like a universal language that would enable people from different countries to communicate effectively with one another.

6.3.1.3 Operates on different hardware and network configurations

Transmission Control Protocol/Internet Protocol is accepted and can be configured for almost every network created.

6.3.1.4 A Routable protocol

TCP/IP can figure out the path of all the data as it moves through the network. The size of any TCP/IP network is almost unlimited since it is a routable protocol.

6.3.1.5 Reliable, efficient data delivery protocol

TCP/IP can guarantee the transfer of data from one host to another

6.3.2 International Organization for Standardization (ISO)

The International Standards Organization (ISO) has set up a framework for standardizing communication systems called the Open Systems Interconnection (OSI) reference model. The OSI architecture defines the communication process as a set of seven layers, with specific functions that are isolated and associated with each layer.

***Table 6.1**: The seven layers of the OSI model*

Application	**Layer7**	Supports applications for communicating over the network
Presentation	**Layer6**	Formats data so that it is recognizable by the receiver
Session	**Layer5**	Establishes connections, then terminates them after all the data has been sent
Transport	**Layer4**	Provides flow control, acknowledgments, and retransmission of data when necessary
Network	**Layer3**	Adds the appropriate network addresses to packets
Data-Link	**Layer2**	Adds the MAC addresses to packets
Physical	**Layer1**	Transmits data on the wire

The OSI model has break down many tasks that are required in moving data from one host to another in steps and this is its main goal. These steps are known as layers. and the OSI model is made up of seven distinctive layers. Each of the seven layers has unique responsibilities. The layers and their respective responsibilities are shown in Table 6.1 The OSI model serves as a method of compartmentalizing data-communication topics in such a way that it is helpful to network administrators when troubleshooting **(Held, 2003:41-42)**.

6.3.4 Internet Protocol (IP) addresses.

An internet protocol address uniquely identifies every host that is part of the network. Just as the mailing address uniquely identifies a house, an IP address uniquely identifies a host. Consider a mailing address to be made up of two parts. Part of it shows the postal carrier in what street the house is and part of it tells which house it is on that street. All addresses on that street include the same street name but have unique numbers for each house. The IP addresses share a similar fashion: They can be broken down into two portions. One part of the IP address represents the network that the host is on, while the other part represents that unique host on that particular network **(Blank, 2004:68)**. The conventional way to express an IP address is the dotted-quad format, such as 192.168.111 1

6.3.5 Local Addresses

For a local network that does not connect to the Internet, the IP addresses are only required to be unique within the local network. An address range in each class is reserved for local networks that do not communicate with outside networks:

Class A: 10.0.0.0 to 10.255.255.255
Class B: 172.16.0.0 to 172.31.255.255
Class C: 192.168.0.0 to 192.168.255.255

These ranges are preserved with classless addressing as well. Networks that use addresses in these ranges should not directly connect to the Internet or to another local network that might be using the same addresses **(Axelson, 2003)**. However, it is possible to connect devices with local addresses to the Internet by using a router that performs Network Address Translation (NAT). Class A, B, and C are the only available address classes for TCP/IP host IP addresses. In contrast, no host can have a Class D address. These addresses are invalid for use by any workstation or host and they are called multicast addresses.

6.3.6 The Subnet Mask

The term subnetting refers to the process of dividing a network into groups known as sub networks, or subnets. For a small, isolated local network subnetting should not be a concern. Determining which bits in the host address is the subnet ID, requires the use of a 32-bit value called the subnet mask. In the subnet mask, the bits that match with the bits in the network address and the subnet ID are equal to ones, while the bits that correspond to the bits in the host ID are zeros. Class B network can be used as an example, whereby two bytes reflect the network address and the other two bytes are the host address. The subnet mask for Class B network with eight bits of subnet ID should appear as: 255.255.255.0. With eight bits of subnet ID, the network can encompass up to 254 subnets, and every subnet can accommodate up to 254 hosts. Similarly, the subnet mask for Class C network with four bits of subnet ID is: 255.255.255.240 **(Axelson, 2003).**

6.3.7 Broadcast Addresses

A destination address containing all ones is purely a broadcast to all hosts in a network or subnet. For example, a network with a network address and an IP prefix of:192.168.100.0/28 *can accommodate up to 14 hosts (192.168.100.241 through to 192.168.100.254) and a* broadcast of: 192.168.100.255 is directed to all hosts within the network. In addition an Ethernet frame with a destination address of all ones is another way to do broadcasting **(Clark, 2003).** **Note:** In this project the settings are done using Class B, although most of the equipment used had a default address in the range of Class C. In order to determine whether the destination IP *address is within the same subnet as the source IP addresses a logical AND of each IP address* with the source's subnet mask is performed. Should the two values be the same, then the destination is in the same subnet and the source can use direct routing. This is illustrated in example 1 and 2 and Figure 6.2 respectively.

Example 1

```
Source address = 192.168.0.229
Source subnet mask = 255.255.255.224
Destination address = 192.168.0.253
Subnet mask AND Destination address = 192.168.0.224
Subnet mask AND Source address = 192.168.0.224
192.68.0.224 XOR 192.68.0.224 = 0.0.0.0
```

In this example the values match therefore, the destination and the host address are in the same subnet.

Example 2

```
Source address = 10.2.1.3
Source subnet mask = 255.255.0.0
Destination address = 10.1.2.1
Subnet mask AND Destination address = 10.1.0.0
Subnet mask AND Source address = 10.2.0.0
10.1.0.0 XOR 10.2.0.0 = 0.3.0.0
```

Here the values do not match as a result, the source and destination address are not within the same subnet (**Axelson 2003**).

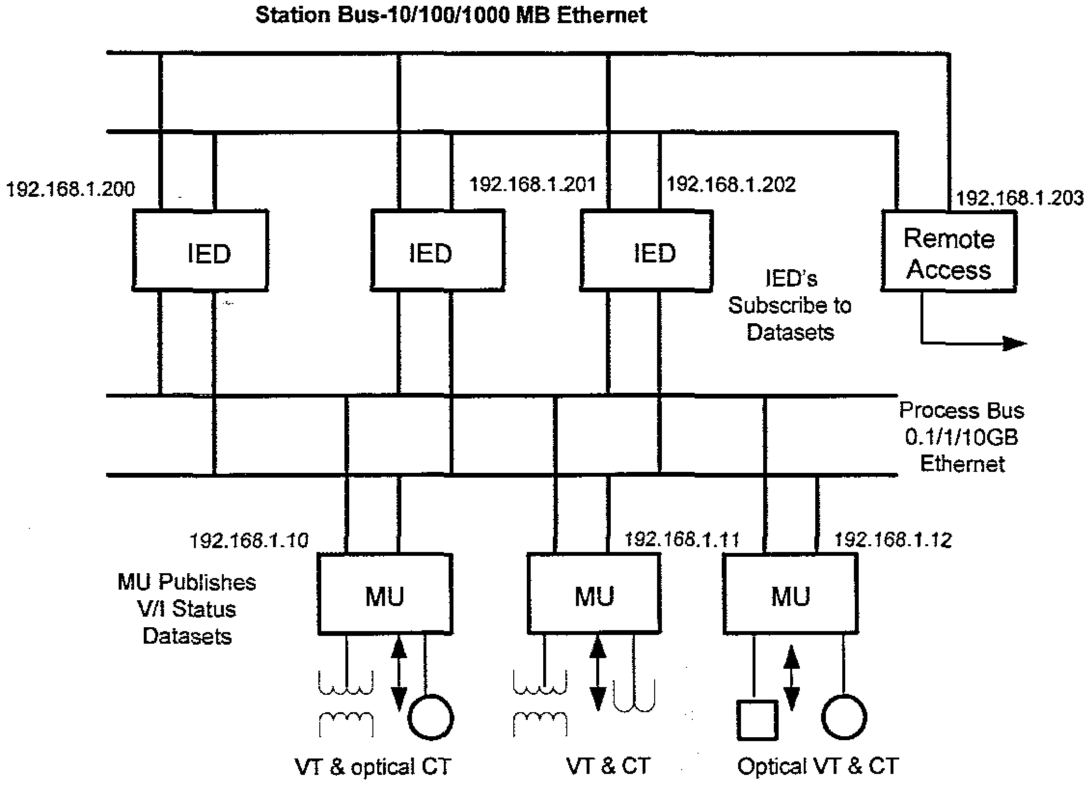


Figure 6.2: *IEC61850 Station Devices of a sub network*

6.4 IEC61850 AS A SOLUTION TO COMMUNICATION NEED

IEC 61850 standard was developed to be the solution for all substation communications irrespective of vendors and communication mediums. The IEC 61850 standard together with communications networks provides an internationally recognized method of local and wide area data communication for substation. The standard has in-built capabilities for high-speed control and data sharing over communications network, thus eliminating most dedicated control wiring (**Dolezilek and Udren, 2006**). The standard also provides the necessary tools for engineering solution and defines all the required file formats for substation configuration and ultimately. individual Intelligent Electronic Devices (IEDs) can be configured.

6.4.1. Substation Configuration Language

The IEC61850-6-1 standard specifies the Substation Configuration Language (SCL) that is based on the extensible Markup Language (XML) to explain the configuration of IEC61850 based systems. The SCL specifies a hierarchy of configuration files that allow multiple levels of the system to be described in definite and standardized XML files. Various SCL files include the system specification description (SSD), the IED capability description (ICD), the substation configuration description (SCD), and the configured IED description (CID) files. All these files are constructed using the same methods and format but have different scopes depending on the needs **(Baigent, Adamiak & Mackiewicz, 2004:10).** SCL defines standard data formats that are used by the system configuration tool. The system configuration tool is an engineering tool used to configure the IEC 61850 logic.

6.4.2. IEC 61850 system Architecture

Communication architecture began with the development of the Utility Communication Architecture (UCA). The basic architecture of IEC 61850 is the addition of an Abstract Layer of Generalized Communication and Specific Communication Services Mappings (SCSM). These layers are added on top of the International Standards Organization (ISO) Open Systems Interconnection (OSI) 7th-layer of the communications system model. These layers with the protocols that are supported at each level are illustrated in Table 6.3.

Table 6.2: *ISO layer-7 with the 2 additional layers on top*

Application Independent Abstract Communications
Specific Communications Services Mappings
Application layer

6.5 REQUIREMENTS OF NETWORK ARCHITECTURE

There are three main network architectures (e.g. Cascading, Ring, and Star) that are normally implemented with Ethernet Switches within substations with several variations and hybrids of the three. Each of the three basic architectures offers different performances vs. cost tradeoffs **(Pozzuoli, 2003:6)**. IEC 61850 is based on Ethernet; therefore the network that is developed within the substation will define the reliability and speed of the communications. The Local Area Network (LAN) can be configured in many different ways to create a system that can be either quite simple providing minimal redundancy or very complex creating a fully redundant network.

6.5.1 Star Architecture

The star architecture is the simplest and cheapest. The switch that creates a common connection is referred to as the 'backbone' switch because all the other switches uplink to it in order to form a star configuration. This type of configuration offers the slightest amount of latency (e.g. delay), but the disadvantage is if the backbone switch fails then all switches are isolated or if one of the uplink connections fails then all IED's connected to that switch are lost. On the other hand if an individual communications link fails, then all forms of communication to that particular IED is interrupted. A typical Star architecture is shown in Figure 6.3.

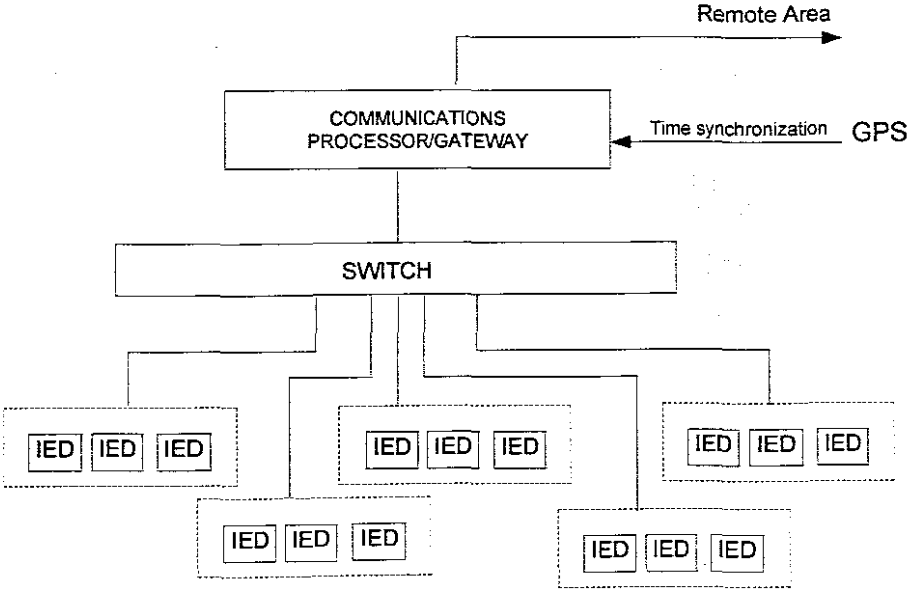


Figure 6.3: *Star Architecture*

6.5.2 Ring Architecture

Typically, ring architectures are very similar to the Cascading architectures except that the loop is closed through the network switches. This provides some level of redundancy (an alternative communications path exists) if any of communication channels between network switches fails. The disadvantage of the topology is that it does not cater for individual network switch failure. This architecture is illustrated in Figure 6.4.

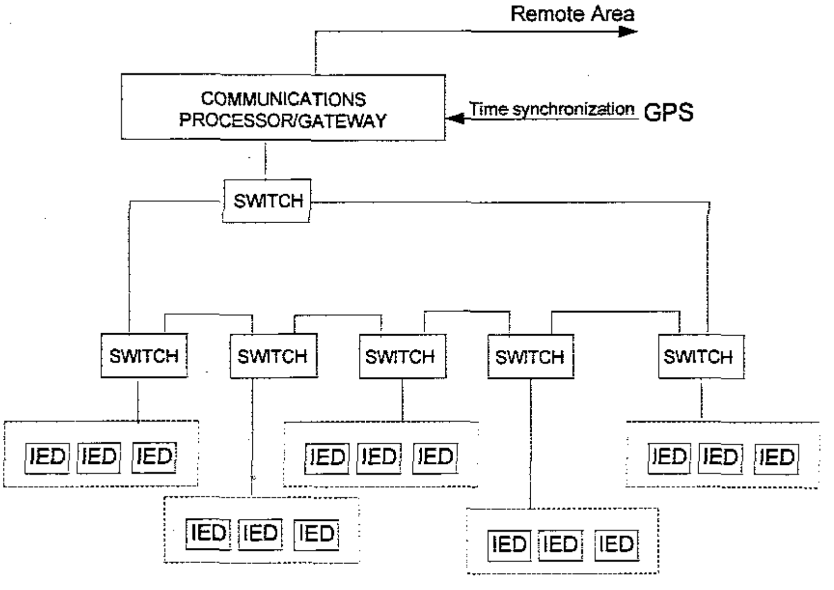


Figure 6.4: *Ring Architecture*

6.5.3 Cascading Architecture

A cascading architecture is shown in Figure 6.5. Each switch is connected to the previous or next switch in the cascaded format via one of its ports. These ports are referred to as uplink ports and are often operating at a higher speed than the ports that is connected to the IED's. The maximum number of switches, which can be cascaded, depends on the tolerated worst case delay of the system.

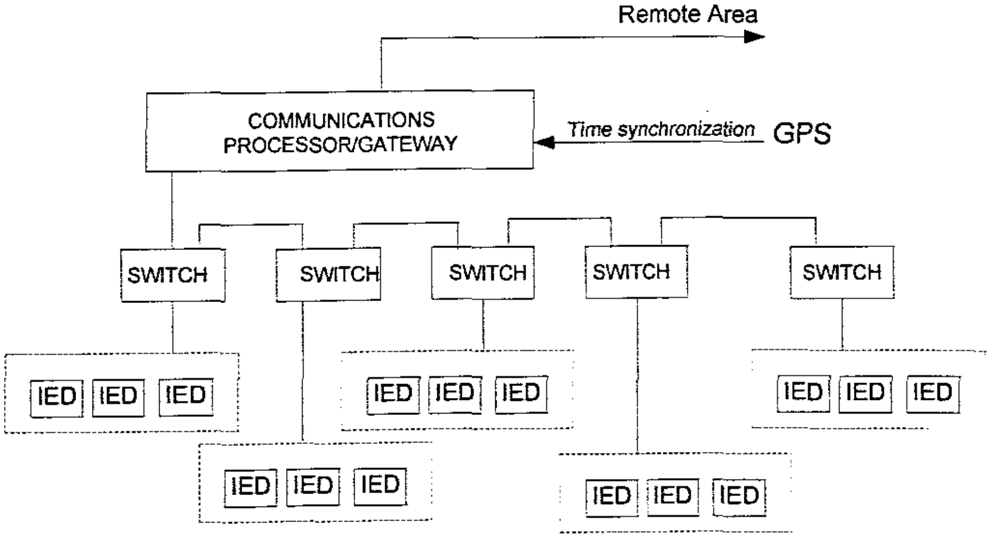


Figure 6.5: *Cascading Architecture*

6.5.4 Recommended CPUT Architecture

The IEC 61850 based technology is used to determine the location of the fault and take the necessary actions to isolate the faulted section and restore power using predetermined control sequences. All Merging Units (MU) and input/output Units (IOU) will communicate with the central Distribution Automation System Computer (DASC), Figure 6.6. The DASC will:

- Detect the occurrence of a fault
- Determine the location of the fault
- Determine which switches need to be opened
- Determine which switches need to be closed
- Record the fault currents
- Perform other functions as necessary (power quality, load profiles, etc.)

The individual IEDs, merging units and input/output units will be connected with the DASC over an available communications interface **(Apostolov, 2009).**

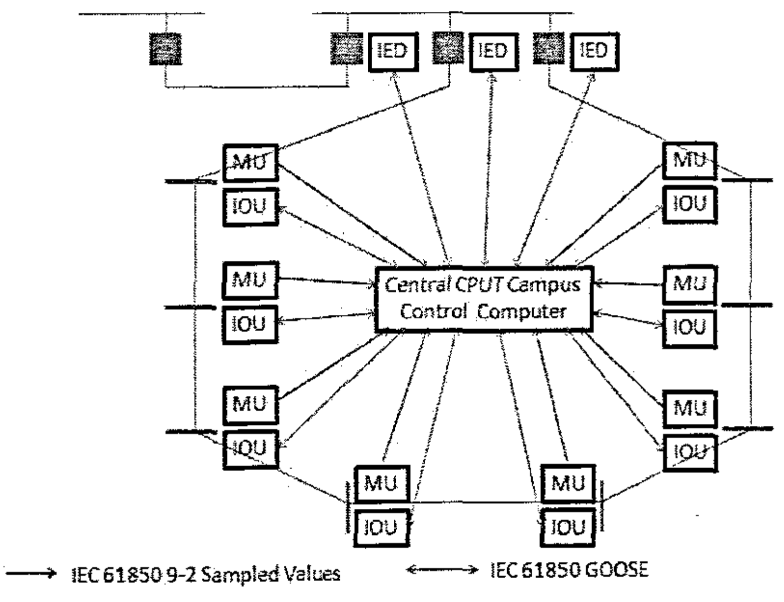


Figure 6.6: *CPUT recommended Distribution Automation System architecture*

When a fault occurs, a multifunctional IEC 61850 based protection IED will trip the feeder breaker in the main campus station and send a GOOSE message to the Distribution Automation System Computer (DASC). At the same time the system will detect (based on fault detection algorithms) which is the faulted section using information from the Merging Units (MU) and Input/Output Units (IOU) in the substations. GOOSE messages will be sent to the required IOUs to open and close the motor operated switches. Once the status of the switches has changed, the IOUs will send GOOSE messages indicating it. Then the IED in the main substation will close the breaker to restore the power. A GOOSE message will be sent also to the IOU to close the motor operated switches of the Normally Open point in the loop. However, if this is a no-load switch, it may be necessary to open the main substation breaker before this switching can be executed.

6.6 ALGORITHMS FOR DESIGN AND IMPLEMENTATION OF PROTECTION AND COMMUNICATION STRUCTURES

6.6.1 CPUT substation automation simulation system

The power network chosen for the simulation studies is based on the CPUT network. CPUT electrical network consists of thirteen substations that should be protected, monitored, automated and controlled. When a fault occurs, a multifunctional IEC 61850 based protection IED will trip the feeder breaker and send a GOOSE message to the Distribution Automation System Computer (DASC). In this system, the feeder, busbar and bay control relays *communicate using IEC 61850 GOOSE messages for the protection and control schemes,* including breaker failure and bus protection, bay interlocking and event report triggers.

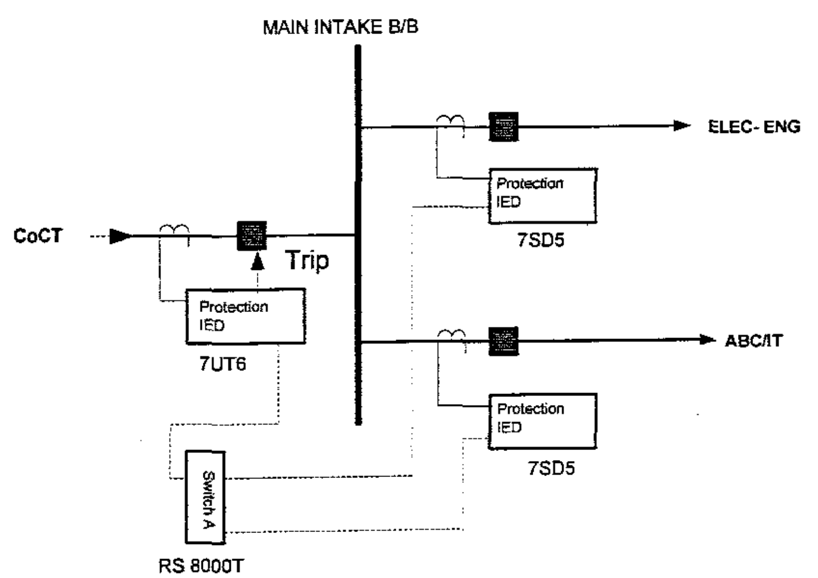


Figure 6.7: *CPUT Main Intake substation*

The implementation of IEC 61850 has made it possible to build a decentralized automation system, distributed over several intelligent electronic devices (IEDs). For this application, the SIEMENS IED's and software are used to solve some problems for protection, control, automation and interlocking, Figure 6.7. In terms of time synchronization, the SEL satellite-synchronized clock is used. The main aim of the simulation is to test the communication between IED's using IEC61850 principles and to apply all possible faults that could occur in the said network and monitor the reaction of the protective devices towards the faults.

6.6.2 Implemented Networking Hardware and Software

This section primary objective is to focus on the products or hardware's that are used to construct Ethernet-type networks within a single location in this case, the Main Intake substation simulation system, Figure 6.7. In addition, the use of switches to extend Ethernet connectivity among the communicators, and the role of network software and how they relates to the personal computer's operating system is included in the discussion. The main focus is on two areas. First, the focus is based on the basic operation of several hardware components that are the building blocks of the network and are important in extending the connectivity capability of an Ethernet local area network: merging units, switches, IED's, Ethernet connections (copper and fiber optics), servers and personal computers (PC). The next focus is on the role and operation of three major types of software required for local area network operations: computer operating systems, LAN operating systems, and application programs.

6.6.2.1 Personal computer with software on board

The personal computer accommodates the operating system and other related software required for local area network operations.

6.6.2.2 RS 8000T Ruggedcom switch

The Ruggedcom Switch (RS8000T) is a substation hardened, fiber optical Ethernet switch that is specifically designed to operate in harsh environments such as in electric utility substations and harsh industrial environments. The RS8000T Zero-Packet-Loss technology provides multiple fiber optical port, speed selections and 10/100 RJ45 twisted-pair connectivity.

Table 6.3: *RS 8000T Ruggedcom switch characteristics*

RS8000 T Ruggered Switch			
Model	**Quantity**	***Ports Type Options and Media***	***Connector Type***
RS8000T	2	100BaseFX Multi-mode Fiber	MTRJ
		100BaseFX Single-mode Fiber	LC
	6	Auto-negotiating 10BaseT / 100BaseTx Twisted Pair	RJ45

Since it is specifically tested to the same standards as the mission critical protective relaying equipment (i.e. ANSI/IEEE C37.90 and IEC 60255), the RS8000T is ideally suitable to form the Ethernet network in a UCA2 (Utility Communications Architecture 2.0) based substation automation network **(Ruggedcom Installation Guide rev103, 2009).**

6. 6.2.3 Category 5 (Cat 5) Ethernet cable with RJ 45 connector

The networks of all three speeds can make use of cables that meets the Category 5e specification defined in the EIA/TIA-568-B standard. Cat 5e cable is made up of four unshielded twisted pairs (UTPs) of wires. Varying the number of twists per inch from pair to pair helps with the reduction of noise in the wires. Twisted-pair cables are popular because they are inexpensive, and yet they can carry signals over long distances. There are two most common pin outs for the RJ-45 connectors that are used with twisted-pair cable. The difference between the two pin outs is the swapping of the wires in pairs 2 and 3. Within a cable (except for crossover cables), both ends must use the same pin out (straight cables). To avoid mix-ups, crossover cables should be prominently labelled. Crossover cables application can be included by using switches that have auto-crossover capability. These switches detect the need for a crossover application and automatically perform the crossover internally **(Axelson, 2003).**

6. 6.2.4 Siemens Siprotec 4 devices

The Siemens Siprotec 4 devices are used for protection, control and monitoring purposes and their operation is based on IEC 61850 standard. For interoperability the SEL 421 IED is used to communicate with the SIEMENS SIPROTEC4 devices.

6. 6.2.5 Fiber optic cables and connectors

Fiber-optic cable, enable signals to be transmitted as pulses of light. In fiber-optic communications visible or infrared light can be used. Using light instead of electrical signals to transmit data has several advantages that include the ability to carry data over long distances. For fiber-optic media arrangements, the maximum length of a segment ranges from a few hundred meters to 2000 meters for half duplex and 5000 meters for full duplex compares to 100 meters for twisted-pair media arrangements. The two popular connectors for fiber-optic cables are the Low Cost Fibre Optical Interface, the SC, connector and the ST connector

6. 6.2.6 CMC 256 Omicron test device

The CMC 256 is a PC-controlled test device intentional for testing of protection relays, transducers and energy meters. Additionally to the testing functions, the optional high-performance measurement functions of (0 Hz (DC) to10 kHz) for ten analogue inputs are available. The CMC 256 device is part of the OMICRON Test Universe which, in addition to the test device, consists of a PC, the test software, and, when required, external amplifiers. The configuration and control of the CMC 256 is performed through the test software of the OMICRON Test Universe and the following options are available:

- Analyzer: software module for measurements and analysis of AC and DC voltages,
- EP (Extended Precision): the CMC 256 with extended output power accuracy e.g. (used for energy meter test applications),
- NET-1: the CMC 256 with two Ethernet interfaces replacing the parallel port interface.

In addition, the NET-1 option provides the basis for the processing of substation protocols according to the UCA 2.0 specification and the IEC 61850 standard. The two Ethernet ports allow flexible configurations, e.g. separation of data traffic from different network segments or segregation of substation protocol data and test set control commands **(CMC 256 Manual, 2004:82-83)**.

6. 6.2.7 SEL-2407 Satellite-Synchronized Clock

The SEL-2407 Satellite-Synchronized Clock provides time display, reliability, durability and high-accuracy timing to +/- 100 nanoseconds. The SEL-2407 is used to synchronize the time of all IEDs, as a result enhancing the IEDs capabilities. This is especially true in fault analysis environment, where alignment of disturbance records is critical. These devices are vendor specific since the IEC 61850 does not include them in the standard. The majority of the vendors support Inter-Range Instrumentation Group (IRIG-B). The IRIG-B is distributed to each IED using dedicated copper wires. There are two forms of IRIG-B, the modulated (with an accuracy of "between one millisecond and ten microseconds") and the un-modulated (with an accuracy of between "one microsecond and ten nanoseconds"). Network Time Protocol (NTP) makes use of the LAN to distribute the time synchronization signal. This makes it very easy to distribute however, the accuracy is "between a few milliseconds and a few hundred milliseconds" **(Dickerson, 2008)**.

6.6.3 Development of the project software

Figure 6.8 shows a simplified compact sequence graphic that can be used as a guide when configuring IEDs and when creating projects, using DIGSI4. DIGSI4 is the innovation tool for the operation of all the SIPROTEC4 protection devices (IED's).With this software, the devices can be parameterized, process data can be viewed, fault record can be evaluated and interlocks between devices can be achieved. The steps shown in Figure 6.8 will be followed to create a Generic Object Oriented Substation Event (GOOSE) application. With this type of service, information on events can be rapidly transmitted between different intelligent electronic devices.

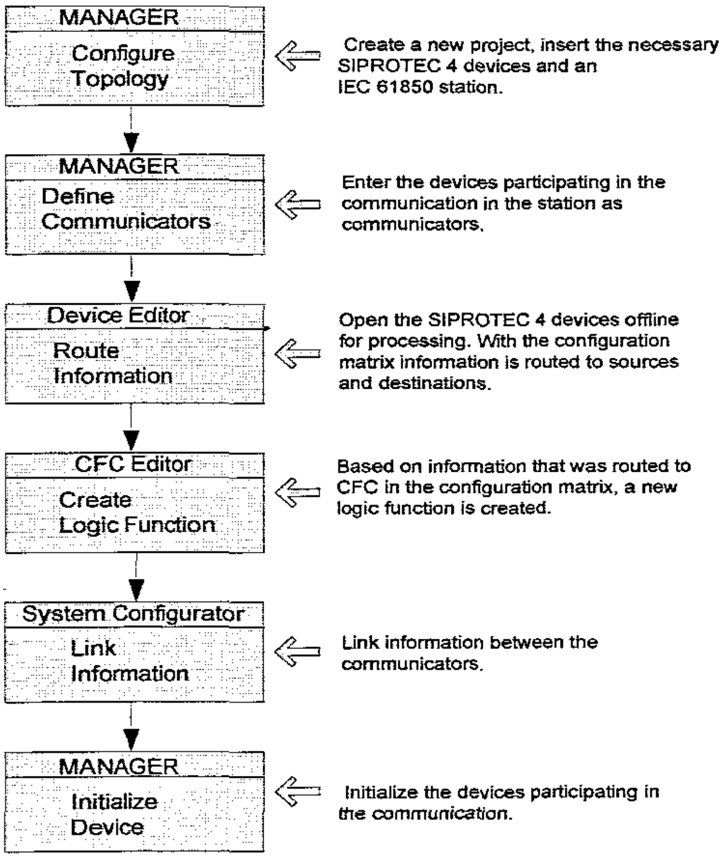


Figure 6.8: DIGSI4 project logic Guide

6.6.4 Communication establishment between IED's

Immediately after creating and structuring the project using DIGSI4, the communication between IED's is established by configuring and routing a test signal to indicate the presence and communication between the IED's by pressing F1 and F2 function keys on devices (1) front panel. This assists with troubleshooting during and after programming.Figure 6.9 shows a block diagram that represents the functionality of all the steps that are taken to program the testing signals. The method for verifying communication requires the exchange of indications between the participating devices (device 1, 2 & 3). As soon as the F1 key is pressed on Device 1, a testing signal (indication) is sent via the system interface. This indication should continuously exist until it is explicitly canceled and the key only responds with a short signal irrespective of how long the key is pressed down. As a result, a choice was made to activate the indication

Test Signal by pressing the F1 key and to cancel the indication by pressing the F2 key as the solution. For a function to decide something, it should first know which key was pressed. Therefore, a link between the keys and the function was created by means of two indications (the LED ON and LED OFF indication). These two indications provide the CFC function with the input signals and are sent as soon as the associated function key is (F1 or F2) pressed.

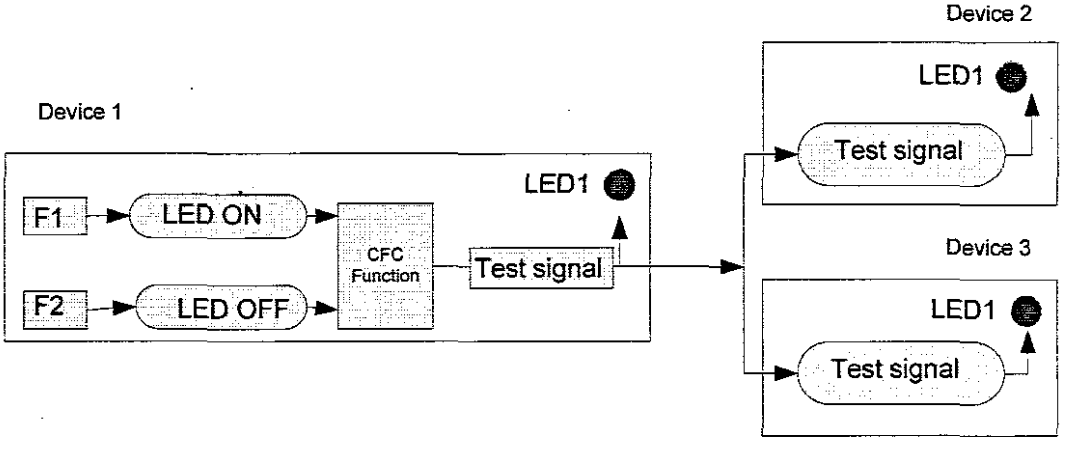


Figure 6.9: Overview of the broadcasting and subscribing devices

6.6.5 Configuring of the CPUT substation automation simulation system

The project is created and structured using the DIGSI4 manager. From the menu File, a project can be created and at the same time the project name is issued, in this case "CPUT Reticulation Network". After opening and naming the project, the list view already includes a folder with the name Folder. Since any further folder insert by the user will be named accordingly, the folders are then named individually. For the first folder the name is changed to Bellville Campus while the second folder is named Main Intake Substation, Figure 6.10.

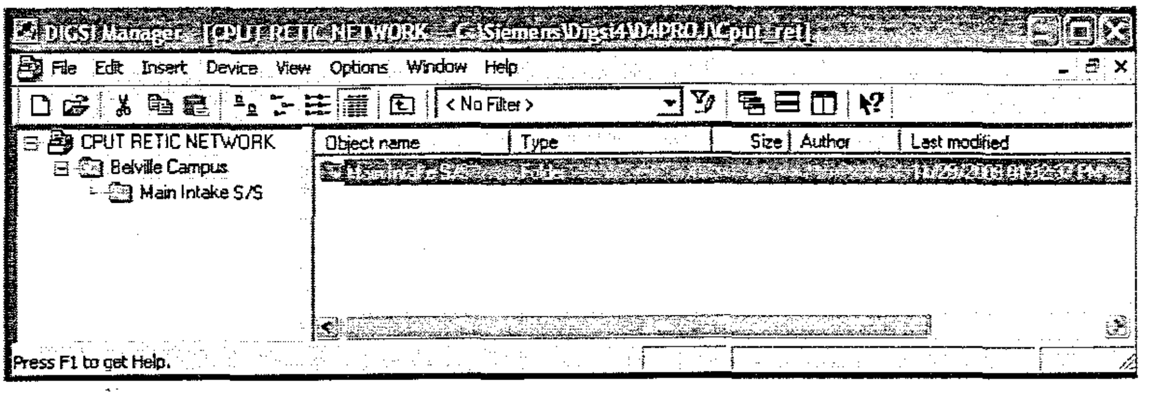
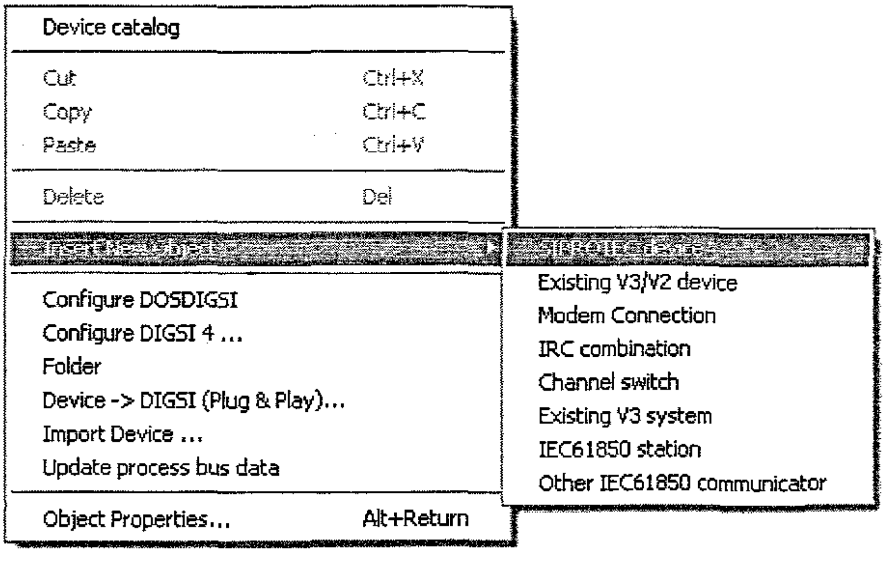
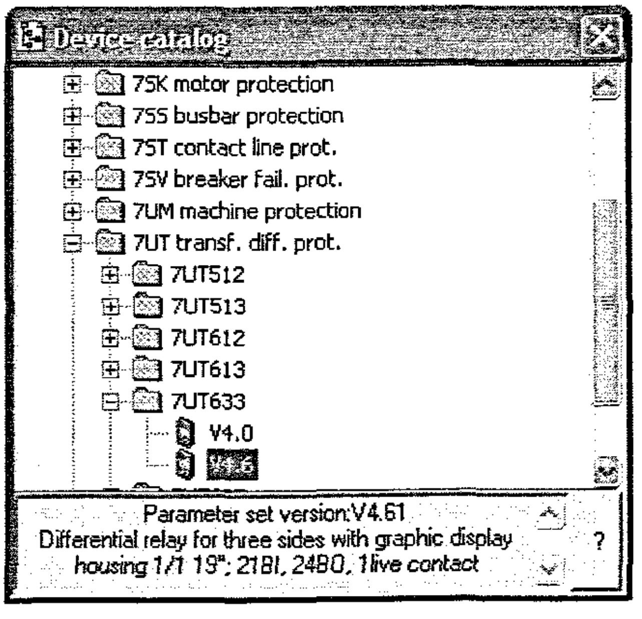


Figure 6.10: Project hierarchical structure

SIPROTEC device can be added to the topology by right clicking the folder and follow the instruction shown in Figure 6.11a and b. From the device catalog, the IED's can then be inserted by dragging and dropping them in the project space.



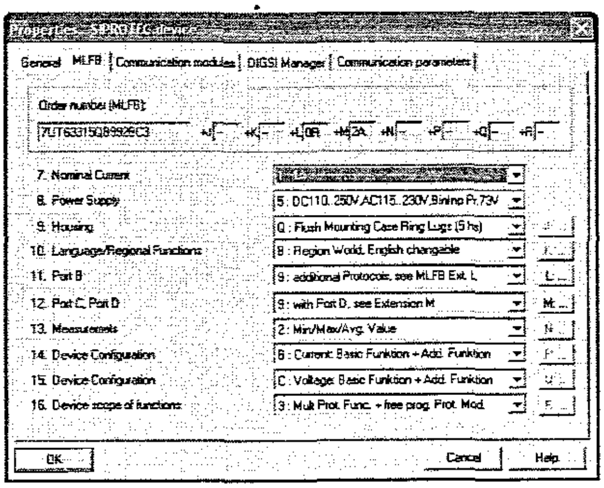
(a)SIPROTEC 4 device insert context menu



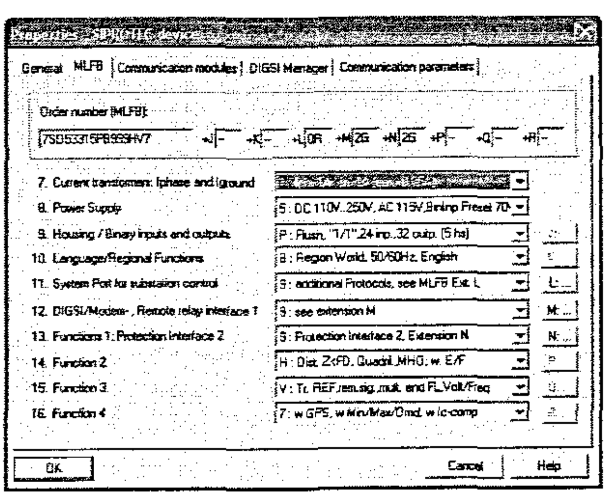
(b) Device catalog

Figure 6.11: *Inserting SIPROTEC device into a project*

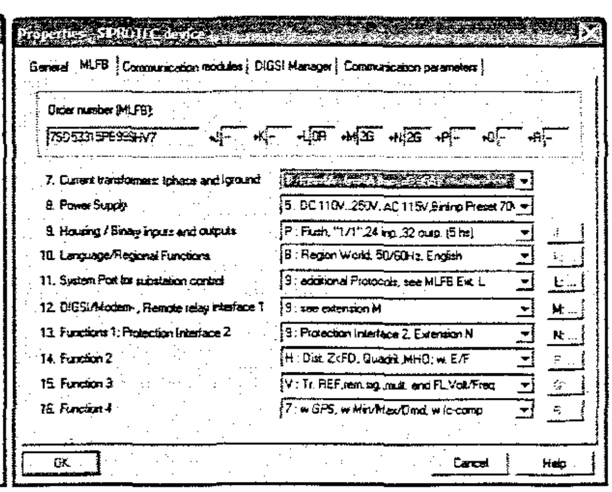
Before the SIPROTEC 4 devices are placed in the desired location, there is one thing that remains to be done. Although the DIGSI 4 Manager knows that the user wants to insert a SIPROTEC 4 device of any version, it does not yet know the exact design of the device. Therefore the device design that is reflected in the order number (MLFB) must be entered in the MLFB properties box. **Note:** always select the MLFB number that is stamped on the device even if the original communications module for an EN100 module has been exchanged. In this case, the identifying letter for the original port should be selected first. Then, the Properties dialog box of the inserted SIPROTEC device should be opened. Select the module **EN100** as the port in the **Communication Modules** tab, Figure 6.12.



Device 1



Device 2

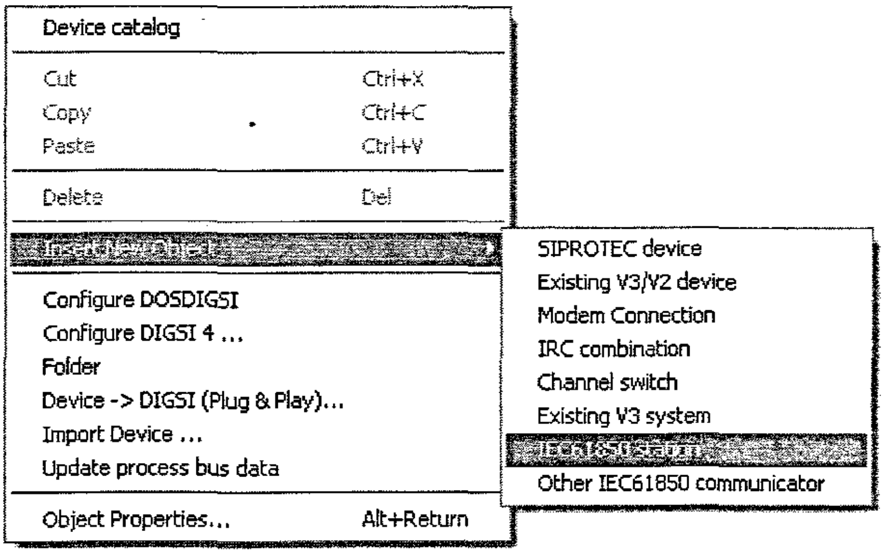


Device 3

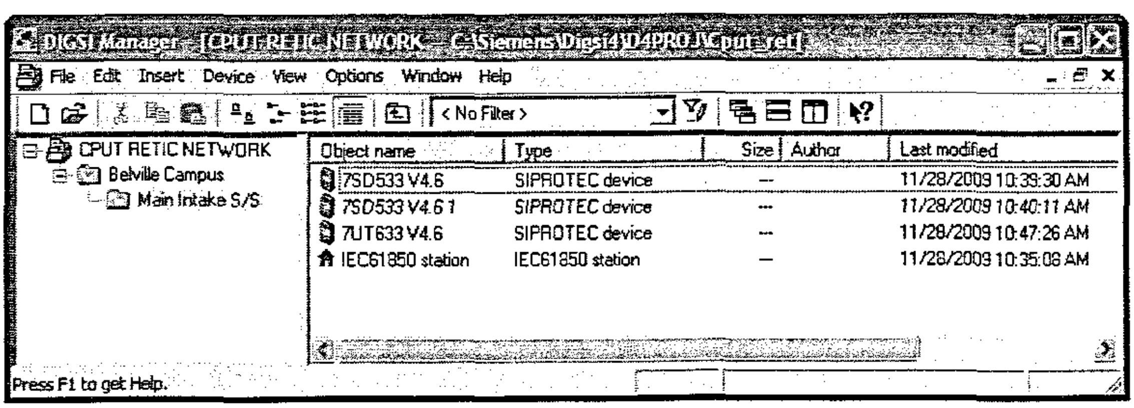
Figure 6.12: *Device properties dialog box*

It is very important to select the correct system port in the appropriate variant, as this will avoid incorrect operation and unnecessary troubleshooting.

After all the required IED's for the project has been identified and entered, the IEC 61850 communication is then created. The IED's can then be entered as communicators in the IEC61850 station, Figure 6.13a and b.



(a) IEC 61850 insert context menu



(b) Implementation of IEC 61850 Station

Figure 6.13: *Inserting the IEC 61850 Station into the project*

The IEC 61850 Station as shown in Figure 6.13 houses and unites the selected devices and allows them to communicate with one another via the Ethernet according to IEC 61850, Figure

6.14. As to which devices these are, in particular, is a choice of the programmer and this can be easily defined in the station's Properties dialog. The names of the selected devices are displayed as potential communicators, and they are assigned to the station with just a few mouse clicks. The station element also serves as the gateway to information such as communication connections and data links between the communicators and these can be edited using the DIGSI System Configurator.

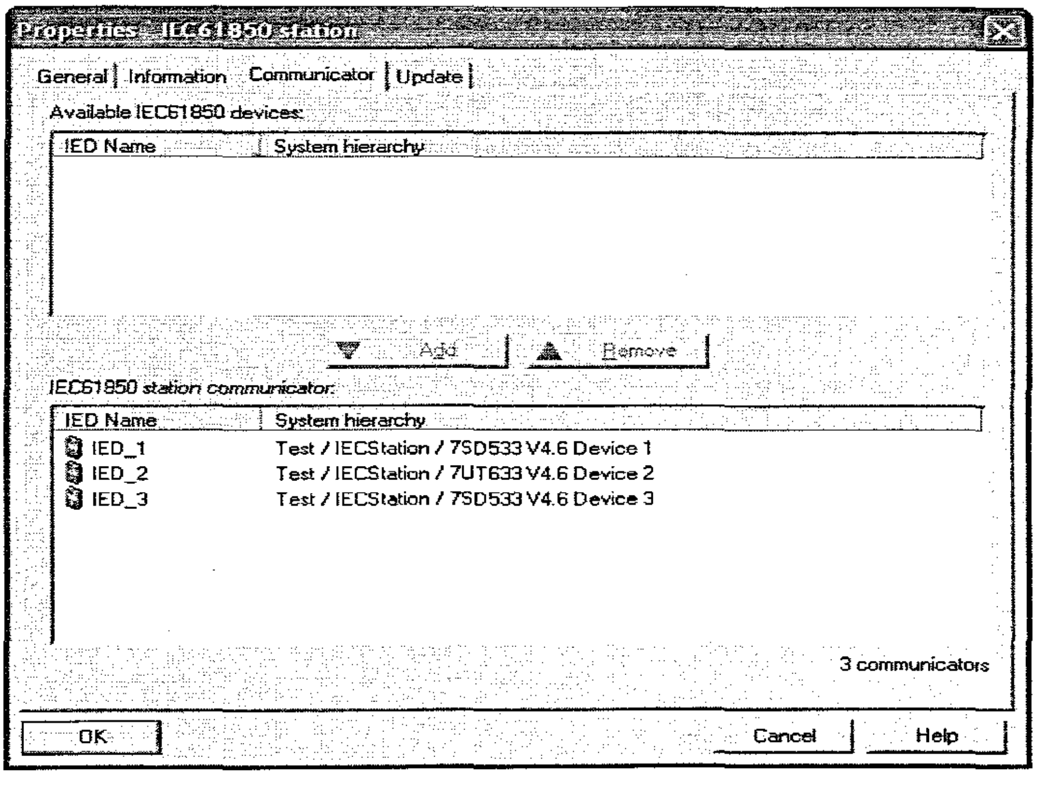


Figure 6.14: *IEC61850 station with communicator*

With DIGSI, Version 4.6, it is possible to integrate IEC 61850-conforming devices with different functionalities or even from other vendors (in this case SIEMENS and SEL device) into a project (interoperability), Figure 6.15. For this, the device's description are imported and then placed as communicators of the station. This is simply easy since a different IEC61850 communicator can be inserted into the project structure just like any other SIPROTEC4 object. Simply select **Insert new object → Other IEC61850 communicator** from the shortcut menu. This opens a new File dialog. With this, the device description in the ICD format can be selected. An icon for the communicator is then inserted in the project. However, this is unlike normal devices icon, even if it is to some extent pale faced, Figure 6.16.

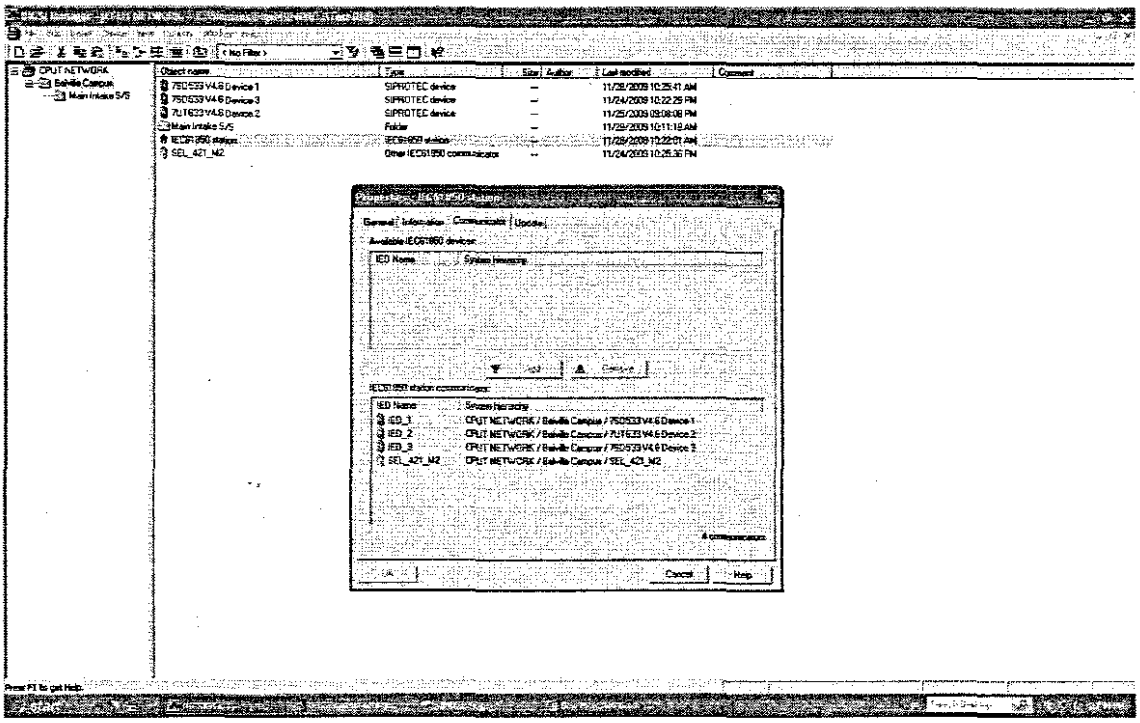


Figure 6.15: *Inserting the IEC 61850 SEL device into the project*

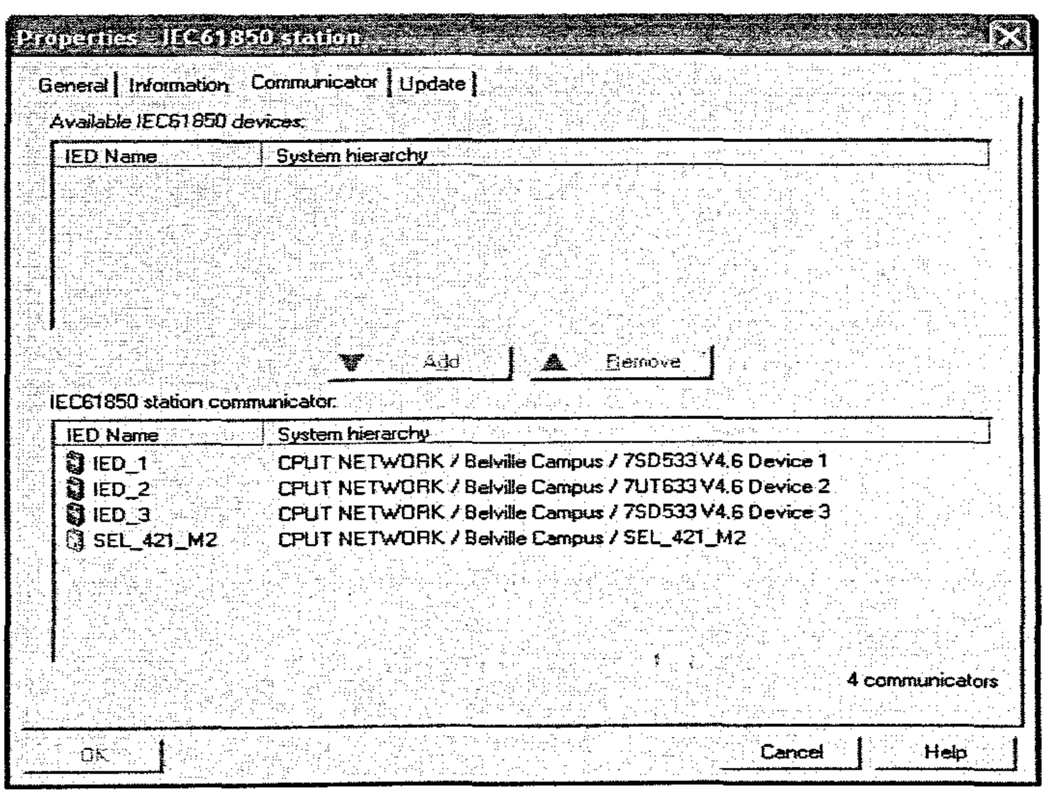


Figure 6.16: *IEC61850 station with communicator from different vendor*

It should be noted that third party IEC 61850 communicators cannot be edited with DIGSI. The devices must first be configured with the manufacture configuration software before the updated device description is being imported into DIGSI. As part of the IEC 61850 subnet, each communicator is required to have a unique name. It is recommended that such name should be made up of only eight digits (a maximum of eight letters or numbers). Modified vowels or spaces are not allowed and the first character should be a letter. Beside the device unique name, there had to be an additional name, which is the IED name. The IED name is entirely part of the communication parameters of SIPROTEC 4 devices and is used in IEC 61850 as a device name, Figure 6.17.

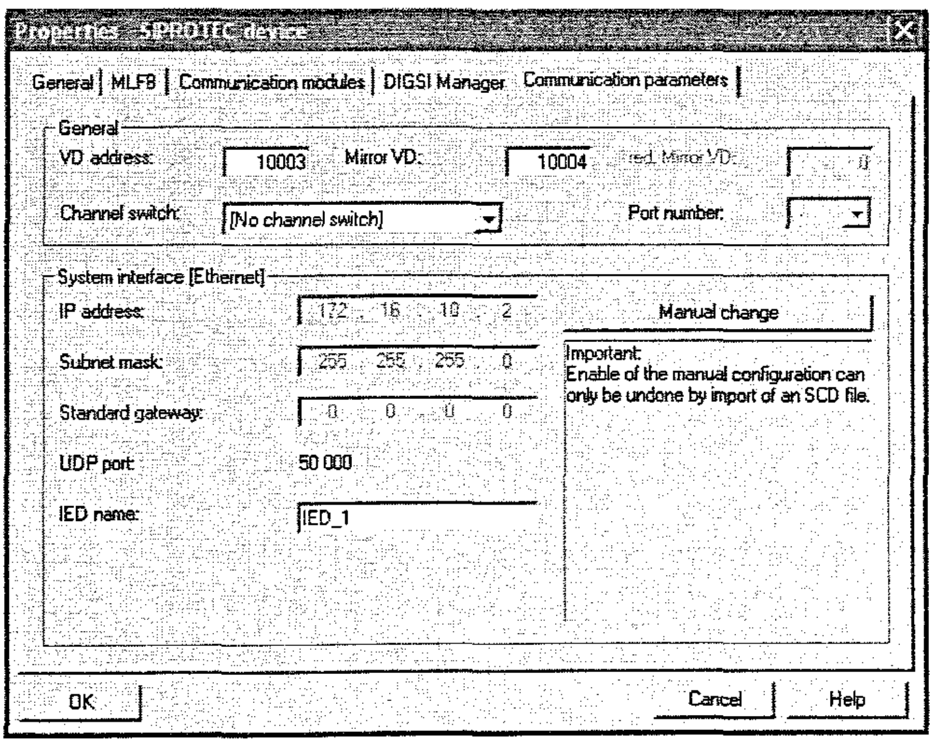


Figure 6.17: *Device properties dialog*

6.6.6 Routing of Information in Communicators

The method for checking communication between devices requires the exchange of indications between the selected devices. The definition of indications, how they are triggered and where they go is done separately for each device in the Configuration Matrix, Figure 6.18. In this case three devices have been chosen for demonstration. Device 1 is chosen as the publisher while device 2 and 3 serves as subscribers. Here a single bit is used, and this is what is described in the standard as an Op (Operate) data object (DO). A big advantage of using GOOSE messages is that, there is almost no limitation of terminals anymore. Unlike the hard wired version where the amount of input and outputs is fixed and differs from model to model, in the IEC61850 world the user can add as much "virtual outputs" and "virtual inputs" as preferred. As soon as the matrix is opened, a new information group is created, (in this case "Comm. Test) in which all the indications needed for the communication test can be stored (LED ON and LED OFF). From the information catalog, a selection of the required information can be done and placed in the information group. After all the necessary indications are generated and named, they have to be routed to the correct sources and destinations. This process is done as indicated by Figure 6.18.

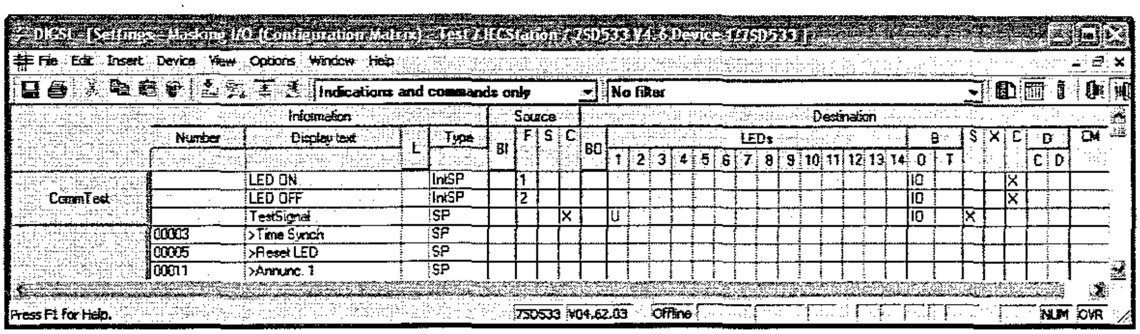


Figure 6.18: Configuration matrix for device 1

The two indications LED ON and LED OFF are sent by pressing the F1 or F2 keys on the device front panel. Therefore, the first of these indications is routed to F1 as source, and the second to F2 as source. Both indications share a common destination, the CFC function in which they have to compete against each other. Therefore these indications should be routed to the CFC as destination after the CFC has been configured.

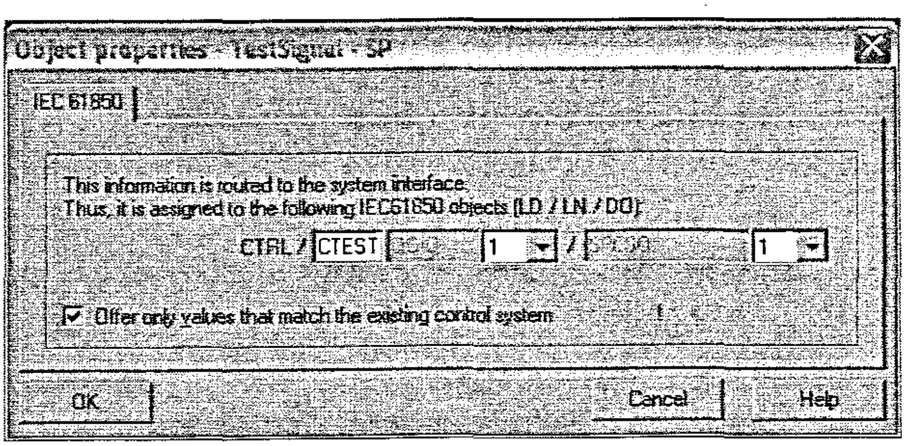


Figure 6.19: IEC61850 conforming data object dialog

Then again, and this is the main purpose of the whole exercise, the indication must be transferred to Devices 2 and 3 via the system interface. A checkmark must be placed in the Destination System Interface column as indicated in Figure 6.18. However only when routing these indications to the system interface do the user have to assign the respective information to an IEC 61850-conforming data object, Figure 6.19. As soon as self-defined information is routed to one of the system interface columns, a dialog box appears and in it, the basic components of the path are already specified for the respective information. According to the IEC61850, the information is presented based on a complete path with the following syntax:

- Logical Device (LD)
- Logical Node (LN)
- Data Object (DO)

Since the information is presented based on a complete path the user should only define an individual prefix for the logical node and select, the instance numbers, for the logical node and the data object respectively if need be.

For the matrix of the receiving devices, one indication of the same type is inserted into both devices 2 and 3 and then routed to the same sources and destinations, Figure 6.20. For that reason only the procedure for Device 2 is shown since the same procedure applies to device 3. The inputs for the indications comes from outside through the system interface. Therefore, the check mark ('x') is placed in the Source System Interface column.

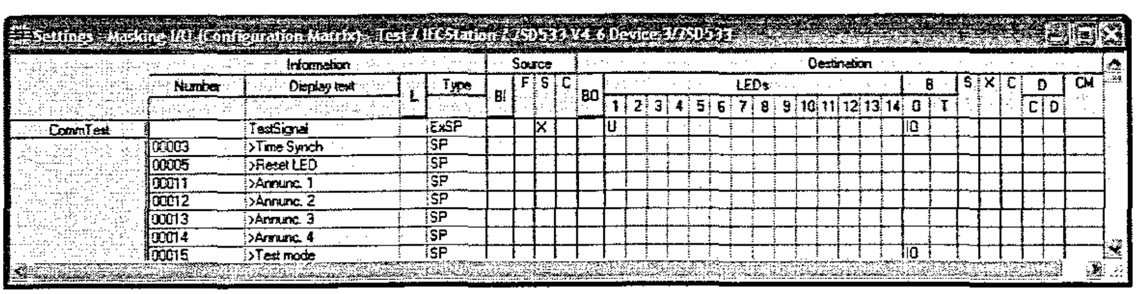


__Figure 6.20:__ Configuration matrix for device 2

After routing the information to the system interface, simply complete the prefix and the same prefix as the one used for device 1 can be used (CTEST), Figure 6.21.

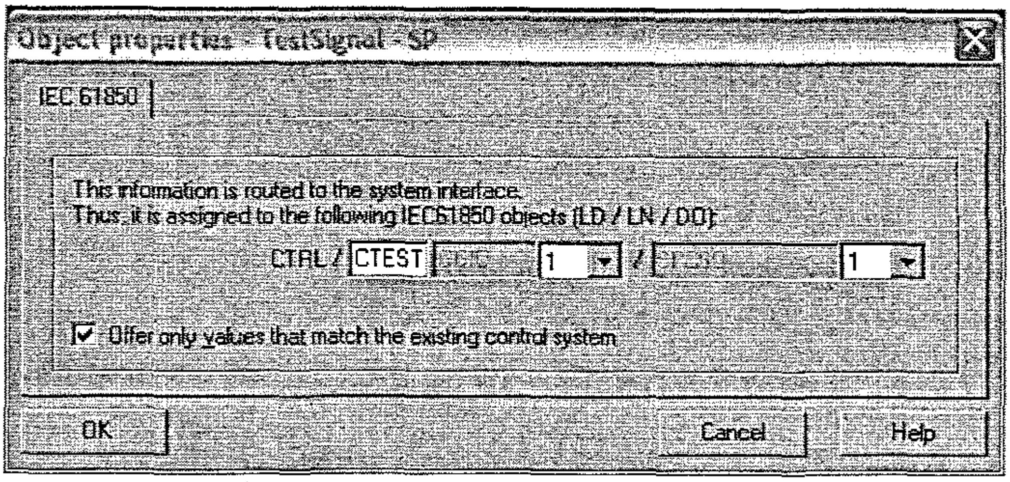


Figure 6.21: *IEC61850 conforming data object dialog*

6.6.7 Creation of a CFC Function

The fundamental procedure for creating the logic functions is very systematic and straight forward. After all the required information are routed as input value or as results for the logic function within the device matrix to CFC as destination or as source, as done in 6.6.6, the next step should be, to insert a new CFC chart inside the DIGSI Device Editor and open it with the CFC Editor.

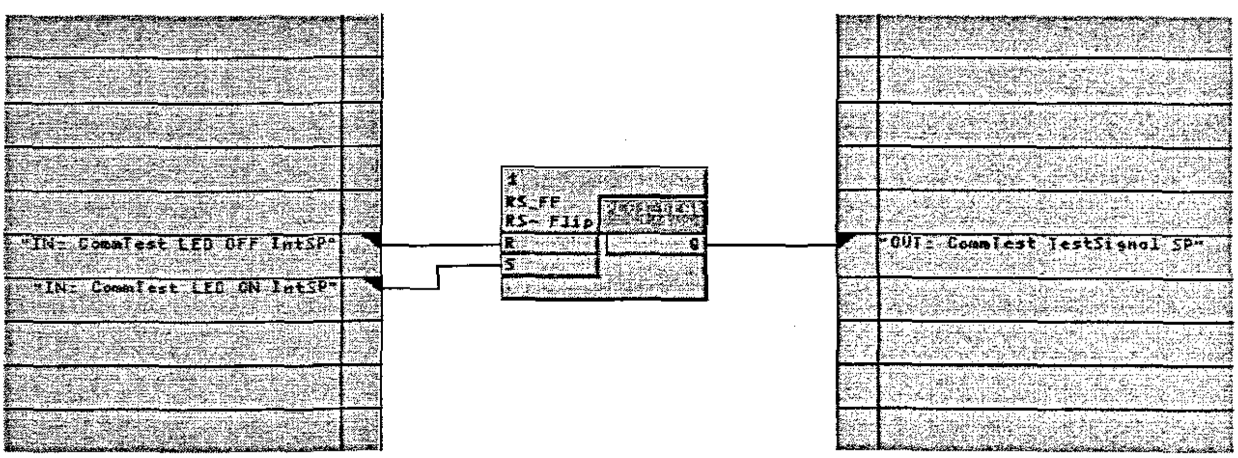


Figure 6.22: *CFC editor logic function*

The individual information is linked with functional blocks that are summarized in various types in a catalog. By using the drag & drop method, the information is placed in the CFC plan, parameterize and then get interconnected with the input and output information. The correct run sequence for the chart should be selected. Finally, the chart is compiled into a language that is understandable for the SIPROTEC 4 devices and stored together with the parameter set.

The requirement given in a point 6.6.6 is implemented with the RS-Flip- Flop block. The SET input of the Flip-Flop is interconnected with the information LED ON; while on the other hand, the RESET input is interconnected with the information LED OFF. The connection between the Flip-Flop output and the indication Test Signal makes this function perfect. The completed CFC function is shown in Figure 6.22.

6.6.8 Routing of information between Communicators

Section 6.6.6 has clearly defined the necessary indications and routings for both the participating devices. With that alone, a functioning communication, cannot be achieved as, the individual information is more or less standing around helplessly. For that reason, the DIGSI System Configurator is used to link the information between the communicators and set GOOSE application. The System Configurator obtains its information about the individual communicators from the relevant device descriptions (ICD files). Therefore, it is important that an ICD file exists for every communicator within an IEC 61850 station and must be kept up to date, at all time. With SIPROTEC 4 devices the ICD files are generated as soon as the device editor is opened. In a case where the IEC 61850 communicators are not SIPROTEC 4 devices, the corresponding ICD files should be imported into the project.

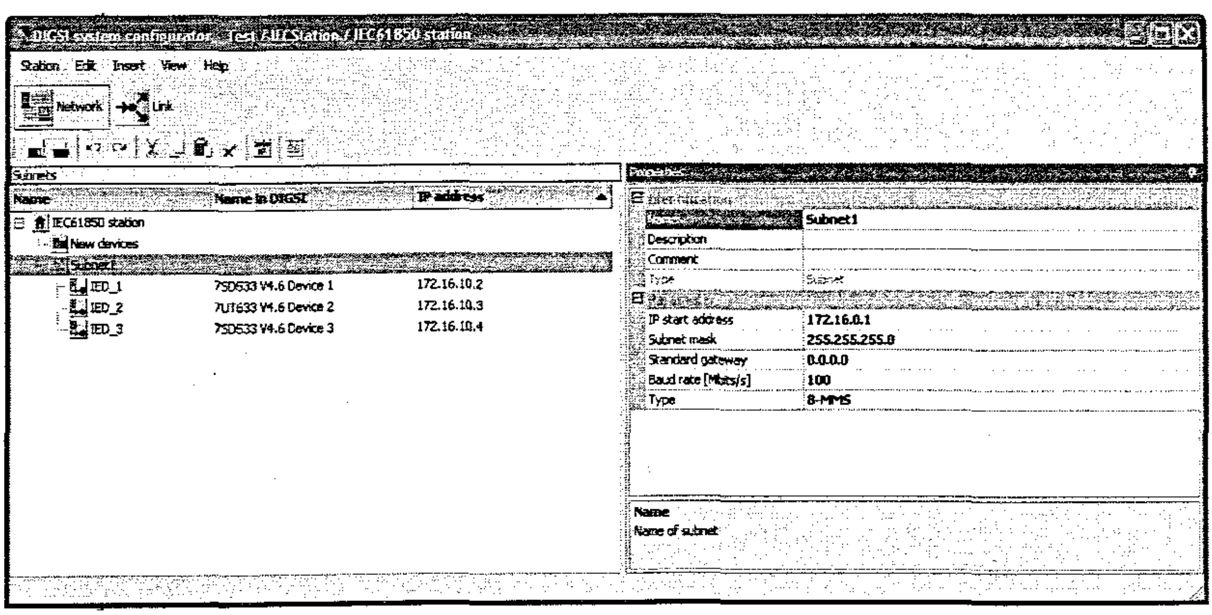


Figure 6.23: *Network area with a single subnet basic information*

On the left side of Figure 6.23 is the Network area that illustrates the current network structure. In this case, the structure consists of only one subnet. This dialog consists of all important, basic information about the communicators that are used in the project. The "Name" column, illustrate the IED names of the three devices that the user or the DIGSI Manager assigned in the DIGSI project. To the right of this is the "Name in DIGSI column" that illustrates the names of the devices as they are displayed within the project window of the DIGSI Manager.

By selecting a communicator from the Subnets window (e.g. IED_1), the Properties window will then indicate, among other things, the device type, IP address or even the manufacturer in the Identification section. The manufacturer identification could be interesting to see (as proof) since, according to IEC 61850, devices from different vendors can take part in the communication. This is illustrated in Figure 6.24 below.

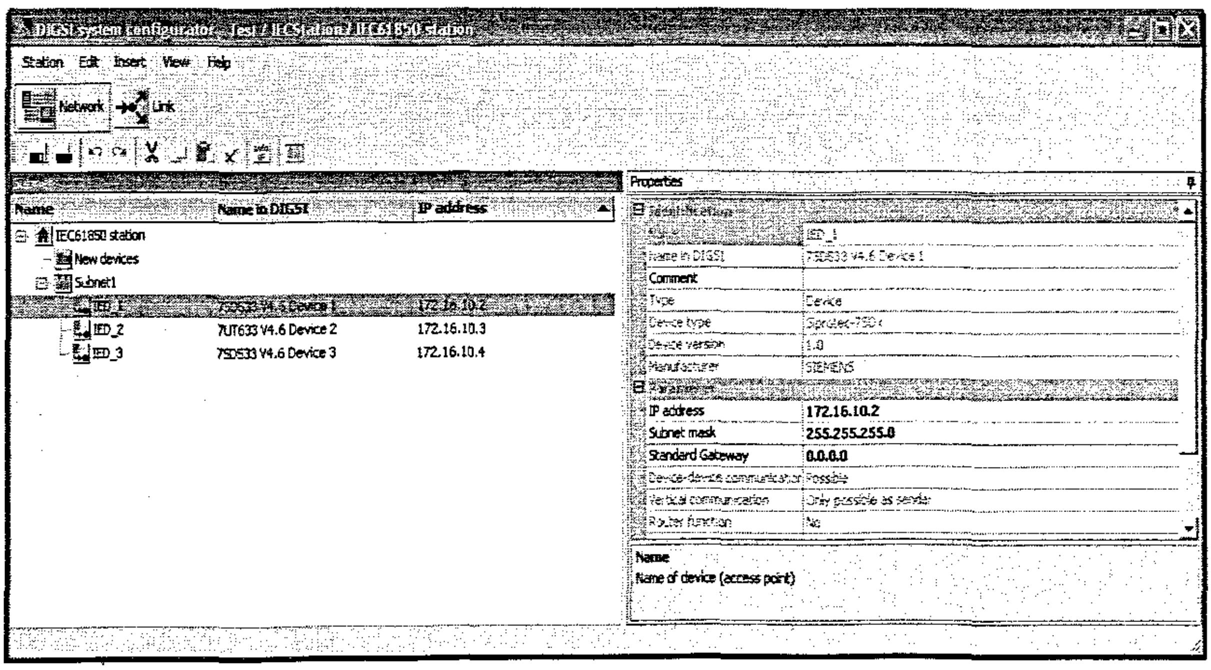


Figure 6.24: The Network area with Subnets, devices and IP addresses information

One other important thing is the IP address, it establishes good-housekeeping within the network. Hence, *invalid or double-assigned IP addresses are the root cause of information* congestion that leads to the end of a functioning communication in the Ethernet network. For this reason, the DIGSI System Configurator suggests a correct and unique IP address for each communicator when a station is opened for the first time. In most applications, such address can be accepted without being changed. Another method of issuing IP addresses is the automatic addressing where the user is only required to assign an initial IP address for the subnet. The DIGSI System Configurator then does the rest and assigns each communicator in the selected subnet with a correct IP address. It should be noted that only the IEC 61850 communicators of a DIGSI project are displayed and taken into account when addresses are being assigned. Other communicators of the network, such as, switches and PCs are not managed in the System Configurator.

In Figure 6.25, the Link area defines which information should be exchanged between individual communicators. As already seen in the previous sections, the data objects of different communicators should be linked with one another. In a traditional sense, a contact is wired as source with a binary input as destination. However, in this case, the project is dealing with a logical wiring that is done via the Ethernet bus.

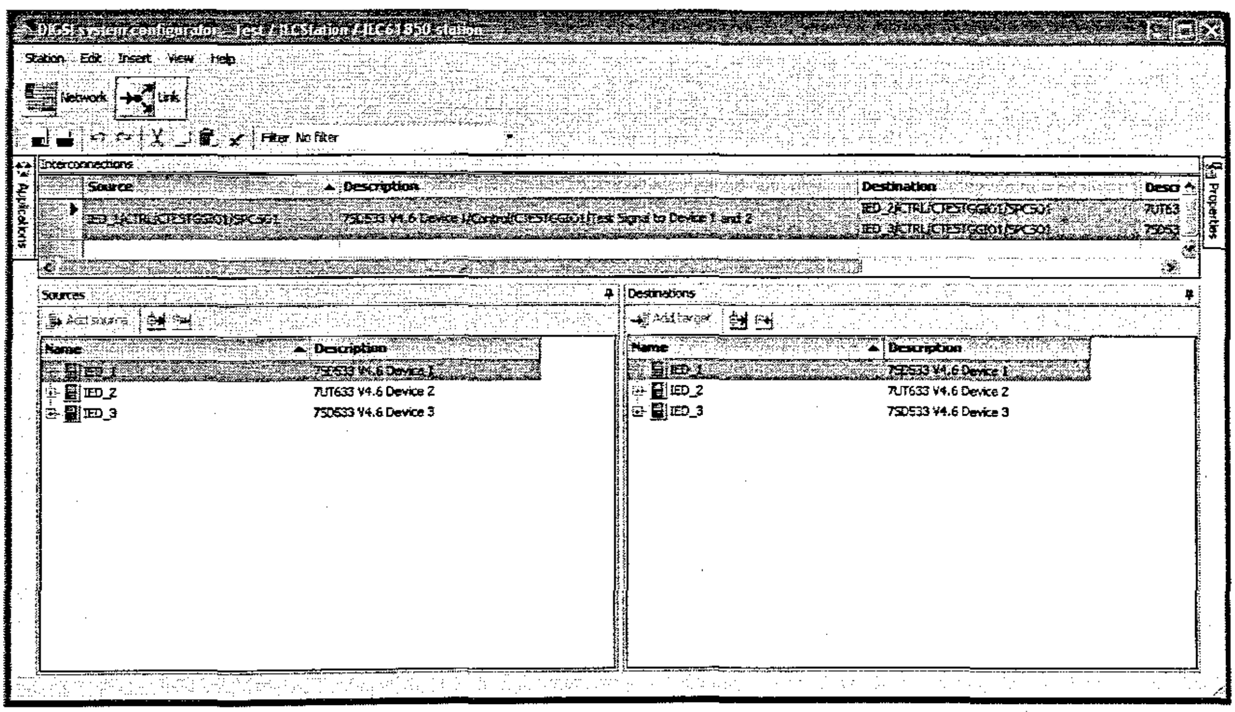


Figure 6.25: *System Configurator Link area*

In order to create a link, data object from Communicator A should be selected as source and the matching data object of Communicator B as destination. The result of this interconnection is displayed inside the Interconnections Table. The source and destination objects are clearly arranged in two separate windows in the form of a hierarchical tree structures as shown in

Figure 6.25. The sequence on how to interconnect sources and destinations with one another is open and is completely up to the user.

The interconnections are compiled as application-related at all times. Two categories of applications exist and these include the Report Applications and GOOSE Applications. Currently, the main interest is in the GOOSE application. With this application, the information on events can be broadcast quickly between different communicators and this is one of the main requirements. A GOOSE application is always taken as a subordinate of a certain subnet. This is because according to the standard, GOOSE communications, must technically be limited to one subnet at all times which makes them inactive beyond the limit of a subnet. A number of GOOSE applications can be generated within a subnet and an examples of this could be certain interlocks, measured value tasks or as in this case, a communications test. The GOOSE message is basically identified by its unique name as shown by the System Configurator in the source and destination windows in Figure 6.26 (e.g."IED_1/CTRL/CTESTGGIO1.SPCO1").

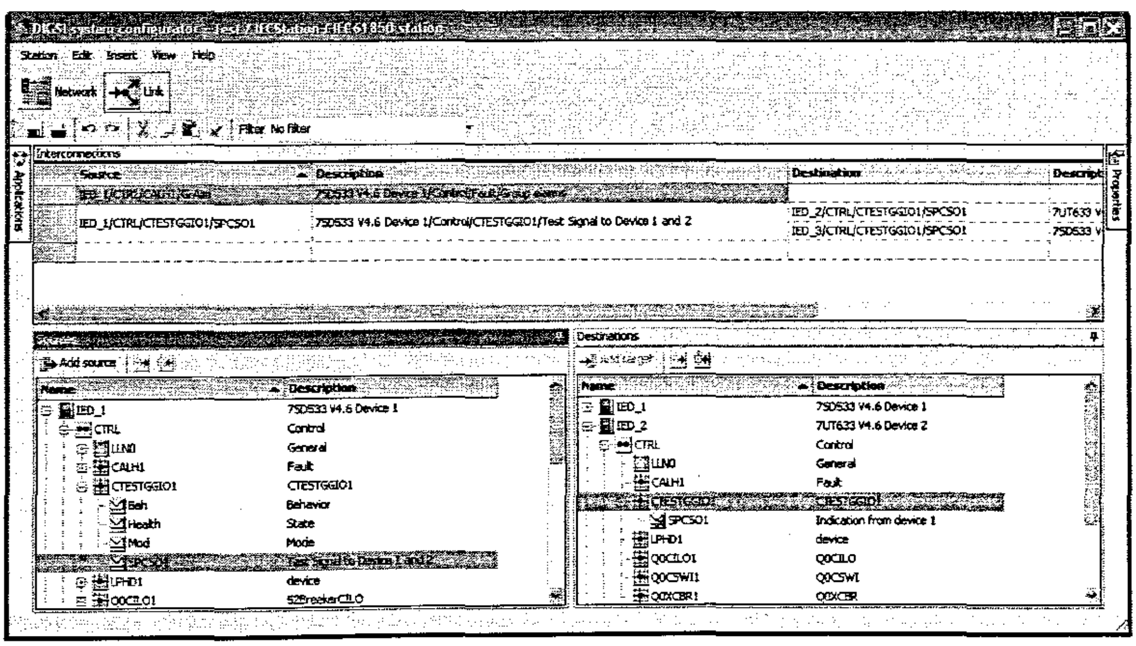


Figure 6.26: *System Configuration with GOOSE messages*

Finally after the system configuration is completed and the "wiring list" is filled out, the system gets stored in the SCD file. The IED's need to get updated with this system information, so that they know as to which GOOSE message they signed up for and which GOOSE message needs to get send out. As a result, all proprietary tools must be capable of importing the SCD file and extract the information required to configure the IED's in the correct way.

6.6.9 Timing the GOOSE messages

Timing the GOOSE messages is a very controversial debate. This is mostly caused by the fact that at times the comparison is not made out of the correct facts. Another contributing reason could be the fact that different manufacturers use different solutions for publishing and subscription of GOOSE messages, which result in different timing. A good example is that, a GOOSE message which is published by means of an external communication processor is usually slower than a GOOSE message which utilizes an integrated processor with a sophisticated algorithm. Figure 6.9 shows an example, in which the two IED's where simultaneously triggered via the Ethernet communication. The first relay used the F1 and F2 keys as triggers to publish GOOSE messages as well as to reset an output which is an input of the two secondary IED's. Figure 6.27 revealed test results that are valid for Siemens 7SD5 and 7UT6 IED's. According to Holbach, Dufaure and Duncan 2009, the IED's from other manufactures gave similar results but solutions with bigger deviations than the results shown here do exist. Modern test sets that give the user the ability to test the timing of GOOSE messages are available and it is recommended to test the GOOSE speed for any particular IED.

EventLog - 2009/10/13 - Test / IECStation / 7SD533 V4.6 Device 3/7SD533 V04.63.01

Number	Indication	Value	Date and time
	Indication from Device 1	OFF	13.10.2009 09:14:52.[illegible]
	Indication from Device 1	ON	13.10.2009 09:14:52.920
	Indication from Device 1	OFF	13.10.2009 09:14:53.320
	Indication from Device 1	ON	13.10.2009 09:14:53.720
	Indication from Device 1	OFF	13.10.2009 09:14:54.820
	Indication from Device 1	ON	13.10.2009 09:14:55.140
	Indication from Device 1	OFF	13.10.2009 09:14:56.320
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	ON	13.10.2009 09:54:47.891
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	OFF	13.10.2009 09:54:49.491
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	ON	13.10.2009 09:55:26.590
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	OFF	13.10.2009 09:55:28.290
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	ON	13.10.2009 09:55:29.490
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	OFF	13.10.2009 09:55:31.690
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	ON	13.10.2009 09:55:32.390
009.0101.01	Failure EN100 Link Channel 1 (Ch1)	OFF	13.10.2009 09:55:34.190
	Indication from Device 1	ON	13.10.2009 13:45:29.987
	Indication from Device 1	OFF	13.10.2009 13:45:32.187
	Indication from Device 1	ON	13.10.2009 13:45:32.857
	Indication from Device 1	OFF	13.10.2009 13:45:33.587
	Indication from Device 1	ON	13.10.2009 13:45:34.187
	Indication from Device 1	OFF	13.10.2009 13:45:34.787
	Indication from Device 1	ON	13.10.2009 13:45:35.287
	Indication from Device 1	OFF	13.10.2009 13:45:35.787
	Indication from Device 1	ON	13.10.2009 13:59:01.860
	Indication from Device 1	OFF	13.10.2009 13:59:05.170
	Indication from Device 1	ON	13.10.2009 13:59:07.060
	Indication from Device 1	OFF	13.10.2009 13:59:09.060
	Indication from Device 1	ON	13.10.2009 13:59:11.960
	Indication from Device 1	OFF	13.10.2009 13:59:14.260
	Indication from Device 1	ON	13.10.2009 13:59:16.560
	Indication from Device 1	OFF	13.10.2009 13:59:18.039
	Indication from Device 1	ON	13.10.2009 14:04:29.772
	Indication from Device 1	OFF	13.10.2009 14:04:35.792
	Indication from Device 1	ON	13.10.2009 14:04:40.552

Figure 6.27: Test record of GOOSE Messages

6.6.10 Priority Tagging

Standard Ethernet serves as a path over which GOOSE messages are being transmitted. In order to enhance the timing of the GOOSE messages, a Virtual LAN tagging is used, and it includes priority tagging. The standard network components such as network switches support the priority tagging of telegrams. The benefit of the priority tagging resides in the ability of the telegram source to inform the network infrastructure that the telegram has a higher priority or not. According to Duncan 2009, the switches work with priority oriented FIFOs that allow a GOOSE telegram to get ahead of the other Ethernet traffic, and this is displayed in Figure 6.28.

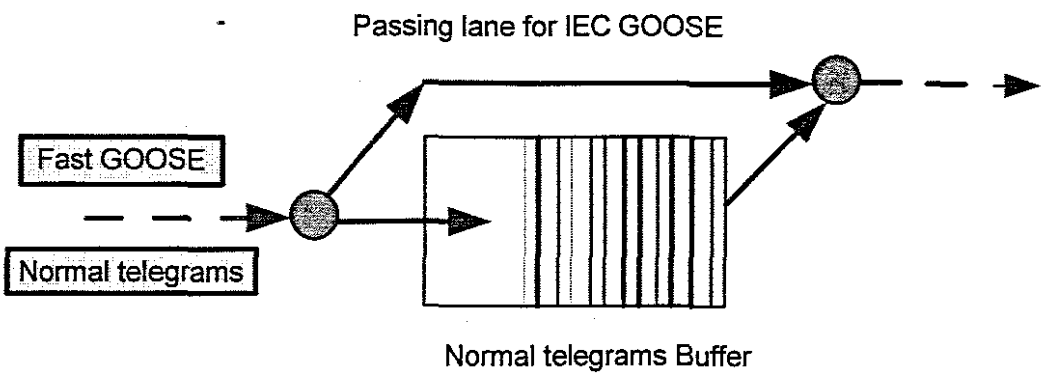


Figure 6.28: *Intelligent Switch - Priority tagging in Ethernet*

6.6.11 In-build supervision

As the GOOSE communication purely relies on the multicast principle, (e.g. one telegram is published to multiple subscribers), there is no acknowledgement. Therefore, the publisher has to sequentially send out the telegram several times for every different state of data that have to be transmitted. Each GOOSE telegram includes a field; (Time Allowed to Live) set by the publisher to notify each subscriber about the lifetime of each telegram. In case no new repetition is received by a subscriber within the (Time Allowed to Live) timeout since the latest received telegram, the subscriber will then declare the connection as down and forward the information as questionable to the application. The GOOSE telegram offers the built-in supervision for all the information that it conveys **(Holbach & Dufaure, 2009)**.

6.6.12 Network quality

The GOOSE message includes quality information that enables the network quality to be diagnosed. Every GOOSE message includes a state and a sequence number. A sequence number characterizes a repetition of any given state. Every GOOSE subscriber tracks the state and sequence numbers and can therefore, deliver important network diagnosis in case the expected increment is not achieved. This could be due to network congestion (overload), or loss of telegram. The diagnosis of the network quality occurs during the commissioning phase to ensure that the system contain the necessary bandwidth to cater for the worst overload that can be experienced.

6.7 PROTECTION, AUTOMATION AND INTERLOCKING FUNCTION OF THE CPUT MAIN INTAKE SUBSTATION

Based on the CPUT network operational conditions, the thesis has established the substation logic and automation schemes at the Main Intake substation, and has implemented the exchange of information between IEDs using the IEC 61850 GOOSE protocol. The reverse busbar blocking scheme is implemented. The design approach implemented in developing the logic schemes is based on the following factors:

- The bay logic schemes are preferably developed at the IED level, in a decentralized manner for information sharing purposes. The application of GOOSE messages is prioritized.
- The logic schemes processing time is shortened enough to ensure correct operation between IEDs. This is achieved by applying a common processing time, to all the user logic schemes associated, directly or indirectly, with the IED protection functions.
- At substation level, the information exchange among IEDs is achieved using IEC 61850 GOOSE messages.

The application of IEC 61850 devices has reduced the IED's physical I/Os, increased the communications speed, and has reduced the required cables inside the panels. The topology used ensures that a single failure of the Ethernet communications network should not compromise any execution of the logic schemes. The exercise of automation to perform equipment switching that was previously executed by operators resulted in an increase in system safety, reliability, and availability. A large reduction in the interruption time that CPUT could experience is reduced since automatic reclosure (AR) functionality is included. It should be noted that all of the schemes discussed in this section are implemented using GOOSE messages.

6.7.1 Reverse Busbar Blocking Scheme

In distribution systems, the reverse busbar protection is known to be a cost-effective solution for speedy clearance of busbar faults. Reverse busbar blocking scheme can only be applied on single busbars with a fixed direction of power-flow and fault current flow **(SIEMENS PTD PA 13, 2008)**. Figure 6.29 and 6.30, show typical applications as used at the CPUT Main Intake substation to replace the existing traditional co-ordination. The types of IED's used are the 7SD5 on the two outgoing feeders and the 7UT6 on the incoming feeder. **Note:** ***Fault in feeder:*** *the protection device next to the fault releases a trip signal, and issues a block signal to the incoming bay.* For this application as illustrated in Figure 6.29, the protection device on the incoming bay will be provided with blocking signals from the outgoing bays (the feeder bays). If one of the outgoing bays detects a fault, (pick-up signal), a blocking signal is automatically routed to the protection of the incoming bay (GOOSE Message to Block the Fast Overcurrent Element of the Incoming Feeder). This blocking signal prevents the fast tripping of the incoming bay (I>> stage) from operating. The blocking signal may only last for one second. A CFC-chart in the incoming bay is required for this application.

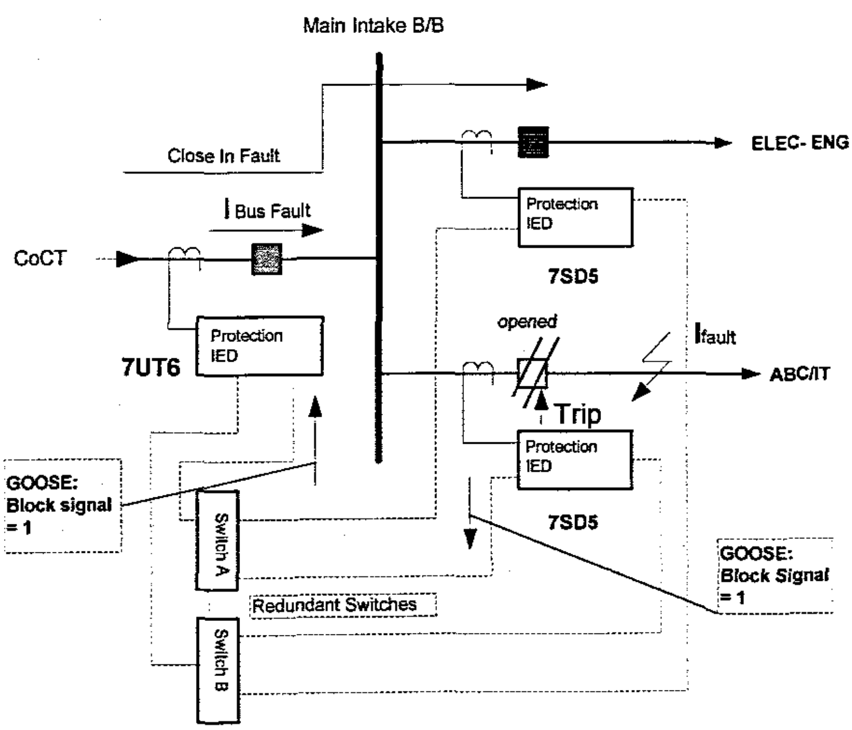


Figure 6.29: *Fault on the feeder*

Note: ***Fault on busbar:*** *the protection device in the incoming bay issues a fast trip with I>> stage after the set delay, e.g. 40ms. None of the feeder bays relays pick up hence, they do not issue a block signal, Figure 6.30.* Although it is possible to allocate a signal from a binary input so that it provides the blocking of a protection stage it is not possible to allocate more than one binary input to directly block one protection stage (the reason being that if two binary inputs that provide the same blocking signal have a different state, the device logic would not know which of the two binary inputs should be used).

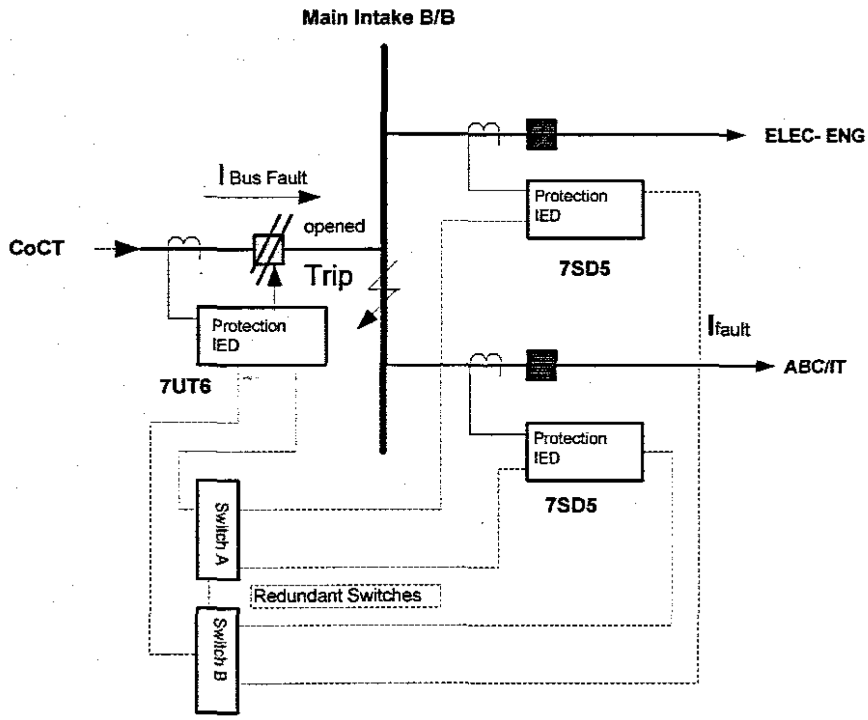
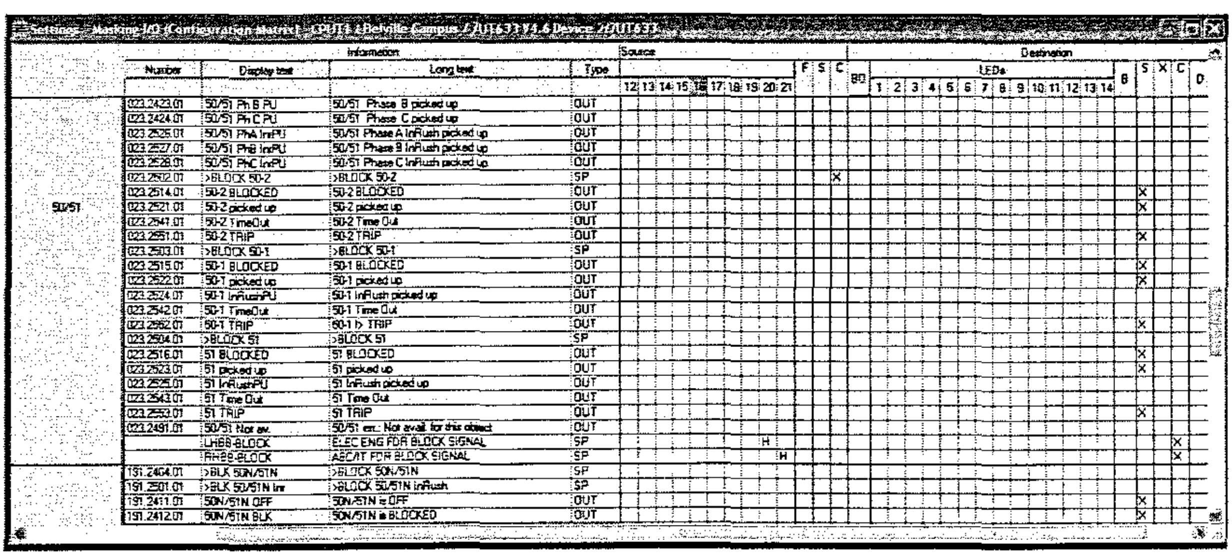


Figure 6.30: *Fault on busbar*



Settings - Masking I/O (Configuration Matrix) - CPUT1 / Belville Campus / 7UT633 V4.6 Device 2/7UT633

	Number	Display text	Long text	Type	12	13	14	15	16	17	18	19	20	21	F	S	C	BO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	B	S	X	C	D
50/51	023.2423.01	50/51 Ph B PU	50/51 Phase B picked up	OUT																																	
	023.2424.01	50/51 Ph C PU	50/51 Phase C picked up	OUT																																	
	023.2526.01	50/51 PhA InPU	50/51 Phase A InRush picked up	OUT																																	
	023.2527.01	50/51 PhB InPU	50/51 Phase B InRush picked up	OUT																																	
	023.2528.01	50/51 PhC InPU	50/51 Phase C InRush picked up	OUT																																	
	023.2502.01	>BLOCK 50-2	>BLOCK 50-2	SP													X																				
	023.2514.01	50-2 BLOCKED	50-2 BLOCKED	OUT																														X			
	023.2521.01	50-2 picked up	50-2 picked up	OUT																														X			
	023.2541.01	50-2 TimeOut	50-2 Time Out	OUT																																	
	023.2551.01	50-2 TRIP	50-2 TRIP	OUT																														X			
	023.2503.01	>BLOCK 50-1	>BLOCK 50-1	SP																																	
	023.2515.01	50-1 BLOCKED	50-1 BLOCKED	OUT																														X			
	023.2522.01	50-1 picked up	50-1 picked up	OUT																														X			
	023.2524.01	50-1 InRushPU	50-1 InRush picked up	OUT																																	
	023.2542.01	50-1 TimeOut	50-1 Time Out	OUT																																	
	023.2552.01	50-1 TRIP	50-1 I> TRIP	OUT																														X			
	023.2504.01	>BLOCK 51	>BLOCK 51	SP																																	
	023.2516.01	51 BLOCKED	51 BLOCKED	OUT																														X			
	023.2523.01	51 picked up	51 picked up	OUT																														X			
	023.2525.01	51 InRushPU	51 InRush picked up	OUT																																	
	023.2543.01	51 Time Out	51 Time Out	OUT																																	
	023.2553.01	51 TRIP	51 TRIP	OUT																														X			
	023.2491.01	50/51 Not av.	50/51 err.: Not avail. for this object	OUT																																	
		LHBB-BLOCK	ELEC ENG FOR BLOCK SIGNAL	SP									H																							X	
		RHBB-BLOCK	ABC/IT FOR BLOCK SIGNAL	SP										H																						X	
	191.2404.01	>BLK 50N/51N	>BLOCK 50N/51N	SP																																	
	191.2501.01	>BLK 50/51N Inr	>BLOCK 50/51N InRush	SP																																	
	191.2411.01	50N/51N OFF	50N/51N is OFF	OUT																														X			
	191.2412.01	50N/51N BLK	50N/51N is BLOCKED	OUT																														X			

Figure6.31: *Incoming Bay relay input/output matrix*

The instantaneous **(I>>)** stage of the in-comer relay is blocked with the *023.2502.01 >Block 50-2* signal and the *191.2514.01 >Block 50N-2* signal. These signals are allocated with the *source CFC*, refer to Figure 6.31. Here the outgoing feeder relays with their blocking signal connected in parallel and designated as LHBB-block and RHBB-block, provides a blocking input signal to the incoming bay relay via the binary input. The blocking signal is routed to the user defined single-point annunciation (binary input 20 and 21) in the matrix. The new user defined single point annunciations, which should be connected to the binary inputs is therefore generated. This signal is routed with *destination CFC*, so that it is available inside the CFC charts, Figure 6.32.

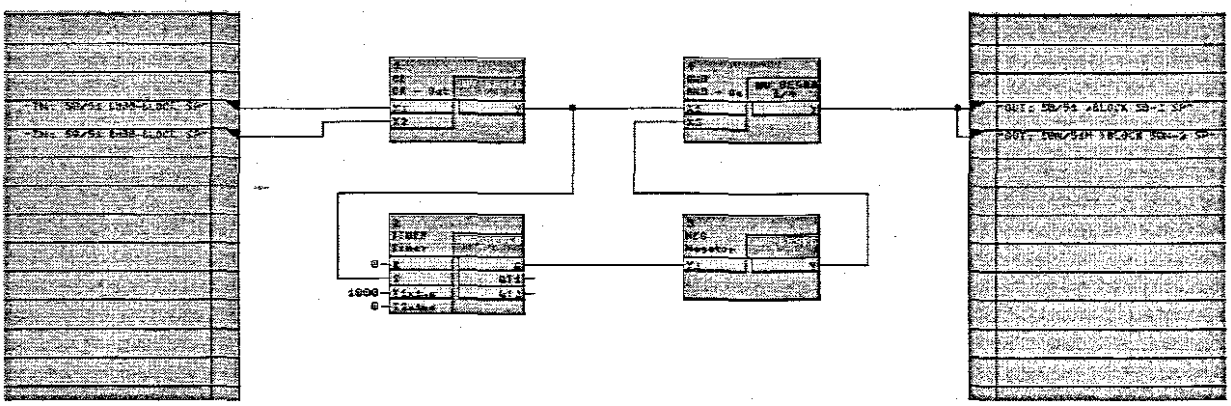
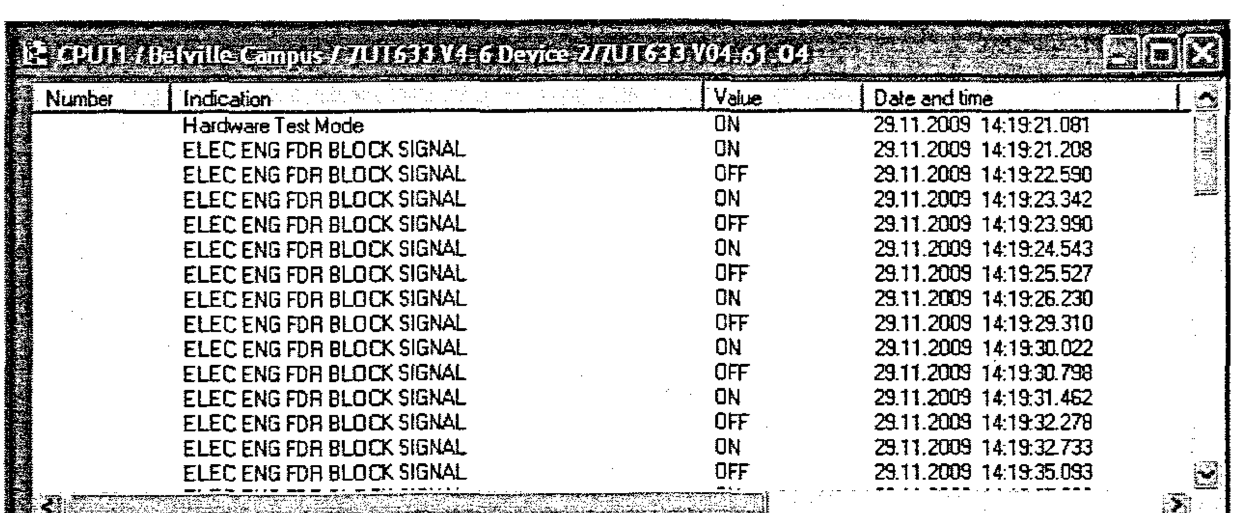


Figure 6.32: *Blocking CFC chart in the incoming bay*

The GOOSE event for the outgoing feeder relays with their blocking signal designated as LHBB-block and RHBB-block, which provides a blocking input signal to the incoming bay relay via the binary input, is shown in Figure 6.33 and 6.34 respectively. The *023.2502.01 >Block 50-2* signal and the *191.2514.01 >Block 50N-2* signal that block the instantaneous (**I>>**) stage of the in-comer relay is shown in Figure 6.35.



Number	Indication	Value	Date and time
	Hardware Test Mode	ON	29.11.2009 14:19:21.081
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:21.208
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:22.590
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:23.342
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:23.990
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:24.543
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:25.527
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:26.230
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:29.310
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:30.022
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:30.798
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:31.462
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:32.278
	ELEC ENG FDR BLOCK SIGNAL	ON	29.11.2009 14:19:32.733
	ELEC ENG FDR BLOCK SIGNAL	OFF	29.11.2009 14:19:35.093

Figure 6.33: *Blocking signal from Electrical Engineering feeder protection device*

CPUT1 / Belville Campus / 7UT633 V4.6 Device 2/7UT633 V04.61.04

Number	Indication	Value	Date and time
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:34:50.636
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:34:57.978
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:00.058
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:01.258
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:02.193
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:03.090
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:04.745
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:06.090
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:07.193
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:08.330
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:09.497
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:10.321
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:11.089
	ABC/IT FDR BLOCK SIGNAL	OFF	29.11.2009 14:35:14.290
	ABC/IT FDR BLOCK SIGNAL	ON	29.11.2009 14:35:15.417

Figure 6.34: *Blocking signal from ABC/IT feeder protection device*

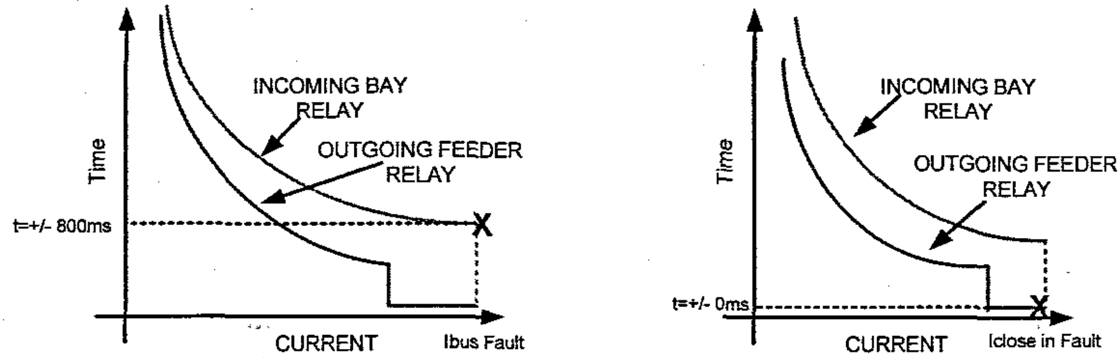
CPUT1 / Belville Campus / 7UT633 V4.6 Device 2/7UT633 V04.61.04

Number	Indication	Value	Date and time
191.2502.01	>BLOCK 50N-2	ON	29.11.2009 14:46:36.634
191.2514.01	50N-2 BLOCKED	ON	29.11.2009 14:46:37.043
191.2502.01	>BLOCK 50N-2	ON	29.11.2009 14:46:37.529
191.2514.01	50N-2 BLOCKED	ON	29.11.2009 14:46:37.954
191.2502.01	>BLOCK 50N-2	ON	29.11.2009 14:46:38.594
191.2514.01	50N-2 BLOCKED	ON	29.11.2009 14:46:38.937
191.2502.01	>BLOCK 50N-2	ON	29.11.2009 14:46:39.425
191.2514.01	50N-2 BLOCKED	ON	29.11.2009 14:46:39.812
023.2502.01	>BLOCK 50-2	ON	29.11.2009 14:47:43.685
023.2514.01	50-2 BLOCKED	ON	29.11.2009 14:47:43.685
023.2514.01	50-2 BLOCKED	ON	29.11.2009 14:47:45.398
023.2502.01	>BLOCK 50-2	ON	29.11.2009 14:50:29.798
023.2514.01	50-2 BLOCKED	ON	29.11.2009 14:50:31.045
023.2502.01	>BLOCK 50-2	ON	29.11.2009 14:50:31.948
023.2514.01	50-2 BLOCKED	ON	29.11.2009 14:50:32.316

Figure 6.35: *Blocking signal on the incomer protection device*

A logic selectivity scheme adopted (using DIGSI4), provides high-speed protection against internal substation faults. With this scheme, a definite-time overcurrent element is enabled in the incoming bay relay to detect faults in the 11 kV busbar. Whenever the fault is detected in one of the *feeder relay operation* boundaries, a signal is sent to block the definite-time overcurrent element of the incoming bay relay to prevent the uncoordinated operation. GOOSE messages serve the purpose. With the existing traditional co-ordination, faults that occur in the 11 kV busbar are cleared in a fairly long period of time, in the region of +/-800 milliseconds, Figure

6.36a. On the other hand with IEC61850, a close-in fault in any of the feeders is rapidly cleared by the instantaneous overcurrent element of the feeder relays, Figure 6.36b.



a) Traditional Coordination

b) Time to Clear a Close-in Fault in the Feeder

Figure 6.36: *Logic and Time based characteristic*

6.8 IEC61850 BASED TEST LAB

A laboratory replica of a typical substation automation system is created at the CPUT's control and automation laboratory to perform the platform tests of the CPUT reticulation network protection project. All the simulations in this chapter were provided using this system. The DIgSILENT results obtained in chapter 6 were also validated using this system; Figure 6.32.The main objectives of the Test Lab are to conduct all the approval tests of the CPUT Power system, to validate the system as a whole, and to verify the consistency of the logic schemes in details for the Main Intake substation. Additional to this is the training of students that are in the protection field and employees from utility companies. Using this Test Lab, CPUT can observe and validate all information, including communications speed between the protection devices and system data traffic. It should be noted that it is not necessary to change the wiring of the Test Lab when performing different schemes, since the exchange of information between the IEDs is accomplished through GOOSE messages; therefore, only the IED's settings are changed. Currently the application of different schemes is limited using the Test Lab due to some equipment that is not yet available (the OMICRON Test Sets). These sets include the CMC 256 with NET-1 option, a CMC 256 plus and a CMC 356. They enable the testing of multifunctional relays (IED's) with binary status signaling via GOOSE messages and they provide the following features:

- Capturing GOOSE messages from the network and reacting on specific status information in the messages,
- Simulating IEDs to send out GOOSE messages,
- Configuration software module, which is used to set up the subscriptions for receiving GOOSE messages and to set up the simulation of IEDs for sending GOOSE messages etc

6.9 TESTING AND APPLICATION (OVERCURRENT)

The aim of the test is to determine the pick-up values, drop-off values and testing of the tripping time of the particular protection functions. For the testing of protective equipment to be accomplished, the test set and the protection device to be tested must be linked together physically and by means of software. In this application, a CMC 256 with NET-1 option OMICRON test set is used in conjunction with the personal computer, the 7SD5 and 7UT6 SIEMENS IED's. The software involved in this application is the, OMICRON test universe V2.3, DIGSI4 and SIGRA4 from SIEMENS. After all the equipment has been connected and powered, the test set need to be configured. This is achieved by associating the test set with the computer (by ensuring that their IP addresses are of the same range).Now that the test set is associated with the rest of the equipments, system set-up is then performed. This includes entering of the test parameters and settings in both the IED's and the CMC 256 test set. It is important to make sure that the settings in the relays correspond with the one in the setting sheet that is generated using DIgSILENT. The instantaneous (INST) and overcurrent (OC) characteristics are used for faults between line one to line three (L1, L2 and L3). In this case a stand-alone testing is performed.

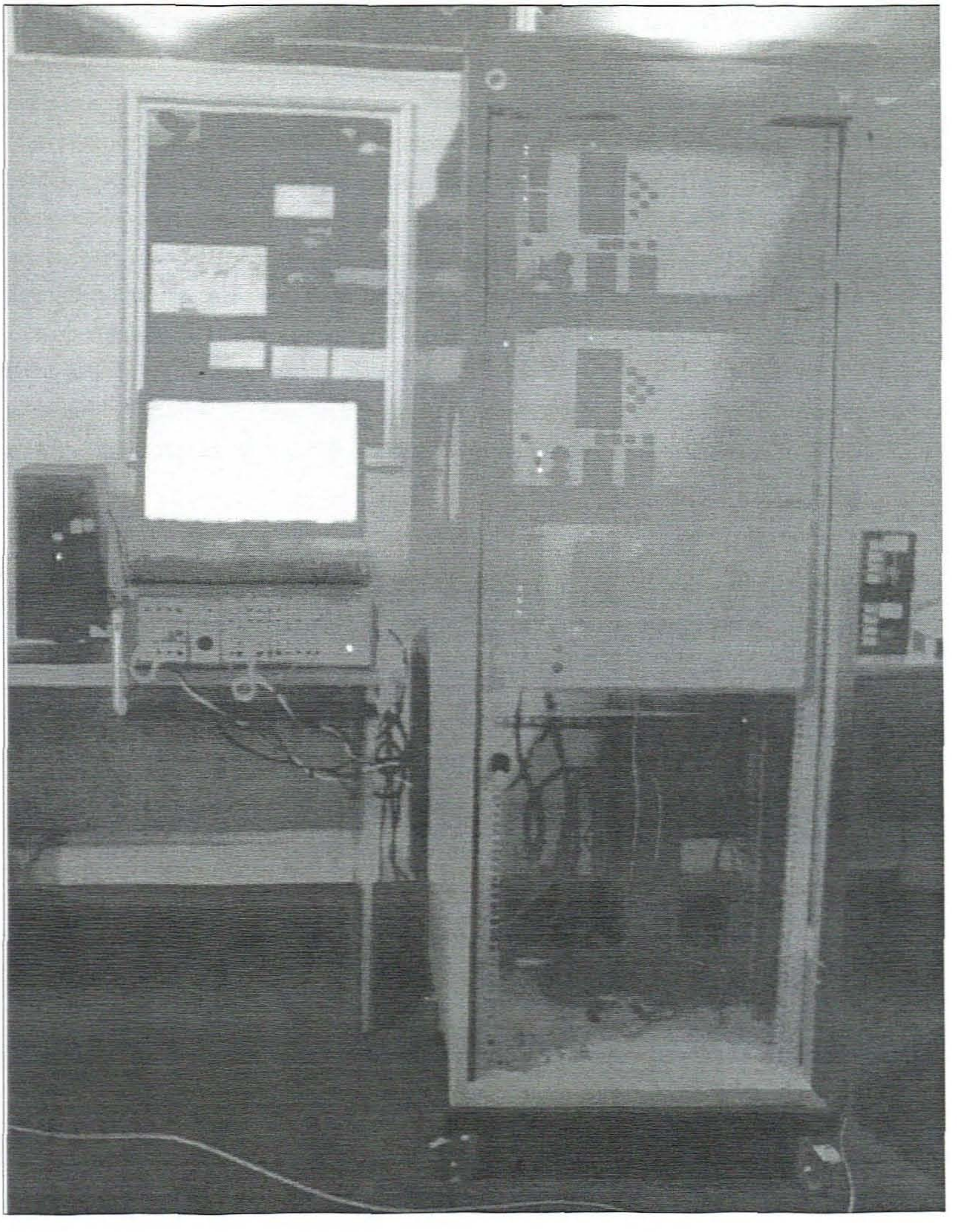


Figure 6.37: *Platform for Testing in the Laboratory*

6.9.1 Test object overcurrent INST L1-L2

With the fault between L1and L2, the manual and automatic testing using the OMICRON overcurrent testing module is used on a non-direction overcurrent IED with definite time and inverse time curve characteristics. The phase faults are simulated using the positive sequence model. Table 6.4 indicates the settings for the phase to phase fault. The pick-up current (I>) and the instantaneous current (I>>) settings are shown. The time multiplier of 0.3, 0.1, and 0.05 sec are chosen. For the IDMT, the IEC Normal Inverse characteristic is used. The test currents are defined in multiple of pick-up currents and the first shot is executed at a current of 1.24 times pick-up, Table 6.5. The test results for the fault in question are shown in Table 6.6. Here the nominal time, actual time and the deviations are shown. The overcurrent characteristics diagram is shown in Figure 6.38. Next to the characteristic diagram is the block that indicates the fault type and the status of the test. Six test points were allocated and has passed.

Table 6.4: *Test object overcurrent parameters INST L1-L2*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	Yes	3.000 In (3.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.5: *Pick-up test settings for fault type L1-L2*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.24 I>	1.24	n/a	9.741 s	6.439 s	17.61 s	35.21 s
2.26 I>	2.26	n/a	2.549 s	2.164 s	2.993 s	5.987 s
4.13 I>	4.13	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
5.42 I>	5.42	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
7.95 I>	7.95	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
8.91 I>	8.91	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms

Table 6.6: *Test results for fault type L1-L2*

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:51:25	Test End:	28-Oct-2009 13:51:49
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L1-L2

Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.24 I>	1.24	n/a	9.741 s	9.819 s	0.80	Tested		Passed
2.26 I>	2.26	n/a	2.549 s	2.543 s	-0.24	Tested		Passed
4.13 I>	4.13	n/a	100.0 ms	132.6 ms	32.60	Tested		Passed
5.42 I>	5.42	n/a	100.0 ms	130.2 ms	30.20	Tested		Passed
7.95 I>	7.95	n/a	100.0 ms	128.2 ms	28.20	Tested		Passed
8.91 I>	8.91	n/a	100.0 ms	128.1 ms	28.10	Tested		Passed

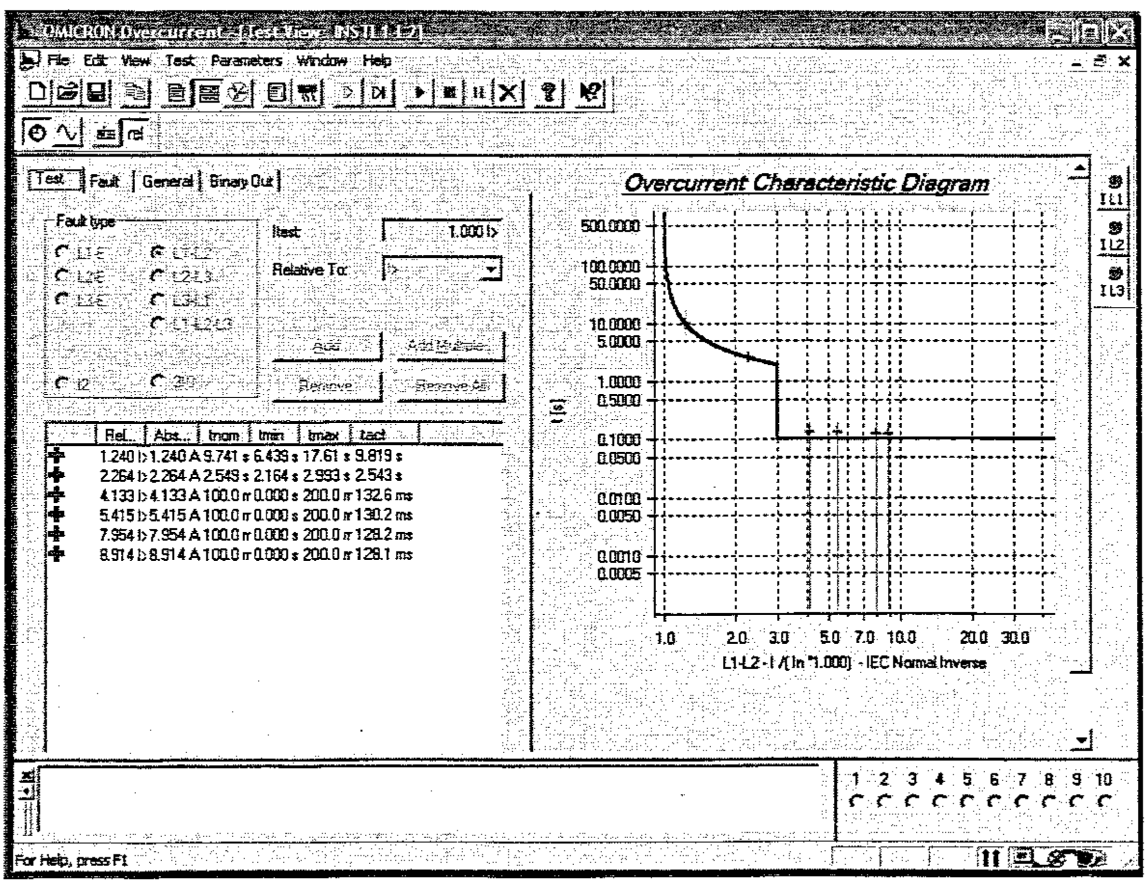


Figure 6.38: Test view INST L1-L2

6.9.2 Test object overcurrent INST L2-L3

The overcurrent parameters for the fault between Line 2 and Line3 are illustrated in Table 6.7. Again time discrimination and discrimination by both time and current (IDMT) is applied. An appropriate time delay of 0.1 sec is set on the relay for time discrimination characteristic. Although the current threshold must be exceeded to initiate the definite time, the quantity of the fault current does not have any influence on the time delay. The pick-up test settings are shown in Table 6.8 while the testing results are illustrated in Figure 6.39 and Table 6.9 respectively. The pick-up and tripping characteristics are further analyzed using SIGRA4, Figure 6.40. The SIGRA4 application program plays a major role in support of the fault events analysis. It presents a graphic display of the recorded data during the fault event and uses the measured values to calculate further variables, such as impedances, outputs or R.M.S. values, which make it easier to analyze the fault record. Cursor 1 and cursor 2 are assigned to the time axis. If a cursor is moved along the time axis the related instants can be read in the corresponding tables in all views. The pick-up and tripping characteristics are shown in Figure 6.41.

Table 6.7: *Test object overcurrent parameters INST L2-L3*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	Yes	3.000 In (3.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.8: *Pick-up test settings for fault type L2-L3*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.24 I>	1.24	n/a	9.741 s	6.439 s	17.61 s	35.21 s
2.26 I>	2.26	n/a	2.549 s	2.164 s	2.993 s	5.987 s
4.13 I>	4.13	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
5.42 I>	5.42	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
7.95 I>	7.95	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
8.91 I>	8.91	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms

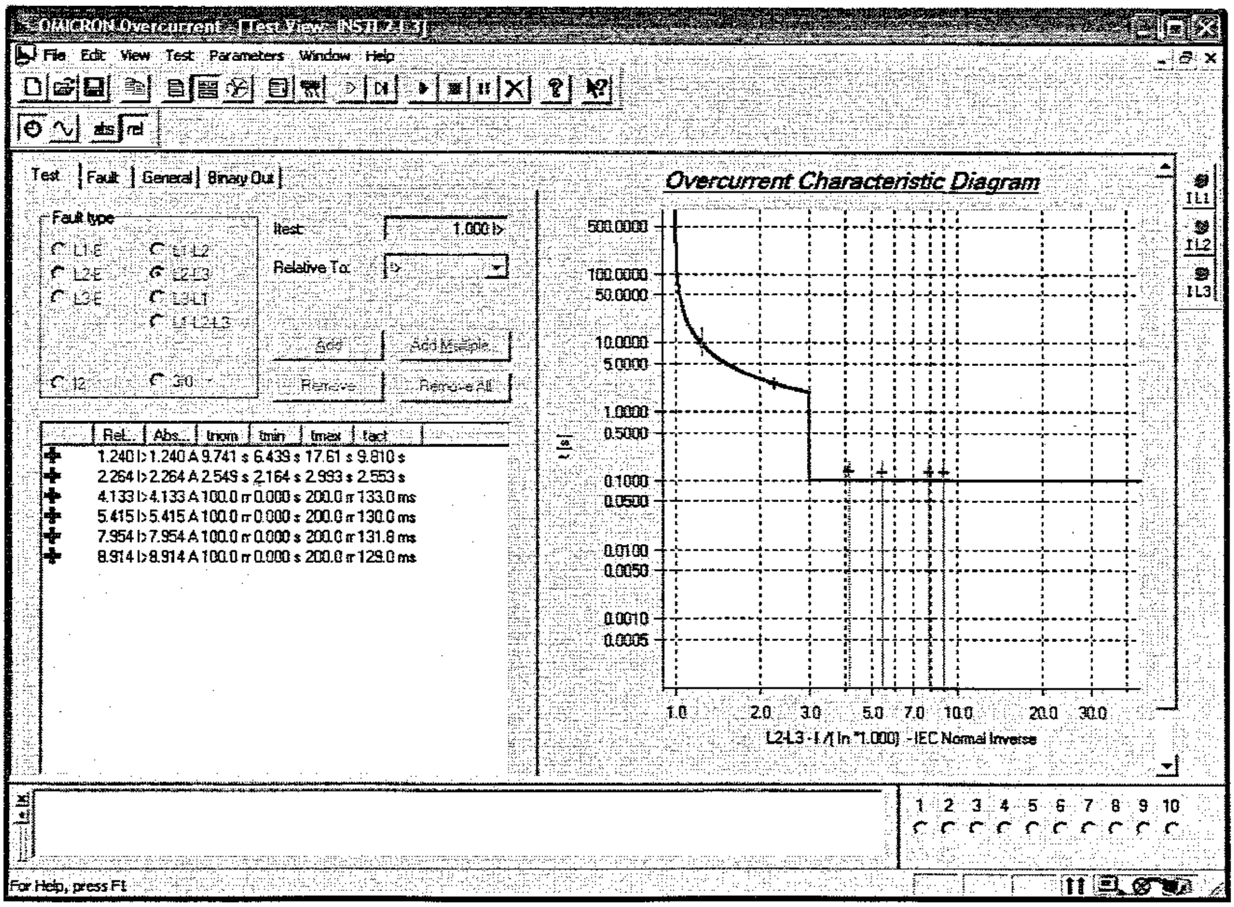


Figure 6.39: *Test view INST L2-L3*

Table 6.9: *Test results for fault type L2-L3*

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:59:47	Test End:	28-Oct-2009 14:00:12
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L2-L3

Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.24 I>	1.24	n/a	9.741 s	9.810 s	0.71	Tested		Passed
2.26 I>	2.26	n/a	2.549 s	2.553 s	0.14	Tested		Passed
4.13 I>	4.13	n/a	100.0 ms	133.0 ms	33.00	Tested		Passed
5.42 I>	5.42	n/a	100.0 ms	130.0 ms	30.00	Tested		Passed
7.95 I>	7.95	n/a	100.0 ms	131.8 ms	31.80	Tested		Passed
8.91 I>	8.91	n/a	100.0 ms	129.0 ms	29.00	Tested		Passed

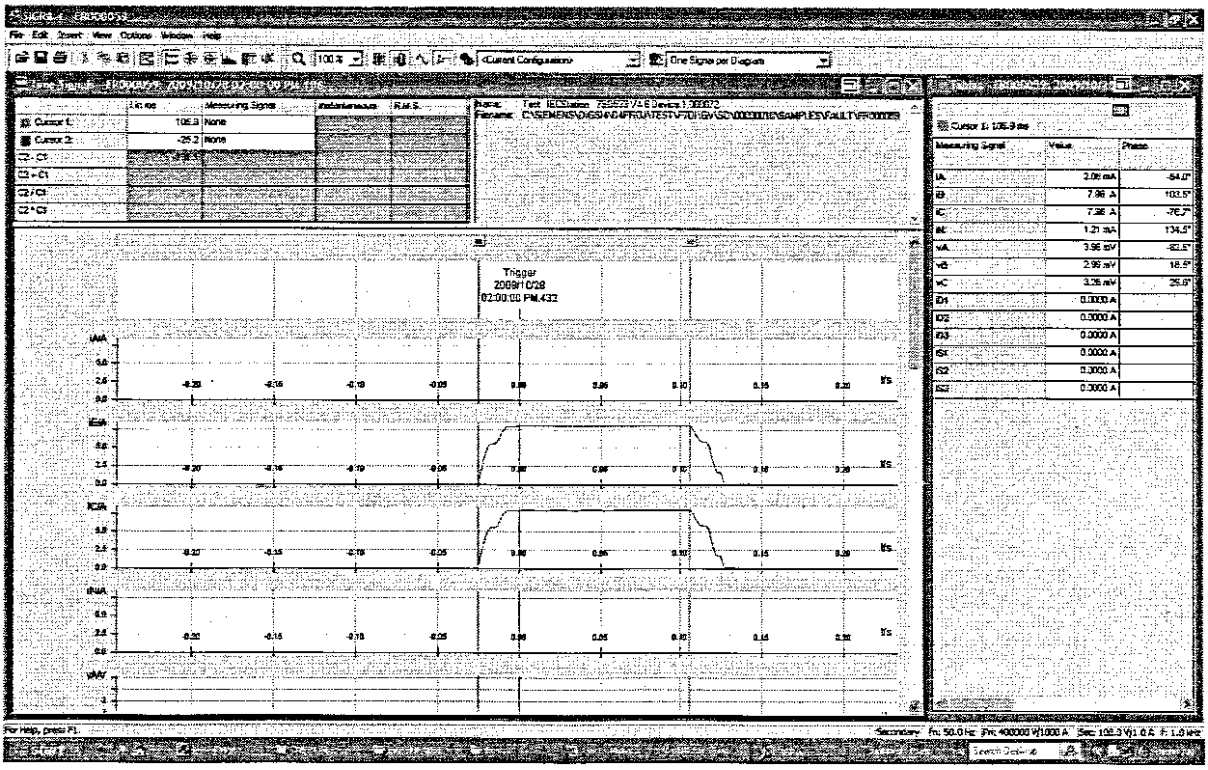


Figure 6.40: Time signal L2-L3

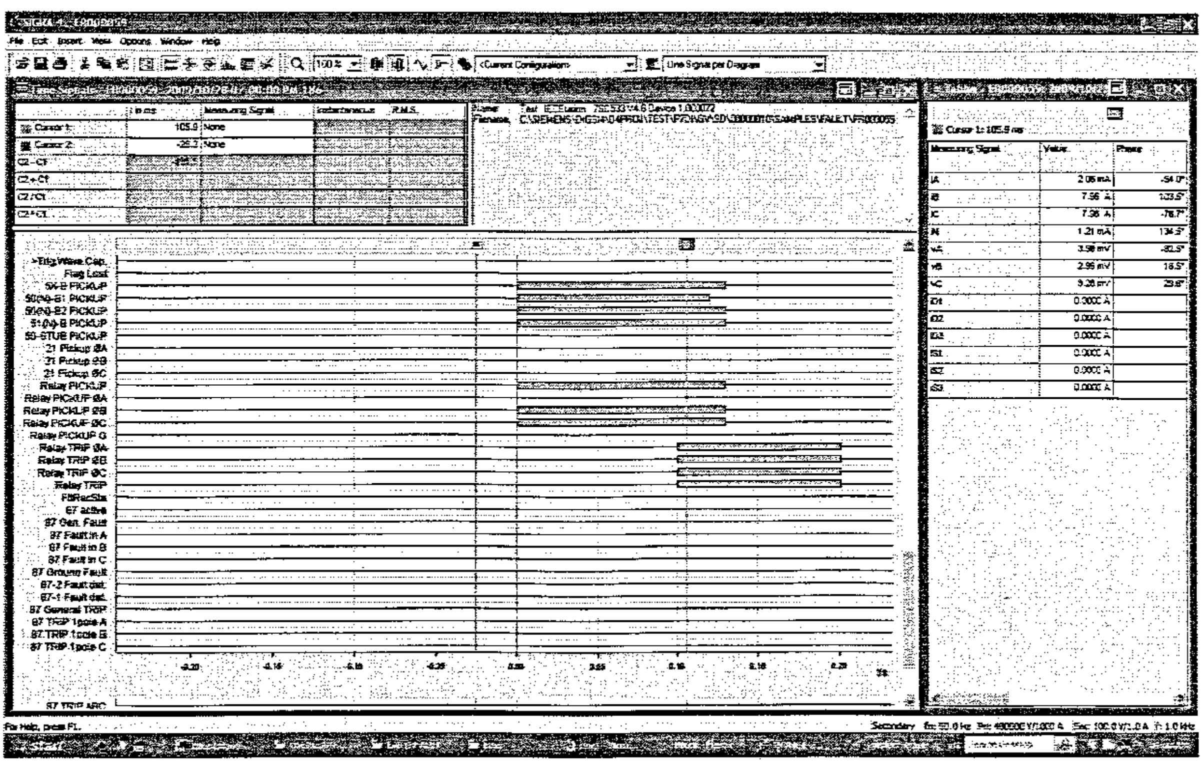


Figure 6.41: Tripping and pick-up indication L2-L3

6.9.3 Test object overcurrent INST L3-L1

The test set presents two of the relay in the Main Intake substation. The relay on the incoming side is 7UT6 while the one on the outgoing feeder is the 7SD5. The pick-up signals from the 7SD5 relays which are the outgoing feeder relays route the blocking signal to the 7UT6 which is on the incoming bay. The blocking signal prevents the fast tripping (I>>) of the incoming bay relay.Table 6.10 indicates the test object parameters for the fault between line3 and line1. The time and current tolerance settings are shown. The parameters such as the CT star point connection and the directionality of the relay are selected. Six testing points are defined as shown in Table 6.11. Here the direction, nominal time, minimum time, maximum time and maximum fault time is defined. All the selected test points have passed the test. The test results (the nominal and actual tripping times) are illustrated in Table 6.12 and the assessment of the test is graphically presented in Figure 6.42. In the Time Signal view as shown in Figure 6.43, cursor 1 and cursor 2 are displayed as vertical lines across all the diagrams of the view. The table view on the right hand side of the time signal view displays the behaviour of several signals at the same instant. All the instants are specified via cursor 1. The tripping and pick-up indication is presented by Figure 6.44.

Table 6.10: *Test object overcurrent parameters INST L3-L1*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	Yes	3.000 In (3.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.11: *Pick-up test settings for fault type L3-L1*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.24 I>	1.24	n/a	9.741 s	6.439 s	17.61 s	35.21 s
2.26 I>	2.26	n/a	2.549 s	2.164 s	2.993 s	5.987 s
4.13 I>	4.13	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
5.42 I>	5.42	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
7.95 I>	7.95	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
8.91 I>	8.91	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms

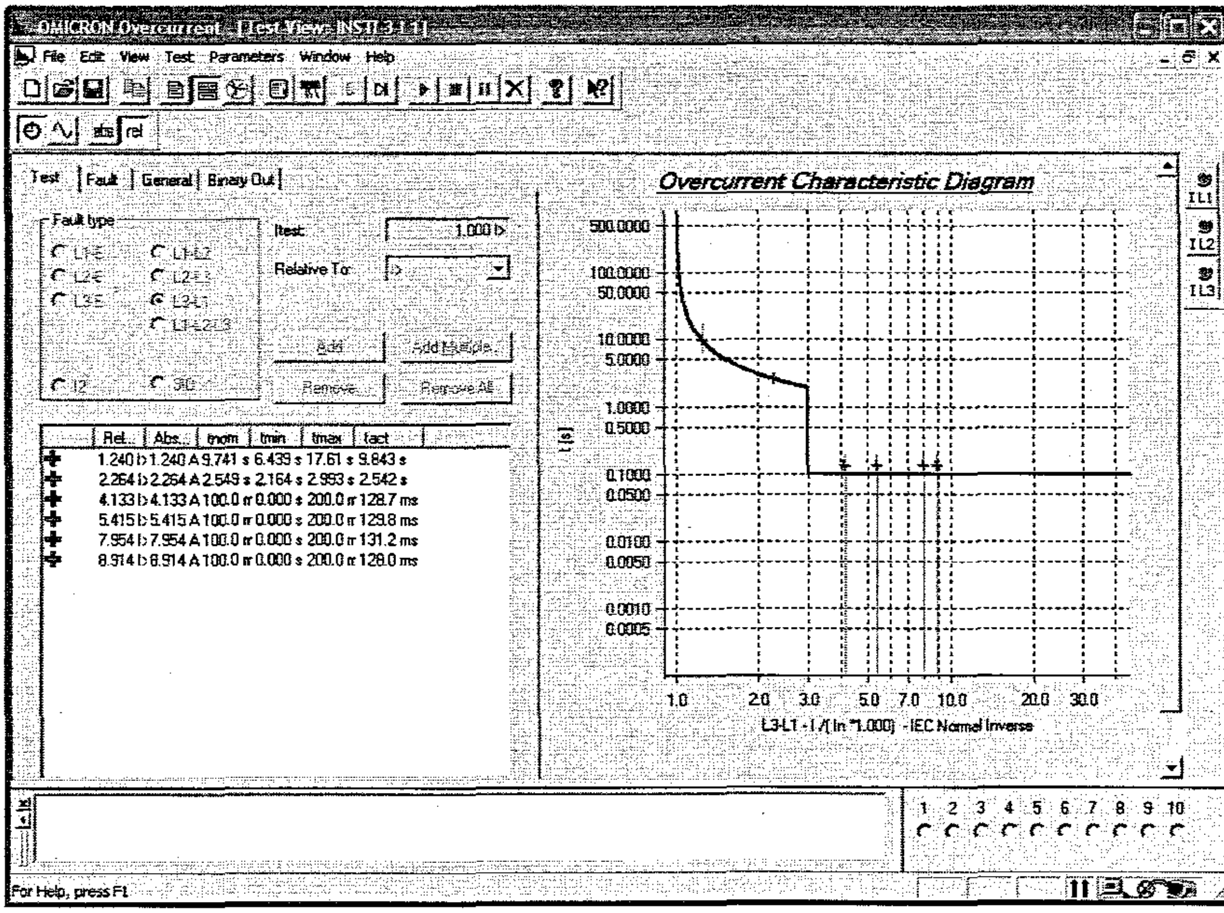


Figure 6.42: Test view INST L3-L1

Table 6.12: Test results for fault type L3-L1

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 14:01:05	Test End:	28-Oct-2009 14:01:30
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L3-L1

Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.24 I>	1.24	n/a	9.741 s	9.843 s	1.04	Tested		Passed
2.26 I>	2.26	n/a	2.549 s	2.542 s	-0.29	Tested		Passed
4.13 I>	4.13	n/a	100.0 ms	128.7 ms	28.70	Tested		Passed
5.42 I>	5.42	n/a	100.0 ms	129.8 ms	29.80	Tested		Passed
7.95 I>	7.95	n/a	100.0 ms	131.2 ms	31.20	Tested		Passed
8.91 I>	8.91	n/a	100.0 ms	128.0 ms	28.00	Tested		Passed

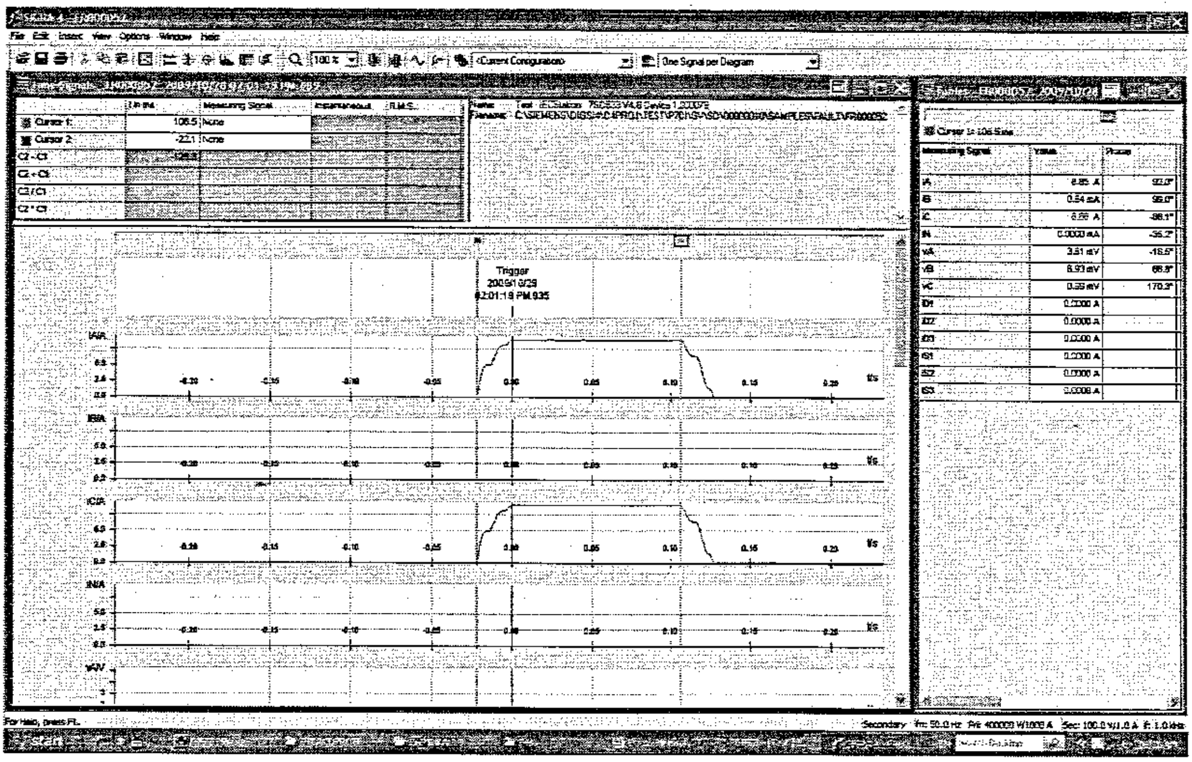


Figure 6.43: Time Signal L3-L1

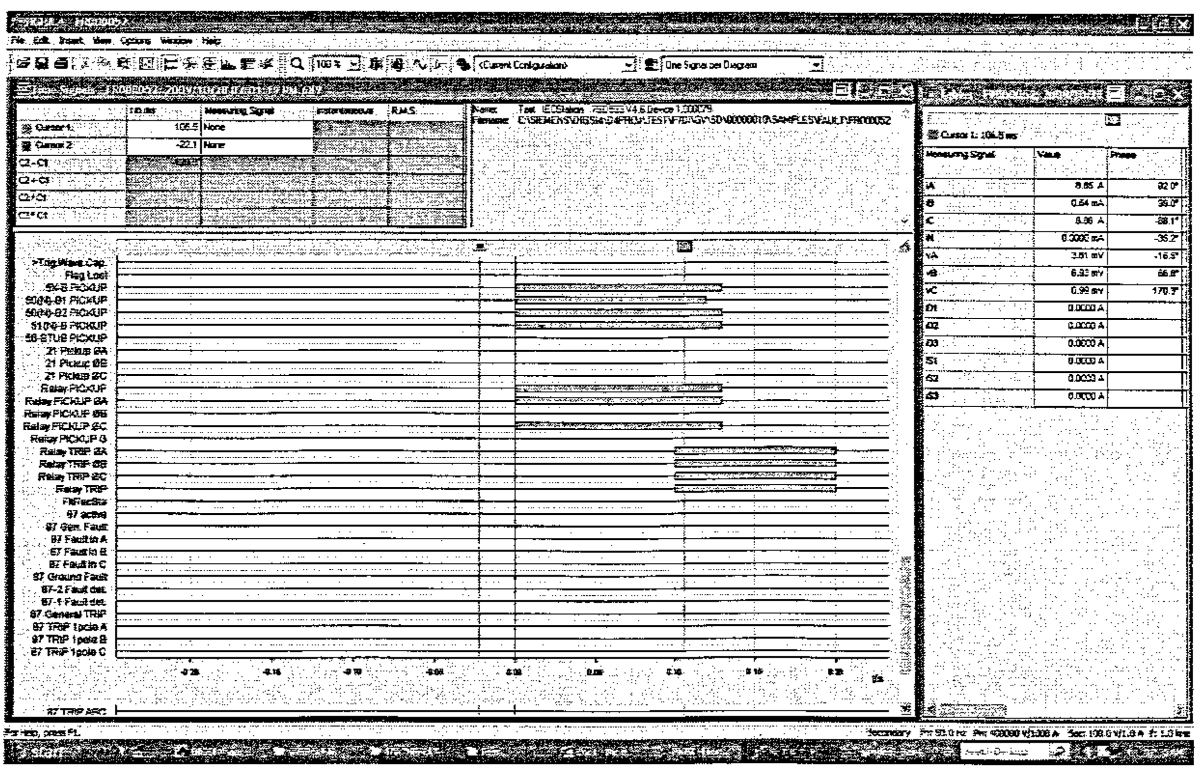


Figure 6.44: Tripping and pick-up indication L3-L1

6.9.4 Test object overcurrent OC L1-L2

In the previous tests, more than one methods were combined into one operating characteristics (the current-time diagram). The aim is to further utilize the advantages of the different discrimination techniques. For this test, only one method is used (the IDMT). With this characteristic, the operating time is inversely proportional to the fault current level and it is a function of both current and time. This means that the higher the fault current, the faster the operating time and vice-versa. Table 6.13 indicates the parameters and the IEC 60255 normal inverse characteristic is chosen. Four test points are identified as shown by Table 6.14. The overcurrent characteristic diagram in Figure 6.45 indicates the testing results that correspond with the ones tabulated in Table 6.15. The plus sign "+" is an indication that the test has passed. As shown in the results table the secondary fault current of 1.60A trips at 7.452 sec while a fault current of 4.85 trips in 2.180 sec. As earlier said, it is evident that the high the fault current the faster the tripping time and vice-versa. The deviations in percentage between the nominal and actual operating times are shown.

Table 6.13: *Test object overcurrent parameters OC L1-L2*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.500	IEC Normal Inverse
I>>	No	4.000 In (4.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.14: *Pick-up test settings for fault type L1-L2*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.60 I>	1.60	n/a	7.452 s	5.931 s	9.520 s	19.04 s
2.29 I>	2.29	n/a	4.201 s	3.568 s	4.929 s	9.858 s
3.51 I>	3.51	n/a	2.755 s	2.386 s	3.162 s	6.323 s
4.85 I>	4.85	n/a	2.182 s	1.904 s	2.482 s	4.964 s

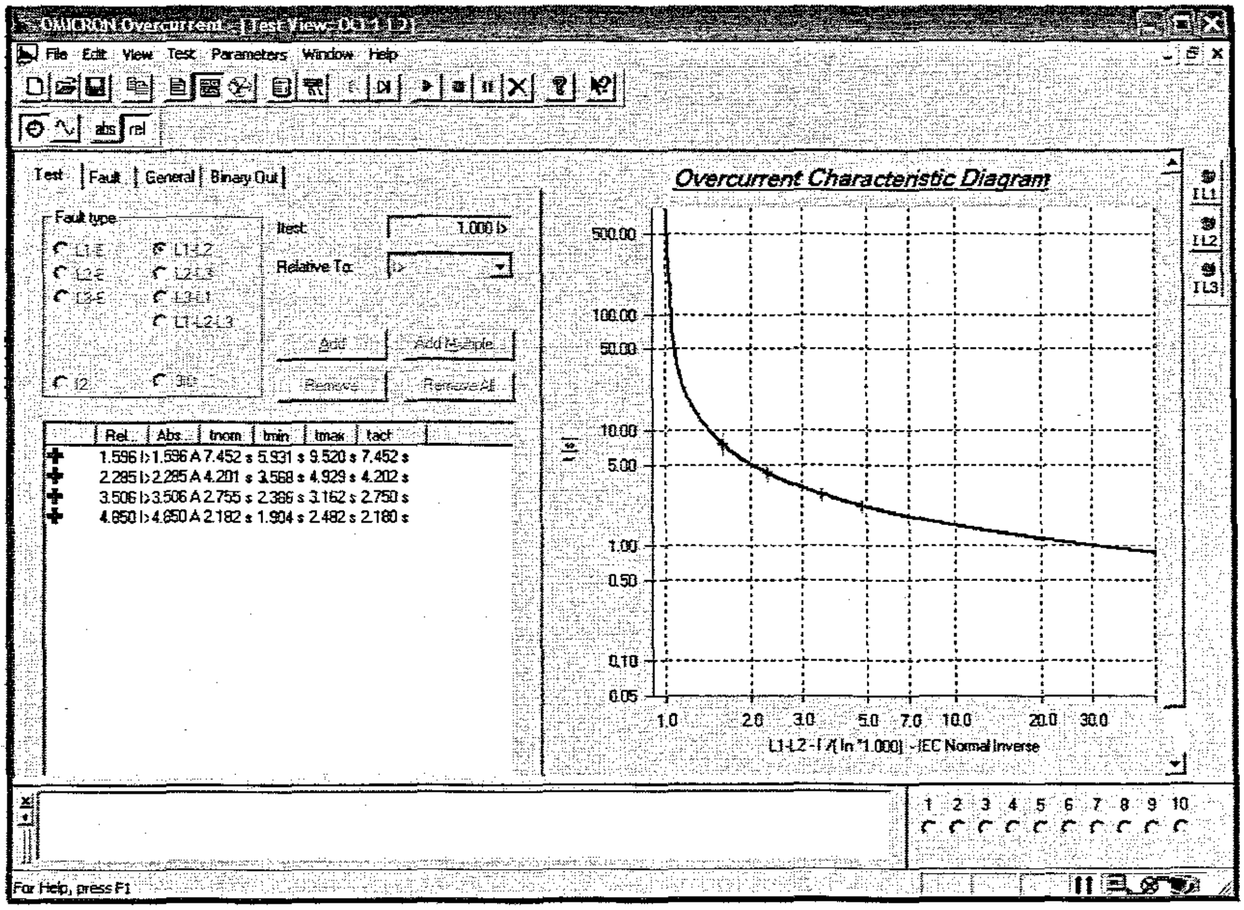


Figure 6.45: *Test view OC L1-L2*

Table 6.15: *Test results for fault type L1-L2*

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 12:42:22	Test End:	28-Oct-2009 12:42:44
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L1-L2

Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.60 I>	1.60	n/a	7.452 s	7.452 s	0.01	Tested		Passed
2.29 I>	2.29	n/a	4.201 s	4.202 s	0.03	Tested		Passed
3.51 I>	3.51	n/a	2.755 s	2.750 s	-0.19	Tested		Passed
4.85 I>	4.85	n/a	2.182 s	2.180 s	-0.08	Tested		Passed

6.9.5 Test object overcurrent OC L2-L3

For the fault between line 2 and line 3, the parameters and test settings are shown in Table 6.16 and 6.17 respectively. The OMICRON test results are shown in Figure 6.46 and Table 6.18 while the SIGRA4 results followed as shown in Figure 6.47 and 6.48 respectively. In order to show that the results from all two software's correspond, a fault current of 3.84A with a tripping time of 1.538 sec is used as it can be seen from Figure 6.46 and Table 6.18 of the OMICRON test results. These values are recorded on the SIGRA4 results which are reflected in Figure 6.47 and 6.48. The fault current can be read from the time signal graph or the table on the right hand corner of both Figures while the tripping time of 1.538 sec is shown in the table that is situated in the left hand top corner of the same Figures.

Table 6.16: *Test object overcurrent parameters OC L2-L3*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	No	4.000 In (4.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.17: *Pick-up test settings for fault type L2-L3*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.39 I>	1.39	n/a	6.356 s	4.721 s	9.048 s	18.10 s
1.81 I>	1.81	n/a	3.528 s	2.909 s	4.297 s	8.594 s
2.61 I>	2.61	n/a	2.172 s	1.859 s	2.525 s	5.050 s
3.84 I>	3.84	n/a	1.541 s	1.338 s	1.764 s	3.527 s
4.59 I>	4.59	n/a	1.357 s	1.183 s	1.546 s	3.092 s

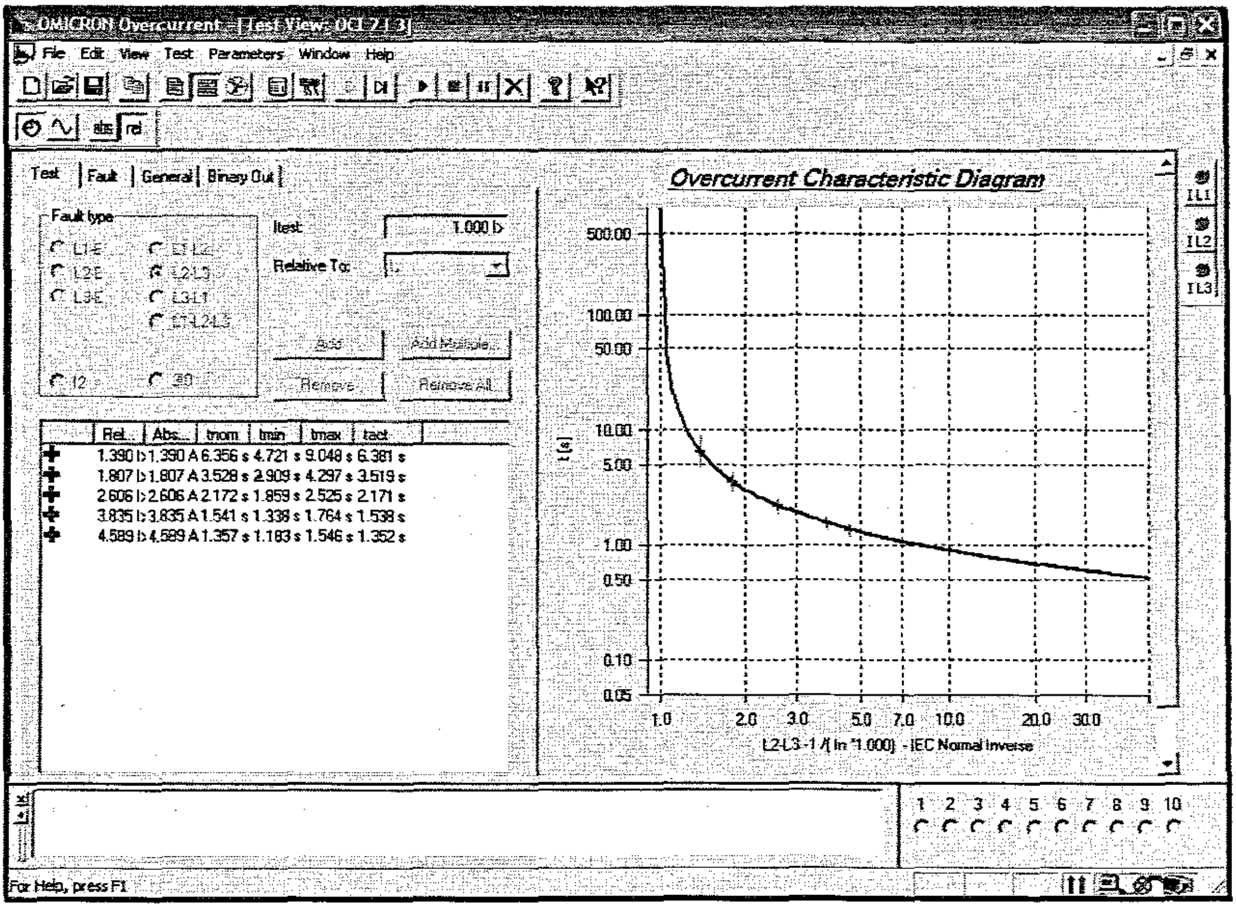


Figure 6.46: Test view OC L2-L3

Table 6.18: Test results for fault type L2-L3

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:35:27	Test End:	28-Oct-2009 13:35:51
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L2-L3

Relative	I[A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.39 I>	1.39	n/a	6.356 s	6.381 s	0.39	Tested		Passed
1.81 I>	1.81	n/a	3.528 s	3.519 s	-0.25	Tested		Passed
2.61 I>	2.61	n/a	2.172 s	2.171 s	-0.03	Tested		Passed
3.84 I>	3.84	n/a	1.541 s	1.538 s	-0.23	Tested		Passed
4.59 I>	4.59	n/a	1.357 s	1.352 s	-0.40	Tested		Passed

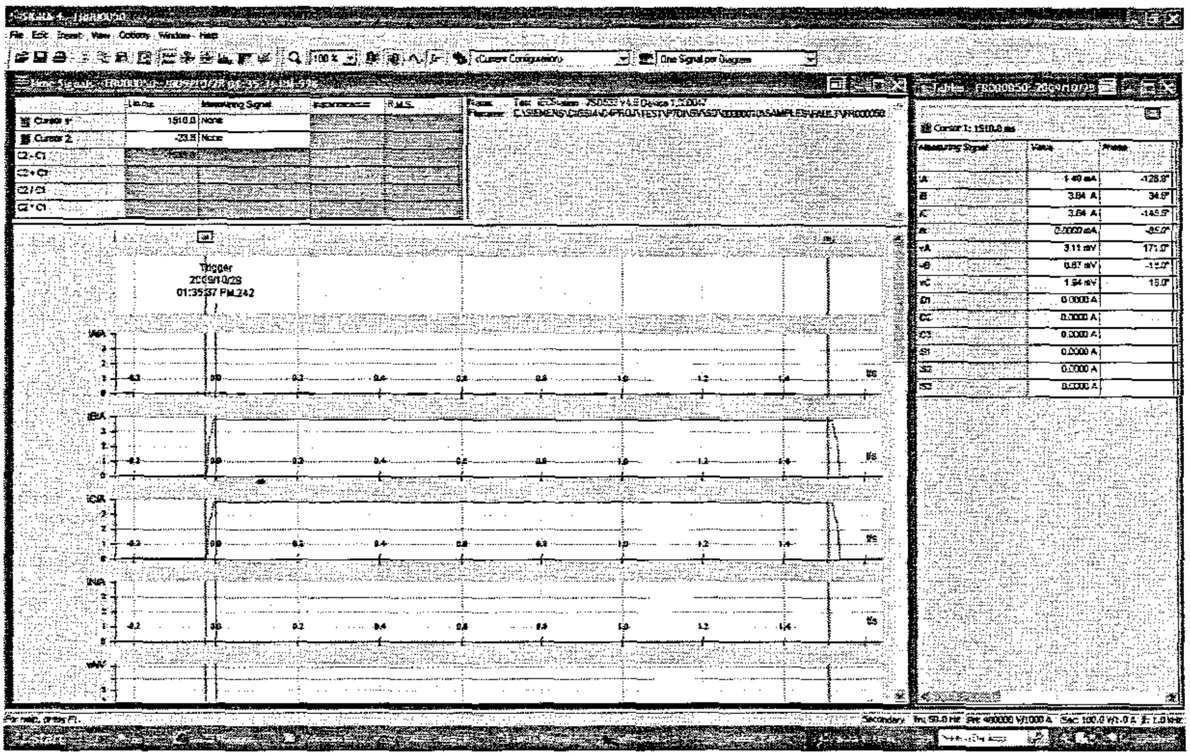


Figure 6.47: Time signal OC L2-L3

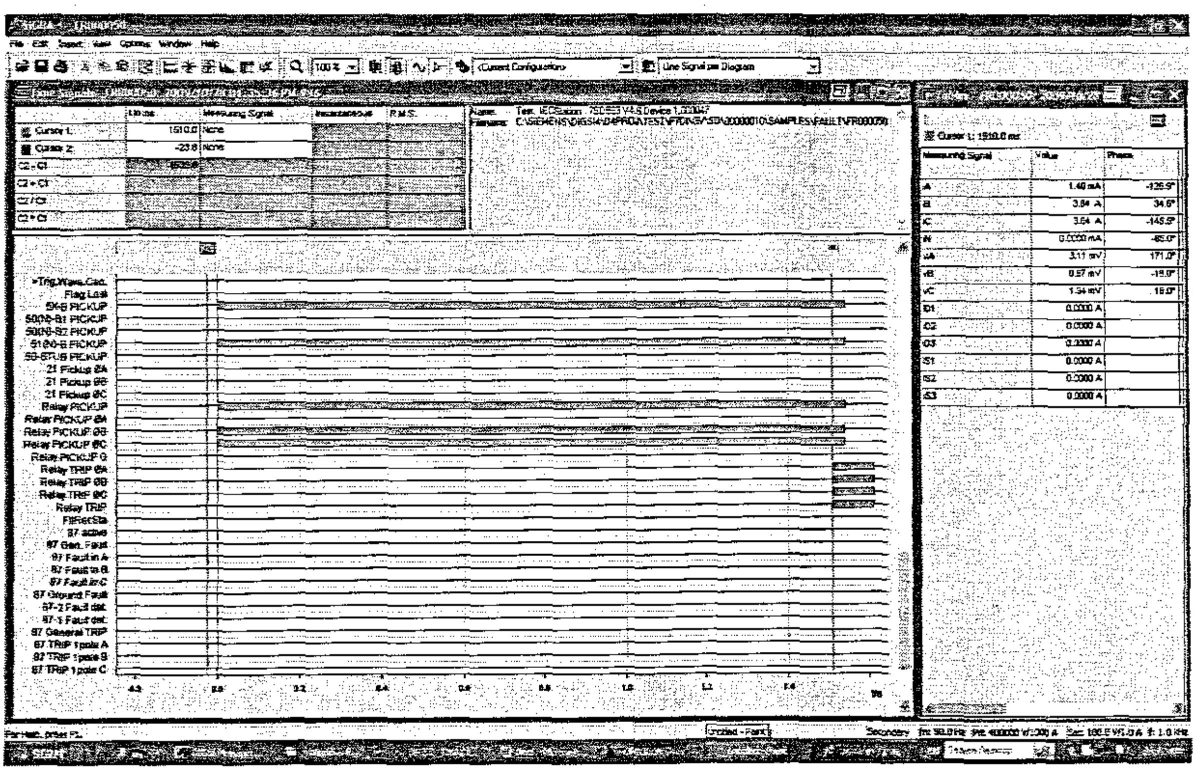


Figure 6.48: Tripping and pick-up indication OC L2-L3

6.9.6 Test object overcurrent OC L3-L1

The test object parameters and pick-up settings for the fault between line 3 and line 1 are tabulated in Table 6.19 and 6.20. Figure 6.49 and Table 6.21 present the results obtained from the OMICRON. The tripping results (1.357 sec) for the fault current of 4.59A as shown in Table 6.21 are shown in Figure 6.50 and 6.51 of the SIGRA application program. Using the Normal Inverse characteristics equation the testing results can be proved as follows.

$$\textbf{\textit{Trip time}} = \frac{0.14}{PSM^{0.02} - 1} \times TM$$

$$= \frac{0.14}{4.59^{0.02} - 1} \times 0.3$$

$$= 1.357 sec$$

Table 6.19: *Test object overcurrent parameters OC L3-L1*

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	No	4.000 In (4.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Table 6.20: *Pick-up test settings for fault type L3-L1*

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.39 I>	1.39	n/a	6.356 s	4.721 s	9.048 s	18.10 s
1.81 I>	1.81	n/a	3.528 s	2.909 s	4.297 s	8.594 s
2.61 I>	2.61	n/a	2.172 s	1.859 s	2.525 s	5.050 s
3.84 I>	3.84	n/a	1.541 s	1.338 s	1.764 s	3.527 s
4.59 I>	4.59	n/a	1.357 s	1.183 s	1.546 s	3.092 s

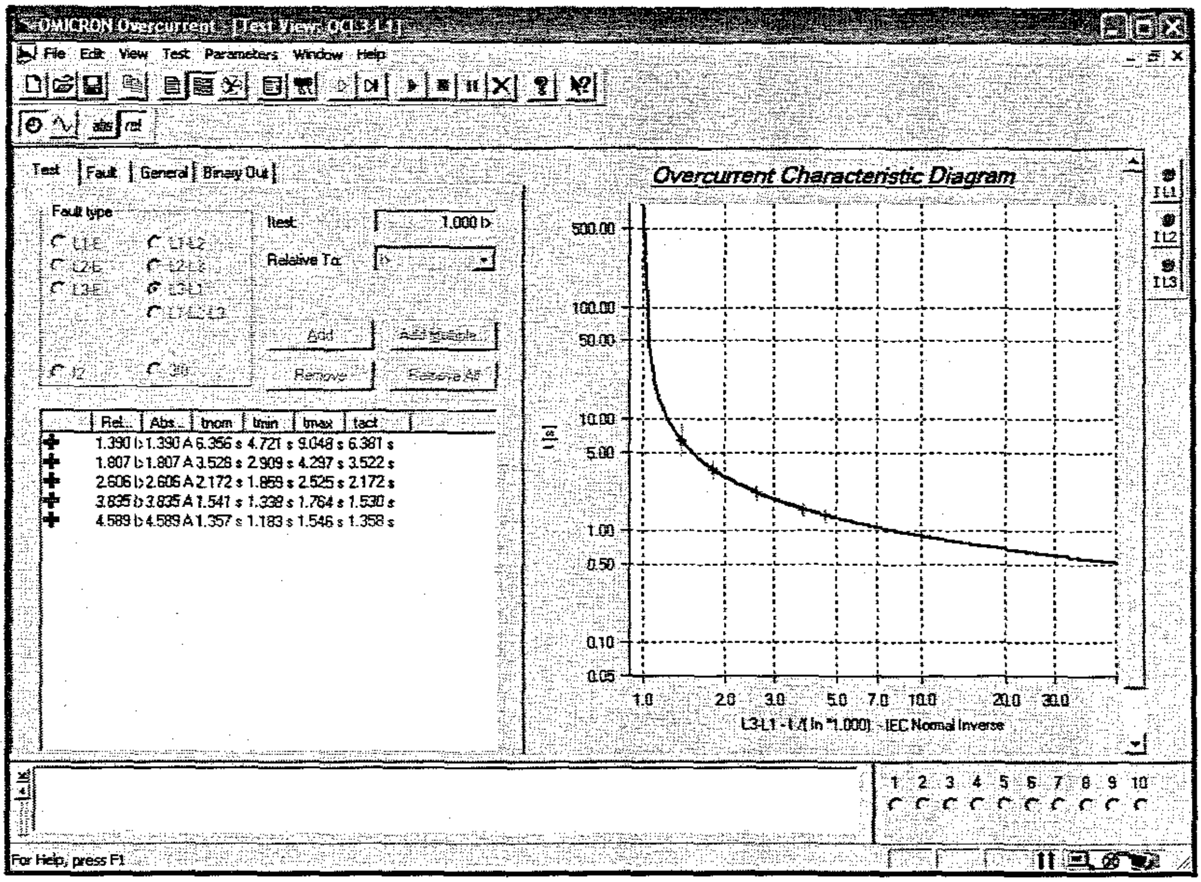


Figure 6.49: Test view OC L3-L1

Table 6.21: Test results for fault type L3-L1

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:38:02	Test End:	28-Oct-2009 13:38:27
User Name:	Fessor	Manager:	
Company:	CPUT		

Test Results for Fault Type L3-L1

Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.39 I>	1.39	n/a	6.356 s	6.381 s	0.39	Tested		Passed
1.81 I>	1.81	n/a	3.528 s	3.522 s	-0.17	Tested		Passed
2.61 I>	2.61	n/a	2.172 s	2.172 s	0.04	Tested		Passed
3.84 I>	3.84	n/a	1.541 s	1.530 s	-0.76	Tested		Passed
4.59 I>	4.59	n/a	1.357 s	1.358 s	0.06	Tested		Passed

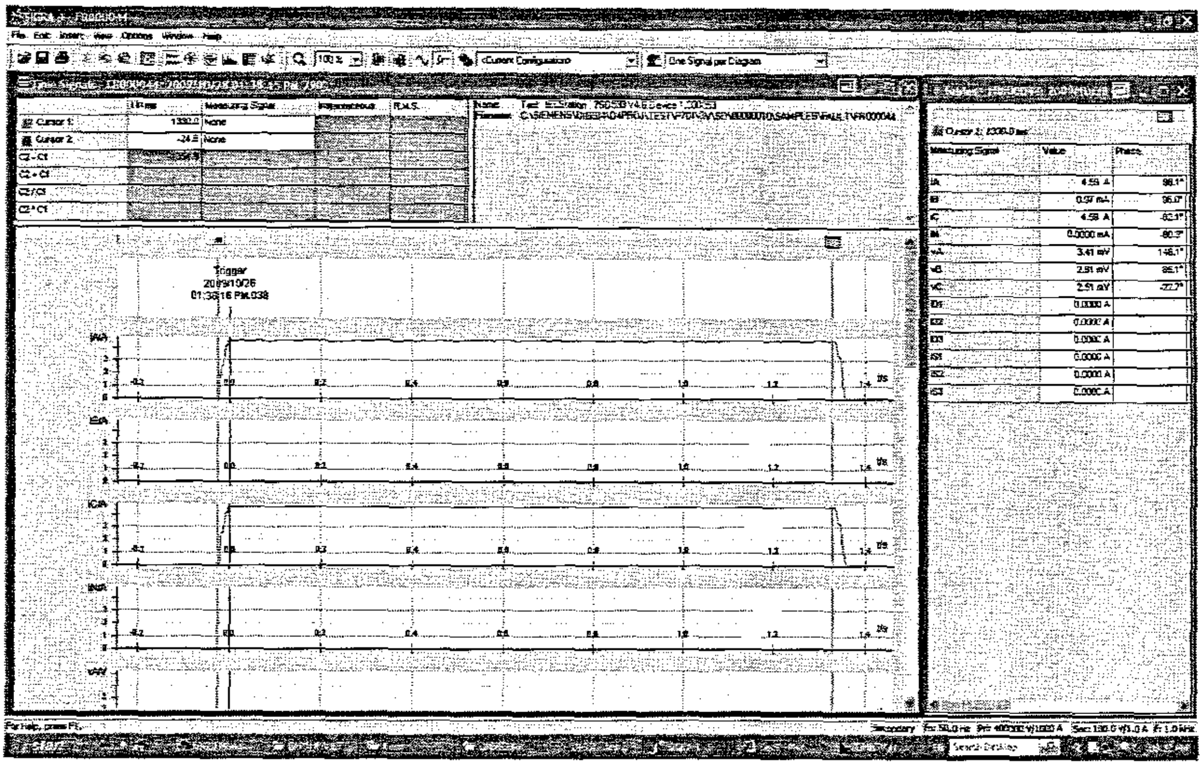


Figure 6.50: Time signal OC L3-L1

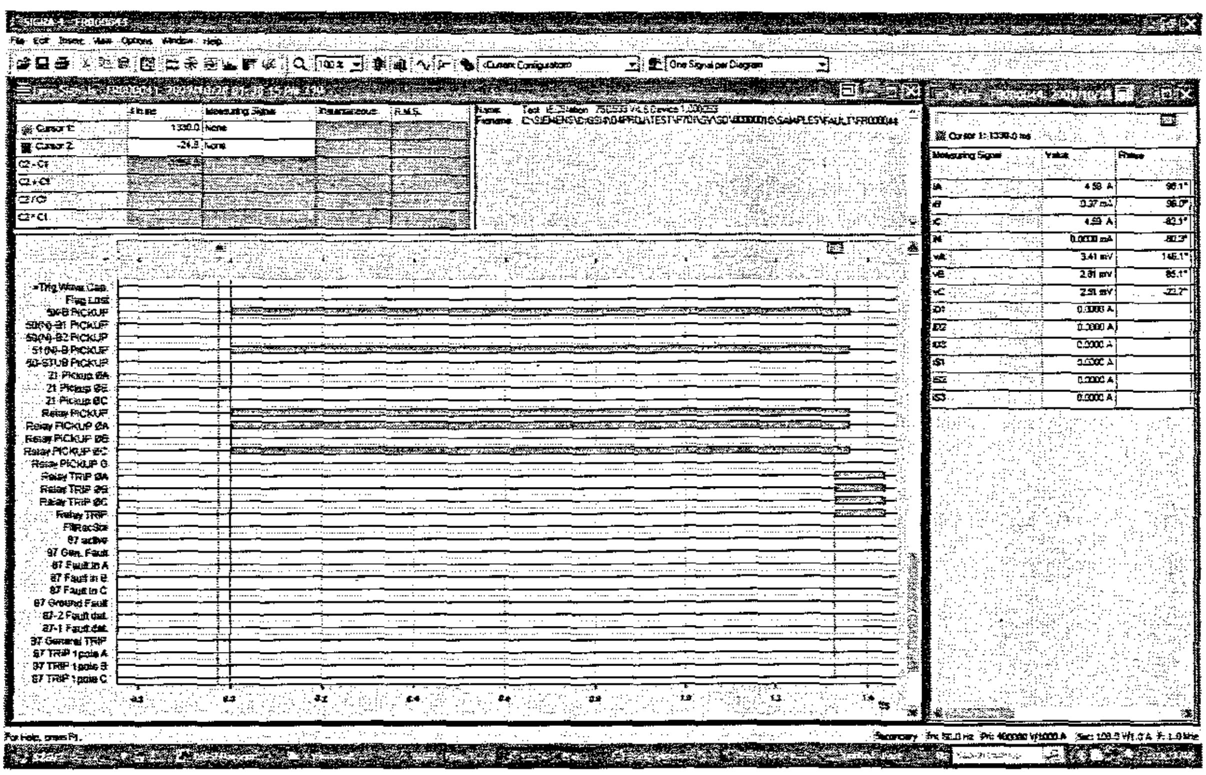


Figure 6.51: Tripping and pick-up indication OC L3-L1

6.9.7 Exchanging Data with Applications from the Power Distribution Area using DIGSI XML

The XML (eXtensible Markup Language) is accepted as a standard for data exchange, particularly between different platforms. The DIGSI XML Code is structured in different levels that are differently indented and thus can easily be distinguished from one another. A series of other interesting applications is as follows:

- **Line Calculation**
  In terms of line calculations programs, users simulate different fault situations and based on the results, the necessary setting data for the protective devices are determined. Programs such as SINCAL and SIGRADE from Siemens, Power Factory from *DIgSILENT automatically supply setting recommendations. All programs mentioned* above offers interfaces compatible to DIGSI XML. Therefore, the settings data are exported into an XML file and the data of this file can then be imported into DIGSI 4. This process avoids the traditional way of printing these data out in order to then retype them in DIGSI 4.

- **Protection Test**
  The OMICRON Company has further established a RIO format file based on XML "the XRIO format". OMICRON has introduced the format (with the Test-universe 2.0), that separates the settings parameters from the actual functional implementation parameters. DIGSI (Version 4.8 and above) actively supports the new XRIO format. Therefore, the protective settings of each SIPROTEC 4 device can be exported in the XRIO format. The OMICRON provides XRIO converters free-of-charge for the Test universe, version 2.0, with which the setting values can be easily imported and thus making it easy and efficient to create the test programs.

- **Line and Protective Data Management**
  Protective devices contain large number of parameters with the associated settings. Program for line and protective data management are transferred, using XML. As an additional benefit, XML enables the users to optimize and analyze data, refer to Appendix C. An example of such programs is the Test Base from OMICRON and Station Ware from DIgSILENT.

6.10 DISCUSSION OF THE OBTAINED RESULTS

With the above information, it can be seen how theory and simulation has been put into practice. The calculated tripping time using five selected testing point is compared with the results from the simulation, using three different software's and their deviation from the calculated results are shown in Table 6.22. The normal inverse characteristics and a time multiplier of 0.5 are used for the calculation of the actual tripping time. The normal inverse characteristics formula is used for calculation.

$$Trip\ time = \frac{0.14}{PSM^{0.02} - 1} \times TM$$

CALCULATED			
$I_{fault}(A)$	$T_{nom}(S)$	$T_{act}(S)$	
1.390	10.59	10.594	
1.807	5.881	5.881	
2.606	3.619	3.619	
3.835	2.569	2.569	
4.589	2.262	2.263	

DIgSILENT			Deviation
$I_{fault}(A)$	$T_{nom}(S)$	$T_{act}(S)$	
1.390	10.59	10.622	-0.028 s
1.807	5.881	5.879	0.002 s
2.606	3.619	3.604	0.015 s
3.835	2.569	2.560	0.009 s
4.589	2.262	2.250	0.013 s

OMICRON			Deviation
$I_{fault}(A)$	$T_{nom}(S)$	$T_{act}(S)$	
1.390	10.59	10.62	-0.026 s
1.807	5.881	5.880	0.001 s
2.606	3.619	3.608	0.011 s
3.835	2.569	2.562	0.007 s
4.589	2.262	2.258	0.005 s

SIGRA4			Deviation
$I_{fault}(A)$	$T_{nom}(S)$	$T_{act}(S)$	
1.390	10.59	10.62	-0.026 s
1.807	5.881	5.880	0.001 s
2.606	3.619	3.608	0.011 s
3.835	2.569	2.562	0.007 s
4.589	2.262	2.258	0.005 s

Table 6.22: *Comparison of the calculated and simulation tripping time*

The results obtained using the software's has proven the results from the calculations in chapter 6. The comparison of the calculated and simulation time indicates some deviation. It should be noted that human errors have also contributed to the deviations. Communication between different software is established and desired results have been obtained. Different hardware configuration has been carried out and this has made it possible to obtain the required results. The extension of the protection Test Lab will enable a variety of schemes to be tested and accomplished.

6.11 CONCLUSIONS

The chapter has analyzed the effect of using Ethernet networks and IEC 61850 protocols for protection, integration, and automation using the IEC 61850 GOOSE messages to communicate high-speed information between IED's or other devices on the local area network. All the testing *and protection schemes applied in this chapter where facilitated by the protection Test Lab. It is* therefore recommended for power protection engineer to work hand in hand with communications engineers or information technology departments, to be able to provide protection and control specifications under this new communications environment, and be able to trade off between protection, control performance and communications network complexity. *Since the IEC 61850 GOOSE is an event-driven broadcasting message that has a built-in* retransmission mechanism to increase its dependability, the priority tag has further reduced the network transmission delay time for critical messages.

CHAPTER 7

CLOSURE AND RECOMMENDATION

This chapter summarizes the main results obtained in the framework of this project by providing broad conclusions and discussions on the key findings, which is followed by suggestions. Further work is recommended as possible extensions of this thesis in the areas to be mentioned.

7.1 CONCLUSIONS

The thesis analyzed the Performance requirements for protection applications and the factors that need to be considered in order to meet the characteristics of the distribution network protection standard. In this thesis, Distribution network protection had been the area of interest with an objective to isolate problems with a minimum service disruption. Therefore, the thesis has looked at the main types of faults that occur in electrical power systems, by describing the most common faults and the causes thereof and by outlining the steps used in calculating the most common faults that occurs in power networks. A look into different protection alternatives and new technologies for Electrical Power Distribution Systems that unify protection and control units so that they can be incorporated into Intelligent Substation as opposed to the most existing (conventional substation) had been done and proven. A laboratory replica of a typical substation automation system is created at the CPUT's control and automation laboratory to perform the platform tests based on the IEC 61850 standard for distribution network protection. This standard defines the integration requirements of IED's for multiple protection schemes as well as control and automation techniques. All networks where modelled using the Power Factory DIgSILENT software. The three main simulations accomplished include Load flow analysis, Fault analysis, Protection analysis and the Protective relay co-ordination. The protection results obtained from DIgSILENT were validated using the Test Lab. The CPUT network protection is simulated using the Test Lab. The main software that has played a major role in setting and testing activities of the Lab IED's includes DIGSI4; SIGRA4 and the Omicron Test Universe V2.2 and 2.3. The Omicron test set is used to inject the testing signal (results from DIgSILENT) onto the IED's. For the simulation and testing to pass, all the results from the used software should correspond and this has been achieved. The main deliverables obtained in this project can be summarized as follows.

7.1.1 Analysis of the fault types and calculation theory for protection application

In order to apply protection relays, it is usually necessary to know the limiting values of current and voltage, and their relative phase displacement at the relay location, for various types of short circuits and their position in the system. The following activities have been carried out.

- The nature and causes of faults in power systems is analyzed.
- The types of faults and the effect that they pose on the power systems is analyzed
- Analysis of the difference between 'active' and 'passive' is performed
- Different types of faults on a three-phase system are simulated.
- The analysis of transient and permanent faults is carried out.
- The comparison of symmetrical versus asymmetrical faults is analyzed
- The analysis of the power system electrical behavior under fault conditions is implemented.
- The three basic network laws that govern the relationship between the voltages, impedances and currents in a linear network is analyzed and implemented.
- Network theorems and reduction of formulas are implemented
- The relationship between the Thevenin's equivalent circuit and Norton equivalent circuit is demonstrated.
- The Per-unit system is implemented.
- The method for calculating short circuit currents is implemented.
- Symmetrical component analysis of the three phase network is carried out.
- The relationship between symmetrical components in a power system is analyzed
- The importance and construction of sequence networks is analyzed
- The equations and network connections for various types of faults is implemented and analyzed.
- The distribution of current and voltage in power systems due to fault condition is simulated and analyzed.
- The effect of system earthing on zero sequence quantities is analyzed.

A good understanding and working knowledge of system fault analysis is very important for the protection personnel as they are required to know how the systems operate and behave under load and fault conditions.

7.1.2 Relays and technology development analysis

The thesis has analyzed the evolution of relays as well as their operating philosophy since they are being classified in accordance with the functions that they carry out. The theoretical part of the relays settings and calculations is covered and the application of standard graphical *representation of settings that can be applied instead of calculations has been looked into.* The following results are obtained.

- The theoretical characteristic of the relays operation as defined in IEC 60255-3 standard is implemented in simulation.
- Plug setting (Current pick-up) calculation is derived and analyzed.
- The factors that influence the choice of plug setting are analyzed.
- The time multiplier setting for protection relays are calculated and analyzed.
- The relays impacts on CTs and VTs (Burden) are simulated and results are analyzed.
- The difference between mechanical, digital and numerical relay rests on points of fine technical details. This detail is shown and is analyzed.
- The operating environment of relays in terms of electromagnetic compatibility (EMC) is discussed.
- The relays accuracy and settings is calculated, implemented and analyzed.
- The IEC 61850 GOOSE Applications within a Substation is overviewed.
- The upgrading of substations and the application of IED's is proposed and analyzed.
- Time Synchronization as per IEC61850 is implemented.
- The benefit of IEC 61850 application is acknowledged.

The huge number of electromechanical and static relays is still giving dependable service within most power systems today; therefore the thesis has touch on these technologies although the purpose of the project is to focus on modern protection relay practice (IED's).

7.1.3 Relay input sources design and analysis

The concepts of relay input sources are clearly defined. The thesis has further explained the CT's and VT's generation from the conventional type to the "All optical sensing type" and the challenges involved. The following has been carried out.

- The difference between the metering and protection instrument transformers is analyzed.
- The comparison between conventional type and the non conventional type instrument transformer is done.
- The standards, rating, accuracy classes and the errors characteristics of instruments *transformers are analyzed.*
- The sizing of primary and secondary current upon which the performance of the transformer is based is analyzed.
- The analysis of rated accuracy limit factor (RALF) of instrument transformers is done.
- The magnetizing characteristic of CTs that determine the performance of CTs is overviewed.
- Specifications and design requirements for current transformers for general protection purposes as stated by the IEC 60044-1 standard are defined
- The saturation of CTs when subjected to very high primary current is calculated and analyzed.
- The connection of current transformers in power circuit is overviewed.
- The ratio and phase errors of the *instrument transformers are calculated using the vector* diagram.

- *The CTs and VTs classes' analysis and application is carried out.*
- The IEC standard 61858 that covers the optical communication from the process side are discussed.
- The analysis of the functionality and mechanism of fiber optical sensor (FOS) is carried out.
- The Merging Unit (MU) which is an interface unit that allows multiple analogues CT/VT's, binary inputs and is capable of producing multiple time-synchronized data is described.
- The analysis of non-conventional instrument transformers and intelligent CB drive is carried out.

It is noticeable on the basis of above that the new technology has brought important contribution and advantages over conventional instruments, hence as parts of this project the non-conventional instrument transformers are proposed to be applied in conjunction with the IED's. Their standards, rating, accuracy classes and the errors characteristics are explained in this thesis. The process of how to specify them for a particular IED's or application is covered in detail.

7.1.4 IED's application and protection function design and simulation

The protection functions and applications of protective relays and multifunctional devices (IED's) in a distribution environment are presented using DIgSILENT. Typical settings configuration and IED's coordination focusing on the main types of protection as well as the areas of application are designed and simulated.

- The modeling (load flow and protection) of CPUT and EUREKA network is done using DIgSILENT software.
- Protection device settings (over-current IED) are calculated and applied in DIgSILENT
- Calculation of maximum fault level is performed using DIgSILENT
- Calculation of three-phase short-circuit current levels for the CPUT and EUREKA network is carried out according to the IEC 60909 standard
- The selection of CT transformer ratio is done based on the calculations.
- Principle of protection co-ordination is calculated and simulated in DIgSILENT.
- Grading Margin between 0.2 and 0.4 is used
- Time Multiplier Settings that adjust the operating time of the *inverse type characteristics* are calculated and applied in DIgSILENT.
- Plotting of relays characteristics is done using DIgSILENT
- Overcurrent grading of the transformer feeder is performed and simulated.
- Performance of protection relays is simulated and assessed in DIgSILENT software environment.
- Relays correct and incorrect operation is simulated and observed in DIgSILENT.
- *Different network topologies and arrangements are designed and simulated using* DIgSILENT.
- Selection criteria of power system topologies are analyzed.
- Time-based discrimination principle is simulated and tested.
- Radial power system with time-based discrimination is developed and simulated.
- Time-based discrimination with definite time is developed, simulated and tested.

- *Time-based discrimination with IDMT* is developed, simulated and tested.
- Discrimination using current magnitude is developed, simulated and tested.
- A combination of current-based and time-based discrimination, is developed, simulated and tested.
- A combination of logic and time-based discrimination, is developed, simulated and tested.
- A combination of time-based and directional discrimination, is developed, simulated and tested.

Since the general layout of the power network has a strong influence on protective relaying, the network topologies have been covered in order to identify the most important characteristics of each topology for comparison purposes.

7.1.5 Ethernet and IEC61850 substation communication design and application

The communication network ensures that raw data, processed information and commands are shared quickly, effectively and error-free among the various field instruments, and IED's. Therefore this thesis has analyzed the effect of using Ethernet networks and IEC 61850 *protocols for protection, integration, and automation using the* IEC 61850 GOOSE *messages to* communicate high-speed information between IED's or other devices on the local area network.

- A laboratory replica of a typical substation automation system is created at the CPUT's control and automation laboratory to perform the platform tests of the distribution network protection applications.
- Overview of the IEC61850 cross-level communication is carried out.
- The Ethernet and network basics are developed and implemented in the Lab scale system.
- Transmission Control Protocol/Internet Protocol that allows communication between Devices is implemented.
- *The International Organization for Standardization* (ISO) *Open Systems Interconnection* (OSI) reference model is analyzed.
- The RS 8000T Ruggedcom switch characteristics are analyzed and the switch is applied in the creation of the Lab scale system.
- The CMC 256 Omicron test device is connected to the Lab scale system to inject the testing signal.
- The configuration and control of the CMC 256 is performed through the test software of the OMICRON Test Universe.
- All IEDs connected to communicate in the Lab scale system are issued with Internet Protocol (IP) addresses.
- Communication establishment between IED's is developed and implemented using the DIGSI4 software.
- As part of the IEC 61850 subnet, each IED's communicator is given a unique name.
- The information is routed between communicator using DIGSI4 software.
- At substation level, the information exchange among IEDs is achieved using IEC 61850 GOOSE messages.

- Reverse Busbar Blocking Scheme is developed and implemented using the CPUT Main Intake substation layout.
- The test to determine the pick-up values, drop-off values and testing of the tripping time of overcurrent protection is carried out using the OMICRON Test Universe V2.3, DIGSI4 and SIGRA4 software's.
- Comparison of the calculated and simulated tripping time is carried out and analyzed.

7.2 APPLICATION OF THE RESULTS

This project work provided the area which combines the aspects of power systems protection, data networking, software development and substation automation. Based on the above the applications can be considered for industrial and educational institutions.

7.2.1 CPUT Campus reticulation network refurbishment

In terms of CPUT reticulation network the results can be considered in addressing the followings:

- The rating of equipments for the network upgrade
- Substation automation requirements
- Reticulation network automation and protection grading requirements
- Assist with the choice of network topology and protection equipments to be used.

7.2.2 Testing Lab (Laboratory Scale Plant)

The developed laboratory replica of a typical substation automation system can be used to address the following:

- Integration of the IEC 61850 based substation into CPUT curriculum.
- Student research, experiments as well as simulation performance in order to gain knowledge and skills for designing and engineer substations with IEC 61850 standard equipments.
- Training for academic Institution and utility Industries.
- Simulation of system conditions that are not capable on plant that is in service.
- Establish a center for substation automation and energy management systems that offers educational, training and research opportunities.

7.3 SUGGESTIONS ON FURTHER RESEARCH

The objective of protection in power systems remains the same and that is to isolate the problems with minimum service disruption. Further work is recommended as an extension of this thesis in the following areas:

A further research in the application of MU and GOOSE messages for protection is one of the areas. Distance protection and differential protection in distribution system have to be carried *out to study the behaviour of the schemes in complex power systems. Differential protection will* be carried out on a protection of the combined cable and overhead line power system. The application of protection signaling and inter-tripping, its relationship with other systems using communication transmission media that provides the communication links between distanced protection equipment will be part of the scope. Associated with this will be different schemes *such as negative sequence protection, adaptive protection and selective tripping. A better* understanding of synchronization error (Sync-errors) is one of the requirements since communication network will be required for differential protection application. The hardware implementation (Laboratory Scale Plant) requires further improvements in order to address all protection applications that are applicable to a typical distribution network, hence, further *extension is recommended.*

7.4 PUBLICATIONS

APPENDICES

SETTINGS FOR CPUT NETWORK TRLAYS

APPENDIX
A

```
---------------------------------------------------------------------------
|                             |  DIgSILENT  | Project:                    |
|                             | PowerFactory |----------------------------
|                             |   13.2.331  | Date:  12/7/2009            |
---------------------------------------------------------------------------
| MAIN IN-ELEC ENG               Relay Type : 7SJ5311-5BA0-3A0            |
|  Location      :  Cubicle      : Cub_4       Branch     : 120C3P-0.385  |
|                   Busbar       : MAIN INTK SUB          /               |
|-------------------------------------------------------------------------|
|  CT 2000/1                                     Ratio      : 2000A/1A    |
|    No. Phases     : 3          Phase 1     : a     Phase 2    : b       |
|    Connection     : Y                                                   |
|                                                                         |
|  Measurement                                                            |
|    Nominal Current ( 1.0             A     ) :     1.00 A               |
|                                                                         |
|  Ioc >            ( IEC: I>>   ANSI: 50    )       Out of Service   : No  |
|    Tripping Direction                      : None                       |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :     8.000 p.u.             |
|    Time Setting    ( 0.0 - 60.0    s     ) :     0.200 s                |
|                                                                         |
|  Ioc >>           ( IEC: I>>   ANSI: 50    )       Out of Service   : Yes |
|    Tripping Direction                      : None                       |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :     0.100 p.u.             |
|    Time Setting    ( 0.0 - 60.0    s     ) :     0.000 s                |
|                                                                         |
|  Ioc >>>          ( IEC: I>>>  ANSI: 50    )       Out of Service   : Yes |
|    Tripping Direction                      : None                       |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :     0.100 p.u.             |
|    Time Setting    ( 0.0 - 60.0    s     ) :     0.000 s                |
|                                                                         |
|  Toc              ( IEC: I>t   ANSI: 51    )       Out of Service   : No  |
|    Tripping Direction                      : None                       |
|    Current Setting ( 0.1 - 4.0     p.u.  ) :     1.000 p.u.             |
|    Time Dial       ( 0.05 - 3.2          ) :     0.150                  |
|    Characteristic                          : IEC 255-3 inverse          |
|                                                                         |
|  Ioc Ie>          ( IEC: IE>>  ANSI: 50N   )       Out of Service   : Yes |
|    Tripping Direction                      : None                       |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :     0.300 p.u.             |
|    Time Setting    ( 0.0 - 60.0    s     ) :     0.000 s                |
|                                                                         |
|  Ioc Ie>>         ( IEC: IE>>  ANSI: 50N   )       Out of Service   : Yes |
|    Tripping Direction                      : None                       |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :     0.100 p.u.             |
|    Time Setting    ( 0.0 - 60.0    s     ) :     0.000 s                |
|                                                                         |
|  Toc Ie           ( IEC: IE>t  ANSI: 51N   )       Out of Service   : Yes |
|    Tripping Direction                      : None                       |
|    Current Setting ( 0.1 - 4.0     p.u.  ) :     0.500 p.u.             |
|    Time Dial       ( 0.05 - 3.2          ) :     0.150                  |
|    Characteristic                          : IEC 255-3 inverse          |
|                                                                         |
---------------------------------------------------------------------------
```

```
-------------------------------------------------------------------------------
|  Logic I                                           Out of Service   : No    |
|    Breaker                        Cubicle    Branch                         |
|     MAIN INTK SUB        \          Cub_4      120C3P-0.385                  |
|  Logic Ie                                          Out of Service   : No    |
|    Breaker                        Cubicle    Branch                         |
|     MAIN INTK SUB        \          Cub_4      120C3P-0.385                  |
-------------------------------------------------------------------------------
| MAIN IN-ABC/IT                 Relay Type : 7SJ5311-5BA0-3A0                |
|  Location     :  Cubicle        : Cub_5       Branch     : 120C3P-0.270     |
|                  Busbar         : MAIN INTK SUB         /                   |
|-----------------------------------------------------------------------------|
|  CT 2000/1                                      Ratio       : 2000A/1A      |
|    No. Phases     : 3          Phase 1     : a     Phase 2     : b          |
|    Connection     : Y                                                       |
|                                                                             |
|  Measurement                                                                |
|    Nominal Current ( 1.0           A      ) :      1.00 A                   |
|                                                                             |
-------------------------------------------------------------------------------
-------------------------------------------------------------------------------
|  Ioc >            ( IEC: I>>   ANSI: 50    )       Out of Service   : No    |
|    Tripping Direction                        : None                         |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :      7.200 p.u.                |
|    Time Setting    ( 0.0 - 60.0    s     ) :      0.100 s                   |
|                                                                             |
|  Ioc >>           ( IEC: I>>   ANSI: 50    )       Out of Service   : Yes   |
|    Tripping Direction                        : None                         |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :      0.100 p.u.                |
|    Time Setting    ( 0.0 - 60.0    s     ) :      0.000 s                   |
|                                                                             |
|  Ioc >>>          ( IEC: I>>>  ANSI: 50    )       Out of Service   : Yes   |
|    Tripping Direction                        : None                         |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :      0.100 p.u.                |
|    Time Setting    ( 0.0 - 60.0    s     ) :      0.000 s                   |
|                                                                             |
|  Toc              ( IEC: I>t   ANSI: 51    )       Out of Service   : No    |
|    Tripping Direction                        : None                         |
|    Current Setting ( 0.1 - 4.0     p.u.  ) :      1.000 p.u.                |
|    Time Dial       ( 0.05 - 3.2           ) :      0.100                     |
|    Characteristic                            : IEC 255-3 inverse            |
|                                                                             |
|  Ioc Ie>          ( IEC: IE>>  ANSI: 50N   )       Out of Service   : Yes   |
|    Tripping Direction                        : None                         |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :      0.300 p.u.                |
|    Time Setting    ( 0.0 - 60.0    s     ) :      0.000 s                   |
|                                                                             |
|  Ioc Ie>>         ( IEC: IE>>  ANSI: 50N   )       Out of Service   : Yes   |
|    Tripping Direction                        : None                         |
|    Pickup Current  ( 0.1 - 25.0    p.u.  ) :      0.100 p.u.                |
|    Time Setting    ( 0.0 - 60.0    s     ) :      0.000 s                   |
|                                                                             |
-------------------------------------------------------------------------------
```

APPENDIX B
SETTINGS FOR EUREKA NETWORK RELAYS

```
---------------------------------------------------------------------------
|                          |   DIgSILENT   | Project:                      |
|                          |  PowerFactory |-------------------------------|
|                          |    13.2.331   | Date:  12/7/2009              |
---------------------------------------------------------------------------
| Cojac_ BL3                     Relay Type : 7SJ5311-5BA0-3A0             |
|  Location     :  Cubicle       : Cub_3      Branch     : Cojac-BL3       |
|                  Busbar        : Cojac                 /                 |
|--------------------------------------------------------------------------|
|  Current Transformer                         Ratio      : 400A/1A        |
|    No. Phases     : 3         Phase 1    : a    Phase 2    : b           |
|    Connection     : Y                                                    |
|                                                                          |
|  Measurement                                                             |
|    Nominal Current ( 1.0          A      ) :    1.00 A                   |
|                                                                          |
|  Cojac_BL3          ( IEC: I>>   ANSI: 50    )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Pickup Current   ( 0.1 - 25.0     p.u.  ) :   17.000 p.u.             |
|    Time Setting     ( 0.0 - 60.0     s     ) :    0.800 s                |
|                                                                          |
|  Ioc >>             ( IEC: I>>   ANSI: 50    )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Pickup Current   ( 0.1 - 25.0     p.u.  ) :    0.100 p.u.             |
|    Time Setting     ( 0.0 - 60.0     s     ) :    0.000 s                |
|                                                                          |
|  Ioc >>>            ( IEC: I>>>  ANSI: 50    )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Pickup Current   ( 0.1 - 25.0     p.u.  ) :    0.100 p.u.             |
|    Time Setting     ( 0.0 - 60.0     s     ) :    0.000 s                |
|                                                                          |
|  Cojac_BL3(1)       ( IEC: I>t   ANSI: 51    )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Current Setting ( 0.1 - 4.0      p.u.  ) :    1.000 p.u.              |
|    Time Dial        ( 0.05 - 3.2          ) :    0.550                   |
|    Characteristic                         : IEC 255-3 inverse            |
|                                                                          |
|  Ioc Ie>            ( IEC: IE>>  ANSI: 50N   )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Pickup Current   ( 0.1 - 25.0     p.u.  ) :    0.100 p.u.             |
|    Time Setting     ( 0.0 - 60.0     s     ) :    0.000 s                |
|                                                                          |
|  Ioc Ie>>           ( IEC: IE>>  ANSI: 50N   )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Pickup Current   ( 0.1 - 25.0     p.u.  ) :    0.100 p.u.             |
|    Time Setting     ( 0.0 - 60.0     s     ) :    0.000 s                |
|                                                                          |
|  Toc Ie             ( IEC: IE>t  ANSI: 51N   )      Out of Service   : Yes |
|    Tripping Direction                     : None                         |
|    Current Setting ( 0.1 - 4.0      p.u.  ) :    0.100 p.u.              |
|    Time Dial        ( 0.05 - 3.2          ) :    0.110                   |
|    Characteristic                         : IEC 255-3 inverse            |
|                                                                          |
|  Logic I                                            Out of Service   : No  |
|    Breaker                              Cubicle    Branch                |
|     Cojac             \                  Cub_3      Cojac-BL3            |
|  Logic Ie                                           Out of Service   : No  |
|    Breaker                              Cubicle    Branch                |
|     Cojac             \                  Cub_3      Cojac-BL3            |
---------------------------------------------------------------------------
```

```
----------------------------------------------------------------------------
| Heilbot_BL3                    Relay Type : 7SJ5311-5BA0-3A0              |
|  Location     :  Cubicle       : Cub_1      Branch    : Heilbot- BL3      |
|                  Busbar        : Bishop Lavis 3       /                   |
|---------------------------------------------------------------------------|
|  Current Transformer                          Ratio      : 400A/1A        |
|    No. Phases    : 3       Phase 1    : a     Phase 2    : b              |
|    Connection    : Y                                                      |
|                                                                           |
|  Measurement                                                              |
|    Nominal Current ( 1.0          A    ) :    1.00 A                      |
|                                                                           |
-----------------------------------------------------------------------------

-----------------------------------------------------------------------------
|  Heilbot_BL3      ( IEC: I>>   ANSI: 50   )      Out of Service    : No   |
|    Tripping Direction                    : None                           |
|    Pickup Current  ( 0.1 - 25.0   p.u. ) :   15.800 p.u.                  |
|    Time Setting    ( 0.0 - 60.0   s    ) :    0.400 s                     |
|                                                                           |
|  Ioc >>           ( IEC: I>>   ANSI: 50   )      Out of Service    : Yes  |
|    Tripping Direction                    : None                           |
|    Pickup Current  ( 0.1 - 25.0   p.u. ) :    0.100 p.u.                  |
|    Time Setting    ( 0.0 - 60.0   s    ) :    0.000 s                     |
|                                                                           |
|  Ioc >>>          ( IEC: I>>>  ANSI: 50   )      Out of Service    : Yes  |
|    Tripping Direction                    : None                           |
|    Pickup Current  ( 0.1 - 25.0   p.u. ) :    0.100 p.u.                  |
|    Time Setting    ( 0.0 - 60.0   s    ) :    0.000 s                     |
|                                                                           |
|  Heilbot_ BL3     ( IEC: I>t   ANSI: 51   )      Out of Service    : No   |
|    Tripping Direction                    : None                           |
|    Current Setting ( 0.1 - 4.0    p.u. ) :    1.000 p.u.                  |
|    Time Dial       ( 0.05 - 3.2        ) :    0.400                       |
|    Characteristic                        : IEC 255-3 inverse              |
|                                                                           |
|  Ioc Ie>          ( IEC: IE>>  ANSI: 50N  )      Out of Service    : Yes  |
|    Tripping Direction                    : None                           |
|    Pickup Current  ( 0.1 - 25.0   p.u. ) :    0.100 p.u.                  |
|    Time Setting    ( 0.0 - 60.0   s    ) :    0.000 s                     |
|                                                                           |
|  Ioc Ie>>         ( IEC: IE>>  ANSI: 50N  )      Out of Service    : Yes  |
|    Tripping Direction                    : None                           |
|    Pickup Current  ( 0.1 - 25.0   p.u. ) :    0.100 p.u.                  |
|    Time Setting    ( 0.0 - 60.0   s    ) :    0.000 s                     |
|                                                                           |
|  Toc Ie           ( IEC: IE>t  ANSI: 51N  )      Out of Service    : Yes  |
|    Tripping Direction                    : None                           |
|    Current Setting ( 0.1 - 4.0    p.u. ) :    0.100 p.u.                  |
|    Time Dial       ( 0.05 - 3.2        ) :    0.070                       |
|    Characteristic                        : IEC 255-3 inverse              |
|                                                                           |
|  Logic I                                         Out of Service    : No   |
|    Breaker                           Cubicle   Branch                     |
|     Bishop Lavis 3       \           Cub_1      Heilbot- BL3             |
|  Logic Ie                                        Out of Service    : No   |
|    Breaker                           Cubicle   Branch                     |
|     Bishop Lavis 3       \           Cub_1      Heilbot- BL3             |
-----------------------------------------------------------------------------
```

```
| EU_Cojac                            Relay Type : 7SJ5311-5BA0-3A0              |
|   Location      :  Cubicle          : Cub_0.2     Branch    : Eureka-Cojac     |
|                    Busbar           : Busbar B              / Station2         |
|--------------------------------------------------------------------------------|
|   Current Transformer                                Ratio       : 400A/1A     |
|     No. Phases      : 3          Phase 1     : a     Phase 2     : b           |
|     Connection      : Y                                                        |
|                                                                                |
|   Measurement                                                                  |
|     Nominal Current ( 1.0            A      ) :      1.00 A                    |
|                                                                                |
|   EU_Cojac              ( IEC: I>>    ANSI: 50    )       Out of Service   : No  |
|     Tripping Direction                           : None                        |
|     Pickup Current   ( 0.1 - 25.0     p.u.   ) :     18.000 p.u.              |
|     Time Setting     ( 0.0 - 60.0     s      ) :      1.200 s                 |
|                                                                                |
|   Ioc >>                ( IEC: I>>    ANSI: 50    )       Out of Service   : Yes |
|     Tripping Direction                           : None                        |
|     Pickup Current   ( 0.1 - 25.0     p.u.   ) :      0.100 p.u.              |
|     Time Setting     ( 0.0 - 60.0     s      ) :      0.000 s                 |
|                                                                                |
|   Ioc >>>               ( IEC: I>>>   ANSI: 50    )       Out of Service   : Yes |
|     Tripping Direction                           : None                        |
|     Pickup Current   ( 0.1 - 25.0     p.u.   ) :      0.100 p.u.              |
|     Time Setting     ( 0.0 - 60.0     s      ) :      0.000 s                 |
|                                                                                |
----------------------------------------------------------------------------------

----------------------------------------------------------------------------------
|   EU_Cojac(1)           ( IEC: I>t    ANSI: 51    )       Out of Service   : No  |
|     Tripping Direction                           : None                        |
|     Current Setting ( 0.1 - 4.0      p.u.   ) :      1.000 p.u.              |
|     Time Dial        ( 0.05 - 3.2            ) :      0.650                   |
|     Characteristic                               : IEC 255-3 inverse           |
|                                                                                |
|   Ioc Ie>               ( IEC: IE>>   ANSI: 50N   )       Out of Service   : Yes |
|     Tripping Direction                           : None                        |
|     Pickup Current   ( 0.1 - 25.0     p.u.   ) :      0.100 p.u.              |
|     Time Setting     ( 0.0 - 60.0     s      ) :      0.000 s                 |
|                                                                                |
|   Ioc Ie>>              ( IEC: IE>>   ANSI: 50N   )       Out of Service   : Yes |
|     Tripping Direction                           : None                        |
|     Pickup Current   ( 0.1 - 25.0     p.u.   ) :      0.100 p.u.              |
|     Time Setting     ( 0.0 - 60.0     s      ) :      0.000 s                 |
|                                                                                |
|   Toc Ie                ( IEC: IE>t   ANSI: 51N   )       Out of Service   : Yes |
|     Tripping Direction                           : None                        |
|     Current Setting ( 0.1 - 4.0      p.u.   ) :      0.100 p.u.              |
|     Time Dial        ( 0.05 - 3.2            ) :      0.050                   |
|     Characteristic                               : IEC 255-3 inverse           |
|                                                                                |
|   Logic I                                                 Out of Service   : No  |
|     Breaker                                  Cubicle    Branch                 |
|      Busbar B              \ Station2         Cub_0.2    Eureka-Cojac          |
|   Logic Ie                                                Out of Service   : No  |
|     Breaker                                  Cubicle    Branch                 |
|      Busbar B              \ Station2         Cub_0.2    Eureka-Cojac          |
----------------------------------------------------------------------------------
```

APPENDIX C

BASIC STRUCTURE OF DIGSI XML FILE FOR THE 7SD533 RELAYS

XML (eXtensible MarkupLanguage) is accepted as a standard for data exchange, particularly between different platforms. The DIGSI XML Code is structured in different levels that are differently indented and thus can easily be distinguished from one another. Little minus and plus signs allow you to hide or once again display the contents of individual levels and nodes using a mouse-click.


```
<?xml version="1.0" encoding="UTF-8" ?>
- <!--
 This file was generated by DIGSI 4.82 (http://www.DIGSI.com) (Siemens AG) on
 2009/12/02 10:52:24
 -->
- <DeviceData xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
  xsi:noNamespaceSchemaLocation="DIGSIXML1-1.xsd">
- <General>
  <GeneralData Name="DIGSI" ID="4.82.16.995" />
  <GeneralData Name="Name" ID="7SD533 V4.6 Device 1" />
  <GeneralData Name="Topology" ID="CPUT RETIC NETWORK / Belville Campus / Main
   Intake S/S / 7SD533 V4.6" />
  <GeneralData Name="Version" ID="V4.62.3" />
  <GeneralData Name="MLFBDIGSI" ID="7SD53315PB999HV7----0R2G2G------" />
  <GeneralData Name="VDAdr" ID="10003" />
  <GeneralData Name="Binary Input" ID="1-24" />
  <GeneralData Name="Binary Output" ID="1-31" />
  <GeneralData Name="LEDs" ID="1-14" />
  <GeneralData Name="Function Keys" ID="1-4" />
  <GeneralData Name="DeviceLanguage" ID="C" Language="English (US)" />
  <GeneralData Name="DIGSILanguage" ID="B" Language="English" />
  <Value Name="IPAddress">172.16.10.2</Value>
  <Value Name="SubnetMask">255.255.255.0</Value>
  <Value Name="StandardGateway">0.0.0.0</Value>
  <Value Name="IEDName">IED_1</Value>
   </General>
- <Settings>
- <FunctionGroup Name="Device Configuration">
- <SettingPage Name="Device Configuration">
- <Parameter DAdr="0103" Name="Setting Group Change Option" Type="Txt">
  <Value>7</Value>
  <Comment Number="7" Name="Disabled" />
  <Comment Number="8" Name="Enabled" />
  <Comment DefaultValue="7" />
   </Parameter>
- <Parameter DAdr="0110" Name="Trip mode" Type="Txt">
  <Value>25279</Value>
  <Comment Number="25278" Name="3pole only" />
  <Comment Number="25279" Name="1-/3pole" />
  <Comment DefaultValue="25278" />
   </Parameter>
- <Parameter DAdr="0112" Name="87 Differential protection" Type="Txt">
  <Value>7</Value>
  <Comment Number="8" Name="Enabled" />
```

```
  <Comment Number="7" Name="Disabled" />
  <Comment DefaultValue="8" />
    </Parameter>
- <Parameter DAdr="0115" Name="21 Phase Distance" Type="Txt">
  <Value>7</Value>
  <Comment Number="25101" Name="Quadrilateral" />
  <Comment Number="25102" Name="MHO" />
  <Comment Number="7" Name="Disabled" />
  <Comment DefaultValue="25101" />
    </Parameter>
- <Parameter DAdr="0116" Name="21G Ground Distance" Type="Txt">
  <Value>7</Value>
  <Comment Number="25101" Name="Quadrilateral" />
  <Comment Number="25102" Name="MHO" />
  <Comment Number="7" Name="Disabled" />
  <Comment DefaultValue="25101" />
    </Parameter>
- <Parameter DAdr="0120" Name="68 Power Swing detection" Type="Txt">
  <Value>7</Value>
  <Comment Number="7" Name="Disabled" />
  <Comment Number="8" Name="Enabled" />
  <Comment DefaultValue="7" />
    </Parameter>
- <Parameter DAdr="0121" Name="85-21 Pilot Protection for Distance prot" Type="Txt">
  <Value>7</Value>
  <Comment Number="25113" Name="PUTT (Z1B)" />
  <Comment Number="25114" Name="POTT" />
  <Comment Number="25115" Name="Unblocking" />
  <Comment Number="25116" Name="Blocking" />
  <Comment Number="7" Name="Disabled" />
  <Comment DefaultValue="7" />
    </Parameter>
- <Parameter DAdr="0122" Name="DTT Direct Transfer Trip" Type="Txt">
  <Value>7</Value>
  <Comment Number="7" Name="Disabled" />
  <Comment Number="8" Name="Enabled" />
  <Comment DefaultValue="7" />
    </Parameter>
- <Parameter DAdr="0124" Name="50HS Instantaneous SOTF" Type="Txt">
  <Value>7</Value>
  <Comment Number="7" Name="Disabled" />
  <Comment Number="8" Name="Enabled" />
  <Comment DefaultValue="7" />
    </Parameter>
- <Parameter DAdr="0125" Name="Weak Infeed (Trip and/or Echo)" Type="Txt">
  <Value>7</Value>
  <Comment Number="7" Name="Disabled" />
  <Comment Number="8" Name="Enabled" />
  <Comment DefaultValue="7" />
    </Parameter>
```

INSTL1-L2: Test settings for the fault between L1 and L2

Test Object - Overcurrent Parameters

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	*On Line*		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	Yes	3.000 In (3.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Test Settings for Fault Type L1-L2

Fault Model

Prefault time:	0.000 s		
Postfault time:	500.0 ms		
Max. fault time abs.:	240.0 s	Max. fault time rel.:	100.00 %
Fault voltage:	1.732 Vn		
Load Current:	0.000 In		
Angle:	-75.00 °		
Th. Reset Enabled:	No		
Th. Reset Method:	Manual		

Pick-up Test

Test Type:	Do not perform test
Trip Value:	n/a
Resolution:	100.0 ms
Evaluate:	No

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.24 I>	1.24	n/a	9.741 s	6.439 s	17.61 s	35.21 s
2.26 I>	2.26	n/a	2.549 s	2.164 s	2.993 s	5.987 s
4.13 I>	4.13	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
5.42 I>	5.42	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
7.95 I>	7.95	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
8.91 I>	8.91	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms

Binary Outputs

Bin. out 1:	0
Bin. out 2:	0
Bin. out 3:	0
Bin. out 4:	0

Trigger condition

Trigger Logic: *OR*

Trip: 1
Start: X

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:51:25	Test End:	28-Oct-2009 13:51:49
User Name:	Fessor	Manager:	Prof, Tzoneva
Company:	CPUT		

Test Results for Fault Type L1-L2

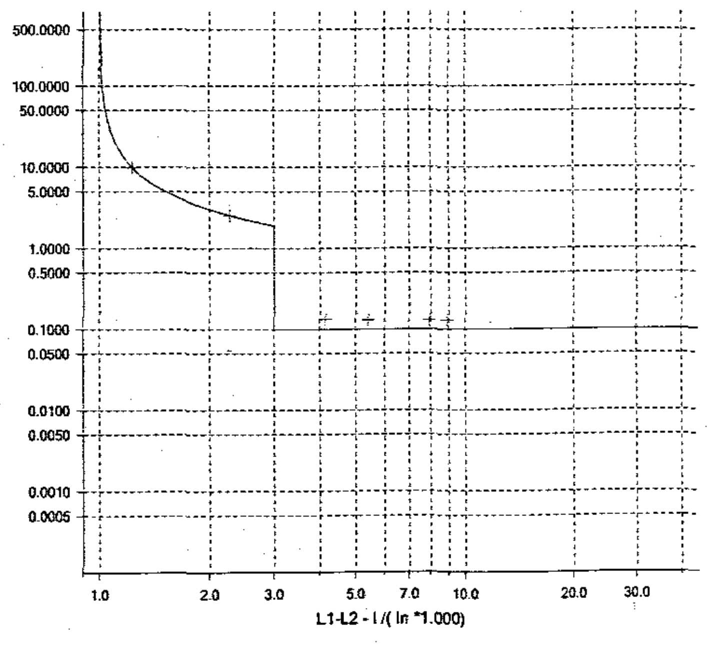
Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.24 I>	1.24	n/a	9.741 s	9.819 s	0.80	Tested		Passed
2.26 I>	2.26	n/a	2.549 s	2.543 s	-0.24	Tested		Passed
4.13 I>	4.13	n/a	100.0 ms	132.6 ms	32.60	Tested		Passed
5.42 I>	5.42	n/a	100.0 ms	130.2 ms	30.20	Tested		Passed
7.95 I>	7.95	n/a	100.0 ms	128.2 ms	28.20	Tested		Passed
8.91 I>	8.91	n/a	100.0 ms	128.1 ms	28.10	Tested		Passed

Pick-up Test Results

Test Status: No results available!

Pick-up value:
Dropout value:
Reset ratio:
Ratio error (Relative):
Assessment:

Overcurrent Characteristic Diagram



State:

6 out of 6 points tested.
6 points passed.
0 points failed.
General Assessment: Test passed

INSTL2-L3: Test settings for the fault between L2 and L3

Test Object - Overcurrent Parameters

Overcurrent protection

Abs. Time Tolerance:	0.100 s	Rel. Time Tolerance:	10.00 %
Abs. Current Tolerance:	0.10 In	Rel. Current Tolerance:	5.00 %
PT connection:	On Line		
CT Starpoint Connection:	Towards Line		
Directional:	No		
Reset Ratio:	0.95		
Apply Auto Reset:	No		

Threshold	Active	Pick-up Current	Time	Characteristic
I>	Yes	1.000 In (1.000 A)	0.300	IEC Normal Inverse
I>>	Yes	3.000 In (3.000 A)	0.100 s	
I>>>	No	10.000 In (10.000 A)	0.050 s	

Test Settings for Fault Type L2-L3

Fault Model

Prefault time:	0.000 s		
Postfault time:	500.0 ms		
Max. fault time abs.:	240.0 s	Max. fault time rel.:	100.00 %
Fault voltage:	1.732 Vn		
Load Current:	0.000 In		
Angle:	-75.00 °		
Th. Reset Enabled:	No		
Th. Reset Method:	Manual		

Pick-up Test

Test Type:	Do not perform test
Trip Value:	n/a
Resolution:	100.0 ms
Evaluate:	No

Relative	I [A]	Direction	tnom	tmin	tmax	Max. Fault Time
1.24 I>	1.24	n/a	9.741 s	6.439 s	17.61 s	35.21 s
2.26 I>	2.26	n/a	2.549 s	2.164 s	2.993 s	5.987 s
4.13 I>	4.13	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
5.42 I>	5.42	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
7.95 I>	7.95	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms
8.91 I>	8.91	n/a	100.0 ms	0.000 s	200.0 ms	400.0 ms

Binary Outputs

Bin. out 1:	0
Bin. out 2:	0
Bin. out 3:	0
Bin. out 4:	0

Trigger condition

Trigger Logic:	OR
Trip:	1
Start:	X

Test Module

Name:	OMICRON Overcurrent	Version:	2.30
Test Start:	28-Oct-2009 13:59:47	Test End:	28-Oct-2009 14:00:12

User Name: *Fessor* *Manager:* *Prof, Tzoneva*
Company: CPUT

Test Results for Fault Type L2-L3

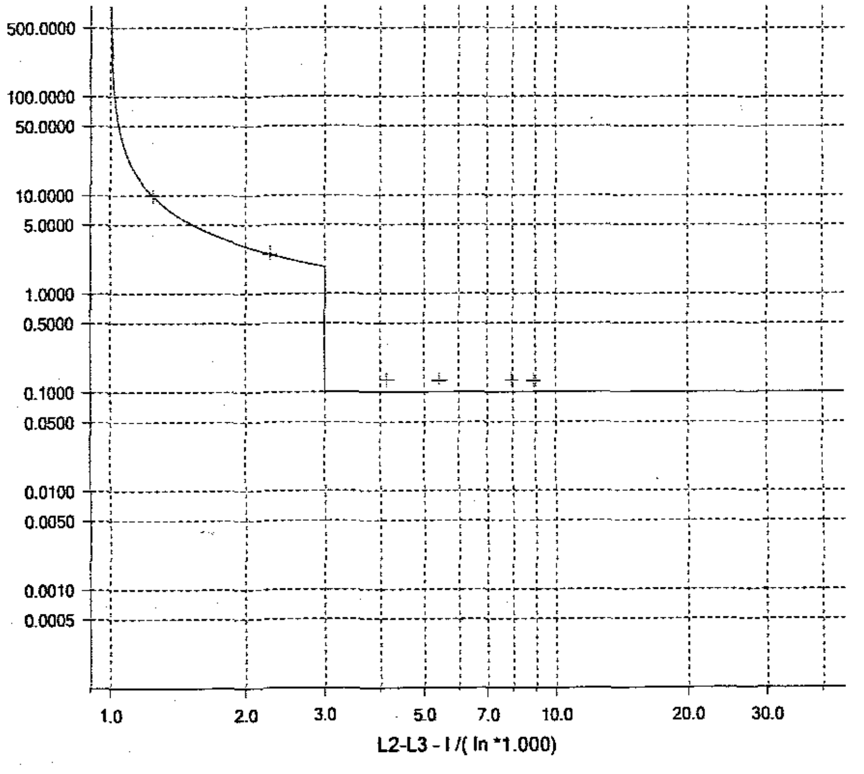
Relative	I [A]	Direction	tnom	tact	Deviation [%]	State	Overload	Result
1.24 I>	1.24	n/a	9.741 s	9.810 s	0.71	Tested		Passed
2.26 I>	2.26	n/a	2.549 s	2.553 s	0.14	Tested		Passed
4.13 I>	4.13	n/a	100.0 ms	133.0 ms	33.00	Tested		Passed
5.42 I>	5.42	n/a	100.0 ms	130.0 ms	30.00	Tested		Passed
7.95 I>	7.95	n/a	100.0 ms	131.8 ms	31.80	Tested		Passed
8.91 I>	8.91	n/a	100.0 ms	129.0 ms	29.00	Tested		Passed

Pick-up Test Results

Test Status: No results available!

Pick-up value:
Dropout value:
Reset ratio:
Ratio error (Relative):
Assessment:

Overcurrent Characteristic Diagram



State:
6 out of 6 points tested.
6 points passed.
0 points failed.
General Assessment: Test passed

REFERENCES

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