Cape Peninsula
University of Technology

DEVELOPMENT OF AN IEC 61850 STANDARD-BASED AUTOMATION SYSTEM FOR A DISTRIBUTION POWER NETWORK

by

FERDIE GAVIN JULIE

Thesis submitted in fulfillment of the requirements for the degree

Master of Technology: Electrical Engineering

in the Faculty of Engineering

at the Cape Peninsula University of Technology

Supervisor: Prof. R. Tzoneva
Co-supervisor: Prof. A. Apostolov

DECLARATION

I, Ferdie Gavin Julie, declare that the contents of this thesis represent my own unaided work, and that the 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

The electric power distribution network, an essential section of the electric power system, supplies electrical power to the customer. Automating the distribution network allows for better efficiency, reliability, and level of work through the installation of distribution control systems. Presently, research and development efforts are focused in the area of communication technologies and application of the IEC 61850 protocol to make distribution automation more comprehensive, efficient and affordable. The aim of the thesis is to evaluate the relevance of the IEC61850 standard-based technology in the development and investigation of the distribution automation for a typical underground distribution network through the development of a distribution automation algorithm for fault detection, location, isolation and service restoration and the building of a lab scale test bench

Distribution Automation (DA) has been around for many decades and each utility applies its developments for different reasons. Nowadays, due to the advancement in the communication technology, authentic and automatic reconfigurable power system that replies swiftly to instantaneous events is possible. Distribution automation functions do not only supersede legacy devices, but it allows the distribution network to function on another lever. The primary function of a DA system is to enable the devices on the distribution network to be operated and controlled remotely to automatically locate, isolate and reconnect supply during fault conditions.

Utilities have become increasingly interested in DA due to the numerous benefits it offers. Operations, maintenance and efficiencies within substations and out on the feeders can be improved by the development of new additional capabilities of DA. Furthermore, the new standard-based technology has advanced further than a traditional Distribution Supervisory and Control Data Acquisition (DSCADA) system. These days the most important components of a DA system include Intelligent Electronic Devices (IEDs). IEDs have evolved through the years and execute various protection related actions, monitoring and control functions and are very promising for improving the operation of the DA systems.

The thesis has developed an algorithm for automatic fault detection, location, isolation and system supply restoration using the functions of the IEC61850 standard-based technology. A lab scale system that would meet existing and future requirements for the control and automation of a typical underground distribution system is designed and constructed. The requirement for the lab scale distribution system is to have the ability to clear faults through reliable and fast protection operation, isolate faulted section/s, on the network and restore power to the unaffected parts of the network through automation control operation functions

of the IEC61850 standard. Various tests and simulations have been done on the lab scale test bench to prove that the objective of the thesis is achieved.

Keywords: IEC61850 Standard, Distribution automation, Distribution automation system, IEDs, Lab scale test bench, Protection, Algorithm for automatic control

ACKNOWLEDGEMENTS

I wish to thank:

- Professor R. Tzoneza, (Head of the Centre for Substation Automation and Energy Management Systems – CSAEMS) my supervisor for her support and dedication.
- Professor A. Apostolov, (PAC World Magazine) co-supervisor for his professional input.

DEDICATION

I would like to thank my supervisors for their guidance and invaluable advice. .I also owe my deepest gratitude to my family for the lack of time spent with them during the thesis

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

GLOSSARY

SAIDI - The System Average Interruption Duration Index (SAIDI) is the average power interruption duration for each customer on a specific feeder.

SAIFI - The System Average Interruption Frequency Index (SAIFI) is the average number of interruptions experienced by a customer.

CAIFI - The Customer Average Interruption Frequency Index (CAIFI) is an index used in the electrical performance analysis

IEC61850 - Its a communication standard used for the realization of automation in the substation. It is a part of the International Electro-technical Commission’s (IEC) Technical Committee 57 (TC57)

TCP/IP – Transmission Control Protocol and the Internet Protocol is the computer networking model and set of communications protocols used on the Internet and similar computer networks.

GOOSE - **Generic Object Oriented Substation Events** (**GOOSE**) where any format of data, such as status, value, etc. is grouped into a dataset and transmitted within a time period of a few milliseconds.

IED – Intelligent Electronic Device describes microprocessor-based controllers used in power system equipment.

HMI - Human–machine interface, the interface between the human-machine interaction

DA - **Distribution Automation** describes the intelligent automatic control of devices on the distribution network.

DAS – Described as a system which makes it possible for power utilities to monitor, coordinate and operate distribution equipment remotely, usually from a control center.

S/S – A substation is a part of the electrical network system, which comprise of the generation, transmission and the distribution system respectively

FDISR – Fault Detection, Isolation and Service Restoration

MODBUS - Modbus is a serial communications protocol

DNP3 - Distributed Network Protocol is a set of communications protocols

SCADA - Supervisory Control and Data Acquisition is described as a system that operates with coded signals that control equipment remotely over a communication medium

SCL – Substation Configuration description Language is the language defined by the IEC 61850 standard used for the configuration of substation devices/apparatus.

ICD - IED Capability Description

SSD - System Specification Description

SCD - Distribution Substation Configuration Description

CID - Configured IED Description

Power System – It is a combination of electrical components that is used to transmit electrical power. It can be divided into generation, transmission and distribution systems.

RTU - Remote Terminal Unit is a device that interfaces electrical equipment objects to a SCADA (system control and data acquisition) system. It is used to transmit data to a master system and control the connected electrical equipment remotely.

CT – Current Transformer is a type of instrument transformer that delivers a proportional reduced secondary current which can be used by protective devices, measuring devices and recording instruments.

VT - Voltage transformer also known as potential transformer (PT) is a type of instrument transformer, that produces a proportional reduced secondary voltage that can be used by metering and protection devices.

CHAPTER ONE

INTRODUCTION

1.1 Introduction

The general idea of an automated distribution power system is to use technologies to isolate faults, locate the faulty sections, re-configures the network, restore power, and maintain stability of the network. Existing distribution power control systems with no or limited control and communication capabilities have to be put back with digital systems in order to furnish the power system with the power to restructure itself automatically and obstruct extended power loss to customers. Such a system consists of an advanced sensing, communications, and control functions that provide increased system reliability. When the efficiency and reliability of an existing power system is improved it will decrease the need for major infrastructure investments in the future. The benefits the automated systems provide go well beyond the indirect benefits such as enhanced reliability and electricity supply security to the consumers. It addresses the concerns of the availability of a more secure point of supply and results in increased system information [Park et al., 2008], [Lin et al., 2009] and [Chen et al., 2000].

Presently there is only a handful, 15% to 20%, distribution systems worldwide that are equipped with advanced automated systems [Giacomoni, 2011]. Even the power systems at the distribution level in North America with the planet's most promoted power systems, less than 25% of the distribution system has data and communications systems installed. To succeed, a reliable communications network is crucial together with interoperable Intelligent Electronic Devices (IEDs) communicating with one another [Nordell, 2008]. Distribution Automation Systems (DAS) and IEDs are the foundation of a more "intelligent" and more reliable network.

This chapter describes the following: 1.1 Introduction, 1.2 Awareness of the problem, 1.3 Motivation for the research project, 1.4 Problem statement, 1.5 Research aim and objectives, 1.6 Hypothesis, 1.7 Delimitation of research, 1.8 Assumptions, 1.9 Research design and methodology, 1.10 Chapters breakdown, 1.11 Conclusion.

1.2 Awareness of the problem

The latest approaches in digital technology have made possible the improvement of automatic power distribution automation approaches. Distribution Automation has been around for many decades and each utility apply it for different reasons.

Today, due to increased capability in the communication technology environment, distribution automation system (DAS) is not only remote control and operation of feeder equipment, but it results in a highly authentic, self-healing power system. Distribution automation allows the power system to function on a more advanced level. It does not only replace manual devices and procedures. The primary function of a DA system is the control and operations of breakers and line switches to automatically locate, isolate and restore power during fault conditions in a power system. There are a few reasons why DAS are needed such as to address performance as well as authenticity and condition of power distribution. Usually the automation of substations and feeders are combined to share universal monitoring and controlling apparatus. Remote information retrieval is required in order to accomplish the optimal benefit of the supervisory control function.

1.3 Motivation for the research project

Distribution automation was chosen for a topic of the thesis because of several reasons. There is a great deal of new developments in this field therefore working in this environment will give valuable knowledge. The complexity and detail this topic covers will also be a challenge during the duration of the project. The electric power distribution network, an essential section of the electric power system, supplies electrical power to the customer. Distribution automation in the distribution environment enables utilities to make use of highly efficient up-to-date technology in the control of the distribution system, which can lead to the enhancement of efficiency, reliability, and quality of their service. Today, investigation and advancement attempts are concentrated in the fields of communication technologies and the application of the IEC 61850 standard-based technologies in the distribution environment. However, investigations on the applicability of the new IEC61850 standard to solve the problem for automated, fast and reliable DAS are still needed.

1.4 Problem Statement

Present proprietary automation systems are expensive, they are not interoperable with devices from other manufacturers, have limited data retrieval capabilities, are difficult to configure, etc. Better solutions are necessary to be investigated one of them is the technology based on the IEC61850 standard which is widely used in substation automation. This technology has the capabilities to can be applied in the distribution environment, but further investigation is required to prove this. This idea is considered in the thesis.

1.4.1. Sub-Problems

1.4.1.1 Development of a model for the distribution automation system.

An investigation has to be done to move from a hardwired protected system to an automated protected system with advanced features through the implementation of an integrated communication infrastructure. The manual operations of a typical distribution system have to be replaced with automatic functions that require no human interventions. This sub-problem has to be solved for the CPUT distribution network.

1.4.1.2 Development of an algorithm for fault detection, location, isolation and service restoration.

Algorithms for the automatic fault detection, location, isolation and service restoration that are based on protection functions, status information from the line equipment status information of the breakers and the use of SELogic equations.

1.4.1.3 Configuration of the IED settings and their integration on the developed algorithm.

The performance of a protective system is as good as how well its settings are set and programmed. The system requirements were investigated and the protective device settings were calculated for optimal protection operation and performance. At the heart of the automated system is an algorithm system that governs the operation of the test bench system. The operational requirements of the system were analyzed and the logics of the relevant devices were applied.

1.4.1.4 Design and implementation of a test bench

A lab-scale test bench had to be built representing a distribution environment consisting of two substations and two radial feeders with several line sections, line switches, fault path indicators and a normally open point. Software tools, hardware platforms and test equipment are used in the real-time implementation of the system. Omicron 256plus has to be used for setting up and monitoring the system performance through simulated case studies. Several tests have to be performed by the application of secondary test currents. Quick CMC as well as state sequencer is test modules of the Omicron to be extensively used.

Quickset AccSelerator software tool from SEL is used to program protection IEDs as well as applying protection settings. Quickset AccSelerator Architect software tool is used to configure and commission the IEC61850 communications of the IEDs in this thesis

1.4.1.5 Analysis of the improved protection scheme

Several case studies have to be performed on the lab scale test bench system with IEC61850 compliant devices. Faults have to be simulated on each line section of the test system and the system performance of the system has to be investigated. The settings of the protection devices and algorithms have to be verified and their application efficiency analyzed.

1.4.1.6 Investigation of the reliability of the automated system

An unstable system that does not perform its functions as per design could be very dangerous to personnel and equipment. The reliability of the required system functions has to be investigated by performance analyses of the built test bench through several case studies.

1.5. Research Aim and Objectives

This project will explore how the contribution of a DAS system on the medium voltage network can benefit the utility and its customers. The benefits are economical and operational due to improved performance by reducing SAIDI, SAIFI, and CAIDI. The aim of this project thesis is to:

- Evaluate the application of the IEC61850 standard-based technology in the development and investigation of the distribution automation for the Cape Peninsula University of Technology (CPUT) Bellville Campus reticulation network through the development of a distribution automation algorithm for fault detection, location, isolation and service restoration and the building of a lab scale test bench.

The objectives for achieving the thesis aim are:

- CPUT network data gathering
- Development of a one line model of the distribution network
- Development of methods and algorithms for fault detection, location, isolation, and service restoration

- Integrity checking of the distribution power system model
- Development of software for the implementation of the algorithms for fault detection, location, isolation, and service recovery.
- Real-time implementation of the DAS by building lab scale prototype.
- Experiments with the lab scale prototype to proof the developed methods and algorithms

1.6. Hypothesis

IEC 61850 standard-based concepts, methods, and technology currently available in substation automation allow successful building and operation of automated Distribution Automation Systems.

1.7. Delimitation of Research

The CPUT DAS will be designed based on open-system architecture, which means that the system can be expanded by the addition of unlimited hardware and software. The main parts are the line equipment devices, Intelligent Electronic Devices (IEDs), and a communication system. The experiments on the lab scale test bench will be performed by an Omicron 256plus secondary injection test set. The tests will not be done on a real distribution network. The methods that are developed are based on the capabilities and functionalities of the IEC61850 standard and not based on artificial intelligence or neural networks.

1.8. Assumptions

The following assumptions used as a basis for developments in the thesis are done:

- The distribution network to be studied has one normally open point.
- There is only one source of supply on the distribution network.
- Devices from only one manufacturer will be used.
- Omicron binary outputs can be used to replace the functions of the fault path indicators.
- IEDs at the substations can be configured as substation breakers on the developed test bench.
- The distribution network can be reconfigured in such a manner that the network can be supplied from any one of the substations.

1.9. Research Design and Methodology

The aim of the research is to establish communication-based distribution automation system through the establishment of a communication network between the substation IED and the field devices out on the feeder allowing integration of their functions in the implementation of a developed DA algorithm. These devices should be able to perform fault detection, isolation and service recovery without human intervention. The implementation of the IEC61850 standard makes it possible for the objective to be met. The research methods used in achieving the thesis aim are:

- Development of mathematical methods

- Development of algorithms for fault detection, location, isolation, and service recovery.
- Building of a lab-scale test bench
- Investigations of the performance of the protection and automation functions of the test bench.

1.9.1 The need for DA

One of the main elements of ineffective power distribution presently, is as a result of the lack of information on the loading at main intake substations. Overloading occurs due to lack of monitoring, which results in the unacceptable voltage levels at the customer's terminal. It is impossible to disconnect specific loads, for example, load shedding or during fault conditions because there are not enough breakers in the distribution network. As a result of this situation the circuit breaker at the main substation has to be used. However, the main purpose of these circuit breakers is to provide protection during fault conditions. When the breaker trips and locks out, it interrupts supply to the entire line and this has an effect on a large number of customers. This situation is not ideal and needs more flexibility to reduce the effect of faults on the customer. There is a need for more flexible tools to achieve distributed data acquisition, monitoring and control. Ideally, if there is a fault on a feeder the faulty section needs to be identified, the supply re-routed to the healthy portions by the opening and closing of breakers, in order to reduce the affected area

1.9.2 Impact of DA on Distribution Networks

Basic analysis of power system conditions can be performed by distribution operators using simple functions of a distribution SCADA system. The operator makes decisions based on his experience and the limited information that the SCADA system provides. Without an analysis of this data and without the support of "intelligent" application programs the operator does not really have enough information to make the optimal decision.

The most basic monitoring and control of remote equipment remains the use of the SCADA system for data retrieval and issuing of control commands through the control center or by an application program. Utilities can benefit from the basic expansion of monitoring and control of distribution equipment which results in shorter fault duration. Operators can be alarmed on potential overload conditions, on power quality problems and other circumstances that can have a negative impact on the distribution system. They are then in a situation in which they can take corrective action much quicker as a result of this information.

At the moment utilities perform maintenance on distribution equipment on a periodic basis. There are no systems in place to give feedback whether the equipment needs the maintenance or if the maintenance should be done on a more regular basis or if it is an emergency. More informed decisions can be made if feedback such as how many times a device has operated, the status of the equipment, information on what the fault currents are, environmental information such as moisture and temperature, etc. are available. In addition to monitoring and control, suitable IEDs with the ability to communicate with one another in the distribution network can be installed to perform these functions

1.9.3 Distribution Automation in South Africa

There have been several factors that are driving utilities to improve service reliability and simultaneously reduce operational cost. Companies worldwide has experimented with automation by rolling out pilot projects. In South Africa the utility ESKOM embarked on a Distribution Automation research program in 1998 to investigate the automation of existing distribution networks. This involved the investigation of several technologies and analysis of the capability within South Africa to develop and support DAS. In 2003, ESKOM successfully commissioned and demonstrated its first DA pilot system, with a number of others already in the planning and design stages [Gutschow and Kachieng'a, 2005]

High level business factors such as reliability improvement of electrical supply and reduction of operational maintenance are the key factors for the implementation of DA. Other factors specific to South Africa are [Gutschow and Kachieng'a, 2005]:

:

- Minimum quality of service and quality of supply standards imposed by the National Electricity Regulator (NER) of South Africa;
- The deregulation and restructuring of the Electricity Distribution Industry (EDI);
- Increasing customer requirements for higher reliability of electrical supply, improved quality of supply, and low annual electricity tariff increases;
- Technology enablers such as advances in protection, control, and telecommunications technologies;
- Socioeconomic factors such as the need for low-cost electricity and non-payment of services.

1.9.4. The Advantages of Implementing DA

The advantages of the DA are grouped into two categories, i.e., tangible and intangible benefits. Tangible benefits, or so-called "hard" benefits, can be quantified in financial or technical performance terms and can benefit both the utility and the end consumer, as shown in Table 1 [Gutschow and Kachieng'a, 2005]. The intangible benefits are: increased customer satisfaction, increased system information, improved quality, etc. [Su and Teng, 2007].

Utilities implementing Distribution Automation Systems are receiving benefits from many areas. Automation is first implemented at the top of the control hierarchy where integration of multi-functions gains efficiencies across the entire business [Northcote-Green and Wilson, 2008]. Implementation of downstream automation systems requires more difficult justification and it is usually site specific.

Table 1.1: Tangible and Intangible Benefits. [Gutschow and Kachieng'a 2005]

Tangible Benefits	**Intangible Benefits**
Financial savings to the utility	
• Deferral of capital expenditure required or capacity upgrades • Decreased loss of electricity sales during outages • Decreased technical losses • Decreased process and maintenance costs • Avoided penalty costs imposed by the Regulator	• Improved power system planning and engineering • More efficient plant maintenance • Enhanced fault detection and diagnostic study • Customer retention through improved quality of supply • Better customer and governmental relations • Additional customer service • Competitive advantage
Benefits to customers	
• Improved supply reliability • Improved quality of supply • Reduced interruption costs for customers	

1.9.5. Financial justification

The reduction of operation and maintenance costs, improvement of service reliability, and improved process effectiveness are the objectives of DA implementation. However, the applications of DAS systems require a considerable financial expenditure. Introducing automated systems to distribution networks will eventually make electricity more reliable, efficient, and cleaner. It may also become cheaper. The big question though would be how much it will cost to implement it and how much it will save the utility and the end consumer in the long run. It is not easy for utilities to financially support the capital expenditure for developing DAS systems. The current CPUT Bellville campus network is more than 30 years old and many parts of the Medium Voltage Distribution Network have to be replaced. Since a large amount of money has to be invested in equipment replacement an opportunity for DA has become viable.

The case study considered in the thesis is for the CPUT distribution network. The Cape Peninsula University of Technology, Bellville Campus (CPUT) campus network is more than 30 years old and the protection and network equipment has become obsolete and as one might expect has to be replaced. The renovation allows also some distribution automation functions to be introduced and built. The thesis proposes a solution of the campus distribution automation system.

The IEC61850 standard is not widely used in the distribution environment since it is the communication standard for substations. Utilities are also reluctant to make huge investments in the communications infrastructure on distribution feeders. Therefore, literature research had to be done to first of all review if it is possible to use the standard in the distribution environment. IEEE journals, papers, relevant books and the internet were used to gather a huge amount of information.

1.10 Chapters Breakdown

1.10.1. Chapter One

This chapter describes the awareness of the problem, motivation of the research, protection and control in distribution networks, problem statement, sub problems, research aim and objectives, hypothesis, delimitation of research, project assumptions, research design and methodology, thesis chapter breakdown and conclusion.

1.10.2. Chapter Two

This chapter reviews the literature of automated systems in the distribution power system environment. Various technical papers, journals and articles were read and analyzed.

1.10.3. Chapter Three

This chapter discusses the most widely used communication protocols currently in use on the distribution power system as well as the IEC61850 standard. Communication between the RTUs and the control center SCADA is established through protocols that are designed to provide information on the status of the field devices. Communication protocols can be considered as the language that the equipment and applications have to use to successfully exchange information and data.

1.10.4. Chapter Four

This chapter comprehensively discusses the concept of the automated strategy as well as the design of the case study. The test bench system consists of a physical structure, communications, structure and a control structure. The chapter also discusses the IEC61850 standard-based implementation of the system, programming of the IEDs and GOOSE messages diagnostics. The question whether the IEC61850 standard can be implemented in the distribution environment since it is the communication standard for substations was answered positively.

1.10.5. Chapter Five

This chapter investigates the operation of the developed distribution automation system that uses IEC61850 standard functionalities which are able to successfully solve the problem that utilities face with extended outages on distribution ring networks. The chapter shows how faults on each of the line sections were simulated and the system response analyzed. These simulations proved fast fault clearing times, successful fault isolation is achieved and all the system requirements are fulfilled. The question of the impact of multiple faults in the automation process was also addressed. Finally the question of whether the system would operate as expected if the algorithm conditions are not met were also addressed.

1.10.6. Chapter Six

This chapter summarizes the thesis and describes areas for future work.

1.11 Appendix A

In this Appendix the ACSELERATOR Quickset SEL-5030 software tool is described. It shows in detail the steps to take to connect (serial or network connections with settings) to the protective device, configuring the device protection settings, configuring the device logics and all the other IED functions.

1.12 Appendix B

This Appendix shows in detail the complete configuration of the SEL2440 discrete programmable controller.

1.13 Appendix C

This Appendix shows the parameter settings of the SEL2440 controller.

1.14 Appendix D

This Appendix shows the parameter settings of the SEL351A protection IED.

1.15 Appendix E

This Appendix shows how the ACSELERATOR® Architect software tool is used for the design and commissioning of IEC61850 substations through editing and creating IEC61850 reports and GOOSE messages.

1.16 Appendix F

Appendix F shows how the Omicron secondary injection test set was used to perform full-range functionality and comprehensive tests of the protective IEDs. It shows it detail the setup of the control center for the various tests, setup of the test object, configuration of the hardware and the setup of the various test modules. It also shows the GOOSE configuration test module setup.

1.17. Conclusion

Increased capability in the communication technology has led to the distribution automation systems (DAS) to be more than just remote control and operation of feeder equipment. Automation allows the power system to operate at a more advance level, it does not only replace manual devices and procedures. The primary function of a DAS is to facilitate the remote controlling of breakers and line switches to locate, isolate and restore supply during fault conditions in a power system. The need for distribution automation, the financial justification and distribution automation in South Africa is described.

The next chapter provides a review of the methodologies found in the literature through the analyses of various technical papers, journals and relevant internet sites.

CHAPTER TWO
LITERATURE REVIEW

2.1 Introduction

The improvement of the operating performance of the distribution system through the application of computer and communication technologies has emerged in the 1970s as a Distribution Automation (DA) concept [Mohagheghi, 2009]. Until now DA has evolved considerably and numerous utilities worldwide adopted the concept. Presently there is more attention given to DA by utilities because of the renewed push towards reliable and efficient distribution networks and customers has become more sensitive to supply outages due to increasing dependency on electricity.

Every utility's needs are unique, however, in general the requirements are the implementation of automation machinery for protection, control, monitoring, and processing of electrical distribution systems. This enables the power companies to monitor, and process distribution components from remote locations. Numerous developed DA schemes are available for the automation of electric feeders in the distribution environment. They can be grouped into three main categories: semi-automatic, distributed, and centralized DA schemes [Kazemi, 2008].

Radial distribution networks predominantly only needed limited real-time control because they had been designed to operate within voltage levels and expected loads. Feeder circuit breakers at the Distribution substation protect the distribution network and outside the substation the rest of the network is protected by other protective devices such as reclosers, sectionalizers, and fuses. In the past line operators were responsible to locate the faults on the networks manually, thereafter do the necessary switching and return power to the customers. Investments in control systems in the substation and down the line were not justifiable because of the amount of energy lost when compared to a high voltage transmission line. Simple SCADA was the first type of remote control that was introduced at large distribution networks, but the small distribution substations, in general, remained under manual control. In the past power companies were responsible for the generation, transmission and distribution of energy to the customer. However the free market for energy supply (deregulation) had its impact on the distribution network, pointing out the need for reduced outage times. This has led to the automation of the feeder system as a tool for improved reliability and customer service. Simultaneously, the enhancement of the simple SCADA with a distribution management system (DMS) has led to a much higher level of distribution network control.

Various technologies have been trying to accomplish DA in the field of system protection and control as well as metering. A reliable communication infrastructure can be said to be the most essential characteristic under these different technologies. Other than local automation schemes which employ voltage sensing and other principles to initiate applications, the majority DA implementations need communication to initiate action to the control center [Northcote-Green and Wilson, 2007]. Data that is transmitted need to go with supplementary characteristics such as the address of the receiving device, the address of the sending device, description and length of information, time print of the disturbance, its priority as well as its quality [Mohagheghi et al., 2009]. Vendor specific protocols were employed to create the information and use it in various functions in the early days. The drawbacks of these technologies were that they were vendor specific and were not suitable with schemes and technologies of other vendors. The IEC 61850 standard was recommended as a flexible communication protocol with interoperability capability between various vendors and with an exceptionally progressive object orientated modeling structure [Mohagheghi et al., 2009].

The IEC TC57 work group described the IEC 61850 standard for "Communication Networks and Systems in Substations". The open based standard is not exclusively used between the station level computer and bay level apparatus, it is also used in open communication to the primary apparatus [Kim and Lee, 2005]. The role of the IEC 61850 standard is of great consequence due to the development of DA. DA needs exceptional integration and sharing, approves homogeneous platform and a model for it to achieve interoperability of the electric devices and schemes. The IEC 61850 standard will become the main criterion for DA [Cong et al., 2008]. Basic functions of DA include Fault Detection, Fault Isolation and Service Restoration (FDISR). FDISR will detect the faulted area, isolate the faulted area by opening relative boundary switches and reconfigure the network by re-closing tie switches.

There are several key issues a utility/power company has to consider when it wants to apply automation on its distribution networks. It has to do a cost and feasibility study when it intends to replace old equipment with automation ready equipment or if it intends to modify existing equipment. It also has to consider what type of automation it will apply, for example, central or distributed, system or local or a combination of these. And finally, without a proper business case any automation project will not be successful.

This chapter presents a literature review of the published papers considering the development and implementation of Fault Detection, Isolation and Service Restoration (FDIR) through the implementation of IEC 61850 based approach. DA can be implemented successfully with a combination of a suitable communication infrastructure and suitable Intelligent Electronic Devices (IEDs).

The chapter is organized as follows: Section 1 describes a brief introduction of the Distribution Automation System (DAS), Section 2 gives a brief description of how the literature search was conducted, describes the power distribution system, discusses the control hierarchy of network optimization and summarizes the benefits of distribution automation. Section 3 presents literature review, and summarizes the services of DA. Section 4 describes the comparative analyses of the various papers in the literature, discusses the problems, approaches and methods considered in the thesis. Section 5 describes the conclusion.

2.2 Literature Search

There has been considerable interest in using IEC 61850 based approaches for reconfiguration in distribution systems over the recent years. The main papers that consider this new approach are, [Zadeh and Manjrekar, 2011], [Jansen et al., 2011], [Mahmood, 2009], [Xu et al., 2010], [Mohagheghi et al., 2009], [Coffele et al., 2014], [Siirto et al., 2014] and [Cong et al., 2008]. On the basis of these papers consideration and using the keywords: “IEC 61850”, Distribution Automation”, “Feeder Automation” and “Distribution Power System Reconfiguration”. The papers are published from 1982 to 2014, covering a period of 32 years. Figure 2.1 presents a graph showing the most relevant papers published per year. Analysis of the graph shows that during the early years only a few papers were published. During 2008, 2009 and 2011 the most papers were published. The analysis also shows that the majority of papers published in this field is from Asia.

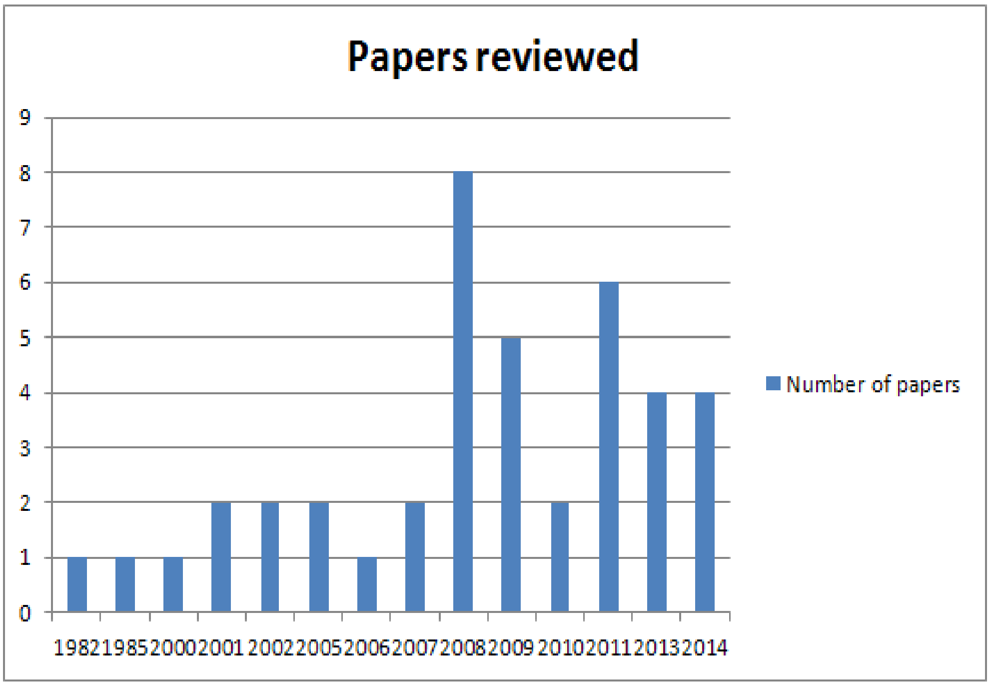


Figure 2.1: Graph of the number of papers per year reviewed in the literature study

2.2.1 Power Distribution System

The first electric power station, Pearl Street Electric Station, in New York was commissioned in 1882 [Gonen, 1986]. Power is delivered to the customer through a continuous network, with generation, transmission and distribution systems. In order to meet the demands of the service area, large power generating stations are installed. Then the bulk power is transmitted in transmission network [132kV-765kV] in the transmission grid, thereafter it is stepped down to distribution level [3.3kV, 6.6kV, 11kV, 22kV, 33kV and 66kV]. The electric power is then further stepped down again by distribution transformers to secondary distribution level [240V single phase and 415V three phase] for the end user.

2.2.2 Distribution Automation Concept

The Distribution Automation concept was developed to improve the Supervisory Control and Data Acquisition (SCADA) at medium/high voltage levels [Marais, 1998]. DA is not SCADA it provides enhanced automation features which separate it from SCADA. Furthermore, DA allows lower level decision making through distributed processing without human intervention [Marais, 1998].

The electric power industry has adopted the following definition for the concept of Distribution Automation:

"A combination of technologies that facilitate an electric utility to remotely monitor, coordinate and operate distribution components in a real-time mode from remote locations."

The term mentioned in the definition "distribution components" points out to the full Distribution System. Therefore DA encompasses the control and monitoring of the entire Distribution System (feeders, transformers and bus bars). To achieve the "remote" controlling of devices the distribution components necessitate the integration of a communication infrastructure. (The distribution communication system is the key critical facility). DA enhances SCADA, where the field crew in the past had to manually react to certain system conditions, the remote field devices now automatically react to system conditions in a much faster response time. Furthermore the definition point out that DA is not a single technology but a set of technologies. DA gives descriptions of several services and functions. The Electric Power Research Institute (EPRI) has identified 161 possible DA services [Marais, 1998].

2.2.3 Control Hierarchy

The application of network optimization occurs in a structured controlled hierarchy which encircles the need of the various layers of the network [Northcote-Green and Wilson, 2007]. It becomes necessary to do network control from the control center. The operation of devices relies on a communication link from the control center to the various devices situated along the power network. The combination of the control room, communication infrastructure and IED comprises a SCADA system. SCADA systems are actioned to control the various layers of the network, Figure 2.2.

The hierarchy consists of the following layers according to [Marais, 1998]:

Utility Layer –	The top layer deals with all the business wide Information Technology (IT), asset management and the energy trading system.
Substation Layer –	Circuit breaker control inside the substation together with the communication of all IEDs are dealt with in this layer.

Distribution Layer - This layer deals with real-time control capability via remote control and automation of devices located on medium voltage systems.

Consumer Layer - Here the delivery system interconnects with the customer directly.

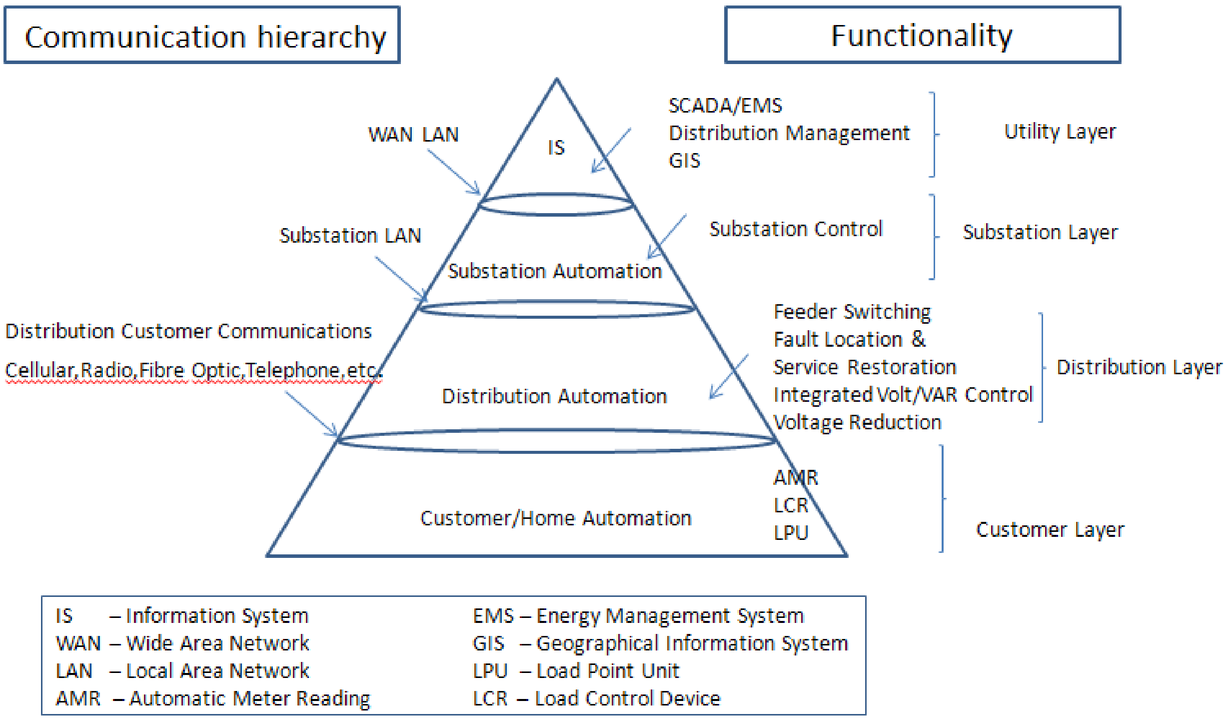


Figure 2.2: Interfaces between functionalities and communication hierarchies.

2.2.4 The advantages of implementing DA

. The advantages of DA are broadly grouped into tangible and intangible benefits. Tangible benefits, or so-called "hard" benefits, can be assessed in financial or technical performance terms and can benefit both the utility and the end consumer [Gutschow and Kachieng'a, 2005]. Improved customer satisfaction, better system information quality, etc. are examples of intangible benefits [Su, 2007]. Albeit not all of the DA gains can be assessed, they are still relevant to utilities [Matsumoto et al.; 1998].

The implementation of DA resulted in several benefits to power utilities, which include improved system reliability and increased operation efficiency. The implementation and acceptance of DA differ from utility to utility due to the limited benefit-to-cost ratios of the past The benefits demonstrated through automating substations are now being extended outside the substation to devices along the feeder. The key areas are [Northcote-Green and Wilson, 2007]:

- **Reduced operation and maintenance costs.**
  The operating costs through the entire utility have been reduced by the implementation of automation. Fast fault location has reduced the response time of field services personnel as they are called out directly to the faulted equipment/area.

- **Improved reliability**
  The reduction of power outage durations has been realized through automation. Statistics have shown that the average fault duration can be improved by 20-30% on overhead feeders on distribution networks on an annual basis.

- **Capacity project deferrals**
  The load can be transferred from one feeder to another during peak periods through automatic operation of Normally Open Points (NOPs). This will avoid any transformer transfer capacity strengthening at substations as maximum demands normally occur during certain periods of the day and the rest of the day the demand for power is normal.

- **New customer service**
  Automatic Meter Reading (AMR) enables utilities with more flexibility in tariff offering and it allows the customer with greater selectivity and control of consumption.

- **Improved Information for Engineering and Planning**
  IEDs provide increased real-time data trough automation, providing increased visibility to network planners and field service crew and the controllers at the control center.

- **Power Quality**
  Through the implementation of automation increased operational efficiency and improved system reliability have been achieved.

2.3 Literature Review

The literature review was conducted through analyses of relevant technical papers, books and journals. A new approach of using IEC 61850 in the introduction of feeder automation is discussed in reference [Wang and Ma, 2008]. Reference

[Apostolof and Vandiver, 2011] discusses the requirements of shortening the fault duration in the substation through the use of IEC61850 standard-based GOOSE messages. Reference [Mohagheghi et al., 2009] shows by way of examples how the standard can be used to model basic components (such as Reclosers, Shunt capacitors, and Tapchangers) commonly used in DAS systems. Reference [Cong, 2008] gives an introduction of the conventional improvement arrangement of IEC61850 and its essential obstacles as well as the new development method to solve these problems. [Zadah and Manjrekan, 2007] presents a new IEC61850 based approach for distribution line and cable protection, taking data from both ends of the feeder into account. Providing a solution for Smart Grid applications using IEC61850, database management using Common Information Models (CIM) as well as distribution management systems (DMS) is provided in the reference, [Janssen et al., 2011]. A concept and design of digital distribution automation as well as analysis of the construction model are given in reference [Xu et al., 2010].
The literature reviewed for this thesis mainly focuses on the services provided by the Fault Detection, Isolation and Service Restoration functions.

2.3.1 Services.

[Marais, 1998], points out that SCADA and Reticulation Control are the most important services of DA which enable utilities to improve the quality of supply (QOS) and increase business process efficiencies. However, there are additional services (161 identified by EPRI), that enable the application of DA. Every utility is different from one another and each of their needs is unique. Although EPRI has identified 161 candidate services, utilities will only implement the services that will satisfy their specific needs and requirements.

Not all the services are justifiable [Marais, 1998] and [Chen and Sabir, 2001] – the services that are justifiable include: SCADA at Medium Voltage (MV) substations, automatic bus sectionalizing, automation of pole-top devices, automation of fault location, isolation and service restoration to un-faulted areas of the network and load control and loss management.

2.3.1.1 Fault Detection, Isolation and Service Restoration (FDISR)

Singling out the most critical feature of a DA system is its “self-healing” capability. The self-healing function allows the power to be restored automatically and as speedily as possible to the unaffected portions of the system while the operating field staff carries out the necessary repairs to the faulted section. FDISR creates a switching algorithm that re-energize portions of a distribution system that have been affected by a fault in the power system. Following the occurrence of a fault FDISR automatically executes the algorithm to restore power supply where possible. Without FDISR a much greater portion of the network will be affected and will remain affected until field operating staff has arrived at the scene to locate and repair the fault. The fault location can be identified by protective relay IEDs and fault path indicators. Once the location of the fault has been identified the fault can be repaired or the problem area disconnected. Customers on the “healthy” portion of the network will also be affected and can be without supply for several hours. The duration of the supply interruption to the same customers can be significantly reduced by the FDISR application [Northcote-Green and Wilson, 2007].

During a fault condition on the network fault detectors mounted on the field devices out on the feeder report the fault to FDISR. The FDISR application first allows the protective IED or Recloser to isolate the fault. Thereafter FDISR perform control actions to open the switches that bound the faulted (between two line switches) area isolating the damaged portion of the feeder. Thereafter, it closes other switches to restore power to the unaffected portion of the feeder through the supply from an alternative source of supply, where possible. All these actions are performed automatically without any human/manual intervention. These actions are:

Fault Detection: FDISR application is started by a permanent fault on the feeder.

Fault location: Following fault detection the fault location step determines “where” the fault on the network is. The network is divided into portions that are bounded by switches. A Fault Path Indicator is installed at each switch. The Fault Path Indicator (FPI) checks if the fault current has passed through it and then indicates that a fault exist “downstream” of it.

Fault Isolation: The automatic opening of only the switches needed to isolate the faulty portion of the feeder.

Service Restoration: When the faulty portion of the feeder has been isolated the FDISR application tries to restore power to the unaffected portions of the feeder via available sources of supply with sufficient capacity. This includes an alternative source of supply, existing source of supply and/or closing of a Normally Open Point.

2.3.1.2 Distribution Supervisory Control and Data Acquisition (DSCADA)

The goal of an automated distribution system is to be able to continuously monitor and automatically control the distribution field devices located in distribution substations and on the feeders [Nunoo and Ofei, 2010].

It is a worldwide case that very few DSCADA facilities are available on the distribution system, especially on the field devices in the distribution system that are outside the substation perimeter. Without robust and reliable communication infrastructure, for retrieval of measurement data and remote control commands to field devices, an automated distribution system is not possible. The widespread application of DSCADA is made difficult as a result of a lack of two-way communication facilities at the field devices. Several challenges in the application of communication on the distribution system exist, such as the wide area, it is covering and the existence of obstructions between field devices exists [Greer et al., 2011].

2.3.1.3 Automatic Bus Sectionalising

After the primary protection cleared a permanent fault, automatic bus sectionalising operates through a sequential process. Therefore, its purpose is to isolate faulted substation and line equipment through the operation of appropriate line switches. Overload detection and reporting is one of its functions as well as service restoration, by opening and closing of specific breakers and switches. All these functions can be realized through implementation of a suitable communications infrastructure [Marais, 1998].

2.3.1.4 Integrated Volt/VAR Control

The substation bus, feeder and remote point voltages are maintained within a specified set bandwidth through this service. On/Off-load transformer tap changers are used to regulate the bus voltage.

Feeder or pole-top capacitor banks and voltage regulators are used to regulate the voltage of feeder remote points in distribution networks. Capacitor bank switching is also used to control the feeder reactive power.

The Fault Detection, Isolation and Service Restoration services are used in this thesis.

2.4 Comparative Analysis of Existing Publications

A comparative analysis of the papers in the field of Fault Detection, Isolation and Service Restoration is done based on the following criteria: aim, approach, methods used, protection, communication/protocol, simulation/implementation and benefits/ drawbacks. Existing papers and proposed solutions are shown in Table 2.1 and Figure 2.1 shows a graph of the number of papers that were analyzed in the literature review over a period of 30 years.

2.4.1 Discussion

Discussions are now done column by column from Table 2.1 because it is necessary to select the best approach and method from the proposed solutions for building a DA test system and to develop algorithms for fault detection and service restoration based on IEC 61850 approach.

2.4.2 Problems considered

From Table 2.1 the various problems that are considered include: methodologies for economic evaluation of the implementation of DA to the distribution network as indicated by references [Fernandes et al., 1982], [Su and Teng, 2007], [Simard et al., 2006] and [Blair et al., 1985]; methods developed for fault location and service restoration algorithms referenced by [Alya 2009], [Mahmood, 2009], [Altin, 2009], [Zadeh and Manjrekar, 2011], [Park,2008], [Yang et al., 2009], [Guo-fang and Yu-ping, 2008], [Gomes et al., 2005], [Janssens et al., 2011], [Xu et al., 2010], [Xu-ping et al., 2011], [Greer et al., 2011], [Matsumoto et al., 2002], [Mun, 2001], [Park et al., 2008], [Shahsavari et al., 2014] and [Yang et al., 2009], [Chen et al., 2013], [Angelo and Selejan,2013], methodology for multi-agent based distribution automation system [Lim et al., 2008], evaluation of improved reliability with implementation of feeder automation [Viet and Van Ban, 2002], Validation of data models according to [Choi et al., 2010] and [Mohagheghi et al., 2011], the introduction of a wireless sensor network that solves the switch co-ordination problem [Miao et al., 2007], the introduction of the Fault Passage Indicator into the protection of the distribution feeder using an interconnected internet communications scheme [Wu et al., 2013], proposing an assessment method to determine the impacts of progressive centralized Feeder Automation (FA)scheme [Kazemi and Fotuhi-Firuzabad,2008],the implementation of computer applications that uses a restoration plan [Siirto et al., 2014], investigation of specific comparative case studies [Kazemi et al., 2014], adaptive overcurrent protection system which automatically changes the protection settings [Coffele et al., 2014], and discussions on shortening the fault duration in order to reduce the risk on the distribution network referenced by [Apostolov and Vandiver, 2011].

Utilities are challenged with the identification and evaluation of candidate DA schemes and determining which ones to implement. The cost to a utility for DA system depends on various factors such as, the size of the utility, communications infrastructure, amount of functions implemented in the automatic control system, amount and type of data required, etc. Cost to benefit assessments plays a critical role in addressing the problem. Cost to benefit assessment refers to the benefit obtained as a result of increased reliability because of increased investment in the distribution network. Therefore through cost/benefit assessments reliability evaluation of automatic control systems are possible.

The restoration problem is addressed through the deployment of various methods and approaches to solve the problem of reaching a feasible restoration plan. These methods and approaches include Genetic Algorithm (GA), State estimation, Artificial Intelligence, Swarm Intelligence, Weighted-Least Square (WLS), Newton-Raphson, etc. In certain instances a combination of these methods are also used where one is used as the main method and the other as a back-up. The restoration problems were originally addressed because of the long times it requires to locate the faulty portions of the network and restoring power to unaffected portions on the network. Conventional distribution systems are operated radially, using only over current and earth fault protection, and only time-current for protection co-ordination and usually are only supplied by a single source of supply. These traditional operational factors pose challenges on fault location and service restoration on the distribution system. However, many advancements in the technology of Fault location, Isolation and service restoration such as the IEC 61850 standard in combination with Ethernet communication infrastructure has aided in resolving the problem of traditional techniques in complex distribution systems.

Table 2.1: Various problems considered in the existing literature

Paper	Aim	Approach	Methods	Protection	Communication and Protocol	Simulation / Implementation	Benefits/Drawbacks
Alya, 2009	Develop methodology using optimal reconfiguration of the network	Optimization and decision making process based on augmenting of the sum of load capacity on the system.	Swarm intelligence. Algorithm to support and accelerate the governing evaluation for reconfiguration obstacle to show the most suitable switching approach.	Not mentioned	Not mentioned	Test system simulations	Fast computational time. Algorithm is easy, adaptive, coding is simple to put into service
Mahmood, 2009	Automation feeder reconfiguration using load balancing. Automatic load transfer from a heavy loaded feeder to a lightly loaded feeder.	Matching the impedances of two different feeders by estimating voltage angle at both feeders through state estimator. As well as forced commutation technique for the phase difference accommodation.	Apply The weighted-least squares (WLS) method of state estimation for impedance matching.	Not mentioned	Not mentioned	Test case simulation using PSCAD/EMTDC software. Also tested on two real distribution network feeders.	Utilities are not yet convinced to implement techniques for feeder reconfiguration due to slow open/close operation time of medium voltage line switches. Switches do not offer ride through capability to the sensitive loads. No calculations, computations, manipulations, and knowledge-based-rules are needed for reconfiguration.
Altin, 2009	Application of a program for fault detection and system restoration in medium voltage distribution systems called TUDOSIS	Designed and integrated the distribution automation system, using the technology available in accordance with applicable international standards.	Fault detection and isolation	Directional over-current and line differential protection	Fiber optic cable and DNP based on IEC 870-5 protocol	SCADA-based Distribution Automation System (DAS) implementation.	The DAS system cannot function properly with more than two sources. If the protection fails then the fault isolation algorithm will not initiate. The improved fault isolation algorithm of TUDOSIS DAS system attends to the shortcomings of the previous system which could not keep up with the expansion and developments of the medium voltage distribution networks in Turkey.
Zadeh and Manjrekar, 011	Put forward flexible distribution overhead line/underground	Positive sequence voltage and current phasors at	Application of IEC61850 based approach.	Communicati on channel based	IEC 61850 protocol and GOOSE	Power System Model using an electromagnetic	Test results show the recommended design has the ability to sense and locate

	feeder protection and fault locator design.	both ends of a distribution line/cable feeder are used for the determination of the location of a fault on the distribution feeder.		protection principles and breaker fail protection.	messages	transient program EMTDC - a simulated two-machine three-phase 23 kV power system.	faults under different system conditions. It also meets the requirements of modern distribution systems where traditional overcurrent-based protection schemes have failed.
Janssen et al., 2011	Integrating IEC 61850 and Smart Grid together.	Using IEC 61850 and evaluation with respect to the implementation of IEC 61850 for process-bus communications	Use of standardized communication protocols.	Protection not specified.	Radio, telecomm cables or power lines. IEC 61850 protocol.	Field implementation, Web2Energy project	The paper shows that by evaluating the processing achievement of an outright IEC 61850 based protection system - it furnishes good grounds for imminent Smart Grid technologies.
Xu, et al., 2010	A concept and design of Digital Distribution Automation System (DAS) as well as analysis of the construction model.	Implementation of Non-Conventional Instrument Transformers (NCIT) for digital data collection and processing. Breaker operation based on mature intelligent breaker technology. Implementation of Ethernet communication.	Intelligent distribution network through digital technologies adopted for sampling, control and digital transmission.	Protection not specified.	Copper, fiber optic cable and Ethernet communication. IEC 61850 and IEC 60870-5-104 protocols	Test Distribution Automation system - consists of 5 converters, 1 concentrator and 1 main station; Primary equipment of test networks – 2 outlet switches, monitored by the sub-station/concentrator; 5 feeder switches, monitored by Feeder Terminal Units (FTUs)/converters.	No development of mature information-sharing unified modeling platform for the field of distribution automation yet Wiring and installation for field construction (primary and secondary equipment) is complicated. Interoperability of products from different vendors, easy maintenance, low cost. High data transmission efficiency and rapid response. Easy realization and expansion of distribution applications.
Apostolov and Vandiver, 2011	Discussions of the requirements of shortening the duration of different fault types in the distribution substation.	The behaviour of feeder and substation protection is analysed. Implementation of IEC GOOSE in distribution protection schemes is	IEC 61850 advancement and implementation of distributed protection designs	Distribution bus protection Flexible backup tripping Responsive tripping scheme Breaker	Peer-to-peer communication and IEC 61850 protocol	Lab scale arrangement for IEDs or distributed operations grounded on IEC 61850 standard. System consists of five components: Configuration Tool, Simulation Tool, Virtual IED simulator, Evaluation Tool and	Flexible protection lessen fault duration Serious enhancements in the distribution substation protection by using IEC 61850 GOOSE messaging. No need for hard wired connections when high speed messages are used.

		analysed. Studying the effects on the achievements of the protective IEDs caused by changes in system configuration		Failure protection GOOSE.		Reporting Tool	
Mohaghegh hi et al., 2009	All exclusive and detailed data models for diverse components of distribution automation systems.	Providing examples on how the standard can be used to model basic components (such as Reclosers, Shunt capacitors, and Tap changers) commonly used in DA systems.	Modeling components in a distribution automation System using IEC 61850.	Not mentioned	GOOSE messages. IEC 61850 protocol	Not mentioned	Present release of IEC61850 standard does not address communications outside the substation. IEC 61850 has added expandibility than legacy protocols. Has greater detailed text for information and is open impending service systems.
Cong, et al., 2008	Presentation of the conventional progression approach of IEC61850 and its fundamental challenges . As well as presenting the new development method to solve these problems	Client-side and server-side computer program based on IEC 61850 protocol is implemented.	A new advancement approach of IEC 61850 protocol, that ignores some complicated elements in the traditional Advancement approach of IEC 61850.	Not mentioned	IEC 61850 protocol	Not mentioned	Drawbacks such as: complicated modeling, extensive progress period and high advancement expenditure. IEC 61850 has favorable scalability and engineering.
Simard et al., 2006	Description of the monetary and specialized assessment in warrantying the automation of Hydro-Québec's distribution network.	Comparative studies of conventional methods compared to the implementation of distribution automation.	Feasibility study for the improvement of network performance.	Reclosers	Not mentioned	Not mentioned	Direct benefits Supply stability and security Supply capability Contraction in Labor expenditure Indirect benefits Advance expenditure Civil Costs Data administration, anticipating maintenance and

							Quality of supply
Blair et al., 1985	Approach for assessing monetary usefulness of automation of electric distribution networks.	Calculation of the current-worth and yearly dividend needs for different expansion plans over a study cycle.	Cost-to-benefit analysis.	Not mentioned	Power line carrier, radio and telephone communication systems	Methodology was confirmed through the use a generalized distribution system model and the PSE&G monetary assessment.	Investment savings outage related savings consumer related savings operations savings
Su and Teng, 2007	Developing a methodology for monetary assessment for a Distribution Automation (DA) project	Performed expense-positioned analysis and current-worth investigation to indicate the best profitable schemes in the implemented DA system. Also awareness investigation of the profit/expense proportions regarding consumer categories, feeder loads, feeder lengths, numbers of switch, and breakdown rates for further Feeder Automation (FA) development.	Cost-to-benefit analysis	Not mentioned	Fiber optic, power line carrier and telephone line. Protocol not mentioned.	Monetary assessment of the Taipower DA project. Potential gains are derived based on mathematical estimation formulas.	FA is the most favourable operation achieved in the utility indicated by the results. Benefits include: Greater information accuracy for processing and other purposes; • negotiated capital outlay; • reduced processing and maintenance expenditure; • enhanced interruption reaction and recovery; • better processing capability; • better customer experience; • confident civil image.
Fernandes et al., 1982	Methodology to evaluate technical and Monetary usefulness of preferred distribution automation functions.	Conceptual implementation on a distribution system. As well as a comparison of non-automated and automated distribution system in	Cost-to-benefit analysis	Not mentioned	Distribution line carrier, radio and telephone line. Protocol not mentioned.	Conceptual implementation applied to different parts of the Niagara Mohawk distribution system. Analysis based on estimated benefits and costs by comparing data of a ten year period:	Expenditure linked gains. Outage linked gains Customer linked gains. Operational gains No homogeneous assessment for the application of distribution automation schemes.

		identifying the most beneficial functions.				1978-1988	
Guo-fang and Yu-ping, 2008	Fault Location Algorithm for an Urban Distribution Network with Distributed Generation	Variation in Fault current levels between system source and Distributed Generation is used for direction detection	Innovative algorithm established on short-circuit current magnitude variance	Over current protection	Not mentioned	PSS/E simulation performed on a lab scale system. Lab scale system studied the 69-segment, 8-lateral distribution feeder, based on distributed generators.	Magnitude variance is a responsive quantity and the algorithm has no terminal dead area. Distributed Generation source has huge short – circuit currents. Further research is needed in the field of limiting the fault currents.
Gomes et al., 2005	Network recovery algorithm procedure especially appropriate to substantial distribution systems.	Utilising a load-flow program established on the computation of the least possible system losses, deriving which switches to open.	New heuristic strategy. Adequate calculation resources i.e. Newton–Raphson power flow routine using rectangular coordinates.	Not mentioned	Not mentioned	Simulations -algorithm was realized in C++, using object-orientated programming and sparcity routines of linear systems.	The explanation operation results to ideal or to a near-ideal result.
Xue Ping et al., 2011	A procedure based on premeditated islanding for using Distributed Generators for recovering service in the distribution network as well as recovery plan of distribution network with DGs	Current distribution system islanding algorithms are correlated and analyzed. Algorithm of premeditated islanding are considered based on the closed-loop architecture and open-loop procedure	An algorithm based on Minimum spanning tree and dynamic programming	Not mentioned	Not mentioned	Not mentioned	The use of intentional islanding can result in the reduction of power losses and improved reliability. Results demonstrate the method can cope with the complicated architecture of ring networks.
Miao, et al., 2007	Introduction of a Wireless sensor network, which solves the traditional switch co-ordination problem.	A protection criterion, which references to the adjacent Switch position and simulations that research the delay of data transportation and	Network modelling, fault analysis and feasibility study.	Recloser and sectionaliser combination	Wireless sensor network. Protocol not mentioned.	Simulation using MATLAB.	Practicality and monetary challenges in DA systems. Enhancement and expansion of the automation level are restrained. Auto reclosing of reclosers have extensive impact on equipment. The sensor node technology is becoming increasingly mature

		packet loss rate					and developed.
Kazemi, and Fotuhi-Firuzabad, 2008	Suggesting an assessment measure to evaluate the reaction of a progressive centralized Feeder Automation scheme.	The system investigates various starting points including single phase to ground and phase to phase circuit fault occurrences. Various values of manual switching times are also added in the investigation.	Event tree methodology	Not mentioned	Not mentioned	Simulations employing programming (program not mentioned) on a typical distribution lab scale system.	Study results indicate load point and overall system authenticity benefit indicators have been enhanced considerably.
Greer,2011 et al.,	Examines advanced strategies in DA systems and argues the possible impact on the process of the distribution system. As well as how the performance of the DA system is affected by communication outages.	Multiple distribution automation controllers (DACs) for automation. The practice of alternate logic to allow for the recovery of the distribution system when a communications channel is down, is suggested.	Wide-area automatic control systems	Loop schemes – monitoring voltage	Fibre optic. Protocol not mentioned.	Applied on an case study radial network. Network consists of four sources, four feeder breakers, and twelve reclosers..	Schemes have rigid logic processing means of state of the art controls. Schemes are cost effective to install. Schemes put into service employ protection-adapted communications cleared faults and reconnect load in less than one second and even in some cases, only for a few cycles. Drawback: control determination depends only on local evaluation. Loop schemes can closed onto a fault.
Park et al., 2008	Restoring power after a single phase fault occurred in an ungrounded distribution system.	Allow for the remote control as well as monitoring the status of field devices employing Feeder Remote Terminal Unit (FRTU) to move the feeder normally open point switch	Fault detection and service recovery approach by way of fuzzy method.	Not mentioned	Not mentioned	Proposed method is being considered for real-time assessment	Single phase to ground fault will not affect supply to consumers.. The recommended approach can be used on single-tie or multi-tie systems. Low fault current makes very challenging to identify single phase to ground faults
Lim et al.,	Multi-agent based	Remote Terminal	Heuristic rules based on	Not	DNP 3 over	Implementation - an	Not mentioned

2008	Distribution Automation System (DAS) methodology.	Unit (RTU) agents, Main Transformer (MTR) agents, Feeder Circuit Breaker (FCB) agents, and Feeder Terminal Unit (FTU) agents are used to derive a restoration plan.	standard operation Procedures	mentioned	Ethernet	actual test was made in Gochang Power Test Centre in Korea .	
Chen et al., 2000	Solving the probabilities for the Distribution Automation System (DAS) in Taiwan Power Company.	The object-oriented programming (OOP) setup is applied to obtain the proper switching procedure to be done by reducing the expenditure of the objective function.	Binary Integer Programming (BIP) technique	Over current	Not mentioned	Simulation and implementation - a Taipower distribution power system with six feeders - computer simulation. Computer program not mentioned.	OOP can transfer the actual status information, potential, and explanation of objects i to the data of programs and representative functions. It is also simple to expand, tweak, manage and reuse.
Yang et al., 2009	Introducing an original algorithm for fault isolation and service recovery in an ungrounded distribution system	Altering the single-connection feeder into a multi-connection feeder.	Communication based Feeder Agent Service Restoration Algorithm	Not mentioned	Not mentioned	Implementation and simulations – the agent service recovery algorithm has been corroborated by means of fault simulations in an ungrounded multi-connection distribution system.	No power interruptions after a ground fault.
Matsumoto et al., 2002	Developing Advanced Distribution Automation System (ADAS) in the Kansai Electric Power Company, Inc. (KEPCO)	Adopted client-server application with general purpose computer and split server function. The ADAS is also interconnected	Genetic Algorithm (GA) method to determine optimal switching processes	Not mentioned	Not mentioned	Implementation on pilot systems during 2002. Will be rolled out to the remaining systems during 2004.	Low installation cost, compact size and easily extendable system. The ADAS has improved system performance and at the same time reduced operation cost.

		with a Business Processing System (BPS)					
Mun et al., 2001	Development of real-time service restoration system for distribution automation system	The service recovery question is defined as a constrained multi-objective optimization problem to minimize switch operation.	Genetic Algorithm for service recovery in distribution systems	Not mentioned	Not mentioned	The algorithm has been tested on an actual distribution system in Kangdong (Korea).	Introduced method has the means to operate least number of switches and maintain adequate operating conditions, such as power flow and system voltage level.
Viet and Van Ban, 2002	Assessment of enhanced authenticity with the implementation of feeder automation.	Feeder automation system established on substation automation platform	Substation Automation platform that can be applied on the distribution feeder.	Not mentioned	Can be constructed to communicate to each linked relay in DNP3.0, Modbus, Modbus Plus or Ethernet protocols.	Assessment investigation established on real data obtained.	Simple to create and maintain. No electrical feeder models and central SCADA demands. The system does not require DMS/SCADA. System runs broad array of FA functions unachievable on single IEDs and its alternative expenditure is the lowest. Its drawback, adverse handling complicated conditions.
Choi et al., 2010	Authorization of data and models in real time, concentrating on the elementary tool in any automation and control system.	Apply the concept of the SuperCalibrator and automation to the smart grid concept.	State estimation – Robotic approach with plug-and-play capability.	Not mentioned	IEC 61850, DNP and MODBUS	A small scale power system has been developed at Georgia Tech. The model consists of several numerical relays and a GE Hard Fiber scheme. The process of the scheme is controlled by a computer, function generator, and a set of Amplifiers giving the appropriate power for system operation.	Capable of detecting and correcting bad assessment information utilizing the assurance level of the states predicted. improved and dependable real-time modeling.
Shu et al., 2005	Description of the major technologies of smart distribution automation remote terminal and the suggestion of a set of	Through fault simulation testing, signal flooding testing, remote alteration testing, measure data	Analysis of the key technologies and through practical application.	Over current	Serial and Ethernet communication. GB 101 and 104 protocol	Simulations - Guangdong power grid, Lab of Power Grid automation.	High reliability, real-time data, high security for devices and data, simple operation and flexible maintenance

	adequate testing approachess on the system and building blocks	change testing, electrical and magnetic properties testing and master site communications testing technologies.					
Peng et al., 2011	Assessment of the reaction of distribution automation and aiding of distribution automation planning.	Calculation of the automation effect through the application of failure condition, event investigation and enumeration.	Benefit evaluation through the use of differential evolution algorithm	Not mentioned	Not mentioned	Evaluation using FMEA (failure mode and effect analysis)	It is difficult to evaluate the benefits of distribution automation technology. This paper views enhancing power supply reliability profit as the greatest automation gain.
Qingnong, 2008	Techniques of visualization for distribution automation systems	The new techniques include: three-dimensional graph procedure established on openGL, the algorithm of contouring and the algorithm of area drawing	Graph visualization technique method,	Not mentioned	Not mentioned	Visualiation software such as MapInfo, ARCInfo and SmallWorld.	Flow current dynamic attributes - The data is explicit in this approach. Its shortcoming is that it doesn't have the comprehensive scheme view. Three-dimensional technology - The benefits are : enhanced distribution network's demand, employ less resources, high performance-to-expense rate, and high speed. Simple demonstration of electrical system data. Provides the three-dimensional scheme
Chen and Sabir, 2001	Describing the effect of free trading on electricity companies and the gains of the employment of distribution automation and system monitoring.	The process of distribution automation includes planning strategies, justification of distribution automation functional projects and identification of distribution	Methodologies based on customer outage expenditure (CIC), diagnose hierarchy process (AHP) and capability-sharing determination.	Not mentioned	Fiber optic cable. Protocol not mentioned.	Not mentioned	Gaind of distribution automation provide monetary gains, operational & maintenance gains and customer related gains.

		automation projects.					
Zovada, 2008	Analysis of the architecture of an integrated monitoring system and address some of the developments and results of Hydro-Quebec's projects.	The infrastructure of the monitoring system foundation is established on sensors, transducers and smart electronic devices (lED) collecting information throughout the distribution system.	Presentation through the employment of pilot projects.	Not mentioned	RS232 serial or remote download using a SMP4 interface	Laboratory testing - benchmarking system consists of: • VARIAC 600 V, 200 A supplied by a power source 600V/400 A 3-phase. • Load including an inductive load of 15 mH (5.6Ohms at 60 Hz) and a resistive load of 7.2 Ohms (including 9 resistors of 65 Ohms in parallel).	The accuracy of meters is higher than that of controllers and relays. The accuracy of the chain sensor lED is acceptable.
Xu and Xu, 2008	Demonstration of the characteristics and general scheme designs of distribution automation system (DAS) of northeast rural county cities of China.	Isolators of voltage-time type are employed, specification of instalment and setting of reclosers are presented, general mechanisms of tie isolators are presented; the easy communication modes and high performance devices are employed for the harsh winters of northeast areas.	Local control type with upgrade capability to central control type.	protection or over-current locking	SMS. Protocol not mentioned	Not mentioned	Difficulty in the investment in fiber communication infrastructure. No specialized departments in distribution automation. Great expenditure to replace existing reclosers and circuit breakers.
Siirto et al., 2014	Presentation of the functionalities of the newly developed model "CITY-FLIR" for fault location, isolation and service recovery in the distribution	Combination of a substation computer technology application and SCADA/DMS as well as IEC61850 standard-based	Computer application makes use of a restoration plan. Various agent or multi-agent systems (MAS)	Directional overcurrent, earth fault.	GOOSE and telecommunicatio n	Case study is described	Not mentioned

	environment.	technology.					
Shahsavari et al., 2014	Investigation of the placement problem of Fault Indicators (FI) on distribution networks	Multi-objective approach	Particle swarm optimization (MOPSO) established algorithm, together with a fuzzy determination process	Not mentioned	Not mentioned	Implementation on a standard test system (RBTS4) and a real-life distribution network located in northwest of Iran.	Reduction in both SAIFI and CAIDI therefore resulting in higher reliability level.
Kazemi et al., 2014	Evaluation of the reliability impact during communications failure in the automated fault-management schemes (AFMS).	Modular approach	Specific comparative case studies	Not mentioned	GSM	Real urban network is used as a test system	Communication failure increases the duration of the sustained fault interruptions.
Coffele et al., 2014	Presentation of an adaptive overcurrent protection system which automatically changes the protection settings of all protection relays due to the impact of Distributed Generation (DG), active network management (ANM), and islanding on the distribution network.	The centralized approach is used. Calculation of the setting calculations and its modification commands are performed by one processing unit, rather than the agent-based approach	A program, written in Python 2.7 software platform.	Overcurrent	DNP3, Modbus, IEC60870-5-103, and IEC61850	Implementation and demonstration in a lab scale environment. The real-time digital simulator (RTDS) is employed for simulations.	During earth fault conditions the adaptive protection can be marginally slower. It provides improved selectivity and sensitivity compared to conventional overcurrent protection when the topology of the network is changed.

2.4.3 Methods used

The different methods that are used in the literature are: cost/benefits comparisons [Su and Teng, 2007], [Fernandes et al., 1982], [Simard et al., 2006], [Blair et al., 1985] and [Peng et al 2011], heuristic strategies - calculation capabilities such as a Newton–Raphson power flow routine using rectangular coordinates [Gomes et al.,2005], substation automation function that can be used on electric feeders [Viet and Van Ban, 2002], state estimation – robotic approach with plug-and-play capability [Choi et al., 2010], fault detection and service restoration method through fuzzy theory [Park et al., 2008] and [Shahsavari et al., 2014], fault detection and service restoration method through embedded intelligent software [Chen et al., 2013] ,binary integer programming [Chen et al., 200], modelling components based on IEC 61850 approach [Mohagheghi et al., 2009] and [Kazemi et al., 2014] standardized communication protocols [Janssen et al., 2011], development and implementation of distributed protection schemes [Apostolov and Vandiver, 2011], event tree methodology [Kazemi and Fotuhi-Firuzabad, 2008], wide-area automatic control [Greer et al., 2011], novel algorithm based on fault current amplitude [Guo-fang and Yu-ping, 2008], novel algorithm based on the centralized approach [Coffele et al.,2014], minimum spanning tree [Xue Ping et al., 2011], network modelling [Miao et al.,2007], introduction of the fault passage indicator into the protection of distribution feeders [Wu et al., 2013], heuristic rules based on standard operation procedures [Lim et al., 2008], Genetic Algorithm (GA) [Matsumoto et al., 2002] and [Mun et al., 2001], and self-healing technologies such as: substation computer and DMS/SCADA, peer to peer GOOSE based communication and voltage and current based solution [Angelo and Selejan, 2013].

[Su and Teng, 2007] propose an expense positioned monetary assessment approach. Standard mathematical formulas are used to quantify interruption expenditures and the gains of the system. In the benefit analysis the method considers CIC (Customer Interruption Cost) and utilizes present-worth investigation to calculate the project monetary evaluation. In the economic evaluation analysis certain parameters are assumed, such as: feeder length, the number of load switches, the growth rate and the feeder failure rate. [Fernandes et al., 1982] and [Blair et al., 1985] suggest that there is a need for a generalized approach to assist the monetary assessment of DA. An analysis of a suitably selected distribution power network or a portion of a network has to be done that covers a period of several years. The analysis has to be done in the first instance without DA implementation expansion and then thereafter assuming that selected functions are implemented.

From the analysis the revenue requirements for the separate alternatives can be determined. There are four various methods for economic evaluation: lasting plant, brief term, year-long and recover cost. [Simard et al., 2006] report that three separate schemes (escalating grid robustness, breaking up of the feeder to lessen the total number of users on a section of line and automated distribution line) are analyzed in terms of cost per feeder and network improvement. Analysis shows that DA is the best scheme in terms of cost to benefit ratio. Software development by the utility is used to simulate the effect of different ways to implement DA. [Peng et al., 2011] put forward a benefit evaluation method of DA to find the value of the result of the implementation of DA. The method makes use of differential expansion design to advance the pertinence of the approach. In the main there are three conditions of assessment: DA related standards and planning principles, DA input cost and the income as a result of DA. The evaluation method makes use of ENS (Energy not Supplied) and automation input costs as the calculation indicator to obtain the expenditure and revenue of various automation methods. The calculation modes for power supply security makes use of FMEA (Failure Mode and Effect Analysis) Enumeration method is used to simulate each and every possible fault on the distribution power network thereafter analyze what the effects are when DA is implemented. [Gomes et al., 2005] propose a new heuristic methodology for establishing the structure of the radial distribution network with minimum loss possible. The method is implemented on a meshed distribution network with all the load switches in the close position. The switching criterion is positioned on the minimal comprehensive loss, increase and is obtained using a power flow program. The branch exchange technique is then used to refine the procedure. [Viet and Van Ban, 2002] suggests a substation automation platform system solution in a single physical box which can be used in feeder automation. The system's primary function is fault detection, isolation and service restoration (FDISR) and can be configured as a feeder SCADA system as well. FDISR is based on the ORION Automation tool with DA-Master software. The ORION tool will correlate with protection devices out along the distribution network and execute the FDISR function. [Choi et al., 2010] presents the concept of the SuperCalibrator and automation of the smart grid concept. Distributed state estimation is performed by SuperCalibrator and then model-based error correction enables the grid to be modelled in real-time. Robotic operation of the smart grid with plug and play capability is made possible by automation. A self-healing grid where the healthy portion of the network is unaffected by the faulted part is made possible by the combination between the SuperCalibrator and automation. [Park et al., 2008] proposes a fault detection and service restoration method through shifting the normally open point between interconnected feeders during a single phase to ground fault condition for ungrounded distribution power systems. The status of every protection device on the power system is monitored by Feeder Remote Terminal Units (FRTU) which communicates the data to the Distribution Automation System (DAS). The method is suitable for a single - tie as well as multi-tie system applications. [Chen et al., 2011] presents the development of an object-oriented programming (OOP) model for load switches on a distribution power system. Binary Integer Programming (BIP) with branch and bound technique is implemented to demonstrate the switching operation for distribution power systems. Load profile determination is used to solve the overload problem and FDISR function. [Mohagheghi et al., 2009] suggest SCADA systems, advanced sensors and electronic controllers are to be integrated into the DAS system for the distribution power system to be operated at optimum performance and reliability levels. Originally the IEC 61850 standard was earmarked for applications in the substation environment, but the need for the extension of the standard of DA applications integrating field devices out on the distribution feeder has grown significantly. [Janssen et al., 2011] present the interfaces between the IEC 61850 standard, ICT network security (IEC TS 62351) and database management using Common Information Models (CIM) to establish "plug and play" and interoperability capabilities. Simultaneously a complete protection system based on the IEC 61850 process-bus architecture that operates in various configurations for bay and inter-bay communications are evaluated. [Apostolov and Vandiver, 2011] analyses the behavior of typical distribution feeder protection, substation protection systems as well as the use of GOOSE messaging in the implementation and development of distribution feeder schemes. [Kazemi and Fotuhi-Firuzabad, 2008] presents a reliability worth assessment approach of an advanced feeder automation scheme described as the Low Interruption System (LIS) scheme. The technique is based on event tree methodology where the effects of the different fault conditions as well as the various manual switching durations are taken into account in the analysis. [Guo-fang and Yu-ping, 2008] suggest a fault location algorithm based on the difference of the magnitude between the system source and the distributed generation (DG) source. The system source contributes a greater amount of fault current than the DG source. [Xue Ping et al., 2011] propose an algorithm based on the minimum spanning tree and dynamic programming method. Intentional islanding are thoroughly studied through comparing and research on existing distribution system islanding algorithms, based on the closed-loop design and radial operation of interconnected distribution systems. [Miao et al., 2007] introduce wireless sensor network which solves the problem of traditional feeder automation methods. The new automation scheme will operate with existing equipment (reclosers and sectionalizers) installed on the distribution power system. A protection criterion that references the adjacent switch state is provided through network modelling and fault analysis. [Lim et al., 2008] proposes Distributed Restoration method by changing the Feeder Remote Terminal Unit (FRTU) to Multi-Agents as an improvement to the deficiencies of the centralized restoration

DAS system. A terminal agent with a communication functionality device called MASX was developed to convert FRTU to be able to perform agent functions. [Matsumoto et al., 2002] present the development of an Advanced Distribution Automation System (ADAS) through the combination of newly developed GA and Artificial Intelligence (AI) methods. Since AI is better than the GA method the main calculation is performed by AI method and in GA method the calculation is backed up. [Mun et al., 2001] presents the development of GA for service restoration function in distribution systems. The service restoration problem is formulated as a multi objective problem. [Shahsavari et al., 2014] presents a multi-objective particle swarm optimization (MOPSO) based algorithm, together with a fuzzy decision making method which selects the best suited result among the gathered Pareto optimal set of solutions to solve the optimizing problem. [Siirto et al., 2014] proposes that automation systems that already exist on field devices to be integrated in order to combine information for a complete solution for distribution automation. [Kazemi et al., 2014] suggests a modular approach for the evaluation of the reliability impact of the communications failure in the automated fault-management schemes (AFMS). [Coffele et al., 2014] considers a centralized approach in the developed adaptive protection system which automatically changes the protection settings of all protection relays due to the impact of Distributed Generation (DG), active network management (ANM), and islanding on the distribution network. The adaptive overcurrent protection system has been developed using three-layer architecture. The system includes additional functions that are not present in traditional protection systems. The additional functions are controlled via a novel developed algorithm which is initiated by changes in the distribution network topology, connection-disconnection of DG and islanded/grid-connected changes. [Wu et al., 2013] proposes the extension of the IEC61850 beyond the substation for the provision of network wide communications. Faults Passage Protection is used for the protection of the distribution feeders using an associated internet communications scheme. Fault Passage Protection is part of an enhanced feeder protection scheme with the addition of a fault detector element, (FD) [Parikh al., 2013]. [Chen et al., 2013] proposes the Implementation of the distribution automation system which reforms the fault detection, isolation and service restoration (FDIR) function automatically. The master station use embedded intelligent software to locate the fault, propose the optimal restoration strategy and perform the remote operation of the line switch. [Angelo and Selejan, 2013] present available technologies that will assist utilities improve overall system reliability through the restoration of power to the healthy portions of the grid automatically. Self-healing technologies such as: substation computer and DMS/SCADA, peer to peer GOOSE based communication and voltage and current based solution

Analysis of the various methods considered in the literature shows that the methods can be grouped in technical, mature analytical and modern analytical methods. The methods that will be used in this thesis that are most beneficial to the project are considered in [Apostolov and Vandiver, 2011], [Wu et al., 2013], [Parikh et al., 2013], and [Siirto et al., 2014].

2.4.4 Protection Systems

For any Distribution network to have an acceptable level of reliability, quality and reduced occurrences of faults, it has to be well designed and properly maintained [Northcote-Green and Wilson, 2007]. In the distribution system, there is systems present that assists with achieving these requirements. These systems include protection systems which purpose is to rapidly clear faults and to reduce damage to the high voltage equipment to the minimum and prevent injury to personnel. However, the economic costs and benefits must be evaluated in order to present a balance between what the protection scheme requires and to the available budget [Hadzi-Kostva, 2005]. In a distribution system the most common primary equipment are circuit breakers, sectionalizers, reclosers, fuses, relays, and lightning arresters.

. Protection system requirements can be summarized as follows:

- Reliability: the ability of the protection to operate correctly
- Speed: in order to avoid damage, faults have to be cleared in minimum operating time.
- Selectivity: only isolate the faulty section of the network and maintaining continuity of supply to the unaffected section.
- Cost: maximum protection capabilities at the lowest possible price.

A significant amount of energy is released when a fault occurs on the Distribution network, which can cause damage to equipment and possible injury to personnel if the fault is not removed. These faults are detected by protective equipment and result in breaker operation or opening of switches that remove the faulted component. Current transformers (CT) provide a basic form of overcurrent protection and feeds secondary current that is proportional to the system current into the protection relays. The graded overcurrent system is a result of the basic principle of protection against excess current. The relay settings are calculated to show the operating times at maximum fault current and then check if at the minimum fault level the operating time is also satisfactory.

The various methods implemented to achieve proper relay protection co-ordination utilize time or current amplitude or a combination of both. There are three methods, discrimination by time, discrimination by current and discrimination by time and current, and their aim is to achieve accurate discrimination [NPAG, 2002].

Discrimination by Time

In this method the breaker nearest to the fault to open first by allowing enough time intervals by all the IEDs controlling the circuit breakers in the power system.

Discrimination by Current

The fault current varies with the location of the fault due to the different fault impedances for different faults. The IEDs responsible for tripping the circuit breakers are pre-set to allow only the breaker nearest to the fault to trip. For this method to work enough impedance between IEDs in series must exist in order to have sufficient difference in fault current.

Discrimination by Time and Current

Due to the shortcomings of both discrimination by time and discrimination by current have lead to the development of the Inverse Definite Minimum Time characteristic (IDMT). With this method the operating time is inversely proportional to the fault current and is a function of both time and current.

Over current, distribution bus protection, selective back up protection, sympathetic tripping scheme, breaker failure and loop schemes are the various protection methods and schemes that are mentioned in the reviewed papers [Xyngi, 2011]. Over current and earth fault protection will be used in the lab scale project.

Overhead distribution network usually has reclosers and sectionalisers installed out on the line. The recloser has fault breaking capabilities and can trip on fault conditions downstream of it. Therefore, when these devices are used in the DAS the need for Fault Passage Indicators (FPIs) are not required. However, in underground cable networks usually line switches are used to sectionalise the feeder during fault conditions. These devices do not have fault breaking capability therefore during a fault condition the breaker in the substation has to clear the fault. Thereafter, only can the line switches open to isolate the fault. In a DAS system these actions occur automatically. In these systems the use of FPIs is required because these devices will “inform” the DAS where the fault on the network is.

2.4.5 Thesis approach

The approaches that are the most convenient to use in this thesis are considered by [Janssen et al., 2011], [Apostolov and Vandiver, 2011], [Siirto et al., 2014], [Mohagheghi et al., 2009], [Shahsavari et al., 2014] and [Cong et al., 2008]. These approaches are based on the IEC 61850 standard for the development and implementation of DA on distribution feeders. However the direct application of these approaches are not being precisely applied, but is modified because this thesis considers a lab-scale approach.

This thesis deals with the development of fault detection, fault location, fault isolation and service restoration algorithms, building of a lab-scale test system, use of IEC GOOSE messages for system protection and breaker status, logics based on the coordination of IED functions as well as tests and simulations using secondary fault injection test set.

2.5 Conclusion

Distribution automation refers to a system that enables an electric utility to remotely monitor, coordinate and operate distribution components in a real-time mode [Lakhoua and Jbira 2012]. In the past two decades, utilities have been automating the operation of the distribution network to provide a higher level of reliability and operational efficiency. However, the automation efforts were not excessive and if applied on a wider scale the improvements in reliability can be much higher. In most utilities the substations are fairly automated, but the distribution feeders are much less automated. Due to the relatively low calculation capabilities as well as the lack of communication capabilities of early Supervisory Control and Data Acquisition

(SCADA) systems the promised improvements in reliability could not be delivered. The level and capability of existing monitoring, control, and communication technologies played a major role in the development of distribution automation.

In this chapter various papers were reviewed, compared and analyzed in order to interpret and understand the various methods and approaches implemented in distribution automation. This project concentrates on fault detection, isolation and service restoration on a simulated underground cable network based on the IEC 61850 standard approach.

In order to achieve an intelligent automatic distribution system the need for suitable communication infrastructure is paramount. The next chapter discusses the various communication protocols used in distribution power systems.

CHAPTER THREE

DISTRIBUTION AUTOMATION COMMUNICATION PROTOCOLS

3.1 Introduction

Supervisory Control and Data Acquisition (SCADA) scheme comprises of SCADA hosts, Remote Terminal Units (RTUs) and equipment which are installed on the feeder [Kalapatapu, 2004]. These systems monitor and control field devices on the distribution feeder as well as equipment in the substation from a control center along the local and wide area networks. Communication between the RTUs and the control center SCADA is established through protocols that are designed to provide information on the status of the field devices [Kalapatapu 2004]. Communication protocols can be considered as the language that the equipment and applications have to use to successfully exchange information and data. There are several protocols presently in use at utilities all over the globe, they include proprietary and non-proprietary protocols.

Generation units, the transmission system, and the distribution system are part of an interconnected network of a typical power system. In an ideal situation the various sections within the complete system must be able to have a communication capability with one another and be able to share data. However, this is not happening due to various reasons such as the amount of data involved, limitations on existing communications infrastructure and security concerns. Due to these limitation factors a sub-system approach rather than a holistic approach was often adopted therefore data sharing and communication systems were developed to deal with subsystems only.

A typical distribution network consists of a distribution substation and field devices along the distribution feeder. Depending on the extent of the system several protection and control devices mostly from different manufacturers will be present on the system. The most widely used standard protocols for the realization of data sharing and coordination between the devices are, DNP3, MODBUS and IEC 61850 [Kalapatapu 2004]. These standard protocols enable the transmission of data to the control center and between the distribution substation and field devices. Data transferred between substations and field device to provide information for the improvement of protection, control and monitoring decisions and data transferred to the control center enable increased power system stability, security and reliability.

DNP3 and MODBUS are legacy protocols in the power industry, whereas the IEC 61850 standard is considered the next generation communication protocol.

With legacy protocols traditionally each manufacturer developed their own proprietary protocols for communication to their own systems. This situation resulted in major difficulties in integrating products from other manufacturers. This also resulted in utilities not being able to establish communications between various products from multiple manufacturers. Interoperability between devices from multiple manufacturers has become a prerequisite for efficient distribution automation systems. Therefore a change in the distribution electric industry of communication protocols from specific manufactures to open connection standards has been welcomed The IEC 61850 standard was introduced as an adaptable communication protocol that allow products from the various manufacturers to operate between one another [Simard & Chartrand, 2007].

This chapter discusses the most widely used communication protocols currently in use on the distribution power system as well as the IEC61850 standard.

3.2 Distributed Network Protocol (DNP3)

DNP3 is a free and public protocol and is grounded on the criteria of the International Electro-technical Commission (IEC). The DNP3 standard describes communications amongst client stations, RTUs and IEDs. DNP3 was earmarked for SCADA utilization, e.g. acquiring of data and control signals amongst different computer apparatus, at first. Nonetheless, today countries like North America, South America, South Africa, Asia and Australia widely use the DNP3 communication protocol in various industries such as electrical, water environment, oil and gas, surveillance, etc.

Reliable transmission of comparatively small data packets (called frames) is the bases of the DNP3 protocol design [Mohagheghi, et al., 2009].

Figure 3.1 illustrates a DNP3 frame consisting of a header and information segment where the header indicates the frame extent, data link governs data and describe the DNP3 device origin and target addresses. The data segment is referred to as the payload and reflects the information that has moved downward from the higher layers [http://www.dnp.org, 2012]

DNP3 Frame

Header	Data Section

Header

Sync	Length	Link Control	Destination Address	Source Address	CRC

Figure 3.1: DNP3 Frame [http://www.dnp.org, 2012]

Substations have many devices that have to be monitored e.g. breakers (is it open or close), current transformers (what is the load), voltage transformers (what is the busbar voltage), etc. Remote Terminal Units (RTUs) in the substation or out on a line gathers information and communicates with the master station in the control center through the DNP3 communication protocol.

DNP3 is described as a layered protocol, but instead of complying with the OSI (Open Standard Interconnection) 7 layer protocol, it complies with a reduced 3 layer standard for more simplified implementations. The simplified standard was recommended by the IEC (International Electrotechnical Commission) and calls it the (EPA) Enhanced Performance Architecture. However the EPA adds an additional layer called the pseudo-transport layer which grants the distribution of the message [http://www.dnp.org, 2012].

3.2.1. Physical Layer

This layer deals with the real communication medium such as copper, fiber, radio or satellite used to facilitate the communication of the protocol. Presently DNP3 communication is described over a straightforward sequenced physical layer like RS-232 or RS-485 however, recent communications are specified over Ethernet.

3.2.2 Data Link Layer

This layer governs the logical connection between the originator and receiver of data and it enhances the physical link failure characteristics.

3.2.3 Pseudo-Transport Layer

Application layer messages are segmented into various information channel frames in this layer. A single byte function code is inserted in each frame. This is to indicate whether the information channel frame is the initial frame of the message, the last or both.

3.2.4 Application Layer

When a complete message is received, the application layer responds and constructs messages established on the requirement and the information available. A message that is built pass downward to the pseudo-transport layer, here it is segmented, then moves to the data link layer thereafter, to the physical layer where it is finally communicated.

DNP3 offers the following [http://www.dnp.org, 2012]:

- Requests and responds with numerous information categories in individual messages.
- Segment messages into various frames to provide exceptional failure detection and restoration.
- Includes only altered information in reply messages.
- Assigns preference to information items and requests data systematically established on their preference.
- Responds without inquiry (unsolicited).
- Supports time synchronism and a common time arrangement.
- Allows various master and peer-to-peer applications.
- Allows user defined objects, incorporating file transmission.

3.3 MODBUS

Modbus yield client/server data exchange amongst devices linked on a network. It is located at level 7 of the OSI model and is an application layer protocol. MODBUS has been used as the industry serial standard from 1979 and is still used as a communication protocol in automation devices [http://www.modbus-IDA.org, 2013].

MODBUS is generally implemented employing the subsequent transmission protocols, i.e. TCP/IP over Ethernet, serial transmission modes of MODBUS networks, MODBUS TCP/IP and MODBUS framing method [http://www.prosoft-technology.com 2013]:

3.3.1 TCP/IP over Ethernet

The Modbus protocol specifies the means a “master” device polls one or more “slave” devices. MODBUS also defines how the data is read and written in actual time by way of RS232, RS422, or RS485 serial data communication. The Modbus protocol does not have the greatest potential available, but through its directness it grants fast implementation furthermore, its adaptability allows it to be utilized anywhere.

3.3.2 Serial Transmission Modes of MODBUS networks

The establishment of master-slave communications between intelligent devices are made through the use of the MODBUS protocol. Two serial types of transmission modes exist, i.e.: ASCII (American Standard Code for Information Interchange) Transmission mode and RTU (Remote Terminal Unit) Transmission Mode [http://www.Modbus-IDA.org, 2013].

In the ASCII Transmission Mode every element data unit in a message is transmitted as 2 ASCII characters. This method grants delay interruptions lasting near a second between characters when a message is sent.

In the RTU (Remote Terminal Unit) Mode, every 8-bit message data unit has two 4-bit hexadecimal characters, and the message is transmitted in an uninterrupted flow. It has a bigger character density, meaning that it can send more information for the same baud rate

3.4 MODBUS TCP/IP

MODBUS TCP/IP operates on the Ethernet and refers to the Transmission Control Protocol and Internet Protocol. The Modbus messaging architecture specifies the guidelines for coordinating and describing the data. TCP/IP grants blocks of binary information to be traded amongst computers. Ensuring correct reception of all data packets is the primary function of TCP and IP verify that messages are accurately addressed and routed. The TCP / IP solution does not specify the explanation or interpretation of the data it is only a transport protocol. [http://www.modbus-IDA.org, 2013]

3.4.1 MODBUS message framing

A message's starting and ending is tagged by a message frame. This allows the receiving device to resolve which device is being addressed and know when the message is concluded. The message frame also indicates errors when limited messages are identified. The device that transmits a message put a MODBUS message in a message frame. A simple PDU (Protocol Data Unit) is defined by the MODBUS protocol. Figure 3.2 shows a general Modbus Application Data Unit (ADU) [Mohagheghi, et al., 2009] where the address section consists of the address of the server and the function field consists of the code of the function to be executed by the server.

	Protocol Data Unit (PDU) Application Data Unit (ADU)		
1 Byte Address Field	1 Byte Function Field	Variable Data Field	2 Bytes Error Checking Field

Figure 3.2: MODBUS ADU [Mohagheghi, et al., 2009]

3.5 IEC 61850

3.5.1 Introduction

The standard IEC 61850 from the beginning was constructed to describe application objects which can be transmitted over data communications technology. As a result many years of development in the field of automation and protection object modelling transpired. IEC61850 is also based on the need to have devices interoperable via a communication link. Interoperability is the capability of a couple or more IEDs from like or distinct vendors to transfer data and use that data for their own functions. There is also a desire to replace devices from one vendor to a different vendor (interchangeability) leaving out any modifications to other elements in the scheme. Interchangeability needs the standardization of functions applicable in every device not specified in IEC61850. The objective of the standard is to provide a communication standard, which support future technological developments and meet performance and cost requirements [Baigent et al., 2010]

Object modelling approach, logical node and data classification, specific object definitions and descriptions, and abstract communications service interface (ASCI) are described in Part 7 of the standard. The use of substation configuration language in configuration tools for users to configure IEDs is described in Part 6 of the standard. Communications over the station bus, the LAN interconnecting the IEDs and the relay room, is described in Part 8. Communications over the process bus, the LAN connection to the high voltage yard for voltage and current sampled values, power equipment status report etc. are described in Part 9 [http://www.webstore.iec.ch, 2012].

The benefits the IEC61850 standard provides in the distribution power system environment includes [http://www.neteon.net, 2010]:

- Reduced installation and maintenance expenditure by self-describing equipment that lessons manual configuration.

- Contraction in engineering and commissioning with regulated object models and naming conventions for all equipment that excludes manual structure and mapping of I/O indicators to power system variables.
- Reduced time required to construct and use new and revised devices by means of regulated configuration files.
- Reduced wiring expenditure while enabling further progressive protection capabilities through the deployment of peer-to-peer messaging for point-to-point transfer of information between devices and a fast process bus that allows distribution of instrumentation indicators between devices.
- Reduced communication framework expenditure by employing freely accessible TCP/IP and Ethernet technology.
- A comprehensive set of functions for reporting, data access, event logging, and control satisfactory for most applications
- Ultimate adaptability for users who prefer an expanding number of flexible products to be utilized as interoperable system components.

3.5.2 IEC 61850 communication

Standards, which already exist and generally accepted communication fundamentals are incorporated in IEC 61850. The standard allows correct information exchange between functions within a device by structured definition of data.

The standard supports the substation automation schemes by the communication of sampled values for CTs and VTs, rapid transfer of I/O data for protection and control, control and trip indicators, engineering and configuration, monitoring and supervision, control centre communication, time –synchronization, etc. Figure 3.3 shows the communications stack of the protocol.

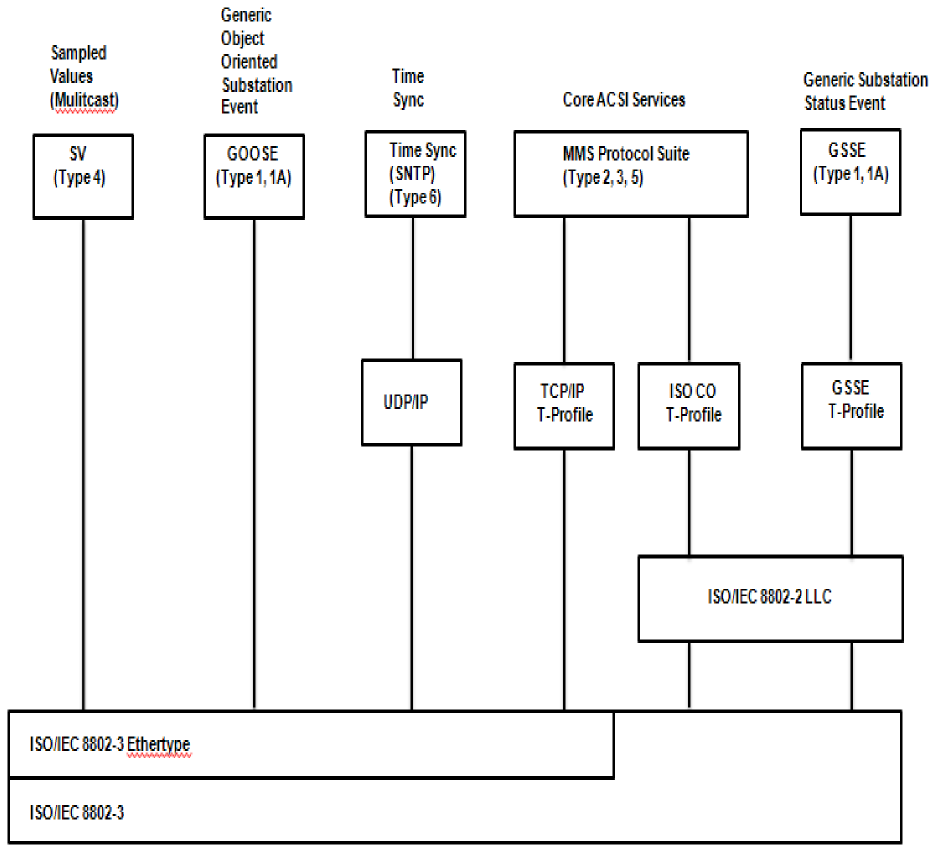


Figure 3.3: Communications stack [Baigent, et.al, 2010]

IEC 61850-8-1 provides instructions for instruments and guidelines needed to deploy the services, objects, and algorithms specified in IEC 61850-7-2, IEC 61850-7-3, and IEC 61850-7-4 at the same time using the ISO 9506 (all parts) MMS, SNTP, and alternative operation protocols [http://www.webstore.iec.ch,2012].

. Messages of Type 1 (fast messages) and Type 1A (trip) are mapped to distinct Ether-types to optimize interpretation of receiving messages. Messages of Type 2 (medium speed messages), 3 (low speed messages), and 5 (file transfer functions) need message conformed services. The MMS standard gives precisely the data modelling approaches and services needed by the Abstract Communication Service Index (ACSI). As shown in Figure 3.3 the Sampled Values and GOOSE operations map straight into the Ethernet data frame through excluding processing of any middle layers; the MMS Connection Oriented layer can work over TCP/IP or ISO; the Generic Substation Status Event (GSSE) is the same deployment as the UCA GOOSE and works over connectionless ISO services; all information maps onto an Ethernet data frame using either the data type “Ether-type” in the case of Sampled Values, GOOSE, Time Sync, and TCP/IP or “802.3” data type for the ISO and GSSE messages [Baigent et al., 2010].

3.5.3 Physical communication

In a power system, three levels of functions occur– process, bay, and station functions [Skendzic et al., 2007]. In the process level high voltage devices will be found such as: power transformers, circuit breakers, voltage transformers, etc. High voltage devices usually are hardwired by way of copper cable to bay level. Data such as analogue input and output information which contains current and voltage transformer outputs are transferred, as well as trip signals from protective relays. Figure 3.4 shows through numbers one to ten the logical interfacing between station, bay, and process levels, where number four and five show the interfacing amongst process and bay level. Number one and six show protection and control-data transfer amongst bay and station level.

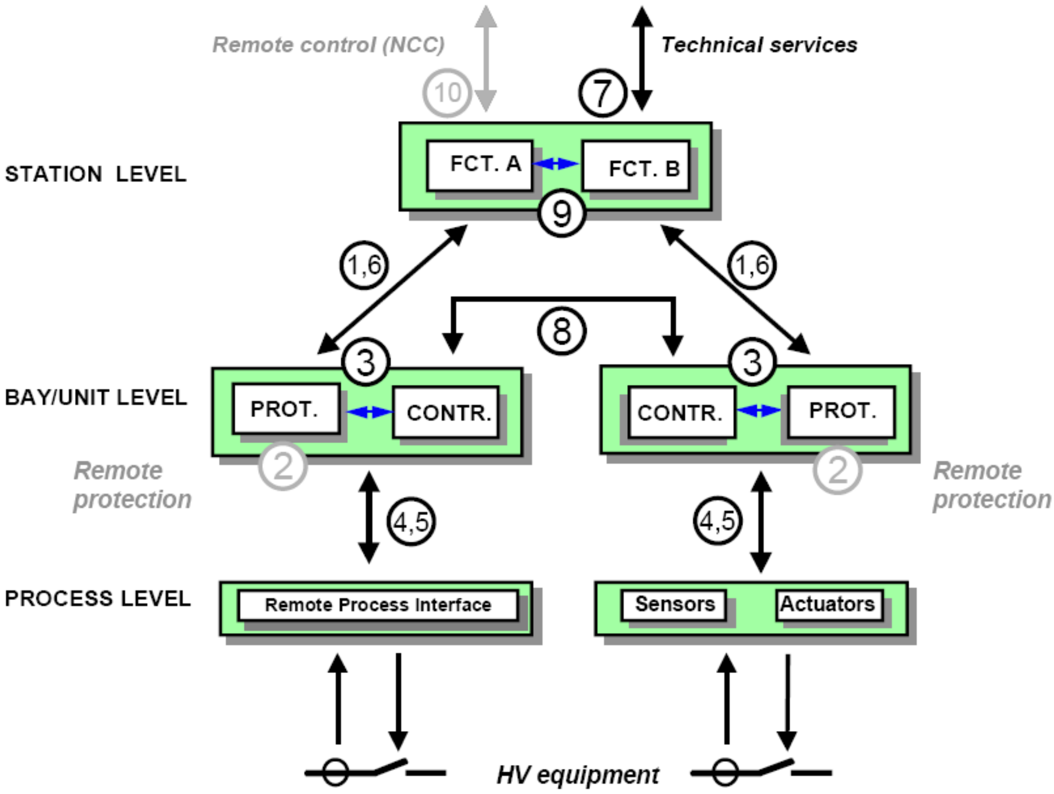


Figure 3.4: Logical interfacing between station, bay, and process levels [Skendzic et al., 2007]

Future plans are to connect process bay devices such as, intelligent sensors over the network via LAN technology [Skendzic et al., 2007]. Protection, control, and monitoring devices such as, protection relays are contained in bay level. Bay level devices have the ability to communicate between the different bays by way of IEC 61850 GOOSE messaging services. Interface eight shows bay to bay communication or horizontal communication. Communication between various functions within a single IED is shown by interface three. Currently bay level devices communicate with station level devices via IEC 61850 however, communication between the bay and process level devices are via hardwiring. This will be the case until the process level device technology becomes more matured. The station computer, database, and communication technology are contained in the station level. Data transfer between IEDs in the station bus is already possible and as process level devices are developed more time-critical messages will be transferred by utilizing the process bus. Presently, Merging Units (MUs) have to be used to interface signal outputs, since substation high voltage devices are not intelligent devices. The purpose of the MU is to gather analogue signals and convert it in digital form which can be used by protection and control IEDs over the network. Hardwiring will be reduced extensively by using MUs.

Logical Interfaces as illustrated in Figure 3.4 are: [http://seclab.illinois.edu]

1. Protection – information transfer amongst bay and station level
2. Protection – information transfer amongst bay level and remote protection
3. Information exchange within bay level
4. CT and VT spontaneous information transfer amongst process and bay levels
5. Control- information transfer amongst process and bay level
6. Control- information transfer amongst bay and station level
7. Information transfer between substation and remote engineer's workplace
8. Direct information exchange amongst the bays, especially for fast functions like interlocking
9. Information transfer within station level
10. Control-information exchange amongst substation (devices) and a remote control center

3.5.4 IEC 61850 Content

The IEC 61850 standard consists of ten sections where the large sections are further split into smaller sections resulting in the entire standard to comprise of a total of fourteen parts as shown in Table 3.1 [http://www.webstore.iec.ch] Parts one to five describe the general information about the standard and parts six to ten describe detailed information about services, data mapping, abstract communication service interface substation configuration language manufacturing message specification, and testing [Adamiak et al., 2009]. An overview of the all the parts are described in part one, the glossary is reflected in part two. Basic requirements for substation automation are described in part three and part four describes general information and specification of IEDs from its development to complete system engineering and quality assurance. Specific detailed information around the methods and concepts of the standard are described in part five and it also specify performance and interoperability requirements [http://www.webstore.iec.ch, 2012]

Substation Configuration Language (SCL), software engineering tools, and data exchange between IEDs are described in part six [www.webstore.iec.ch IEC61850-6, 2004]. Part seven is divided into four sections, they are: 61850-7-1 which give an overview of the communication architecture and communication between IEDs [http://www.webstore.iec.ch, 2012]. Part 61850-7-2 describes the ACSI (Abstract Communication Service Interface) and related services [IEC61850-7-2, 2003]. Part 61850-7-3 contains common data classes and data attribute specifications [http://www.webstore.iec.ch, 2012]. And lastly the data classes and logical node classes are defined in Part 7-4. Part eight details the mapping of time critical and non-time critical messages [http://www.webstore.iec.ch, 2012]. The standard defines the collection of data in Part 9.1 and Part 9.2. [http://www.webstore.iec.ch, 2012]. Part 9.1 describes a Unidirectional Multi-drop direct fixed channel transporting a fixed dataset. Part 9.2 specifies a dataset that can be transported as a multicast from a publisher to numerous subscribers. Part ten is the last part and holds the specification for compliance testing.

Table 3.1: The fourteen parts of the IEC 61850 standard

Part 1	Introduction and review
Part 2	Glossary
Part 3	General requirements
Part 4	System and project management
Part 5	Communication requirements for functions and device models
Part 6	Substation automation system configuration description language
Part 7-1	Basic communication structure for substation and feeder equipment –ACSI
Part 7-2	Basic communication structure for substation and feeder equipment – Principles and models
Part 7-3	Basic communication structure for substation and feeder equipment – Common data classes
Part 7-4	Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes
Part 8	Specific communication service mapping (SCSM) – Mapping to MMS (ISO/IEC 9506 Part 1 and Part 2)

Part 9-1	Specific communication service mapping (SCSM) – Serial unidirectional multi-drop point to point link
Part 9-2	Specific communication service mapping (SCSM) – Mapping on a IEEE 802.3 base process bus
Part 10	Conformance testing

3.5.5 Data modelling approach

A detailed model for the organization of data by the power network devices is provided by IEC 61850 [Mesmaeker, 2005]. The devices can configure themselves and therefore reduce long system configuration efforts. For the configuration of objects where Substation Configuration Language (SCL) files are used, the SCL file only has to be imported into the device to configure it. There are cost and time saving benefits when configuring an IEC 61850 device because the object definitions can be extracted by the 61850 client application over the network. The model of a device as defined in part seven of the standard is a virtualized model with an abstract outlook of the device as well as its objects. Based on MMS, TCP/IP and Ethernet the abstract model is profiled to a unique protocol stack. The model also makes it easier to refer to individual objects. Figure 3.5 shows an example of a data point reference.

The name of the device is Relay1, the next part shows the logical node. The group of the node can be identified by the first letter in the logical node name. Table 3.2 shows the logical node groups and from the table the “X” indicates switchgear and XCBR1 indicates circuit breaker one. The XCBR logical node has a reference number one, which identifies the first circuit breaker as XCBR1 and the second one would be XCBR2. The ´$´ sign is a separation mark which is used in MMS protocol. The position of the circuit breaker is Pos and the value of the status is contained in stVal [Adamiak et al., 2009].

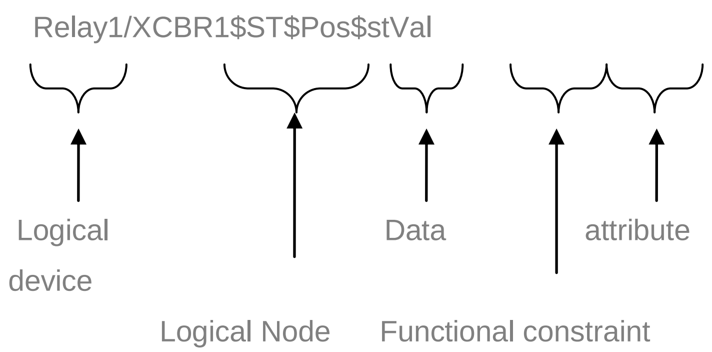


Figure 3.5: IEC 61850 object name structure

The key elements in the data model as defined by the standard are logical nodes. These logical nodes in an instance of the data model may be grouped together into a bay. A bay is not a physical device, but can be represented in the data model as a logical device. There can be one or more physical devices in a power system and it can have one or more servers. In a data model the server is the highest object in its hierarchy. Logical devices are groupings of functionality referring to a specific physical device and reside in a server. Therefore, one server can comprise of one or more logical devices, which can comprise of more than one logical node.

As a result of the object oriented approach of developing the standard users are able to name power system components in a substation in a manner which is meaningful, Table 3.2 [http://www.nettedautomation.com]

Table 3.2: Logical node Groupings [http://www.nettedautomation.com, 2012]

Logical node Groups	Group Designator
System Logical Nodes	L
Protection Functions	P
Protection related functions	R
Supervisory Control	C
Generic References	G
Interfacing and Archiving	I
Automatic Control	A
Metering and Measurement	M
Switchgear	X
Instrument Transformer	T
Power Transformer	Y
Further Power System Equipment	Z
Sensors	S

3.5.6 Logical nodes

The physical device is the first part of an IEC61850 device model and is the mechanism that links to the network through a network address. A physical device can contain one or several logical nodes [Adamiak et al., 2009]. The standard defines a logical node as the most basic part of a function that transfers data. A specific function within a physical device is shown by a logical node. Ninety one (91) logical node classes which are grouped into thirteen (13) logical node groups with names and associated services are defined by the standard. Figure 3.6 shows an example of a logical node [Adamiak et al., 2009]. One or several elements of data with a unique name, provided by the standard, reside within every logical node. For example, a circuit breaker is modelled as an XCBR logical node, this logical node have an array of information like Loc for establishing if operating local or remote, OpCnt for an operations count, Pos for the position, BlkOpn inhibit breaker open instructions, BlkCls inhibit breaker close instruction, and CBOpCap for the circuit breaker operating ability.

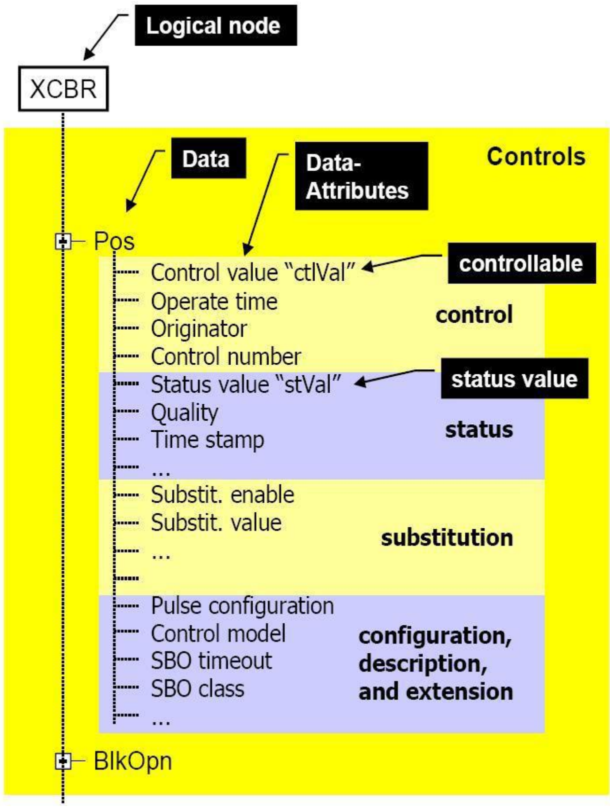


Figure 3.6: Example of a logical node [http://seclab.illinois.edu/]

Every logical node has an addition to the logical name, the LN-Instance-ID. For further identification every logical node can in addition deploy a unique LN-prefix for added identification. For example, logical nodes that begin with the letter "A" are logical nodes for automatic control and LNs that begin with "C" are for Supervisory Control. Logical nodes contain elements of data which has to conform to the description of a common data class (CDC). The nature and arrangement of the information are described by every common data class, for example, measured information, status settings, status information, etc. Every common data class has a unique name and a set of attributes with a specific name and specific type. Every logical node comprises of mandatory and optional data, but logical devices and servers may be pre-defined by manufacturers.

3.5.7 Station and process buses

The station and process buses consist of electrical or optical connections with communication network switches as the active communication elements. The switches have to be managed switches, meaning they have to support the definition of virtual private LANs (VLAN), priority tagging and time synchronization. IEDs are connected to the communication LAN through switches, which direct the LAN traffic to and from the devices. Monitoring of the station and process bus has to be done in the event of performance degradation or failure, which has to be added in the substation disturbance handling. Alarms and events in the station and process buses should be treated in the same way as events and alarms in the rest of the substation. The topology of a bus may be a single point-to-point connection between two IEDs or it may be a complex network with multiple switches in a redundant or backed up configuration

Voltage and current sensors make it possible to transmit sampled values from the source to the substation by converting base quantities in digital format. The ability to "know" status information remotely and controlling outputs are just as important as sampled values. Sampled Measured Values services as defined by IEC 61850 and through the employment of a process bus make this possible. The collection of power system data such as current, voltage, status information from feeders and transducers is part of the Process Layer of the system. The Merging Unit (MU) is supplied by current and voltage signals and status information. These signals are sampled at an agreed rate to ensure that any IED can input data from many MUs and automatically process the data.

3.5.8 Substation Configuration Language (SCL)

Substation Configuration Language (SCL) describes the configuration of IEC61850 based systems and using the extensible Markup Language (XML) [Hou & D. Dolezilek, 2008]. IED Capability Description (ICD), Substation Configuration Description (SCD), System Specification Description (SSD), and Configured IED Description (CID) files are the different SCL files.

There are various schemes where the opportunity of a precise disconnected description language delivers huge gains to the users outside of configuring IEC 61850 customer operations. These benefits include: [http://www.webstore.iec.ch, 2012]

SCL facilitates system development tools when they are not connected to develop the files required for IED configuration from the power system scheme greatly lowering the expenditure and intention of IED configuration by excluding many, if not all, manual configuration assignments.
SCL allows the distribution of IED configuration between users and suppliers to lower or exclude differences and misinterpretations in system configuration and system needs. Users can present its own SCL files to assure that IEDs are dispatched to them accordingly configured.
SCL enables IEC 61850 applications to be configured when not connected without the need to be linked to the network for client configuration.
SCL can be utilized dictated by the user's prerequisites. A user can decide to utilize CID files to maintain assistance in IED configuration employing its current system design mechanism. Or SCL can be employed to reconstruct the full power grid design mechanisms to exclude manual configuration, exclude manual information entry mistakes, lower misinterpretations among system structures and specifications, improve the interoperability of the system, and significantly enhance the capacity and efficacy of power grid engineers [Lim et al., 2006].

Figure 3.7 presents IEC61850 construction employing System Configurator and IED Configurator [Lim et al., 2006]. Starts with, collecting all the data from the SSD (System Specific Description) file that encompass the system linked data and the ICD (IED Capability Description) that encompass IED linked data, and then it establish the SCD (Substation Configuration Description) file. This file constructs the function and information transmission for each IED. Then the IED Configurator collects the SCD file and generates the CID (Configured IED Description) file that encompass the format convenient for the IED. Then the CID file is transmitted to a distinct IED via a communication link.

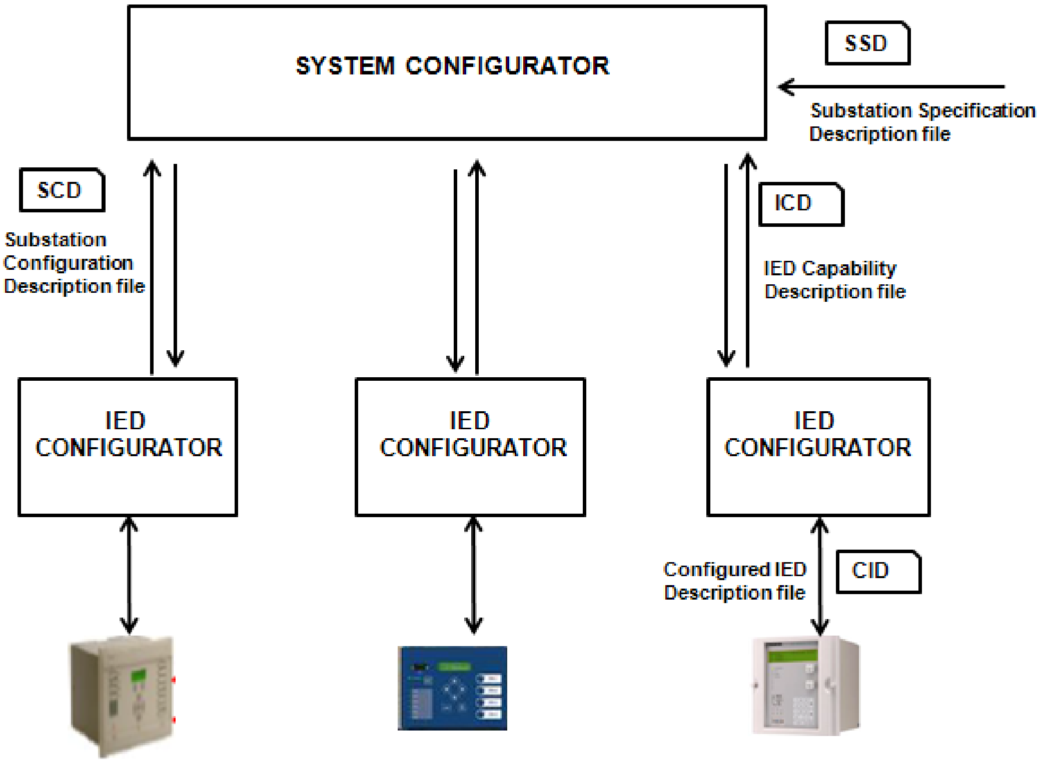


Figure 3.7: System Configurator and IED Configurator [http://www.academia.edu]

3.5.9 Manufacturing Message Specification (MMS)

MMS (Manufacturing Message Specification) is a global regulated messaging system for transferring actual information and supervisory control data among linked devices and/or computer applications in a way that is outonomous [http://www.sisconet.com, 2012].

The MMS standard was established by the Technical Committee Number 184 of the International Organization for Standardization (ISO). MMS are adopted by various industries such as, electric utilities, aerospace, energy management, automotive industry, and many more. In the electrical utility industry, there are MMS applications in many devices such as IEDs, Distributed Automated Systems (DAS) and Remote Terminal Units (RTUs). Peer-to-peer communications over a network are being provided by an abundant set of services by MMS. The messaging services provided by MMS are generic enough to be appropriate for a wide variety of devices, applications, and industries.

Interoperability is the capability of a couple or more linked applications to transmit appropriate supervisory control and process information among them without the need to construct the communications climate by the applications

Applications from different vendors have a good chance of interoperability due to the fact that MMS gives definition, structure, and meaning to the message. The Virtual Manufacturing Device (VMD) model is the key feature of MMS [http://www.nettedautomation.com]

The VMD model specifies objects that reside on the server, services for manipulation and access of the objects, and the behavior of the server when the services are received. The client / server exchange among applications and mechanisms is a fundamental part of the VDM model. A device that consists of a VMD and its objects is a server and a device that requests data or functions from the server is called a client. Both MMS client and server functions can be supplied by numerous MMS applications.

3.5.10 Generic Object Orientated Substation Event (GOOSE)

The purpose of GOOSE messaging is to provide uninterrupted state of logics or analogue values of IEDs [Hou & Dolezilek, 2008]. The continuous indication through control messaging is paramount if the idea of GOOSE messaging is to be realized. In a protection system, functions are dependent on feedback of many different relay contacts. These contacts can change state at any given time and the protection system holistically has to keep track of the changes in real-time [Hou & Dolezilek, 2008]. Scheme wiring makes these functions possible. For GOOSE messaging to work it has to do the same as control wiring using a LAN connection. A GOOSE message is sent as a multicast message via a LAN, meaning that it is not addressed to a specific IED. The content of the message is available for any IED on the network and the IEDs will determine if they want to utilize the information. The subscriber is any IED that is configured to use the content of the message and the publisher is the IED that transmits the message. The publisher does not know if all the subscribers received the most recent information – unconfirmed service. Subscribers do not confirm receipt of the message due to the absence of such a mechanism nor does it ask for a message to be sent again. Therefore the LAN is flooded with the latest GOOSE messages by the publisher and the subscriber has to ensure that it captures the messages.

For a protection scheme to function properly the many different IEDs have to update their contact status and analog values every few milliseconds. This means that every publisher repeats the latest messages several times to keep the subscribers up to date. Figure 3.8 illustrates how messages are repeated with intervals. A message is published with a long time interval of 1 minute if there is no status change within a certain dead band [Brantley, 2008]. The updated message is sent instantaneously if the published message changed state. As fault conditions exist on the power network the time interval between publishing messages becomes faster to keep the subscribers updated. Intervals of message transmission returns to a stable state after the power network returns to normal. This happens because the GOOSE message logic in the publishing relay picks up that there are no further state changes. The illustration also shows that the intervals become longer between messages as the network normalizes. If the protection functions on the LAN suddenly changes than the time intervals between messages become faster [Brantley, 2008].

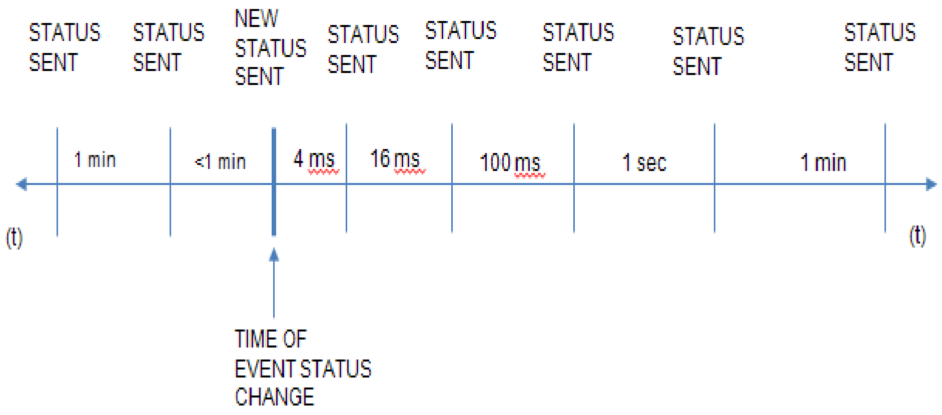


Figure 3.8: Message intervals [Brantley, 2008].

3.5.11 Time Synchronization

Time synchronization nowadays is a requirement in most devices in an automated substation. All the devices in the substation that are connected to the network must be synchronized because of the introduction of the IEC 61850 based communication solution. The further down one goes on the substation function level hierarchy the more accurate the synchronization accuracy has to be. In the station level the time at which a system activity occurred is shown to the field operator, here accuracy requirements are in the order of a few hundred milliseconds. Protection and control devices are found in bay level. These devices require an accuracy of one half to one millisecond for event time stamping. However, MUs on the process level requires an accuracy of a few microseconds for measuring value sampling. Clock precision of about 100 µsec is possible by utilizing existing standard Ethernet controllers.

SNTP (Simple Network Time Protocol) time synchronization method using LAN has to be used according to the standard the other methods are outside the scope of the standard. NTP (Network Time Protocol) and SNTP are common synchronization methods used in LANs and has accuracies in the millisecond range. The other methods in achieving time synchronization are radio waves and GPS (Global Position System). GPS makes is possible to reach escalated synchronization accuracy, however is much more expensive compared to methods using LAN. The accuracy of the SNTP synchronization method is approximately 1 millisecond, this however does not comply for sampled values and merging units. To solve this problem IRIG-B (Inter-Range Instrumentation Group time code B) can be used. The IRIG-B however, need an external time source such as a GPS clock because it is not a time source. The system has to be redundant for the automation to function properly, therefore the external time sources for IRIG-B must be doubled or an alternative time source could be an SNTP master. To meet all these requirements the Precision Time Protocol (PTP) was developed. PTP is described in IEEE1588 standard. The PTP method provides than one microsecond accuracy with dispersed clocks via Ethernet. PTP has been updated from PTPv1 to PTPv2 and the latest version was published as IEEE1588-2008.

3.6 Comparison between legacy protocols and the IEC61850 standard.

When the IEC61850 standard is compared with legacy communication protocols it is more advanced. It is defined by object oriented modelling functionality as well as detailed defined communication interfaces. When the IEC 61850 standard is compared to the traditional protocols such as DNP3 and MODBUS the primary benefits of IEC 61850 are the following [Schwartz, 2002]:

- IEC 61850 standard allows the various manufacturers to create application specific extensions, similar to traditional protocols, however the standard additionally presents near to 100 logical node classes with an excess of 2000 data objects/attributes.
- Traditional protocols are less extendable.
- Traditional protocols use indexed addressing, whereas the standard uses hierarchical names.
- IEC 61850 standard backs condition, quality, time sprint, and principle of transportation identical to DNP3 and IEC 60870-5 but unlike Modbus.
- In the IEC 61850 standard the data, such as LNs, data objects and attributes are more detailed.
- Traditional protocols are less adaptable in specification, supervision and restrict the user to specify, alter and remove the parameters at any point, whereas these capabilities are boundless in the IEC 61850 standard.
- IEC 61850 grants the means to transport substation events (GOOSE messages) and sampled values.

- IEC 61850 grants direct access to the entire data structure of all objects by attaining the directory where the particular service is defined in 60870-5-103 and does not exist in the DNP3 protocol.
- IEC61850 grants the solutions of viable objects and communication service linked objects, whereas the legacy protocols do not.
- The choosing of the information for broadcasting, permit/block the communication control objects, and modifying reporting or logging conduct is managed with enhanced adaptability in the IEC 61850 standard.
- IEC 61850 grants a explicit description of device configuration in XML configuration, where traditional protocols use hardcopy documents.
- IEC 61850 unconditionally backs multi-vendor engineering mechanisms and is exposed for imminent service systems. Traditional protocols are limited to specific vendor engineering for its own services.

3.7 Discussion

DNP3 is the prevailing SCADA communication protocol in use in the USA as well as in South Africa in the distribution power system environment. Nevertheless the extensive use, it lacks some of the features required in an advanced automated distribution system. [White, 2006] found that DNP3 is being in the market for several years, but still poses several implementation challenges and flaws. As in the case with Modbus it also has several limitations which make it unsuitable in advanced distribution automation system applications. It is a master-slave protocol and the master node needs to poll every field device periodically, which uses the network as well as bandwidth time. MODBUS restricts the amount of devices in the field that can be linked to a master station. It also caps the number of remote communication devices that can screen data [http://www.modbus-IDA.org, 2013].

The infrastructure of legacy protocols limits data communicated by SCADA as well as providing the ability to create new applications. To improve the situation a utility has to ask the question, should the existing communications protocol be replaced and at what cost. For legacy systems already in-service, it is not economically viable to replace them completely, but rather to integrate them with an IEC 61850 system. If the system has to be replaced entirely it will not only have cost implications, but will also be disruptive to existing applications as well. [Mohagheghi, et al., 2009] report that when legacy protocols are mapped to IEC 61850 they will have the ability of new control and monitoring functionality. Using a consistent mapping solution will minimize possible integration problems between the two different types of systems. The communication protocol IEC61850 has been developed to achieve interoperability between devices from various vendors to be able to exchange data between them. Therefore, if the communication technology changes no changes are needed for the devices. However, this is not the case for communication equipment that uses legacy proprietary protocols as it does not separate the data of the functions, services and communications protocols. Proprietary protocols have master-slave systems and require physical wiring between devices. Traditional protocols only describe how information are sent on the cable however, it does not define the management of information in term of the application, therefor requiring manual object configuration and mapping it to power grid fluctuations and index numbers, I/O modules, low level register numbers etc. IEC 61850 is based on Ethernet and have client-server systems that have increased performance. Client-server communication is flexible when it comes to data transmission and the data to be exchanged is controlled by the client [De Mesmaeker, 2005]. IEC61850 eliminates much of the manual object configuration and mapping as the devices can configure themselves. IEC 61850 also presents a thorough model describing power grid devices and how to formulate information in a manner that is persistent for devices from different vendors [Adamiak et al., 2009]. Power grids are designed to have robustness and have to last for several years. It is therefore obvious that there will always be legacy devices on the system at any given point in time. When new technologies have to be introduced into the power system, there has to be ways of how the legacy protocols can be accommodated. This is necessary for any successful implementation and is considered from both technical as well as an economical point of view

3.8 Conclusion

Over the years, many proprietary communication protocols that are used in the distribution electrical environment have hindered utilities to achieve true and complete protection integration, monitoring and control. The industry has reached a stage where more interoperable and platform-independent protocols are required. Therefore the major challenge is to accomplish interoperability between different IEDs of multiple manufacturers. The IEC 61850 standard has been developed as a future proof and adaptable communications protocol with advanced object oriented modelling structure to meet these requirements. The increased pressure on utilities to deliver in the form of improved customer service and quality of supply as well as saving on maintenance and operational cost have led to the extension of automation beyond the substation boundaries. This will allow interoperability between the different devices of the distribution automation system out along the distribution feeders. However, for this system to function efficiently communication infrastructure covering the entire wide area connecting all the different field devices with one another and the distribution automation system has to be installed. When the IEC 61850 standard is extended to the feeders similar logical nodes which is already defined in the IEC 61850 standard, GOOSE messaging and sampled values can be used.

The IEC 61850 protocol is selected to build the DAS in the thesis as it guarantees best functionality and operability solutions. The next chapter describes the method of achieving an automated distribution automation system. It will show how the GOOSE services together with hardwiring are used to achieve a fully functional DAS through a built test bench. It will also show the different IEDs used in the test bench and how they are programmed.

CHAPTER FOUR

THE DEVELOPMENT OF AN ALGORITHM AND ITS IMPLEMENTATION IN FAULT DETECTION, ISOLATION AND SERVICE RESTORATION – CASE STUDY

4.1 Introduction

The fact that the majority of distribution protection systems do not meet the required automatic control capabilities all around South Africa has led to the need for the investigation of the implementation of distribution automation using intelligent automatic and control capabilities of the new technologies. The thesis objective is to design and construct a lab scale system that would meet existing and future requirements for control and automation of a typical underground distribution system. The currently installed distribution systems in the local utility as well as municipalities lack automatic control abilities. In many utilities presently control officers at the control centre analyze loading conditions before transferring load to an alternate source. However, this is not practical to expect humans to perform these tasks “flawlessly” as networks are becoming increasingly more complex. There are numerous checks to be performed before any action can be taken, i.e. the monitoring of the protection breaker status before automatic switching can be initiated. In addition checks should be performed not to exceed equipment rating, which could compromise the safety of personnel and equipment. The new distribution automation systems can perform all these tasks without human intervention.

Initially the question was asked, “can the IEC61850 standard be implemented in the distribution environment since it is the communication standard for substations”. Tests and simulations that have been done on the lab scale system showed that it is indeed possible. The requirement for the lab scale distribution system is to have the ability to clear faults through reliable and fast protection operation, isolate faulted section/s, on the network and restore power to the unaffected parts of the network through automation control and automation function of the IEC61850 standard.

4.2 Concept of a fully automated strategy

Various methods and approaches have been discussed in Chapter two that address the problem of the automation of distribution networks. Distribution Automation using

IEC61850 communications is a new concept and the manner in which it is implemented in the thesis is an innovative approach.

Existing distribution system operations are based on manual functions and the operations require long time periods for the system to be restored to its normal operation mode after a disturbance occurred. The IEC61850 standard allows all the manual functions to be substituted with fully automated calculations of optimization algorithms and internet communication through GOOSE messaging. Table 4.1 illustrates the substitution of manual functions through existing IEC61850 standard based functions.

TABLE 4.1: Manual functions replaced with standard based functions

FUNCTION	EXISTING SYSTEM	TEST SYSTEM
FAULT DETECTION	Protection device operation via hardwiring	IED operation via GOOSE messaging
FAULT LOCATION	Visual inspection of fault indicators	Automatic retrieval of fault locator information through the automation system.
FAULT ISOLATION	Manual operation of breakers and switches	GOOSE messaging as well as automatic switching.
SERVICE RESTORATION	Manual operation breakers and switches	GOOSE messaging as well as automatic switching.

Automatic bus sectionalizing, fault isolation and service restoration functions using IEC61850 communications are the main focuses of this thesis. An un-faulted line section that has been isolated due to a permanent fault on the power system can be restored through algorithms created in the FDISR function. Typically the switching algorithm will be as follows: In underground cable networks the feeder breaker will trip and will not auto-reclose when a permanent fault occurs. The next step is to locate the fault, here it is assumed that only the fault detectors between the fault and the source will show fault targets. Therefore the algorithm "searches" for the line section where the sensor has only been targeted at one end and not at the other end. After the faulted line section has been successfully identified the line switches at both ends will be opened. To restore power to the un-faulted sections are part of the service restoration function which will include the closing of the normally open point or the reclosing of the substation breaker depending on the location of the fault. switching is executed automatically, usually in less than one minute after the fault has occurred.

4.3 Description of the case study

4.3.1 Existing CPUT Distribution System Background

The original power network that supplied the campus was an overhead line which was built in 1962 with maximum demand (NMD) of 500kVA. Figure 4.1 shows the geographical position of all the various substations of the CPUT distribution network. Substation No.1 was the main intake substation and supplied the entire campus. Due to various reasons an alternative supply was used to supply the campus and hence Pentech Main Intake substation was built during 1986. This substation still supplies the campus network, with a Maximum Demand (NMD) of 2 MVA. The distribution network is designed to be 11 kV with a ring network, operated radially, Figure 4.1. There are fourteen 11000/400V downstream substations each with transformers and LV switchgear. The distribution network is operated radially in an interconnected underground cable network with one power source and one normally open point separating the two rings.

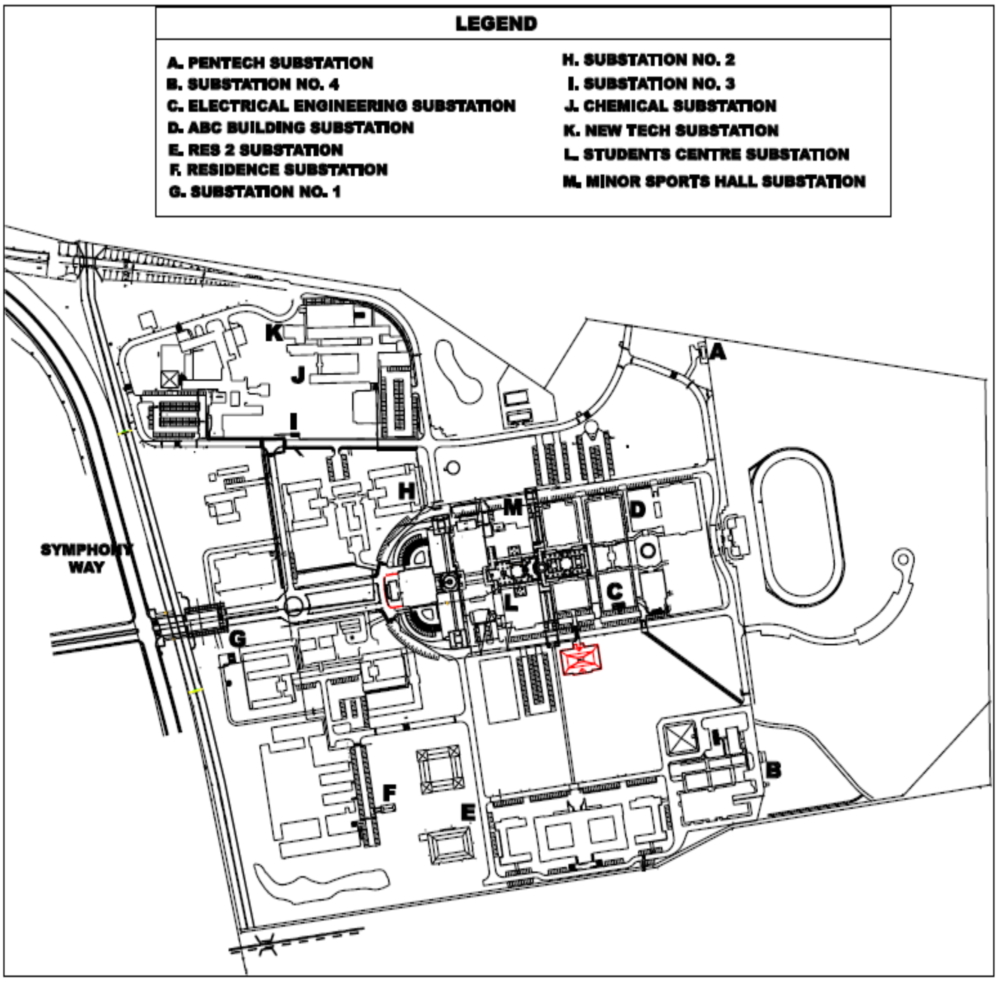


Figure 4.1: Geographical position of the various substations on the CPUT distribution network.

As might be expected, there are several shortcomings with the existing distribution network. The age of the primary equipment as well as the control plant, safety, lack of remote monitoring are the main concerns. The oil-filled 11kV switchgear has become a high risk due to its age and the lack of availability of spares.

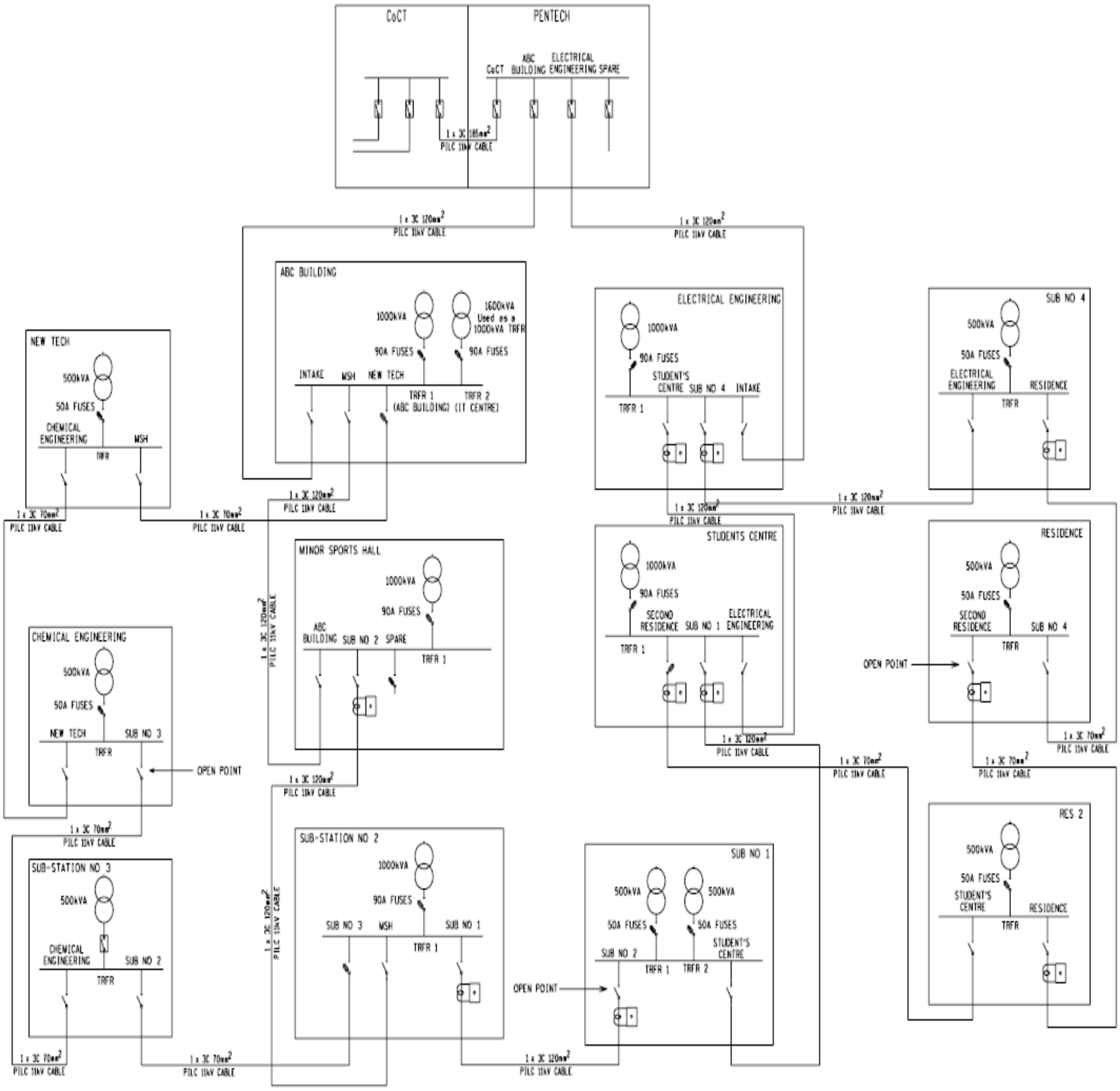


Figure 4.2: Distribution network overview

4.3.2 Existing Protective Equipment

The distribution network is protected by Inverse Definite Minimum Time (IDMT) CDG 36 type electromagnetic relays and High Rupturing Capacity fuses (HRC). Relays are installed at the main intake substation and fuses at the tee-offs to the downstream substations. Field operating staff locates short circuits by reading off short circuit indicators. Indicators are present in nearly all substations. The indicators have to be reset manually. Switching operations in substations are also carried out manually. There are no remote control functionality and no control centre.

4.3.3 Future Campus Network

CPUT has made a decision to refurbish the 11kV main intake substation as well as the 11000/400V downstream substations. The new substations will supply more loads per feeder as the campus is growing in size with extra campus buildings being built. The 11kV oil-filled switchgear will be replaced by sulfur hexafluoride (SF6) units as the industry is continuously moving towards a safer, more compact and reliable environment. The electromagnetic relays will also be replaced with multi-functional protection and control micro-processor IED's. The downstream substations will be fitted with complete new protection as they are only fuse-protected at the moment.

The main objectives of the project are to reduce operating and maintenance cost, improve service reliability, and provide better customer reliability with enhanced technology level for the distribution automation system of the CPUT reticulation network to be built. The CPUT DA system will be designed based on IEC 61850 standard technologies. The main parts are the feeder control center, line equipment devices for controls and data acquisitions and the communication system. The cable equipment devices will capture the feeder operating data and will transfer them to the control center, and will execute the control actions from the substation. The functions included in the CPUT DA system are for both operational and planning purposes. The DA functions are used to monitor the system status, record system operation data, and control line equipment devices according to the operation condition. The proposed campus topology is illustrated in Figure 4.3.

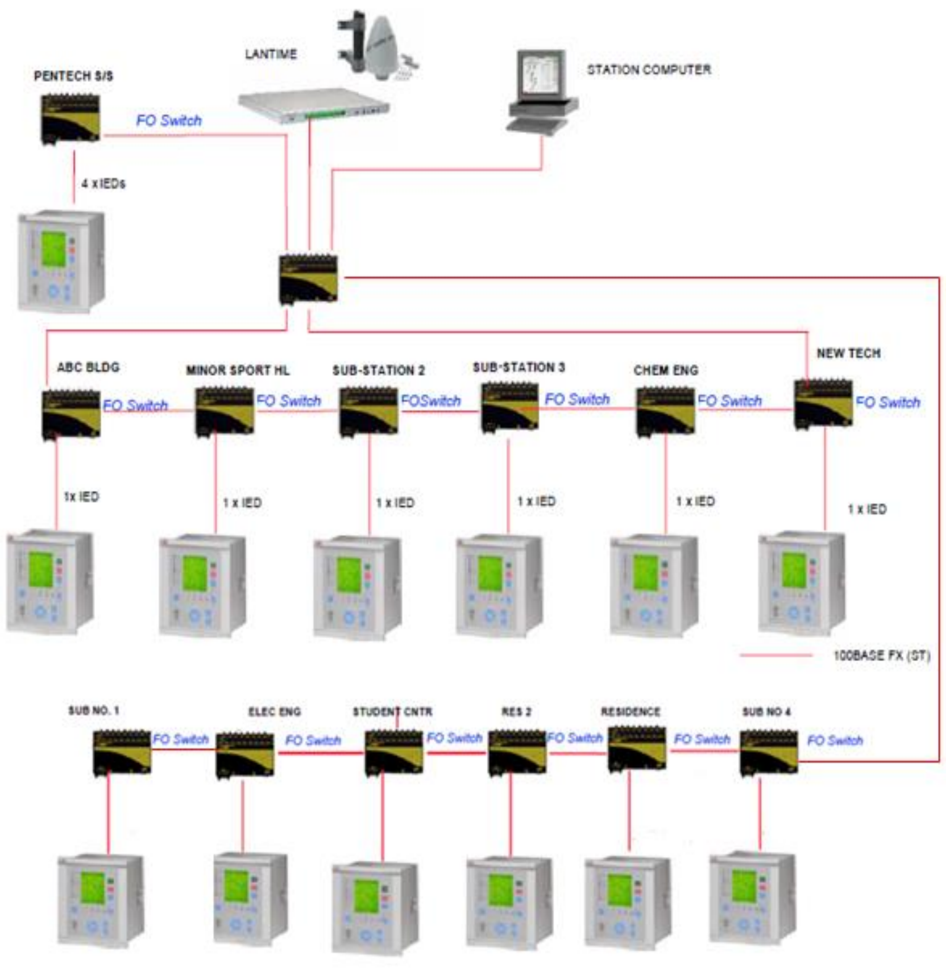


Figure 4.3: Proposed topology of the IEC61850 standard-based automated system for the CPUT reticulation network

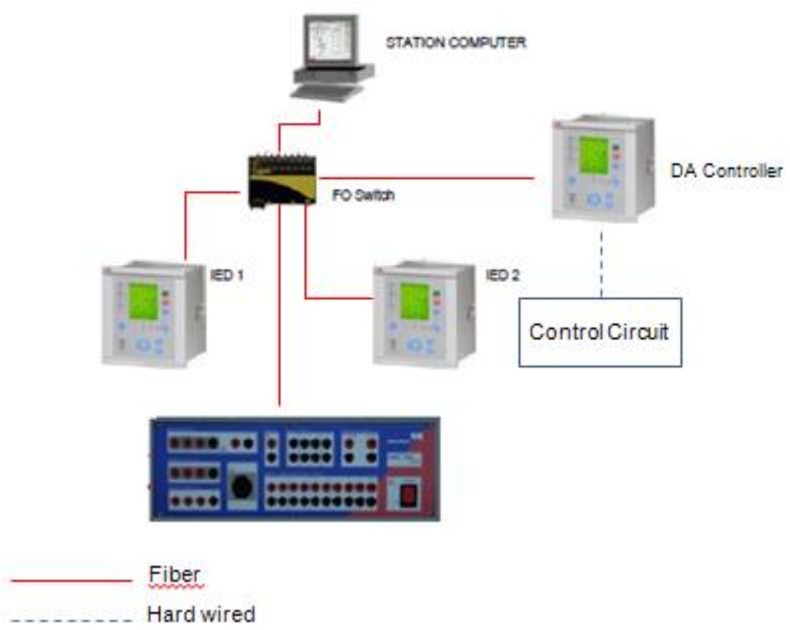


Figure 4.4: Test System topology

4.3.4 Test System Operation

The objective of the lab scale system is to simulate a distribution automation system involving two substations with one radial cable feeder respectively that can be interconnected through a Normally Open Point (NOP). As previously described the switches on the distribution system that normally operate in the open position and are situated between two or more feeders are called normally open points. Switches that are operated in the normally closed position are called sectionalizing switches. Each feeder consists of two line sections where a line section can be seen as line segments bounded by two sectionalizing switches. The first line section is the zone between the breaker at substation one and the first downstream switch (SW2). The second line section is between SW3 and the normally open point (SW4). The third section is between the normally open point and SW5 and the fourth line section between SW6 and the breaker at substation B. Figure 4.5 illustrates a single line electrical diagram of the network. The system includes fault locators at each switch. Figure 4.5 shows that the normally open point is represented by SW4, and it separates the two feeders. The protection breaker at the substation A is represented by Brkr1 and similarly Brkr2 is the breaker at the substation B. The system uses an IP-based communication system and it communicates via an Ethernet system supporting peer-to-peer communications.

The execution of all the functions of the DAS is governed by an intelligent algorithm. The algorithm relies on the status information of the line equipment installed on the distribution feeder as well as devices communicating the presence of the passage of fault current. The computation of the algorithm is performed in a central place and can be at any substation. The decision making process affects all the feeders that are interconnected. The automation strategy requires fault current sensor units, IEDs and relays for the control circuit. The purpose of the sensors is to determine the location of the fault by relaying the passage of fault current at the point of the sensor installation. The IEDs are used for the primary protection issuing trip commands to the protection circuit breakers. Set/Reset relays are employed and hardwired into the distribution automation controller for the manual operation of the sectionalizing switches on the distribution feeder. Finally the inputs and outputs of the distribution automation controller are responsible for the tripping or closing instructions for protection circuit breakers and sectionalizing switches. The commands between the distribution automation controller and the IEDs use GOOSE messaging. Ethernet packets are transmitted via fiber-optic cabling. Commands to set/reset relays are via copper hardwiring.

4.3.5 Protection

Protection functions predominantly used in the distribution environment are usually over current and earth fault, sensitive earth fault, breaker fail and auto reclose control. This thesis uses only over-current and earth fault protection for the demonstration of fault conditions on the simulated network. The main purpose of protection is to detect and clear permanent faults as well as overloads. IEDs are used to detect and clear faults by the issuing of trip signal commands to circuit breakers. Circuit breakers are capable of interrupting fault current, whereas line switches are not. They are used for switching during off-load conditions. The protection settings applied on the test system protection devices do not have to grade with one another as the feeders are operated radially and supplied from one source.

Figure 4.5: Single line electrical diagram of the test system

4.3.6 Algorithm of operation

When a fault occurs in the power system the protective IED causes the circuit breaker at the substation to open resulting in power loss to the customer. Thereafter field operating staff has to attend to three consecutive problems:

1) Find the fault
2) Isolate the fault
3) Restore the power.

The test DAS system achieves these goals through automatic fault location, isolation and restoration based on IEC61850 standard. The fault location algorithm determines where the faulty section on the distribution network is. The tool receives information from the fault locators mounted at each sectionalizing switch. When the protection circuit breaker at the substation trips the fault locators that had "seen" the fault send the information through GOOSE messaging. Analyses of the information allow the DAS to determine the location of the fault. The Fault Isolation tool opens the two line switches bounded by the faulted line section. Thereafter the power is restored by closing the protection circuit breaker at the substation only or re-configuring the distribution network by closing the Normally Open Point (NOP) depending on where the fault is on the distribution network. A flow chart for fault detection, isolation and service restoration is illustrated in Figure 4.6 and Figure 4.7 illustrates the steps the FDISR takes at the time of a permanent fault.

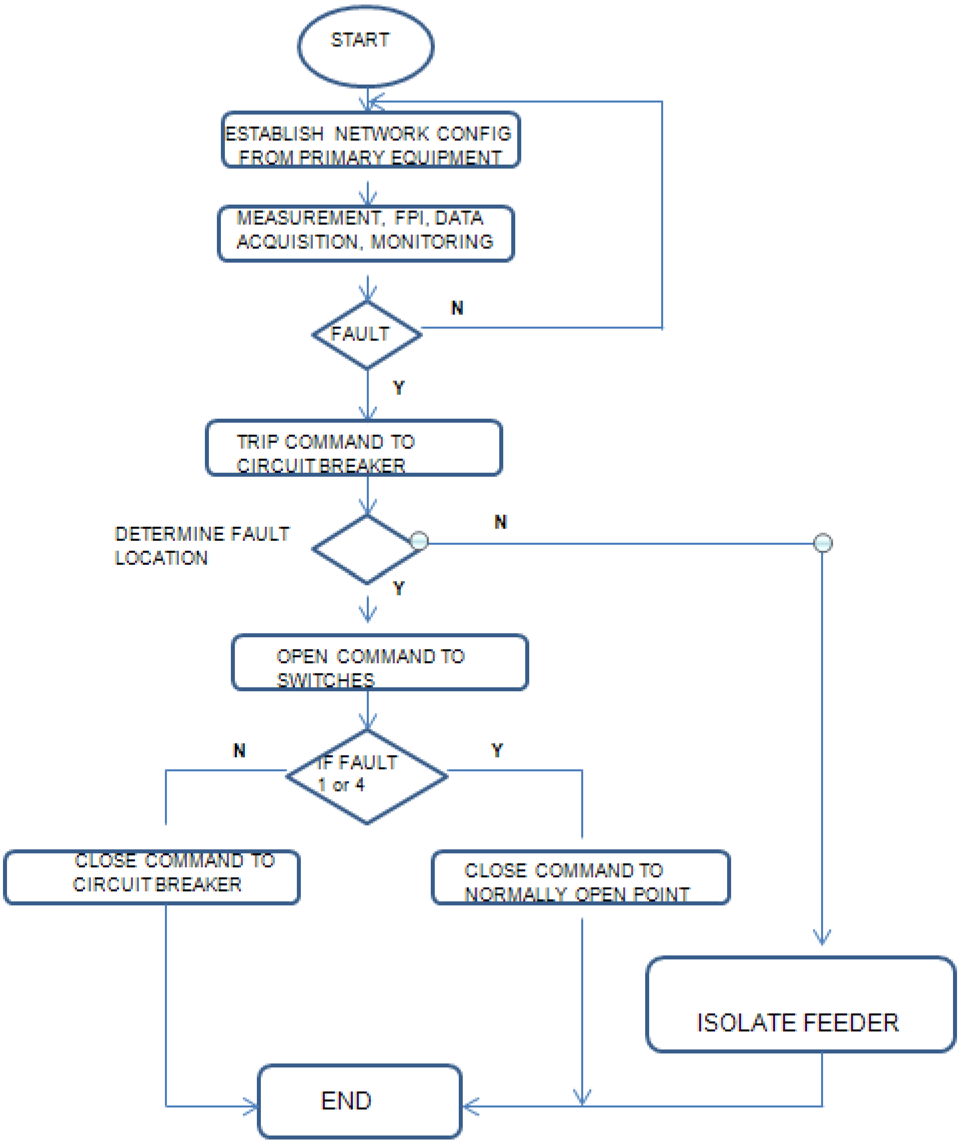


Figure 4.6: Flow chart fault detection, isolation and service restoration process in the test system

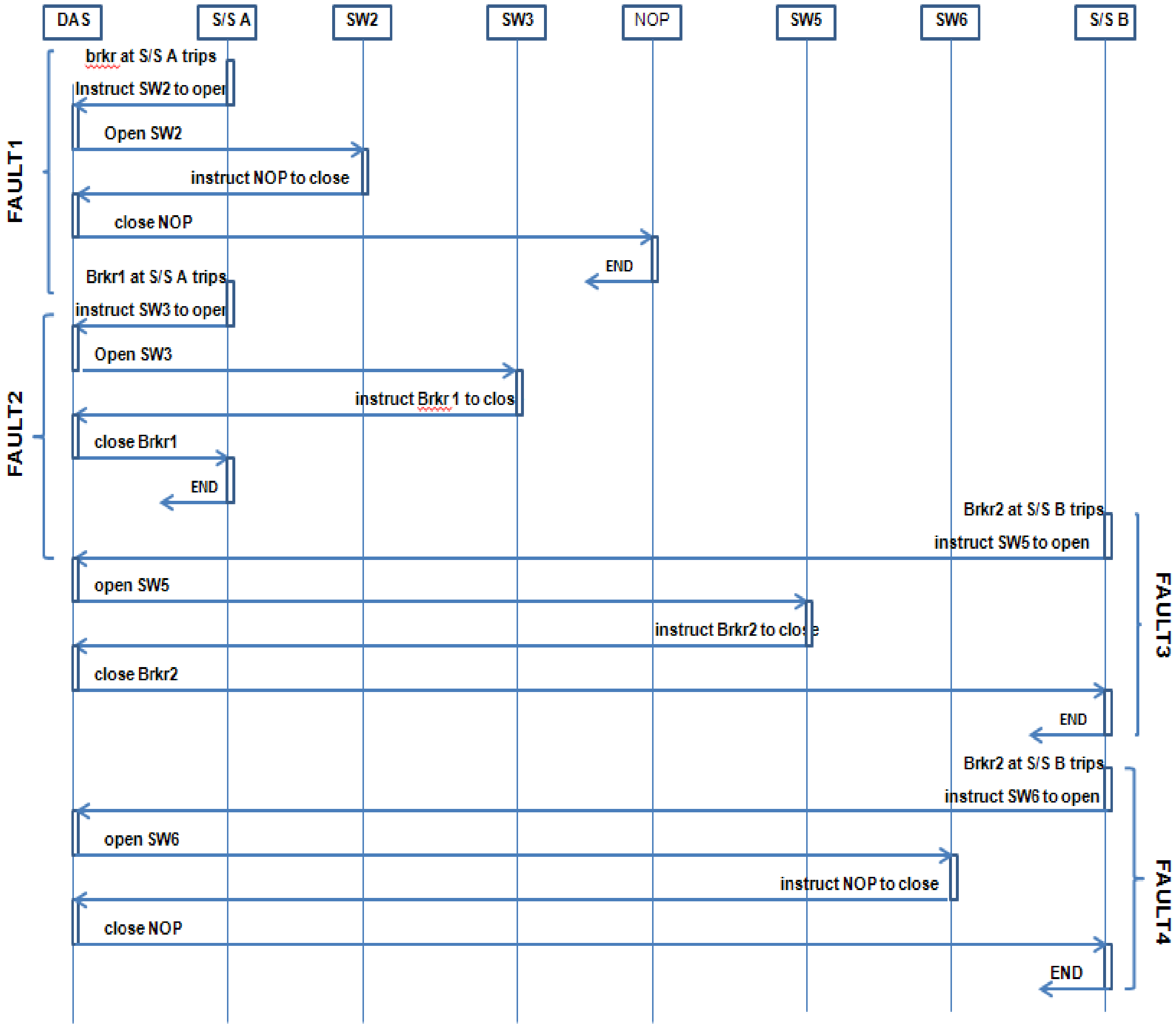


Figure 4.7: FDIR steps for different positions of the fault

4.3.7 Description of the FDIR algorithm steps:

- **Service restoration line section1 (Fault1 applied on line section1):**

  (Line section 1 is the portion of the line between S/S A and SW2)

  Step1 – Protection IED at the substation A sends a GOOSE message to trip the circuit breaker at the substation A.

  Step2 – Only the one fault path indicator has indicated fault passage on line section1 therefore fault has been identified to be in line section1.

  Step3 – Line section1 boundary switches as well as the substation breaker is opened to isolate the fault.

  Step4 – (Future Work) Substation A requests substation B if enough reserve capacity is available to supply additional load by monitoring the load quantities on the feeder.

  Step5 – (Future Work) Substation B confirms or declines.

  Step6 – DA controller sent instruction for NOP (SW4) to close. The un-faulted line sections are supplied from substation B.

- **Service restoration line section2 (Fault2 applied on line section2):**
  (Line section 2 is the section of the line between SW3 and SW4)
  Step1 – Protection IED at substation A sends a GOOSE message to trip the circuit breaker at substation A.
  Step2 – Fault path indicators one and two indicated fault current passage, therefore the fault has been identified to be in line section 2.
  Step3 – Boundary switches on line section 2 are opened isolating the fault.
  Step4 – DA controller sends a GOOSE message to IED at the substation A to close the circuit breaker at substation A.

- **Service restoration line section3 (Fault3 applied on line section3):**
  (Line section 3 is the section of the line between SW5 and SW4)
  Step1 – Protection IED at the substation B sends a GOOSE message to trip the circuit breaker at the substation B.
  Step2 – Fault has been identified to be on line section 3 as fault path indicators 3 and 4 have operated.
  Step3 – Boundary switches on section 3 are opened isolating the fault.
  Step4 – DA controller sends a GOOSE message to IED at the substation B to close the circuit breaker at the substation B.

- **Service restoration line section4 (Fault4 applied on line section4):**
  (Line section 4 is the section of the line between S/S B and SW6)
  Step1 – Protection IED at substation B sends a GOOSE message to trip the circuit breaker at the substation B.
  Step2 – Fault has been identified to be in line section 4 through fault path indicator operations.
  Step3 – Line section 4 boundary switches opened to isolate the fault.
  Step4 – (Future Work) Substation B requests the substation A if enough reserve capacity is available to supply additional load.
  Step5 – (Future Work) Substation A confirms or declines.
  Step6 – Normally open point is closed via a close command from the DA controller to supply un-faulted line sections from the substation A.

4.4 Test System Physical Structure

SEL IED's were used for the implementation of the demo equipment. SEL has proven to be leaders in automation and their customer service has been impressive in the past. All software used in the configuration of the IED's was supplied by the vendor. The used equipment is listed in Table 4.2.

Table 4.2: Distribution automation system equipment list

IED	Description
1 x SEL 2440	DiscretE Programmable Automatic Controller
2 x SEL 351A	Overcurrent and Earth fault IEDs
1 x RuggedCom switch	Managed switch with eight RJ45 connections
5 x MK2KP Omron Aux relays	SET-RESET relays
OMICRON 256 Plus	Secondary test set for fault simulation

The purpose of the demo system is to demonstrate that fault detection, isolation and restoration through automatic switching can be achieved by implementing the IEC61850 standard. The protection breakers at both substations are simulated by the breaker indications within the SEL 351A (Overcurrent and Earth fault) IED's. The line switches are simulated by set-reset auxiliary relays which have extra contacts used for status indications. The set-reset relay contacts are hardwired into a Discrete, Programmable Automatic Controller, SEL2440. The line switches can be manually operated by means of push buttons. The fault indicators are simulated by OMICRON binary outputs. The demo system has an Ethernet switch with eight RJ45 connections. The demo-system is powered by an 110V DC supply. Figure 4.8 shows the IEC 61850 standard-based test system. Short description of the used equipment is given below:

Figure 4.8: Picture of the IEC 61850-based DA system test system panel

4.4.1 SEL2440

The Discrete, Programmable Automation Controller (DAC) provides digital logic capabilities that operate on physical inputs and outputs and virtual inputs and outputs via GOOSE messaging. The SEL-2440 provides features such as Sequence Event Report (SER), IEC 61850 communications, Flexible SELOGIC®, Modbus® RTU and Modbus TCP/IP communications and many more.

4.4.2 SEL351A

The SEL-351A IED provides a wide range of functions such as protection, monitoring, control, and fault locating characteristics. It uses powerful SELOGIC control equations and can be used to provide protection and control applications. These applications can be implemented to protect almost any power system, line, feeder, transformer, capacitor bank, reactor, and generator. The SEL 351A uses multiple inverse curves to coordinate with upstream and downstream protective devices. SEL-351A control logic enables the Replacement of traditional panel control switches, traditional latching relays, traditional indicating panel lights and external timers, therefore improving integration significantly.

4.4.3 Fault Path Indicators (“SENSORS”)

This is a virtual IED and was created to simulate the Fault Path Indicators (FPIs) for each line section of the simulated network. The “SENSORS” IED was created to indicate the presence of a fault condition on the simulated network. It is simulated by binary outputs from the OMICRON secondary test set. Binary output 1 simulates FPI 1, output 2 simulates FPI 2 and so on. The various binary outputs are sent by the OMICRON via GOOSE messaging.

4.4.4 OMICRON

CMC 256PLUS is a highly accurate secondary injection test set for protection devices. It is a versatile device and can be used in many applications. It is used for secondary fault simulation, IEC GOOSE simulation and subscription as well as assessing the operation (time taken for the network to reconfigure) of the simulated test system.

4.4.5 SET/RESET auxiliary relays

The MK2KP type OMRON set/reset relay is set (ON) and reset (OFF) by applying a voltage pulse. The relay holds its set or reset position until it receives the next inverting input. The relay is hardwired to the SEL 2440 and its main function is to simulate the line switches as well as manually operate them.

4.5 Communications Structure

The first step in the communication process is to obtain the IP addresses and network mask from each device. It is possible to obtain the default IP address from the IED by connecting serially to the devices. After obtaining and setting the IP address's communication to the device via LAN is then possible. The next step in the communication process is to configure the data sets for GOOSE messaging. The devices have pre-defined datasets. However, it was decided to create new datasets. The data sets were also renamed as close as possible to the function they perform to simplify the structure of the GOOSE message. By doing so the process of identifying the various GOOSE messages was made easier. In order to use the configuration tools effectively it is necessary to understand the basic fundamentals behind the IEC61850 standard. It is also important to "play" around with the configuration programs since each manufacturer has different approaches to configuration. Table 4.3 shows the TCP/IP communication settings for the system.

Table 4.3: TCP/IP communication settings for the test system

IED	IP address	Network mask
SEL 2440	192.186.1.4	255.255.255.0
SEL 351A	192.168.1.2	255.255.255.0
SEL 351A	192.168.1.3	255.255.255.0
COMPUTER	192.168.1.1	255.255.255.0

IED's with network mask 255.255.255.0 show that the devices that have the first three numbers the same are on the same network. The last number can be any number between 0 and 255. The MAC address, VLANID and VLAN priority are additional communication settings made to the devices. The VLAN ID was set to one, VLAN priority to four. The MAC address for GOOSE transmission is 01-0C-CD-01-00-00 and it is defined by the IEC61850 standard. All the IEDs are connected to a single Ethernet switch enabling the configurator to configure the IED's with a single computer via Ethernet. Figure 4.10 shows the communication configuration settings of one of the SEL351A IEDs. AccSELerator Quickset, software configurator tool, is used to set the IP address and subnet mask of the device as well as the IP address of the computer. Figure 4.8 shows the communications structure of the test system as well as the hardwiring between the DA controller and the line switches.

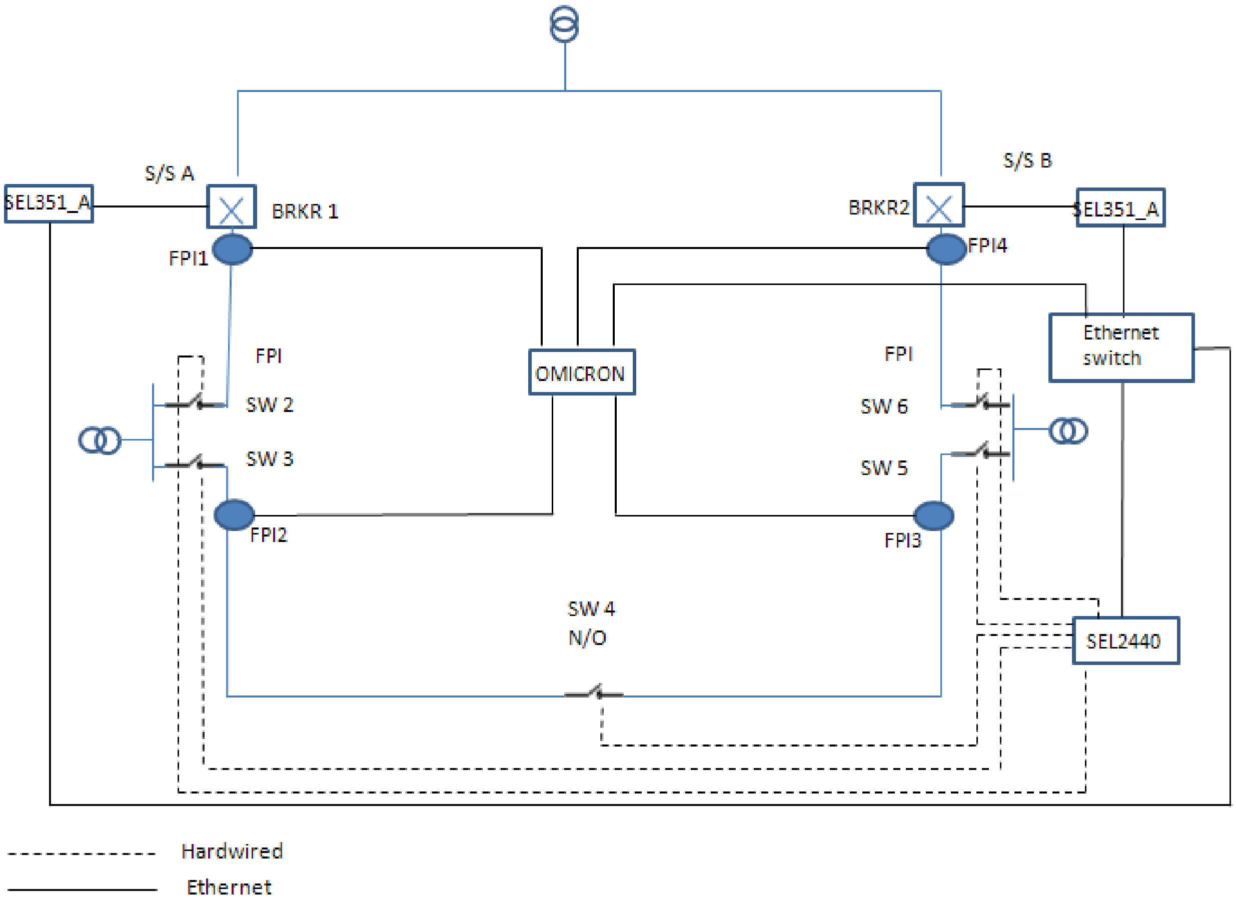


Figure 4.9: Communications structure of the test system as well as the hardwiring between the DA controller and the line switches.

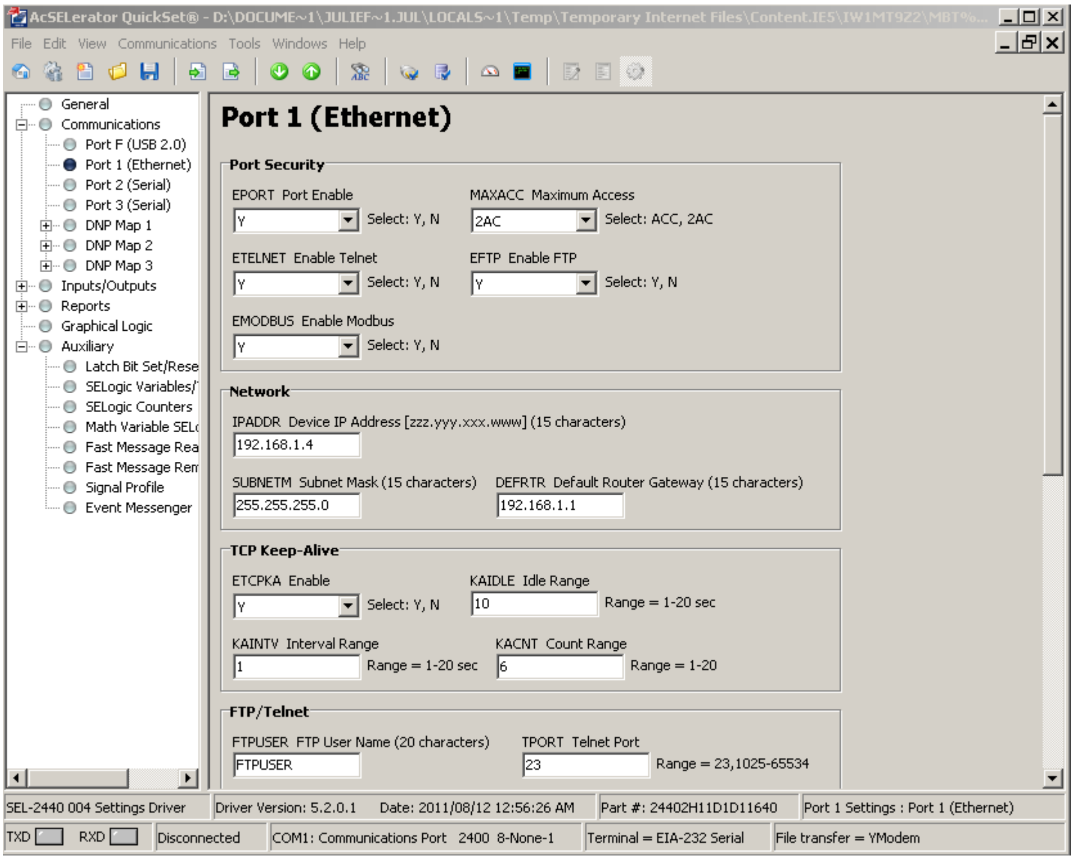


Figure 4.10: Communication settings for the SEL 351A

4.6 Software

4.6.1 ACSELERATOR QuickSet

The ACSELERATOR QuickSet software program uses the Microsoft® Windows® operating system to apply and retrieve settings as well as assist analyses of the SEL family IEDs. ACSELERATOR QuickSet is used in the thesis to create and manage relay settings, create settings off-line, create SELOGIC control equations organize settings using relay database manager, upload and download settings via PC connection. ACSELERATOR QuickSet is also used to verify settings, event analyses and assist with commissioning and testing of SEL IEDs and many more. Meter data, Relay Word bits and output contacts can be monitored by using the Human Machine Interface (HMI) function. In order to establish a connection to a device the computer communications port must be properly set. Throughout the development of the project Ethernet network communications option was used. Once a connection has been established the Terminal function within QuickSet can also be used to send commands to the connected device.

4.6.2 ACSELERATOR Architect

SEL AccSELerator Architect is a configuration tool used to configure SEL devices for communication between devices. Figure 4.11 illustrates the main sections in the configuration tool which are: GOOSE Receive, GOOSE Transmit, Reports and Datasets. AcSELerator Architect Software is used in the design and commissioning of IEC 61850 communications. It can be used to create and edit data sets, create Generic Object Oriented Substation Event (GOOSE) transmit messages, map GOOSE receive messages to IED's from SEL and non-SEL relays, create configured IED description (CID) files to send to SEL IEC 61850-compliant relays as well as read in all IEC 61850 Substation Configuration Language (SCL) files (SCD, ICD, CID) [www.selinc.com].

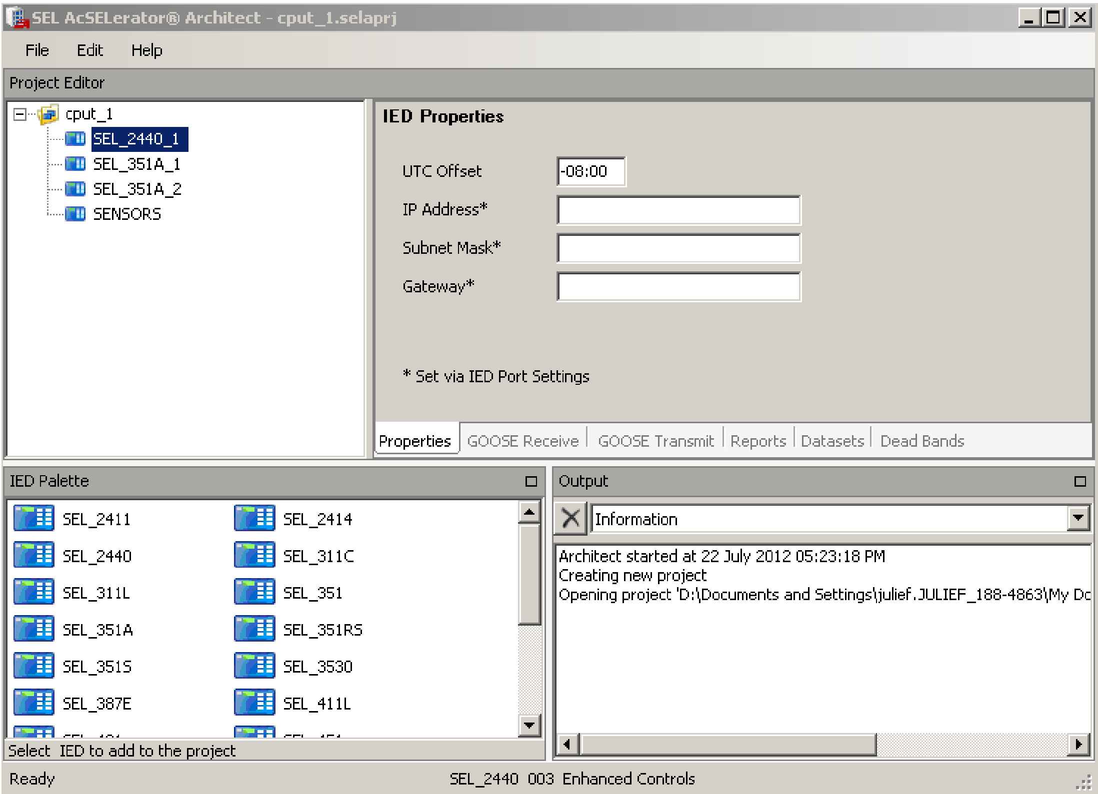


Figure 4.11: SEL AcSELerator Architect

4.6.3 Wireshark

Ethernet recording software, Wireshark is a tool available to assist with troubleshooting of GOOSE messaging. Wireshark will capture and store the GOOSE message since the message travels over the Ethernet.

4.7 Monitoring and Control Structure (circuit diagram and functions)

The monitoring and control of the functions related to the line switches are hardwired to the distribution automation controller. SET/RESET auxiliary relays allow the user to manually operate the line switches via push buttons and return the simulated network to its normal state after automatic reconfiguration has taken place. The simulated system is not designed to automatically return to its normal state. Figure 4.12 shows the hardwiring between the auxiliary relays and the DAS controller. The user has to switch the line switches as well as the circuit breakers to its normal state after automatic switching has taken place and the isolated line section has been repaired.

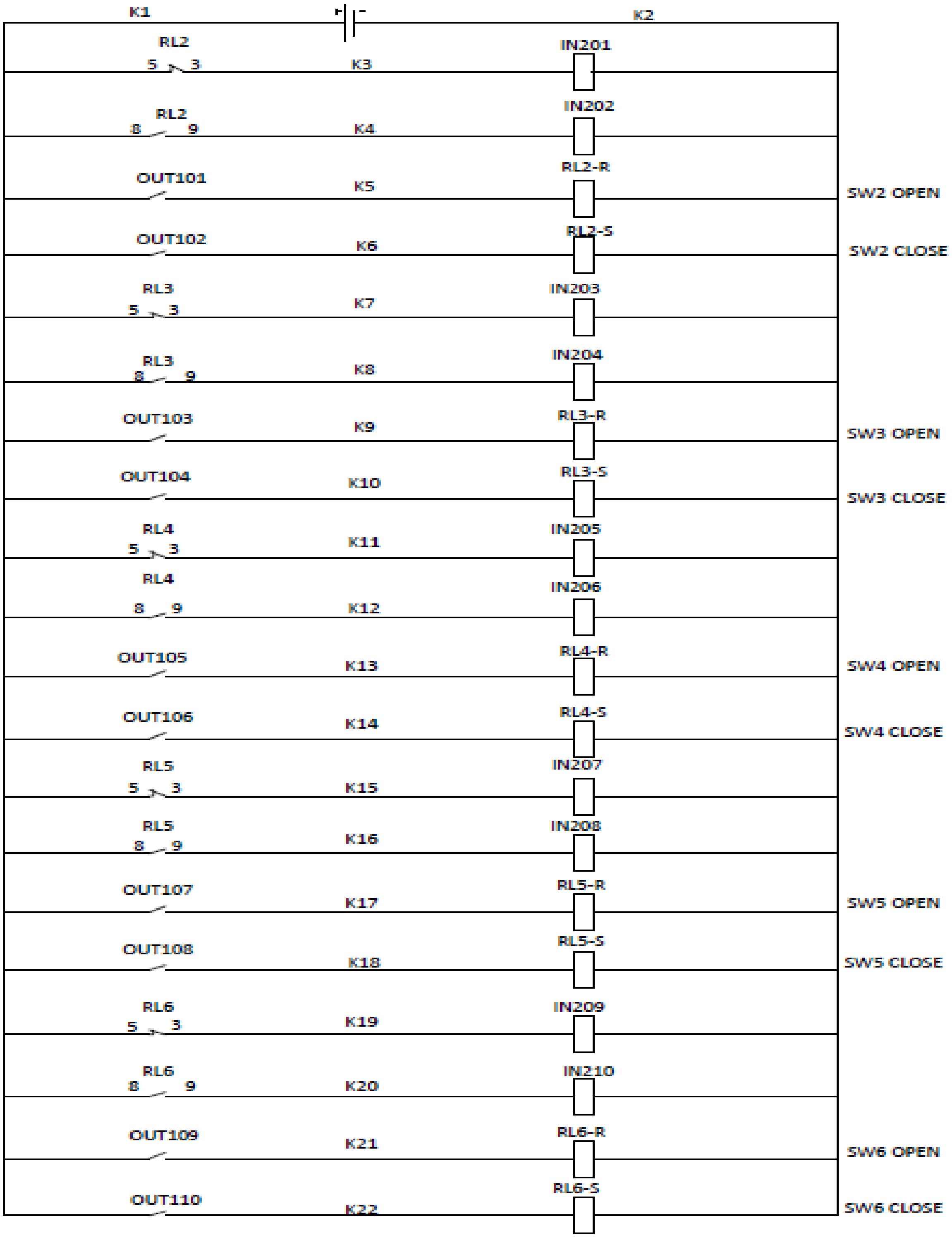


Figure 4.12: Hardwiring between auxiliary relays and SEL2440

The status functions within the SEL351A IEDs were used to simulate the substation breaker at both substations A and B respectively, as follows:

4.7.1 Breaker Trip

Figure 4.13.a shows an application of the “TRIP” pushbutton whereby pressing the “TRIP” control button will issue a trip to the substation breaker. The BREAKER OPEN LED illuminates continuously confirming the relay completed the trip sequence.

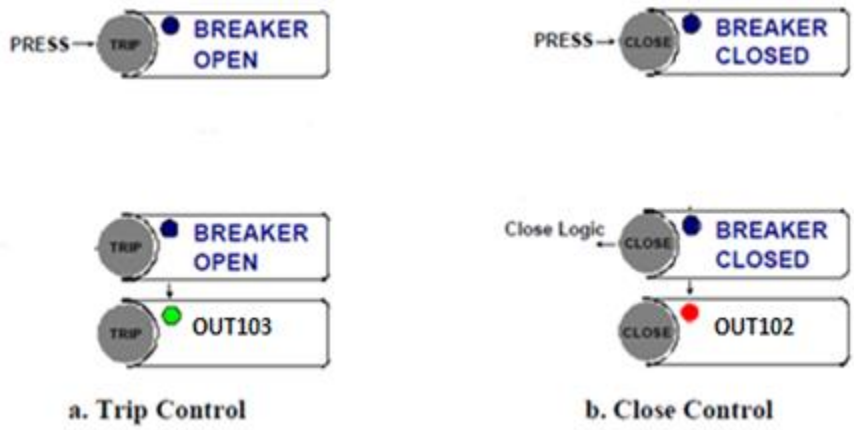


Figure 4.13: Operational Sequence for Operator-initiated Breaker Trip and Close Commands

4.7.2 Breaker Close

Figure 4.13b: shows an application of the “CLOSE” control button whereby pressing the “CLOSE” PUSHBUTTON” will close the substation breaker. The “BREAKER CLOSED” LED illuminates continuously confirming the breaker is in the close position. Figure 4.14: illustrates the wiring diagram of the breaker open and close functions.

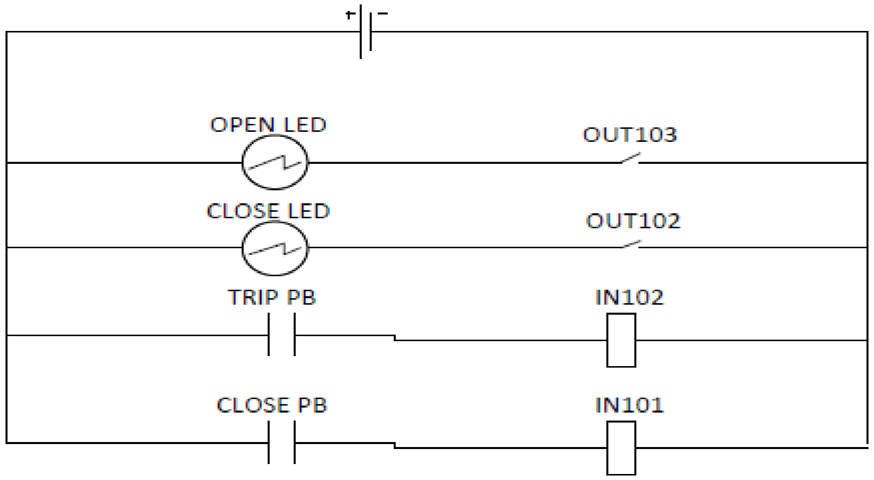


Figure 4.14: User-defined wiring for breaker control

4.8. IEC 61850 standard-based implementation

4.8.1 DA Algorithm

The objective of the scheme is to reduce outage time experienced by customers on un-faulted line sections on a network as a result of a permanent fault. To achieve this, the scheme has to recognize the occurrence of a permanent fault, isolate the faulty line segment and restore power to the un-faulted line segments through automatic switching. The scheme relies on quick and effective peer-to-peer-communications between IEDs. The scheme is designed for IEDs to communicate through Ethernet between each other and hard-wiring between set-reset relays and SEL 2440. The set-reset relays are used to represent line links as explained earlier. The logic was designed for the scheme to automatically reconfigure following a permanent fault on the network. Thereafter the network can be normalized by manually operating the push buttons mounted on the demo system.

4.8.2 Scheme initiation

The scheme is initiated when a fault occurs anywhere between BRKR1 and SW4 or BRKR2 and SW4. Once initiated the scheme opens the relevant switches or breakers to isolate the faulty line section. The scheme is designed to have to "know" the substation breaker status at all times. If not, the scheme will only assert outputs for fault isolation, but not for automatic restoration. The substation breakers, BRKR 1 and 2, status information is published via GOOSE messaging.

To illustrate the operation of the Demo scheme a detailed explanation of the faults that can happen in each line section on the network follows:

4.8.3 Permanent fault in line section1 - between Substation A and SW 2 – Fault1

The breaker at substation A is the primary protecting device as the line switch at location SW2 cannot break fault current. When a permanent fault occurs between the substation and SW2 as shown in Figure 4.15 a GOOSE message, OC_EF_TRIP.PRO.G51PTOC.Op, is transmitted to trip the breaker at substation A causing the line sections 1 and 2 to be de-energized. Protection elements P50 (VB002) or G51 (VB009) is used to identify the fault. Together with the fault the scheme requires the breaker status (VB004) as well as the fault location before it can continue with the automation process. The logic is shown in Figure 4.16. The fault location is simulated by the OMICRON binary outputs that act as fault path indicators. For this fault, the binary output 1 will be triggered as it simulates that fault current have passed FPI1. When these conditions are met the SEL 2440 IED which is programmed to subscribe to these conditions will assert OUT101, which will open SW2. Thereafter SEL 2440 IED will assert OUT106 which will close SW4 (NOP).

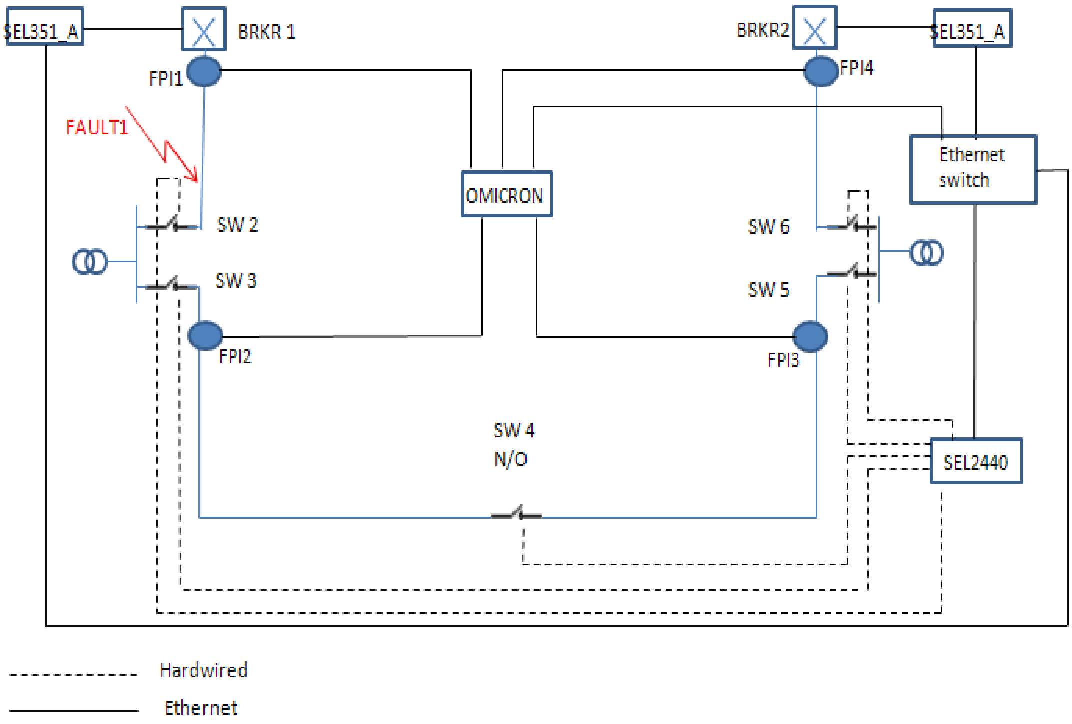


Figure 4.15: Single line diagram illustrating fault between S/S A and SW2

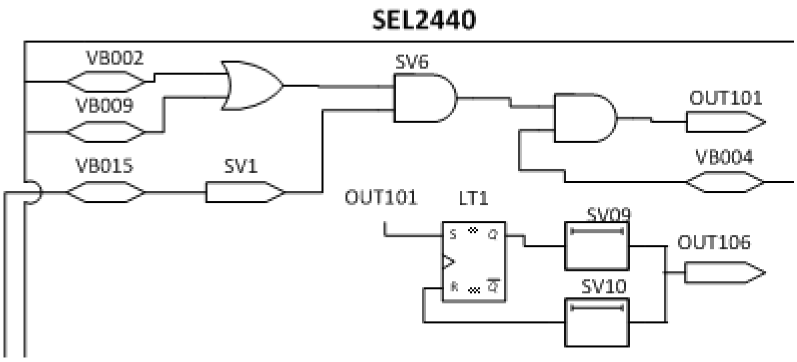


Figure 4.16: Logic diagram of the fault between S/S A and SW 2

4.8.4 Fault on line section2 - between SW3 and SW4 – Fault2

Figure 4.17 illustrates a fault on line section 2. Protection elements P50 or G51 or N51 are used for fault identification. OMICRON binary output 1 and binary output 2 are used for fault location. These binary outputs act as fault path indicators (FPIs), meaning that if binary output 1 and 2 are asserted, fault current has passed FPIs1 and 2. Therefore, with binary outputs 1 and 2 both asserted it shows that the fault location is identified to be in line section 2 (between SW3 and SW4). When a fault occurs between line section SW3 and SW4 the GOOSE message CFG.LLN0.DSET14 is transmitted to trip the breaker at substation A. This causes the entire feeder which is from S/S A up to SW4 to be de-energized. When these conditions are met as shown by the logics in Figure 4.18 the SEL 2240 IED will cause OUT103 to assert, which is to open SW3. Thereafter a GOOSE message CFG.LLN0.BRKR1_CLOSE ANN.SVTGGIO2.Ind04 is sent to close the breaker at substation A.

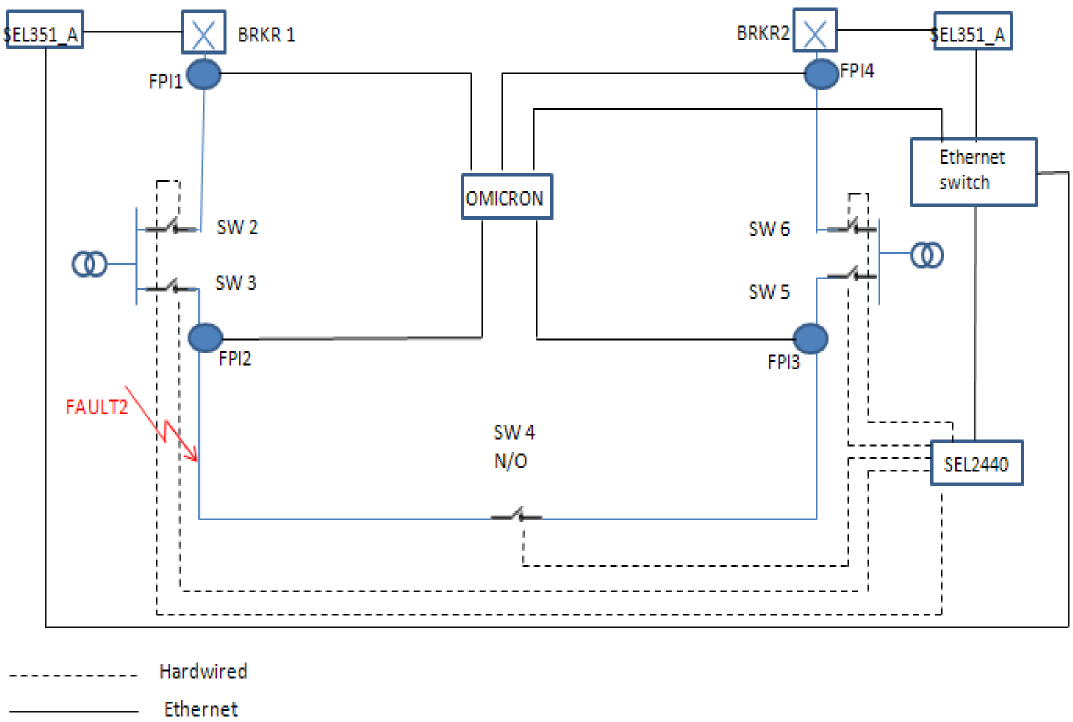


Figure 4.17: Single line diagram illustrating fault between SW3 and SW4

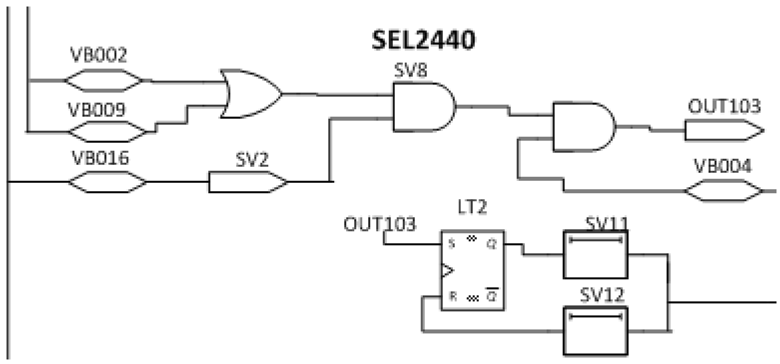


Figure 4.18: Logic diagram of the fault between SW3 and SW4

4.8.5 Fault on line section 3 - between SW4 and SW5 – Fault 3

Figure 4.19 illustrates a single line diagram for a fault on line section 3. The breaker at substation B is the primary protecting device. When a permanent fault occurs between line switches SW4 and SW5 a GOOSE message CFG.LLN0.DSET14 will be transmitted to trip the breaker at S/S B causing line section 3 and 4 which is from S/S B up to SW 4 to be de-energized. Protection element P50 (VB007) or (VB005) G51 or N51 (VB006) is used to identify the fault. As seen by the Logics diagram in Figure 4.20 SV013 is asserted by protection operation and SV3. The fault location is simulated by OMICRON binary outputs 3 and 4. When SV13 and the breaker close status (VB008) are asserted OUT107 will be asserted. This will open SW5 and thereafter the GOOSE message CFG.LLN0.BRKR2_CLOSE.ANN.SVTGGIO2. Ind04 will be transmitted, which will close the breaker at S/S B. However, if any, of the binary outputs 1 or 2 or both are also asserted the breaker at S/S B will trip but the automation stopped. Therefore the logics provides provision for multiple faults on the distribution system.

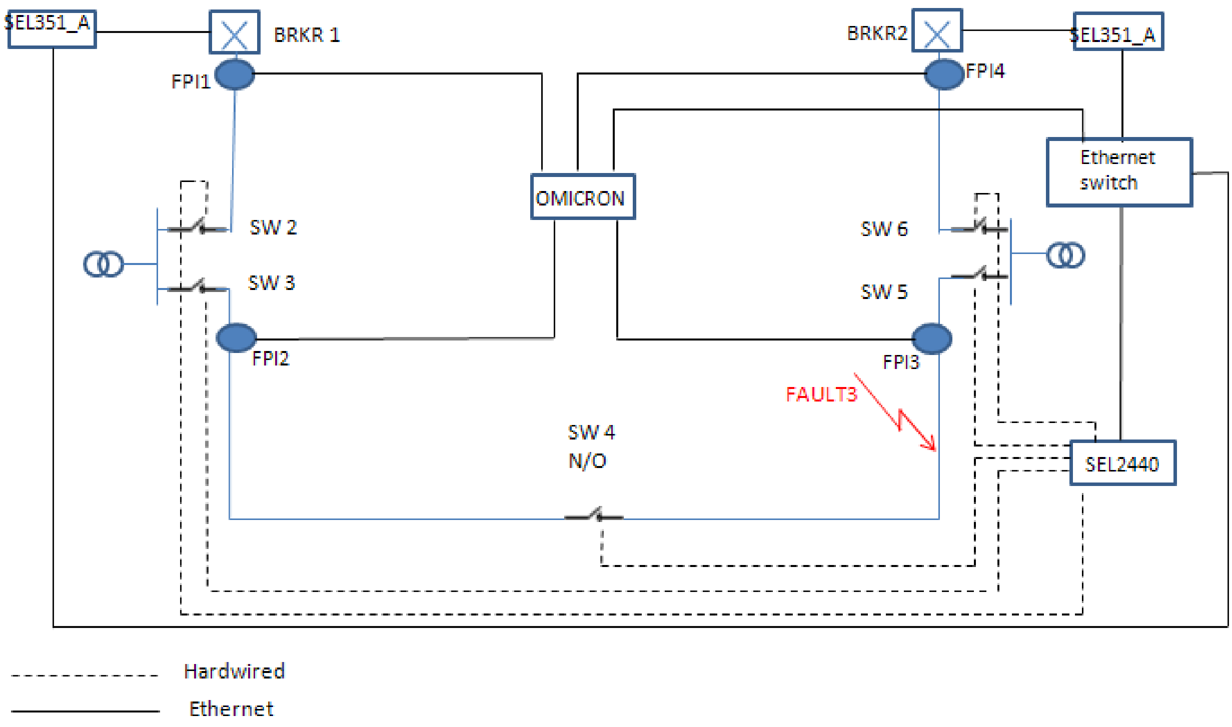


Figure 4.19: Single line diagram illustrating fault between SW 4 and SW 5

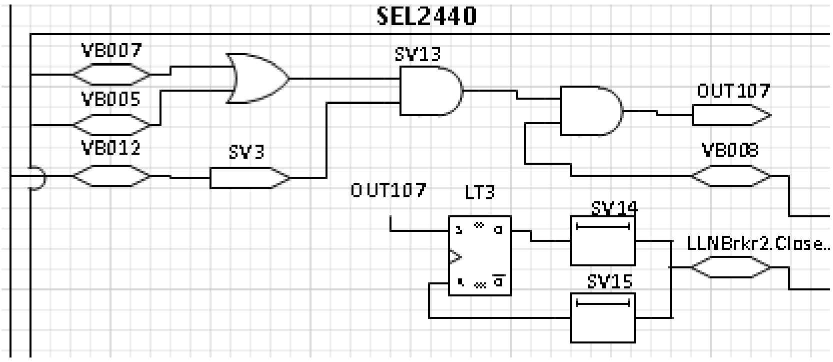


Figure 4.20: Fault Detection and Automatic Restoration Logic for Fault3

4.8.6 Fault on line section 4 - between S/S B and SW6 – Fault 4

Figure 4.21 illustrates the single line diagram for a fault on the line section 4. When a fault occurs between substation B and SW 6 the breaker at substation B will trip via GOOSE SEL351A_2.TRIP.PRO.G15PTOC.Op causing line sections 4 and 3 to be de-energized. Binary output 4 will be asserted for a fault in this section. When these conditions are true SW 6 will open and SW 4 will close via SEL 2440. This will isolate the faulty section and restore supply to the un-faulted section via Substation A.

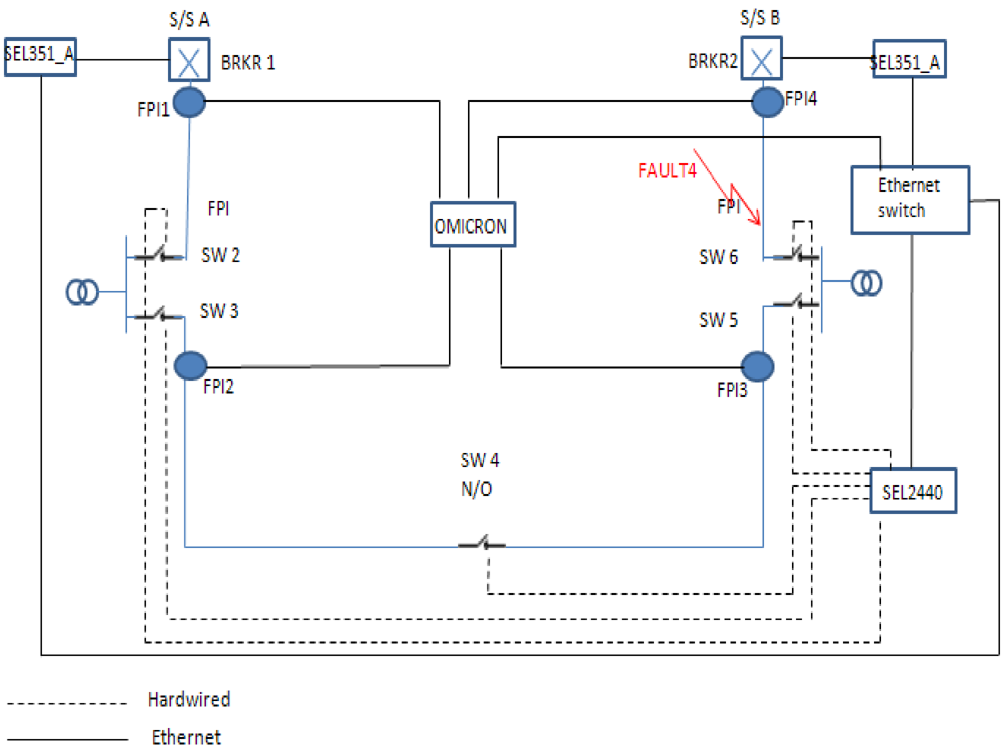


Figure 4.21: Single line diagram for a fault between S/S B and SW 6

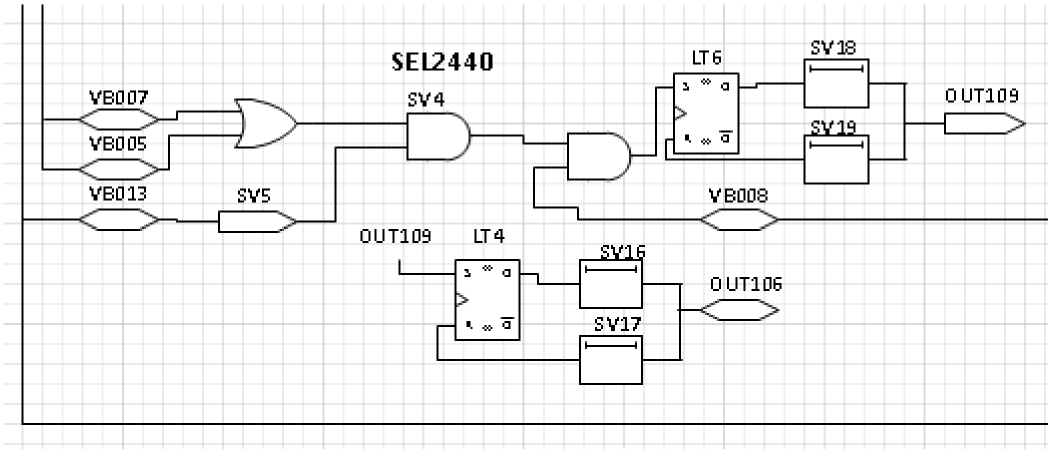


Figure 4.22: Fault Detection and Automatic Restoration Logic for Fault4

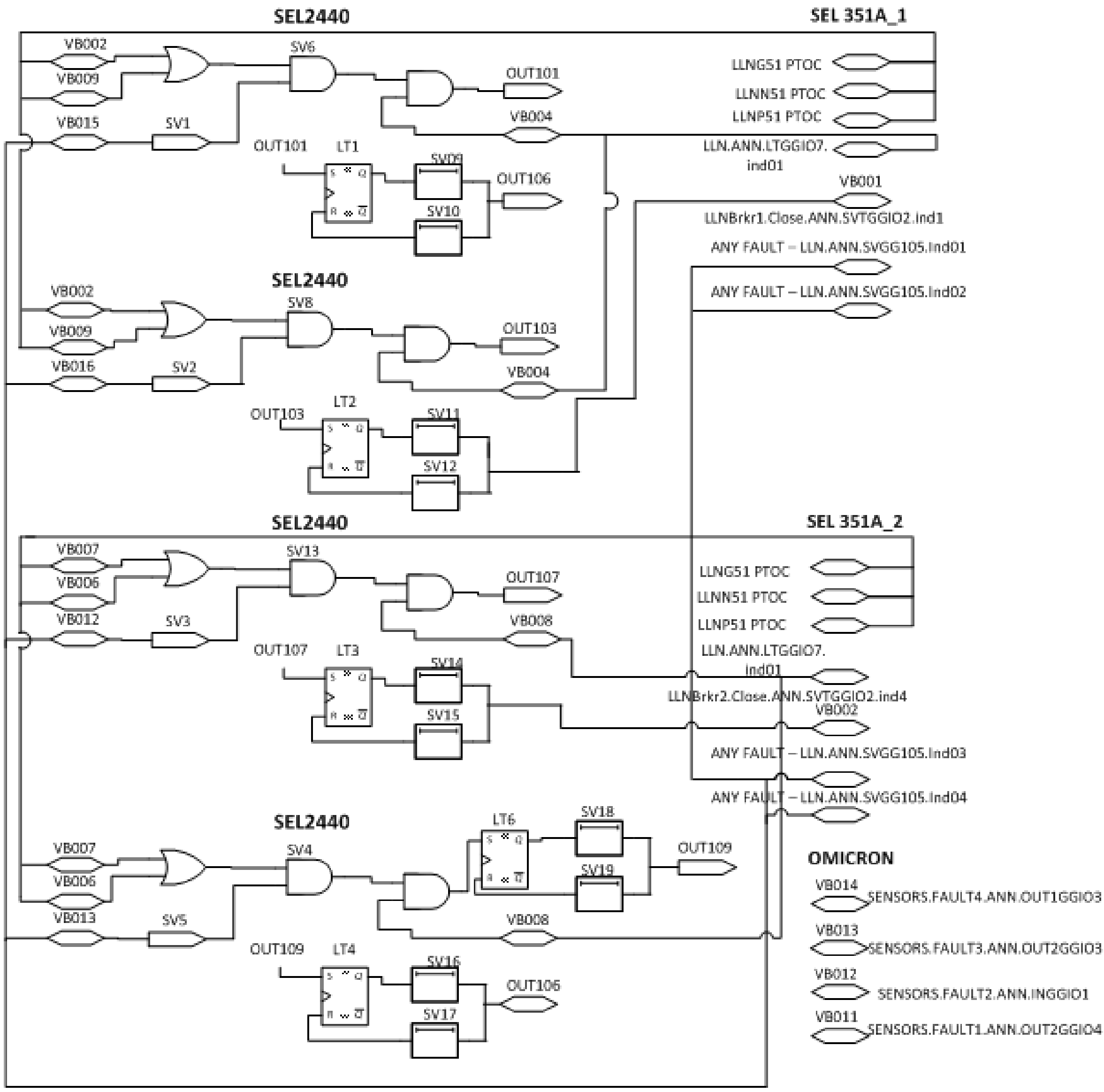


Figure 4.23: Logic diagram of the whole DAS system

4.9 Programming of the Intelligent Electronic Devices

4.9.1 Configuration of the IED Message Contents

Using SEL AcSELerator Architect configuration software all the IEDs are configured but only the GOOSE message contents required are selected from an elaborate internal IED database. The message information is mapped to a dataset that is associated with a GOOSE message. All the required data can be put in a single dataset. For consistency the datasets can be renamed to suit the customer requirements. Figure 4.24 illustrates a digital dataset. Data are published when the contents of a dataset have changed in the form of a GOOSE message. The GOOSE message is then published more frequently and then goes less frequent until it is the same as the configured rate. Whenever there is a change in the data contents the process repeats itself.

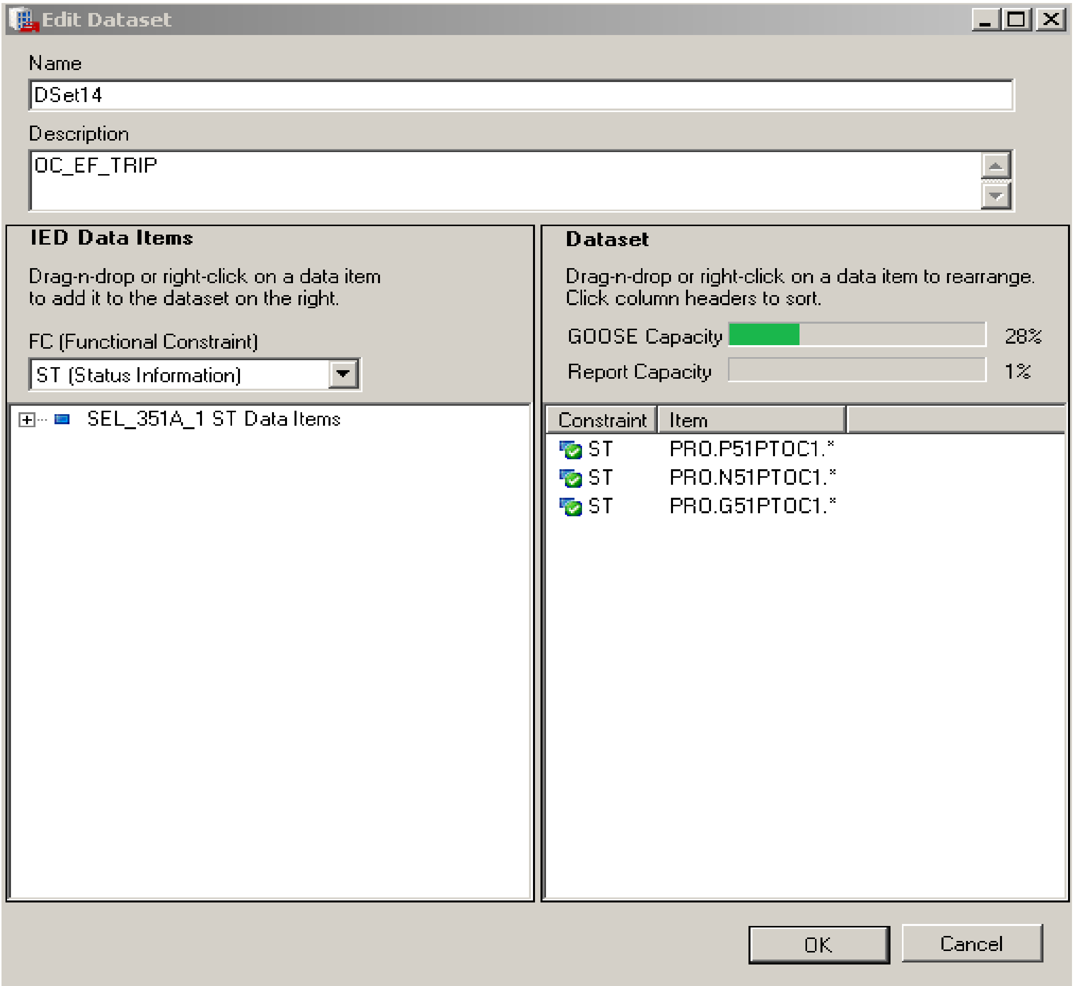


Figure 4.24: Configured dataset for the SEL 351A IED

4.9.2 Configuration of the IED GOOSE Message Publication

When there is no change in the contents of the dataset, the GOOSE message is published at a fixed rate which acts as a heartbeat. The subscriber does not acknowledge the receipt of the GOOSE message from the publisher confirming successful transmission. This is not ideal for applications such as protection and automation since they are time critical. However, the time-to-live (TTL) value improves the method. A new published message includes a TTL value for the subscriber which tells the subscriber the maximum time when a new GOOSE will be published. A new message will be published when there is a change in the content of the dataset or when the maximum delay timer has expired.

All the IEDs used in the project publish messages and some IEDs subscribe to certain messages. Figure 4.25 shows the messages published by SEL 2440 IED.

SEL 2440 messages:

- Message Name 1: BRKR1_CLOSE publish the message to all the devices in the project that would like to subscribe to it.

  Function performed: SEL 2440 sends BRKR1_CLOSE GOOSE message to close BRKR 1 at substation A.

- Message Name 2: BRKR2_CLOSE. It identifies the message and publishes to all the devices in the project that would like to subscribe to it.

  Function performed: SEL 2440 sends BRKR2_CLOSE GOOSE message to close BRKR 2 at substation B.

Figure 4.24 shows how the SEL2440 GOOSE messages are configured.

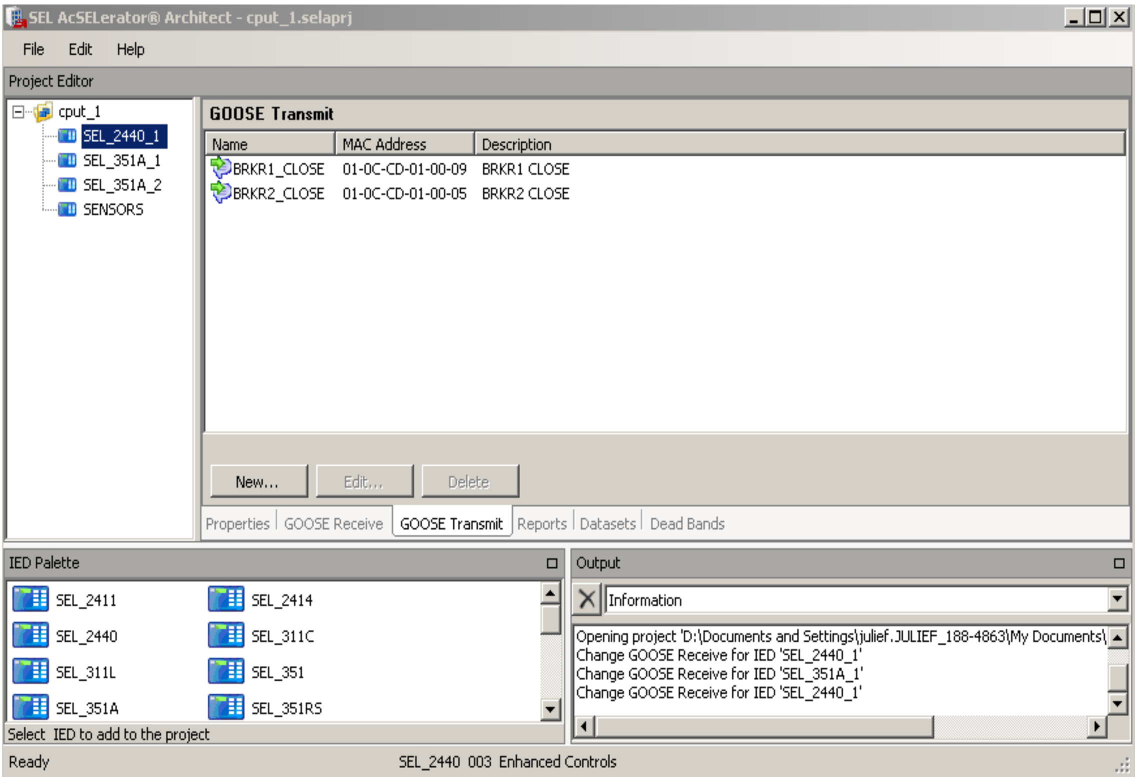


Figure 4.25: SEL 2440 GOOSE message configuration

4.9.2.1 SEL 351A_1 messages

- First message Name: CFG.LLN0.ANY_PICKUP. It identifies the message and publishes content to all the devices in the project that would like to subscribe to it.

  Function performed: IED collects binary output information from the Omicron test set, and based on the information it receives it establishes the location of the fault.
- Second Message Name: CFG.LLN0.DSET14.

  Function performed: IED publishes that a protection operation occurred.
- Third Message Name: CFG.LLN0.DSET17.

  Function performed: IED publishes, whether the breaker at substation A is in the open or close position (breaker status).

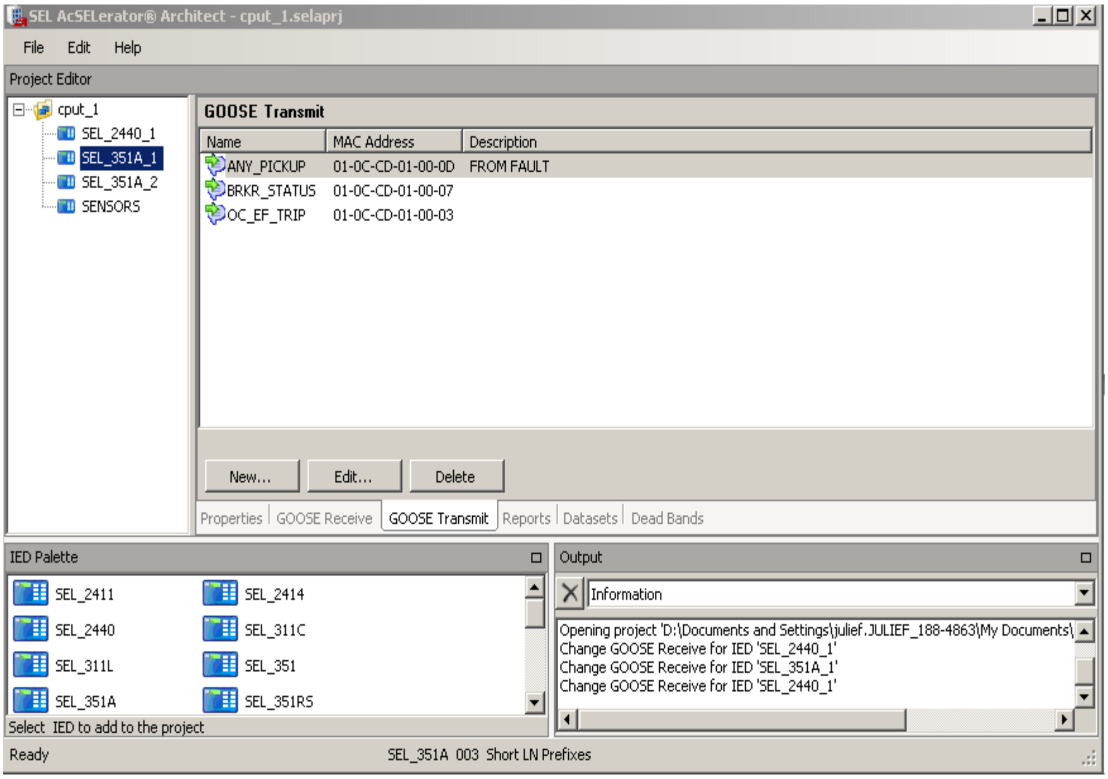


Figure 4.26: Parameters of SEL 351A_1

4.9.2.2 SEL 351A_2 messages

The IED is configured exactly in the same way as the SEL 351A_1 device, Figure 4.27

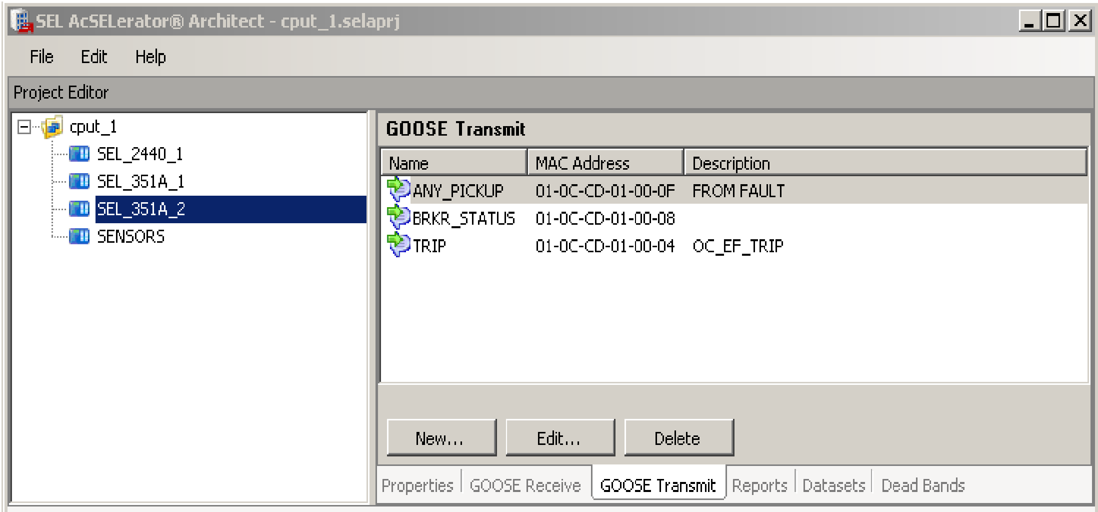


Figure 4.27: SEL 351A_2 GOOSE messages configuration

4.9.2.3 OMICRON GOOSE messages

- Message Name is: CFG.LLN0.FAULT1

  Function performed: It is used to simulate a fault indication for a fault on the line section 1.
- Similarly, CFG_LLN0_FAULT 2, 3 & 4 are used to indicate faults on the remaining line sections.

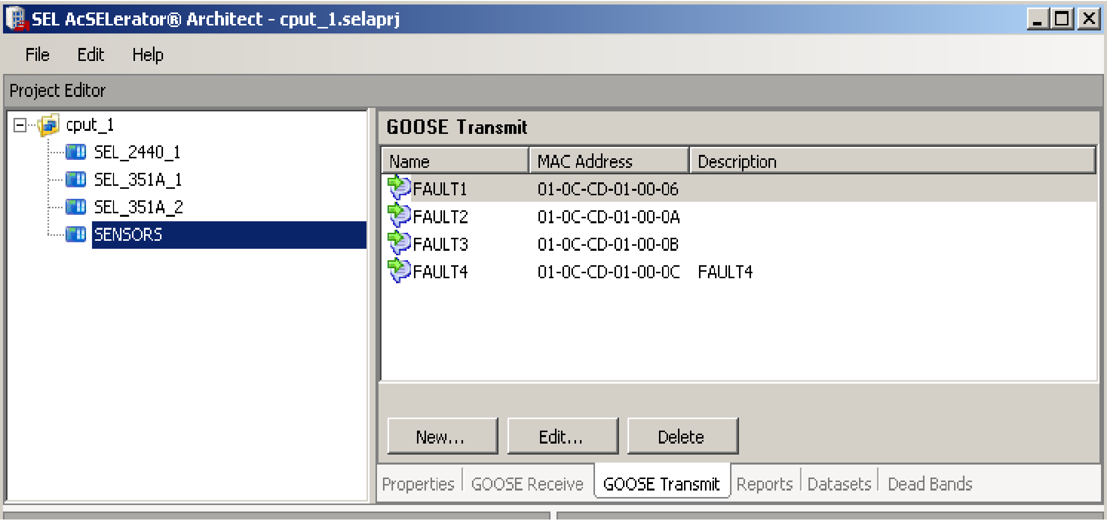


Figure 4.28: SENSORS IED GOOSE messages for fault indications

4.9.3 Configuration of the IED GOOSE Message Subscription

4.9.3.1 SEL2440 subscription

Some IEDs are configured to subscribe to specific GOOSE messages published by other IEDs. Here in this project the SEL 2440 subscribes to messages published by SEL 351A_1, SEL351A_2 and SENSORS IEDs. The GOOSE Receive pane of the configuration software shows a list of GOOSE messages available for subscription as illustrated in Figure 4.29. Every incoming GOOSE message is mapped to a virtual bit.

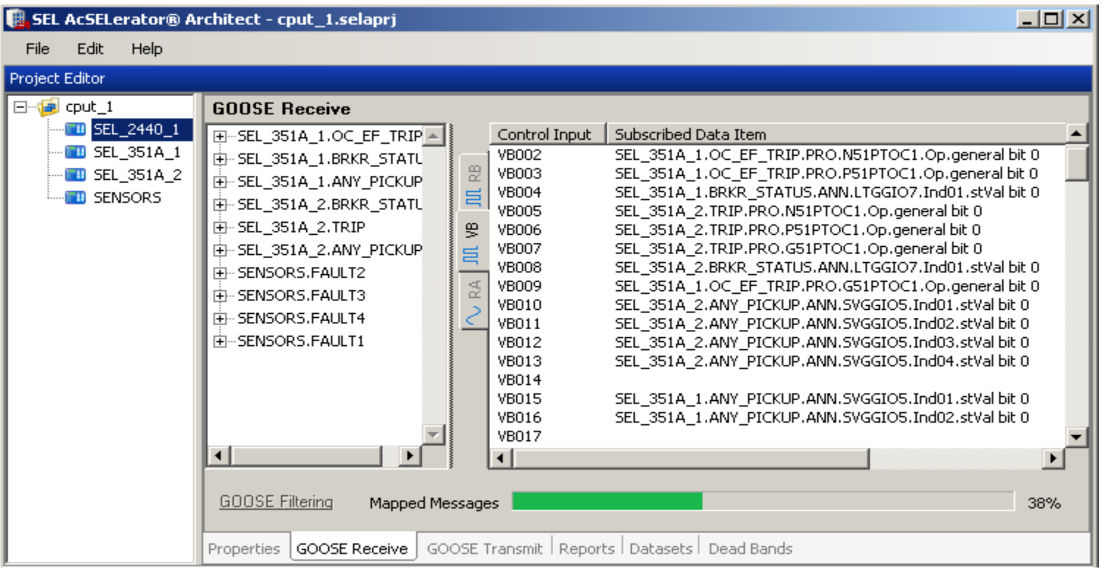


Figure 4.29: Dataset mapping for the SEL 2440

Figure 4.30 illustrates an expanded view of the contents of a GOOSE message received from IED 351A_1. It shows that a protection operation from IED 351A_1 will transmit a GOOSE message, IED SEL 2440 subscribes to it and it is mapped to a Virtual Bit 003.

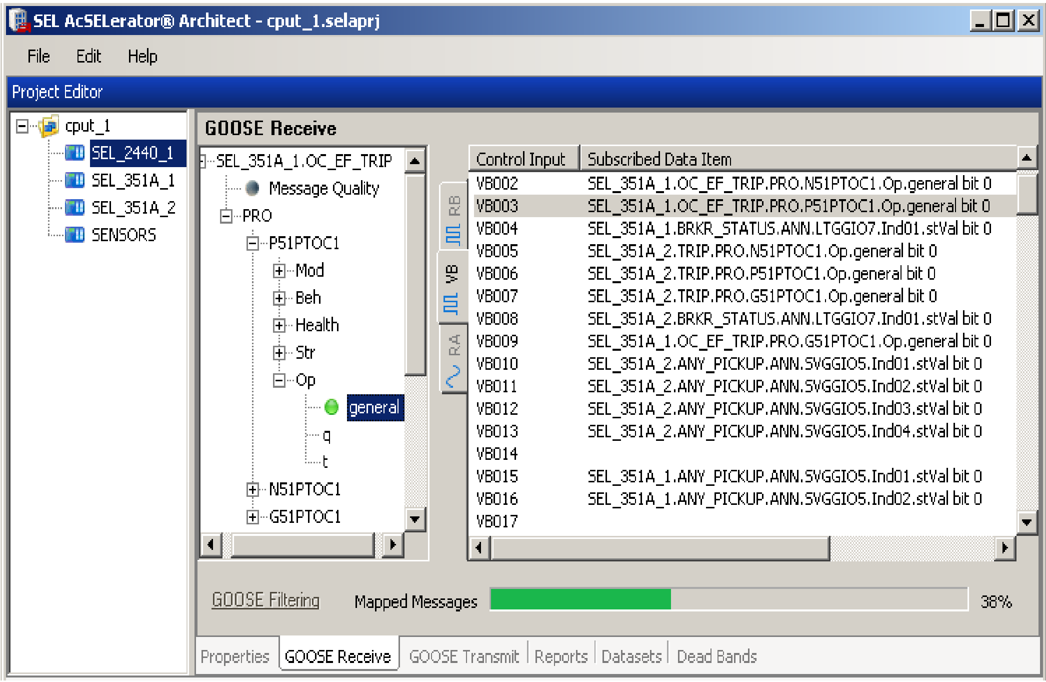


Figure 4.30: Expanded view of the contents of a message.

4.9.3.2 SEL 351A_1 subscription

Every IED in the project is configured to subscribe to GOOSE messages published by other IEDs related to the project. The subscription settings viewed in the right hand side of the configuration software that is linked to a GOOSE message is automatically created by the configuration software. Every incoming GOOSE message can be mapped to various logic bits such as, remote bits (RB), virtual bits (VB) and remote analog (RA). In this project all incoming GOOSE messages are mapped to virtual bits. Figure 4.31 shows the GOOSE messages received by the SEL 351A_1

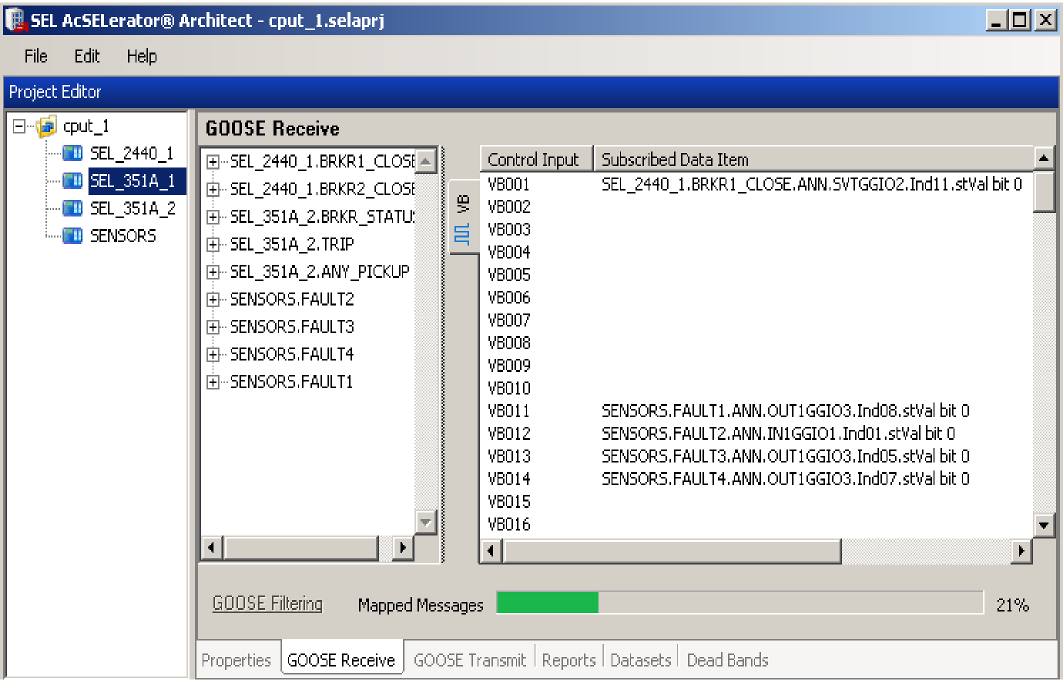


Figure 4.31: Dataset mapping for SEL 351A_1

4.9.3.3 SEL 351A_2 subscription:

IED is configured in the same way as SEL 351A_1. Figure 4.32 shows the GOOSE messages received by the SEL351A_2

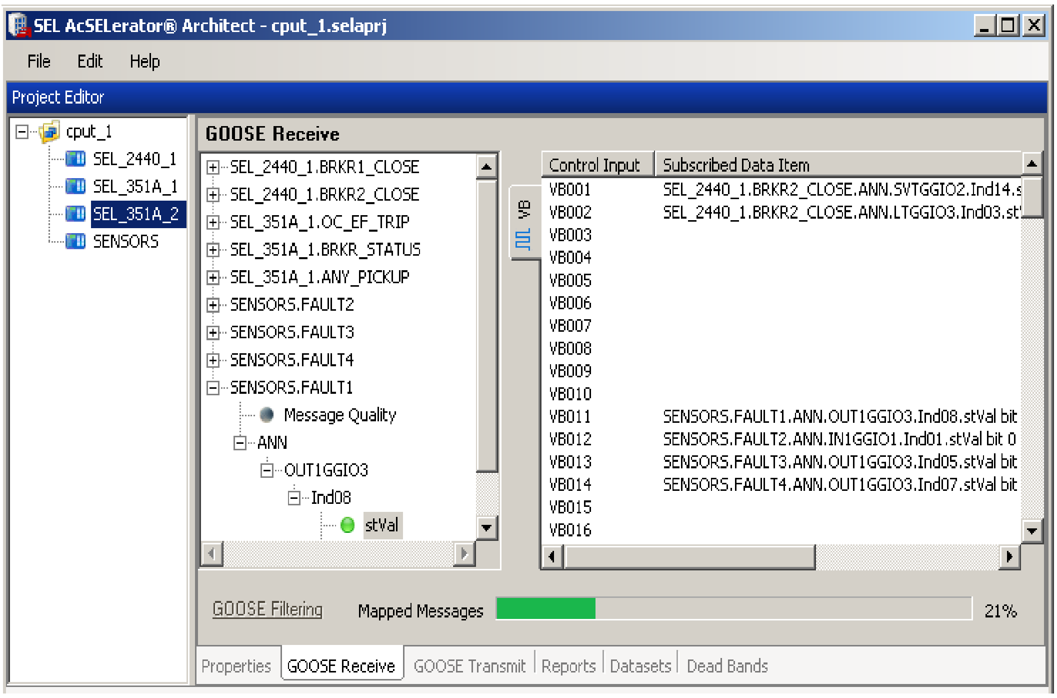


Figure 4.32: Dataset mapping for the SEL 351A_2 received GOOSE messages

Table 4.4 shows all the GOOSE messages published and received by all the devices installed in the project. Table 4.5 shows all the published and received GOOSE messages together with their virtual addresses.

TABLE 4.4: All published GOOSE messages

DEVICE	**GOOSE MESSAGE**	**FUNCTION**	**DEVICE SUBSCRIBE**
SEL 2440	CFG.LNN0.BRKR1_CLOSE	Close breaker at s/s A	SEL 351A_1 at s/s A
SEL 2440	CFG.LLN0.BRKR2_CLOSE	Close breaker at s/s B	SEL 351A_2 at s/s B
SEL 351A_1	CFG.LLN0.DSET17	Breaker status	SEL 2440
SEL 351A_1	CFG.LLN0.DSET14	Protection function	SEL2440
SEL 351A_2	CFG.LLN0.DSET17	Breaker status	SEL 2440
SEL351A_2	CFG.LLN0.DSET14	Protection function	SEL 2440
OMICRON SENSOR1	CFG.LLN0.FAULT1	Simulates FPI1	SEL 2440
OMICRON SENSOR2	CFG.LLN0.FAULT2	Simulates FPI2	SEL 2440
OMICRON SENSOR3	CFG.LLN0.FAULT3	Simulates FPI3	SEL 2440
OMICRON SENSOR4	CFG.LLN0.FAULT4	Simulates FPI4	SEL 2440

TABLE 4.5: All Goose messages received and mapped virtual bits

DEVICE	GOOSE RECEIVE	DEVICE PUBLISH	MAPPED TO
SEL2440	OC_EF_TRIP.PRO.N51PTOC1.Op.general bit 0	SEL351A_1	VB002
SEL2440	OC_EF_TRIP.PRO.P51PTOC1.Op.general bit 0	SEL351A_1	VB003
SEL2440	BRKR_STATUS.ANN.LTGGIO7.Ind01.stval bit 0	SEL351A_1	VB004
SEL2440	TRIP.PRO.N51PTOC1.Op.general bit 0	SEL351A_2	VB005
SEL2440	TRIP.PRO.P51PTOC1.Op.general bit 0	SEL351A_2	VB006
SEL2440	TRIP.PRO.G51PTOC1.Op.general bit 0	SEL351A_2	VB007
SEL2440	BRKR_STATUS.ANN.LTGGIO7.Ind01.stval bit 0	SEL351A_2	VB008
SEL2440	OC_EF_TRIP.PRO.G51PTOC1.Op.general bit 0	SEL351A_1	VB009
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind01.stVal bit 0	SEL351A_2	VB010
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind02.stVal bit 0	SEL351A_2	VB011
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind03.stVal bit 0	SEL351A_2	VB012
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind03.stVal bit 0	SEL351A_2	VB013
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind01.stVal bit 0	SEL351A_1	VB015
SEL2440	ANY_PICKUP.ANN.SVGGIO5.Ind02.stVal bit 0	SEL351A_1	VB016
SEL351A_1	BRKR1_CLOSE.ANN.SVTGGIO2.Ind1.stVal bit 0	SEL2440	VB001
SEL351A_1	FAULT1.ANN.OUT1GGIO3.Ind08.stVal bit 0	OMICRON	VB011
SEL351A_1	FAULT2.ANN.IN1GGIO1.Ind01.stVal bit 0	OMICRON	VB012
SEL351A_1	FAULT3.ANN.OUT1GGIO3.Ind05.stVal bit 0	OMICRON	VB013
SEL351A_1	FAULT4.ANN.OUT1GGIO3.Ind07.stVal bit 0	OMICRON	VB014

4.10 GOOSE Messages Diagnostic

To verify the correct publication of the GOOSE messages several characteristics have to be monitored. The quality of data within the message and the quality of the message need to be verified by the IED subscribing to the message. Table 4.6 illustrates the different error codes, if any of the codes are activated the message quality will fail.

Table 4.6: GOOSE message error codes

Message Statistics	Error Code
Configuration revision mismatch between publisher and subscriber	CONF REV MISMA
Publisher indicates that it needs commissioning	NEED COMMISSIO

The publisher is in the test center	TEST MODE
Received message is decoded and reveals error	MSG CORRUPTED
Message received out of sequence	OUT OF SEQUENC
Message time to live expired	TTL EXPIRED

By connecting to the SEL IEDs through the engineering access port, the configuration and status of published and subscribed GOOSE messages can be retrieved. Figure 4.33 illustrates the configuration and performance of a GOOSE message. Every GOOSE message has the following configuration information: message label, multicast address, virtual LAN identifier, dataset name, and priority tag. Every message shows the sequence and status number, the time to live and an error code.

```
=>>GOO

GOOSE Transmit Status

 MultiCastAddr   Ptag:Vlan AppID  StNum      SqNum      TTL    Code
-----------------------------------------------------------------------------
SEL_351A_1CFG/LLN0$GO$OC_EF_TRIP
 01-0C-CD-01-00-03 4:1     3      1          1845       158
 Data Set: SEL_351A_1CFG/LLN0$DSet14

SEL_351A_1CFG/LLN0$GO$BRKR_STATUS
 01-0C-CD-01-00-07 4:1     7      1          1845       158
 Data Set: SEL_351A_1CFG/LLN0$DSet17

SEL_351A_1CFG/LLN0$GO$ANY_PICKUP
 01-0C-CD-01-00-0D 4:1     13     1          1845       129
 Data Set: SEL_351A_1CFG/LLN0$ANY_PICKUP

GOOSE Receive Status

 MultiCastAddr   Ptag:Vlan AppID  StNum      SqNum      TTL    Code
-----------------------------------------------------------------------------
SEL_2440_1CFG/LLN0$GO$BRKR1_CLOSE
 01-0C-CD-01-00-09 4:1     9      3          1850       2000
 Data Set: SEL_2440_1CFG/LLN0$BRKR1_CLOSE

SENSORSCFG/LLN0$GO$FAULT2
 01-0C-CD-01-00-0A 4:1     10     0          0          0      TTL EXPIRED
 Data Set: SENSORSCFG/LLN0$FAULT2

SENSORSCFG/LLN0$GO$FAULT3
 01-0C-CD-01-00-0B 4:1     11     0          0          0      TTL EXPIRED
 Data Set: SENSORSCFG/LLN0$FAULT3

SENSORSCFG/LLN0$GO$FAULT1
 01-0C-CD-01-00-06 4:1     6      0          0          0      TTL EXPIRED
 Data Set: SENSORSCFG/LLN0$FAULT1

SENSORSCFG/LLN0$GO$FAULT4
 01-0C-CD-01-00-0C 4:1     12     0          0          0      TTL EXPIRED
 Data Set: SENSORSCFG/LLN0$FAULT4
```

Figure 4.33: GOOSE diagnostic message

GOOSE message transmit and receive status as well as the configuration information are included in the GOOSE report. Details of the message information are also included in the report. The GOOSE report in Figure 4.33 also shows that the communication to SEL351A_1 and SEL 2440 is successful but communication to SENSORS IED is unsuccessful. As a result the TTL error code has come up since the TTL value has run down to zero and therefore expired.

4.10.1 Wireshark

Another tool available to assist with troubleshooting of GOOSE messaging is Ethernet recording software, Wireshark. Wireshark will capture and store the GOOSE message since the message travels over the Ethernet. Figure 4.34 illustrates a display within wireshark software that shows an extended view of one of the GOOSE messages.

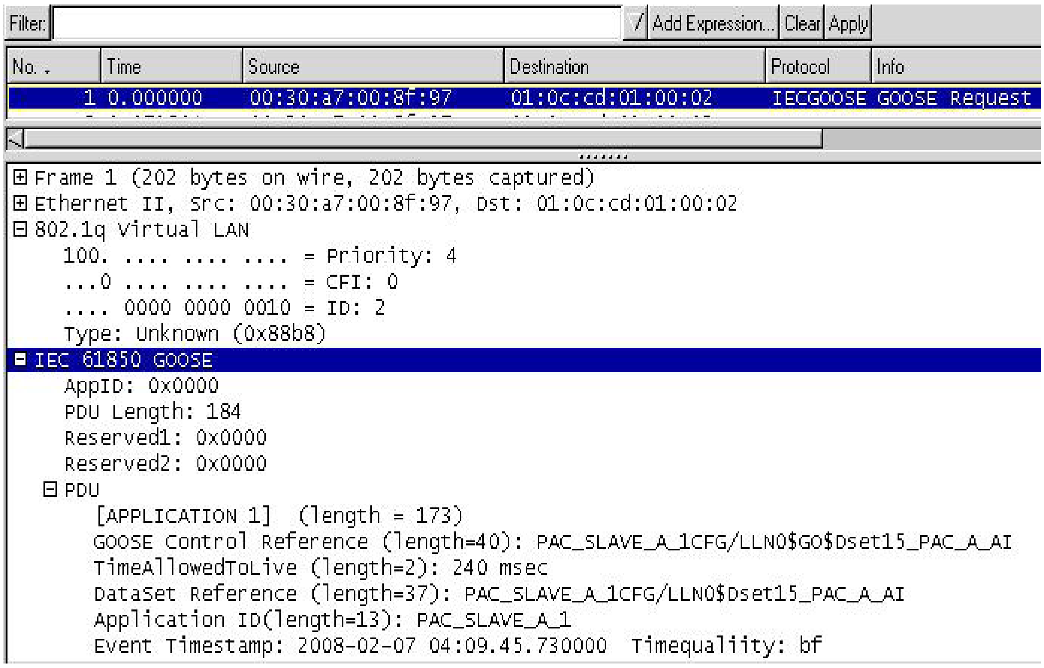


Figure 4.34: Wireshark information of a GOOSE message

4.11 Programming parameters of the protection functions and algorithm logic in IEDs

The protection devices with overcurrent and earth fault functions for the implementation of fault detection as well as an algorithm was developed in the distribution automation thesis. Programming of protection settings was done by using Acselerator Quickset software. The primary settings of the protection devices as well as the Distribution Automation controller are illustrated in Table 4.7 and Table 4.8 respectively. The settings for the protection IED at S/S A and B are the same. The only difference is the relay identifier and the feeder bay name. See Appendix C and D for the complete parameter settings of the SEL351A and SEL2440 devices.

Table 4.7: SEL351A_1 IED settings

SETTING	DESCRIPTION	VALUE
	GROUP 1 GENERAL SETTINGS	
RID	RELAY IDENTIFIER	FEEDER 1
TID	NAME OF FEEDER BAY	STATION A
CTR	CT RATIO	200
	EARTH FAULT PROT SETTINGS	
51NRS	ON	Y
51GP	PLUG SETTING	0.30
51GC	PROTECTION CURVE	C1
51GTD	TIME MULTIPLIER	0.20
	GROUP 1 LOGIC SETTINGS	
	GROUP1 LOGIC SETTINGS	
TR	PROTECTION TRIGGER CONDITIONS	OC+51PT+51GT+51NT
CL	BREAKER CLOSE TRIGGER CONDITIONS	CC+CLOSE+VB001
SET1	LATCH BIT SET	IN101+CC+CLOSE+VB001
RST1	LATCH BIT RESET	IN102+TRIP+OC
SV1	SEL VARIABLE CONTROL EQUATION 1	(!VB013*!VB014)*(!VB012*VB011)
SV2	SEL VARIABLE CONTROL EQUATION 1	(!VB013*!VB014)*(VB011*VB012)
OUT101		TRIP
OUT102		LT1
OUT103		!LT1
DP1	FRONT PANEL DISPLAY POINT 1	LT1
DP2	FRONT PANEL DISPLAY POINT 2	52A
	FRONT PORT COMMUNICATION SETTINGS	
EPORT	Select: Y, N	Y
PROTO	Select: SEL, LMD, MOD, DNP	SEL
MAXACC	Select: 1, B, 2	2
PREFIX	Select: @, #, $, %, &&	@
ADDR	Range = 1 to 99	1
SETTLE	Range = 0.00 to 30.00	0.00
SPEED	Select: 300, 1200, 2400, 4800, 9600, 19200, 38400, 57600	9600
BITS	Select: 6-8	8
PARITY	Select: O, E, N	N
STOP	Select: 1, 2	1
T_OUT	Range = 0 to 30	15
P5 ETHERNET COMMUNICATION PORT SETTINGS		
EPORT	Select: Y, N	Y

IPADDR	Range = ASCII string with a maximum length of 19.	192.168.1.5
SUBNETM	Range = ASCII string with a maximum length of 19.	255.255.255.0
DEFRTR	Range = ASCII string with a maximum length of 19.	192.168.1.1
ETCPKA	Select: Y, N	Y
KAIDLE	Range = 1 to 20	10
KAINTV	Range = 1 to 20	10
KACNT	Range = 1 to 20	5
NETMODE	Select: FIXED, FAILOVER, SWITCHED	FAILOVER
FTIME	Range = 0.10 to 65.00	1.00
NETPORT	Select: A, B	A
NET5ASPD	Select: Auto, 10, 100	Auto
NET5BSPD	Select: Auto, 10, 100	Auto
ETELNET	Select: Y, N	Y
MAXACC	Select: 1, B, 2	2
TPORT	Range = 1025 to 65534, 23	23
TIDLE	Range = 1 to 30	15
AUTO	Select: Y, N	N
FASTOP	Select: Y, N	N
EDNP	Select: 0-3	0
EMODBUS	Select: 0-3	0
EFTPSERV	Select: Y, N	Y
FTPUSER	Range = ASCII string with a maximum length of 20.	FTPUSER
FTPCBAN	Range = ASCII string with a maximum length of 64.	FTP SERVER
FTPIDLE	Range = 5 to 255	5
EHTTP	Select: Y, N	N
HTTPPORT	Range = 1 to 65535	80
HTTPIDLE	Range = 1 to 30	10
E61850	Select: Y, N	Y
EGSE	Select: Y, N	Y
ESNTP	Select: OFF, UNICAST, MANYCAST, BROADCAST	OFF
SNTPPSIP	Range = ASCII string with a maximum length of 19.	192.168.1.1
SNTPBSIP	Range = ASCII string with a maximum length of 19.	192.168.1.1
SNTPPORT	Range = 1 to 65534	123
SNTPRATE	Range = 15 to 3600	60
SNTPTO	Range = 5 to 20	5
	SEQUENCE OF	

	EVENTS RELAY ELEMENTS	
SER1	Valid range = 0, NA or a list of relay elements.	51P,51G,50P1,VB001,VB002,VB003,VB004,CF,CLOSE,TRIP,TRGTR,LT1,LT2
SER2	Valid range = 0, NA or a list of relay elements.	LB3,LB4,IN101,IN102,OUT101,OUT102,OUT103
DP1_1	Range = ASCII string with a maximum length of 16.	BRKR CLOSED
DP1_0	Range = ASCII string with a maximum length of 16.	BREAKER OPEN

Table 4.8: SEL2440 IED settings

SETTING	DESCRIPTION	VALUE
	Latch Bit	
SET01		OUT101
RST01		SV10T
SET02		OUT103
RST02		SV12T
SET03		OUT107
RST03		SV15T
SET04		OUT109
RST04		SV17T
SET05		VB014
RST05		VB015
SET06		VB008 AND VB04
RST06		SV19T
SET07		VB008 AND SV13
RST07		SV22T
SET08		SV08 AND VB004
RST08		SV24
	SEL Variable/Timers	
SV01		VB015
SV02		VB016
SV03		VB012
SV04		NOT SV05 AND (VB005 OR VB007)
SV05		VB013
SV06		(VB003 OR VB009 OR VB001) AND NOT SV01
SV07		IN213 OR IN212 OR VB007 OR VB008
SV08		(VB003 OR VB 009 OR VB001) AND SV02
SV09		LT01
SV10		SV09T
SV11		LT02
SV12		SV11T
SV13		(VB005 OR VB006 OR VB007) AND SV03
SV14		LT03
SV15		SV14T
SV16		LT04
SV17		SV16T

SV18		LT06
SV19		SB18
SV20		NA
SV21		LT07
SV22		SV21
SV23		LT08
SV24		SV23
	SELogic Control Equations	
OUT101		SV06 AND VB004
OUT102		0
OUT103		SV23T
OUT104		0
OUT105		0
OUT106		SV09T OR SV16
OUT107		SV21T
OUT108		0
OUT109		SV18T
OUT110		0
OUT111		SV08T AND IN203

4.11.1 OMICRON Binary output configuration

First a generic IED is added into the DA project (SEL AcSELerator Architect). This IED was renamed SENSORS (see section 4.4.3 SENSORS). It is used to transmit data information with regards to the location of the fault. Since the lab scale system does not have fault path indicators installed a way had to be created to indicate that fault current has passed the line switch locations. Therefore, one can say that it will act as a fault path indicator showing that a fault has passed it. Binary outputs have been mapped to the different SENSORS datasets and when asserted they publish GOOSE messages.

The second step is to export the ICD file from the SENSORS IED to the Omicron secondary injection test set.

The third step in configuring the binary outputs is to import the ICD-file within OMICRON software as shown in Figure 4.35.

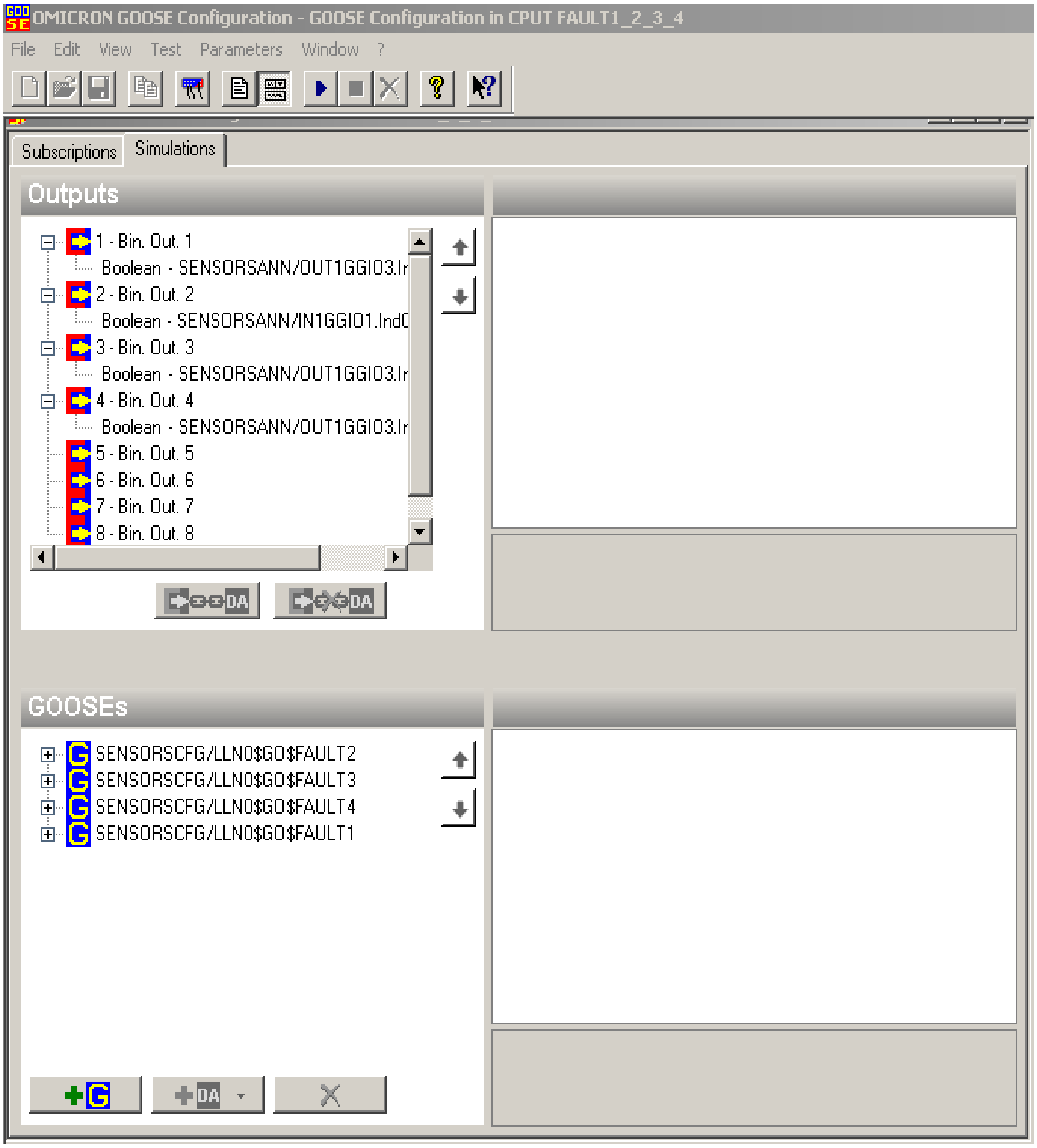


Figure 4.35: Configured binary outputs.

4.11.2 Configuration and function integration for the IEDs real-time operation

All the IEDs are configured to respond to a specific output or GOOSE message. For instance, a condition where SV06 AND VB004 are both asserted will activate OUT101 as illustrated in Figure 4.36: General information, group settings, SEL variables, logics and many other settings form part of the device settings that has to be programmed into the devices for it to react and perform as expected.

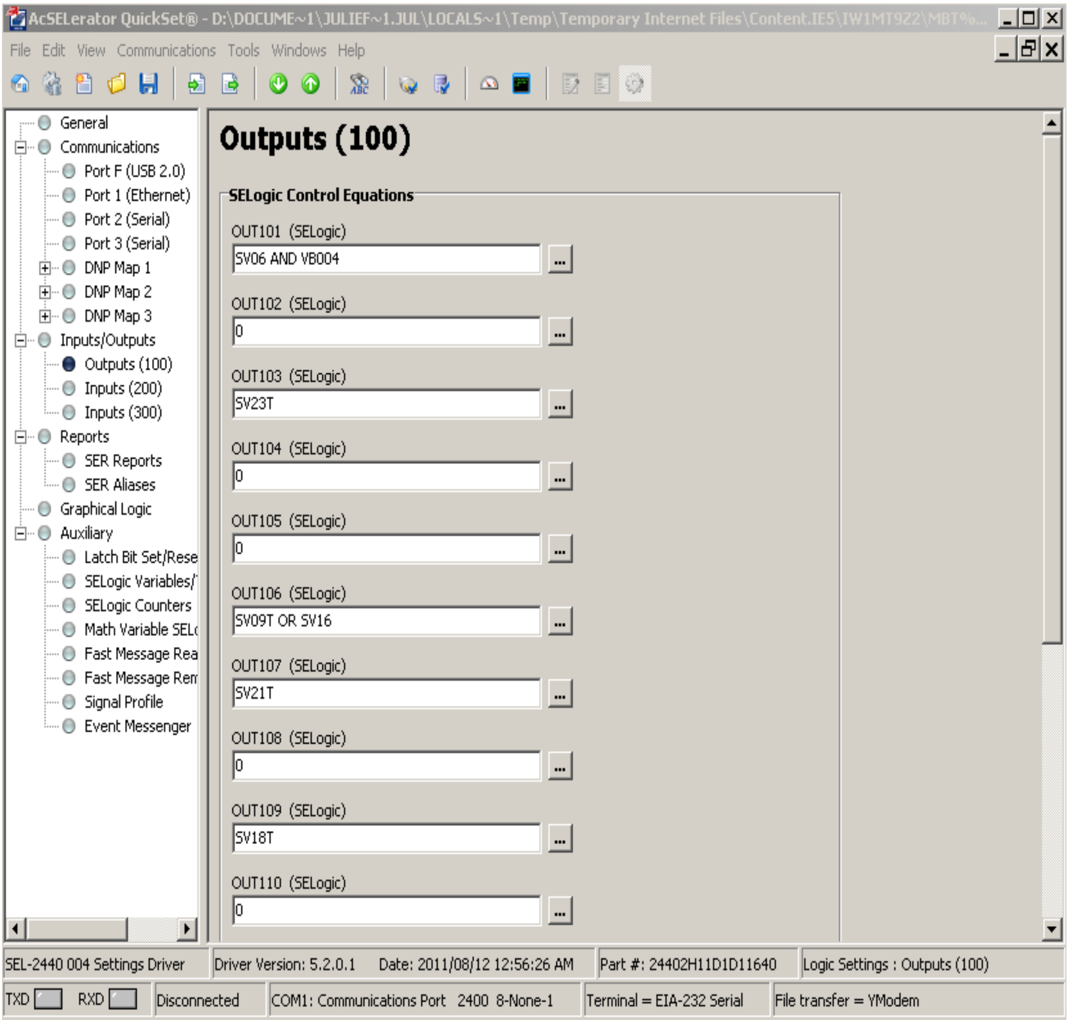


Figure 4.36: IED configuration window

One of the tools Acselerator QuickSet provides is a SER (Sequence Event Reporting), Figure 4.37. It allows the user to monitor any input, output, alarm, virtual bit, etc. operation by simply entering it into the SER string and uploading it to the device.

During commissioning the Human Machine Interface (HMI) can be used to investigate whether specific inputs, outputs, virtual bits etc. behave as expected. In this instance the HMI displays information such as: analog metering, frequency, DC voltage, I/O, user-defined targets, and a front panel display. When in HMI view the configurator can clear reports, reset alarms, force output contacts and adjust time setting. Figure 4.38 shows the HMI Control display.

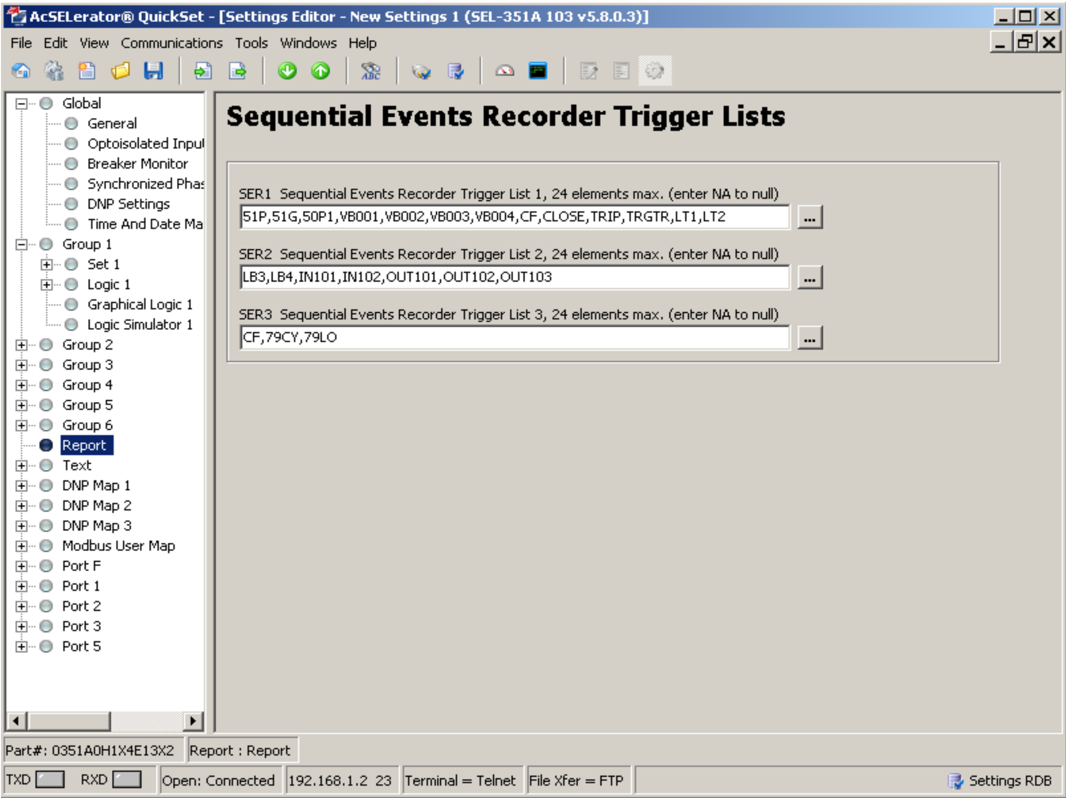


Figure 4.37: Sequence of event report settings

During the final steps in configuring the IEDs is to set Auxiliary settings. Settings such as Latch Bit Set/Reset, SEL Logic Variables/Timers, SEL Logic Counters, etc. falls under Auxiliary settings.

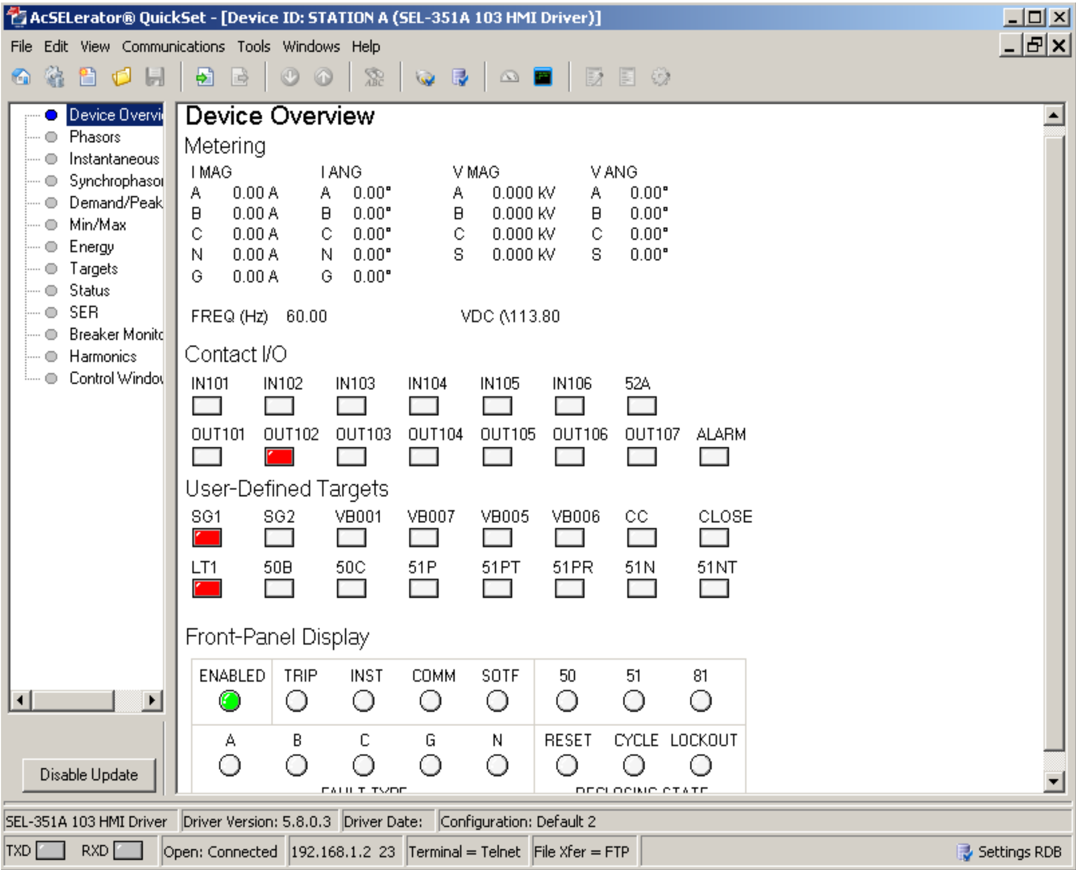


Figure 4.38: HMI control panel

4.12 Conclusion

This chapter describes the design and construction of the lab scale test system and how it meets the requirements for a typical underground distribution system. It also points out the shortcomings in existing distribution systems and describes the added enhanced features without human intervention. The question whether the IEC61850 standard can be successfully implemented in the distribution environment was also answered through the implementation of various case studies.. The physical structure, communications structure the monitoring and control structure that is required for the operation of the DAS system is discussed. Finally, the algorithm that governs the execution of the functions of the lab scale project is described.

In the next chapter the results from various tests that are performed on the test bench are discussed. The OMICRON secondary test set is used exclusively and various case studies are shown. The next chapter also considers how the system will behave when multiple faults occur on the test system.

CHAPTER 5

LAB SCALE IMPLEMENTATION AND SIMULATION – CASE STUDIES

5.1 Introduction

This chapter has put forward an innovative distribution automation system that uses IEC61850 standard functionalities which are able to successfully solve the problem that utilities face with extended outages on distribution ring networks. The implementation of the proposed algorithm, the utilization of a protection scheme, communications infrastructure, intelligent discrete programmable controller and the IEC61850 standard are the building blocks in the test system. In this chapter also, some of the functions of a distribution automation system such as fault detection, fault isolation and service restoration have been tested and the results recorded. Faults on each line section were simulated and the system response analysed. The performance of the algorithm was confirmed through various simulations on the test system. The simulations also proved fast fault clearing times and successful fault isolation when all the system requirements were fulfilled. The question of the impact of multiple faults in the automation process was also addressed. Secondly the question of whether the system will still operate as expected if the algorithm conditions are not met were also addressed. The results show that the IEC61850 standard can be successfully incorporated into the distribution test environment. Traditionally, when a fault occurs the entire feeder is affected and the unaffected sections are also without power. The test system showed successfully the rapid restoration of power to unaffected sections of the network.

This chapter shows the results of the various tests that were done on the test bench through various case studies. Section 5.2 explains the setup of the test bench and how the implementation and performance of the GOOSE messages are evaluated. Section 5.3 describes how the different IEDs behave during normal system conditions. It also describes the GOOSE messages under normal conditions. In section 5.4 the various case studies are described. Section 5.5 considers how the system will behave during multiple fault conditions and 5.6 gives the conclusion.

5.2 Test bench, performance evaluation and case studies

The big drive towards automated distribution systems are the ability of these systems for automatic distribution fault isolation and service restoration. In order to achieve such a system the most important requirement is determining the status of all the line apparatus such as the line switches and circuit breakers either in the closed or open position. The test system has a moderate amount of 5 switches and 2 breakers where power systems in real life may have numerous amounts of switches and breakers. The intelligent automation algorithm was evaluated and optimal performance and correct operation of the system were confirmed through various tests and simulations on the test system. The algorithm uses various conditions that have to be satisfied before it executes an instruction or control. If all the required algorithm conditions are not true the automation process is not initiated and only the protection function will operate and then ends. The algorithm changes the network after a permanent fault has occurred on the feeder to reconfigure the network.

The aim of this chapter is to investigate the performance of the simulated protected scheme using the OMICRON secondary injection test set. The test results obtained from the simulations will be used to evaluate the performance of the scheme. The performance criteria are: fault identification, location and restoration durations.

The operation of the algorithm is based on the exchange of GOOSE messages. All GOOSE messages are described in Chapter 4. Chapter 5 evaluates the implementation and performance of the GOOSE messages through the case studies that are described. Correct power system operation is evaluated through several testing scenarios. The scheme consists of 2 radial feeders with interconnectivity possibility through a normally open point as discussed in Chapter 4. The feeders are supplied from one source and the network has a total of 4 line sections. The system was exposed to several faults simulated on various parts on the network. Each line section was subjected to faults and the results recorded. The feeder protection is based on the SEL 351A IED's, over current and earth fault protection at the substation. The line switches along the feeder has no fault current breaking capacity, therefore, cannot be operated before the substation breaker has been opened. Line sections 2 and 3 are bounded by line switches where line sections 1 and 4 are bounded by a breaker and line switch. The automatic control of the breakers and line switches are accomplished through a centralized discrete programmable controller SEL 2440 as shown in Chapter 4. The manual control of the line switches is done through push buttons mounted on the test system panel. The circuit breakers are simulated within the SEL351A IEDs and can also be operated manually via a pushbutton. Figure 5.1 illustrates a block diagram of the built test system.

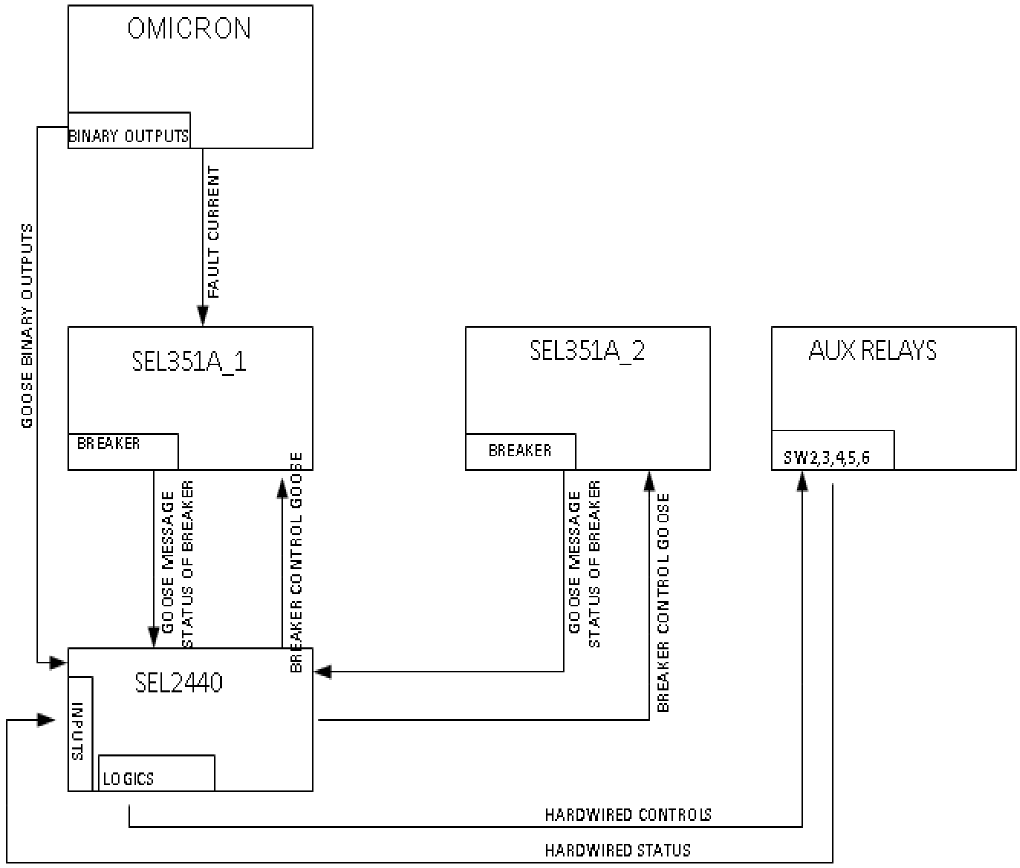


Figure 5.1: The Test System Block Diagram

5.3 Normal conditions

Figure 5.2 shows a customized device overview of the SEL2440 HMI during normal system operation conditions. The overview shows various types of inputs, outputs, virtual bits and SEL variables, exchanged by the device.

5.3.1 SEL2440

When the system is running under normal conditions the active incoming GOOSE message to the SEL2440 is mapped to its virtual bit 4 (VB004) indicating that the substation circuit breaker is in the closed position. The line switches 2, 3, 5 and 6 are indicated by SEL2440 inputs IN202, 204, 208 and 210 respectively. The auxiliary relays installed on the test bench represent the line switch statuses. The status contacts are hardwired to the inputs of the programmable controller. Normally the switches are all in the close position except switch 4 that is indicated by IN205. This is the normally open point which is in the open position.

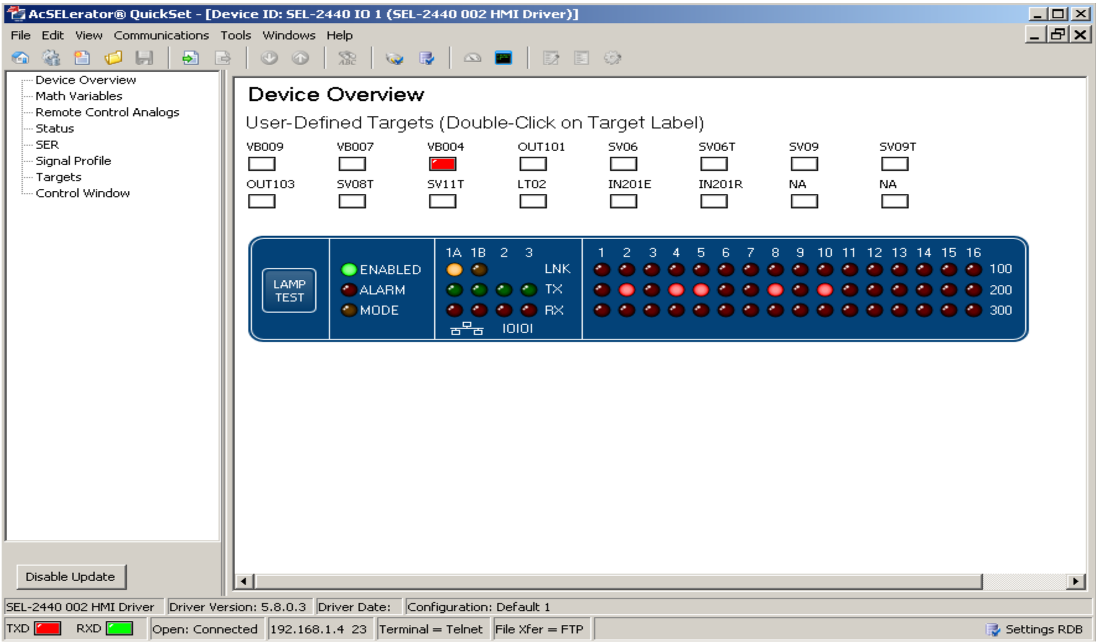


Figure 5.2: SEL2440 HMI device overview under normal conditions

5.3.2 SEL 351A_1 and 2

Figure 5.3 shows the SEL351A_1 device HMI overview during normal system operation conditions. The same conditions hold true for SEL351A_2. During normal conditions OUT102, SG1 and LT1 are asserted. OUT 102 is triggered by incoming GOOSE VB004 and shows the substation circuit breaker indication, SG1 shows that settings group1 are activated on the relay. The SEL 351A protection device has several protection setting groups that can be used during various protection philosophies. The LT1 is latch bit1 and indicates that the substation circuit breaker is latched in the closed position.

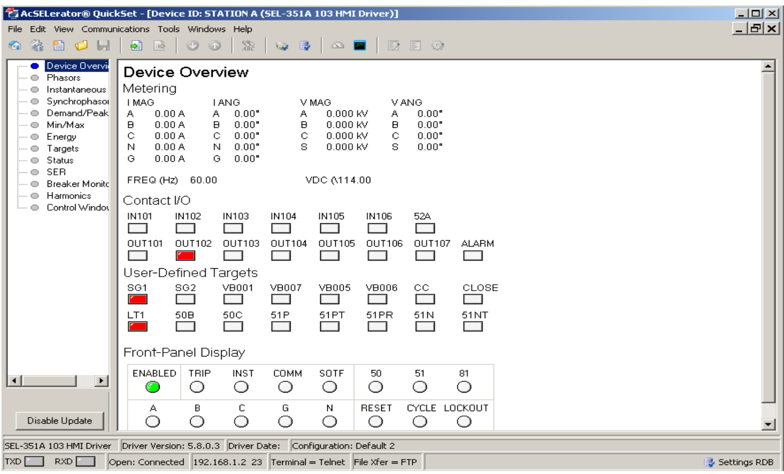


Figure 5.3: SEL 351A HMI device overview during normal operating conditions

These are the main diagrams that will be used to show the changes in the controller and the protection IEDs during the investigations under the various considered case studies. During the different case studies the diagrams will change as the various inputs, outputs, GOOSE messages, SEL variables, etc. are asserted and de-asserted.

5.4 Case studies

The system is designed on a completely centralized communication-based automation system and relevant settings and logics/algorithms were applied. To be able to verify the selectivity and performance of the proposed algorithm, various tests were done.

The protection scheme was tested by the simulation of fault currents on each line section. Only earth faults were simulated as it is the most prevalent type of fault in the distribution system. Over current faults were not considered as their application would not have an effect on the outcome of the results. In a real life system, however, it would, since protection settings for over current are normally set higher and the time dial setting is faster resulting in a faster fault clearing time. Fault clearance time consists of all the time delays of all the devices involved in the algorithm such as the IED delay’s and the breaker contact opening times. Fault locations were simulated, the contacts of the relevant line switches are triggered and their information is presented in the results. Finally the duration of the automatic re-connection of supply to the un-faulted line sections are presented by the monitoring of the corresponding triggered functions that are responsible for the operation of contacts and GOOSE messages.

5.4.1 Case Study 1

Permanent Fault - Line Section 1:

A fault condition is simulated on the line section 1 by the secondary test set, OMICRON CMC256 plus. Figure 5.4 illustrates a state sequence test template of the OMICRON. It is set up to monitor three separate triggering conditions. These conditions include: state 1 “FAULT SEC1”, state 2 “LINE SEC1 OPEN” and state 3 “NOP CLOSE”. During state 1 a 900mA fault condition is simulated on the line section 1. State 2 monitors how long it takes for the faulty line section to be isolated following the fault on the line section and state 3 monitors the time taken for the network to be re-configured through the closing of the normally open point. Figures 5.4 and 5.5 illustrate the assessments of the fault detection, the fault isolation as well as switching over to the alternate supply via the closing of the normally open point.

The performance of the algorithm for fault detection, isolation and restoration is as follows:

The protection function of the SEL351A_1 IED detects a fault on the line and is triggered. The fault clears in 1.479 seconds and a tripping GOOSE message, OC_EF_TRIP.PRO.G51PTOC.Op is published by the SEL351A_1 and the central controller SEL2440 subscribes to the GOOSE message. The Distribution Automation System requires the fault location information to initiate the automation algorithm. The fault location is simulated by the triggering of the OMICRON binary output Bin Out1 for a fault on the line section 1. The status of the binary output data is published and the SEL351A_1 subscribes to it. The fault location logic and protection operation logic trigger the SEL2440 - SV6 (SELVariable 6) logic. The status of the breaker of substation A is transmitted via a GOOSE message, BRKR_STATUS_LLN.ANN.LTGGIO7.ind01 and is mapped to VB004 in the SEL2440 device.

The SEL2440 output, OUT 101 is triggered when the SV6 logic and VB004 are asserted. The output, OUT101 changes SW 2 line switch from the closed to the open position by triggering the relevant auxiliary relay. This process takes 5 milliseconds.

The faulty line section 1 is isolated by the opening of the breaker at the substation A and line switch SW2. The isolation process was achieved in 1.484 seconds. When the output OUT101 of SEL2440 is triggered it latches latch bit LT1 of SEL351A_1 which then triggers output OUT106 of the SEL2440. Output OUT106 issues a control signal to the normally open point SW4 to close by triggering the relevant auxiliary relay. The closing of the normally open point reconfigured the network and restored supply to the line section 2. The time it took the customers to be re-supplied after the initial fault was 1.002 seconds. The total time for fault detection, location, isolation and service restoration is 2.486 seconds, see Figure 5.6 that illustrates the timeline of the various processes.

Test results for single phase and phase to phase faults are exactly the same as the protection settings were configured to be the same in the protection IED as described in section 5.4. The process of the line switches opening and closing can be followed through the screen shots illustrated by Figure 5.2 and 5.7 respectively. After the automation sequence has been completed the faulted zone is isolated and await repairs. The test system is designed to be manually restored to its normal state.

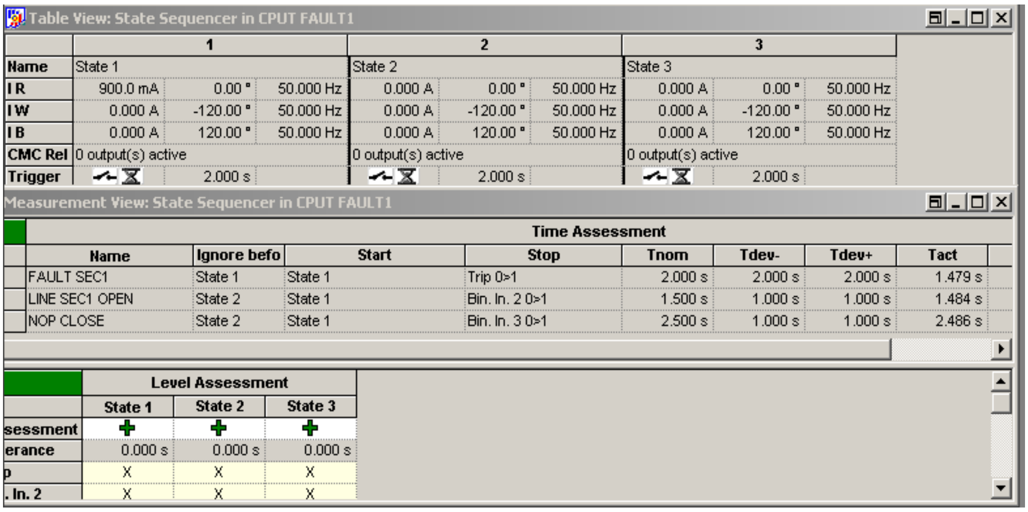


Table View: State Sequencer in CPUT FAULT1

	1			2			3		
Name	State 1			State 2			State 3		
I R	900.0 mA	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I W	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I B	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz
CMC Rel	0 output(s) active			0 output(s) active			0 output(s) active		
Trigger		2.000 s			2.000 s			2.000 s	

Measurement View: State Sequencer in CPUT FAULT1

Time Assessment

Name	Ignore befo	Start	Stop	Tnom	Tdev-	Tdev+	Tact
FAULT SEC1	State 1	State 1	Trip 0>1	2.000 s	2.000 s	2.000 s	1.479 s
LINE SEC1 OPEN	State 2	State 1	Bin. In. 2 0>1	1.500 s	1.000 s	1.000 s	1.484 s
NOP CLOSE	State 2	State 1	Bin. In. 3 0>1	2.500 s	1.000 s	1.000 s	2.486 s

Level Assessment

	State 1	State 2	State 3
sessment	+	+	+
erance	0.000 s	0.000 s	0.000 s
p	X	X	X
. In. 2	X	X	X

Figure 5.4: Test results for line section 1 fault

Figure 5.5 gives additional information from the OMICRON such as the time assessment, analogue fault currents, binary outputs and binary inputs. The assessment window consists of four sections. The first section shows the time assessment and there are three different conditions that are monitored in this section. During the first condition the fault clearance time for a fault on line section 1 is monitored. The time evaluation starts when the fault current is applied and stops when the trip contact OUT101 of the SEL351_1 is triggered. The second condition automatically starts when the first condition ends and stops when the SW2 line switch opens. This is achieved by connecting the SW2 auxiliary relay status contact to the binary input Bin. in 2 of the OMICRON. The third condition is started when the second condition is successfully stopped. It then stops when the normally open point closes. This is achieved by connecting the SW4 auxiliary relay status contact to the binary input Bin in 3 of the OMICRON. The time assessment has a start and stop criteria. This reflects the conditions that will initiate and stop the assessment period. It also has an upper (Tdev+) and lower time (Tdev-) dead band operation perimeters. The Tnom parameter is the nominal time the test is assessed and Tact time is the actual assessment time.

The second section shows the fault current amplitude as well as its time duration. The third section shows the binary outputs and the last section shows the binary inputs.

Test Results

Time Assessment

Name	Ignore before	Start	Stop	Tnom	Tdev-	Tdev+	Tact	Tdev	Assess
FAULT SEC1	State 1	State 1	Trip 0>1	2.000 s	2.000 s	2.000 s	1.479 s	-520.8 ms	+
LINE SEC1 OPEN	State 2	State 1	Bin. In. 2 0>1	1.500 s	1.000 s	1.000 s	1.484 s	-16.00 ms	+
NOP CLOSE	State 2	State 1	Bin. In. 3 0>1	2.500 s	1.000 s	1.000 s	2.486 s	-14.30 ms	+

Assess: + .. Passed x .. Failed o .. Not assessed

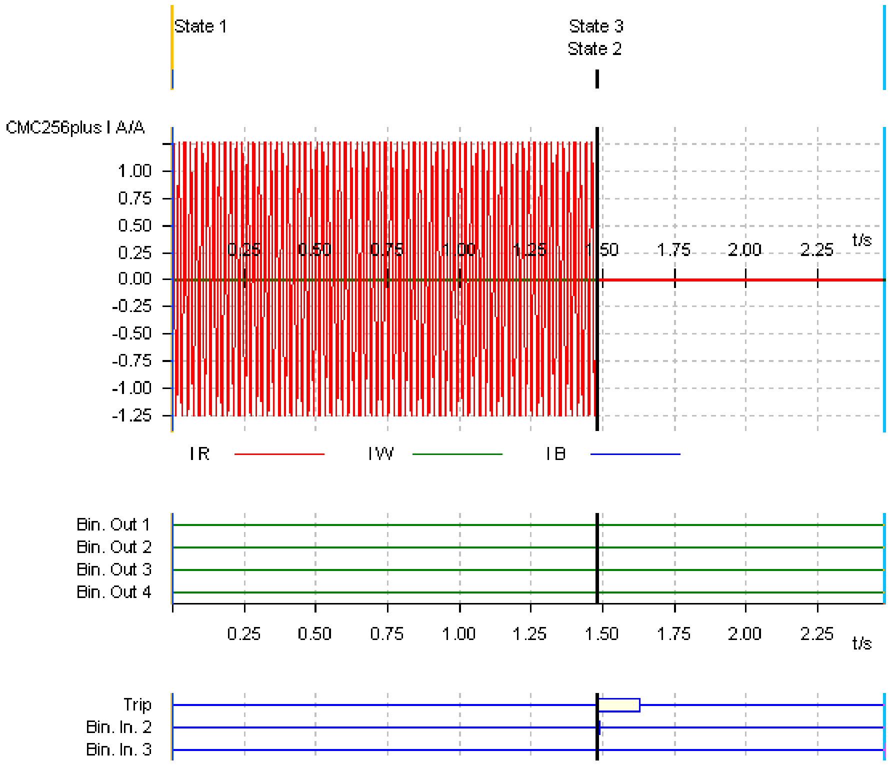


Figure 5.5: Test results for the fault on the line section 1

Figure 5.6 shows the durations of the different stages in the sequence of events from the time the protection elements are triggered to the time the service is restored. The timeline shows that for a fault on line section 1 the fault was cleared in 1.479 seconds, thereafter the isolation took a time of 5milli seconds and finally the service was restored in 1.002 seconds. The fault clearance time can be changed by altering the protection settings. The fault isolation period can also be made faster or slower by changing the pick up or drop off timer settings of the relevant logic functions within the controller. The service restoration time can also be changed to levels required by the user.

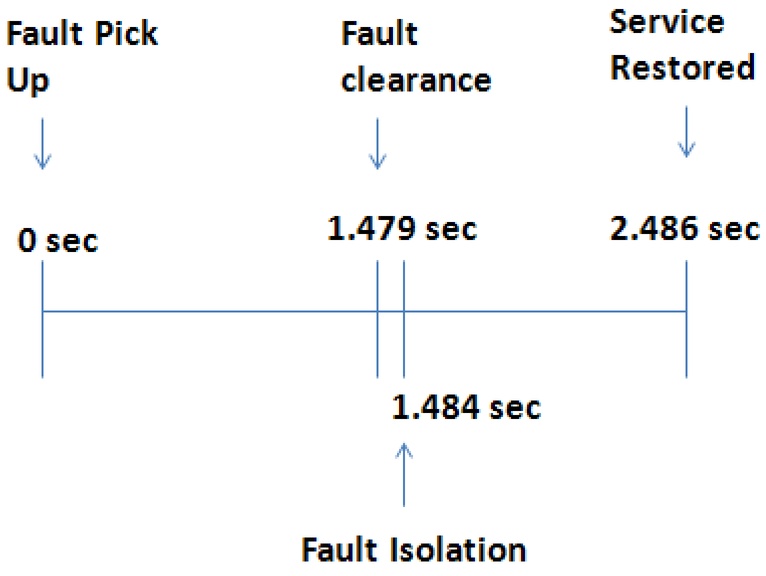


Figure 5.6: Line section 1 fault time line

5.4.2 Post Fault Conditions: Line section 1 – Fault 1

5.4.2.1 SEL2440

After a fault has occurred on line section 1 the SEL2240 controller shows that inputs IN201, IN204, IN206, IN208 and IN210 are asserted as shown in Figure 5.7. Input IN201 indicates that switch SW 2 is in the open position and all the other remaining switches are in the closed position. Table 5.1 shows a table of the various input statuses and their location on the test system after a fault has occurred.

TABLE 5.1: SEL2440 Controller input statuses after a fault has occurred

CONTROLLER INPUT	LINE SWITCH	LINE SWITCH STATUS	LOCATION
IN201	SW2	OPEN	LINE SECTION 1
IN202	SW2	CLOSE	LINE SECTION 1
IN203	SW3	OPEN	LINE SECTION 2
IN204	SW3	CLOSE	LINE SECTION 2
IN205	SW4	OPEN	LINE SECTION 2/3
IN206	SW4	CLOSE	LINE SECTION 2/3
IN207	SW5	OPEN	LINE SECTION 3
IN208	SW5	CLOSE	LINE SECTION 3
IN209	SW6	OPEN	LINE SECTION 4
IN210	SW6	CLOSE	LINE SECTION 4

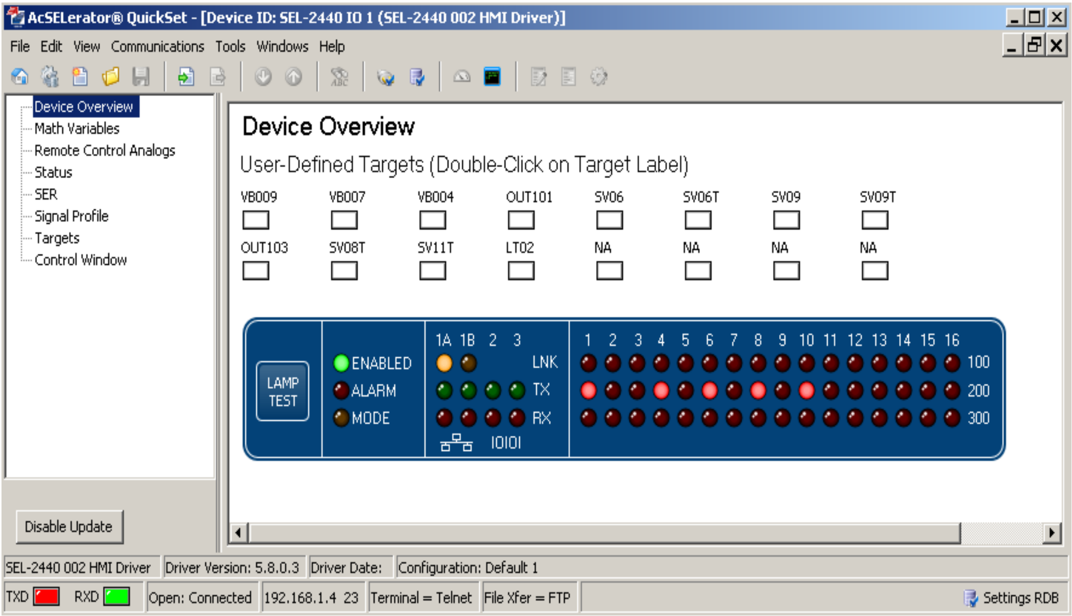


Figure 5.7: SEL2440 device overview after a fault occurred

5.4.2.2 SEL351A_1

After a fault has occurred on line section 1 the protection IED SEL351A_1 show that output OUT102 de-asserted and OUT103 asserted indicating that the circuit breaker at substation A is in the open position. The device overview also shows that latch bit LT1 is no longer triggered and the device has tripped. Figure 5.8 illustrates the device overview after a fault has occurred on line section 1.

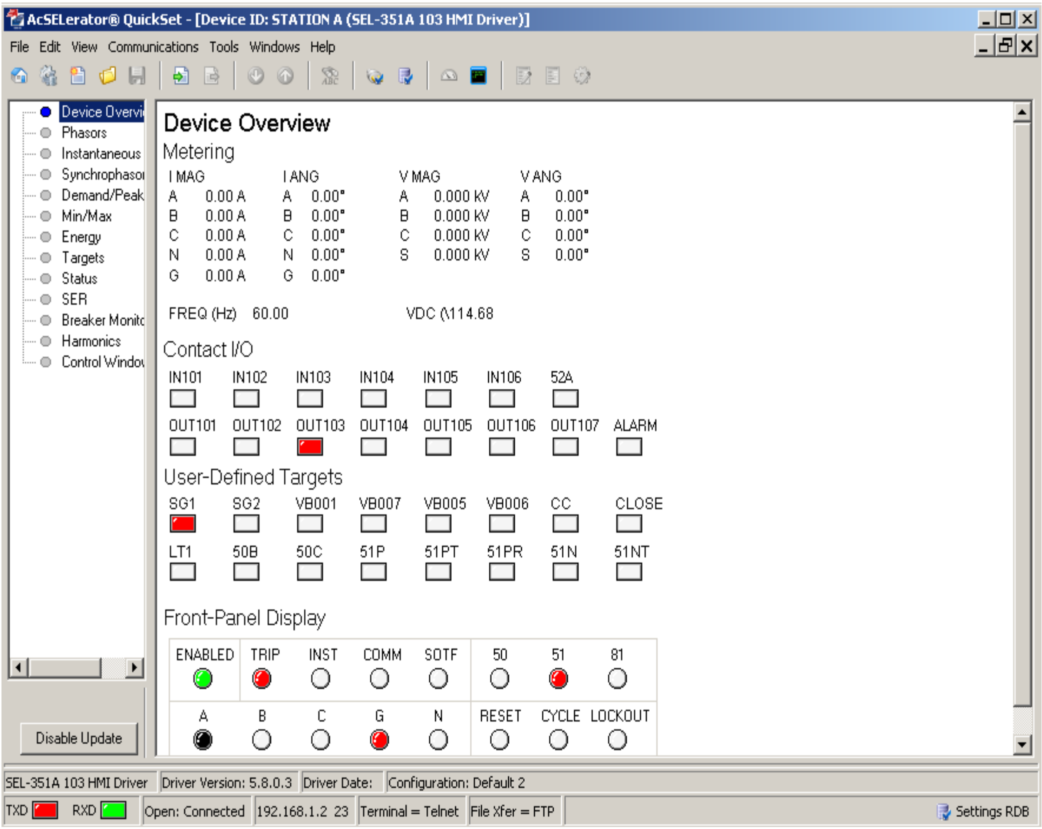


Figure 5.8: SEL2440 post fault, device overview

Figure 5.9 shows a single line diagram of the test system after a fault occurred on the line section 1 and the un-faulted section is restored. The breaker at substation A is in the open position as well as the line switch, SW2. The normally open point SW4 is in the closed position as well as switches SW3, SW5, SW6 and the breaker at substation B.

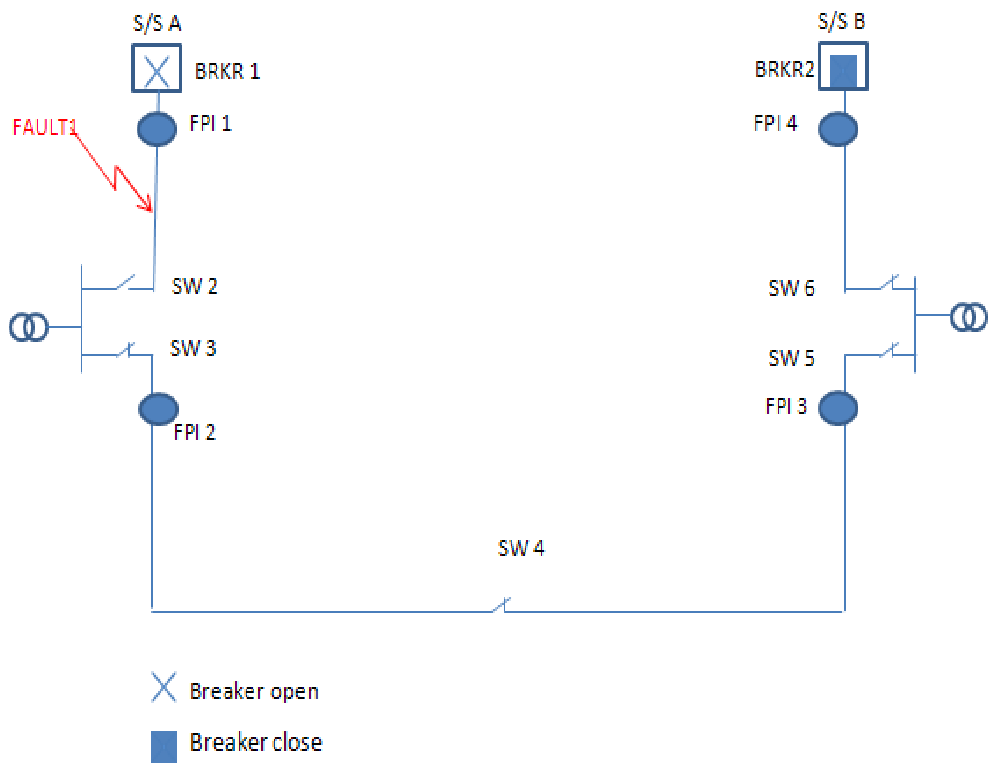


Figure 5.9: Single Line Diagram after automatic restoration

5.4.3 Case Study 2 - Permanent Fault - Line Section 2:

For a fault on the section 2 of the line the protection scheme triggers and clears the fault in 1.485 seconds. Protection IED SEL351A_1 publishes GOOSE message, OC_EF_TRIP.PRO.G51PTOC.Op to which the SEL2440 controller subscribes. The incoming GOOSE is mapped to virtual bit VB002.

For the automatic isolation process to initiate, the SelVariable SV2 logic within the SEL2440 controller has to be triggered. It requires information about the location of the fault as well as the protection trip GOOSE message from the protection device. In order to solve the fault location problem binary outputs from the OMICRON were used in the following way: binary outputs 1 and 2 are triggered to simulate the fault location in section 2 of the line. GOOSE messages SENSORS.CFG.LLN0$GGIO$FAULT1 and SENSORS.CFG.LLN0$GGIO$FAULT2 are published via the OMICRON, and the protection device, SEL351A_1 subscribes to them. The incoming GOOSE messages are mapped to the virtual bits, VB011 and VB012 respectively within the SEL351A_1. The GOOSE configuration simulation setup for the OMICRON binary output Bin out1 is illustrated in Figure 5.10 and for the Omicron binary output Bin out2 in Figure 5.11. The protection device SEL351A_1 in turn publishes that it received the fault location information. The GOOSE messages are described as ANY_PICKUP.ANN.SVGGGIO05.ind01 and ANY_PICKUP.ANN.SVGGGIO05. ind01. The SEL2440 controller subscribes to these incoming GOOSE messages and is mapped to VB016. In the event the controller fails to receive these messages the fault isolation process will fail. Additionally, if the SEL2440 controller receives additional binary output GOOSE messages the isolation process will also fail because it will interpret it as multiple faults. When the isolation process fails the protection device SEL351A_1 will issue a trip to the substation breaker and the entire line will be isolated. This is an unfortunate situation for all the customers will be without power.

When the SelVariable SV08 logic of the SEL2440 controller is successfully triggered and the incoming GOOSE of the breaker status from the protection device SEL351A_1 is received the SEL2440 controller will issue a control signal to trigger its output OUT103. This issues a control to the line switch SW3 to change from the closed to the open position. This is accomplished through hardwiring between the SEL2440 controller output and the auxiliary relay that is used to simulate the line switch SW3. This process takes 7milli seconds after the fault occurred as illustrated by the timeline in Figure 5.12. The fault is isolated through the opening first of the breaker at the substation A and then the SW3 line switch.

When the line switch SW3 is successfully opened the output OUT103 of the SEL2440 controller triggers the logic to re-close the breaker at substation A. A GOOSE message LLN.Brkr1.CLOSE.ANN.SVTGGIO2.ind1 is published by the controller and the protection device SEL351A_1 subscribes to it. The incoming GOOSE is mapped to VB001 within the protection device.

The reclosing of the breaker at substation A to restore power to the un-faulted section took approximately 250 milliseconds. Figure 5.13 illustrates the OMICRON GOOSE configuration that shows the GOOSE message published by the SEL2440 controller to close the beaker was monitored at binary input 9 of the OMICRON.

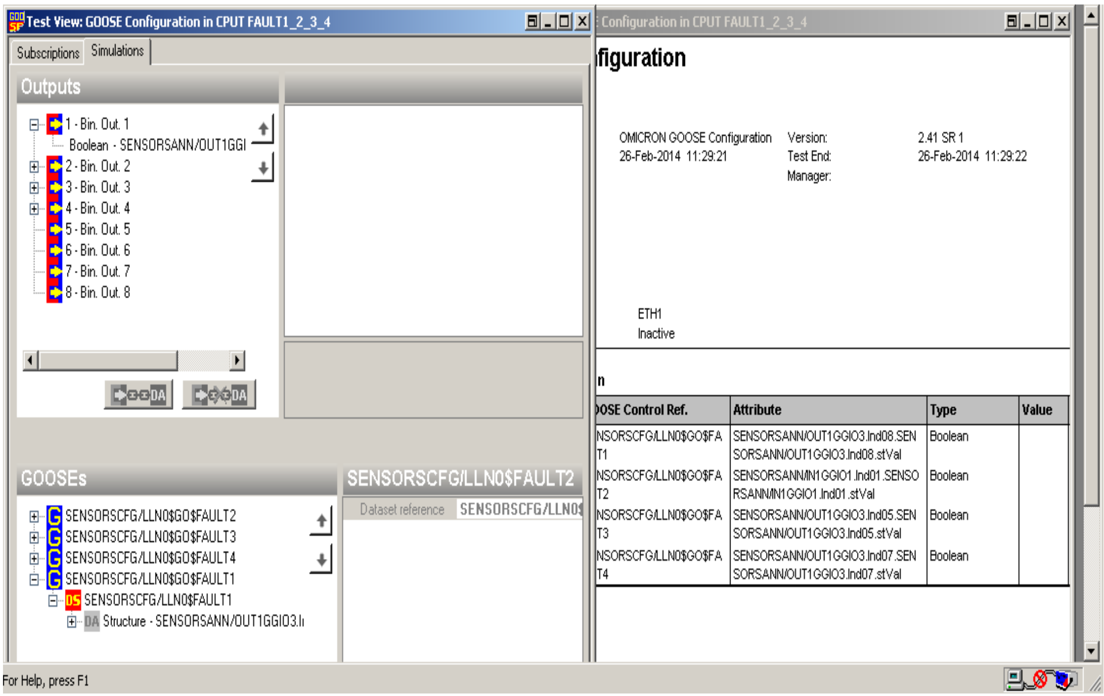


Figure 5.10: Binary output 1 GOOSE configuration, simulation setup

An IED was created within the SEL Architect software called the “SENSORS IED”. The GOOSE messages that were configured within this device are used to react to the presence of a fault. For example, if a fault exists in section 2 of the line the OMICRON binary outputs 1 as well as 2 have to be triggered to simulate that a fault exist in that section. The ICD file of the “SENSORS IED” device was then exported to the Omicron GOOSE module which enabled the test system to simulate binary outputs and use it as fault path indicator functions as described in Chapter 4.4.3. This means that when binary output 1 is triggered it will publish a GOOSE message with the data mapped to it in this case the GOOSE message is SENSORS.ANN.LLN0GIO FAULT1 as illustrated in Figure 5.10. Figure 5.11 shows that binary output 2 is configured as SENSORS.ANN.LLNOGIOFAULT2.

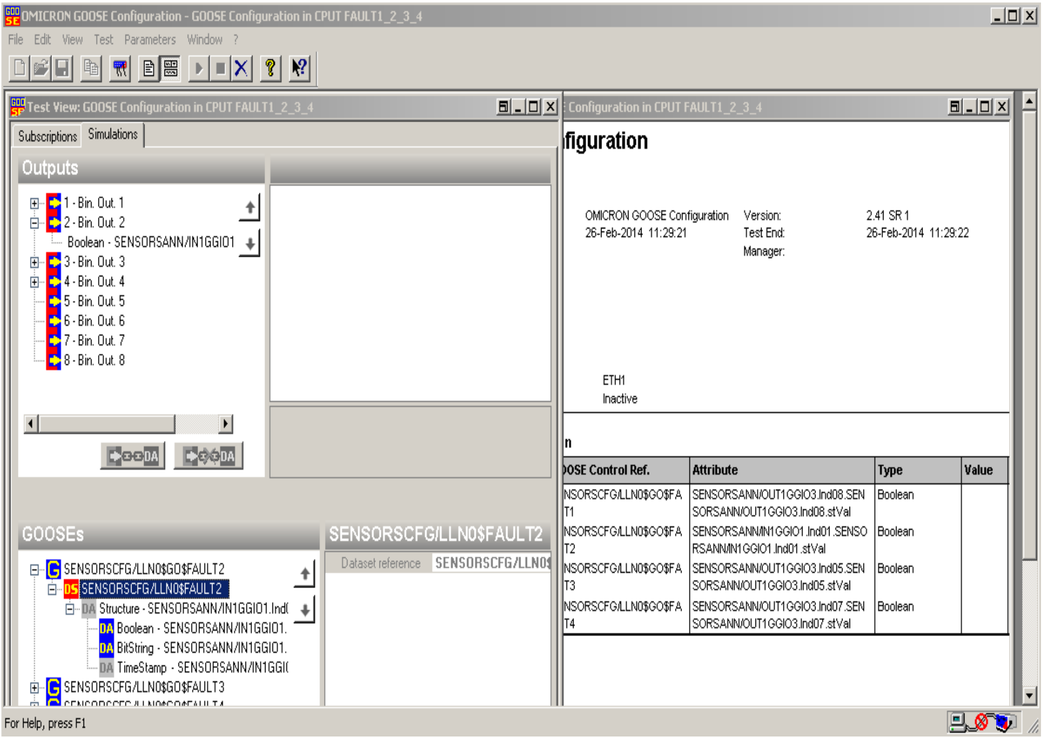


Figure 5.11: Binary output 2 GOOSE configuration, simulation setup

The timeline in Figure 5.12 shows that the fault on the section 2 of the line clears in 1.485 seconds thereafter isolating the fault in 7milli seconds and finally restoring the service after a further delay of 250 milliseconds to the customers on the un-faulted zones. The timeline shows further that it takes a total of 1.742 seconds for the test system to do the entire process from clearing the fault, isolating the fault and restoring the power.

With traditional distribution ring systems the fault isolation process is the only function that can be compared to this test system as old protection schemes have acceptable operation times. However, in the traditional systems the fault must be isolated manually and can take anything from 5 minutes to several hours. After the fault has been isolated the operators can manually restore power to the un-faulted sections. This process may also take several minutes or even hours as they have to drive to the equipment that have to be switched in order to restore the power.

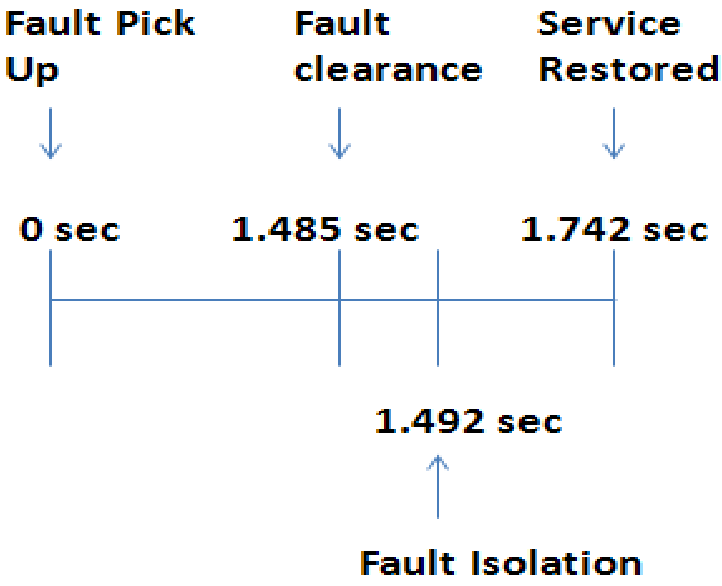


Figure 5.12: Time line for a fault on line section2

GOOSE Configuration

Test Module

Name:	OMICRON GOOSE Configuration	Version:	2.41 SR 1
Test Start:	25-Mar-2014 16:15:40	Test End:	25-Mar-2014 16:15:42
User Name:		Manager:	
Company:			

Settings

General:

Ethernet Port:	ETH1
Simulation Flag:	Inactive

GOOSE Subscriptions

Bin. Inp.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
9 - Bin. In. 9	SEL_2440_1CFG/LLN0GOBRKR1_CLOSE	SEL_2440_1ANN/SVTGGIO2.Ind11.SEL_2440_1ANN/SVTGGIO2.Ind11.stVal	Boolean		no

GOOSE Simulation

Bin. Out.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
1 - Bin. Out. 1	SENSORSCFG/LLN0GOFAULT1	SENSORSANN/OUT1GGIO3.Ind08.SENSORSANN/OUT1GGIO3.Ind08.stVal	Boolean		no
2 - Bin. Out. 2	SENSORSCFG/LLN0GOFAULT2	SENSORSANN/IN1GGIO1.Ind01.SENSORSANN/IN1GGIO1.Ind01.stVal	Boolean		no
3 - Bin. Out. 3	SENSORSCFG/LLN0GOFAULT3	SENSORSANN/OUT1GGIO3.Ind05.SENSORSANN/OUT1GGIO3.Ind05.stVal	Boolean		no
4 - Bin. Out. 4	SENSORSCFG/LLN0GOFAULT4	SENSORSANN/OUT1GGIO3.Ind07.SENSORSANN/OUT1GGIO3.Ind07.stVal	Boolean		no

Figure 5.13: Omicron GOOSE configuration**.**

The fault on section 2 of the line is simulated by a secondary test set, OMICRON CMC256 plus. Figure 5.14 shows the setup for the assessment of the fault that was simulated on the mentioned line section. The OMICRON State Sequencer test module was used to evaluate the duration of the line fault in state 1, the opening duration of the line switch SW3 in state 2 and finally the re-closing duration of the breaker in state 3. A 900mA fault was injected on phase A to trigger the protection function of the protection device SEL351A_1 and it was monitored via binary input Bin.in 1.

This is accomplished through hardwiring the SEL351A_1 protection trip output to the OMICRON binary input 1. When state 1 has been stopped successfully, it will start state 2 “LINE SW3 OPEN”. The time assessment for this state was accomplished through hardwiring between the SW3 auxiliary relay and binary input 3. The time assessment for state 3 was done through the monitoring of the breaker close GOOSE message published by SEL351A_1 via OMICRON binary input Bin.in 9. Figure 5.15 illustrates the successful assessment of all the configured testing states, by the inclusion of the plus sign in the assess column in the first section of the assessment window. The second section shows the analogue representation of the fault current that was applied to the line section. It shows the amplitude and time duration. The graph looks slightly different than in Figure 5.5 because of the time scale of the graphs not being the same. One can clearly see that the time scale is much larger in Figure 5.15. In the third section the binary outputs 1 and 2 were triggered to indicate that the fault has existed in this zone. The test system is designed to react to the activation of the binary outputs to indicate the existence of a fault in a particular section of the line. This operation would be done by Fault Path Indicators (FPI’s) in a real-network scenario. For a fault in line section 2 the binary outputs 1 and 2 must be both asserted to show that fault current has passed the line section 1 as well as the section2 as described in Chapter 4.4.3.

Table View: State Sequencer in CPUT FAULT1_2

	1			2			3		
Name	State 1			State 2			State 3		
I R	900.0 mA	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I W	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I B	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz
CMC Rel	2 output(s) active			2 output(s) active			0 output(s) active		
Trigger					2.000 s			3.000 s	

Measurement View: State Sequencer in CPUT FAULT1_2

Time Assessment							
Name	Ignore befo	Start	Stop	Tnom	Tdev-	Tdev+	Tact
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.485 s
LINE SW3 OPEN	State 2	State 1	Bin. In. 2 0>1	500.0 ms	1.000 s	1.000 s	1.492 s
BRKR CLOSE	State 1	State 1	Bin. In. 9 0>1	500.0 ms	3.000 s	3.000 s	1.742 s

Figure 5.14: Test results for a fault on the line section 2

Name	Ignore before	Start	Stop	Tnom	Tdev-	Tdev+	Tact	Tdev	Assess
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.485 s	485.1 ms	+
LINE SW3 OPEN	State 2	State 1	Bin. In. 2 0>1	500.0 ms	1.000 s	1.000 s	1.492 s	992.1 ms	+
BRKR CLOSE	State 1	State 1	Bin. In. 9 0>1	500.0 ms	3.000 s	3.000 s	1.742 s	1.242 s	+

Assess: + .. Passed x .. Failed o .. Not assessed

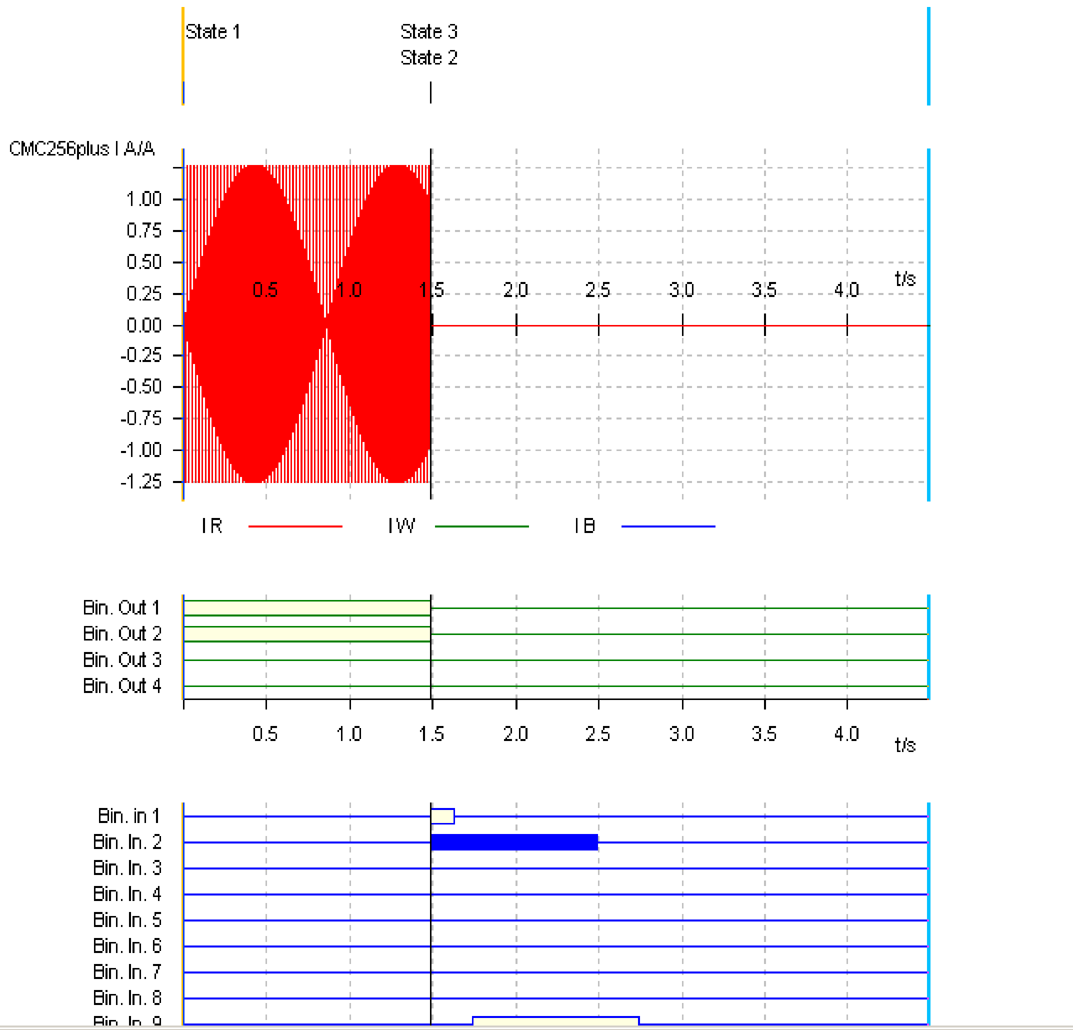


Figure 5.15: Test results for a fault on the line section2

5.4.4 Post Fault Conditions: Line section 2 – Fault 2

5.4.4.1 SEL 2440

When a fault occurs on the line section 2 the circuit breaker at substation A opens through the issuing of a trip command from the protection device SEL351A_1. Thereafter the line switch SW3 opens through the issuing of a control command from the SEL2440 controller to the relevant auxiliary relay. For a fault on this section of the line the test system is expected to keep the line switch SW4 in the open position. When the fault is isolated successfully the circuit breaker at substation A is instructed by the controller to re-close in order to ensure continuity of supply to the customers that are connected to the line section 1. Figure 5.16 indicates the line switch statuses after the fault has been cleared and the customer supplies are re-stored. It shows that inputs IN202 (SW2 close), IN203 (SW3 open), IN205 (SW4 open), IN208 (SW5 close) and IN210 (SW6 close) are asserted. Table 5.1 shows the various SEL2440 controller input statuses and their location on the test system. Virtual bit VB004 is the incoming GOOSE message indicating that the breaker at the substation A is in the closed position. The breaker status GOOSE message is published by the SEL351A_1 protection IED.

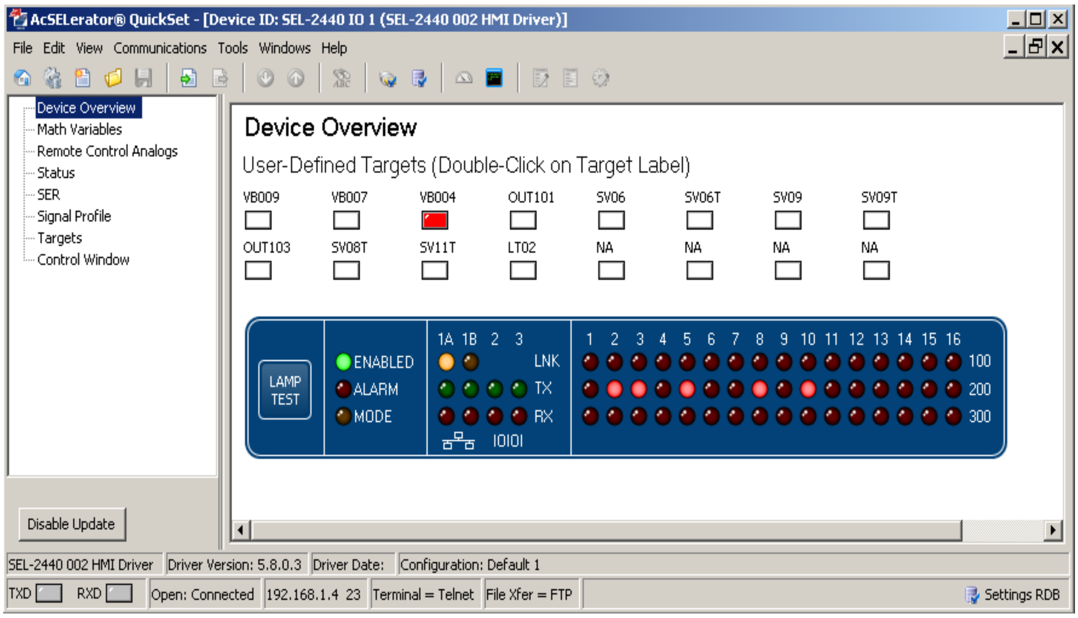


Figure 5.16: SEL2440 post fault, device overview

5.4.4.2 SEL 351A_1

The protection IED behaves in a similar way for the fault in the line section 2 compared to the fault in the section 1. The only difference is that the circuit breaker at the substation A receives a command from the SEL2440 controller to re-close after it has tripped after the fault has been successfully isolated.

Figure 5.17 shows the single line diagram of the test system after a fault on the section 2 of the line has occurred and the un-faulted section has been restored. The breaker at the substation A as well as the line switches SW2, SW3, SW5, SW6 and the breaker at substation B are now in the closed position. The normally open point SW4 is in the open position.

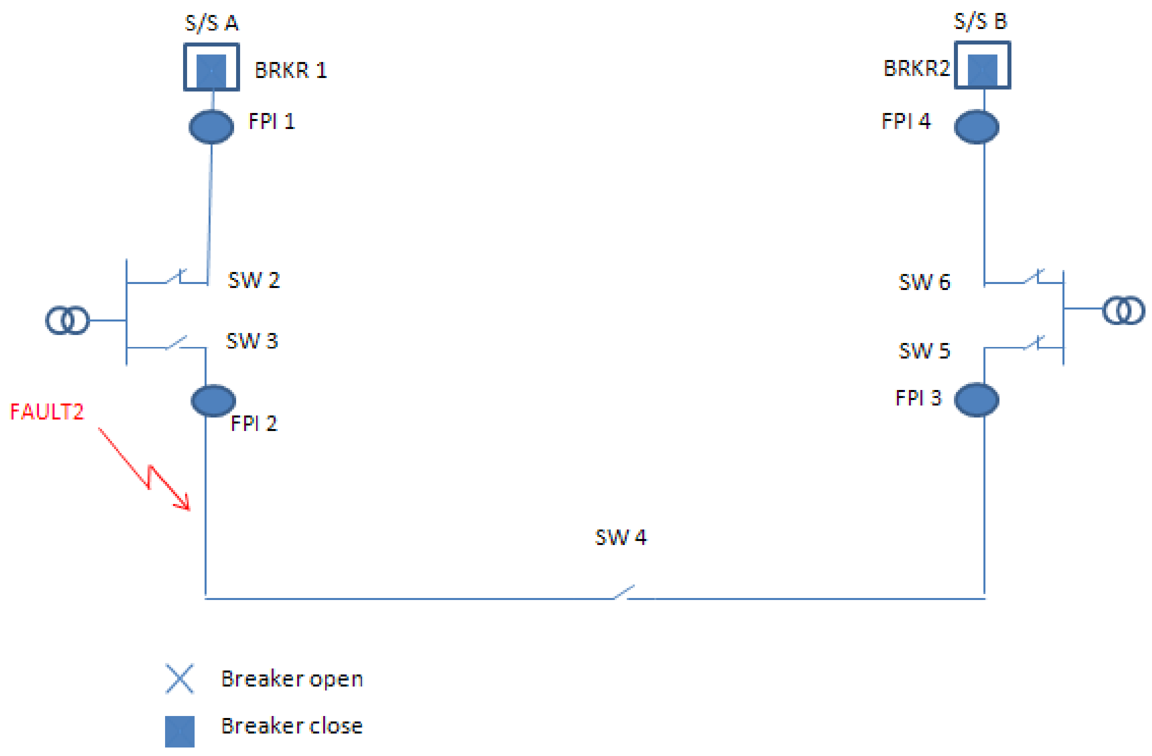


Figure: 5.17: Single Line Diagram after a fault on the line section 2

5.4.5 Case Study 3 - Permanent Fault - Line Section 3:

For a fault on the line section 3 the protection scheme at the substation B will trigger and clear the fault in 1.479 seconds. A GOOSE message, TRIP.PRO.G51PTOC.Op from the SEL351A_2 protection device at substation B is sent to which the SEL2440 controller subscribes. The incoming GOOSE is mapped to virtual bit VB005 at the SEL2440 controller.

The SelVariable SV3 logic of the SEL2440 controller will be triggered when the OMICRON binary outputs 3 and 4 are triggered. The test system is designed that in the event that the OMICRON binary outputs 3 and 4 are triggered the distribution automation system "knows" that the fault is located on the line section 3. The GOOSE configuration for the Omicron binary outputs is illustrated in Figure 5.18. GOOSE messages SENSORS.CFG.LLN0GIOFAULT3 and SENSORS.CFG. LLN0GIOFAULT4 is published when the OMICRON binary outputs are triggered. The incoming GOOSE messages are mapped to virtual bits VB013 and virtual bit VB014 respectively in the protection device SEL351A_2 at the substation B. When the protection device at the substation B receives these GOOSE messages it in turn publishes GOOSE messages ANY_PICKUP.ANN.SVGGGIO05.ind03 and ANY_ PICKUP.ANN.SVGGGIO05ind04 to which the SEL2440 controller subscribes. The incoming GOOSE message is mapped to the virtual bit VB012.

The SEL2440 controller issues a control to trigger its output, OUT107 when the SelVariable SV13 is triggered and the breaker at the substation B is in the closed position. The breaker status is transmitted via GOOSE message, BRKR_STATUS_LLN.ANN.LTGGIO07.ind01 from the SEL351A_2 and is mapped to the virtual bit, VB008. When the output, OUT107 is asserted the line switch SW5 changes from the close to the open position. This process takes 3.3 milliseconds after the fault is cleared and located. The fault is then isolated through the opening first, of the breaker at substation B and then SW5 line switch.

When the line switch SW5 has successfully opened the output OUT107 of the SEL2440 controller initiate the logic to re-close the breaker at the substation B. A GOOSE message LLN.BRKR2.CLOSE.ANN.LTGGIO3.ind03 is published by the controller and the protection device SEL351A_2 subscribes. The incoming GOOSE message is mapped to VB002 of the protective device.

The breaker at the substation B was re-closed and therefore restoring power to the un-faulted line section. This process took approximately 4milli seconds. Figure 5.19 illustrates the OMICRON GOOSE configuration for the fault on the line section 3. It shows that the GOOSE message published by the controller to re-close the beaker was monitored at the OMICRON binary input 10.

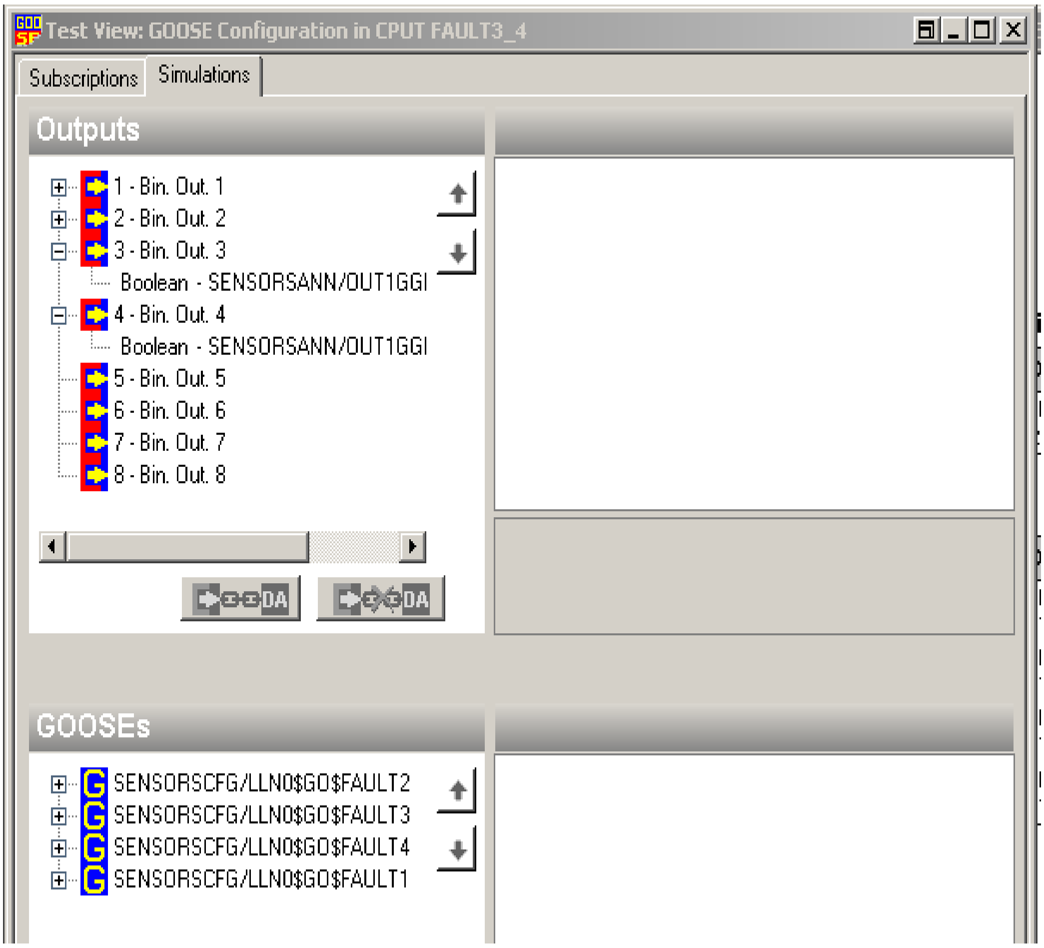


Figure 5.18: OMICRON binary output 3 and 4 GOOSE configuration setup

When binary outputs 3 and 4 are triggered GOOSE messages SENSORS.ANN. LLN0GIOFAULT3 and SENSORS.ANN.LLN0GIOFAULT4 are published respectively.

GOOSE Subscriptions

Bin. Inp.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
10 - Bin. In. 10	SEL_2440_1CFG/LLN0GOBRKR2_CLOSE	SEL_2440_1ANN/SVTGGIO2.Ind14.SEL_2440_1ANN/SVTGGIO2.Ind14.stVal	Boolean		no

GOOSE Simulation

Bin. Out.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
1 - Bin. Out. 1	SENSORSCFG/LLN0GOFAULT1	SENSORSANN/OUT1GGIO3.Ind08.SENSORSANN/OUT1GGIO3.Ind08.stVal	Boolean		no
2 - Bin. Out. 2	SENSORSCFG/LLN0GOFAULT2	SENSORSANN/IN1GGIO1.Ind01.SENSORSANN/IN1GGIO1.Ind01.stVal	Boolean		no
3 - Bin. Out. 3	SENSORSCFG/LLN0GOFAULT3	SENSORSANN/OUT1GGIO3.Ind05.SENSORSANN/OUT1GGIO3.Ind05.stVal	Boolean		no
4 - Bin. Out. 4	SENSORSCFG/LLN0GOFAULT4	SENSORSANN/OUT1GGIO3.Ind07.SENSORSANN/OUT1GGIO3.Ind07.stVal	Boolean		no

Figure 5.19: OMIRON GOOSE configuration

Figure 5.20 shows the time line for the case study of a permanent fault on the line section 3. The timeline shows that for a permanent fault on the line section the fault was cleared in 1.479 seconds thereafter in 3.3 milliseconds isolating the fault and finally, after a further delay of 4 milliseconds the service to the customers on the un-faulted line section was restored. The timeline further shows that it takes a total of 1.486 seconds for the test system to perform the entire process from clearing, isolating the fault and restoring the service. It also shows that the restoration process for the fault in the line section was much faster that in the line section 1 as well as the line section 2. The restoration time was made quicker to illustrate that the various stages of the test system can be adjusted to operate faster or slower depending on the requirements of the distribution system. The other stages include fault detection and fault isolation.

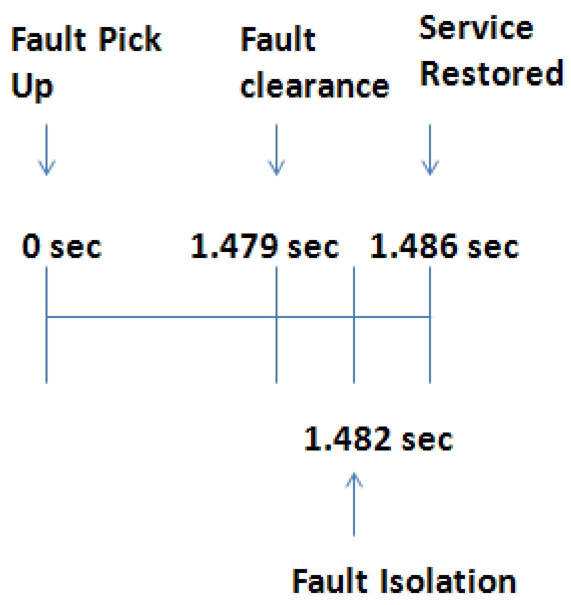


Figure 5.20: Time Line for a fault on line section 3

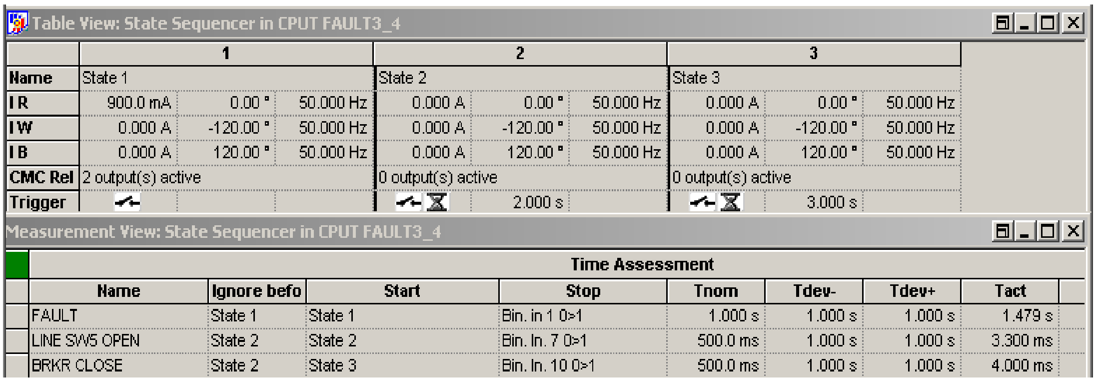


Table View: State Sequencer in CPUT FAULT3_4

	1			2			3		
Name	State 1			State 2			State 3		
I R	900.0 mA	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I W	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I B	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz
CMC Rel	2 output(s) active			0 output(s) active			0 output(s) active		
Trigger					2.000 s			3.000 s	

Measurement View: State Sequencer in CPUT FAULT3_4

Name	Ignore befo	Start	Stop	Tnom	Tdev-	Tdev+	Tact
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.479 s
LINE SW5 OPEN	State 2	State 2	Bin. In. 7 0>1	500.0 ms	1.000 s	1.000 s	3.300 ms
BRKR CLOSE	State 2	State 3	Bin. In. 10 0>1	500.0 ms	1.000 s	1.000 s	4.000 ms

Figure 5.21: Test results for a fault on line section 3

Figure 5.21 shows that a fault was simulated on the line section 3 through a 900mA fault on phase A in State 1. The trip output of the protection device SEL351A_2 is hardwired to the OMICRON binary input 1 to monitor the operation of the protection function. State 2 evaluates the opening of the line switch SW5 and is monitored through the OMICRON binary input Bin.in 7. The relevant auxiliary relay that represents the line switch is hardwired to the OMICRON binary input. When the binary input changes from a zero to a one it triggers and then records the operating time in which the line switch opened. State 3 evaluates the re-closing of the breaker at the substation B through the OMICRON binary input 10. Figure 5.22 illustrates the successful assessment of the fault detected, the fault isolation as well as the re-closing of the tripped breaker at the substation B. It also shows that binary output 3 and 4 were asserted in order to simulate the location of the fault on the line section 3.

Test Results

Time Assessment

Name	Ignore before	Start	Stop	Tnom	Tdev-	Tdev+	Tact	Tdev	Assess
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.479 s	478.8 ms	+
LINE SW5 OPEN	State 2	State 2	Bin. In. 7 0>1	500.0 ms	1.000 s	1.000 s	3.300 ms	-496.7 ms	+
BRKR CLOSE	State 2	State 3	Bin. In. 10 0>1	500.0 ms	1.000 s	1.000 s	4.000 ms	-496.0 ms	+

Assess: + .. Passed x .. Failed o .. Not assessed

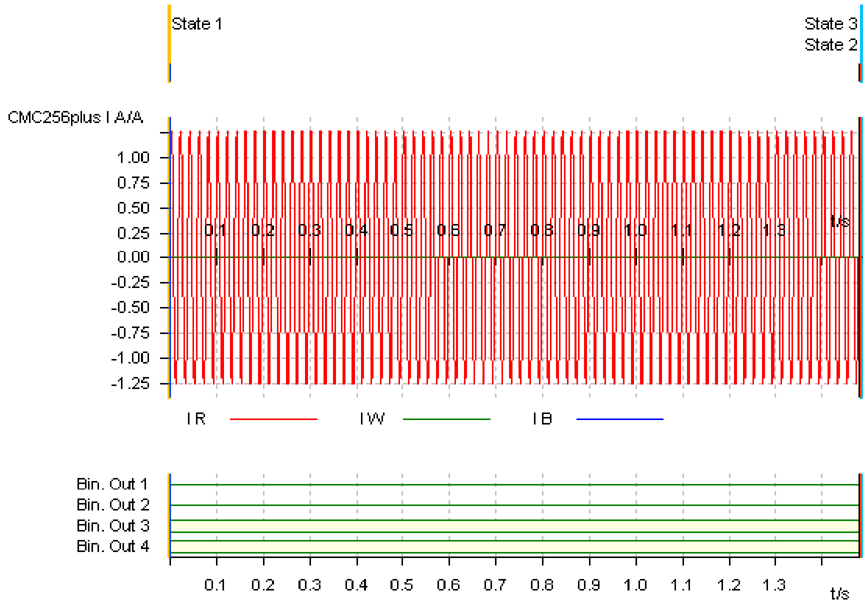


Figure 5.22: Test results for a fault in line section 3

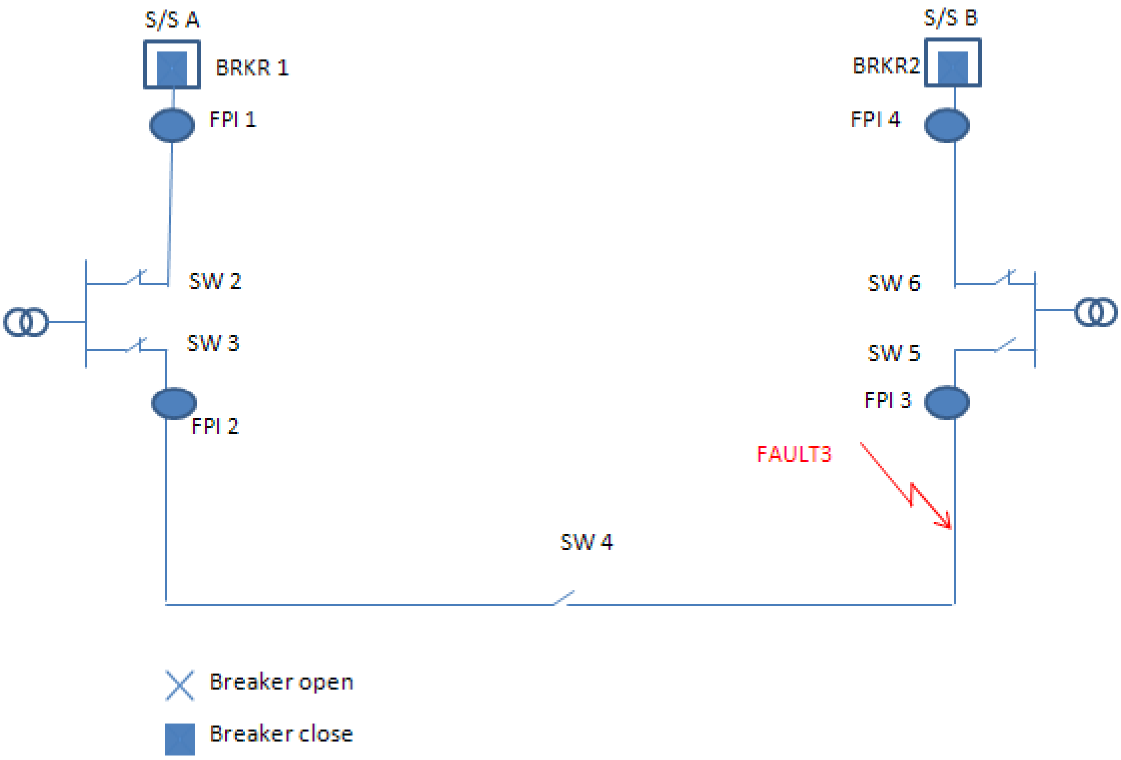


Figure 5.23: Single Line Diagram after a fault on the line section 3

Figure 5.23 shows the single line diagram of the test system after a fault occurred on the line section 3 and the un-faulted section has been restored. The breaker at substation B has been re-closed after SW 5 opened. The normally open point SW4 is in the open position, but the line switch SW6 and the breaker at the substation B is in the closed position. The breaker and all the line switches on the feeder supplied from the substation A are in the closed position.

5.4.6 Case Study 4 - Permanent Fault - Line Section 4:

When a fault occurs on the line section 4 the SEL351A_2 protection device trips and publishes the GOOSE message SEL351A_2.TRIP.PRO.G51PTOC.Op. The SEL2440 controller subscribes to the message and is mapped to virtual bit VB007. The fault detection and clearance process take 1.478 seconds. The SEL2440 SelVariable SV05 logic asserts when it receive OMICRON binary output 4 GOOSE message. The SEL2440 SelVariable SV04 logic assert, when it receives the virtual bit VB007 as well as the SEL2440 SelVariable SV05. The protection trip GOOSE message from the SEL351A_2 is mapped as an incoming GOOSE message to virtual bit VB007 in the SEL2440 controller. SEL2440 output OUT109 is triggered when the SelVariable SV13 logic is asserted and the virtual bit VB008 is received. The status of the breaker at the substation B is published via GOOSE message by the SEL351A_2 IED and is mapped as an incoming GOOSE message to the virtual bit, VB008 at the SEL2440 controller. When the SEL2440 output OUT109 is triggered it changes the line switch SW6 from the closed to the open position. The fault is isolated in approximately 7.5 milliseconds. When the SEL2440 output, OUT109 is asserted the SEL2440 controller issues an instruction for the normally open point SW4 to change its status from the open to the closed position, which takes approximately 4.2 milliseconds.

Test Results

Time Assessment

Name	Ignore before	Start	Stop	Tnom	Tdev-	Tdev+	Tact	Tdev	Assess
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.478 s	477.8 ms	+
LINE SW6 OPEN	State 2	State 2	Bin. In. 7 0>1	500.0 ms	1.000 s	1.000 s	7.500 ms	-492.5 ms	+
LINE SW4 CLOSE	State 3	State 3	Bin. In. 8 0>1	500.0 ms	1.000 s	1.000 s	4.200 ms	-495.8 ms	+

Assess: + .. Passed x .. Failed o .. Not assessed

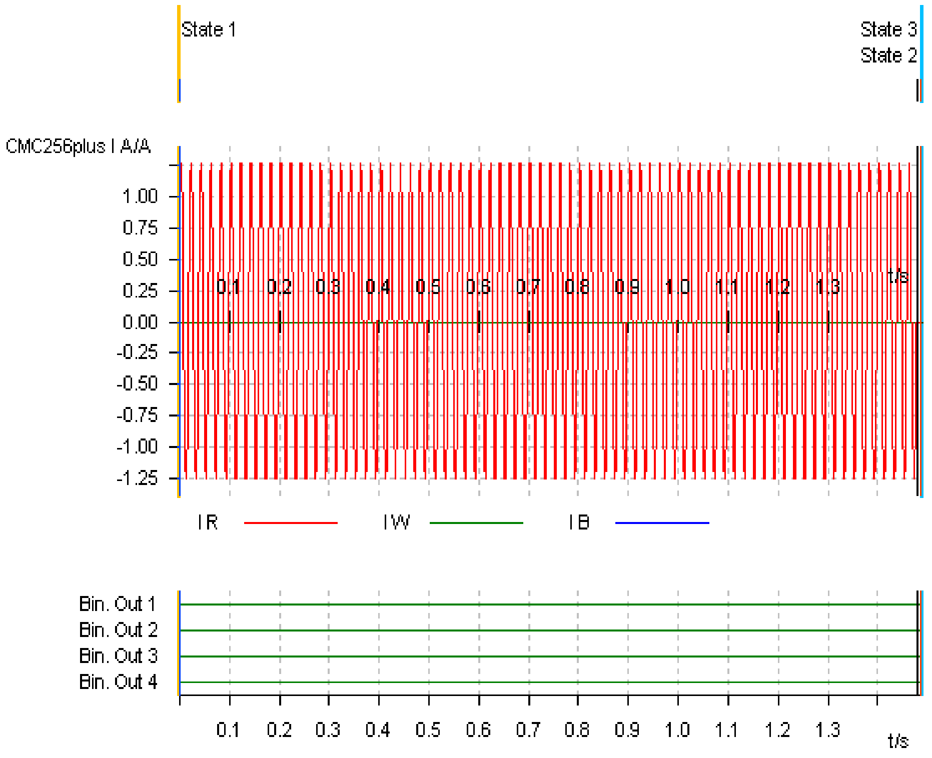


Figure 5.24: Test results for the fault on the line section 4

Figure 5.24 illustrates the setup of the 3 states that are assessed. The first state evaluates the fault on the test system and is monitored by the OMICRON binary input1. It will record the time period from the application of the fault current until the trip output of the SEL351A_2 protection device has operated. The second state evaluates the opening of the line switch SW6 and is monitored by the OMICRON binary input 7. This state will start on successful triggering of the previous state and end when the auxiliary relay that represents the line switch has operated and opened. The third and last state evaluates the closing of the normally open point line switch SW4 and is monitored by the OMICRON binary input 8. This state starts when the line switch SW6 has successfully opened and stops when the line switch SW4 has closed.

The time line as illustrated in Figure 5.25 and it shows that the fault on the line section 4 was cleared in 1.478 seconds. The line switch SW6 have changed from the closed position, to the open position in 7.5 milliseconds after the fault has been cleared and the line switch SW4 closed in 4.2 milliseconds after the switch SW4 has opened. The results show that it takes a total of 1.489 seconds for the test system to do the entire process from detecting and clearing the fault, isolating the fault and restoring the service.

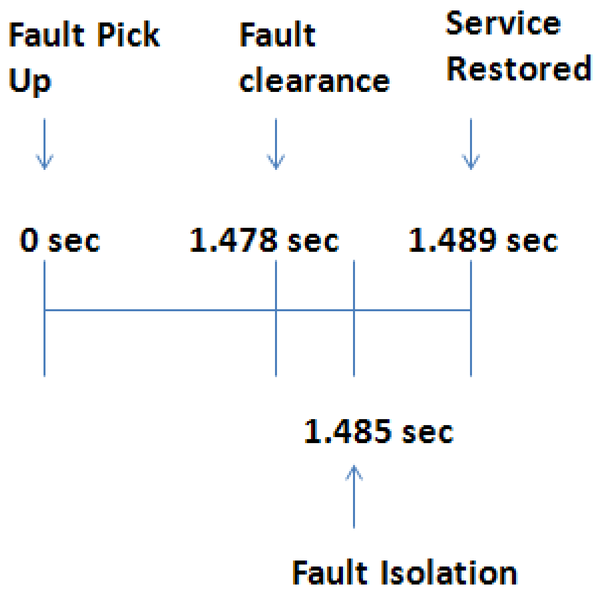


Figure 5.25: Time line for a fault on line section 4

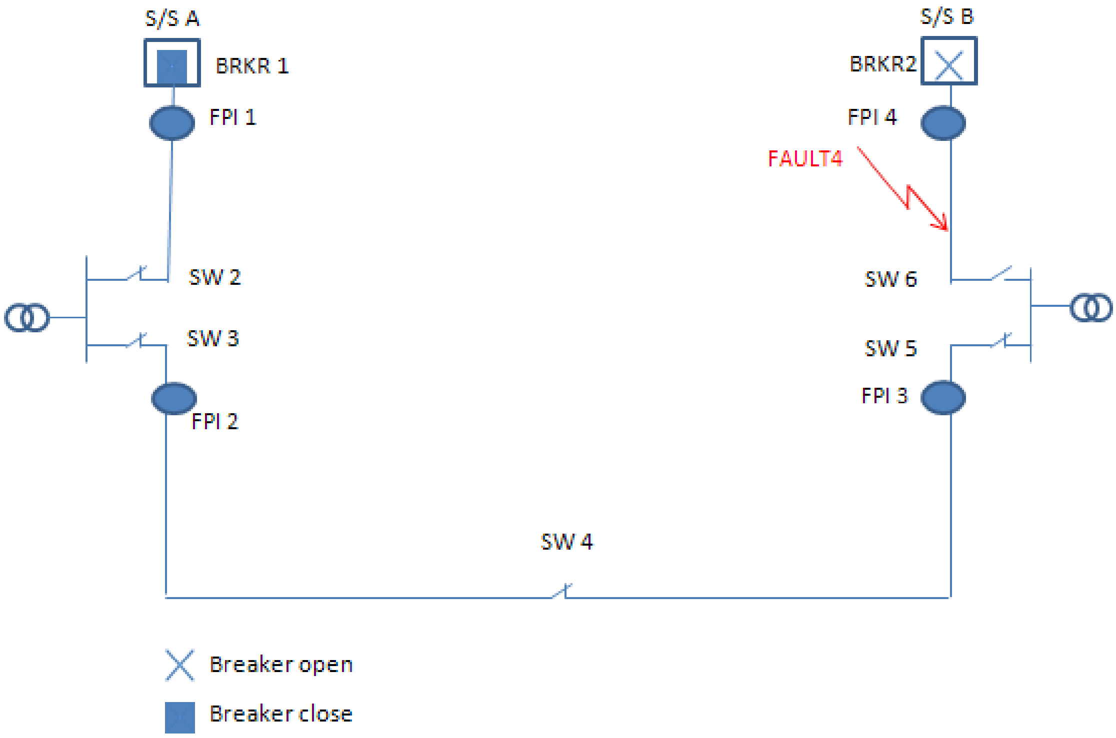


Figure 5.26: Single line diagram

Figure 5.26 shows that after the fault on the line section 4 has been isolated and service has been restored to the un-faulted line section the breaker at the substation B is in the open position as well as the line switch SW6 therefore isolating the faulted section of the line. The customers on the line section 3 are now fed from the substation A as the line switch SW4 was closed.

5.5 Multiple faults.

For the scenario of multiple faults occurring on the system simultaneously simulations were performed to evaluate the system under these conditions. It is expected that the system should be stable in the event of faults happening in different places of the network at the same time. It is also expected that it should still be able to perform its functions as per the design.

5.5.1 Fault on the line section 4 and fault on the line section 1

It is assumed that the fault on the line section 4 occurred before the fault on the line section 1. The test system was restored to its normal running state by manually switching the switches and breakers in its normal positions. The fault on the line section 4 caused the breaker at the substation B and the switch SW6 on the line section 4 to open and the switch SW4 to close. When the fault on the line section 1 was then simulated the breaker at the substation A opens as well as the switch SW2 and the switch SW4 is closed. Therefore the fault on the line section 1 was successfully isolated and the network was re-configured. However, from this scenario, it is observed that all the customers on both the feeders will be without power. This is due to the fact that both substation breakers are in the open position. Even if the switch SW4 is closed it cannot supply any customers as there are no additional power sources.

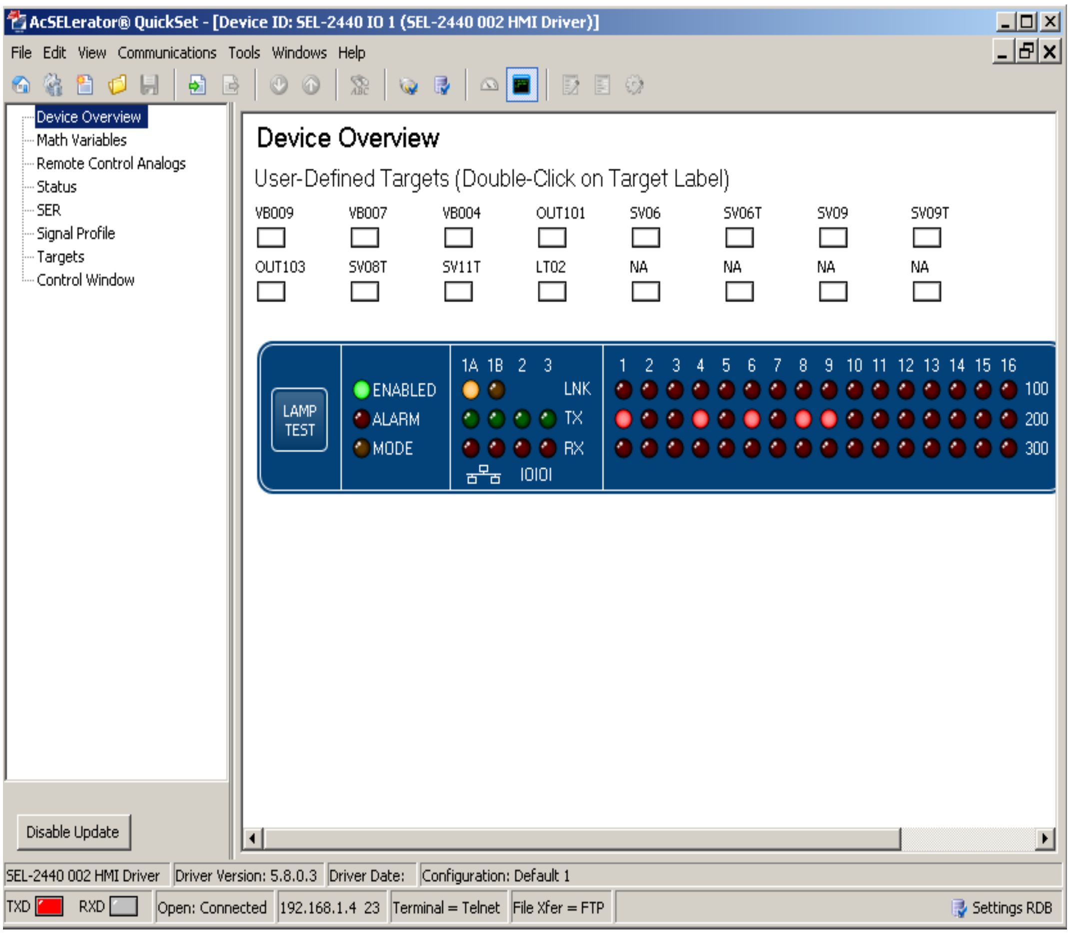


Figure 5.27: SEL2440 Controller inputs after the multiple faults occurred

Figure 5.27 shows that the SEL2440 inputs IN201, IN204, IN206, IN208 and IN209 are asserted. These inputs show the statuses of the line switches after the multiple faults have occurred on the line sections 4 and 1. What can be observed from this case study is that when the line has been reconfigured as a result of a fault it has to be repaired as soon as possible and put the feeder back to service as per normal.

Figure 5.28 shows the single line diagram after the multiple faults have occurred. For the test system network to be more reliable an additional source is required. This additional source has to be connected to the line sections 2 or 3. With the second source connected to the system it would supply customers on line sections 2 and 3 in the event of multiple faults occurring on the line sections 1 and 4.

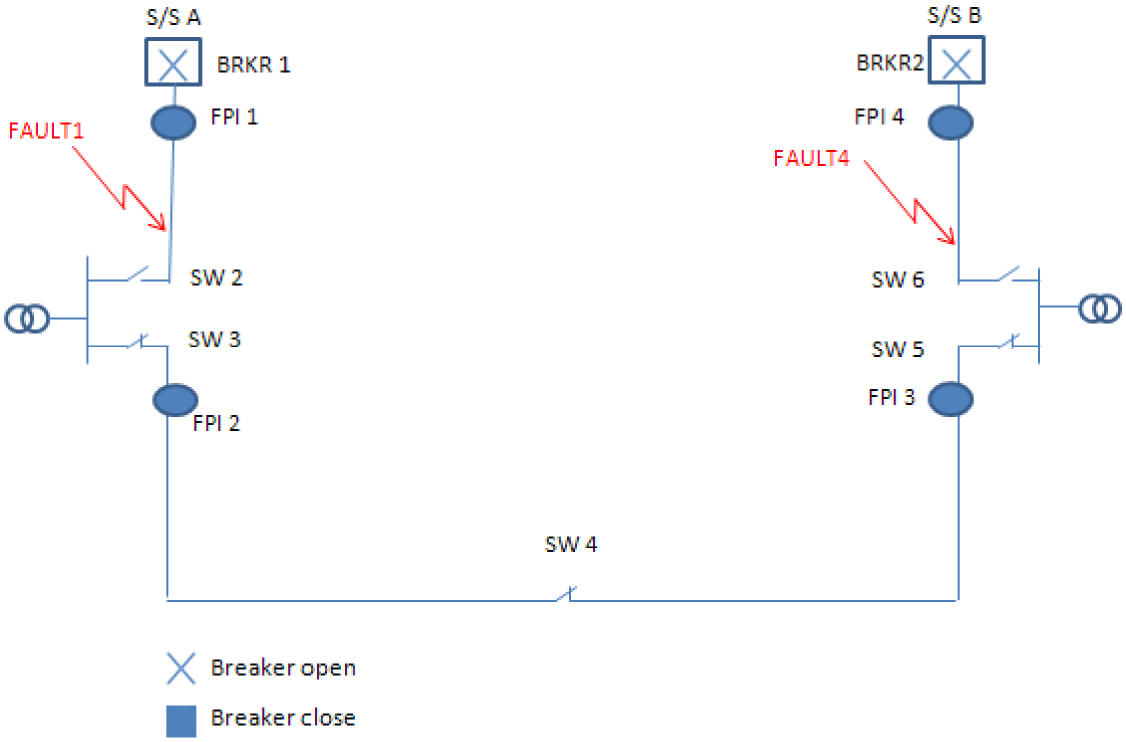


Figure 5.28: Single line diagram after the multiple faults have occurred

Tests were also done while one of the IEDs was disconnected from to the Ethernet switch by disconnecting the LAN cable. It resulted in the protection IED tripping for the faults, but the automation did not initiate. The distribution automation system is a peer-to-peer communication system, therefore if one of the devices is not connected or there's an error in the communications it will negatively affect the functioning of the system.

5.5.2 Fault on the Line Section 3 and Fault on the Line Section 2

It is assumed that the fault on the line section 3 happened before the fault on the line section 2. When the fault on the line section 3 occur the breaker at the substation B tripped and then the line switch SW5 (IN207) open. On the successful isolation of the fault the breaker at the substation B re-closes. When the fault on the line section 2 occurred thereafter, it opened the breaker at the substation A and then the switch SW3 (IN203). On the successful isolation of the fault on the line section 2 the breaker at the substation A is re-closed (VB004 asserted) as illustrated in Figure 5.29. It also shows that inputs IN202, IN203, IN205, IN207 and IN210 are asserted. See Table 5.1 for the location of the various SEL2440 controller inputs on the test system network.

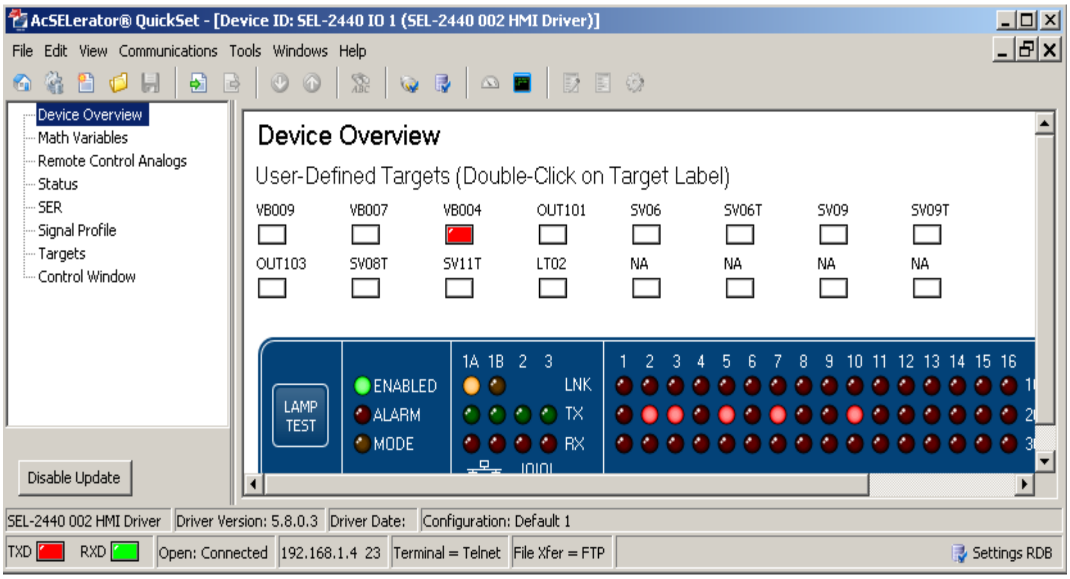


Figure 5.29: SEL2440 Controller Line switch status inputs after multiple faults

The test system behaved as expected. The effects on the customers however are that both the line sections 2 and 3 are isolated and awaiting repair as shown in Figure 5.30. It further shows that the breaker at the substation A and the line switch SW2 are in the closed position, meaning that the customers on the line section 1 are served with power. The customers on the line section 4 also have power since the breaker at the substation B and the line link SW6 are closed. If it is assumed that each line section has the same amount of customers, then one can deduce that with this scenario only 50% of the customers on the entire test system will be served with power. However, when compared to a network without any automation applied all customers would have been without power and had to await repairs for the power to be restored.

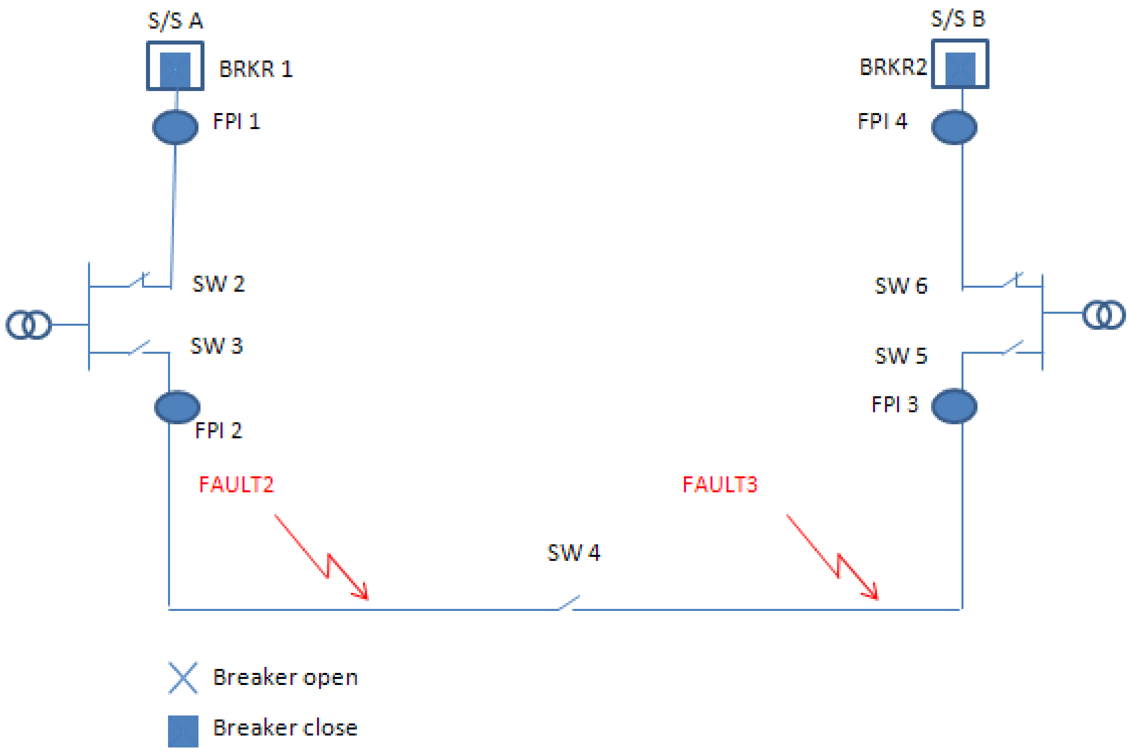


Figure 5.30: Single line diagram after multiple faults have occurred

5.5.3 Fault on the Line Section Fault 3 and Fault on the Line Section 1

It was assumed that the fault on the line section 3 happened before the fault on the line section 1. The status of the network for fault 3 would be that the line switches SW5 will be open as well as the line switch SW4. The breaker at the substation B will be closed. Then a fault simulation was done on the line section 1 and the breaker at the substation A opened as well as SW2 and the normally open point closed as expected. In the event of this scenario taking place, it will result in the line sections 1, 2 and 3 being without power. This is due to the line section 3 fault with the switch SW5 being in the open position. Figure 5.31 shows the line switches statuses of the network for this scenario. Thus, even with automation that has taken place and with the NOP closed enabling power to be supplied via the alternate substation in this case from the substation B, it will have no effect. Thus with the same assumptions made previously, 25% of the network will be served with power in the event of this scenario happening.

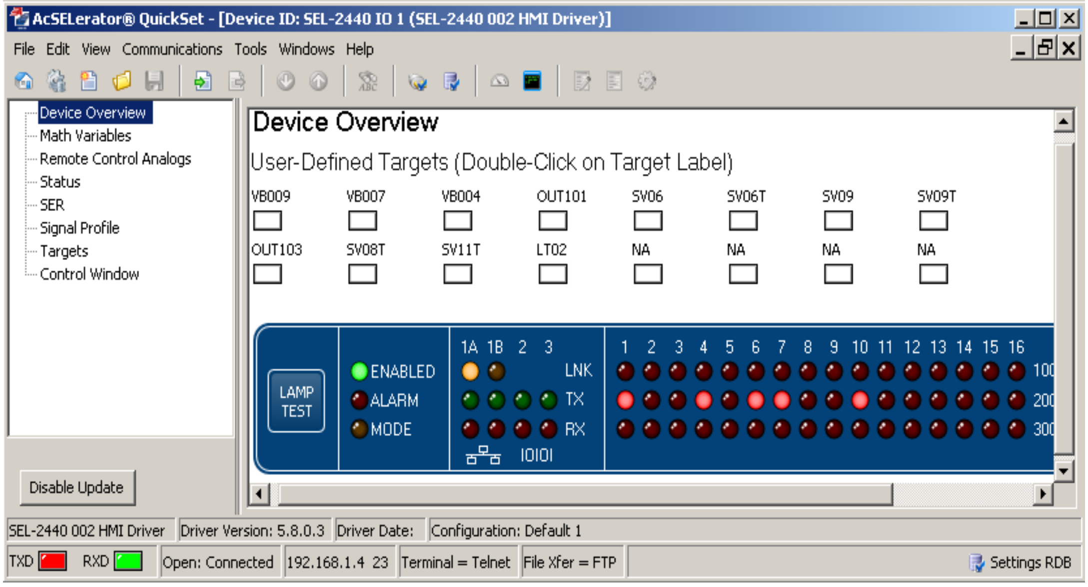


Figure 5.31: SEL2440 controller line link status inputs after multiple faults have occurred

The test system operates as expected for the multiple faults 3 and 1. The fault detection, isolation and restoration functions operated as expected. It was observed that fault 1 closed SW4 which bounds a faulty line section meaning that there is a fault on that section as illustrated in Figure 5.32. However, it will not result in a dangerous situation as the switch SW5 is already in the open position therefore isolating the line section 3. Therefore, there will not be a situation where the substation A will be feeding into a fault.

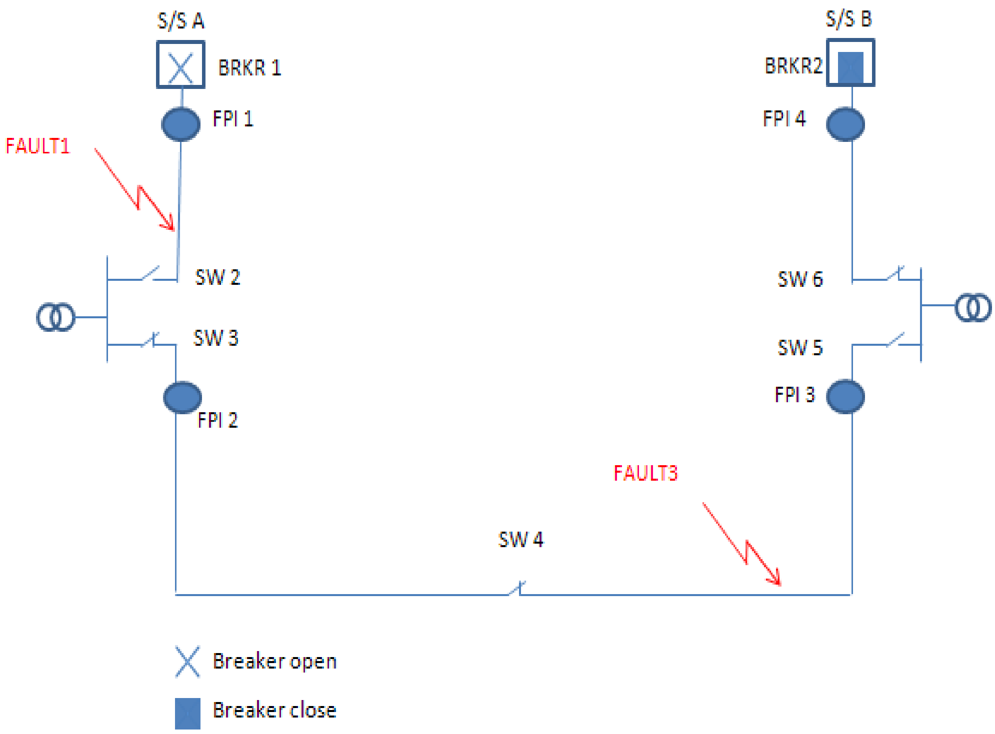


Figure 5.32 : Single line diagram for faults on the line sections 3 and 1

5.5.4 Fault on the line section 4 and fault on the line section 2

It was assumed that the fault on the line section 4 occurred before the fault on the line section 2. After the network was reconfigured by a fault on the line section 4 (feeding from substation B) the breaker and the line switch SW6 will open and the switch SW4 will be closed. Therefore, if a fault on the line section 2 would then occur, the breaker at substation A opens then the line link SW3 would open and then the switch SW4. It is then expected that the beaker at substation A re-closes as the faulty line section 2 is isolated.

The simulations show that the network still behaved as expected when faults were simulated on the line section 2 feeding from the substation A after a fault occurred on the line section 4. It was found that in the event of multiple faults occurring only the customers on the line section 1 will have power as the switches SW 3 and SW 6 are open as shown in Figure 5.33. The simulations showed that in no circumstances were there any line switches that closed onto any faulted sections.

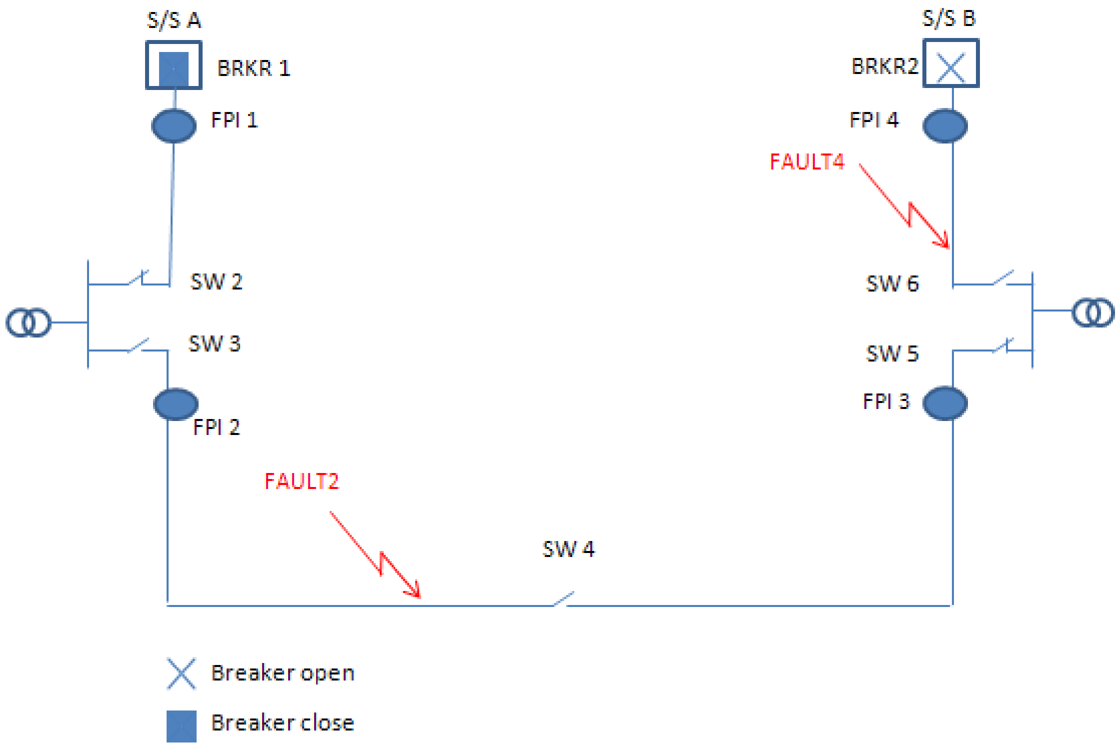


Figure 5.33: Single Line Diagram for the multiple faults 4 and 2

5.6 Conclusions

Several conclusions can be made from the simulations that were performed on the IEC61850 based test system. First of all it must be mentioned that it was possible to successfully incorporate IEC61850 standard functions in the distribution test system environment. Rapid and selective fault isolation were made possible by the use of the SEL 351A over current and earth fault IEDs. The fault clearance times are subject to the protection settings applied to the protection devices. Only earth faults were simulated since the test system did not have to grade with any upstream or downstream protection devices. Therefore the over current and earth fault protection settings in the protection devices were made the same. The algorithm successfully isolated all the faults correctly for all the various case studies The fault isolation duration can be adjusted to the users or the network requirements. The fault isolation duration for this project for the various simulations was between 4 and 250 milliseconds. The algorithm successfully performed the service restoration for all the simulated scenarios. The restoration duration can also be adjusted to what is required and was between 4 milliseconds and 1 second. Multiple faults can occur on any system and when it happens the system should still be able to be stable and operate within parameters. When multiple faults were simulated on the test system more line sections were affected, compared to a fault on only one line section. The test system, however operated successfully for multiple faults. The faults were simulated on one line section, then on the other and not simultaneously. There were certain faults where the entire system would be without power even if the network did successfully reconfigure its self. To overcome this situation an additional power source would be required to supply the un-faulted line sections.

The next chapter describes the conclusions, deliverables, future work and recommendations.

CHAPTER SIX

CONCLUSION, THESIS DELIVERABLES AND FUTURE WORK

6.1 Introduction

Presently there is more attention given to distribution automation by utilities because of the renewed push towards reliable and efficient distribution networks and the customers has become more sensitive to supply outages due to their increasing dependency on electricity.

Every utility's needs are unique, however in general their requirements are the deployment of automation technologies for protection, control, monitoring, and operation of the distribution systems. This enables the utilities to monitor, control, and operate distribution components in a real-time or non-real-time mode from remote locations. In the past line operators were responsible to locate the faults on the networks manually, thereafter do the necessary switching and return power to the customers. In the past power companies were responsible for the generation, transmission and distribution of energy to the customer. However the free market for energy supply (deregulation) had its impact on the distribution network, pointing out the need for reduced outage times. This has led to the automation of the feeder system as a tool for improved reliability and customer service. Simultaneously, the enhancement of the simple SCADA with a distribution management system (DMS) has led to a much higher level of distribution network control. There are several key issues a utility/power company has to consider when it wants to apply automation on its distribution networks. It has to do a cost and feasibility study when it intends to replace old equipment with automation ready equipment or if it intends to modify existing equipment. It also has to consider what type of automation it will apply, for example, central or distributed, system or local or a combination of these. And finally, without a proper business case any automation project will not be successful.

The fact that the majority of distribution protection systems do not meet the required automatic control capabilities all around South Africa has led to the need for the investigation of the implementation of the distribution network using intelligent automatic and control capabilities of the new technologies. Initially the question was asked, "can the IEC61850 standard be implemented in the distribution environment since it is the communication standard for substations". The thesis objective is to develop an algorithm for fault detection, location, isolation and system supply restoration using the functions of the IEC61850 standard-based technology and to design and construct a lab scale system that would meet existing and future requirements for the control and automation of a typical underground distribution system. Tests and simulations that have been done on the lab scale system showed that it is indeed possible. The requirement for the lab scale distribution system is to have the ability to clear faults through reliable and fast protection operation, isolate faulted section/s, on the network and restore power to the unaffected parts of the network through automation control and automation function of the IEC61850 standard. The implementation of the proposed algorithm, the utilization of the protection scheme, communications infrastructure, intelligent discrete programmable controller and the IEC61850 standard are the building blocks in the test system. Faults on each line section were simulated and the system response analyzed. The performance of the algorithm was confirmed through various simulations on the test system. The simulations also proved fast fault clearing times and successful fault isolation when all the system requirements were fulfilled. The question of the impact of multiple faults on the automation process was also addressed

This chapter summarizes the key findings of the research and the thesis deliverables as discussed in section 6.2. Section 6.3 discusses the Academic / Research Application of the thesis. Section 6.4 describes the evaluation of the performance of the developed algorithm and the test bench. Section 6.5 describes the research future work which can enhance the outputs of the research project in the distribution automation environment. Section 6.6 provides the reference for the thesis publication and section 6.7 gives the conclusion.

6.2 Deliverables

The thesis have proved that the problem that utilities face with extended outages on distribution ring networks can be solved through an innovative distribution automation system that uses IEC61850 standard-based functionalities. The implementation of the proposed algorithm, the utilization of a protection scheme, communications infrastructure, intelligent discrete programmable controller, integration with other devices and the IEC61850 standard are the building blocks of the developed test system and present the bigger part of the thesis deliverables, which can be grouped in the following way:

6.2.1 Literature review

Various papers were reviewed, compared and analysed in order to interpret and understand the various methods and approaches implemented in the field of distribution automation. The literature review describes that during the past two decades utilities have been automating the operation of the distribution network to provide a higher level of reliability and operational efficiency. However, the automation efforts were not excessive and if applied on a wider scale the improvements in reliability can be much higher. In most utilities the substations are fairly automated, but the distribution feeders are much less automated. Early

Supervisory Control and Data Acquisition (SCADA) systems promised to improve reliability, but earlier systems had relatively low calculation and communication capabilities. The level and capability of the existing monitoring, control, and communication technologies played a major role in the development of distribution automation. An IEC TC57 work group defined the IEC 61850 standard for "Communication Networks and Systems in Substations". The standard is not only used between the station level computer and bay level devices, it is also used in open communication to the primary equipment. The literature review also presents that the IEC 61850 standard will become the main criterion for distribution automation.

6.2.2 Development of a model of the CPUT distribution network used as a case study

The case study system consists of 2 radial feeders which can be interconnected via a normally open point. Each feeder has two line sections with a line switch at each end of the line section respectively. Each feeder is supplied from a substation that has a protection IED and a circuit breaker installed. Both substations are fed from a single source of supply. The switching devices out on the feeders are line switches and this means that the fault has to first be cleared by the respective circuit breakers and then thereafter by the opening of the line switch. This is due the fact that line switches do not have fault current breaking capacity.

6.2.3 Calculation and implementation of the protection settings of the IED protection scheme.

- SEL351A feeder protection IEDs were considered in this thesis
- A protection IED is installed at each substation, which performs protection functions.
- Only earth fault protection schemes were considered
- Quickset AccSELerator software was used to apply settings to the IED devices
- Performance of protection settings were verified through tests described in Chapter 5
- The protection scheme was tested by the simulation of fault currents on each of the line sections.

6.2.4 Development of algorithms for fault detection, location, isolation and service restoration

- The algorithm is designed on a completely centralized communication-based automation system.
- The algorithm uses various conditions that have to be satisfied before it executes an instruction or control.
- If all the required algorithm conditions are not true the automation process is not initiated and only the protection function will operate and then ends.
- The algorithm changes the network after a permanent fault has occurred on the feeder to reconfigure the network.
- The operation of the algorithm is based on the exchange of GOOSE messages.
- Algorithm is programmed within the SEL2440 controller
- The intelligent automation algorithm was evaluated and the optimal performance and correct operation of the system were confirmed through various tests and simulations.

6.2.5 Development of the test bench system

- A test bench was built that represent a distribution automation system for a typical underground distribution power network.
- Consists of hardwired auxiliary relays as well as GOOSE compliant IEDs, Omicron 256plus, managed Ethernet switch and a personal computer.
- Test bench is used to perform tests to investigate the performance of the GOOSE communication-based developed distribution automation functions.
- Fault conditions are simulated by the Omicron 256plus.
- Fault location function is simulated by the Omicron 256plus test set through the use of its binary outputs.
- Fault detection, location, isolation and service restoration is accomplished by the developed novel algorithm residing in the SEL2440 controller.
- System is designed to be manually reset to normal running condition after a fault has reconfigured the system through operation of hard-wired push buttons.

6.2.6 Software developed and Omicron 256plus test set configuration

- SEL AccSELerator Architect configuration tool is used to configure the SEL devices to enable communication between the devices in this thesis.
- GOOSE Receive, GOOSE Transmit, Reports and Datasets are the main sections of the AccSELerator Architect Software used.
- It is used in the design and commissioning of IEC 61850 communications of the IEDs.
- Used in the setup of the published GOOSE messages and the mapping of the incoming GOOSE messages.
- Development of test files in Omicron and development of software in AccSELerator Architect Software for all deliverables is shown in Table 6.1

Table 6.1: Test files developed in an Omicron test set and GOOSE configuration developed in AccSELerator Architect Software environments.

Omicron file name	Function
CPUT FAULT1.occ	Setup of test module for the capturing of fault clearance, fault isolation and service restoration times for a fault on the line section 1
CPUT FAULT1_2.occ	Setup of test module for the capturing of fault clearance, fault isolation and service restoration times for a fault on the line section 2. GOOSE configuration setup of the Omicron
CPUT FAULT3_4.occ	Setup of test module for the capturing of fault clearance, fault isolation and service restoration times for a fault on the line section 3. GOOSE configuration setup of the Omicron
CPUT FAULT4_BRKR2.occ	Setup of test module for the capturing of fault clearance, fault isolation and service restoration times for a fault on the line section

	4.
CPUT FAULT1_2_due to fault4.occ	Setup of test module for multiple faults on line section 2 and 4
CPUT FAULT1_2_due to fault3.occ	Setup of test module for multiple faults on line section 2 and 3
CPUT FAULT1_due to fault3.occ	Setup of test module for multiple faults on line section 1 and 3
CPUT FAULT1_due to fault4.occ	Setup of test module for multiple faults on line section 1 and 4
AccSELerator Architect file name	
CPUT_1.selaprj	GOOSE transmit and receive configuration setup of SEL2440, SEL351A_1, SEL351A_2 and SENSORS IED's
AccSELerator Quickset file name	
CPUT_PROJ_2440.	Setup of SEL2440 controller IED
CPUT_PROJ_351A_1	Protection settings setup of SEL351A_1 IED
CPUT_PROJ_351A_1	Protection settings setup of SEL351A_2 IED

6.3 Evaluation of the performance of the developed algorithm and test bench

- Omicron 256plus test set was used for all the tests on the built test bench.
- The evaluation was based on case studies performed on each line section of the system.
- Performance evaluation of the system was performed during multiple fault conditions on the system.

6.4 Academic/Research Application

The investigation into the use of the IEC61850 standard in the distribution environment had necessitated the need to design and construct a test bench. The test bench was used to simulate a typical distribution network and housed all the simulated field devices and IEDs that have to be controlled or operated by either GOOSE based messaging or hardwired signals. The test bench can be used by students to do investigations in the distribution automation environment. New DA algorithms can be designed and programmed in the SEL2440 programmable controller and tested in the test bench. They can also use the test bench in understanding the basics in the various parts that the system offers which include: establishment of communication to a single device, communication between devices, programming devices, application of settings, reading settings, understanding the functions of the applied algorithm etc. The developed algorithm can be used by the industrial companies to develop projects for various distribution networks and the test bench can also be used to investigate and evaluate the performance of their projects. The test system will serve as an important demonstration and practical tool of the IEC61850 standard-based technology to students studying in this field.

6.5 Future work

The test system has several functions that have not been included in this work and can be done as future projects. First, the test system presently has to be restored to the normal operation condition manually after it has been reconfigured. It can be done automatically through the issuing of a single action i.e. pushing of a button configured for this purpose. Second, the test system has to ensure that there is enough capacity available from the alternate supply before reconfiguration can happen. Third, the fault location function can be performed by fault passage indicators. Four, the line switches can be controlled by IEDs which will result in the test bench operating with only GOOSE messaging. Five, the test bench system considers only one power source therefore the behaviour of the system under more than one source can also be investigated as a future project. The system has to be able to select the source that has the most capacity available when restoring services. Six, only SEL IEDs were used in this thesis and it would be interesting to see if the system will operate in the same efficient way with multiple vendor devices.

6.6 Thesis publication

Julie. F, R. Tzoneva, (2014) Development of an IEC 61850 standard-based automation system for a distribution power network. Sent to Turkish Journal of Electrical Engineering & Computer Sciences (TUBIKAT), December 2014.

BIBLIOGRAGPHY

A DNP3 Protocol Primer, http://www.DNP.org

Allen, W. 2008, "Effects of Wide-Area Control on the Protection and Operation of Distribution Networks" *Power Systems Conference, 2009, pp 1 - 10*

Angelo, C & Selejan, P, 2013, "Technologies of the self-healing grid". *Electricity Distribution (CIRED 2013), 22nd International Conference and Exhibition*, pp. 1-4.

Ani Pahwa, A., Shultis, J., Rucker,D.M and Dowling, WN,1991. "Field Test of Distribution Automation Equipment at Kansas Utilities" *IEEE Transactions on Power Delivery, Vol. 6, No. 4, October 1991, pp: 1564-1572*

Apostolov, A. & Vandiver, B. 2011 "IEC 61850 GOOSE Applications to Distribution Protection Schemes" *Protective Relay Engineers, 2011 64th Annual Conference pp 178-184*

Baxevanos, I.S. & Labridis, D.P., "Implementing Multi agent Systems Technology for Power Distribution Network Control and Protection Management", *Power Delivery, IEEE Transactions on Power Delivery, Vol 22, Jan, 2007, pp 433- 443*

Belagur, J. & Schmidt, R. 2008, "IP Communication for Substation Automation, Distribution Automation and Other Utility Applications" *Transmission and Distribution Conference and Exposition T&D. IEEE/PES,* 2008, pp: 1 - 9

Blair, W.E., Alto, P., Malvern, P.A. & Gentz, C.H. 1985 "A Methodology for Economic Evaluation of Distribution Automation" *Power Apparatus and Systems, IEEE Transactions on Power Apparatus and Systems Volume: PAS-104, Issue: 10 October 1985 pp: 2954 - 2960*

Brantley, P., Donahoe, K., Jacobus, P.E. & Udren, T.E. 2008, "The Application of IEC 61850 to Replace Auxiliary Devices Including Lockout Relays" *Power Engineering Society Summer Meeting, 2002 IEEE Volume: 1, pp294-296*

Brown, R.E. 2008, "Impact of Smart Grid on Distribution System Design*" Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, IEEE 2008, pp: 1 - 4*

Brunello, G., Smith, R. & Campbell, C.B. 2001 "An application of protective relaying scheme over Ethernet LAN/WAN" Transmission and Distribution Conference and Exposition, IEEE/PES, 2001, Volume: 1 pp: 522 - 526

Chan, M.L., William, H., Crouch, J and Allen, G, 1990. "An Integrated Load Management, Distribution Automation and Distribution SCADA System For Old Dominion Electric Cooperative". *IEEE Transactions on Power Delivery, Vol. 5, No. 1, January 1990, pp: 384-390*

Charles, D., McDaniel, R. & Dood, M. 2007, "Protection, Control, and Automation System for a Multi-station Looped Distribution System" *Industrial & Commercial Power Systems Technical Conference (I&CPS), 2007, pp: 1 - 8*

Chen, C., Lin, C., Hsieh, S & Hsieh, W. 2013, “Development of smart distribution grid.” *Next-Generation Electronics (ISNE), 2013 IEEE International Symposium, pp: 4 – 6*

Chen, C.S., Lin, C.H., Wu, C.J. & Kang, M.S.
“Feeder reconfiguration for distribution systemcontingencies by object oriented programming” *Power Engineering Society Summer Meeting, 2000. IEEE volume 1, pp: 431-436*

Chen, R. & Sabir, S. 2001, “The Benefits of Implementing Distribution Automation and System Monitoring in the Open Electricity Market” *Electrical and Computer Engineering, Canadian Conference, Volume: 2, 2001, pp: 825 - 830 vol.2*

Choi, S., Cokkinides, G.J. & Meliopoulos, A.P.S. 2010, “Autonomous State Estimation for the Smart Grid - Laboratory Implementation” *Transmission and Distribution Conference and Exposition, 2010 IEEE PES, pp: 1 -8*

Civanlar, S., Grainger, J.J., Yin, H. & Lee, S.S.H. 1988 “Distribution feeder reconfiguration *for loss reduction,” IEEE Transactions on Power Delivery, volume 3, no. 3, Jul. 1988, pp. 1217–1223*

Coffele, F., Booth, C and Dyśko, A, 2014, “An Adaptive Overcurrent Protection Scheme for Distribution Networks”. *IEEE TRANSACTIONS ON POWER DELIVERY 1, IEEE CIRE D 20th International Conference on Electricity Distribution, 2014, pp: 1 – 8*

Daniel, E. & Nordell, P.E. 2008, “*Communication Systems for Distribution Automation” IEEE Transactions on Power Apparatus and Systems, Volume: PAS-101 , Issue: 7, 2008 , pp: 1888 - 1893*

Dick, A.J., 1996. “Review of Communications Standards for Distribution Automation Applications” *Methods of Substation Automation, Half Day Colloquium, May 1996, p:1/1- 1/5*

Dodge, M.K. 2000, “Distribution Automation Project at the Northwest Arkansas Regional Airport” *Rural Electric Power Conference, 2000 pp: C6/1 - C6/5*

Dolezilek, D.J. & Schweitzer, S. 2009, “Practical Applications of Smart Grid Technologies” . *Innovative Smart Grid Technologies (ISGT Europe), 2nd IEEE PES International Conference and Exhibition on Power System Technology, 2011, pp: 1 - 8*

Dolezilek, D.J. 1999 “Microprocessor based relay information improves the power system” *Rural Electric Power Conference, 1999, pp: B5/1 - B5/9*

Dong xuejing & Han zhihai Jinan, 2008 *“Development Planning of Distribution Approach About the Maintaining Mode for Distribution Automation in City power supply company” 5CICED200885-05 CP 1349 Technical Session 5, 2008*

DongLi, J., XiaoLi, M., XiaoHui,S. 2011 “Study on technology system of self-healing control in smart distribution grid” *The International Conference on Advanced Power System Automation and Protection,2011, pp: 26 - 30*

Dragan, S., Popovic, D.S & Boskov, E.E. 2008, “Advanced Fault Management as a Part of Smart Grid Solution” *SmartGrids for Distribution, CIRED Seminar 23 - 24 June 2008, pp: 1 - 4*

Fujisawa, A. & Kurokawa, N. 2002, “Oversea Distribution Automation System based on Japanese experience” *Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume: 2, 2002, pp: 1164 - 1169*

Gao Cong, Zhou Hong, Deng Qijun, Zhang Ziyang, 2010 “The research and implementation of IEC 61850 communication protocol for smart grid” *Information Science and Engineering (ICISE), 2010 2nd International Conference on pp: 2463 - 2466*

Giacomoni, M, 2011. “Control and Communication for a Secure and Reconfigurable Power Distribution System”, http://www.freefulldownload.com [14 June 2012]

Glenn, C. & Lampley P.E. 2010, “Distribution Automation at Progress Energy Carolinas” *Power and Energy Society General Meeting, 2010 IEEE pp: 1 - 4*

Gomes, F.V., Carneiro, S., Jr., Pereira*,J.,* Vinagre, M.P., Garcia, N, & Araujo,L.R*. 2005,* “A New Heuristic Reconfiguration Algorithm for Large Distribution Systems” *IEEE Transactions on power systems VOL. 20, No. 3, AUGUST 2005, pp: 1373 - 1378*

Gonen, T. Electric Power Distribution System Engineering Mc Graw-Hill 1986.

Goswami S.K. & Basu, S.K. 1992 “A new algorithm for the reconfiguration of distribution feeders for loss minimization,” *IEEE Transactions on Power Delivery*, volume 7, no. 3, pp. *1484–1491, Jul. 1992.*

Greer, R., Allen, W., Schnegg, J. & Dulmage, A. 2011, “Distribution Automation Systems with Advanced Features” *Rural Electric Power Conference (REPC), 2011 IEEE, pp: C4-1 - C4-15*

Guo-fang, Z. & Yu-ping, L. 2008, “A Fault Location Algorithm for Urban Distribution Network with DG” Electric Utility Deregulation and Restructuring and Power Technologies, DRPT 2008, pp: 2615 - 2619

Gütschow, P. & Kachieng’a, M.O. 2005 “Making Business Sense of Distribution Automation Systems: The Case of Eskom, South Africa” IEEE Transactions on Power Systems, VOL. 20, No.1, pp272 – pp 278, February 2005

Gwan-Su Kim & Hong-Hee Lee, 2005 “A Study on IEC61850 based Communication for Intelligent Electronic Devices” *Advanced Power System Automation and Protection (APAP), 2011 International Conference on Volume: 1 pp: 223 - 227*

Ha, B.N., Lee, S.W., Shin, C.H., Kwon, S.C., Park, S.Y. & Park, M.H. 2009 “Benefits of Distribution Automation and Performance Results From A Network Trial*” Transmission & Distribution Conference & Exposition: Asia and Pacific, 2009, pp: 1 - 4*

Hammond, M.L., Bower, A.J and Wade T, 1997 “*The Practical Implementation of an 11kV Rural Distribution Automation Pilot Scheme*” *UK Developments in Power System Protection, 25-27th March 199 Conference Publication No. 434, IEEE, 1997, pp. 247-pp250*

Hansen, R., Hilton, A., Berger, B., Pullan, W., Gao, Z. & Lee, C.M. 2002, “Low-Cost Automation And SCADA: A Pacific RIM Perspective” *Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume: 3, pp: 2096 - 2099*

Hataway,G., Warren, T. & Stephens,C. 2006, “Implementation of a High-Speed Distribution Network Reconfiguration Scheme” *Power Systems Conference: Advanced Metering, Protection, Control, Communication, and Distributed Resources, 2006, pp: 440 - 446*

He, Y., Cheng, C. & Yiang, W. 2008, “Studies on technical proposal and management model based on automatization system in rural district” *Control and Decision Conference, 2008. CCDC 2008, pp: 185 - 189*

Hoffman, R. & Aouad, P. 2004, “Communications For A Large Distribution Automation Project in Thailand” *Power Engineering Society General Meeting, 2004. IEEE Volume 2 pp: 1446 - 1451 Vol.2*

Hsu, Y.Y. & Kuo, H.C. 2007 “A Heuristic Based Fuzzy Reasoning Approach For Distribution System Service Restoration,” *IEEE Transactions On Power Delivery, Volume 9, NO. 2, April 1994, pp. 948-953*

Hsu, Y.Y., Huang, H.M. 1992 “Distribution System Service Restoration Using A Heuristic Search Approach*,” IEEE Transactions on Power Delivery, Volume 7, No. 2, April 1992, pp. 734-740*

Huang Shu ,Liang xiao-bing & Gao xin-hua. 2010, “Key technologies and test method of Remote Terminal in Intelligent Distribution Automation System*” Electricity Distribution (CICED), China InternationL Conference on power distribution, 2010, pp: 1 - 6*

Hughes, J.W. 2008, “Challenges of Developing the Next Generation Distribution Automation System” *Transmission and Distribution Conference and Exposition, T&D. IEEE/PES, 2008, pp: 1 - 4*

IEC 61850 for dummies http://www.nettedautomation.com

IEC 61850-1. 2003. Communication networks and systems in substations – Part 1: Introduction and Overview. www.webstore.iec.ch

IEC 61850-7-3. 2003. Communication networks and systems in substations – Part 7-3: Basic communication structure for substation and feeder equipment – Common data classes. www.webstore.iec.ch

IEC 61850-7-4. 2003. Communication networks and systems in substations – Part 7-4: Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes. www.webstore.iec.ch

IEC 61850-8-1. 2004. Communication networks and systems in substations – Part 8-1: Specific Communication Service Mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3. www.webstore.iec.ch

IEC 61850-9-1. 2003. Communication networks and systems in substations – Part 9-1: Specific Communication Service Mapping (SCSM) – Sampled values over serial unidirectional multidrop point to point link. www.webstore.iec.ch

IEC 61850-9-2. 2004. Communication networks and systems in substations – Part 9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3. www.webstore.iec.ch

IEC 61850-7-1. 2003. Communication networks and systems in substations – Part 7-1: Basic communication structure for substation and feeder equipment – Principles and models. www.webstore.iec.ch

IEC 61850-5. 2003. Communication networks and systems in substations – Part 5: Communication requirements for functions and device models. www.webstore.iec.ch

IEC 61850-7-2. 2003. Communication networks and systems in substations – Part 7-2: Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI). www.webstore.iec.ch

IEC 61850-6. 2004. Communication networks and systems in substations – Part 6: Configuration description language for communication in electrical substation related to IEDs. www.webstore.iec.ch

IEC 61850 - Communication Networks and Systems in Substations: An Overview of Computer Science http://seclab.illinois.edu/

Introduction to MODBUS TCP/IP, http://www.prosoft-technology.com.

Janssen, M.C., Crossley, P.A. & Yang,L. 2011 "Bringing IEC 61850 and Smart Grid together" *Innovative Smart Grid Technologies (ISGT Europe), 2011 2nd IEEE PES International Conference and Exhibition on pp(s): 1 - 5*

Jintagosonwit, P. 2012, "Implementation Techniques of the IED and Network Monitoring System in IEC61850 SA" *Transmission and Distribution Conference and Exposition (T&D), 2012 IEEE PES, pp: 1 – 5*

Kasajima, T., Endo, R., Wada, Y., Kudo, Y. & Kanawa, H. 2004, "The development of the Advanced Distribution Automation System with optical fiber network of Tokyo Electric Power Co., Inc*." Power Engineering Society General Meeting, 2004. IEEE Volume 2 pp: 1441 - 1445*

Kazemi, S., Fotuhi-Firuzabad, M. & Lehtonen, M. IEEE, Volume*ability Worth Assessment of an Advanced Centralized Feeder Automation Scheme" Electrical Power & Energy Conference, EPEC. IEEE Canada* 2008, pp: 1 - 8

Kazemi, S., John Millar, R., and Lehtonen, M, 2014, "Criticality Analysis of Failure to Communicate in Automated Fault-Management Schemes". *IEEE TRANSACTIONS ON POWER DELIVERY, VOL. 29, NO. 3, JUNE 2014, pp: 1083 -1091*

Kazemi, S., Lehtonen, M. & Millar, R.J. 2011, "Impacts of Automatic Loop Restoration Schemes on Service Reliability" *Reliability of Transmission and Distribution Networks (RTDN 2011), IET Conference on pp: 1 - 6*

Koizumi, S., Okumura, M. & Yanase, T. 2005 *"Application and Development of Distribution* Automation Systems in TEPCO" *Power Engineering Society General Meeting, 2005. IEEE 2005, pp: 2429 - 2435*

Kwon, S., Kim, J., Song, L. & Park, Y. 2008, "Current Development and Future Plan for Smart Distribution Grid in Korea*" Smart Grids for Distribution IET-CIRED Seminar Paper No 141, 2008, pp: 1 - 4*

Kyeong J.M., Park, J.H. & Kim, H. 2001 "Development of Real-Time Service Restoration For Distribution Automation System." *Industrial Electronics, Proceedings. IEEE International Symposium, 2001 Volume: 3, 2001, pp: 1514 - 1519*

Lakhoua, M.N. & Jbira, M.K. 2012 "Project Management Phases of a SCADA System for Automation of Electrical Distribution Networks" *International Journal of Computer Science Issues (IJCSI), Vol. 9, Issue 2, No 2, March 2012*

Le-Tian, T. 2008, "*The Application of Practical Distribution Automation Technology in Shanghai Distribution Grid"* China International Conference on Electricity Distribution, 2008, pp: 1 - 5

Lim, H., Kim, Y.I., Lim, H.T,. Choi, M.S., Hong, S., Lee, S.J., Lim, S.I., Lee, S.W. & Ha, B.N. 2008, "Distributed Restoration System Applying Multi-Agent in Distribution Automation System" *Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, 2008 IEEE, 2008, pp: 1 - 7*

Lim, I., Choi, M., Lee, S. & Kim, T. 2009, "*Intelligent Distributed Restoration by Multi-Agent System Concept in DAS"* Intelligent System Applications to Power Systems, ISAP '09. 15th International Conference on *Power System Technology,* 2009, pp: 1 - 6

Lin, C., Chuang, H., Chen, C., Li, C. & Ho, C. 2009, "Fault Detection, Isolation and Restoration using a Multiagent-based Distribution Automation System" Industrial Electronics and Applications, ICIEA, 4th IEEE Conference on Power System Technology, 2009, pp: 2528 - 2533

Liu, C.C., Lee, S.J. & Venkata, S.S. 1988 "An Expert System Operation Aid For Restoration and Loss Reduction of Distribution Systems," *IEEE Transactions on Power Systems, Volume 3, No. 2, May 1988, pp. 619-626*

Marais, A. & Jones, R. "Distribution automation an impact on Ekom's existing and planned infrastructure", 9 June 1998, http://bits.eskom.co.za

Matsumoto, Y., Ono,A., Hase, S., Kinoshita,T. & Abe, K. 2002, "Development of the advanced distribution automation system using genetic algorithm" Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume: 1, 2002, PP: 214 - 219

McCal, L.V. and Chambers, B.J. 1983, "Defining a Distribution System For Computer Controlled Distribution Automation". *IEEE. Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 8, August 1983, pp: 2665-2669*

Miao, S., Li, Y., Fu, Y., Liu, P. & Zhang, W. 2010, "A Feeder Automation Scheme Based On Wireless Sensor Network" *Proceedings of the 2010 International Conference on Modelling, Identification and Control, Okayama, Japan, July 17-19, 2010 Okayama Japan, pp:* 733 - 738

Modbus Application Protocol Specification V1.1b, Modbus-IDA, December 2006, pp. 1-51, www.modbus-IDA.org.

Mohagheghi, S., Mousavi, M., Stoupis, J. & Wang, Z. 2009, "Modeling Distribution Automation System Components Using IEC 61850" *Power & Energy Society General Meeting, 2009 PES '09 IEEE, pp: 1 - 6*

Mohagheghi, S., Stoupis, J. & Wang, Z. 2009, "Communication Protocols and Networks for Power Systems: Current Status and Future Trends" *Power Systems Conference and Exposition, 2009. PSCE '09. IEEE/PES pp 1-9*

Mohagheghi, S., Tournier, J.C., Stoupis, J., Guise, L., Coste, T., Andersen, C.A. & Jacob, D. 2011, *"Applications of IEC 61850 in Distribution Automation"* Power Systems Conference and Exposition (PSCE), 2011 IEEE/PES, pp: 1 - 9

Morelato, A.L. & Monticelli, A. 1989 "Heuristic Search Approach To Distribution System Restoration," *IEEE Transactions on Power Delivery, Volume 4, no. 4, Oct. 1989, pp. 2235-2241*

Moreno-Muñoz, A., Pallarés-López, V., González de la Rosa, J.J., Real-Calvo, R., González-Redondo, M. & Moreno-García, I.M. 2012, "Embedding Synchronized Measurement Technology for Smart Grid development" *Industrial Informatics, IEEE*

Transactions on Electricity Distribution, pp: 52 - 61

Moxley, R. & Fodero, K. 2004, "High-Speed Distribution Protection Made Easy: Communications-Assisted Protection Schemes for Protection Applications" *Power Systems Conference: Advanced Metering, Protection, Control, Communication, and Distributed Resources, 2006. PS '06, pp: 123 – 138*

Newbould, A. ; Hu, L. ; Chapman, K."Cable automation for urban distribution systems" *Developments in Power System Protection, Conference Publication No.479 IEEE 2001, pp: 319 - 322*

Nhat Nguyen-Dinh, Gwan-Su Kim & Hong-Hee Lee, 2007 "A Study on GOOSE Communication based on IEC 61850 using MMS Ease Lite" *Control, Automation and Systems, 2007. ICCAS '07. International Conference on pp: 1873 - 1877*

Nokhum, S., MarkushevichIvan. C., Herejk and Nielsen, R.E, 1994. "Functional Requirements and Cost-Benefit Study for Distribution Automation at B.C.HYDRO*" IEEE Transactions on Power System. Vol.9, No.2, May 1994, pp: 772-778*

Nordman, M.M. & Lehtonen, M., "Distributed agent-based State estimation for electrical distribution networks", *Power System, IEEE Transactions on Power Delivery, Volume 20, May 2005, pp 652-658*

Northcote-Green J & Wilson R. Control and automation of electrical power distribution systems, NW: Tayler and Francis 2007.

Nunoo, S. & Ofei, A.K. 2010, "Distribution Automation (DA) Using Supervisory Control and Data Acquisition (SCADA) with Advanced Metering Infrastructure (AMI)" *Innovative Technologies for an Efficient and Reliable Electricity Supply (CITRES), 2010 IEEE, pp: 454 - 458*

Overview and Introduction to the Manufacturing Message Specification Overview and Introduction (MMS) http://www.sisconet.com

Parikh, P., Voloh, I & Ontario, M, 2013 "Distributed Fault Detection, Isolation, and Restoration (FDIR) Technique for Smart Distribution System" *Protective Relay Engineers, 66th Annual Conference.GE Global Research Center,Niskayuna, 2013,* pp: 172-176

Parikh, P.P., Kanabar M.G. & Sidhu, T.S. 2010, "Communication Technologies for Smart Grid Applications" *Power and Energy Society General Meeting, 2010 IEEE, pp: 1 - 7*

Park, S., Shin, C., Kwon, S., Ha, B., Choi, M. 2008, "A Fault Detection and Service Restoration Method by Shifting the Feeder Tie Switch for Ungrounded Distribution System" *International Conference on Condition Monitoring and Diagnosis, Beijing, China, April 21-24, 2008, pp: 352 - 356*

Qingnong, L. 2008, "Techniques of Visualization for Distribution Automation System" *China International Conference on Electricity Distribution, 2008, pp: 1 - 6*
Roberts, J. & Zimmerman, K. 1999, "Trip and Restore Distribution Circuits at Transmission Speeds*" Rural Electric Power Conference, 1999, pp: A2/1 - A2/9*

Run-Bua, W. 2010, "Based on the problems of extra (ultra) high substation digitalization and smart grid" *China International Conference on Electricity Distribution (CICED20 10) Sept 12-16.*

Schwarz, K. "Comparison of IEC 60870-5-101/-103/-104, DNP3, and IEC 60870-6-TASE.2 with IEC 61850," February 2002, https://www.nettedautomation.com

SEL instruction manual 351A https://www.selinc.com

SEL instruction manual SEL2440 https://www.selinc.com

SEL instruction manual SEL Acselerator Architect https://www.selinc.com

SEL instruction manual SEL Acelerator Quickset https://www.selinc.com

Seong-Il Lim, Seung-Jae Lee, Myeon-Song Choi, Dong-Jin Lim and Bok-Nam Ha. 2006, "Service Restoration Methodology for Multiple Fault Case in Distribution Systems*" IEEE Transactions on Power Systems Volume: 21, Issue: 4 2006, pp: 1638 - 1644*

Serban, G. Sud, M. 2005, "Implementation of Distribution Automation System (DAS) in the "Electrica" Company – Romania" *18th International Conference on Electricity Distribution Turin, 6-9 June 2005. CIRED2005, 2005, pp: 1 - 5*

Shahsavari, A., Mahdi, S., Fereidunian, *A &* Lesani, H, 2014, "Fault Indicator Deployment in Distribution Systems Considering Available Control and Protection Devices: A Multi-Objective Formulation Approach". *IEEE TRANSACTIONS ON POWER SYSTEMS, VOL.29, NO. 5, SEPTEMBER 2014, pp: 2359-2369*

Shirmohammadi, D. & Hong, H.W. 1989 "Reconfiguration of electric distribution networks for resistive line losses reduction," *IEEE Transactions on Power Delivery, volume. 4, no. 2, Apr. 1989, pp. 1492–1498*

Shirmohammadi, D. 1992 "Service Restoration in Distribution Networks via Network Restoration,'' *IEEE Transactions on Power Delivery, Volume 7, No. 2, April 1992, pp. 952-958*

Siirto, O., Kuru, J & Lehtonen, M. 2014, "Fault Location, Isolation and Restoration in a City Distribution Network". *Electric Power Quality and Supply Reliability Conference (PQ), 2014 IEEE, pp: 367 – 370*

Simard, G. & Chartrand, D. 2007, "Economic and Technical Approach to Justify its Distribution Automation Program" *Power Engineering Society General Meeting, IEEE, 2007, pp: 1 - 5*

Simard, G., Lavoie, V. & Chartrand, D. 2006 "Hydro-Québec's vision of the Distribution Automation" *Transmission and Distribution Conference and Exhibition, 2005/2006 IEEE PES pp: 333 – 338*

Singh, U. & Caceres, D. 2008, "An Integrated Approach for Implementing a Distribution Automation System" *Transmission and Distribution Conference and Exposition: Latin America, IEEE/PES 2008, pp: 332 - 337*

Sloan, G and Clinard,K., 1995. "Making The Right Choices For Distribution Automation" *Rural Electric Power Conference, 1995. Papers Presented at the 39th Annual Conference, 1995, pp: A3/1 - A3/4*

Smith, H.L, 1994. “An overview of distribution automation and demand-side management with implications of future trends*” Computer Applications in Power, IEEE, Volume: 7, Issue:4 , pp: 23-25*

Sperandio, M., Cavalheiro, F.C., Sechi, D.L., Bernardon, D.P., Garcia, V.J., Lopes, G. & Possebon, E. 2011, “Fault Location in Distribution Networks by Combining Studies of the Network and Remote Monitoring of Protection Devices” *Power Engineering Conference (UPEC), Proceedings of 46th International Universities' Power Engineering Conference, 2011, pp: 1 - 6*

Sutherland, P.E., Goodman, F.R. & Short, T.A. 2006, “*Feeder and Network Evolution for the Distribution System of the Future” Transmission and Distribution Conference and Exhibition, 2005/2006 IEEE PES, pp: 348 - 353*

Substation Configuration Language based Enigneering, http://www.academia.edu/

Tannlund, P. & Bjiirkman, G. 2000 “*An Advanced Distribution Automation System Experience from Application Development and Project Implementation”*
Power System Technology, 2000. Proceedings Power Conference International Conference Volume: 1, 2000, pp: 127 - 132 vol.1

Torben, S., Gulbrandsen, T. 1998 “The intelligent ring main unit”. *Fifth International Conference (Conf. Publ. No. 459), 1998, pp: 167 - 172*

Venkata, S.S., Pahwa, A., Brown, R.E. & Christie, R.D. 2004 “What Future Distribution Engineers Need to Learn”, IEEE Transactions on Power Systems, February 2004 Volume 19, Issue 1, pp 17-23

Viet, N.H., Van Ban, N. & Ma, B. 2010, “Automation and Reliability Improvement for Distribution Feeder*”* Probabilistic Methods Applied to Power Systems (PMAPS), 2010 IEEE 11th International Conference on power delivery, 2010, pp: 609 - 614

Peng, W., Jun, L. & Jian, S. 2011, “Research of benefit evaluation method in distribution automation Planning” *Advanced Power System Automation and Protection (APAP) International Conference on Advanced Power System Automation and Protection, 2011, pp: 85 - 87*

Vyatkin, V., Zhabelova, G., Schwarz, N.G.H. & Nair, N.C. 2010, “Towards Intelligent Smart Grid Devices with IEC 61850 Interoperability and IEC 61499 Open Control Architecture” Transmission and Distribution Conference and Exposition, 2010 IEEE PES, pp: 1 - 8

Wen Xul, Zhi-hai Tan4, Xue-liang Huang2, Shu-ming Feil, Chun-jiu Li3 & Hai-tao Jiang White, J. 2005 “Implementation of UCA/IEC 61850 for Substation Automation at Grant County Public Utility District” *Transmission and Distribution Conference and Exhibition, 2005/2006 IEEE PES pp 384-389*

Wu, G., Gong, J. & Liu, Y. 2011, “Construction and Operation of A Distribution Automation System For Large Urban Distribution System”. *The International Conference on Advanced Power System Automation and Protection (APAP) 2011, pp: 822 - 826*

Wu, J., Dostanov, D & Redfern M, 2013, “ Fault Passage Protection based on IDMT Relaying with IEC61850-90 Inter-Substation Communications”, *Developments in Power System Protection, 12th IET International Conference, 2013, pp: 1-6*

Xia Yang, Seong-Il Lim, Seung-Jae Lee & Myeon-Song Choi 2005, *“A New Service Restoration Algorithm for Ungrounded Distribution System”* Power Tech, 2005 IEEE

Russia pp: 1 - 5

XU Wen, LIU Xiao-lan, WEN Yan-jun, JIANG Hai-tao, ZHANG Qiang, ZHANG Jian-min & GAO Yu, 2006 “The Study of Feeder Automation System Based on Quick Communication Mechanism*” International Conference on Power System Technology. Power system Tecnology 2006, pp: 1 – 9*

Xu, Y. & Xu, X. 2008, “Typical Scheme Designs of Distribution Network Automation for Northeast Rural Areas of China” *Electric Utility Deregulation and Restructuring and Power Technologies, DRPT. Third International Conference, 2008, pp: 2028 - 2031*

Xue-Ping, F.,Ying, L. & Bing-Qing, G. 2011 China Electric Power Research Institute, Haidian District, Beijing, China. 2011. “. A New Islanding Method for Distributed Generation and Its Application in Power System Restoration” International Conference on Advanced Power System Automation and Protection (APAP), 2011, pp: 378 - 383

Xul, W., Tan, Z., Huang, X., Feil, S., Li, C. & Jiang, H. 2010, “*Discussion on Digital Distribution Automation System Based on IEC 61850” China International Conference on Electricity Distribution (CICED), pp: 1 - 7*

Zadeh, H.K. & Manjrekar, M. 2011, “A Novel IEC 61850-Based Distribution Line/Cable Protection Scheme Design” *Innovative Smart Grid Technologies (ISGT), 2012 IEEE PES pp: 1 - 6*

Zavoda, F. 2008 “The key role of Intelligent Electronic Devices (IED) in Advanced Distribution Automation (ADA)” China International Conference on Electricity Distribution CICED 2008, pp: 1 - 7

Zavoda, F. 2010, “Advanced Distribution Automation (ADA) Applications and Power Quality in Smart Grids” *China International Conference on Electricity Distribution, 2010, pp 1 - 7.*

Zhabelova, G. & Vyatkin, V. 2012 “Multiagent Smart Grid Automation Architecture Based on IEC 61850/61499 Intelligent Logical Nodes” *IEEE Transactions on Industrial Electronics, VOL. 59, NO. 5, MAY 2012, pp: 2351 - 2362*

Zhang, K.Z.S., Huang, B. & Ma, X. 2009, “Research on integration technology between distribution automation system and geographical information system” *Power and Energy Engineering Conference, Asia-Pacific, 2009. pp: 1 - 4*

Zhao Wang, Lei Jing & Wenxiao Ma, 2008 “Feeder Automation Modeling in IEC61850” *Electricity Distribution, 2008. CICED 2008. Technical Session 2 Power Quality and Power Conservation pp: 1 - 4*

APPENDIX A
OVERCURRENT AND EARTH FAULT IED (SEL351A) CONFIGURATION SETUP USING SEL ACSELERATOR QUICKSET

A.1 Introduction

Intelligent IEDs are required for the realization of the successful implementation of an automatic distribution automation system. Furthermore the IEDs that are required for the distribution system applications in the thesis must have protection, control and monitoring applications and must also serve as information and automation devices. It is because of these reasons why it was decided to choose the SEL351A protection, control and monitoring device for the thesis. The IEDs are able to obtain power system information and then perform calculations and logical functions. The IED has an event report logger that is able to store valuable information and in some way create a local database with data about the power system. Therefore, these IEDs are intelligent. The integration of information is made possible by the available communications channels available in the IEDs.

Equipment information which includes the present status information as well as historical information is some of the data acquisition and processing capabilities of the IED. They provide system information and awareness through supplying data on the condition, performance, health, and history of the equipment.

The information in this appendix provides a step by step guide how to go about configuring the SEL351A IED. The text is based on the SEL351A instruction manual.

A.2 ACSELERATOR Quickset SEL-5030

ACSELERATOR Quickset SEL-5030 software is required to be installed on a PC for the user to be able to use the software. Once the software is installed, the application can be launched. Figure A.1 illustrates the ACSELERATOR QuickSet launchpad. From the Launchpad a new settings template can be created or a settings template can be downloaded from a connected IED through the read tab or a previously created settings template can be opened and viewed.

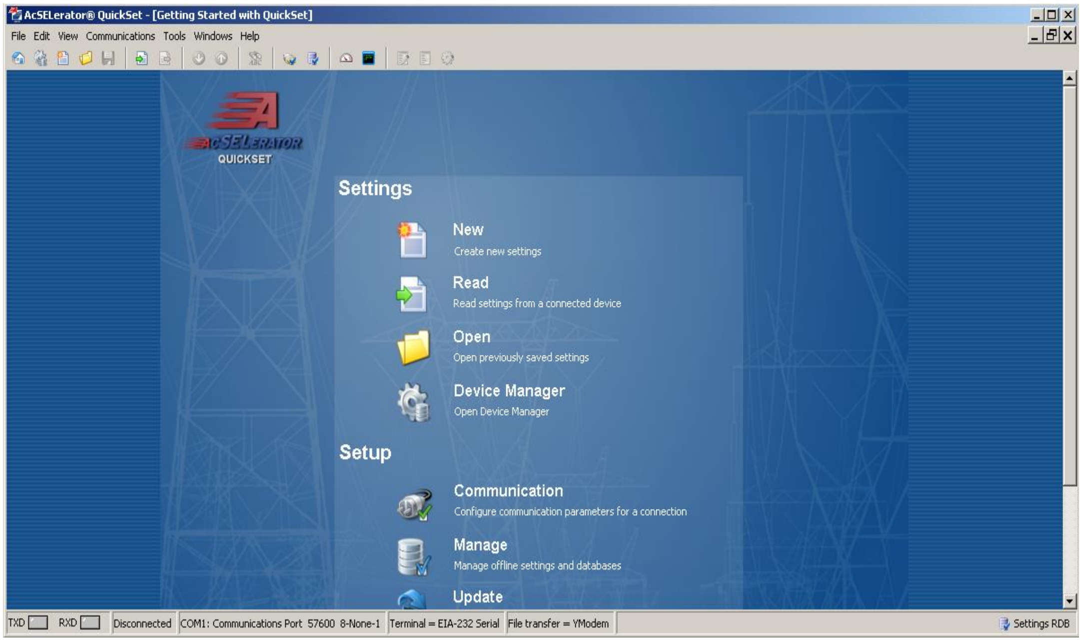


Figure A.1: ACSELERATOR QuickSet launchpad

QuickSet is an easy-to-use yet powerful tool to help get the most out of the SEL device, as follows:

- Create, edit, store, and transfer SEL device settings.
- Develop programmable logic equations offline with easy-to-use configuration tools
- Test and commission installations with display of live device measurements and status information.
- Use the configurable Human Machine Interface to obtain pertinent device data locally or from a remote location.
- Use the built-in waveform viewer to quickly analyze fault records and device element response.
- Obtain full integration with ACSELERATOR QuickSet Designer® SEL-5031 templates for creating custom views of settings to simplify commissioning of multiple SEL devices.
- Retrieve updates delivered to your computer on a schedule that you choose through the use of SEL Compass® software.

The passwords for the different access levels are listed in Table A.1

Table A.1: Factory default passwords

Access Level	Password
0	N/A
1	OTTER
2	TAIL

The SEL software tool provides different access levels that require passwords for security purposes. There are access levels in the device each with a different level of control.

Table A.2: Access levels

Level	Capability
0	Access Level 0 is the lowest security level.
1	Access level 1 is mainly for reviewing information, but not changing it.
2	Access level 2 is mainly for changing device settings, resetting device information or resetting saved data.

To have access to the multiple access levels of the device the ACC and 2AC commands are used respectively.

A.3 SEL351A Communication setup

Before any configuration of the IED can be done communication to the device has to be established. It is achieved through connecting the device to a personal computer via a serial RS232 cable or LAN and configuring the communications parameter settings. Figure A.2 shows the communication parameter settings.

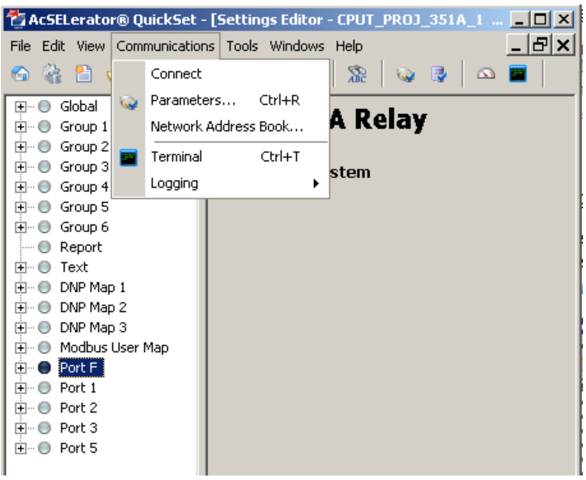


Figure A.2: Communication parameter settings for the SEL351A IED

A.3.1 Serial Communication Parameters

For the connection to an SEL device various options are available in the communication parameters. The PC communications port has to be defined for the connection with the SEL device. All the available serial communication devices are listed in the software tool as follows.

1. Select Parameters and complete the communication parameter settings as shown in Figure A3.

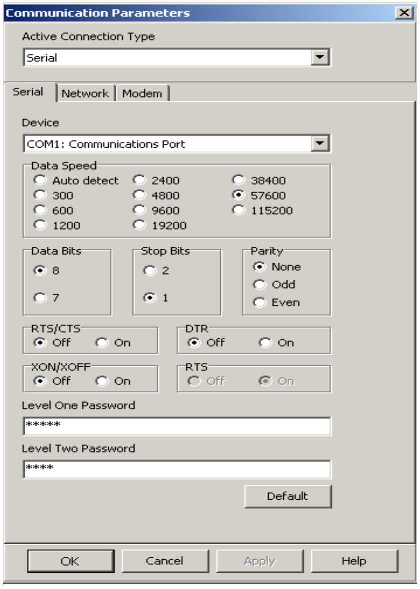


Figure A.3: Serial communications configuration setup for the SEL351A IED

The settings that are important here are the COM port number and the baud rate. Port F is used for serial communications to the device and the settings have to be configured.

2. Figure A.4 shows a screen shot where Port F can be found within the software tool. Security settings, protocol selection and communications settings are the important settings for the establishment of communication with the device.

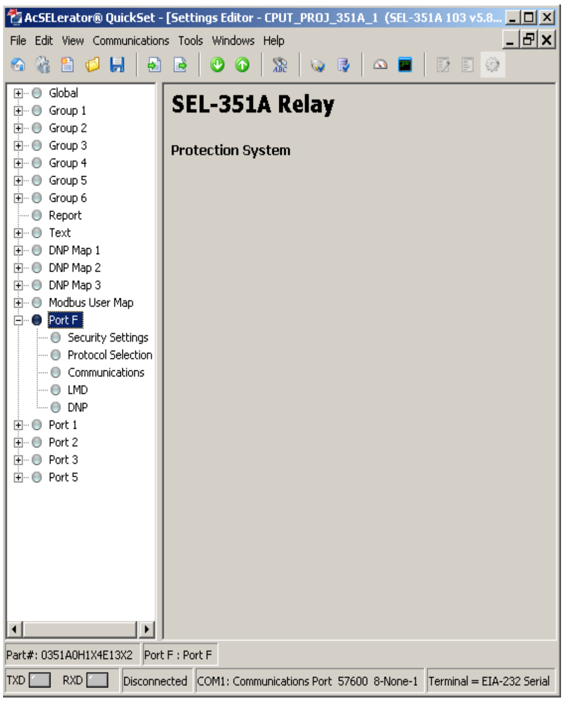


Figure A.4: Front port communication settings to the SEL351A IED.

3. Select EPORT Enable Port to “Y” as shown in Figure A.5,

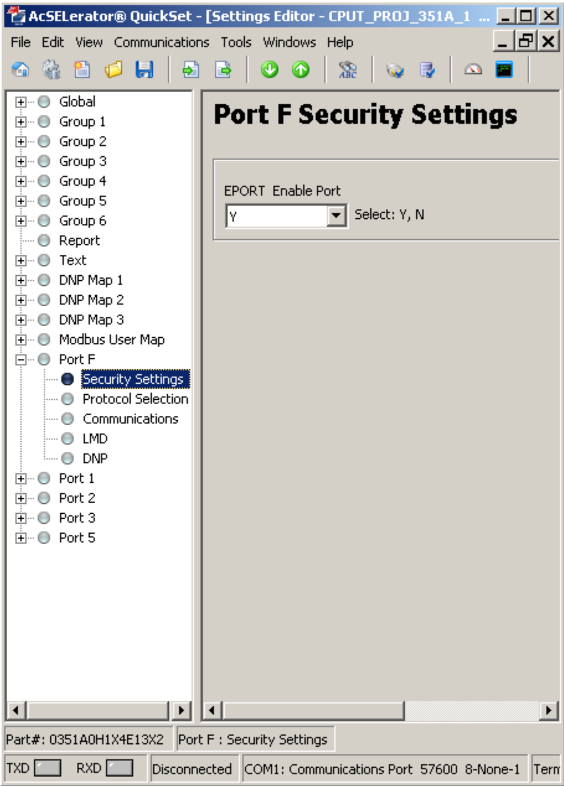


Figure A.5: Port F, security settings

4. Select PROTO Protocol to “SEL” and MAXACC to “C” as shown in Figure A.6.

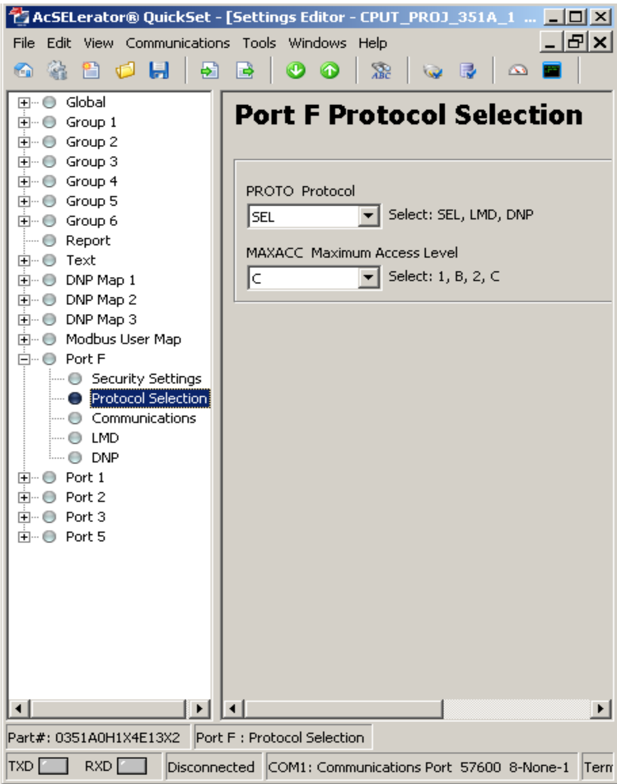


Figure A.6: Port F, Protocol Selection configuration settings

5. Set Port F, Communications settings as in Figure A.7.

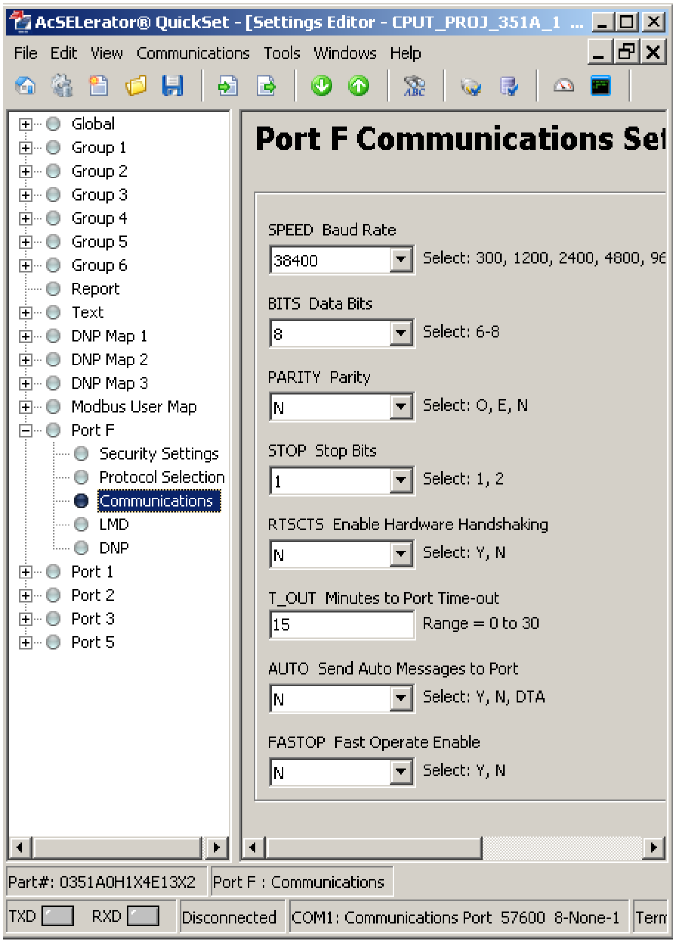


Figure A.7: Port F, communications configuration settings

Following the above steps the user will be able to successfully communicate via a serial connection to the device.

A.3.2 Network Communication Parameters

After the serial settings are properly configured the device can be connected directly to a PC. Only after the PC is communicating serially with the IED can the network settings be configured. The network settings can also be entered manually via the front panel, however, this is not advised as it takes long time to do and may not be easy when many devices are used. The sequence of setting the parameters are:

1. Figure A.8 shows the diagram for the network settings.

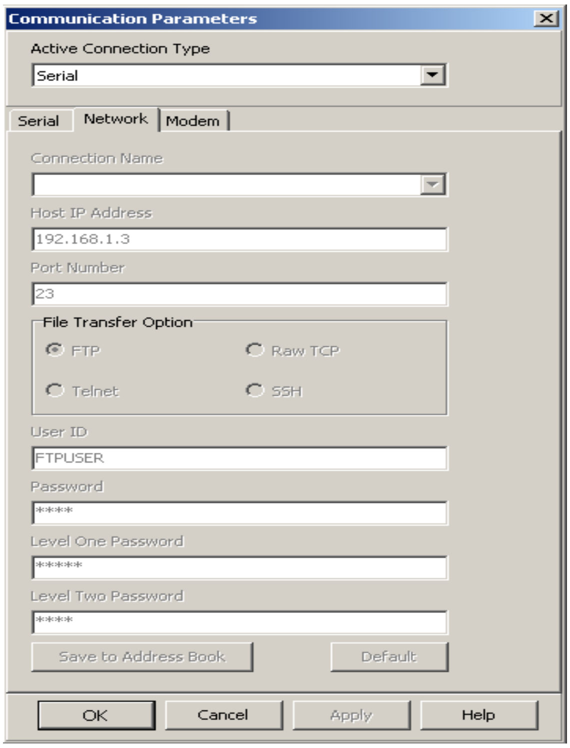


Figure A.8: Network communications configurations setup

The important settings are Host IP Address and File Transfer Option.

The device uses port 5 (LAN port) which is situated at the back of the IED.

2. Figure A.9 shows where port 5 can be found within the software tool.

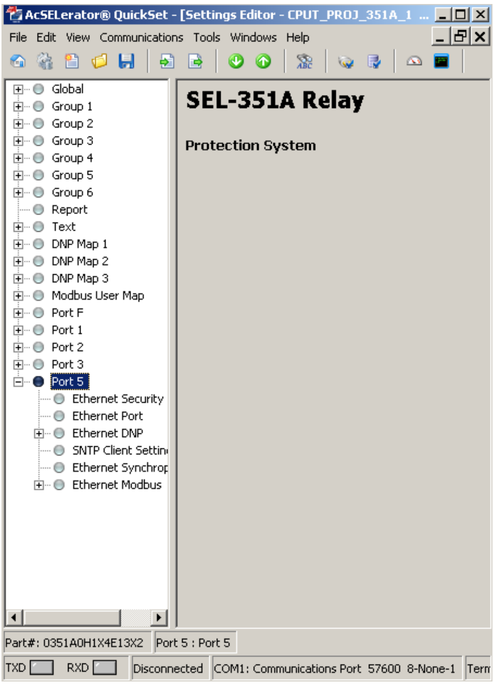


Figure A.9: Port 5 configuration parameter settings

3. Select EPORT Enable Port to “Y” as shown in Figure A.10

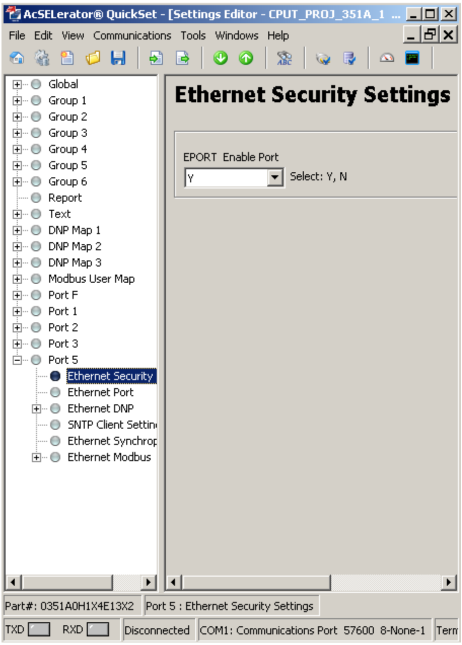


Figure A.10: Port 5 Ethernet security settings

4. Port 5 the Ethernet port to be configured as shown in Figure A.11.1 and 11.2.

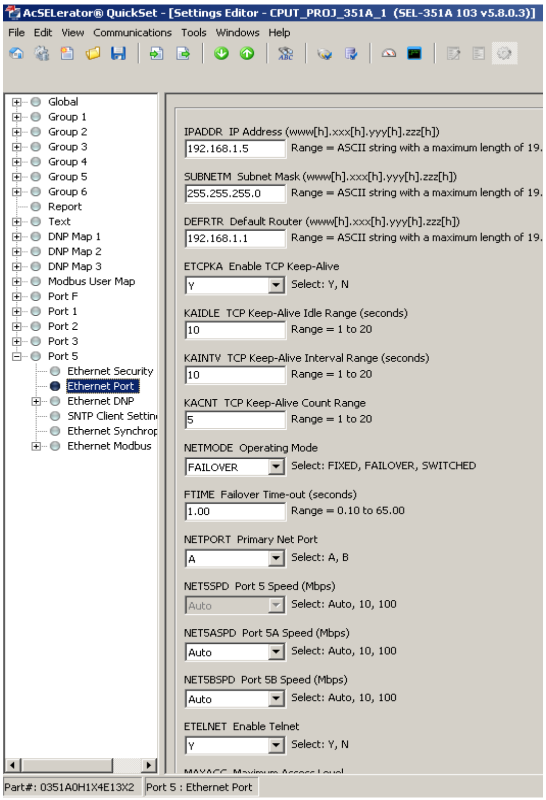


Figure A 11.1: Port 5 Ethernet port settings

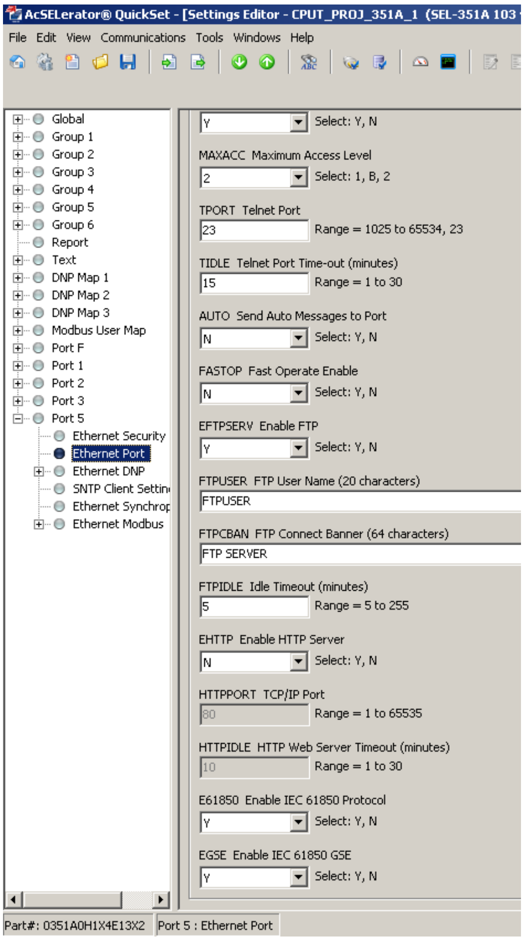


Figure A 11.2: Port 5 Ethernet Port settings

The remaining settings: Ethernet DNP, SNTP Client Settings, Ethernet Synchrophasor and Ethernet Modbus are not used in this thesis, therefore are not required to be configured. After the network communications settings are correctly configured the device can be connected directly to a PC via a network cable or via a managed Ethernet switch.

Following the steps described above will result in successful network communication to the device.

A.3.3 Global - General settings

After the device has been successfully connected to the communications network its protection settings can be configured. In this thesis only the earth fault and over current protection was enabled. Before the protection settings are configured the Global settings can be set. The global setting contain general, opto-isolated input, breaker monitor, synchronized phasor, DNP, date and time management settings. Figure A.12 shows a diagram of the global, general settings.

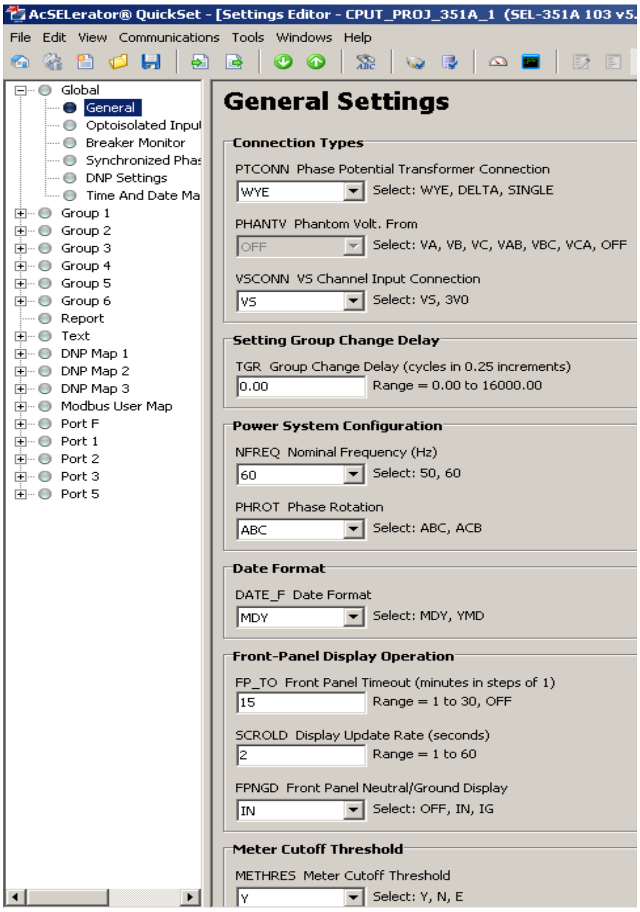


Figure A.12: Global settings

A.3.3.1Global – Group 1

After the configuration of the global settings the protection settings can be completed. There are six protection groups, each one can be configured with its unique set of settings if required and activated when needed. However the device can only activate one setting group at a time. This thesis makes use of the settings group 1. The device, offers several protection functions as shown in Figure A.13.

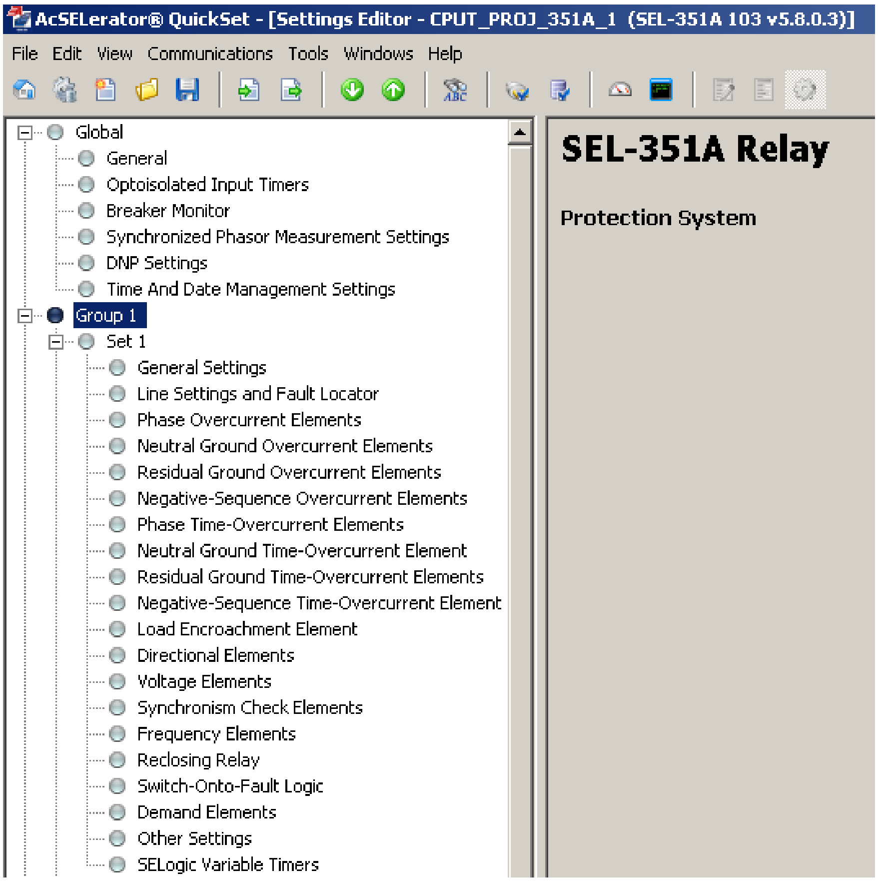


Figure A.13: Protection functions available in the SEL351A IED

A.3.3.1.1Group 1 – General settings

The important functions for this thesis are general settings and neutral-ground time overcurrent elements. Figure A.14 shows the general settings which contains the feeder name, CT ratio, VT ratio, etc. Figure A.15 shows the earth fault protection function is activated by selecting the E51N element to "Y", the pick-up setting is 0.3 Amps, normally inverse "C1" is selected and the time dial is set at 0.2 seconds.

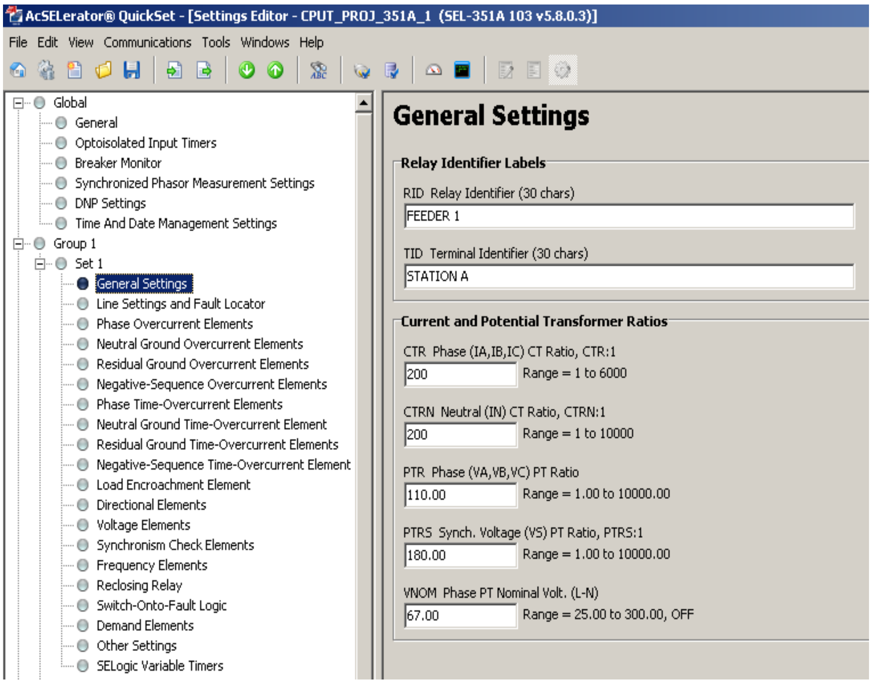


Figure A.14: Group 1 protection general settings

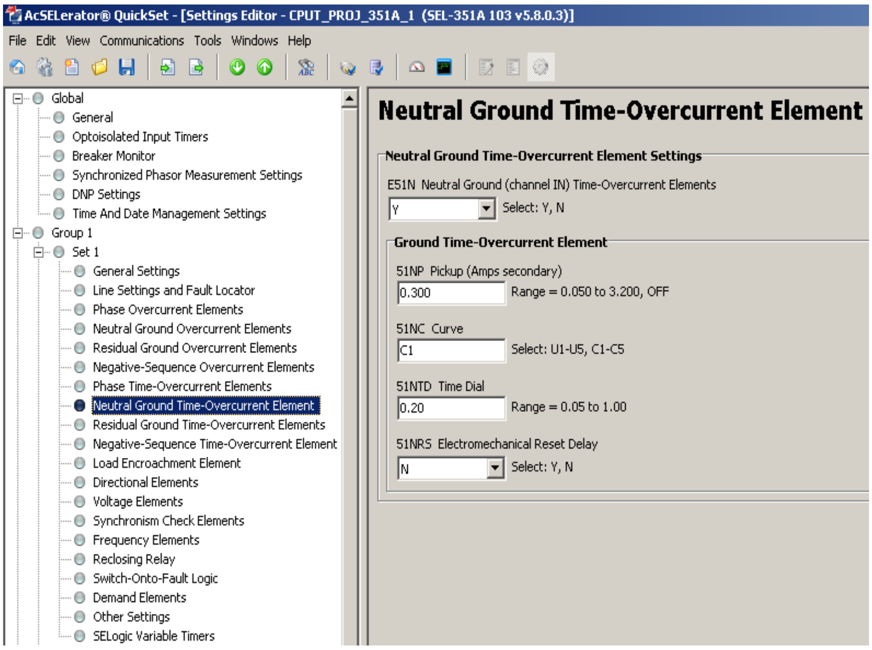


Figure A.15: Earth fault parameter settings

A.3.3.1.2Group 1 – Logic 1 settings

Following the configuration of the protection settings the IED logic settings can be set. The logic function as shown in Figure A.16 contain the trip logic, close logic, latch bit, variable timer input, output and other equation settings.

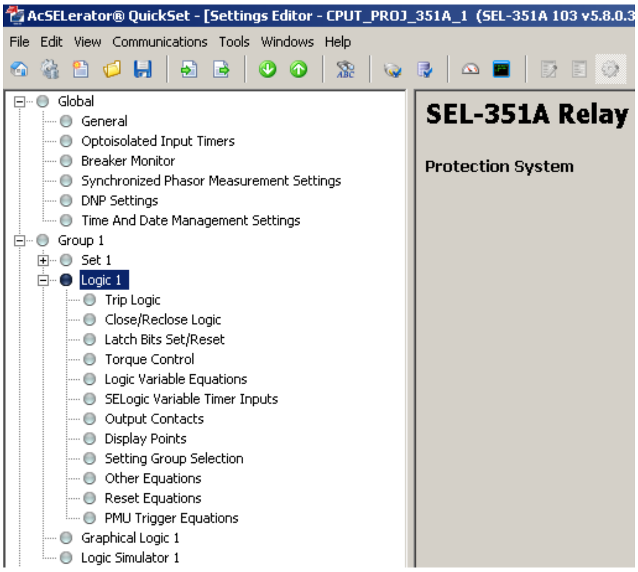


Figure A.16: Logic settings

A.3.3.1.3Trip Logic

The trip logic setting window contains all the conditions which will trigger the trip logic function of the IED. Figure A.17 shows the conditions that trigger the trip logic.

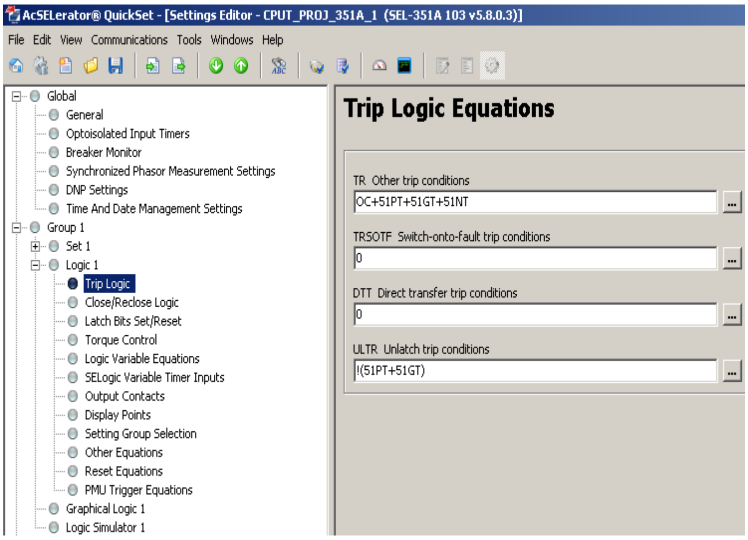


Figure A.17: Trip logic equation conditions

A.3.3.1.4Close/Reclose Logic

The close logic has to be configured for the IED to be able to use the close push button on the SEL351A to close the breaker. Other conditions such as incoming GOOSE messages from other devices have to be configured here as well. Figure A.18 shows the close conditions for the SEL351A device.

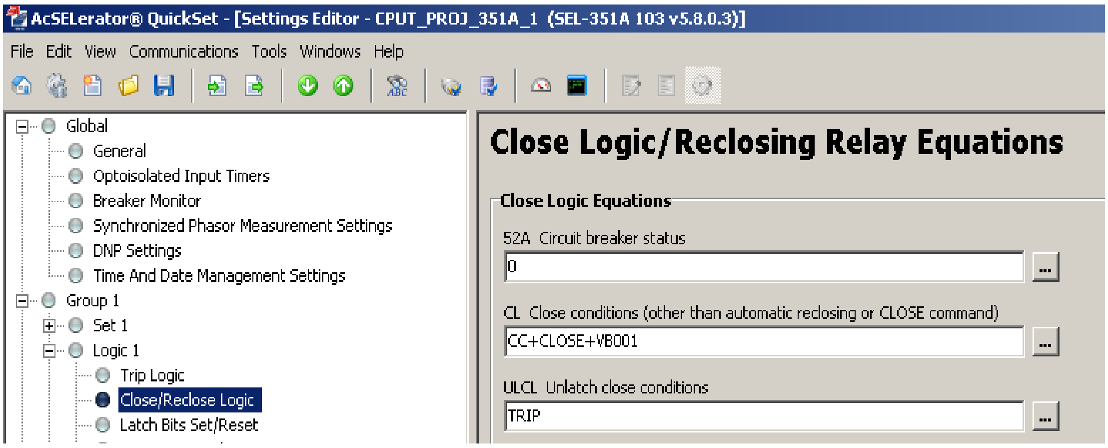


Figure A.18: Close logic for SEL 351A IED

A.3.3.1.5Latch Bits Set/Reset Equations

The latch bit equations have to be configured for the set as well as the reset conditions. Figure A.19 shows the settings for the latch bit set and reset conditions.

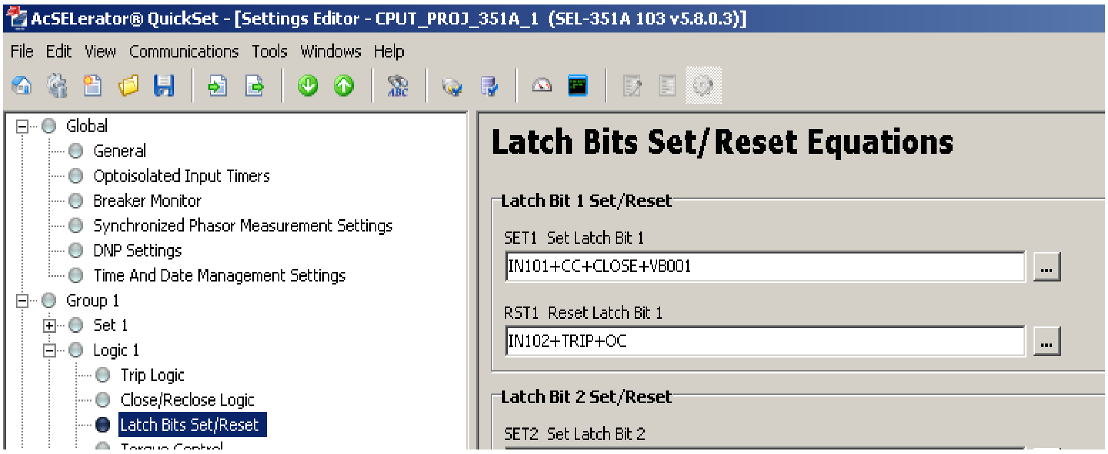


Figure A.19: Latch bit set and reset conditions

A.3.3.1.6Output Contacts

Figure A.20 shows the configuration of the output contacts of the SEL351A IED. OUT101 is used as the trip output of the device, OUT102 the close status indication of the device and OUT103 the open status.

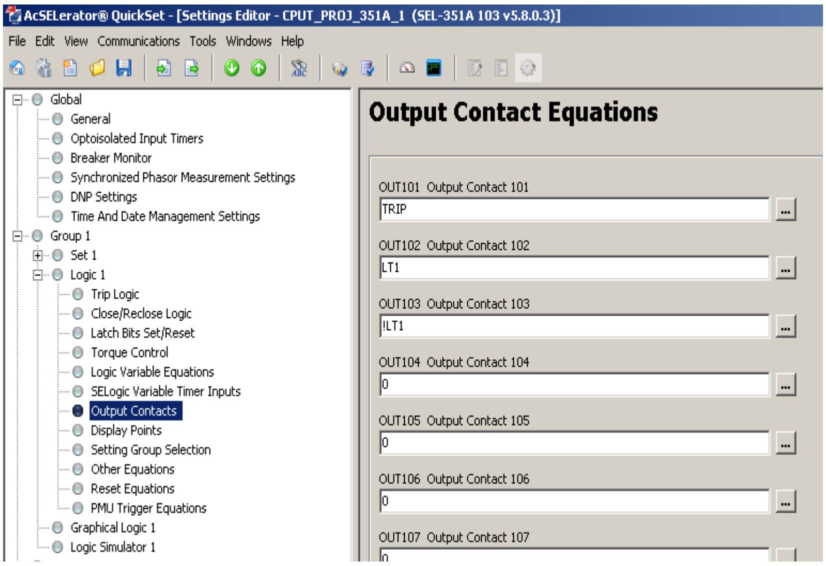


Figure A.20: Output contact equations

A.3.3.1.7Other Equations

Other equations setting windows allows the user to add the conditions that will trigger an event report. This is very handy during troubleshooting or real-time fault investigations. Figure A.21 shows the conditions that will trigger the fault report event for this thesis.

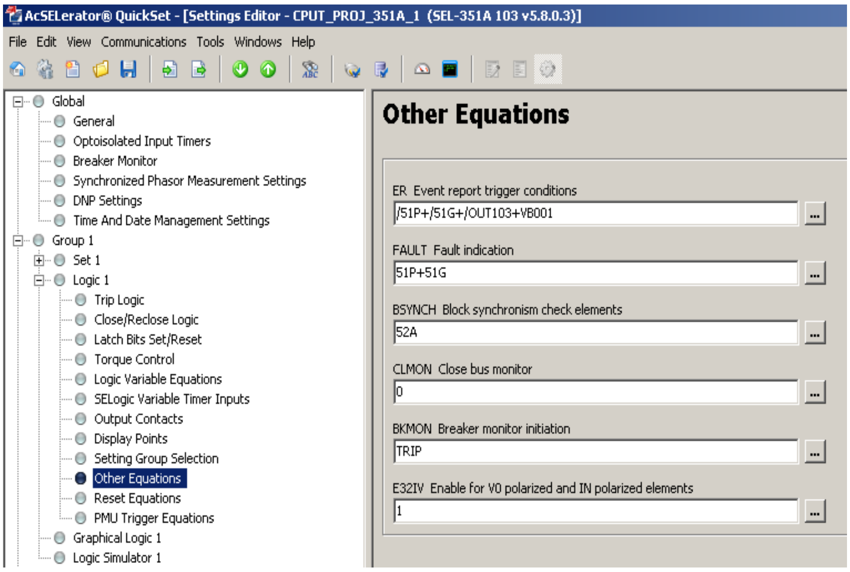


Figure A.21: Other equations – event report trigger conditions.

A.3.3.1.8Event Analysis

The performance of the protection system functioning can be evaluated through the protection system event information which is captured in the SEL device. One of these tools is the sequence of event recorder. The recorder can be downloaded when certain elements within the IED were triggered during fault conditions or even during normal running conditions. The report will show all the elements that were triggered during the event. However the report will only show the elements that are added in the SER1, SER2 and SER3 recorder list setting field.

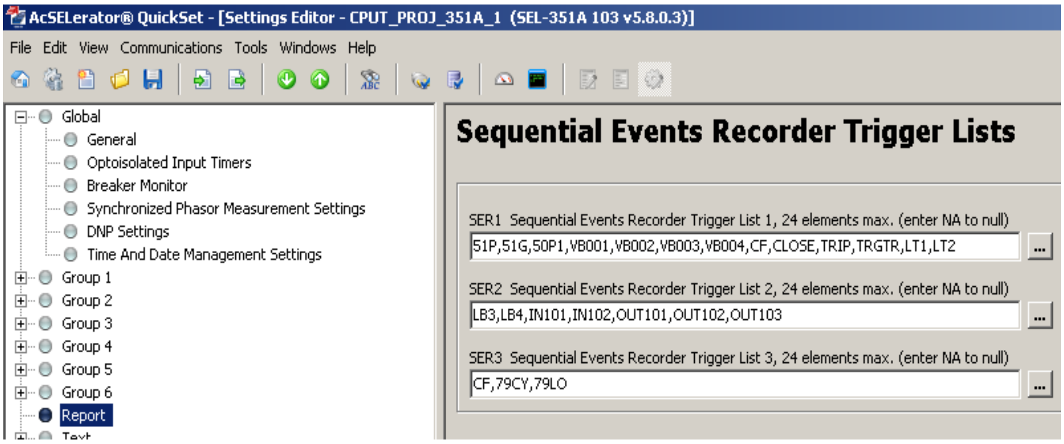


Figure A.22: Sequential event recorder trigger conditions

A.3.4 Conclusion

Appendix A contains detailed information on the communication setup as well as the main protection settings for the SEL351A IED. Appendix B describes the communication setup, input/output configuration, fault analyses reports, latch set/reset equations and SELogic variables for the SEL2440 discrete programmable controller.

APPENDIX B
CONFIGURATION SETUP OF THE SEL2440 DISCRETE PROGRAMMABLE CONTROLLER

B.1 Introduction

The SEL-2440 Discrete, Programmable Automation Controller (DPAC) provides discrete inputs, discrete outputs, programmable logics and support communications protocols such as the IEC61850. Appendix B gives detailed descriptions of the general settings, communication settings, input/output configuration, fault reports, latch bit set/reset equations and SELogic variable equations.

The serial and network communication parameter setup for the SEL2440 is similar to the setup for the SEL351A described in Appendix A therefore they are not described in this appendix.

B.2 General Settings

The settings process starts with the general settings as shown in Figure B.1. The general settings provide the device description and the name of the bay it is installed under device settings field.

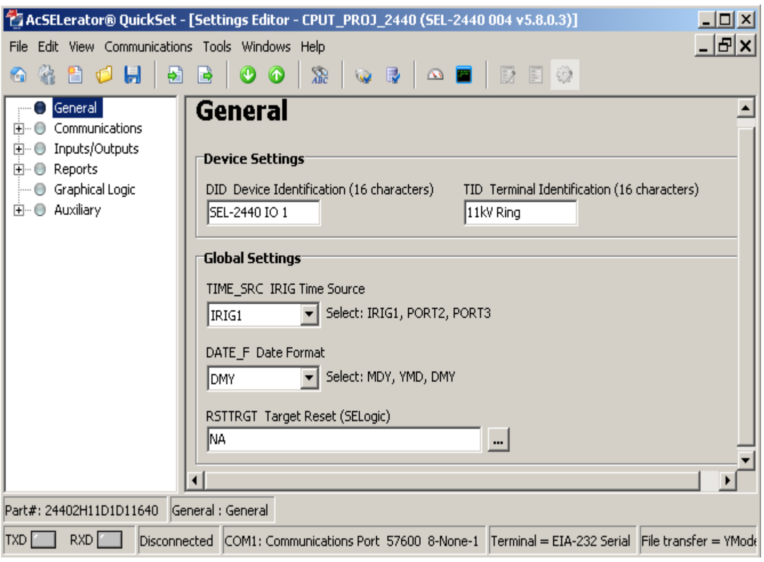


Figure B.1: SEL2440 General Settings

B.3 Communication settings

B.3.1 Front Port Communication Settings

The front port is used for serial communication. Configure the front port settings as shown in Figure B.2

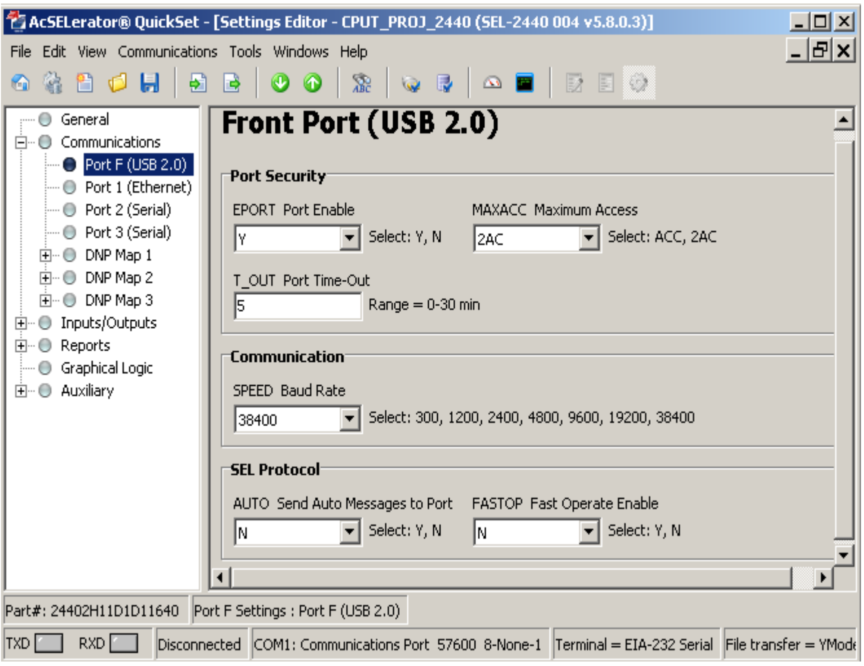


Figure B.2: Port F communication settings

B.3.2 Network Communication Settings

The Ethernet port is situated at the back of the IED. Figures B.3 and 4 show the settings for port 1. The configuration settings consist of the port security, network, TCP keep-alive, FTP/Telnet, switch, IEC61850, and DNP settings as shown in Figures B.3 and 4. Ports 2 and 3 and the DNP3 mapping are not used in the thesis.

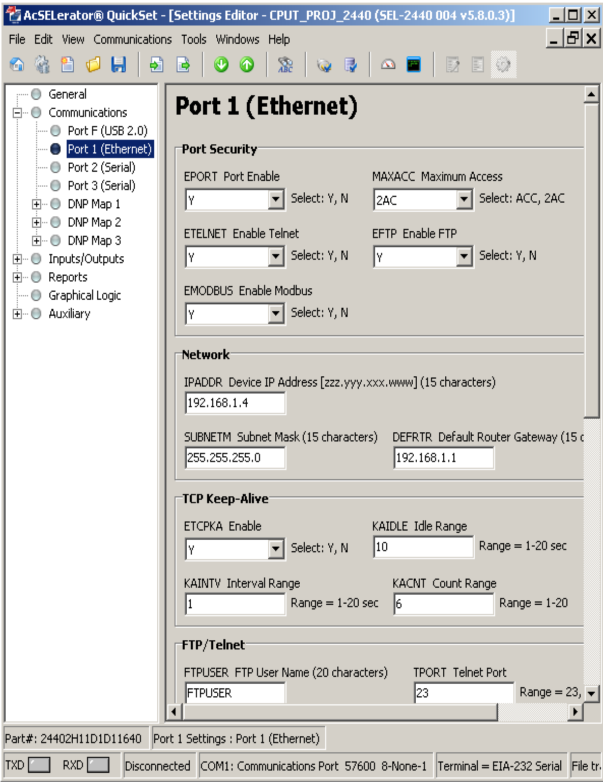


Figure B.3: Ethernet port settings

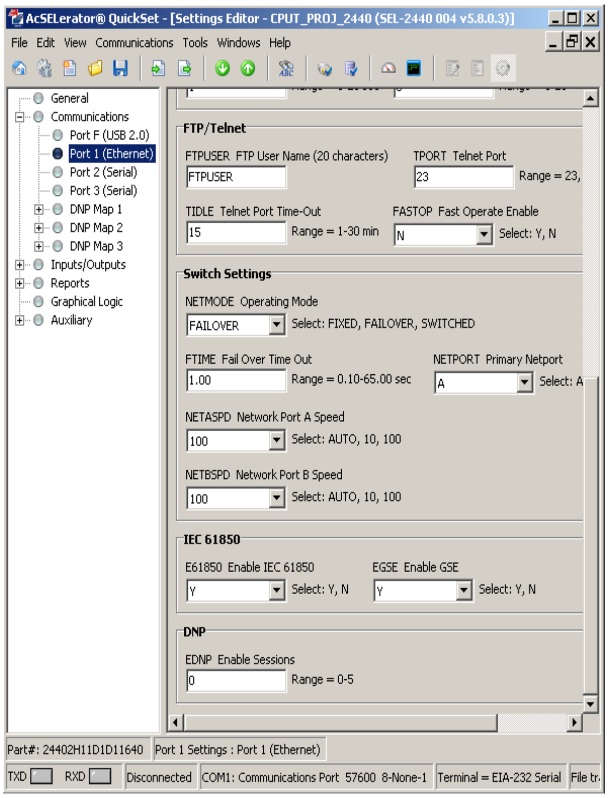


Figure B.4: Ethernet port settings

B.4 Inputs/Outputs

B.4.1 Outputs

Figure B.5 shows the output configuration of the SEL2440 discrete programmable controller. Outputs OUT112 up to OUT116 are not used.

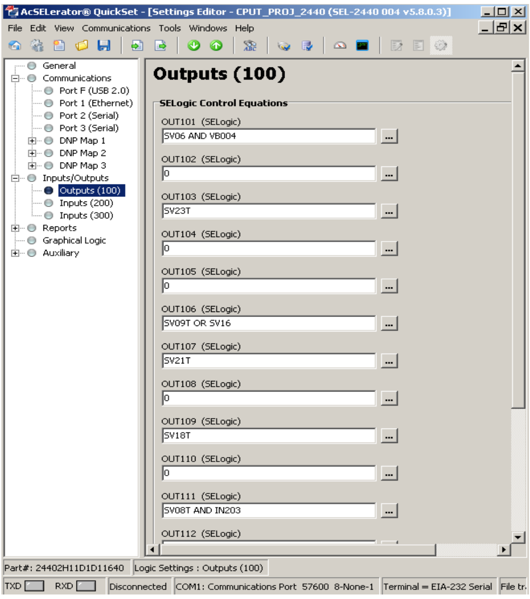


Figure B.5: Output configuration of the SEL2440 controller

B.4.2 Inputs

Debounce refers to a time delay that has to elapse before the processing of the change of state of a digital input occurs. Figure B.6 shows the settings of the debounce timers.

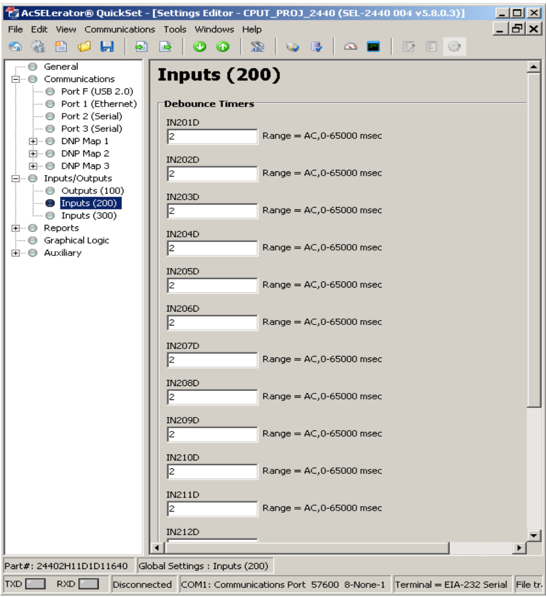


Figure B.6: Debounce timer settings

B.5 Reports

State changes of the IED elements can be captured in the SER report. This is done by entering the Device Word bit into one of the four SER (SER1 through SER4) trigger equations. Each of the four programmable trigger equations allows entry of as many as 24 Device Word bits separated by spaces or commas. Figure B.7 shows the SER report triggering conditions.

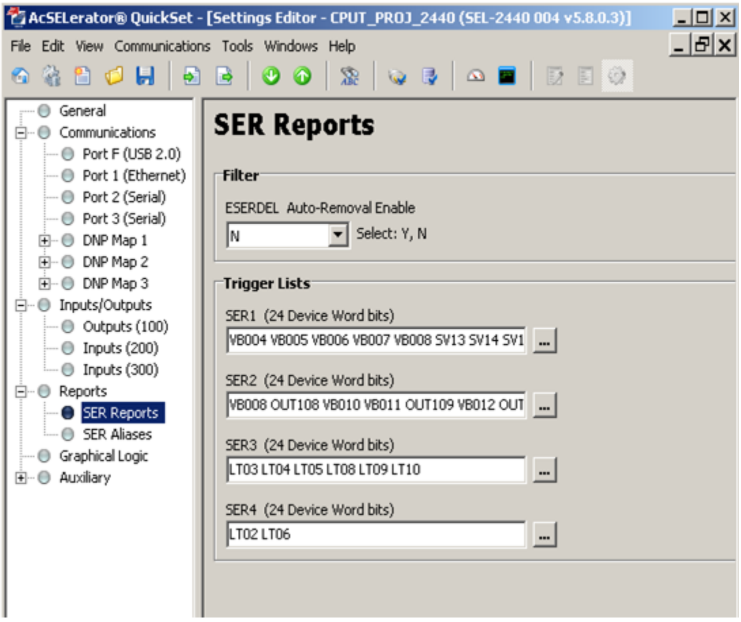


Figure B.7 SER report trigger list

Figure B.8 shows an example of a SER report. Each entry in the SER includes the SER row number, date, time, element name, and element state. In the SER report, the oldest information has the highest number, i.e., the newest information is the Number 137 entry (IN205 asserted). The order of the SER records in the SER report can be changed if the device is online and connected to a personal computer.

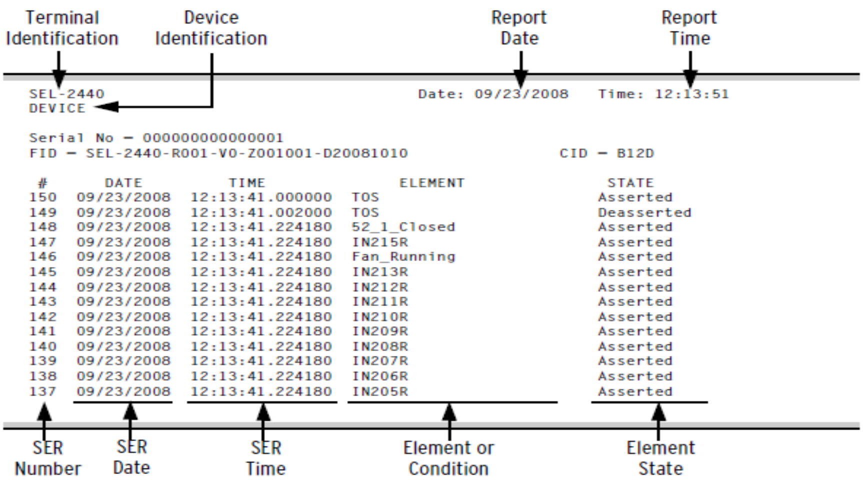


Figure B.8: SER report example (SEL2440 instruction manual 2014)

Digital logic capabilities are provided by the SEL-2440 Discrete Programmable Automation Controller (DPAC) that operates on physical inputs, outputs, virtual inputs and outputs, as shown in Figure B.9. The controller operates by periodically reading physical inputs, evaluating logic (settings), and writing physical output status conditions from devices it is connected to.

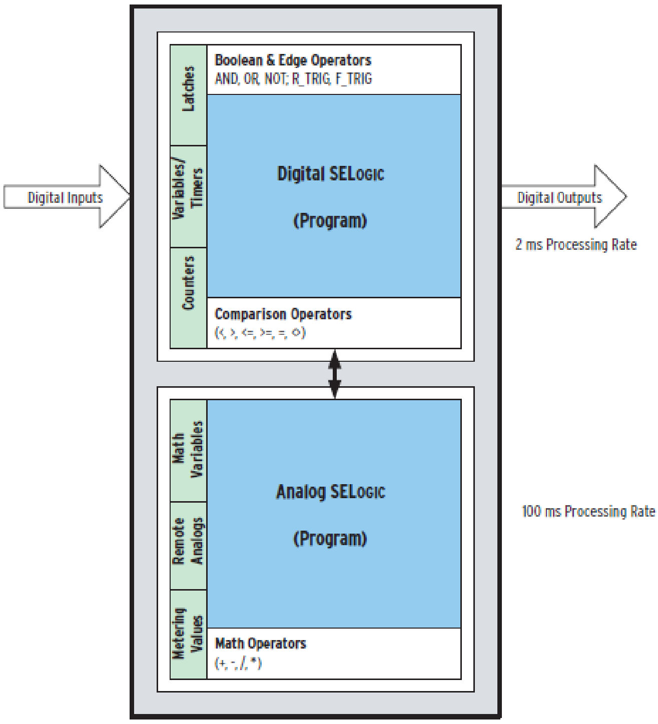


Figure B.9: Program model (SEL2440 instruction manual, 2012)

B.6 Auxiliary

B.6.1 Latch Set/Reset Equations

The traditional latching devices are replaced with the SELogic latches in the SEL2440 controller. These latches keep their state even during power loss to the IED. Figures B.10 and 11 shows the latch bit configuration settings.

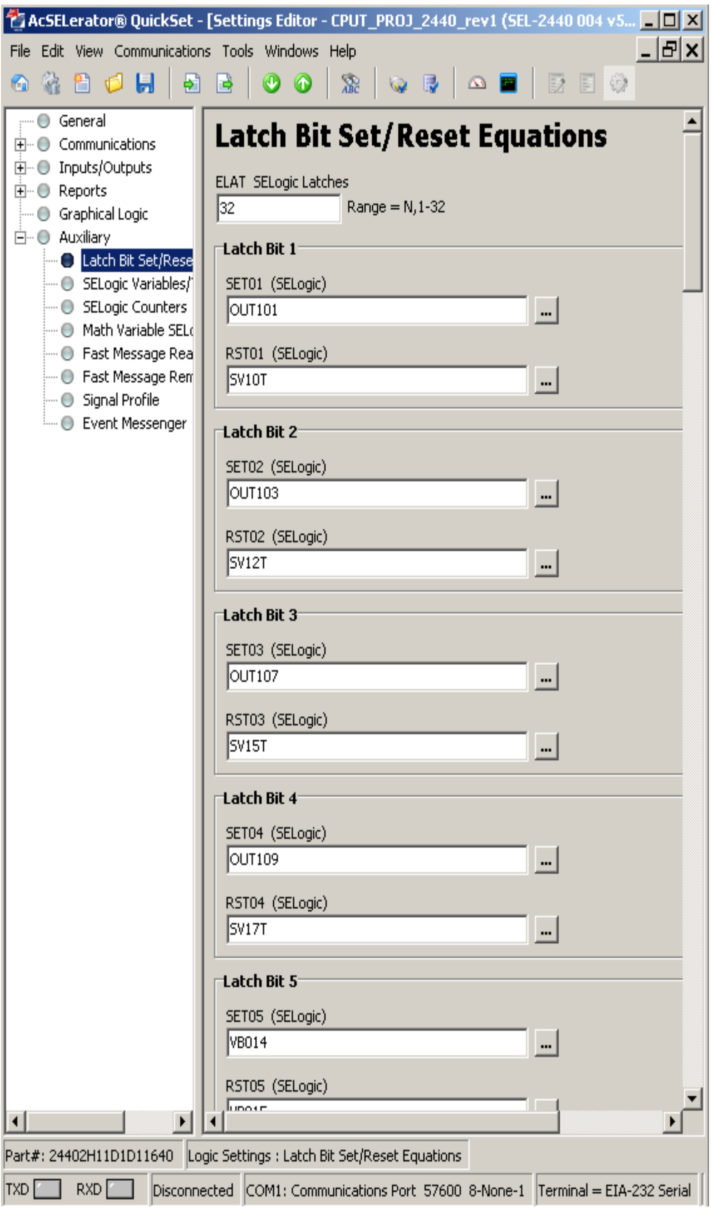


Figure B.10: Latch bit equation settings

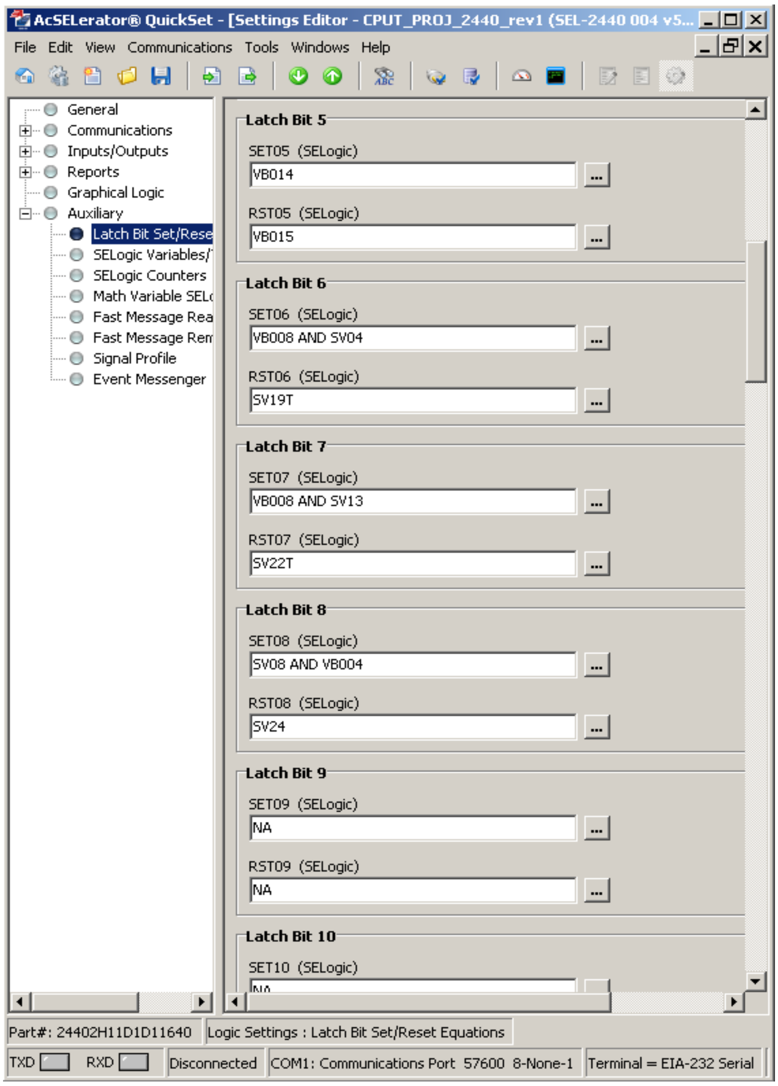


Figure B.11: Latch bit equation settings

B.6.2 SELogic Variable/Timers Settings

Every SELOGIC control equation variable/timer has a SELOGIC control equation setting input and variable/timer outputs. The variable timer outputs have a pick up and dropout setting. This timer setting range applies to both pickup and dropout times. Every SELogic equation can have as many as 15 elements per SELOGIC equation. Figures B.12.1 to B.12.7 shows the SELogic variable/timer input as well as the pickup and dropout timer settings for the thesis project.

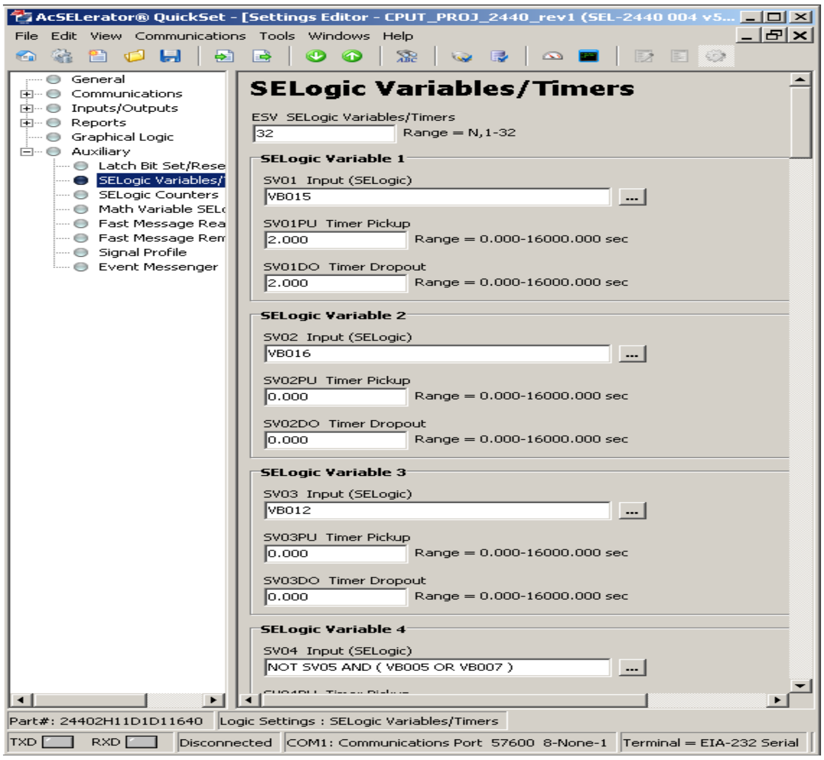


Figure B.12.1: SELogic variable/timer settings

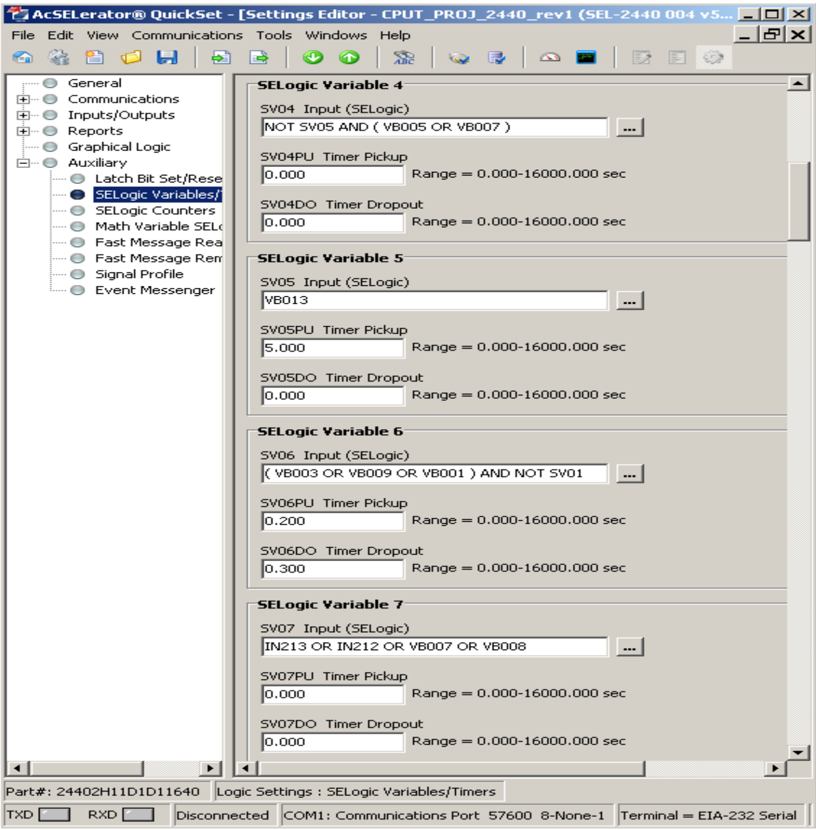


Figure B.12.2: SELogic variable/timer settings

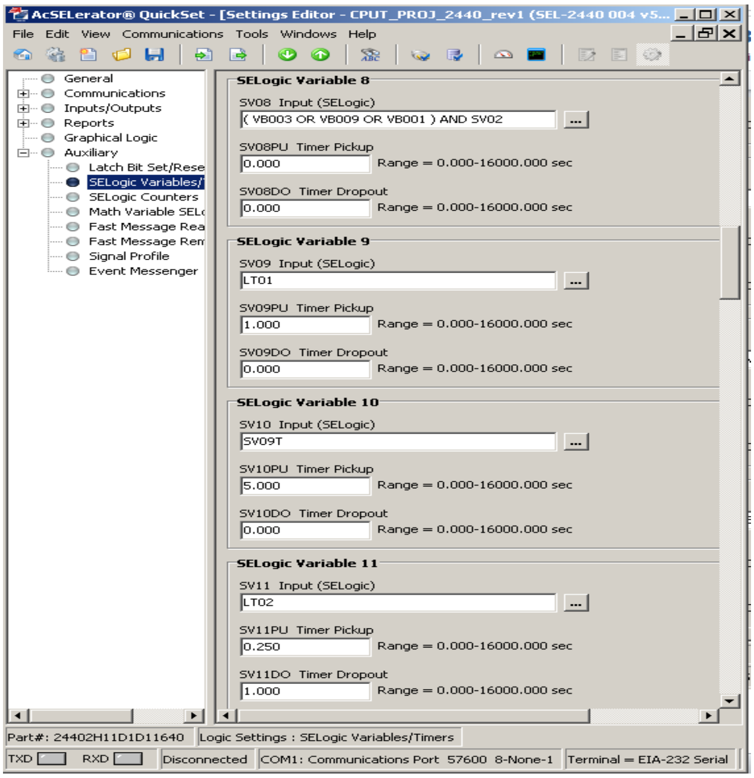


Figure B.12.3: SELogic variable/timer settings

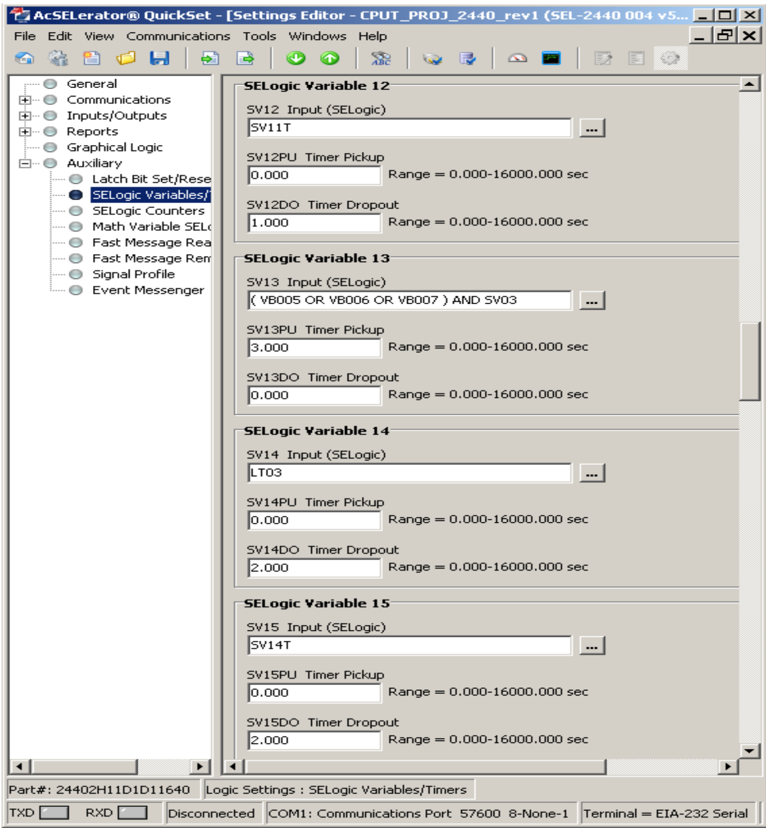


Figure B.12.4: SELogic variable/timer settings

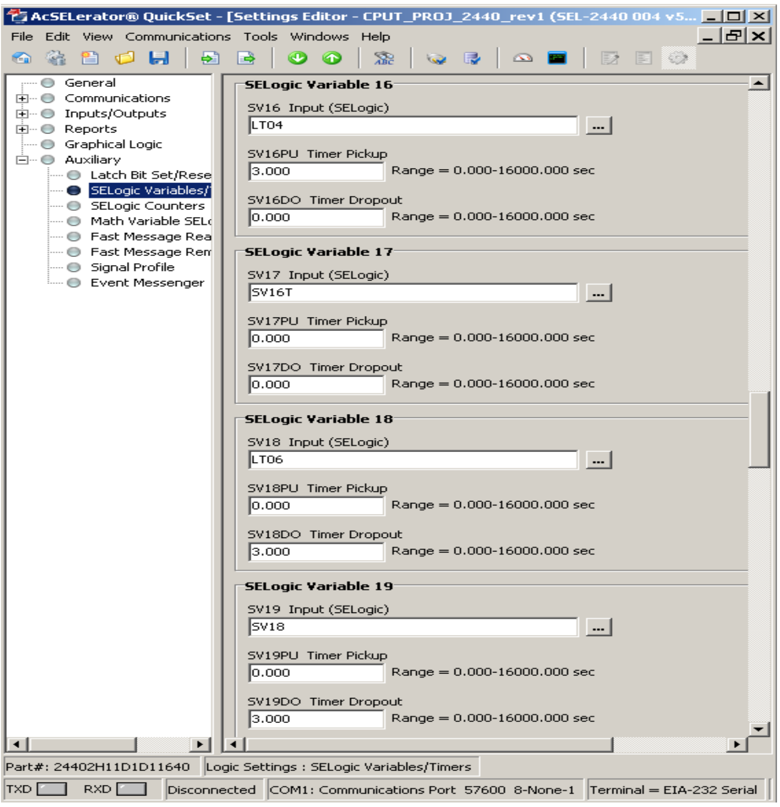


Figure B.12.5: SELogic variable/timer settings

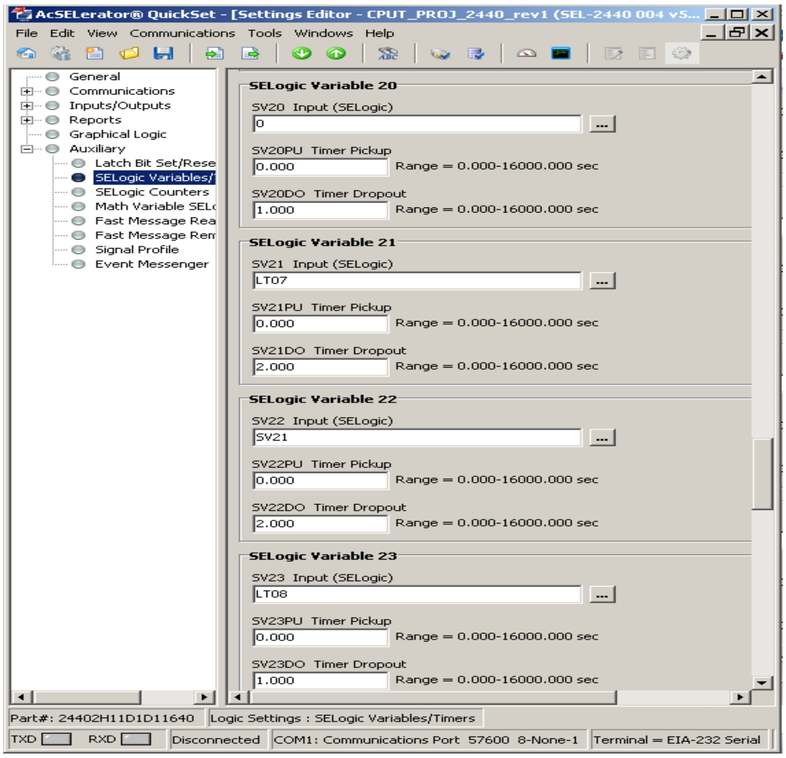


Figure B.12.6: SELogic variable/timer settings

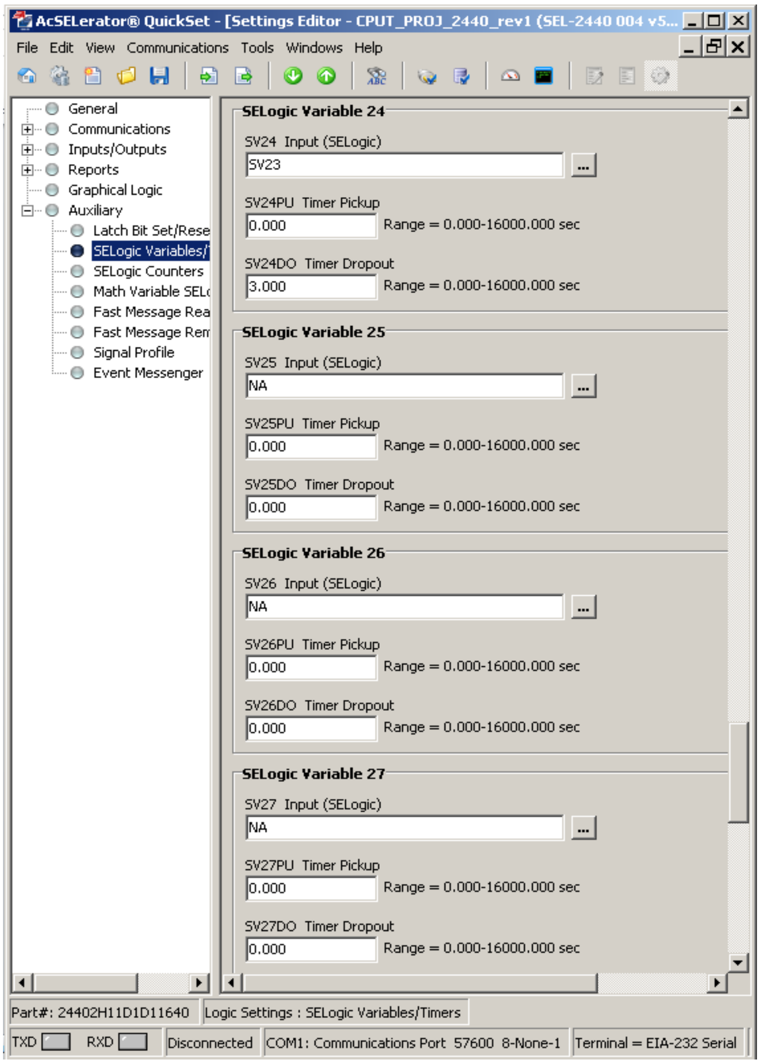


Figure B.12.7: SELogic variable/timer settings

The remaining functions: math variables SELogic equations, Fast message Read, Fast Message Remote analogs, Signal profile and Event messenger are not used in the thesis therefore they are not configured.

B.7 Conclusion

Appendix B describes in detail how the inputs and outputs are configured, the latch bit set/rest equations and the SELogic variable configurations. The GOOSE communication setup is described in Appendix E. The complete parameter settings for the SEL 351A IED is presented in Appendix D.

APPENDIX C

SEL 2440 COMPLETE PARAMETER SETTINGS

Group	Setting	Value	Description
1	DID	SEL-2440 IO 1	DID Device Identification (16 characters)
1	TID	11kV Ring	TID Terminal Identification (16 characters)
L	ELAT	32	ELAT SELogic Latches
L	ESV	32	ESV SELogic Variables/Timers
L	ESC	1	ESC SELogic Counters
L	EMV	N	EMV SELogic Math Variable Equations
L	SET01	OUT101	SET01 (SELogic)
L	RST01	SV10T	RST01 (SELogic)
L	SET02	OUT103	SET02 (SELogic)
L	RST02	SV12T	RST02 (SELogic)
L	SET03	OUT107	SET03 (SELogic)
L	RST03	SV15T	RST03 (SELogic)
L	SET04	OUT109	SET04 (SELogic)
L	RST04	SV17T	RST04 (SELogic)
L	SET05	VB014	SET05 (SELogic)
L	RST05	VB015	RST05 (SELogic)
L	SET06	VB008 AND SV04	SET06 (SELogic)
L	RST06	SV19T	RST06 (SELogic)
L	SET07	VB008 AND SV13	SET07 (SELogic)
L	RST07	SV22T	RST07 (SELogic)
L	SET08	SV08 AND VB004	SET08 (SELogic)
L	RST08	SV24	RST08 (SELogic)
L	SV01	VB015	SV01 Input (SELogic)
L	SV01PU	2.000	SV01PU Timer Pickup
L	SV01DO	2.000	SV01DO Timer Dropout
L	SV02	VB016	SV02 Input (SELogic)
L	SV02PU	0.000	SV02PU Timer Pickup
L	SV02DO	0.000	SV02DO Timer Dropout
L	SV03	VB012	SV03 Input (SELogic)
L	SV03PU	0.000	SV03PU Timer Pickup
L	SV03DO	0.000	SV03DO Timer Dropout
L	SV04	NOT SV05 AND (VB005 OR VB007)	SV04 Input (SELogic)
L	SV04PU	0.000	SV04PU Timer Pickup
L	SV04DO	0.000	SV04DO Timer Dropout
L	SV05	VB013	SV05 Input (SELogic)
L	SV05PU	5.000	SV05PU Timer Pickup
L	SV05DO	0.000	SV05DO Timer Dropout
L	SV06	(VB003 OR VB009 OR VB001) AND NOT SV01	SV06 Input (SELogic)
L	SV06PU	0.200	SV06PU Timer Pickup
L	SV06DO	0.300	SV06DO Timer Dropout
L	SV07	IN213 OR IN212 OR VB007 OR VB008	SV07 Input (SELogic)
L	SV07PU	0.000	SV07PU Timer Pickup
L	SV07DO	0.000	SV07DO Timer Dropout

L	SV08	(VB003 OR VB009 OR VB001) AND SV02	SV08 Input (SELogic)
L	SV08PU	0.000	SV08PU Timer Pickup
L	SV08DO	0.000	SV08DO Timer Dropout
L	SV09	LT01	SV09 Input (SELogic)
L	SV09PU	1.000	SV09PU Timer Pickup
L	SV09DO	0.000	SV09DO Timer Dropout
L	SV10	SV09T	SV10 Input (SELogic)
L	SV10PU	5.000	SV10PU Timer Pickup
L	SV10DO	0.000	SV10DO Timer Dropout
L	SV11	LT02	SV11 Input (SELogic)
L	SV11PU	0.250	SV11PU Timer Pickup
L	SV11DO	1.000	SV11DO Timer Dropout
L	SV12	SV11T	SV12 Input (SELogic)
L	SV12PU	0.000	SV12PU Timer Pickup
L	SV12DO	1.000	SV12DO Timer Dropout
L	SV13	(VB005 OR VB006 OR VB007) AND SV03	SV13 Input (SELogic)
L	SV13PU	3.000	SV13PU Timer Pickup
L	SV13DO	0.000	SV13DO Timer Dropout
L	SV14	LT03	SV14 Input (SELogic)
L	SV14PU	0.000	SV14PU Timer Pickup
L	SV14DO	2.000	SV14DO Timer Dropout
L	SV15	SV14T	SV15 Input (SELogic)
L	SV15PU	0.000	SV15PU Timer Pickup
L	SV15DO	2.000	SV15DO Timer Dropout
L	SV16	LT04	SV16 Input (SELogic)
L	SV16PU	3.000	SV16PU Timer Pickup
L	SV16DO	0.000	SV16DO Timer Dropout
L	SV17	SV16T	SV17 Input (SELogic)
L	SV17PU	0.000	SV17PU Timer Pickup
L	SV17DO	0.000	SV17DO Timer Dropout
L	SV18	LT06	SV18 Input (SELogic)
L	SV18PU	0.000	SV18PU Timer Pickup
L	SV18DO	3.000	SV18DO Timer Dropout
L	SV19	SV18	SV19 Input (SELogic)
L	SV19PU	0.000	SV19PU Timer Pickup
L	SV19DO	3.000	SV19DO Timer Dropout
L	SV20	0	SV20 Input (SELogic)
L	SV20PU	0.000	SV20PU Timer Pickup
L	SV20DO	1.000	SV20DO Timer Dropout
L	SV21	LT07	SV21 Input (SELogic)
L	SV21PU	0.000	SV21PU Timer Pickup
L	SV21DO	2.000	SV21DO Timer Dropout
L	SV22	SV21	SV22 Input (SELogic)
L	SV22PU	0.000	SV22PU Timer Pickup
L	SV22DO	2.000	SV22DO Timer Dropout
L	SV23	LT08	SV23 Input (SELogic)
L	SV23PU	0.000	SV23PU Timer Pickup
L	SV23DO	1.000	SV23DO Timer Dropout
L	SV24	SV23	SV24 Input (SELogic)
L	SV24PU	0.000	SV24PU Timer Pickup
L	SV24DO	3.000	SV24DO Timer Dropout
L	SV25	NA	SV25 Input (SELogic)

L	OUT101	SV06 AND VB004	OUT101 (SELogic)
L	OUT102	0	OUT102 (SELogic)
L	OUT103	SV23T	OUT103 (SELogic)
L	OUT104	0	OUT104 (SELogic)
L	OUT105	0	OUT105 (SELogic)
L	OUT106	SV09T OR SV16	OUT106 (SELogic)
L	OUT107	SV21T	OUT107 (SELogic)
L	OUT108	0	OUT108 (SELogic)
L	OUT109	SV18T	OUT109 (SELogic)
L	OUT110	0	OUT110 (SELogic)
L	OUT111	SV08T AND IN203	OUT111 (SELogic)
L	OUT112	0	OUT112 (SELogic)
L	OUT113	0	OUT113 (SELogic)
L	OUT114	0	OUT114 (SELogic)
L	OUT115	0	OUT115 (SELogic)
L	OUT116	0	OUT116 (SELogic)
PF	EPORT	Y	EPORT Port Enable
PF	MAXACC	2AC	MAXACC Maximum Access
PF	SPEED	38400	SPEED Baud Rate
PF	T_OUT	5	T_OUT Port Time-Out
PF	AUTO	N	AUTO Send Auto Messages to Port
PF	FASTOP	N	FASTOP Fast Operate Enable
PF	ECLASSF1	0	ECLASSF1 Frozen Counter Event Data
PF	DCNTRPT1	ALL	DCNTRPT1 Default Counter Reporting
P1	EPORT	Y	EPORT Port Enable
P1	MAXACC	2AC	MAXACC Maximum Access
P1	FASTOP	N	FASTOP Fast Operate Enable
P1	IPADDR	192.168.1.4	IPADDR Device IP Address [zzz.yyy.xxx.www] (15 characters)
P1	SUBNETM	255.255.255.0	SUBNETM Subnet Mask (15 characters)
P1	DEFRTR	192.168.1.1	DEFRTR Default Router Gateway (15 characters)
P1	NETMODE	FAILOVER	NETMODE Operating Mode
P1	FTIME	1.00	FTIME Fail Over Time Out
P1	NETPORT	A	NETPORT Primary Netport
P1	NETASPD	100	NETASPD Network Port A Speed
P1	NETBSPD	100	NETBSPD Network Port B Speed
P1	ETELNET	Y	ETELNET Enable Telnet
P1	TPORT	23	TPORT Telnet Port
P1	TIDLE	15	TIDLE Telnet Port Time-Out
P1	EFTP	Y	EFTP Enable FTP
P1	FTPUSER	FTPUSER	FTPUSER FTP User Name (20 characters)
P1	EMODBUS	Y	EMODBUS Enable Modbus

P1	ETCPKA	Y	ETCPKA Enable
P1	KAIDLE	10	KAIDLE Idle Range
P1	KAINTV	1	KAINTV Interval Range
P1	KACNT	6	KACNT Count Range
P1	E61850	Y	E61850 Enable IEC 61850
P1	EGSE	Y	EGSE Enable GSE
P1	EDNP	0	EDNP Enable Sessions
P1	DNPNUM	20000	DNPNUM TCP and UDP Port
P1	DNPADR	1	DNPADR Local Address
P1	DNPIP1	0.0.0.0	DNPIP1 Master IP Address [zzz.yyy.xxx.www] (15 characters)
P1	DNPTR1	TCP	DNPTR1 Transport Protocol
P1	DNPUDP1	20000	DNPUDP1 UDP Response Port
P1	REPADR1	100	REPADR1 DNP Address to Report to
P1	DNPMAP1	1	DNPMAP1 DNP Map
P1	DVARAI1	4	DVARAI1 Analog Input Default Variation
P1	ECLASSB1	1	ECLASSB1 Binary Event Data
P1	ECLASSC1	0	ECLASSC1 Counter Event Data
P1	ECLASSF1	0	ECLASSF1 Frozen Counter Event Data
P1	ECLASSA1	2	ECLASSA1 Analog Event Data
P1	DECPLM1	1	DECPLM1 Misc Data Scaling Decimal Places
P1	ANADBM1	100	ANADBM1 Misc Data Reporting Deadband Counts
P1	TIMERQ1	I	TIMERQ1 Minutes for Request Interval (I,M,1-32767)
P1	STIMEO1	1.0	STIMEO1 Seconds to Select/Operate Time-Out
P1	DNPINA1	120	DNPINA1 Seconds to send Data Link Heartbeat
P1	ETIMEO1	5	ETIMEO1 Event Message Confirm Time-Out
P1	DCNTRPT1	ALL	DCNTRPT1 Default Counter Reporting
P1	UNSOL1	N	UNSOL1 Enable Reporting
P1	PUNSOL1	N	PUNSOL1 Enable Reporting at Power-Up
P1	NUMEVE1	10	NUMEVE1 Number of Events to Transmit On
P1	AGEEVE1	2.0	AGEEVE1 Oldest Event to Tx On
P1	URETRY1	3	URETRY1 Max Retry Attempts
P1	UTIMEO1	60	UTIMEO1 Offline Time-Out
P1	DNPIP2	192.168.0.4	DNPIP2 Master IP Address [zzz.yyy.xxx.www] (15 characters)
P1	DNPTR2	TCP	DNPTR2 Transport Protocol
P1	DNPUDP2	20000	DNPUDP2 UDP Response Port
P1	REPADR2	100	REPADR2 DNP Address to Report to
P1	DNPMAP2	1	DNPMAP2 DNP Map
P1	DVARAI2	4	DVARAI2 Analog Input Default Variation
P1	ECLASSB2	1	ECLASSB2 Binary Event Data
P1	ECLASSC2	0	ECLASSC2 Counter Event Data
P1	ECLASSF2	0	ECLASSF2 Frozen Counter Event Data
P1	ECLASSA2	2	ECLASSA2 Analog Event Data
P1	DECPLM2	1	DECPLM2 Misc Data Scaling Decimal Places
P1	ANADBM2	100	ANADBM2 Misc Data Reporting Deadband Counts

P1	TIMERQ2	I	TIMERQ2 Minutes for Request Interval (I,M,1-32767)
P1	STIMEO2	1.0	STIMEO2 Seconds to Select/Operate Time-Out
P1	DNPINA2	120	DNPINA2 Seconds to send Data Link Heartbeat
P1	ETIMEO2	5	ETIMEO2 Event Message Confirm Time-Out
P1	DCNTRPT2	ALL	DCNTRPT2 Default Counter Reporting
P1	UNSOL2	N	UNSOL2 Enable Reporting
P1	PUNSOL2	N	PUNSOL2 Enable Reporting at Power-Up
P1	NUMEVE2	10	NUMEVE2 Number of Events to Transmit On
P1	AGEEVE2	2.0	AGEEVE2 Oldest Event to Tx On
P1	URETRY2	3	URETRY2 Max Retry Attempts
P1	UTIMEO2	60	UTIMEO2 Offline Time-Out
P1	DNPIP3	192.168.0.5	DNPIP3 Master IP Address [zzz.yyy.xxx.www] (15 characters)
P1	DNPTR3	TCP	DNPTR3 Transport Protocol
P1	DNPUDP3	20000	DNPUDP3 UDP Response Port
P1	REPADR3	100	REPADR3 DNP Address to Report to
P1	DNPMAP3	1	DNPMAP3 DNP Map
P1	DVARAI3	4	DVARAI3 Analog Input Default Variation
P1	ECLASSB3	1	ECLASSB3 Binary Event Data
P1	ECLASSC3	0	ECLASSC3 Counter Event Data
P1	ECLASSF3	0	ECLASSF3 Frozen Counter Event Data
P1	ECLASSA3	2	ECLASSA3 Analog Event Data
P1	DECPLM3	1	DECPLM3 Misc Data Scaling Decimal Places
P1	ANADBM3	100	ANADBM3 Misc Data Reporting Deadband Counts
P1	TIMERQ3	I	TIMERQ3 Minutes for Request Interval (I,M,1-32767)
P1	STIMEO3	1.0	STIMEO3 Seconds to Select/Operate Time-Out
P1	DNPINA3	120	DNPINA3 Seconds to send Data Link Heartbeat
P1	ETIMEO3	5	ETIMEO3 Event Message Confirm Time-Out
P1	DCNTRPT3	ALL	DCNTRPT3 Default Counter Reporting
P1	UNSOL3	N	UNSOL3 Enable Reporting
P1	PUNSOL3	N	PUNSOL3 Enable Reporting at Power-Up
P1	NUMEVE3	10	NUMEVE3 Number of Events to Transmit On
P1	AGEEVE3	2.0	AGEEVE3 Oldest Event to Tx On
P1	URETRY3	3	URETRY3 Max Retry Attempts
P1	UTIMEO3	60	UTIMEO3 Offline Time-Out
P1	DNPIP4	192.168.0.6	DNPIP4 Master IP Address [zzz.yyy.xxx.www] (15 characters)
P1	DNPTR4	TCP	DNPTR4 Transport Protocol
P1	DNPUDP4	20000	DNPUDP4 UDP Response Port
P1	REPADR4	100	REPADR4 DNP Address to Report to
P1	DNPMAP4	1	DNPMAP4 DNP Map
P1	DVARAI4	4	DVARAI4 Analog Input Default Variation
P1	ECLASSB4	1	ECLASSB4 Binary Event Data

P1	ECLASSC4	0	ECLASSC4 Counter Event Data
P1	ECLASSF4	0	ECLASSF4 Frozen Counter Event Data
P1	ECLASSA4	2	ECLASSA4 Analog Event Data
P1	DECPLM4	1	DECPLM4 Misc Data Scaling Decimal Places
P1	ANADBM4	100	ANADBM4 Misc Data Reporting Deadband Counts
P1	TIMERQ4	I	TIMERQ4 Minutes for Request Interval (I,M,1-32767)
P1	STIMEO4	1.0	STIMEO4 Seconds to Select/Operate Time-Out
P1	DNPINA4	120	DNPINA4 Seconds to send Data Link Heartbeat
P1	ETIMEO4	5	ETIMEO4 Event Message Confirm Time-Out
P1	DCNTRPT4	ALL	DCNTRPT4 Default Counter Reporting
P1	UNSOL4	N	UNSOL4 Enable Reporting
P1	PUNSOL4	N	PUNSOL4 Enable Reporting at Power-Up
P1	NUMEVE4	10	NUMEVE4 Number of Events to Transmit On
P1	AGEEVE4	2.0	AGEEVE4 Oldest Event to Tx On
P1	URETRY4	3	URETRY4 Max Retry Attempts
P1	UTIMEO4	60	UTIMEO4 Offline Time-Out
P1	DNPIP5	192.168.0.7	DNPIP5 Master IP Address [zzz.yyy.xxx.www] (15 characters)
P1	DNPTR5	TCP	DNPTR5 Transport Protocol
P1	DNPUDP5	20000	DNPUDP5 UDP Response Port
P1	REPADR5	100	REPADR5 DNP Address to Report to
P1	DNPMAP5	1	DNPMAP5 DNP Map
P1	DVARAI5	4	DVARAI5 Analog Input Default Variation
P1	ECLASSB5	1	ECLASSB5 Binary Event Data
P1	ECLASSC5	0	ECLASSC5 Counter Event Data
P1	ECLASSF5	0	ECLASSF5 Frozen Counter Event Data
P1	ECLASSA5	2	ECLASSA5 Analog Event Data
P1	DECPLM5	1	DECPLM5 Misc Data Scaling Decimal Places
P1	ANADBM5	100	ANADBM5 Misc Data Reporting Deadband Counts
P1	TIMERQ5	I	TIMERQ5 Minutes for Request Interval (I,M,1-32767)
P1	STIMEO5	1.0	STIMEO5 Seconds to Select/Operate Time-Out
P1	DNPINA5	120	DNPINA5 Seconds to send Data Link Heartbeat
P1	ETIMEO5	5	ETIMEO5 Event Message Confirm Time-Out
P1	DCNTRPT5	ALL	DCNTRPT5 Default Counter Reporting
P1	UNSOL5	N	UNSOL5 Enable Reporting
P1	PUNSOL5	N	PUNSOL5 Enable Reporting at Power-Up
P1	NUMEVE5	10	NUMEVE5 Number of Events to Transmit On
P1	AGEEVE5	2.0	AGEEVE5 Oldest Event to Tx On
P1	URETRY5	3	URETRY5 Max Retry Attempts
P1	UTIMEO5	60	UTIMEO5 Offline Time-Out
R	ESERDEL	N	ESERDEL Auto-Removal Enable
R	SRDLCNT	5	SRDLCNT Number of Counts

R	SRDLTIM	1.0	SRDLTIM Removal Time
R	SER1	VB004 VB005 VB006 VB007 VB008 SV13 SV14 SV14T SV15 SV15T SV01 VB011 VB012 OUT107 LT07 SV21	SER1 (24 Device Word bits)
R	SER2	VB008 OUT108 VB010 VB011 OUT109 VB012 OUT110 VB013 OUT111 VB014 VB015 OUT112 VB016 OUT113 OUT107	SER2 (24 Device Word bits)
R	SER3	LT03 LT04 LT05 LT08 LT09 LT10	SER3 (24 Device Word bits)
R	SER4	LT02 LT06	SER4 (24 Device Word bits)

APPENDIX D

SEL351A COMPLETE PARAMETER SETTINGS

Group	Setting	Value	Description
PF	EPORT	Y	EPORT Enable Port
PF	PROTO	SEL	PROTO Protocol
PF	MAXACC	C	MAXACC Maximum Access Level
PF	PREFIX	@	PREFIX LMD Prefix
PF	ADDR	1	ADDR LMD Address
PF	SETTLE	0.00	SETTLE LMD Settling Time (seconds)
PF	SPEED	38400	SPEED Baud Rate
PF	BITS	8	BITS Data Bits
PF	PARITY	N	PARITY Parity
PF	STOP	1	STOP Stop Bits
PF	T_OUT	15	T_OUT Minutes to Port Time-out
PF	AUTO	N	AUTO Send Auto Messages to Port
PF	RTSCTS	N	RTSCTS Enable Hardware Handshaking
PF	FASTOP	N	FASTOP Fast Operate Enable
PF	DNPADR	0	DNPADR DNP Address
PF	REPADR	0	REPADR DNP Address to Report to
PF	DNPMAP	1	DNPMAP DNP Session Map
PF	DVARAI	4	DVARAI Analog Input Default Variation
PF	ECLASSB	1	ECLASSB Class for Binary Event Data
PF	ECLASSC	0	ECLASSC Class for Counter Event Data
PF	ECLASSA	2	ECLASSA Class for Analog Event Data
PF	DECPLA	1	DECPLA Currents Scaling Decimal Places
PF	DECPLV	1	DECPLV Voltages Scaling Decimal Places
PF	DECPLM	1	DECPLM Misc Data Scaling Decimal Places
PF	ANADBA	100	ANADBA Amps Reporting Deadband Counts
PF	ANADBV	100	ANADBV Volts Reporting Deadband Counts
PF	ANADBM	100	ANADBM Misc Data Reporting Deadband Counts
PF	TIMERQ	I	TIMERQ Minutes for Request Interval
PF	STIMEO	1.0	STIMEO Seconds to Select/Operate Time-out
PF	DRETRY	0	DRETRY Data Link Retries
PF	DTIMEO	1	DTIMEO Seconds to Data Link Time-out
PF	ETIMEO	5	ETIMEO Event Message Confirm Time-out (sec)
PF	UNSOL	N	UNSOL Enable Unsolicited Reporting
PF	PUNSOL	N	PUNSOL Enable Unsolicited Reporting at Power-up
PF	NUM1EVE	10	NUM1EVE Number of Class 1 Events to Transmit On
PF	AGE1EVE	2.0	AGE1EVE Oldest Class 1 Event to Tx On (seconds)
PF	URETRY	3	URETRY Unsolicited Message Max Retry Attempts

PF	UTIMEO	60	UTIMEO Unsolicited Message Offline Time-out (seconds)
PF	MINDLY	0.05	MINDLY Minimum Seconds from DCD to Tx
PF	MAXDLY	0.10	MAXDLY Maximum Seconds from DCD to Tx
PF	PREDLY	0.00	PREDLY Settle Time from RTS ON to Tx (sec)
PF	PSTDLY	0.00	PSTDLY Settle Time from Tx to RTS OFF (sec)
PF	SLAVEID	1	SLAVEID Modbus Slave ID
P5	EPORT	Y	EPORT Enable Port
P5	IPADDR	192.168.1.5	IPADDR IP Address (www[h].xxx[h].yyy[h].zzz[h])
P5	SUBNETM	255.255.255.0	SUBNETM Subnet Mask (www[h].xxx[h].yyy[h].zzz[h])
P5	DEFRTR	192.168.1.1	DEFRTR Default Router (www[h].xxx[h].yyy[h].zzz[h])
P5	ETCPKA	Y	ETCPKA Enable TCP Keep-Alive
P5	KAIDLE	10	KAIDLE TCP Keep-Alive Idle Range (seconds)
P5	KAINTV	10	KAINTV TCP Keep-Alive Interval Range (seconds)
P5	KACNT	5	KACNT TCP Keep-Alive Count Range
P5	NETMODE	FAILOVER	NETMODE Operating Mode
P5	FTIME	1.00	FTIME Failover Time-out (seconds)
P5	NETPORT	A	NETPORT Primary Net Port
P5	NET5ASPD	Auto	NET5ASPD Port 5A Speed (Mbps)
P5	NET5BSPD	Auto	NET5BSPD Port 5B Speed (Mbps)
P5	ETELNET	Y	ETELNET Enable Telnet
P5	MAXACC	2	MAXACC Maximum Access Level
P5	TPORT	23	TPORT Telnet Port
P5	TIDLE	15	TIDLE Telnet Port Time-out (minutes)
P5	AUTO	N	AUTO Send Auto Messages to Port
P5	FASTOP	N	FASTOP Fast Operate Enable
P5	EDNP	0	EDNP Enable DNP Sessions
P5	EMODBUS	0	EMODBUS Enable Modbus
P5	EFTPSERV	Y	EFTPSERV Enable FTP
P5	FTPUSER	FTPUSER	FTPUSER FTP User Name (20 characters)
P5	FTPCBAN	FTP SERVER	FTPCBAN FTP Connect Banner (64 characters)
P5	FTPIDLE	5	FTPIDLE Idle Timeout (minutes)
P5	EHTTP	N	EHTTP Enable HTTP Server
P5	HTTPPORT	80	HTTPPORT TCP/IP Port
P5	HTTPIDLE	10	HTTPIDLE HTTP Web Server Timeout (minutes)
P5	E61850	Y	E61850 Enable IEC 61850 Protocol
P5	EGSE	Y	EGSE Enable IEC 61850 GSE
P5	ESNTP	OFF	ESNTP Enable SNTP Client
P5	SNTPPSIP	192.168.1.1	SNTPPSIP Primary SNTP Server IP Address (zzz.yyy.xxx.www)
P5	SNTPBSIP	192.168.1.1	SNTPBSIP Backup SNTP Server IP Address (zzz.yyy.xxx.www)
P5	SNTPPORT	123	SNTPPORT SNTP IP (Local) Port Number
P5	SNTPRATE	60	SNTPRATE SNTP Update Rate (seconds)
P5	SNTPTO	5	SNTPTO SNTP Timeout (seconds)

G	PTCONN	WYE	PTCONN Phase Potential Transformer Connection
G	PHANTV	OFF	PHANTV Phantom Volt. From
G	VSCONN	VS	VSCONN VS Channel Input Connection
G	TGR	0.00	TGR Group Change Delay (cycles in 0.25 increments)
G	NFREQ	60	NFREQ Nominal Frequency (Hz)
G	PHROT	ABC	PHROT Phase Rotation
G	DATE_F	MDY	DATE_F Date Format
G	FP_TO	15	FP_TO Front Panel Timeout (minutes in steps of 1)
G	SCROLD	2	SCROLD Display Update Rate (seconds)
G	FPNGD	IN	FPNGD Front Panel Neutral/Ground Display
G	LER	15	LER Length of Event Report (cycles)
G	PRE	4	PRE Cycle Length of Prefault in Event Report (cycles in increments of 1)
G	DCLOP	OFF	DCLOP DC Battery LO Voltage Pickup (Vdc)
G	DCHIP	OFF	DCHIP DC Battery HI Voltage Pickup (Vdc)
G	IN101D	0.50	IN101D Input 101 Debounce Time
G	IN102D	0.50	IN102D Input 102 Debounce Time
G	IN103D	0.50	IN103D Input 103 Debounce Time
G	IN104D	0.50	IN104D Input 104 Debounce Time
G	IN105D	0.50	IN105D Input 105 Debounce Time
G	IN106D	0.50	IN106D Input 106 Debounce Time
G	EBMON	Y	EBMON Breaker Monitor
G	COSP1	10000	COSP1 Close/Open Operations Set Point 1 - max (operations)
G	COSP2	150	COSP2 Close/Open Operations Set Point 2 - mid (operations)
G	COSP3	12	COSP3 Close/Open Operations Set Point 3 - min (operations)
G	KASP1	1.20	KASP1 kA(pri) Interrupted Set Point 1 - min (pri. in 0.01 kA steps)
G	KASP2	8.00	KASP2 kA(pri) Interrupted Set Point 2 - mid (pri. in 0.01 kA steps)
G	KASP3	20.00	KASP3 kA(pri) Interrupted Set Point 3 - max (pri. in 0.01 kA steps)
G	EPMU	N	EPMU Synchronized Phasor Measurement
G	MFRMT	C37.118	MFRMT Messages Format
G	MRATE	2	MRATE Messages per Second
G	PMAPP	N	PMAPP PMU Application(F=Fast Response, N=Narrow BW)
G	PHCOMP	Y	PHCOMP Freq. Based Phasor Compensation
G	PMSTN	STATION A	PMSTN Station Name
G	PMID	1	PMID PMU Hardware ID
G	PHDATAV	V1	PHDATAV Phasor Data Set, Voltages
G	VPCOMP	0.00	VPCOMP Phase Volt. Angle Comp.
G	VSCOMP	0.00	VSCOMP VS Volt. Angle Comp.
G	VCOMP	0.00	VCOMP Voltage Angle Comp. Factor
G	PHDATAI	NA	PHDATAI Phasor Data Set, Currents
G	IPCOMP	0.00	IPCOMP Phase Current Angle Comp.

G	INCOMP	0.00	INCOMP Neut. Current Angle Comp.
G	ICOMP	0.00	ICOMP Current Angle Comp. Factor
G	PHNR	I	PHNR Phasor Num. Representation (I=Integer,F=Float)
G	PHFMT	R	PHFMT Phasor Format (R = Rectangular,P = Polar)
G	FNR	I	FNR Freq. Num. Representation (I=Integer,F=Float)
G	NUMDSW	1	NUMDSW Number of 16-bit Digital Status Words
G	EVELOCK	0	EVELOCK Event Summary Lock Period in Seconds
G	IRIGC	NONE	IRIGC IRIG-B Control Bits Definition
G	UTC_OFF	0.00	UTC_OFF Offset from UTC
G	DST_BEGM	NA	DST_BEGM Month to Begin DST
G	DST_BEGW	2	DST_BEGW Week Of The Month to Begin DST
G	DST_BEGD	SUN	DST_BEGD Day Of The Week To Begin DST
G	DST_BEGH	2	DST_BEGH Local Hour To Begin DST
G	DST_ENDM	11	DST_ENDM Month To End DST
G	DST_ENDW	1	DST_ENDW Week Of The Month to End DST
G	DST_ENDD	SUN	DST_ENDD Day Of The Week To End DST
G	DST_ENDH	2	DST_ENDH Local Hour To End DST
G	METHRES	Y	METHRES Meter Cutoff Threshold
1	RID	FEEDER 1	RID Relay Identifier (30 chars)
1	TID	STATION A	TID Terminal Identifier (30 chars)
1	CTR	200	CTR Phase (IA,IB,IC) CT Ratio, CTR:1
1	CTRN	200	CTRN Neutral (IN) CT Ratio, CTRN:1
1	PTR	110.00	PTR Phase (VA,VB,VC) PT Ratio
1	PTRS	180.00	PTRS Synch. Voltage (VS) PT Ratio, PTRS:1
1	VNOM	67.00	VNOM Phase PT Nominal Volt. (L-N)
1	Z1MAG	10.70	Z1MAG Pos-Seq Line Impedance Magnitude (Ohms secondary)
1	Z1ANG	68.86	Z1ANG Pos-Seq Line Impedance Angle (degrees)
1	Z0MAG	31.90	Z0MAG Zero-Seq Line Impedance Magnitude (Ohms secondary)
1	Z0ANG	72.47	Z0ANG Zero-Seq Line Impedance Angle (degrees)
1	Z0SMAG	1.80	Z0SMAG Zero-Seq Source Impedance Magnitude (Ohms secondary)
1	Z0SANG	84.61	Z0SANG Zero-Seq Source Impedance Angle (degrees)
1	LL	4.84	LL Line Length (unitless)
1	E50P	N	E50P Phase Overcurrent Elements
1	E50N	N	E50N Neutral Ground (channel IN) Overcurrent Elements
1	E50G	N	E50G Residual Ground Overcurrent Elements
1	E50Q	N	E50Q Negative-Sequence Overcurrent Elements
1	E51P	N	E51P Phase Time-Overcurrent Elements
1	E51N	Y	E51N Neutral Ground (channel IN) Time-Overcurrent Elements

1	E51G	1	E51G Residual Ground Time-Overcurrent Elements
1	E51Q	N	E51Q Negative-Sequence Time-Overcurrent Elements
1	E32	N	E32 Directional Control Elements
1	ELOAD	N	ELOAD Load Encroachment Element
1	ESOTF	N	ESOTF Switch-Onto-Fault
1	EVOLT	N	EVOLT Voltage Element
1	E25	N	E25 Synchronism Check
1	EFLOC	Y	EFLOC Fault Location
1	ELOP	N	ELOP Loss-Of-Potential
1	E81	N	E81 Frequency Elements
1	E79	1	E79 Reclosures
1	ESV	1	ESV SELogic Variable Timers
1	EDEM	THM	EDEM Demand Metering Type
1	50P1P	OFF	50P1P Level 1 (Amps secondary)
1	50P2P	OFF	50P2P Level 2 (Amps secondary)
1	50P3P	OFF	50P3P Level 3 (Amps secondary)
1	50P4P	OFF	50P4P Level 4 (Amps secondary)
1	50P5P	OFF	50P5P Level 5 (Amps secondary)
1	50P6P	OFF	50P6P Level 6 (Amps secondary)
1	67P1D	0.00	67P1D Level 1 (cycles in 0.25 increments)
1	67P2D	0.00	67P2D Level 2 (cycles in 0.25 increments)
1	67P3D	0.00	67P3D Level 3 (cycles in 0.25 increments)
1	67P4D	0.00	67P4D Level 4 (cycles in 0.25 increments)
1	50PP1P	OFF	50PP1P Level 1 (Amps secondary)
1	50PP2P	OFF	50PP2P Level 2 (Amps secondary)
1	50PP3P	OFF	50PP3P Level 3 (Amps secondary)
1	50PP4P	OFF	50PP4P Level 4 (Amps secondary)
1	50N1P	OFF	50N1P Level 1 (Amps secondary)
1	50N2P	OFF	50N2P Level 2 (Amps secondary)
1	50N3P	OFF	50N3P Level 3 (Amps secondary)
1	50N4P	OFF	50N4P Level 4 (Amps secondary)
1	50N5P	OFF	50N5P Level 5 (Amps secondary)
1	50N6P	OFF	50N6P Level 6 (Amps secondary)
1	67N1D	0.00	67N1D Level 1 (cycles in 0.25 increments)
1	67N2D	0.00	67N2D Level 2 (cycles in 0.25 increments)
1	67N3D	0.00	67N3D Level 3 (cycles in 0.25 increments)
1	67N4D	0.00	67N4D Level 4 (cycles in 0.25 increments)
1	50G1P	OFF	50G1P Level 1 (Amps secondary)
1	50G2P	OFF	50G2P Level 2 (Amps secondary)
1	50G3P	OFF	50G3P Level 3 (Amps secondary)
1	50G4P	OFF	50G4P Level 4 (Amps secondary)
1	50G5P	OFF	50G5P Level 5 (Amps secondary)
1	50G6P	OFF	50G6P Level 6 (Amps secondary)
1	67G1D	0.00	67G1D Level 1 (cycles in 0.25 increments)
1	67G2D	0.00	67G2D Level 2 (cycles in 0.25 increments)
1	67G3D	0.00	67G3D Level 3 (cycles in 0.25 increments)

1	67G4D	0.00	67G4D Level 4 (cycles in 0.25 increments)
1	50Q1P	OFF	50Q1P Level 1 (Amps secondary)
1	50Q2P	OFF	50Q2P Level 2 (Amps secondary)
1	50Q3P	OFF	50Q3P Level 3 (Amps secondary)
1	50Q4P	OFF	50Q4P Level 4 (Amps secondary)
1	50Q5P	OFF	50Q5P Level 5 (Amps secondary)
1	50Q6P	OFF	50Q6P Level 6 (Amps secondary)
1	67Q1D	0.00	67Q1D Level 1 (cycles in 0.25 increments)
1	67Q2D	0.00	67Q2D Level 2 (cycles in 0.25 increments)
1	67Q3D	0.00	67Q3D Level 3 (cycles in 0.25 increments)
1	67Q4D	0.00	67Q4D Level 4 (cycles in 0.25 increments)
1	51PP	OFF	51PP Pickup (Amps secondary)
1	51PC	C1	51PC Curve
1	51PTD	0.30	51PTD Time Dial
1	51PRS	N	51PRS Electromechanical Reset Delay
1	51AP	OFF	51AP A-Phase Pickup (Amps secondary)
1	51AC	U3	51AC A-Phase Curve
1	51ATD	3.00	51ATD A-Phase Time Dial
1	51ARS	N	51ARS A-Phase Electromechanical Reset Delay
1	51BP	OFF	51BP B-Phase Pickup (Amps secondary)
1	51BC	U3	51BC B-Phase Curve
1	51BTD	3.00	51BTD B-Phase Time Dial
1	51BRS	N	51BRS B-Phase Electromechanical Reset Delay
1	51CP	OFF	51CP C-Phase Pickup (Amps secondary)
1	51CC	U3	51CC C-Phase Curve
1	51CTD	3.00	51CTD C-Phase Time Dial
1	51CRS	N	51CRS C-Phase Electromechanical Reset Delay
1	51NP	0.300	51NP Pickup (Amps secondary)
1	51NC	C1	51NC Curve
1	51NTD	0.20	51NTD Time Dial
1	51NRS	N	51NRS Electromechanical Reset Delay
1	51GP	0.30	51GP Pickup (Amps secondary)
1	51GC	C1	51GC Curve
1	51GTD	0.20	51GTD Time Dial
1	51GRS	N	51GRS Electromechanical Reset Delay
1	51G2P	OFF	51G2P Pickup (Amps secondary)
1	51G2C	U3	51G2C Curve
1	51G2TD	1.50	51G2TD Time Dial
1	51G2RS	N	51G2RS Electromechanical Reset Delay
1	51QP	OFF	51QP Pickup (Amps secondary)
1	51QC	U3	51QC Curve
1	51QTD	3.00	51QTD Time Dial
1	51QRS	N	51QRS Electromechanical Reset Delay
1	ZLF	32.50	ZLF Forward Load Impedance (Ohms secondary)

1	ZLR	32.50	ZLR Reverse Load Impedance (Ohms secondary)
1	PLAF	30.00	PLAF Positive Forward Load Angle (degrees)
1	NLAF	-30.00	NLAF Negative Forward Load Angle (degrees)
1	PLAR	150.00	PLAR Positive Reverse Load Angle (degrees)
1	NLAR	210.00	NLAR Negative Reverse Load Angle (degrees)
1	DIR1	N	DIR1 Level 1 Direction
1	DIR2	N	DIR2 Level 2 Direction
1	DIR3	N	DIR3 Level 3 Direction
1	DIR4	N	DIR4 Level 4 Direction
1	ORDER	OFF	ORDER Ground Directional Priority
1	27P1P	OFF	27P1P Phase Undervoltage Pickup (Volts secondary)
1	27P2P	OFF	27P2P Phase Undervoltage Pickup (Volts secondary)
1	59P1P	OFF	59P1P Phase Overvoltage Pickup (Volts secondary)
1	59P2P	OFF	59P2P Phase Overvoltage Pickup (Volts secondary)
1	59N1P	OFF	59N1P Zero-Seq(3V0) Overvoltage Pickup (Volts secondary)
1	59N2P	OFF	59N2P Zero-Seq(3V0) Overvoltage Pickup (Volts secondary)
1	59QP	OFF	59QP Neg-Seq(V2) Overvoltage Pickup (Volts secondary)
1	59Q2P	OFF	59Q2P Neg-Seq(V2) Overvoltage Pickup (Volts secondary)
1	59V1P	OFF	59V1P Pos-Seq(V1) Overvoltage Pickup (Volts secondary)
1	27SP	OFF	27SP Channel VS Undervoltage Pickup (Volts secondary)
1	59S1P	OFF	59S1P Channel VS Overvoltage Pickup (Volts secondary)
1	59S2P	OFF	59S2P Channel VS Overvoltage Pickup (Volts secondary)
1	27PP	OFF	27PP Phase-Phase Undervoltage Pickup (Volts secondary)
1	27PP2P	OFF	27PP2P Phase-Phase Undervoltage Pickup (Volts secondary)
1	59PP	OFF	59PP Phase-Phase Overvoltage Pickup (Volts secondary)
1	59PP2P	OFF	59PP2P Phase-Phase Overvoltage Pickup (Volts secondary)
1	25VLO	105.00	25VLO Voltage Window - Low Threshold (Volts secondary)
1	25VHI	130.00	25VHI Voltage Window - High Threshold (Volts secondary)
1	25SF	0.042	25SF Maximum Slip Frequency (Hz)
1	25ANG1	25	25ANG1 Maximum Angle 1 (degrees)
1	25ANG2	40	25ANG2 Maximum Angle 2 (degrees)
1	SYNCP	VA	SYNCP Sync. Phase (degrees, lag VA in 30 degree increments)
1	TCLOSD	3.00	TCLOSD Breaker Close Time for Angle Comp.
1	27B81P	40.00	27B81P Undervoltage Block (Volts secondary)
1	81D1P	OFF	81D1P Level 1 Pickup (Hz)
1	81D1D	2.00	81D1D Level 1 Time Delay (cycles in 0.25 increments)

1	81D2P	OFF	81D2P Level 2 Pickup (Hz)
1	81D2D	2.00	81D2D Level 2 Time Delay (cycles in 0.25 increments)
1	81D3P	OFF	81D3P Level 3 Pickup (Hz)
1	81D3D	2.00	81D3D Level 3 Time Delay (cycles in 0.25 increments)
1	81D4P	OFF	81D4P Level 4 Pickup (Hz)
1	81D4D	2.00	81D4D Level 4 Time Delay (cycles in 0.25 increments)
1	81D5P	OFF	81D5P Level 5 Pickup (Hz)
1	81D5D	2.00	81D5D Level 5 Time Delay (cycles in 0.25 increments)
1	81D6P	OFF	81D6P Level 6 Pickup (Hz)
1	81D6D	2.00	81D6D Level 6 Time Delay (cycles in 0.25 increments)
1	79OI1	300.00	79OI1 Open Interval 1 (cycles in 0.25 increments)
1	79OI2	0.00	79OI2 Open Interval 2 (cycles in 0.25 increments)
1	79OI3	0.00	79OI3 Open Interval 3 (cycles in 0.25 increments)
1	79OI4	0.00	79OI4 Open Interval 4 (cycles in 0.25 increments)
1	79RSD	1800.00	79RSD Reset Time from Reclose Cycle (cycles in 0.25 increments)
1	79RSLD	300.00	79RSLD Reset Time from Lockout (cycles in 0.25 increments)
1	79CLSD	0.00	79CLSD Reclose Supv. Time Limit (cycles in 0.25 increments)
1	CLOEND	OFF	CLOEND Close Enable Time Delay (cycles in 0.25 increments)
1	52AEND	OFF	52AEND 52A Enable Time Delay (cycles in 0.25 increments)
1	SOTFD	30.00	SOTFD SOTF Duration (cycles in 0.25 increments)
1	DMTC	5	DMTC Time Constant (minutes)
1	PDEMP	1.00	PDEMP Phase Pickup (Amps secondary)
1	NDEMP	0.300	NDEMP Neutral Ground Pickup (Amps secondary)
1	GDEMP	0.30	GDEMP Residual Ground Pickup (Amps secondary)
1	QDEMP	0.30	QDEMP Negative-Sequence Pickup (Amps secondary)
1	TDURD	9.00	TDURD Minimum Trip Duration Time (cycles in 0.25 increments)
1	CFD	60.00	CFD Close Failure Time Delay (cycles in 0.25 increments)
1	3POD	1.50	3POD Three-Pole Open Time Delay (cycles in 0.25 increments)
1	50LP	0.05	50LP Load Detection Phase Pickup (Amps secondary)
1	SV1PU	12.00	SV1PU SV1 Timer Pickup (cycles in 0.25 increments)
1	SV1DO	2.00	SV1DO SV1 Timer Dropout (cycles in 0.25 increments)
1	SV2PU	0.00	SV2PU SV2 Timer Pickup (cycles in 0.25 increments)
1	SV2DO	0.00	SV2DO SV2 Timer Dropout (cycles in 0.25 increments)
1	SV3PU	0.00	SV3PU SV3 Timer Pickup (cycles in 0.25 increments)
1	SV3DO	0.00	SV3DO SV3 Timer Dropout (cycles in 0.25 increments)
1	SV4PU	0.00	SV4PU SV4 Timer Pickup (cycles in 0.25 increments)

1	SV4DO	0.00	SV4DO SV4 Timer Dropout (cycles in 0.25 increments)
1	SV5PU	0.00	SV5PU SV5 Timer Pickup (cycles in 0.25 increments)
1	SV5DO	0.00	SV5DO SV5 Timer Dropout (cycles in 0.25 increments)
1	SV6PU	0.00	SV6PU SV6 Timer Pickup (cycles in 0.25 increments)
1	SV6DO	0.00	SV6DO SV6 Timer Dropout (cycles in 0.25 increments)
1	SV7PU	0.00	SV7PU SV7 Timer Pickup (cycles in 0.25 increments)
1	SV7DO	0.00	SV7DO SV7 Timer Dropout (cycles in 0.25 increments)
1	SV8PU	0.00	SV8PU SV8 Timer Pickup (cycles in 0.25 increments)
1	SV8DO	0.00	SV8DO SV8 Timer Dropout (cycles in 0.25 increments)
1	SV9PU	0.00	SV9PU SV9 Timer Pickup (cycles in 0.25 increments)
1	SV9DO	0.00	SV9DO SV9 Timer Dropout (cycles in 0.25 increments)
1	SV10PU	0.00	SV10PU SV10 Timer Pickup (cycles in 0.25 increments)
1	SV10DO	0.00	SV10DO SV10 Timer Dropout (cycles in 0.25 increments)
1	SV11PU	0.00	SV11PU SV11 Timer Pickup (cycles in 0.25 increments)
1	SV11DO	0.00	SV11DO SV11 Timer Dropout (cycles in 0.25 increments)
1	SV12PU	0.00	SV12PU SV12 Timer Pickup (cycles in 0.25 increments)
1	SV12DO	0.00	SV12DO SV12 Timer Dropout (cycles in 0.25 increments)
1	SV13PU	0.00	SV13PU SV13 Timer Pickup (cycles in 0.25 increments)
1	SV13DO	0.00	SV13DO SV13 Timer Dropout (cycles in 0.25 increments)
1	SV14PU	0.00	SV14PU SV14 Timer Pickup (cycles in 0.25 increments)
1	SV14DO	0.00	SV14DO SV14 Timer Dropout (cycles in 0.25 increments)
1	SV15PU	0.00	SV15PU SV15 Timer Pickup (cycles in 0.25 increments)
1	SV15DO	0.00	SV15DO SV15 Timer Dropout (cycles in 0.25 increments)
1	SV16PU	0.00	SV16PU SV16 Timer Pickup (cycles in 0.25 increments)
1	SV16DO	0.00	SV16DO SV16 Timer Dropout (cycles in 0.25 increments)
T	NLB1	NA	NLB1 Local Bit 1 Name (14 char; enter NA to null)
T	CLB1	NA	CLB1 Clear Local Bit 1 Label (7 char; enter NA to null)
T	SLB1	NA	SLB1 Set Local Bit 1 Label (7 char; enter NA to null)
T	PLB1	NA	PLB1 Pulse Local Bit 1 Label (7 char; enter NA to null)
T	NLB2	NA	NLB2 Local Bit 2 Name (14 char; enter NA to null)
T	CLB2	NA	CLB2 Clear Local Bit 2 Label (7 char; enter NA to null)
T	SLB2	NA	SLB2 Set Local Bit 2 Label (7 char; enter NA to null)
T	PLB2	NA	PLB2 Pulse Local Bit 2 Label (7 char; enter NA to null)

T	NLB3	MANUAL TRIP	NLB3 Local Bit 3 Name (14 char; enter NA to null)
T	CLB3	RETURN	CLB3 Clear Local Bit 3 Label (7 char; enter NA to null)
T	SLB3	NA	SLB3 Set Local Bit 3 Label (7 char; enter NA to null)
T	PLB3	TRIP	PLB3 Pulse Local Bit 3 Label (7 char; enter NA to null)
T	NLB4	MANUAL CLOSE	NLB4 Local Bit 4 Name (14 char; enter NA to null)
T	CLB4	RETURN	CLB4 Clear Local Bit 4 Label (7 char; enter NA to null)
T	SLB4	NA	SLB4 Set Local Bit 4 Label (7 char; enter NA to null)
T	PLB4	CLOSE	PLB4 Pulse Local Bit 4 Label (7 char; enter NA to null)
T	DP1_1	BRKR CLOSED	DP1_1 Display Point 1 Label (16 char; enter NA to null)
T	DP1_0	BREAKER OPEN	DP1_0 Display Point 1 Label (16 char; enter NA to null)
T	DP2_1	test	DP2_1 Display Point 2 Label (16 char; enter NA to null)
T	DP2_0	NA	DP2_0 Display Point 2 Label (16 char; enter NA to null)
T	DP3_1	NA	DP3_1 Display Point 3 Label (16 char; enter NA to null)
T	79LL	Not used	79LL Last Shot Label (14 char; enter NA to null)
T	79SL	Not used	79SL Shot Counter Label (14 char; enter NA to null)
R	SER1	51P,51G,50P1,VB001,VB002,VB003,VB004,CF,CLOSE,TRIP,TRGTR,LT1,LT2	SER1 Sequential Events Recorder Trigger List 1, 24 elements max. (enter NA to null)
R	SER2	LB3,LB4,IN101,IN102,OUT101,OUT102,OUT103	SER2 Sequential Events Recorder Trigger List 2, 24 elements max. (enter NA to null)
R	SER3	CF,79CY,79LO	SER3 Sequential Events Recorder Trigger List 3, 24 elements max. (enter NA to null)
L1	TR	OC+51PT+51GT+51NT	TR Other trip conditions
L1	TRSOTF	0	TRSOTF Switch-onto-fault trip conditions
L1	DTT	0	DTT Direct transfer trip conditions
L1	ULTR	!(51PT+51GT)	ULTR Unlatch trip conditions
L1	52A	0	52A Circuit breaker status
L1	CL	CC+CLOSE+VB001	CL Close conditions (other than automatic reclosing or CLOSE command)
L1	ULCL	TRIP	ULCL Unlatch close conditions
L1	79RI	TRIP	79RI Reclose initiate
L1	79RIS	0	79RIS Reclose initiate supervision
L1	79DTL	0	79DTL Drive-to-lockout
L1	79DLS	0	79DLS Drive-to-last shot
L1	79SKP	0	79SKP Skip shot
L1	79STL	TRIP	79STL Stall open interval timing
L1	79BRS	TRIP	79BRS Block reset timing
L1	79SEQ	0	79SEQ Sequence coordination

L1	79CLS	0	79CLS Reclose supervision
L1	SET1	IN101+CC +CLOSE+V B001	SET1 Set Latch Bit 1
L1	RST1	IN102+TRI P+OC	RST1 Reset Latch Bit 1
L1	SET2	0	SET2 Set Latch Bit 2
L1	RST2	0	RST2 Reset Latch Bit 2
L1	SV1	(!VB013*!V B014)*(!VB 012*VB011)	SV1 SELogic Control Equation Variable 1
L1	SV2	(!VB013*!V B014)*(VB 011*VB012)	SV2 SELogic Control Equation Variable 2
L1	SV3	0	SV3 SELogic Control Equation Variable 3
L1	OUT101	TRIP	OUT101 Output Contact 101
L1	OUT102	LT1	OUT102 Output Contact 102
L1	OUT103	!LT1	OUT103 Output Contact 103
L1	OUT104	0	OUT104 Output Contact 104
L1	OUT105	0	OUT105 Output Contact 105
L1	OUT106	0	OUT106 Output Contact 106
L1	OUT107	0	OUT107 Output Contact 107
L1	DP1	LT1	DP1 Display Point 1
L1	DP2	52A	DP2 Display Point 2
L1	DP3	0	DP3 Display Point 3
L1	ER	/51P+/51G +/OUT103 +VB001	ER Event report trigger conditions
L1	FAULT	51P+51G	FAULT Fault indication
L1	BSYNCH	52A	BSYNCH Block synchronism check elements

APPENDIX E
GOOSE COMMUNICATION CONFIGURATION

E.1 Introduction

This Appendix describes all the configured GOOSE messages that are used in the thesis.

ACSELERATOR® Architect software tool is used for the design and commissioning of IEC61850 substations through editing and creating IEC61850 reports and GOOSE messages. Architect can be used for the following (SEL instruction manual, 2013):

- Organizing and configuring all the SEL IEDs in the substation project window
- Incoming and outgoing Generic Object Oriented Substation Event (GOOSE) messages configuration
- Read IED Capability Description (ICD) of IEDs other than SEL IED as well as Configured IED Description (CID) files and establish IEC 61850 messaging options available
- Download IED parameter settings as well as IEC 61850 Configured IED Description (CID) files to the SEL IEDs
- Create SEL ICD files which will provide SEL IED descriptions in order to enable other vendors' tools to use SEL GOOSE messages and reporting features
- SEL IED Configuration, protection, logic, control, and communication settings

E.2 Configuration of a New Project

A new project has to be created by placing the required IED icons in the substation editor window as shown in Figure E.1. After an IED has been added to the project the IED has to be configured by using the properties, configuration of GOOSE transmit and receive messages and configuration of datasets tabs.

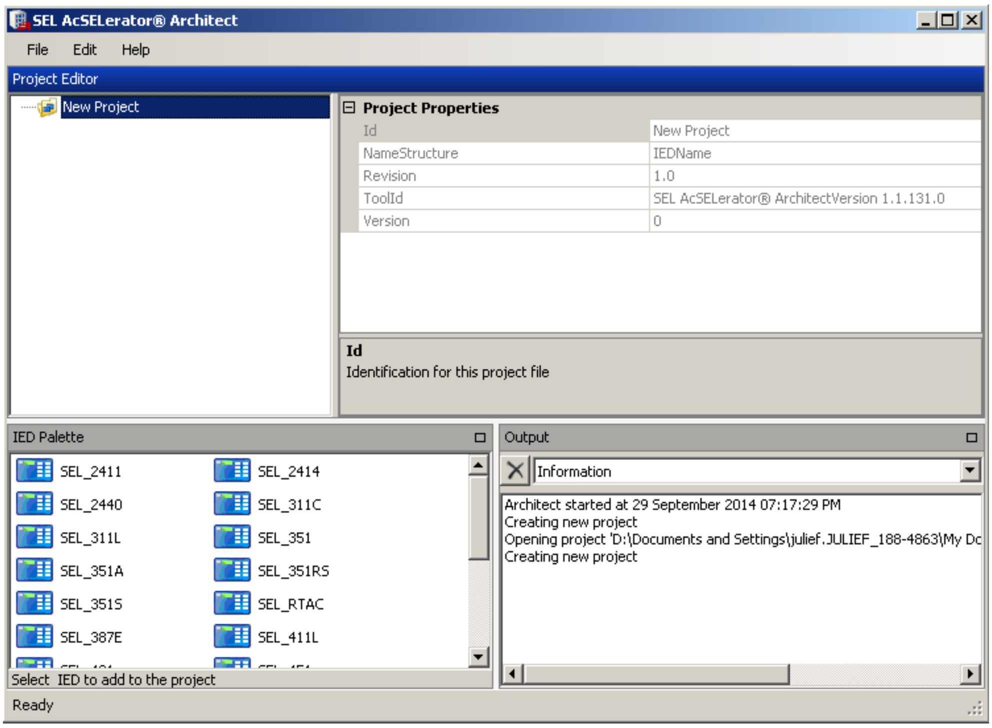


Figure E.1: SEL Acselerator Architect Project Editor

The thesis has a total of four IEDs, which include the SEL2440, SEL351A_1, SEL351A_2 and “SENSORS” IEDS as shown in Figure E.2.

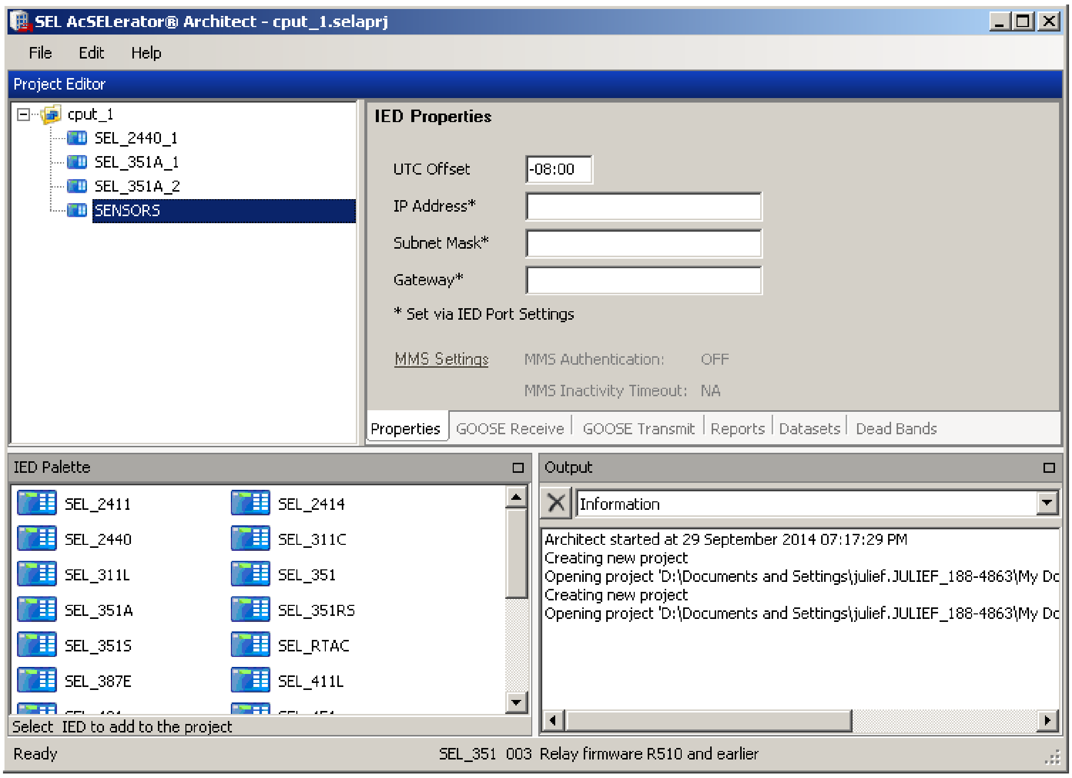


Figure E.2: Test Bench network IEDs in the Project Editor

All the published GOOSE messages have to be edited or new messages have to be created where required. Incoming GOOSE messages for each IED make it possible to receive GOOSE messages from other devices in the project.

E.2.1 SEL2440

Figure E.3 shows all the GOOSE messages the SEL2440 IED subscribes to in the thesis. It further shows that there are a total of fourteen GOOSE messages and to which virtual bit they are assigned to. From the GOOSE message under the Subscribe Data Item column one can see which device has published the message by simply looking at the first part of the message.

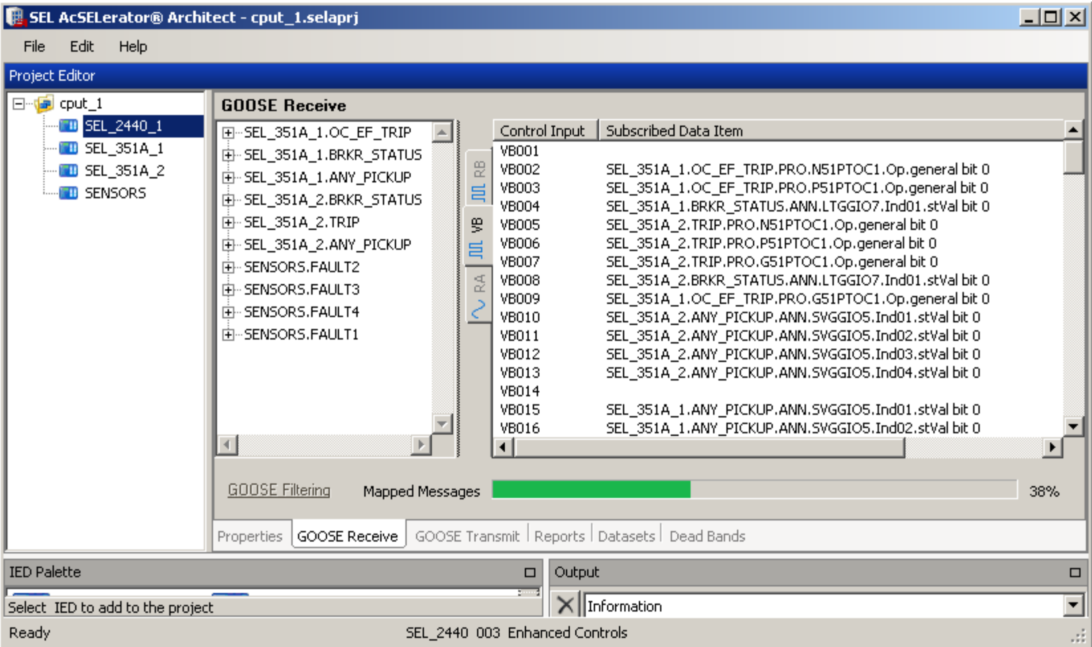


Figure E.3: SEL2440 GOOSE Receive

Figure E.4 shows an expanded view of the earth fault protection GOOSE message that is transmitted by the SEL351A_1 IED to which the SEL2440 IED subscribes.

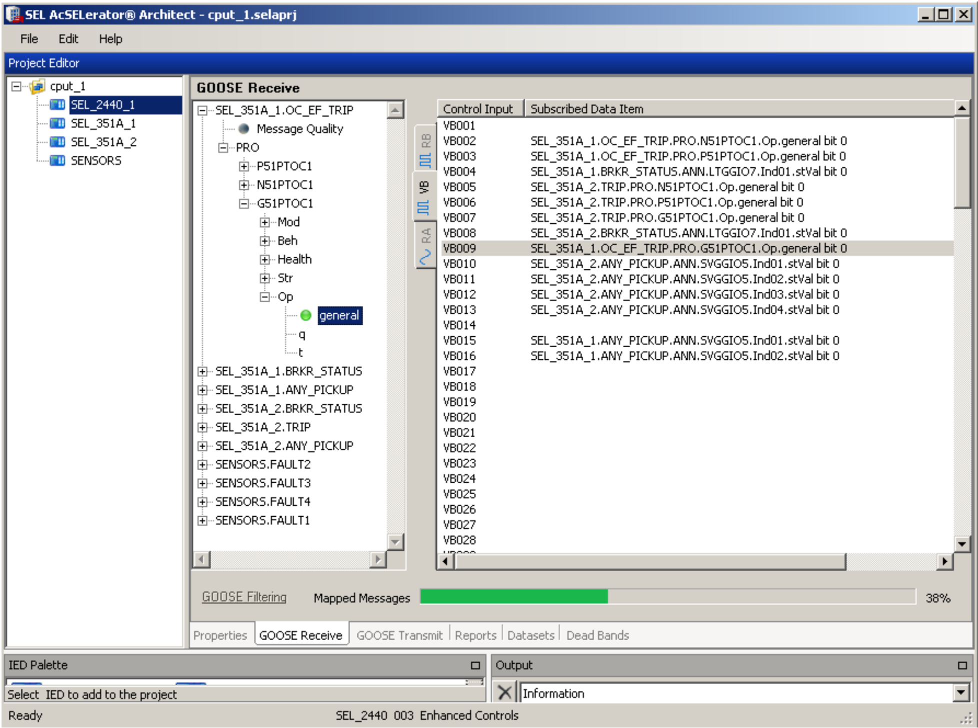


Figure E.4: SEL2440 GOOSE Receive expanded view

The SEL2440 IED has two GOOSE transmit messages as shown in Figure E.5. The first message is used for the purpose of closing the feeder breaker at substation A and the second for the closing of the breaker at the substation B.

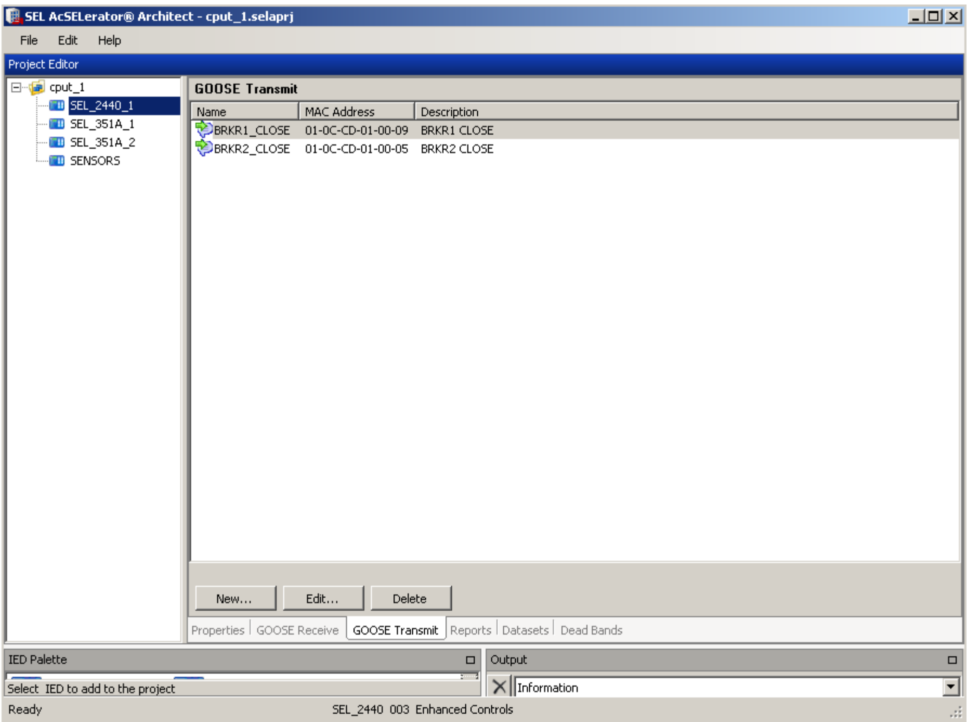


Figure E.5: SEL2440 GOOSE Transmit Messages

Figure E.6 shows the datasets for the SEL2440 IED. Only the first two are used and their qualified and description names are changed to make it more recognisable.

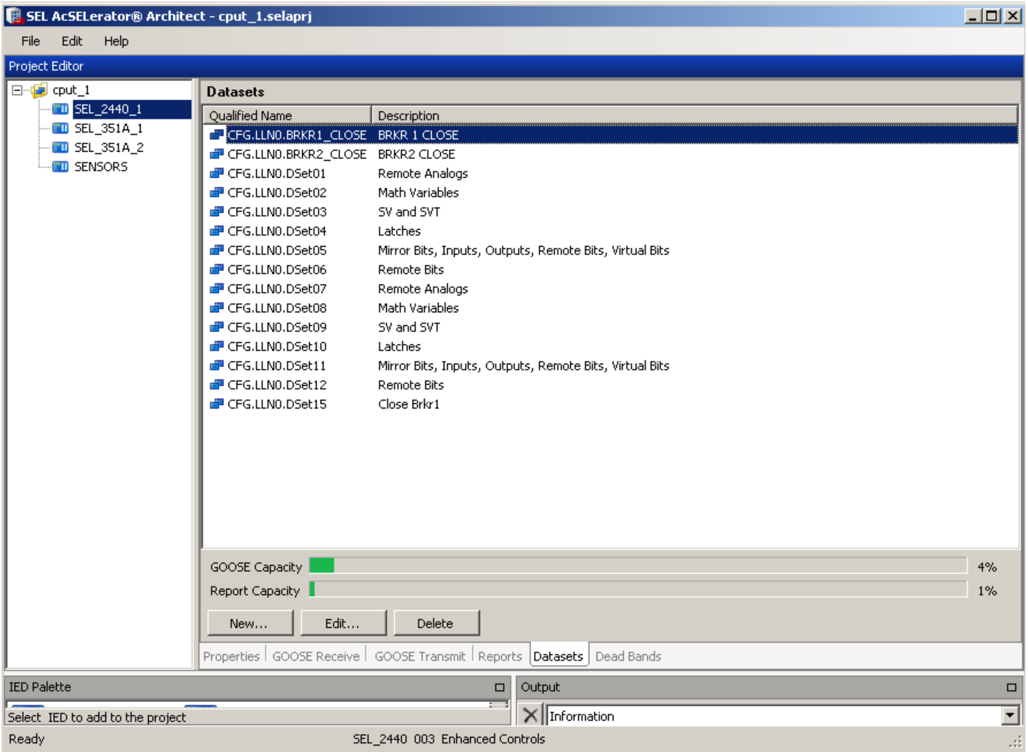


Figure E.6: SEL2440 Datasets

E.2.2 SEL351A_1

The next IED in the Architect project is the SEL351A_1 IED. Figure E.7 shows the GOOSE messages the IED subscribe to as well as from which IEDs the messages originate from.

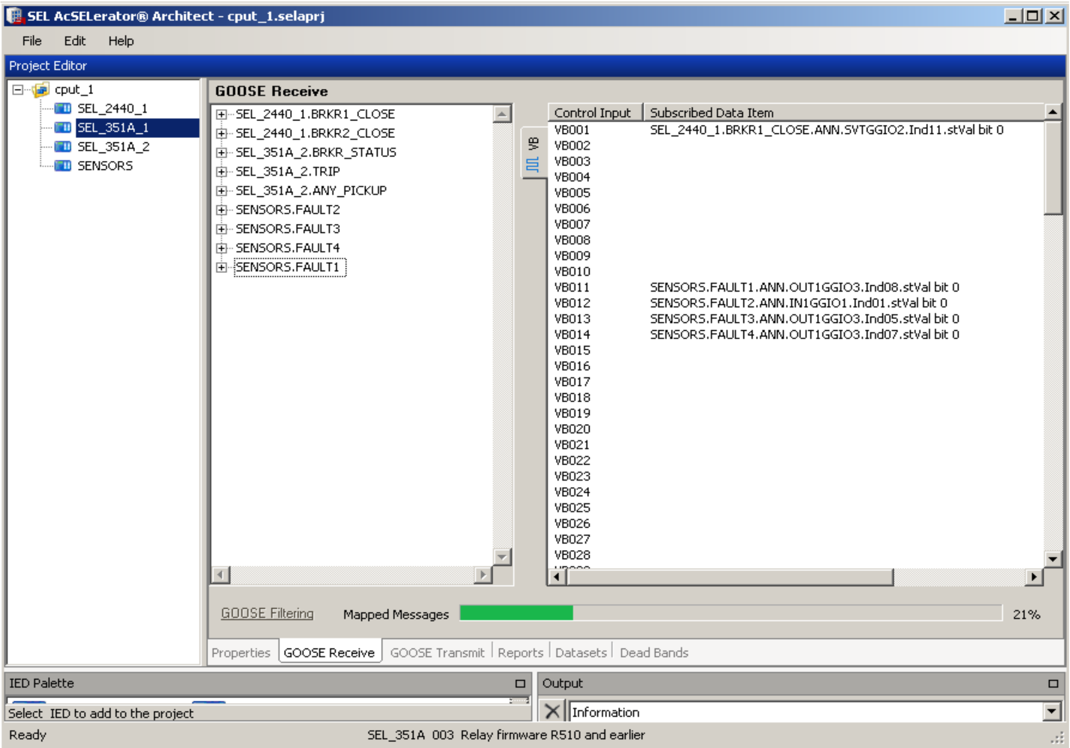


Figure E.7: SEL351A_1: GOOSE Receive Messages

Figure E.8 shows an expanded view of a GOOSE message that the SEL351A_1 IED subscribes to.

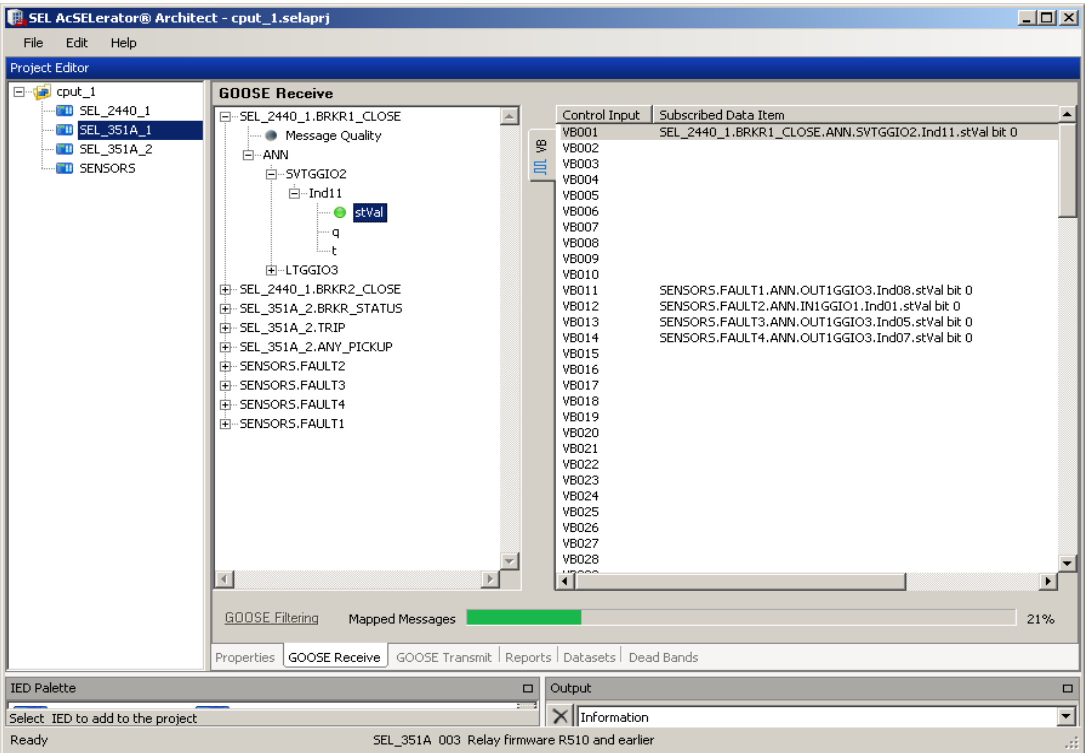


Figure E.8: SEL351A_1 GOOSE Receive expanded view

The GOOSE transmit messages from the SEL351A_1 IED are shown in Figure E.9. It shows that the IED publishes a total of three messages “ANY_PICKUP”, BRKR_STATUS” and “OC_EF_TRIP”.

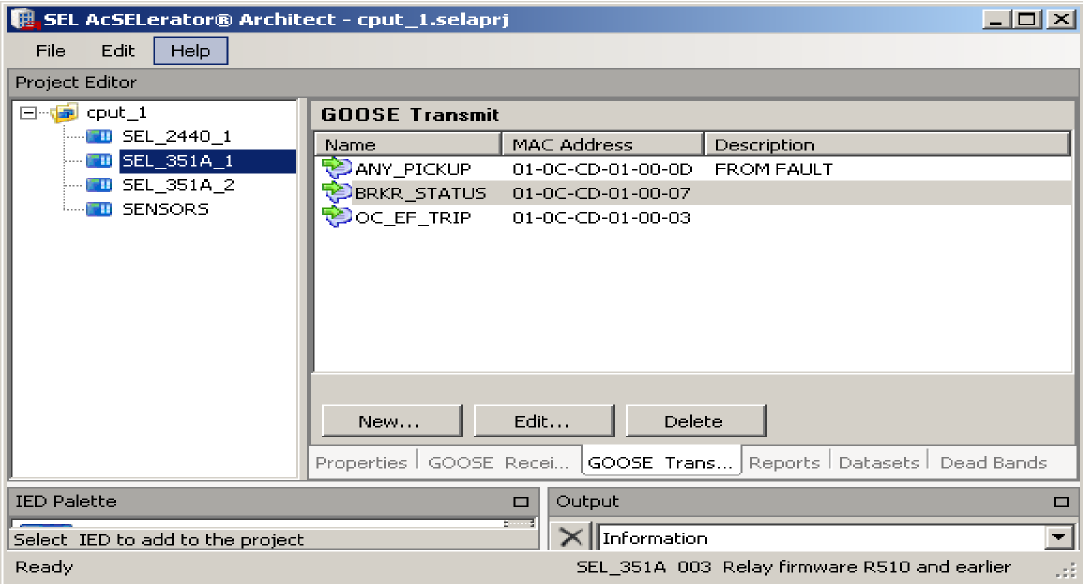


Figure E.9: SEL351A_1 GOOSE Transmit Messages

The datasets used for the SEL351A_1 IED shown in Figure E.10 are “CFG.LLN0.ANY_PICKUP”, “CFG.LLN0.DSET14” and “CFG.LLN.DSET17”.

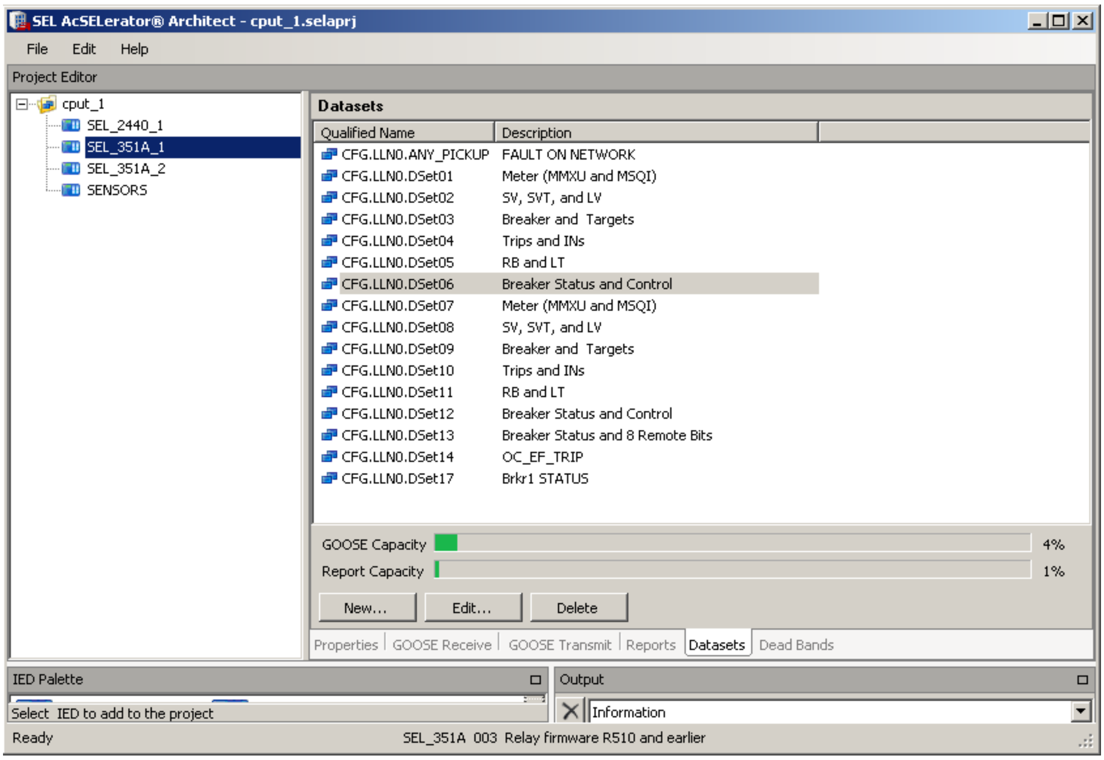


Figure E.10: SEL351_1 Datasets

E.2.3 SEL351A_2

The SEL351A_2 IED is the protection device at substation B and the GOOSE messages it subscribes to are shown in Figure E.11. The incoming messages from the SEL2440 controller are mapped to virtual bits one and two of the SEL351A_1 IED, Figure E.11.

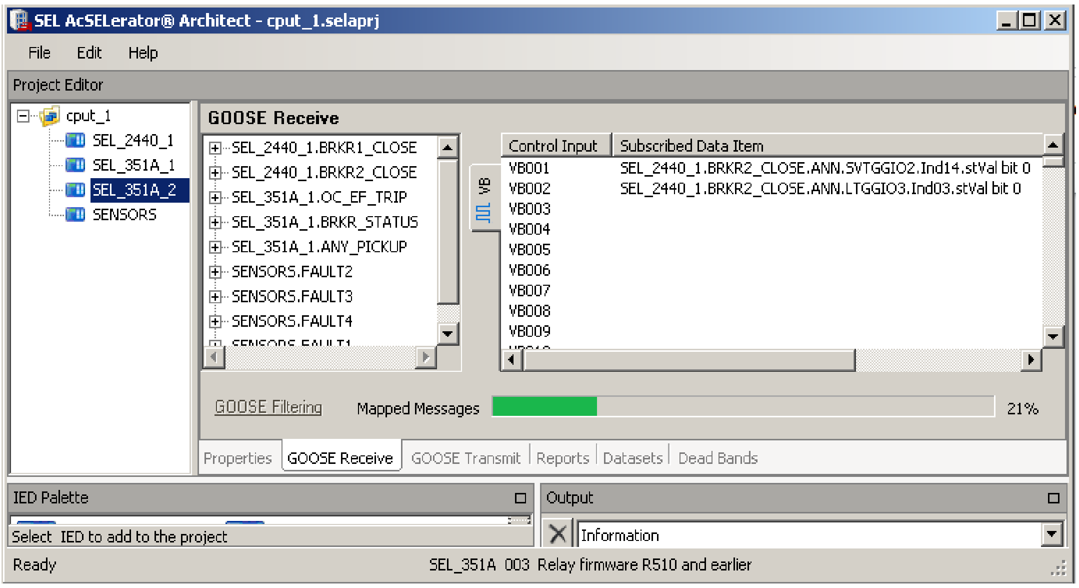


Figure E.11: SEL351A_2 GOOSE Receive messages

The SEL351A_2 IED has three messages it publishes: “ANY_PICKUP”, “BRKR_STATUS” and “TRIP”, Figure E.12

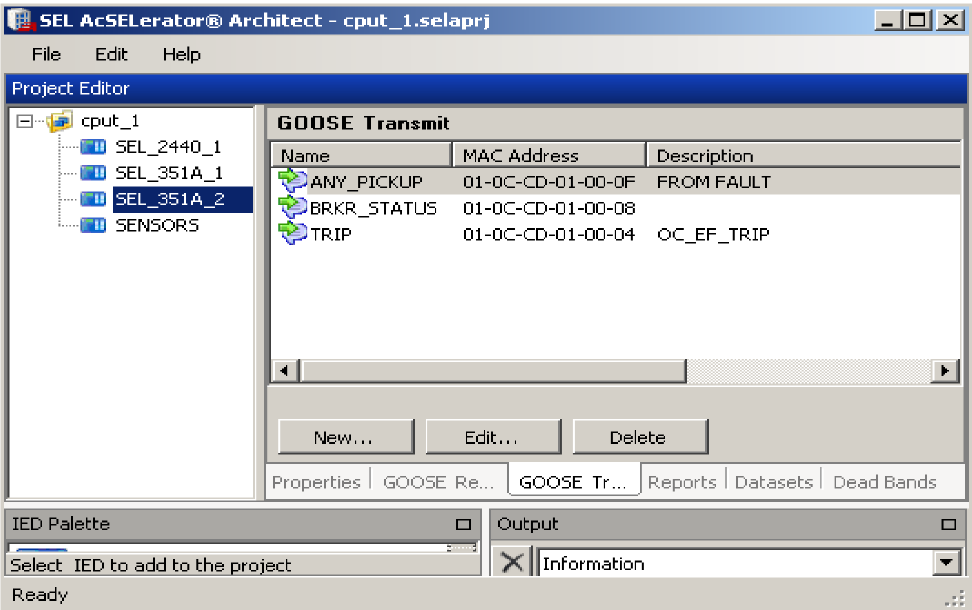


Figure E.12: SEL351A_2 GOOSE transmit messages

The datasets used for the SEL351A_2 IED are “CFG.LLN0.ANY_PICKUP and CFG.LLN0.DSET16” as shown in Figure E.13.

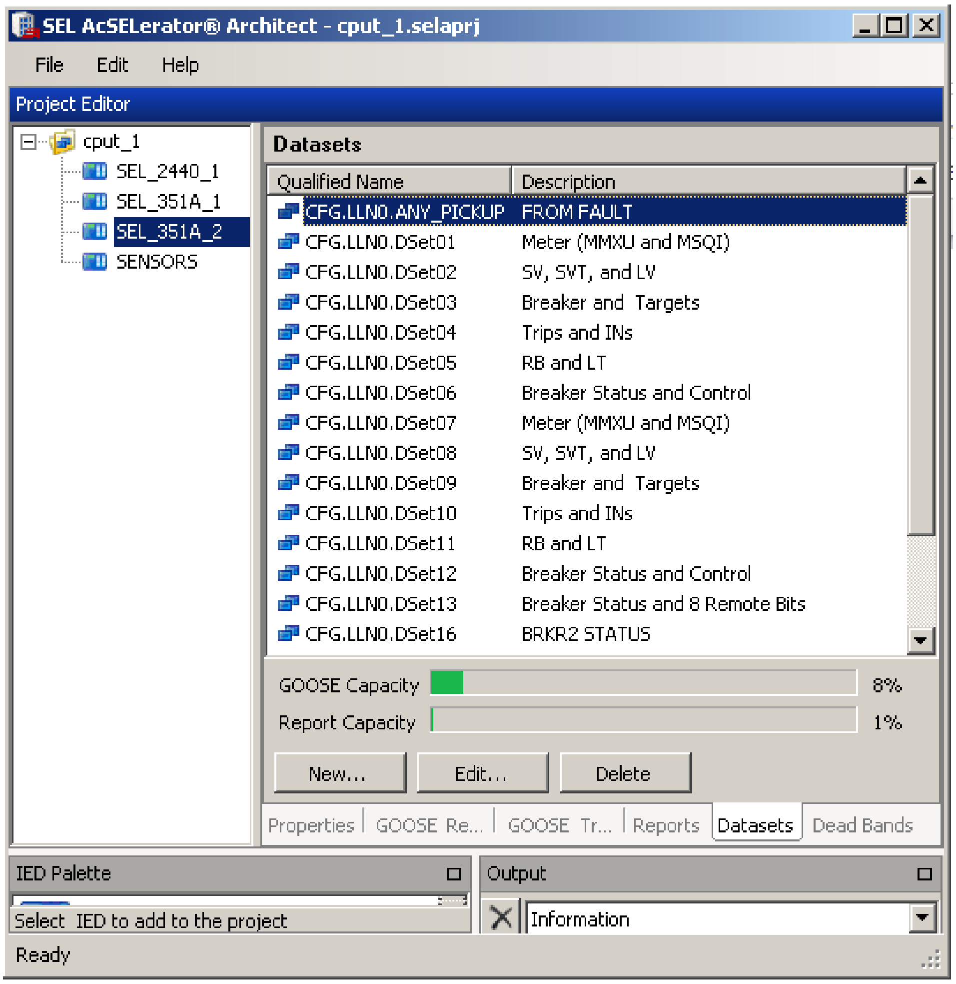


Figure E.13: SEL351A_2 Datasets

E. 2.4 “SENSORS”

The “SENSORS” IED is added in the project to take over the function of the fault path indicators as explained in section 4.4.3. Figure E.14 shows that this IED has no GOOSE messages it subscribes to.

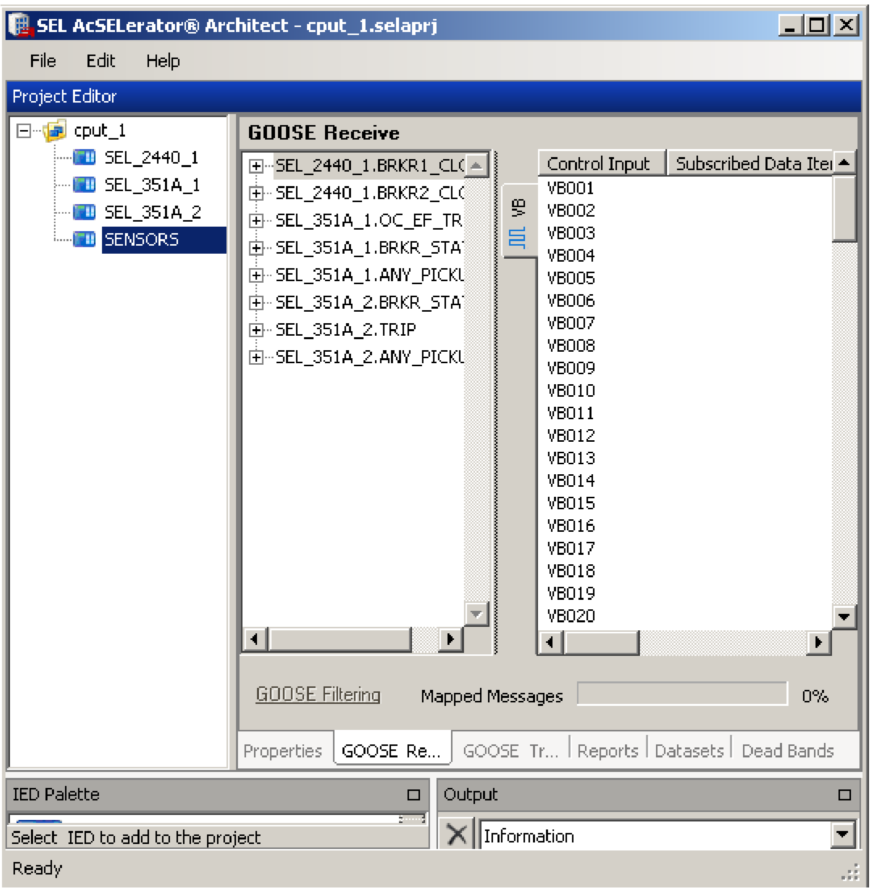


Figure E.14: SENSORS GOOSE Receive messages

Figure E.15 shows that the "SENSORS" IED transmit four GOOSE messages. These messages contain information about the location of the fault on the distribution network. "FAULT1" indicates the location of the fault to be at line section 1 on the distribution system, "FAULT2" line section 2, etc.

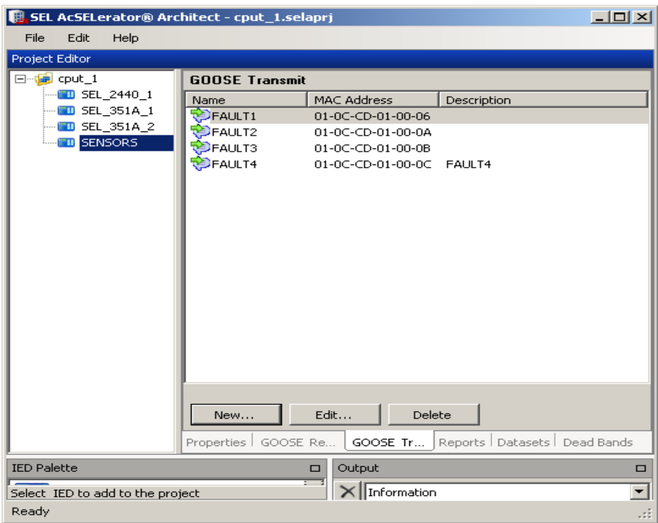


Figure E.15: SENSORS GOOSE Transmit Messages

The datasets used for the “SENSORS” IED are configured as “CFG.LLN0.FAULT1”, “CFG.LLN0.FAULT2”, “CFG.LLN0.FAULT3” and “CFG.LLN0.FAULT4”.

E.3 Conclusion

This appendix describes the GOOSE configuration for all the IEC61850 compliant devices that are used in the thesis. All the functions of the respective GOOSE messages were tested on a lab scale test bench through various case studies.

APPENDIX F
OMICRON TEST SETUP AND CONFIGURATION

F.1 Introduction

This appendix describes how the control centre, device object, hardware configuration and test modules of the Omicron is setup for the various case studies that are performed in the thesis.

F.2 Omicron Test Modules

The Omicron secondary injection test set was used to perform full-range functionality and comprehensive tests of the protective IEDs. The Omicron software contains several function orientated test modules that can be used for testing of the protective devices. The test modules are designed to automate tests and provide automatic assessments. For single tests the test modules can operate stand-alone and when it is required to perform multi-functional tests several test modules can be grouped into an OMICRON Control Center document. The process of creating a test document starts with firstly defining the Test Object parameters, secondly defining the Hardware Configuration parameters and thirdly setting the Test Module parameters.

The Omicron Protection Package provides the following Test modules shown in Table F.1., F.2 and F.3. This thesis makes use of the State Sequencer test module.

Table F.1: Omicron Test Modules (Omicron Test Universe manual, 2013)

Test Modules	
Start a test module either in "stand-alone" mode from the *Start Page* or embed it into the *Control Center* via INSERT | TEST MODULE...	
QuickCMC	With *QuickCMC*, a *CMC* test set outputs analog and digital values statically. In addition, the *CMC* inputs can be monitored and simple measurements can be taken with the binary inputs. *QuickCMC* represents a good starting point for new users.
Ramping	Variation of amplitude, frequency, and phase along a staircase (or ramp) function. Automatic assessment and reporting of pick-up / drop-off values. Simultaneous ramps of two signal parameters (e.g. amplitude and frequency). Calculation of pick-up / drop-off ratio. Automatic repetition of tests with average calculation. Step back and zoom function for higher resolution at the threshold.
Pulse Ramping	Testing of pickup values of multifunctional protection relays with more than one protection function and/or elements without reparameterization of the relay.
State Sequencer	Output of a sequence of states. Can be used to determine trip times or other time measurements with automatic assessment. Permits setting of amplitude, frequency, and phase of each generator in each single state. Includes automatic report creation and Z Shot function for distance applications.
Overcurrent	Designed for overcurrent relays. Tests the operation characteristic to verify the trip time with automatic assessment. Includes automatic pick-up / drop-off test and automatic report creation. Simulates phase-ground, phase-phase, three-phase, negative sequence, and zero sequence faults.
Autoreclosure	Testing of the autoreclosure function with integrated distance protection fault model and distance XRIO interface.

Table F.1.2: Omicron Test Modules (Omicron Test Universe manual, 2013)

Test Modules	
Distance	Provides the functionality to define and perform tests of distance relays by impedance element evaluations using single-shot definitions in the Z-plane with graphical characteristic display. **Definition of relay characteristics** A graphical editor makes the definition of the nominal relay characteristics and settings quick and easy. Start, trip, extended, and no-trip zones can be defined by using predefined elements. A complete overview of all defined zones is provided. The standard XRIO interface, supported by various relay manufacturers, makes it possible to directly import the relay data from relays' parameter setting software.The impedance settings for the zones are entered and displayed in primary or secondary values, as chosen by the user. **Definition of tests** Tests are defined in the impedance plane: Test points are added to a test point table with the mouse or by entering from the keyboard. This table is separated into several tabs, each tab belonging to a fault loop, e.g., A-N (L1-E) , B-N (L2-E), C-N (L3-E), A-B (L1-L2)... etc. Test points can be defined for several fault loops at the same time (e.g. for all single-phase loops) or for every fault loop separately. When a test is performed, the test point lists belonging to the individual fault loops are worked off. The reaction of the relay is compared to the specified nominal settings and an assessment is made. The results are displayed graphically in the impedance plane as well as numerically in the test point table. For a more in-depth analysis of the results, the voltages and currents belonging to a test point and the relays reaction (switching of output contacts) can be graphically displayed. Time measurements by using cursors are possible. **Reporting** *Distance* automatically generates a test report containing the relay settings, the test settings, the test points and the results in tabular and graphical form.

Table F.1.3: Omicron Test Modules (Omicron Test Universe manual, 2013)

Test Modules	
Differential	Provides a compact testing solution for generator, busbar, and transformer differential protection relays. Performs single-phase tests of the operating characteristic (pick-up value, slope test) and the inrush blocking function (harmonic restraint test). For the test of the operating characteristic, test points are defined in the Idiff/Ibias plane either using the mouse or entering from the keyboard. A graphical user interface makes the test definition easy. *Differential* also provides an appropriate testing environment for testing the harmonic restraint function. The amplitude of the fundamental and the percentage of the superimposed harmonic can be defined for each test point. The test currents belonging to the test points are injected to the relay and the reaction of the relay is assessed. By inserting several *Differential* modules into an OMICRON *Control Center* document, different fault loops can be tested automatically.
CB Configuration	The test set *CMC 256* offers a CB simulation that emulates the action of the auxiliary contacts (52a / 52b) of a circuit breaker during tripping and closing. *CB Configuration* configures the Circuit Breaker (CB) simulation state machine in the CMC firmware. This module automatically maps the routed binary input and output signals to the simulation inputs and outputs of the state machine.

F.3 Control Centre for fault simulations on the line section 1

The control centre contains all the information about a test in a single file. This includes the test object information, test assessment, hardware configuration, test results, test parameters, etc. The Omicron is used for all the tests on the test bench. Several functional tests were performed on each line section of the system. The State Sequencer Test Module was predominantly used. Figure F.1 illustrates the Control Centre setup for the test performed on the line section 1.

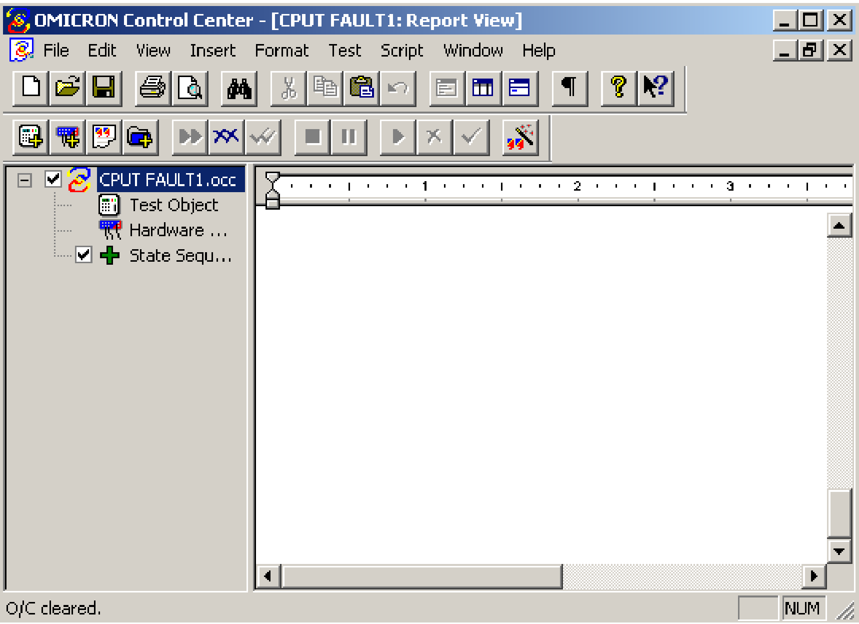


Figure F.1: Control Centre for fault on line section 1

F.3.1 Test Object

The test object refers to the physical device that needs to be tested such as energy meters and protection devices. The test object parameters are accessed and its contents edited in the test object. Figure F.2 illustrates the Test Object parameters window.

In the test object the RIO (Relay interface by Omicron) data are organized in a tree-structure. As a result of the need to have a uniform data format for parameters of protective devices for the different manufacturers the RIO was developed. RIO makes it possible to import the protective device characteristics from various sources into the Omicron software therefore simplifying the setup of the test object.

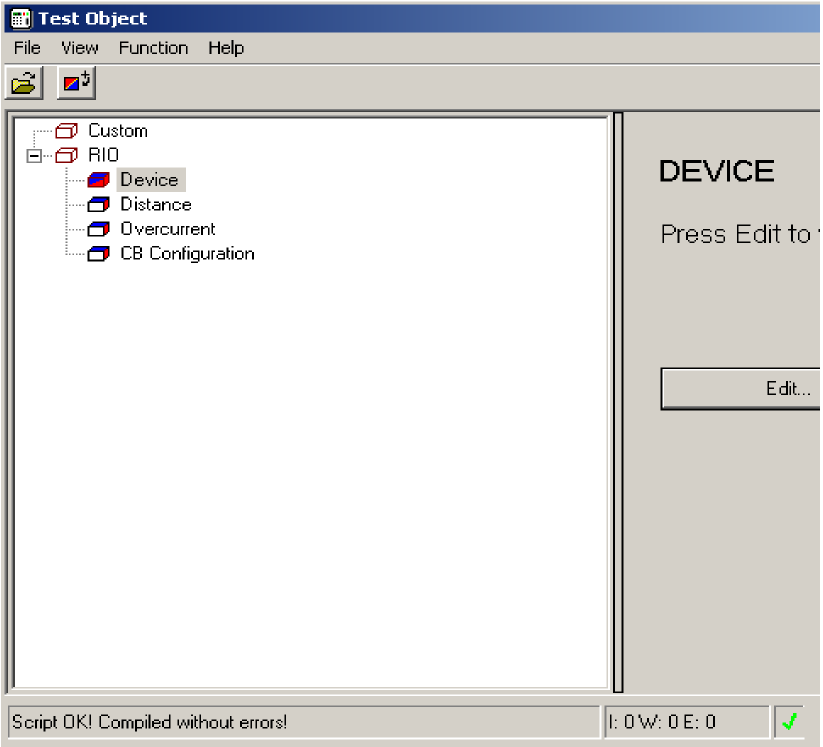


Figure F.2: Test Object

F.3.2 Device Settings

The general information and settings of a test object such as the relay's name, manufacturer, address, serial or model number and any additional information is captured in the device settings. Furthermore it presents parameters such as nominal values, residual factors and limits. Figure F.3 shows the device settings parameters.

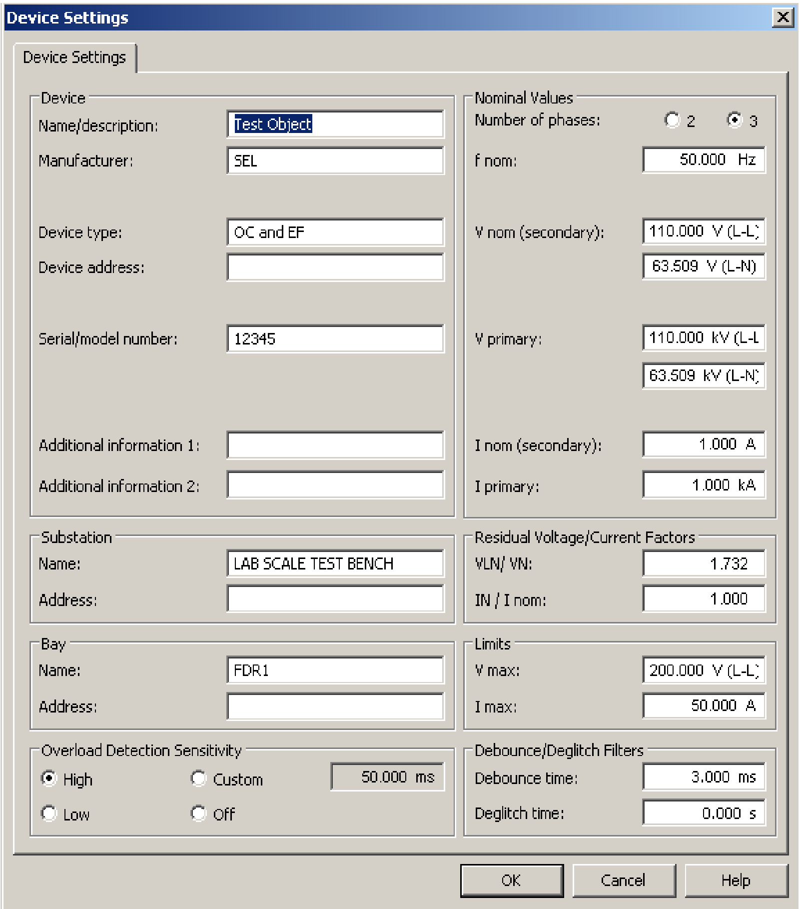


Figure F.3: Test Object, Device Settings

F.3.2.1 Distance Test Object

The Omicron Control Centre is designed to add a distance block to the test object as it centrally stores test object or substation data in the test object block which can be used by other test modules. The distance test module is not used in the thesis.

F.3.2.2 Over current Test Object

The overcurrent protection parameters contain two tabs, the relay parameters and the element tabs.

The Relay Parameters tab contains the general settings for the relay. The available fields are the distance behavior, VT connection, CT star point connection as well as the current and time tolerances are shown in Figure F.4.

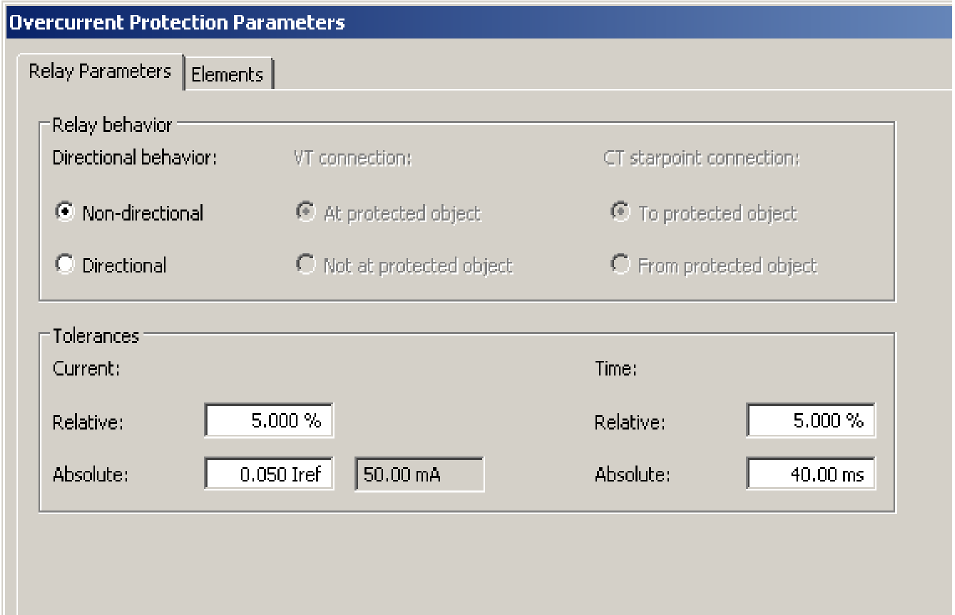


Figure F.4: Overcurrent, Relay Parameters settings for fault on the line section 1

The tripping elements of the protective device are defined in the Elements tab. There are five tripping element types: phase, residual, positive sequence, negative sequence or zero sequence available to choose from.

The tripping elements for five different element types: phase, residual, positive sequence, negative sequence or zero sequence can be defined. The tripping characteristic, directional behaviour, reset ratio, tripping index, pick-up current and whether the element is active or not can be set for each element. Figure F. 5 shows an illustration of the elements tab. It shows that a non-directional, definite time, phase tripping element is selected with current pickup of 4 Amps and time delay of 100milli seconds.

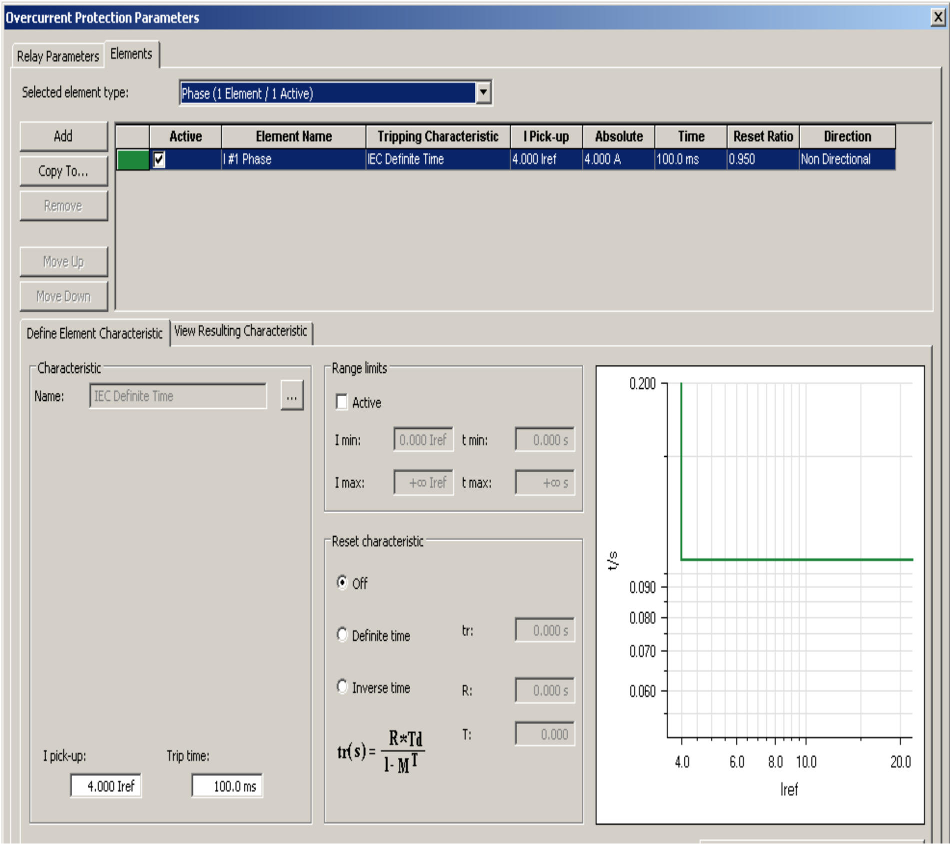


Figure F.5: Overcurrent Protection Parameters Elements tab

F.3.3. Hardware Configuration

The hardware configuration allows the connection between the software and the test object. It contains the information about:

- the assignments between the inputs and outputs of the test software and the test object terminals,
- the used test hardware as well as its configuration and
- the wiring between the test hardware and the test object terminals

F.3.3.1 General Hardware Configuration

The general hardware configuration in Figure F.6 shows the connected Omicron test set and its serial number. Furthermore the voltage and current outputs are also selected in the general hardware configuration and additional amplifiers can be selected if required. The "Voltage Outputs" and "Current Outputs" on the right are only displaying information on the configured configuration and cannot be changed in this window.

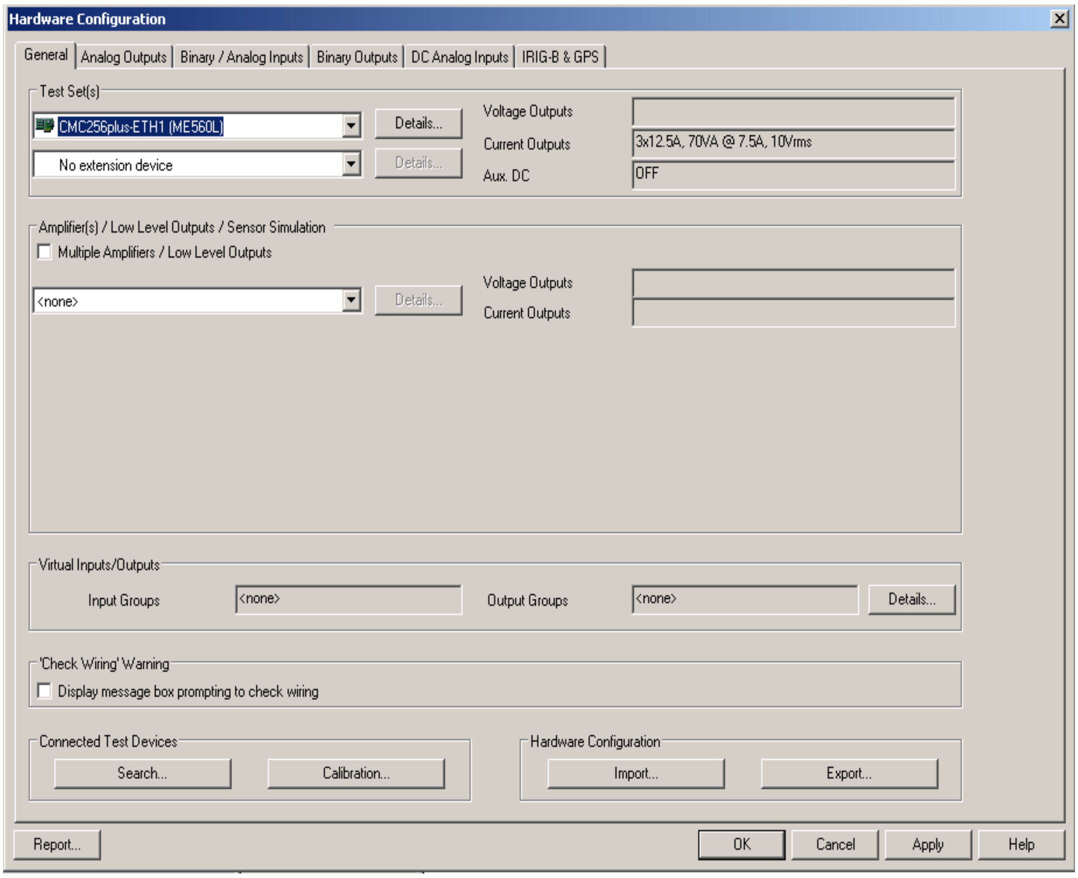


Figure F.6: General Hardware Configuration

F.3.3.2 Analog Ouputs

The analog outputs that are required in the tests are defined in the Analog Outputs tab. The analog output provides information on the display name, connection terminal and detail of the connected Omicron. The Analog Outputs Hardware Configuration is shown in Figure F.7.

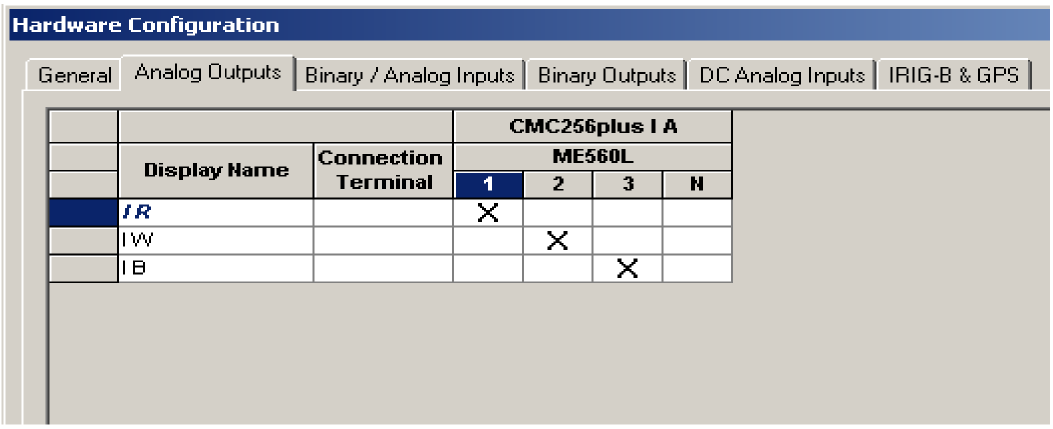


Figure F.7: Analog Output Hardware Configuration

F.3.3.3 Binary/Analog Inputs

The binary and analog inputs are defined in the Binary/Analog Inputs tab. Only the binary inputs are used in the thesis.

The binary inputs can be configured as potential free contacts and potential sensing contacts. To configure a contact as potential free the checkbox is ticked for the specific contact and when configured as potential sensing the voltage level has to be entered under the nominal range. The binary inputs tab also provides information on the display name and the connection terminal. The clamp ratio is not relevant as the "Function" is not set to current but set to binary. The "Threshold" specifies the operating threshold for the binary input when it is selected as potential sensing contact.

The Binary/Analog Inputs Hardware Configuration is shown in Figure F.8. The illustration shows that three binary inputs are selected with display names Trip, Bin.In.2 and Bin.In3. The trip binary input is a potential free contact and the remaining contacts are potential sensing contacts.

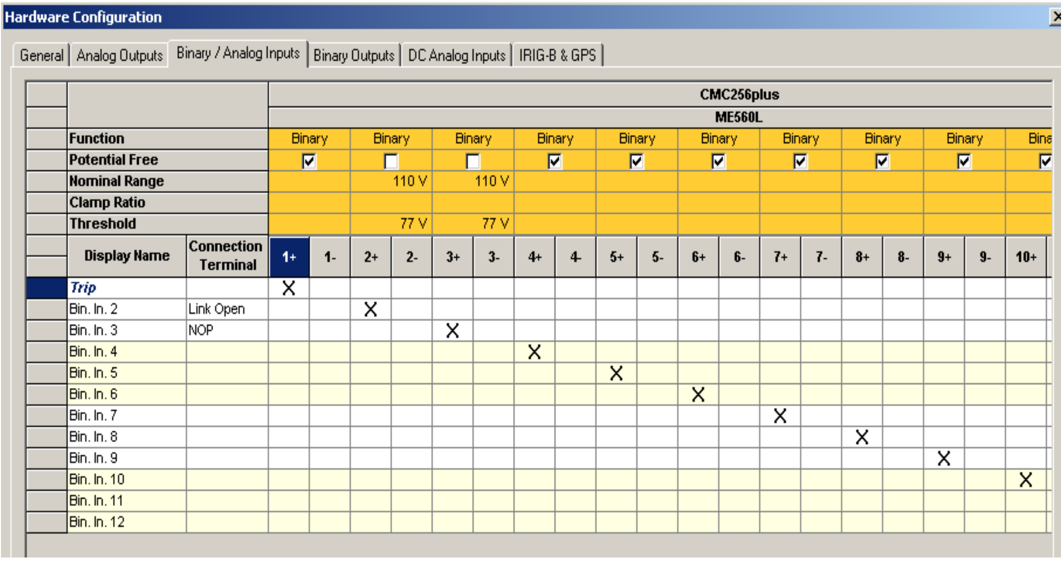
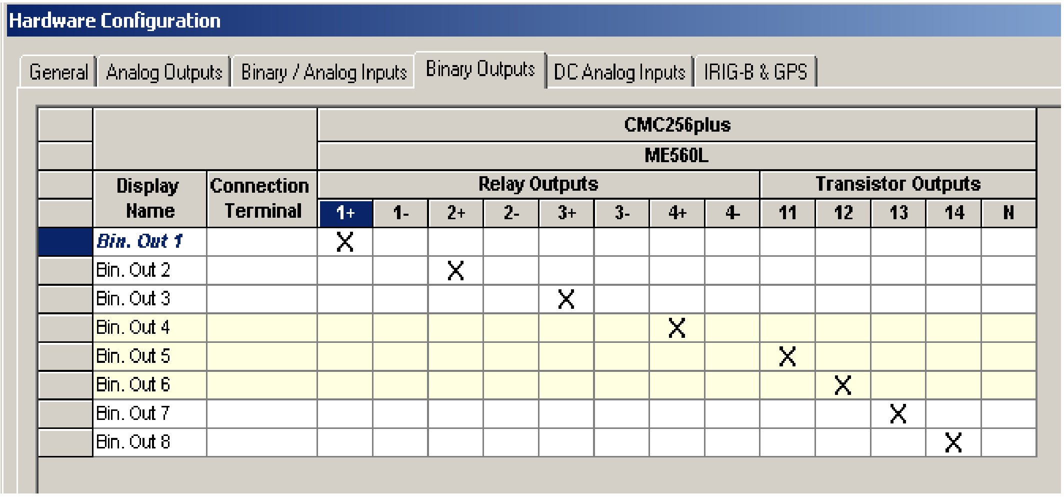


Figure F.8: Binary/Analog Inputs

F.3.3.4 Binary Outputs

The use of the binary outputs is specified on the binary outputs tab. The binary outputs can be designated with unique names entered in the "Display Name" column. If not, the default setting will be used. On the "Connection Terminal" an alternative designation may also be entered. The binary output window shows information such as the display name, connection terminal, relay outputs, transistor outputs and information about the connected Omicron. Figure F.9 shows an illustration of the binary output hardware configuration window.



		CMC256plus												
		ME560L												
Display Name	Connection Terminal	Relay Outputs								Transistor Outputs				
		1+	1-	2+	2-	3+	3-	4+	4-	11	12	13	14	N
Bin. Out 1		X												
Bin. Out 2				X										
Bin. Out 3						X								
Bin. Out 4								X						
Bin. Out 5										X				
Bin. Out 6											X			
Bin. Out 7												X		
Bin. Out 8													X	

Figure F.9: Binary Output Hardware Configuration

F.3.4 Test Modules

One of the steps in creating an Omicron test file is inserting a test module in the Control Centre. Omicron software provides several test modules for the testing of specific protective devices. The test module that is extensively used in the thesis is the state sequencer. The state sequencer makes it possible that one or more conditions (called states) can be defined in a test object. The operating times or other time assessments of protective device can be performed through the use of this test module. In each state the magnitude, frequency, and the phase angle are allowed to be set. The trigger conditions allow the next state to start where there is more than one state in the test module. Therefore the trigger conditions have to be set for each state in the test. The setup and results of the state sequencer for the fault on the line section 1 is shown in Figure F.10. The illustration shows two states in the table view of the state sequencer and three separate assessment conditions.

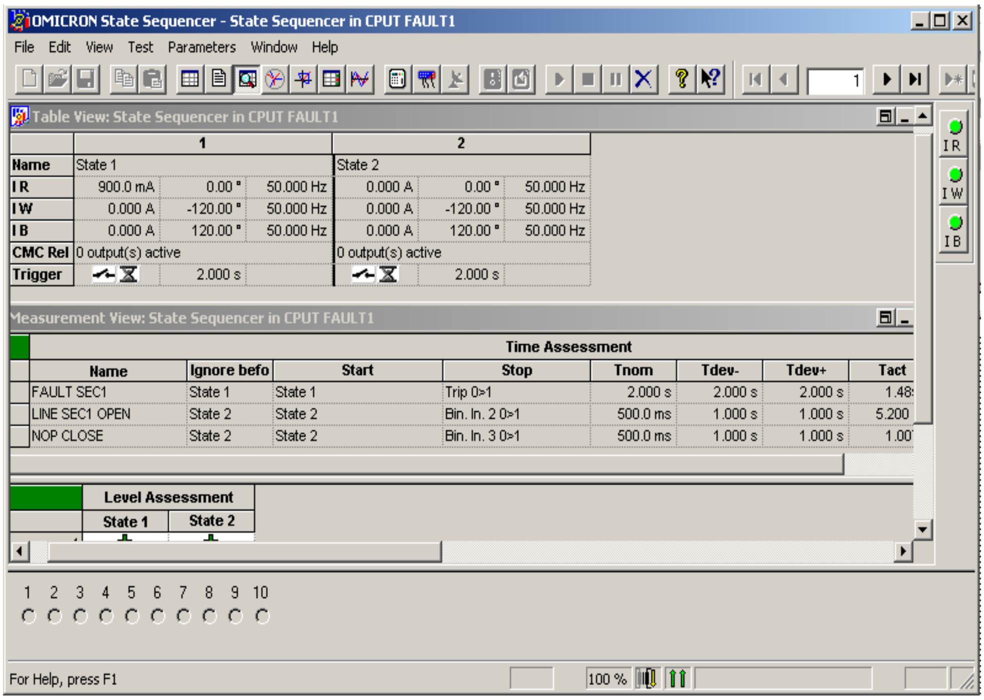


Figure F.10: State sequencer results for fault on the line section 1

F.4 Control Centre for fault simulations on the line section 2

The Control Centre test file for the faults simulated on the line section 2 consists of a test object, hardware configuration, GOOSE configuration and state sequencer test modules. Figure F.11 illustrates the control Centre for the fault on the line section 2.

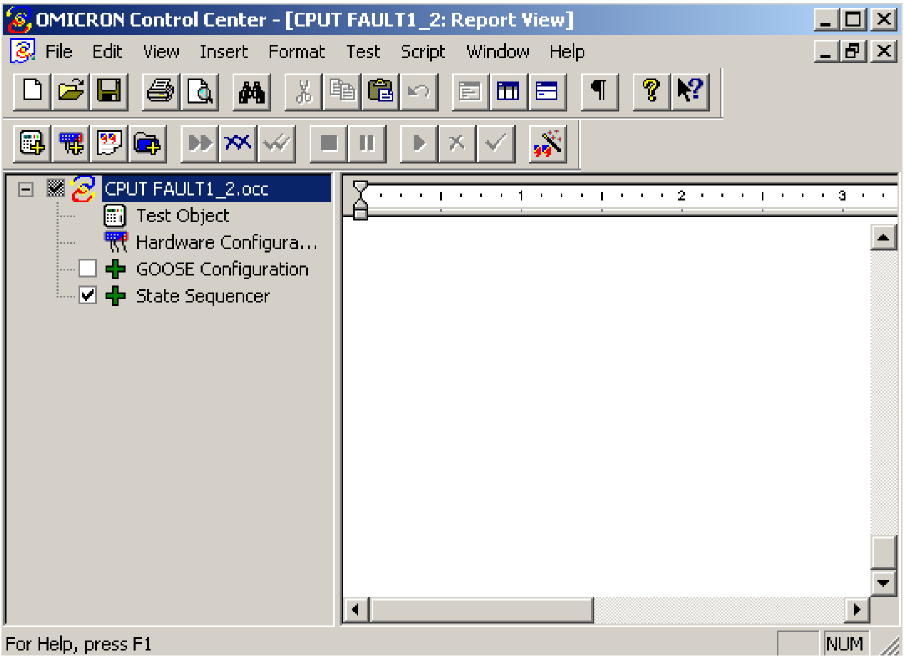


Figure F.11: Control Centre for the fault on the line section 2

F.4.1 Hardware Configuration

The general and analog output hardware configuration is the same as the faults on the line section1 and will remain unchanged for the faults on the other line sections throughout the thesis. For the fault simulations on the line section 2 three binary inputs are used as shown in Figure F.12. It shows that Bin.In1 (TRIP) and Bin.In3 (BRKR CLOSE) are potential free contacts and Bin.In2 (SW3) is a potential sensed contact.

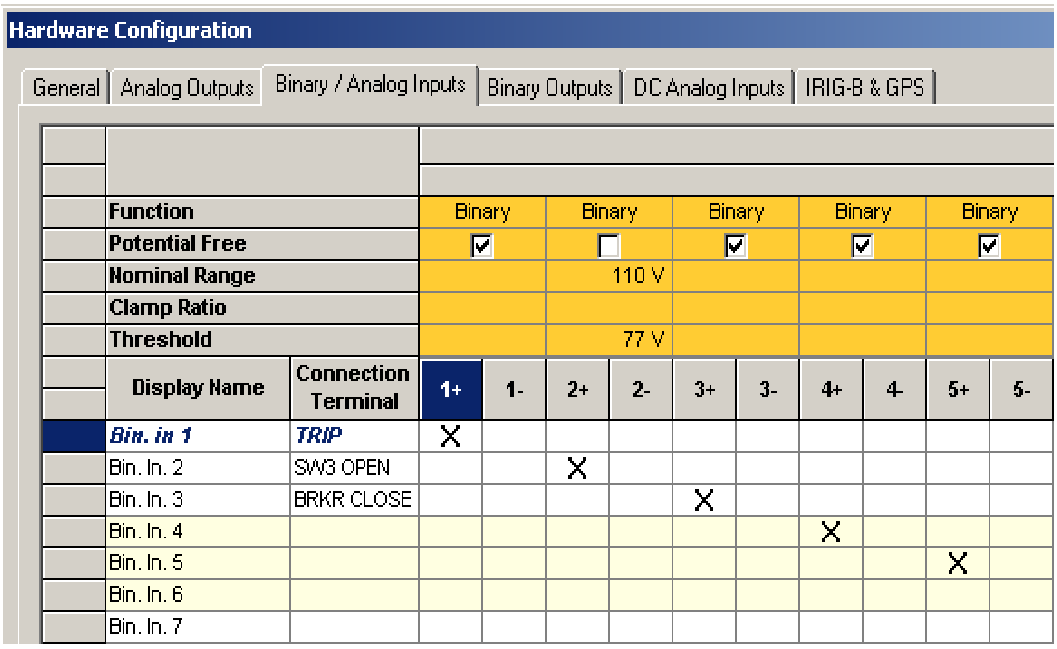


Figure F.12: Binary /Analog Input Hardware Configuration for the fault on the line section 2

F.4.2 Omicron GOOSE Configuration

To enable the Omicron to send and receive GOOSE messages the GOOSE Configuration module needs to be set up. The CMC 850 or CMC356 or CMC 353 or CMC 256plus with the NET-1 option Omicron test set is required for GOOSE message handling. The Omicron has the ability to receive GOOSE messages (or subscribe) as well as sending (or publish) messages. Data items are mapped to binary and virtual inputs of the test set when a message is received. When GOOSE messages are published through simulation the test set uses data items from the binary outputs. The GOOSE configuration test module can be inserted into an Omicron Control Centre test file. The GOOSE features are integrated into the test set in such a manner that the status information in the message is mapped to the binary inputs and outputs of the Omicron. Therefore, all the binary inputs and outputs are available for the GOOSE mapping and are done in the GOOSE configuration test module. The GOOSE configuration test module is kept outside of the other test modules, meaning that when a binary input or output is used to send a GOOSE message it does not interfere with the other test modules.

F.4.2.1 Engineering process

The CID file is created in the protective IED software and not in the Omicron. Therefore, it needs to be exported to the Omicron first. In the next step the CID file is imported to the Omicron by selecting File -> 'Import Configuration as shown in Figure F.13. This will automatically add all the configured GOOSE messages from the CID file to the GOOSE Configuration test module.

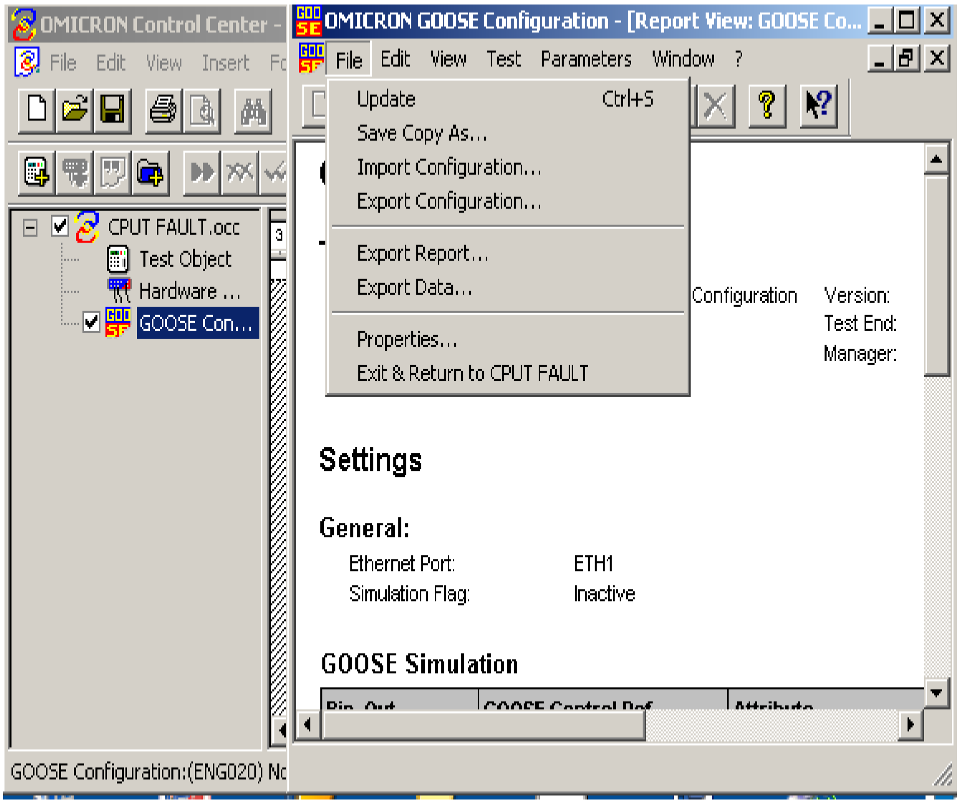
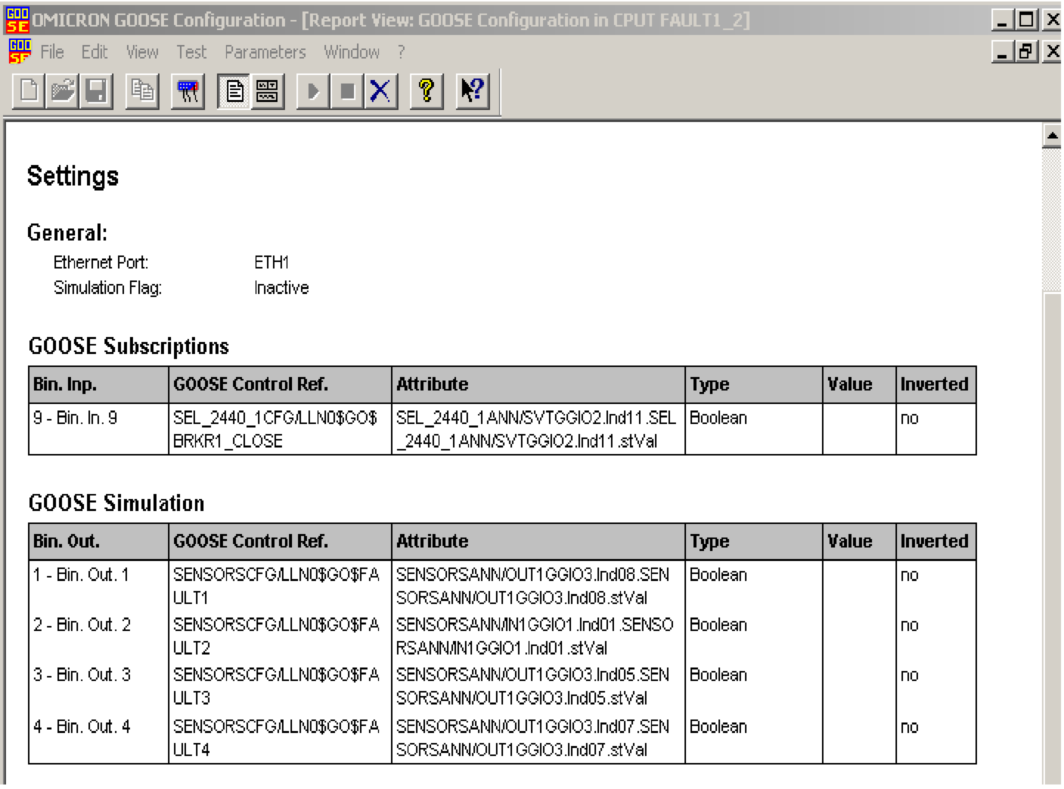


Figure F.13: Importing CID file

The next step after importing the CID file from the relevant IED is to map the binary inputs or outputs of the Omicron. When a binary input/output has to be mapped just move the data item by dragging and dropping it to the binary input/output. The GOOSE configuration is applied and transferred to the Omicron test set by pressing the start button, . Figure F.14 shows the GOOSE Configuration setup for the fault on line section 2. The illustration shows that the binary input, nine of the Omicron subscribes to an incoming GOOSE message from the SEL351A_1 IED. It further shows that the Omicron is able publish any of the four GOOSE messages listed under GOOSE simulation by triggering the binary outputs of the OMICRON test set.

For the fault on the line section 2 binary outputs 1 and 2 are triggered to indicate that the fault current has passed therefore emulating the functions of a fault path indicator.


OMICRON GOOSE Configuration - [Report View: GOOSE Configuration in CPUT FAULT1_2]

File Edit View Test Parameters Window ?

Settings

General:

Ethernet Port: ETH1

Simulation Flag: Inactive

GOOSE Subscriptions

Bin. Inp.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
9 - Bin. In. 9	SEL_2440_1CFG/LLN0GOBRKR1_CLOSE	SEL_2440_1ANN/SVTGGIO2.Ind11.SEL_2440_1ANN/SVTGGIO2.Ind11.stVal	Boolean		no

GOOSE Simulation

Bin. Out.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
1 - Bin. Out. 1	SENSORSCFG/LLN0GOFAULT1	SENSORSANN/OUT1GGIO3.Ind08.SENSORSANN/OUT1GGIO3.Ind08.stVal	Boolean		no
2 - Bin. Out. 2	SENSORSCFG/LLN0GOFAULT2	SENSORSANN/IN1GGIO1.Ind01.SENSORSANN/IN1GGIO1.Ind01.stVal	Boolean		no
3 - Bin. Out. 3	SENSORSCFG/LLN0GOFAULT3	SENSORSANN/OUT1GGIO3.Ind05.SENSORSANN/OUT1GGIO3.Ind05.stVal	Boolean		no
4 - Bin. Out. 4	SENSORSCFG/LLN0GOFAULT4	SENSORSANN/OUT1GGIO3.Ind07.SENSORSANN/OUT1GGIO3.Ind07.stVal	Boolean		no

Figure F.14: GOOSE Configuration for the fault on the line section 2

F.4.3 State Sequencer for the fault on the line section 2

The State Sequencer in Figure F.15 shows three states where the first state is the fault condition the second the process when the line switch 3 isolates the fault and the third when the breaker at the substation A closes to restore power to the unaffected line section 1. It further shows the setup of the three monitoring conditions: FAULT, LINE SW3 OPEN and BRKR CLOSE in the time assessment section of the test module. The first state is monitored via the Omicron binary input 1 and the second state via the binary input 2 and is hardwired to the test set. The third state is monitored via the binary input 9 via GOOSE messaging.

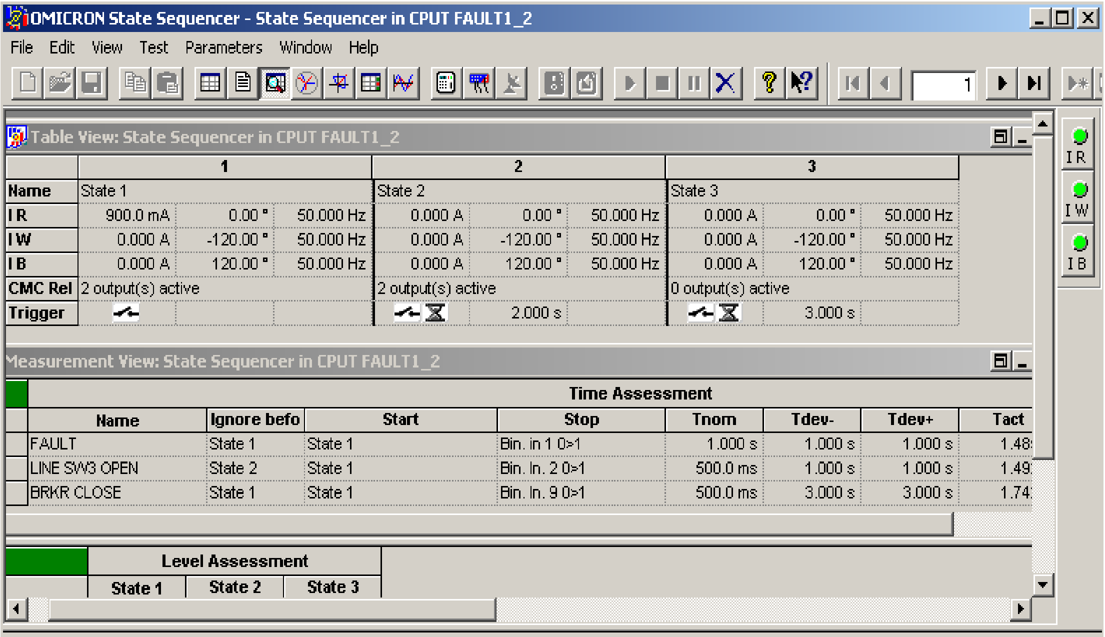


Figure F.15: State Sequencer for the fault on the line section 2

F.5 Control Centre for fault simulations on the line section 3

The control centre setup for the fault on the line section 3 shows a GOOSE configuration and State Sequencer test template as shown in Figure F.16.

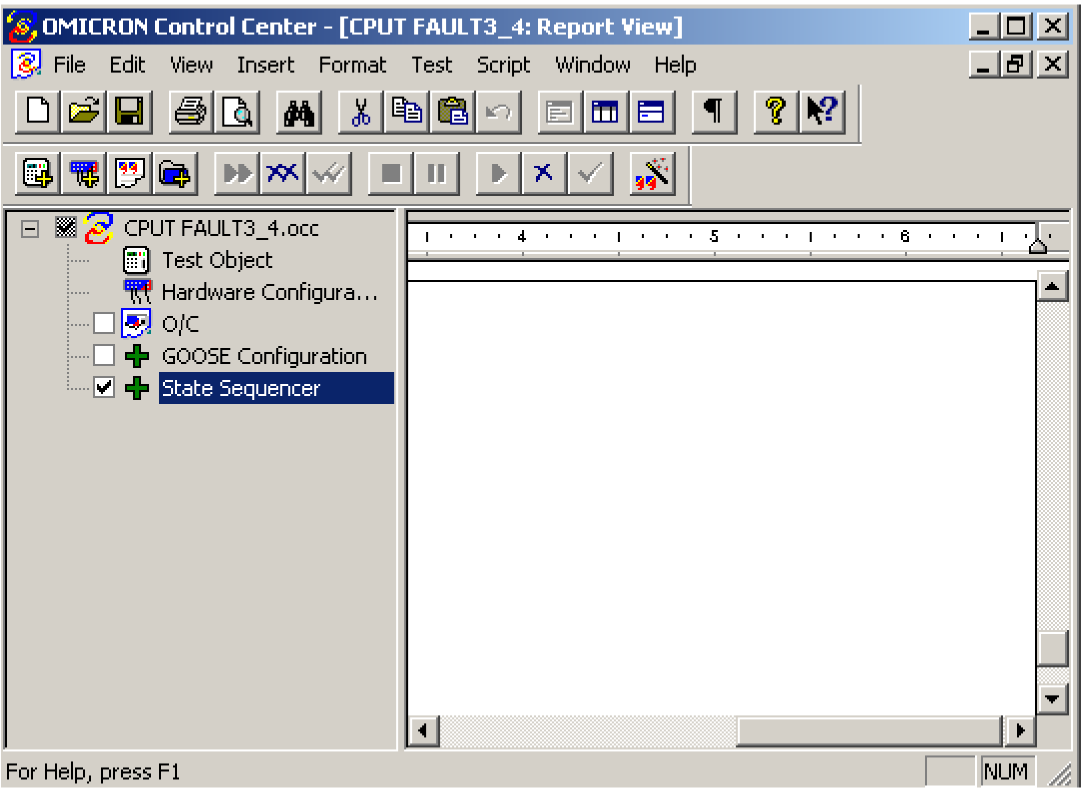


Figure F.16: Control Centre for the fault on the line section 3

F.5.1 Hardware Configuration

Three Binary Inputs are defined for the fault on the line section 3. Figure F.17 shows that binary input 1 is described as "TRIP" in the connection terminal column, binary input 2 as "SW3 OPEN" and binary input 3 as "BRKR CLOSE". Binary input 1 and 3 are potential free contacts but input 2 is potential sensed.

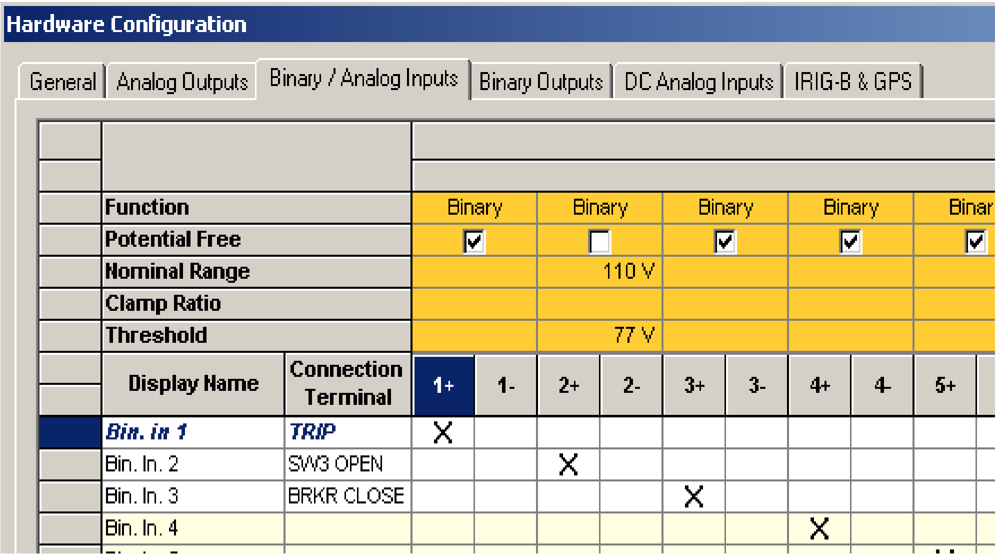


Figure F.17: Binary inputs for the fault on the line section3

F.5.2 Omicron GOOSE Configuration

An illustration of the Omicron GOOSE Configuration test module for the fault on the line section 3 is shown in Figure F.18. It shows that the OMICRON test set subscribes to SEL_2440_1CFG/LLN0GO_BRKR2_CLOSE GOOSE message and that subscribes to four defined publish GOOSE messages.

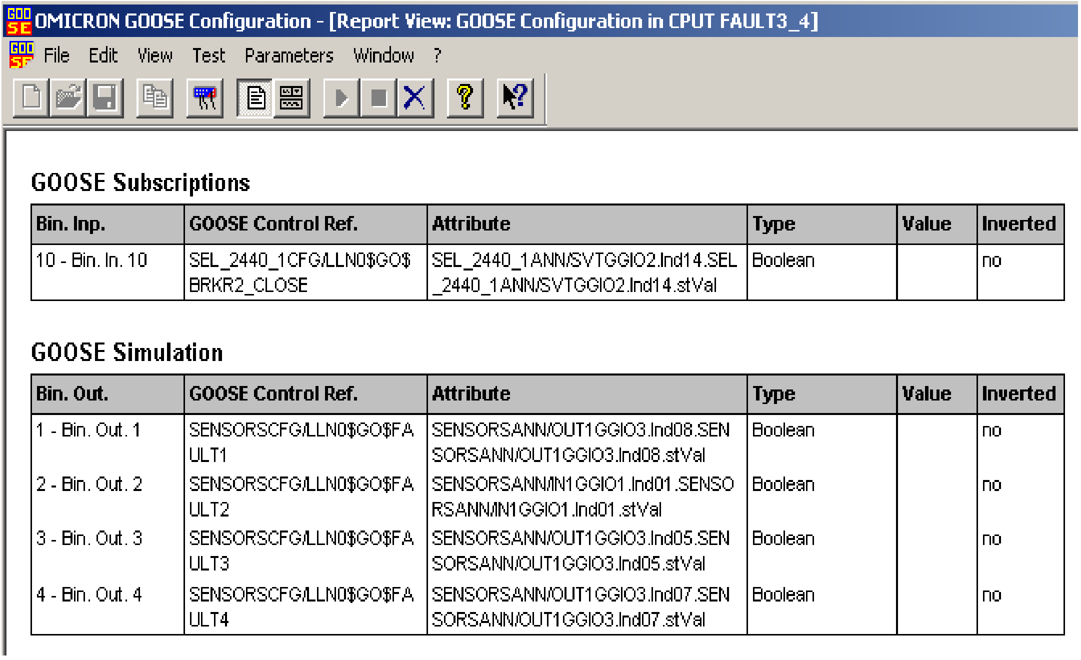


Figure F.18: GOOSE Configuration for the fault on the line section3

F.5.3 State Sequencer

Figure F.19 shows the State Sequencer Test Module. It shows the monitoring conditions for the fault on the line section 3.

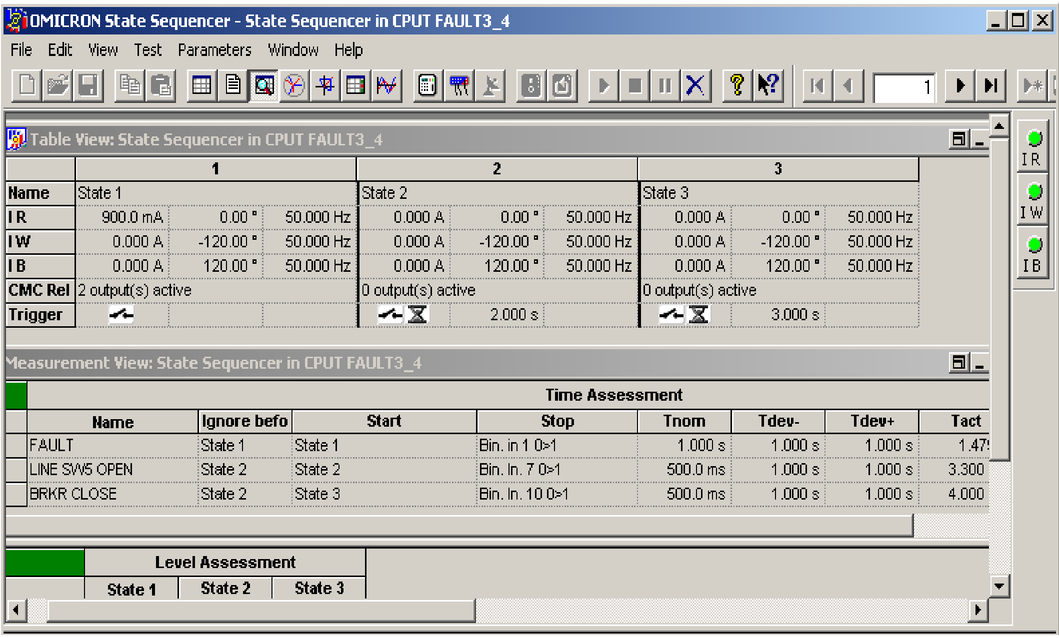


Figure F.19: State Sequencer for the fault on the line section 3

F.6 Multiple Faults

The question was asked how the test bench system would “behave” when there are multiple faults on the system. Therefore, to evaluate the performance of the system faults were simulated on each of the line sections and immediately another fault was simulated on a different part of the test bench network. The following illustrations show step by step how the Omicron was setup as well as the results.

F.6.1 Multiple faults on the line sections 3 and 2

A fault was simulated on the line section 3 first and then on the line section 2. Figure F.20 shows the Control Centre, Figure F.21 the GOOSE configuration and Figure F.22 the State Sequencer for this condition.

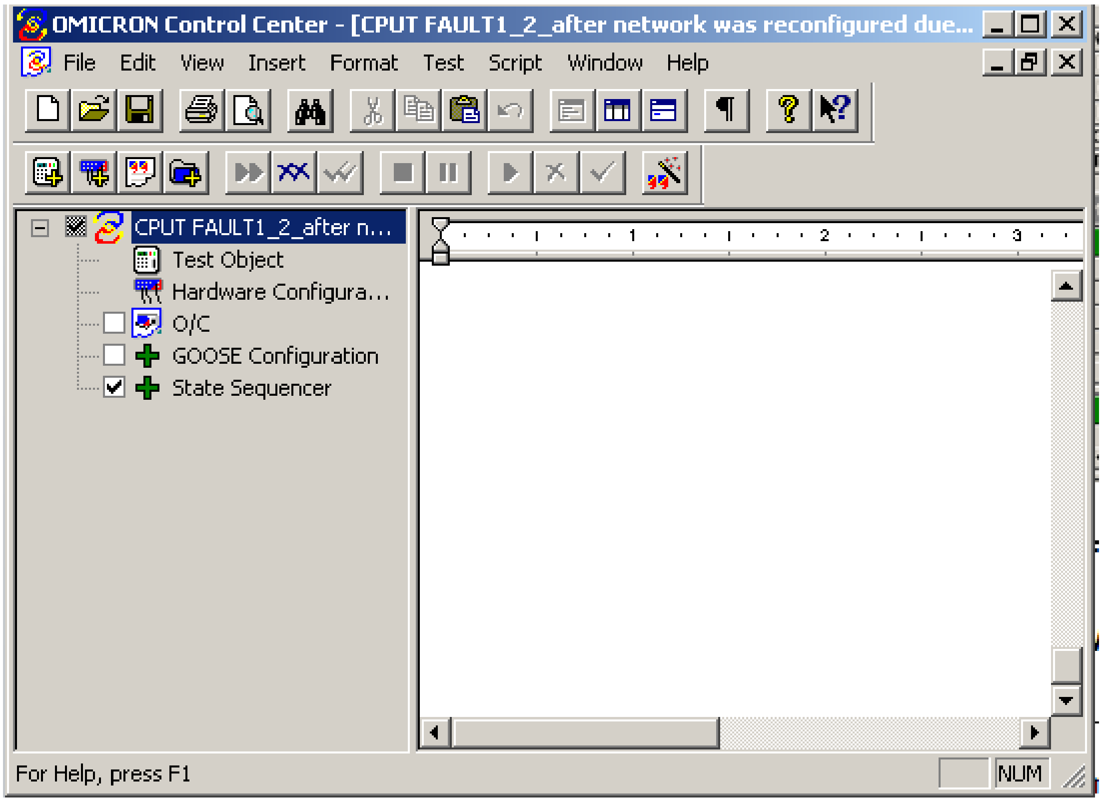
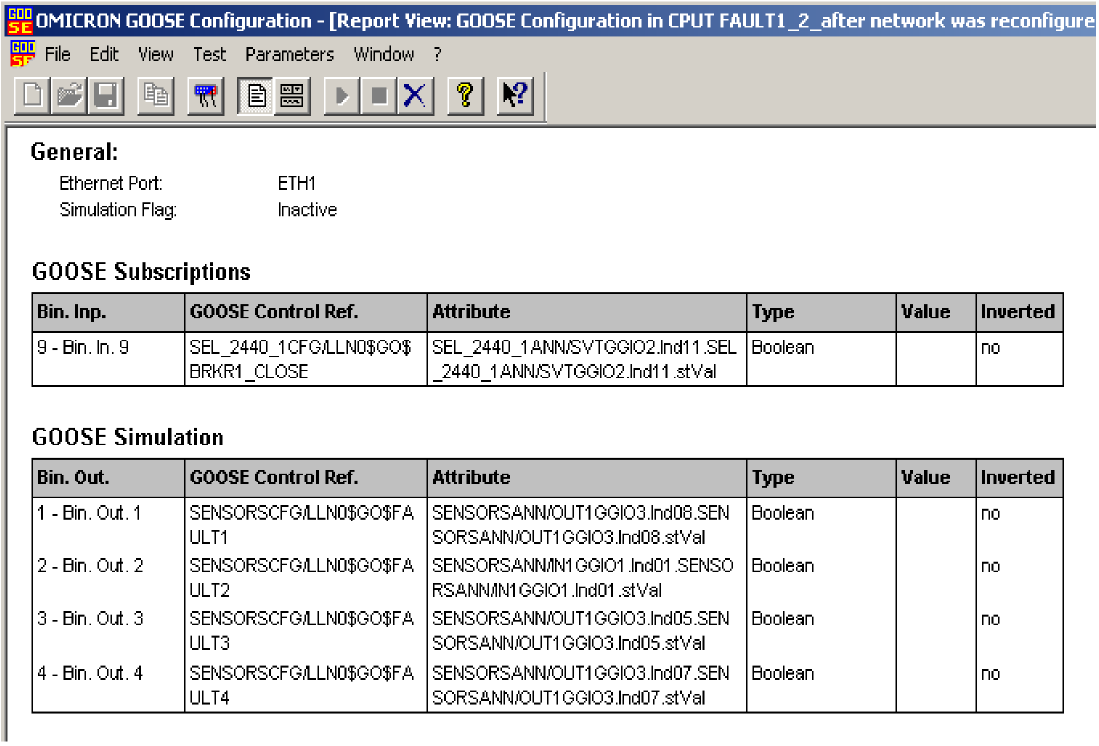


Figure F.20: Control Centre for multiple faults on the line sections 3 and 2



OMICRON GOOSE Configuration - [Report View: GOOSE Configuration in CPUT FAULT1_2_after network was reconfigure

File Edit View Test Parameters Window ?

General:

Ethernet Port: ETH1

Simulation Flag: Inactive

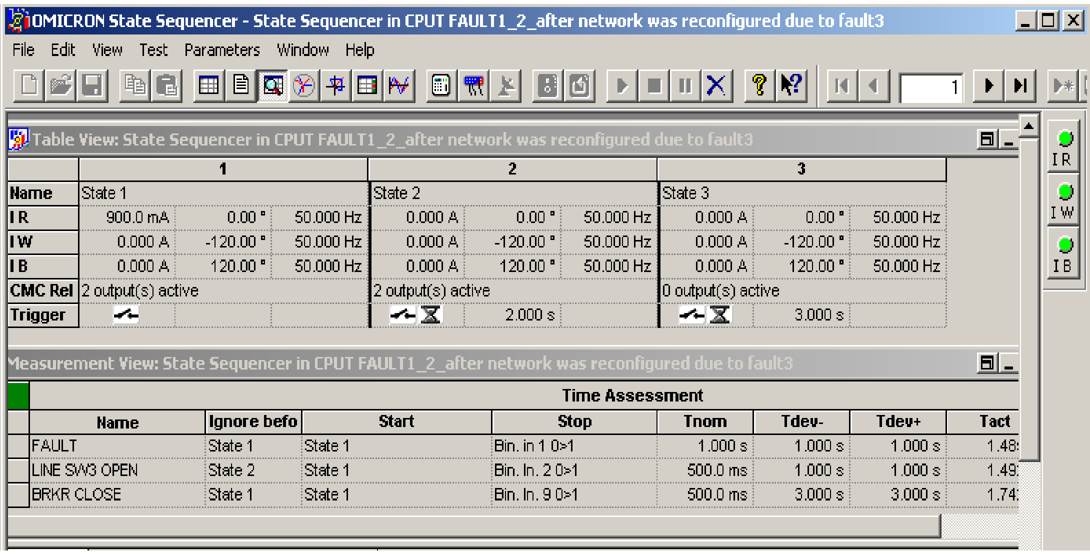
GOOSE Subscriptions

Bin. Inp.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
9 - Bin. In. 9	SEL_2440_1CFG/LLN0GOBRKR1_CLOSE	SEL_2440_1ANN/SVTGGIO2.Ind11.SEL_2440_1ANN/SVTGGIO2.Ind11.stVal	Boolean		no

GOOSE Simulation

Bin. Out.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
1 - Bin. Out. 1	SENSORSCFG/LLN0GOFAULT1	SENSORSANN/OUT1GGIO3.Ind08.SENSORSANN/OUT1GGIO3.Ind08.stVal	Boolean		no
2 - Bin. Out. 2	SENSORSCFG/LLN0GOFAULT2	SENSORSANN/IN1GGIO1.Ind01.SENSORSANN/IN1GGIO1.Ind01.stVal	Boolean		no
3 - Bin. Out. 3	SENSORSCFG/LLN0GOFAULT3	SENSORSANN/OUT1GGIO3.Ind05.SENSORSANN/OUT1GGIO3.Ind05.stVal	Boolean		no
4 - Bin. Out. 4	SENSORSCFG/LLN0GOFAULT4	SENSORSANN/OUT1GGIO3.Ind07.SENSORSANN/OUT1GGIO3.Ind07.stVal	Boolean		no

Figure F.21: GOOSE Configuration for multiple faults on the line sections 3 and 2



	1			2			3		
Name	State 1			State 2			State 3		
I R	900.0 mA	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I W	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I B	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz
CMC Rel	2 output(s) active			2 output(s) active			0 output(s) active		
Trigger					2.000 s			3.000 s	

Name	Ignore befo	Start	Stop	Tnom	Tdev-	Tdev+	Tact
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.48
LINE SW3 OPEN	State 2	State 1	Bin. In. 2 0>1	500.0 ms	1.000 s	1.000 s	1.49
BRKR CLOSE	State 1	State 1	Bin. In. 9 0>1	500.0 ms	3.000 s	3.000 s	1.74

Figure F.22: State Sequencer for multiple faults on the line sections 3 and 2

F.6.2 Multiple faults on the line sections 4 and 2

A fault first occurred on the line section 4 and then on the line section 2. Figure F.23 shows the Control Centre, Figure F.24 the GOOSE configuration and Figure F.25 the State Sequencer for this condition.

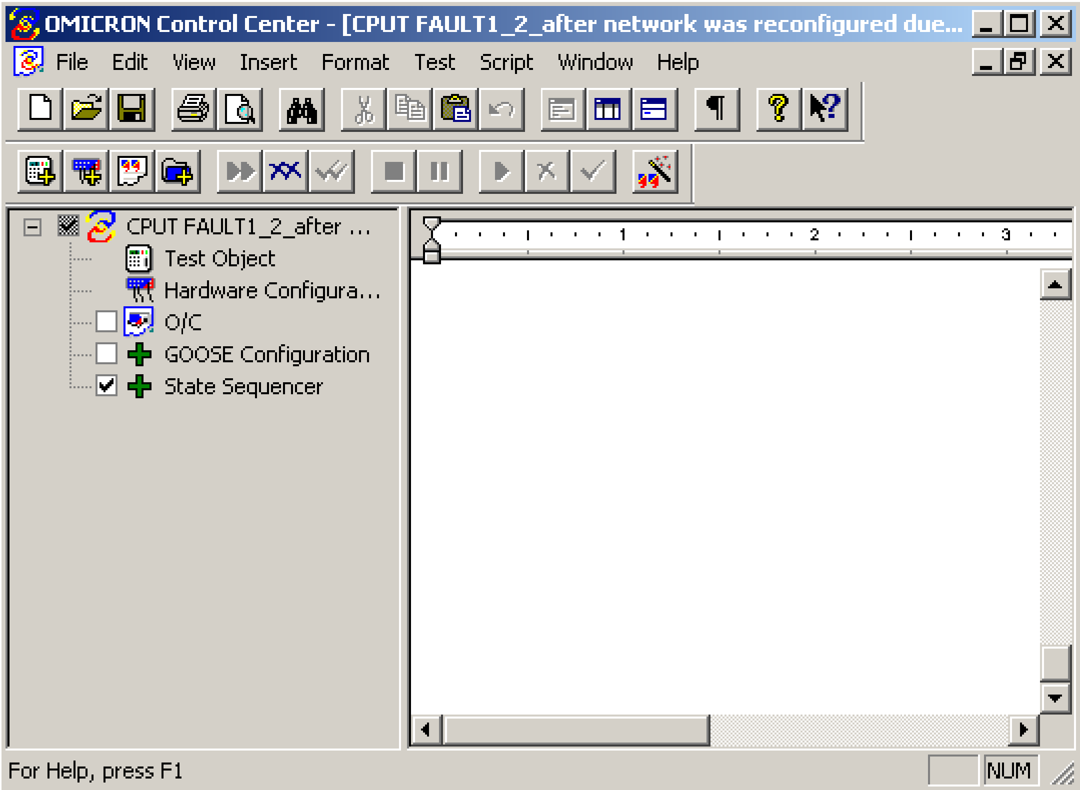
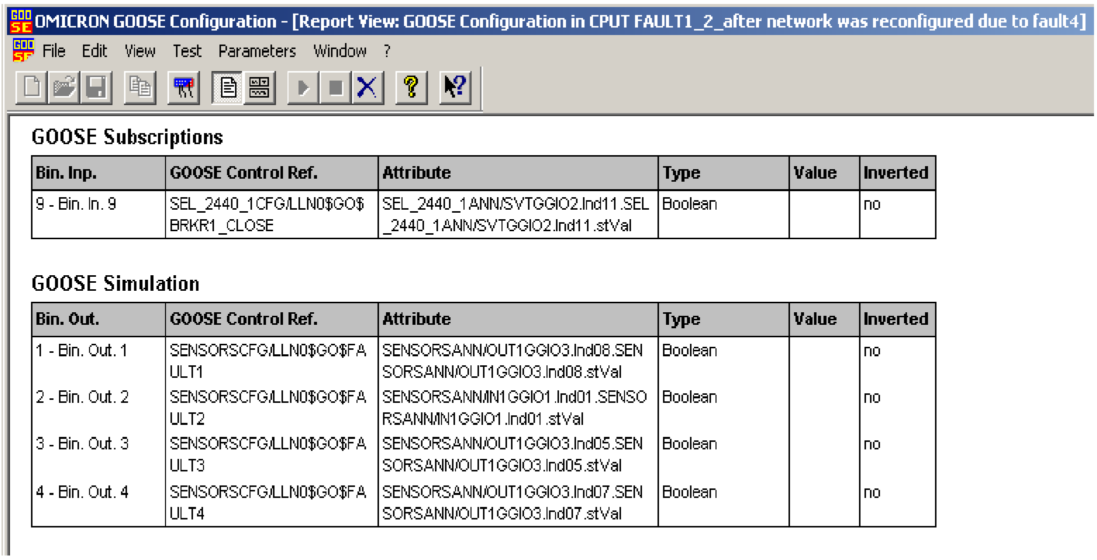


Figure F.23: Control Centre for multiple faults on the line sections 4 and 2



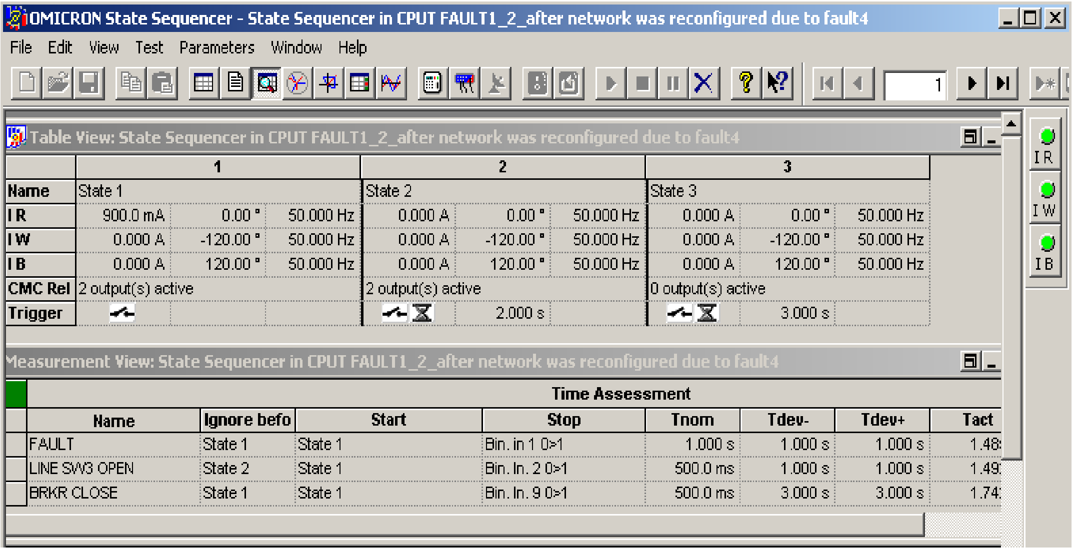
GOOSE Subscriptions

Bin. Inp.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
9 - Bin. In. 9	SEL_2440_1CFG/LLN0GOBRKR1_CLOSE	SEL_2440_1ANN/SVTGGIO2.Ind11.SEL_2440_1ANN/SVTGGIO2.Ind11.stVal	Boolean		no

GOOSE Simulation

Bin. Out.	GOOSE Control Ref.	Attribute	Type	Value	Inverted
1 - Bin. Out. 1	SENSORSCFG/LLN0GOFAULT1	SENSORSANN/OUT1GGIO3.Ind08.SENSORSANN/OUT1GGIO3.Ind08.stVal	Boolean		no
2 - Bin. Out. 2	SENSORSCFG/LLN0GOFAULT2	SENSORSANN/IN1GGIO1.Ind01.SENSORSANN/IN1GGIO1.Ind01.stVal	Boolean		no
3 - Bin. Out. 3	SENSORSCFG/LLN0GOFAULT3	SENSORSANN/OUT1GGIO3.Ind05.SENSORSANN/OUT1GGIO3.Ind05.stVal	Boolean		no
4 - Bin. Out. 4	SENSORSCFG/LLN0GOFAULT4	SENSORSANN/OUT1GGIO3.Ind07.SENSORSANN/OUT1GGIO3.Ind07.stVal	Boolean		no

Figure F.24: GOOSE Configuration for multiple faults on the line sections 4 and 2



	1			2			3		
Name	State 1			State 2			State 3		
I R	900.0 mA	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I W	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I B	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz	0.000 A	120.00 °	50.000 Hz
CMC Rel	2 output(s) active			2 output(s) active			0 output(s) active		
Trigger					2.000 s			3.000 s	

Name	Ignore befo	Start	Stop	Tnom	Tdev-	Tdev+	Tact
FAULT	State 1	State 1	Bin. in 1 0>1	1.000 s	1.000 s	1.000 s	1.48
LINE SW3 OPEN	State 2	State 1	Bin. In. 2 0>1	500.0 ms	1.000 s	1.000 s	1.49
BRKR CLOSE	State 1	State 1	Bin. In. 9 0>1	500.0 ms	3.000 s	3.000 s	1.74

Figure F.25: State Sequencer for multiple faults on the line sections 4 and 2

F.6.3 Multiple faults on the line sections 3 and 1

A fault first occurred on the line section 3 and then on the line section 1. Figure F.26 shows the Control Centre, Figure F.27 the GOOSE configuration and Figure F.28 the State Sequencer for this condition.

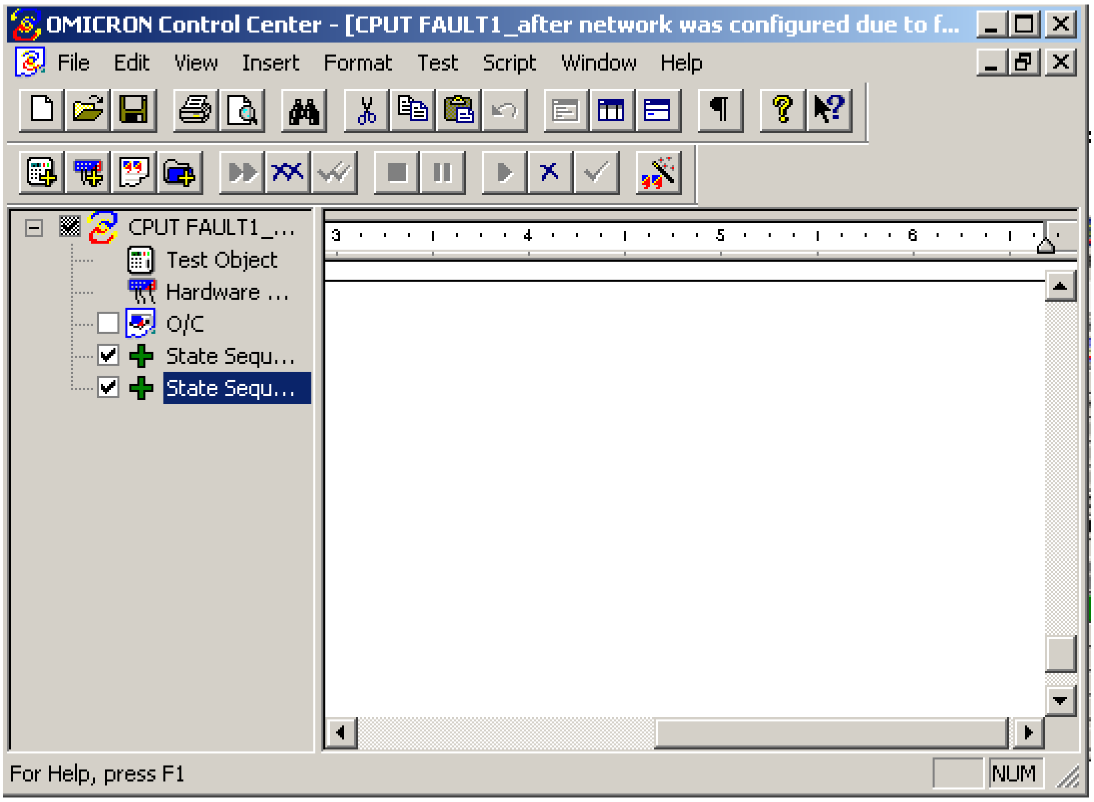


Figure F.26: Control Center for multiple faults on the line sections 3 and 1

F.6.4 Multiple faults on the line sections 4 and 1

A fault first occurred on the line section 4 and then on the line section 1. Figure F.27 shows the Control Centre and Figure F.28 the State Sequencer for this fault condition.

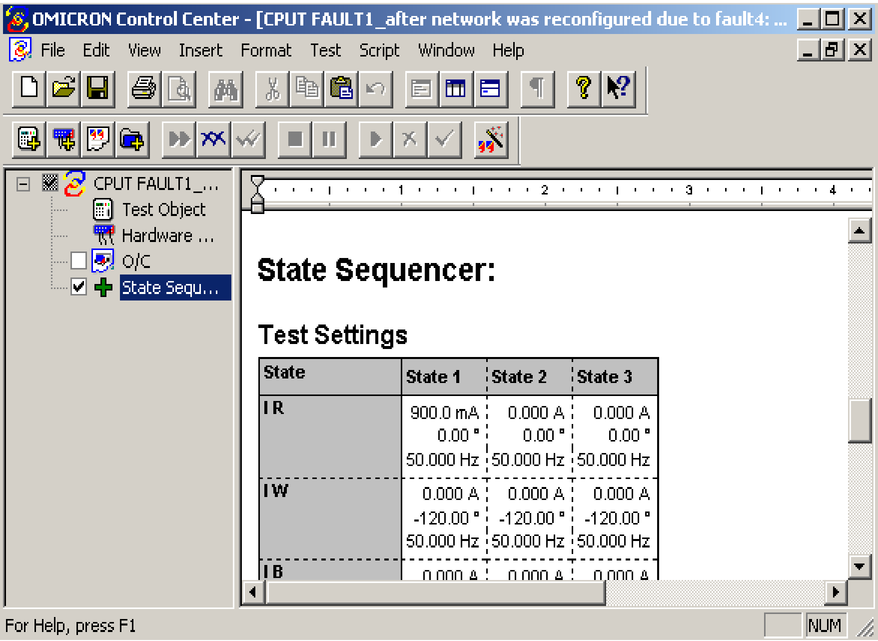


Figure F.27: Control Center for multiple faults on the line sections 4 and 1

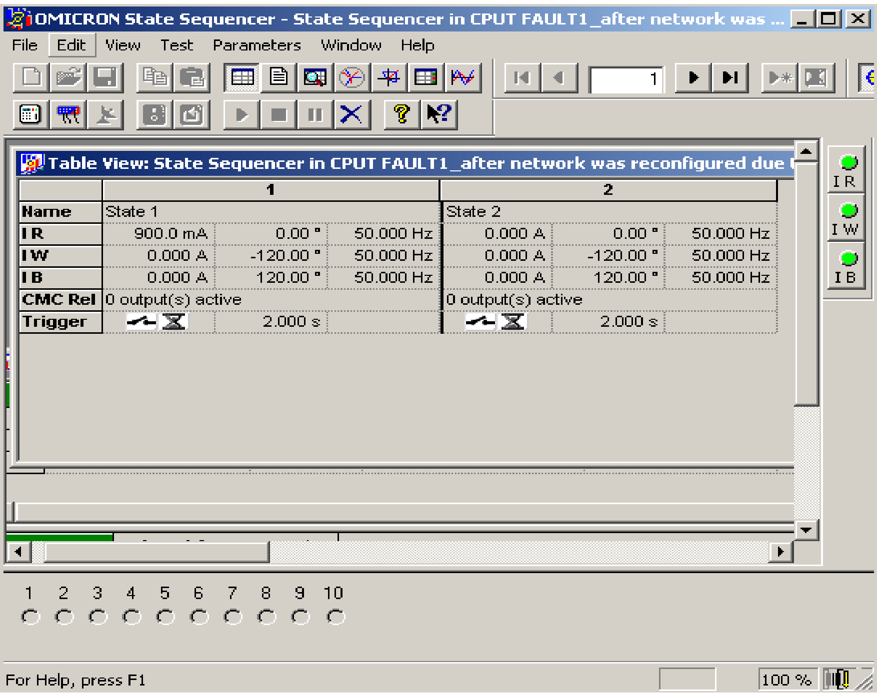


Figure F.28: State Sequencer for multiple faults on the line sections 4 and 1

F.7 Conclusion

The Omicron was extensively used to perform various experiments on the test bench for various case studies. The results from the case studies show that the application of the IEC61850 standard can be successfully implemented in the distribution automation environment.