Managing IEC61850 GOOSE Messaging in Multi-vendor Zone Substations

Sajad Amjadi, M.Eg (Electrical and Electronic Engineering)

College of Engineering and Science

Victoria University

PO Box 14428

Melbourne

Victoria, Australia, 8001

2016

To my beloved and faithful wife, Hakimeh Masoudi, who has emotionally supported and encouraged me to finish this thesis. And also to my family and my family-in-law who have supported me during my studies in Australia.

And also to my supervisor Professor Akhtar Kalam who has guided and inspired me throughout my journey.

Thank you for your support and encouragement.

[redacted]

Table of Contents

Declaration of Originality

"I, Sajad Amjadi, declare that the PhD thesis entitled Managing IEC61850 GOOSE Messaging in Multi-vendor Zone Substations is no more than 100,000 words in length including quotes and exclusive of tables, figures, appendices, bibliography, references and footnotes. This thesis contains no material that has been submitted previously, in whole or in part, for the award of any other academic degree or diploma. Except where otherwise indicated, this thesis is my own work".

[redacted]

Sajad Amjadi 12/08/2016

Acknowledgment

I would like to express my gratitude to everyone who supported me throughout the completion of this research work. It goes without saying; the accomplishment of this dissertation would not have been possible without their dedication and contributions.

First and topmost, my superlative thanks goes to my honourable supervisor Professor Akhtar Kalam. In every sense, none of my research work would have been possible without his insightful comments, constructive criticism and invaluable support during my studies. I also take this opportunity to express my warm regards to my co-supervisor, Adjunct Professor Aladdin Zayegh, who always supported me in my research work. I am appreciative for all the hours of discussion and training both Professor Kalam and Adjunct Professor Zayegh have offered me to develop my knowledge and skills in this research area.

A heartfelt mention also goes out to Professor Helen Borland, Head of the Graduate Research Centre at Victoria University. Obviously, without her support this PhD would have stopped in its preliminary stages.

Furthermore, I would like to convey my appreciation to our industry partners: ABB, GE Digital Electric, Phoenix Electrical, Tricab Group, Australian Power Institute (API), AusNet Services, Omicron, Doble and Australian Strategic Technology. Their assistance and collaboration from the beginning of the project ensured a large number of equipment was delivered securely and expeditiously. In particular, I would like to single-out my industrial supportive colleagues: Maryam Khallaghi, Peter Wong, Filip Ivanovski, Leonardo Torelli, S Madhusudan, Ram Chinnadurai, Graeme McClure, Rajab Dib and Mike Griffin.

Indeed, it is a great pleasure to express my indebtedness to the academic and administration staff at Victoria University, in particular Teresa Gaeta, Joyce Nastasi, Angela Rojter, Elizabeth Smith, Donald Ermel, Abdulrahman Hadbah, Taky Chan, Nitesh Gunoory and Lovelesh Ramsahye, whose efforts at many time has been left unnoticed. I would like to convey my exceptional thanks to my colleagues, Pejman Peidaee, Salman Khan, Srilal Gunasekera, Vasudev Dehalwar, Rahamat Mohammad, Nithya Saiprasad, Piyali Ganguly, and Lasitha Mullage for making my life at Victoria University enjoyable. Last but not the least a very special thanks to my parents, parents-in-law and my beloved wife for their ongoing supports and kind words.

List of Figures

List of Tables

List of Nomenclature

CB	Circuit Breaker
CDC	Common Data Class
CID	Configured IED Description
CT	Current Transformer
DC	Direct Current
DNP	Distributed Network protocol
DNP	Distributed Network Protocol
GFB	GOOSE Function Block
GOOSE	Generic Object Oriented Substation Event
GSSE	Generic Substation State Event
GVRP	Generic VLAN Registration Protocol
HMI	Human Machine Interface
ICD	IED Configured Description
IEC	International Engineering Consortium
IEC TC	International Electrotechnical Commission Technical Committee
IEC61850	International Substation Communication Protocol
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronic Engineers
IP	Internet Protocol
ISO	International Standards Organisation
IUG	International Users Group
LAN	Local Area Network
LED	Light-Emitting Diode
LN	Logical Node
MMS	Manufacturing Message Specification
MMS	Manufacturing Message Specification
OHS	Occupational, Health and Safety
OSI	Open Systems Interconnection

PLC	Programmable Logic Controller
PVID	Port VLAN Identifier
RTU	Remote Terminal Unit
SAS	Substation Automation System
SCADA	Supervisory Control and Data Acquisition
SCC	Substation Control Centre
SCD	Substation Configuration Description
SCD	System Configured Description
SCL	Substation Configuration Language
SCSM	Specific Communication Service Mapping
SM	Single Mode
SMV	Sampled Measured Value
SV	Sampled value
TCP	Transmission Control Protocol
UCA	Utility Communications Architecture
VLAN	Virtual LAN
VT	Voltage Transformer
WAN	Wide Area Network

List of Publications

1. S. Amjadi and A. Kalam, "Device Isolation in IEC61850-Based Substation Protection Systems" I*nternational Journal on Recent Technologies in Mechanical and Electrical Engineering (IJRMEE)*, pp. 43-48, 2015.
2. S. Amjadi and A. Kalam, "IEC61850: a Lingua Franca for Substation Automation *" International Journal of Technical Research & Science (IJTRS)* Vol. 1, pp. 28-34, 2016.
3. S. Amjadi and A. Kalam, "IEC61850 GOOSE Performance in Real Time and Challenges Faced by Power Utilities" *PowerTech, 2015 IEEE Eindhoven*, 2015, pp. 1-6.
4. S. Amjadi and A. Kalam, "Simulation of IEC61850-Based 66/22kV Distribution Terminal Zone Substation*" Engineers Australia Technical Journal, EATJ-S-16-00196* (Under review)
5. P. Peidaee, A. Kalam and S. Amjadi, "Protection Challenges in Distribution Networks Interconnected with DFIG System*" Australian Protection Symposium (APS)*, 2016, Melbourne, pp. 21-27.

Abstract

Due to an urgent need for an international protocol for power protection and substation automation, the International Electrotechnical Committee (IEC) and Institute of Electrical and Electronic Engineers (IEEE) agreed to collaborate together to advance the existing communication protocols for substation automation system (SAS). The objectives were to achieve interoperability and free configuration in a multi-vendor environment substation. The outcome of this agreement was to announce the first edition of the IEC61850 Standard as an international standard in 2004. The standard incorporates the use of logical nodes to resolve problems related to interoperability and interchangeability in multi-vendor zone substation systems. The standard also initiated a cost-effective Generic Object Oriented Substation Event (GOOSE) messaging technology to replace the traditional copper wiring. The second edition of the IEC61850 Standard was published in 2014 which is encapsulated in a series of 20 documents spanning over ten sections.

The last few years has seen numerous studies pointing to the IEC61850 as a worthwhile international standard for substation automation system. There is still, nevertheless, resistance from utilities to welcoming the IEC61850 implementation. This may perhaps be due to the lack of knowledge that engineers have about the standard and/or because of several ambiguous topics that still are not addressed in detail in the context of IEC61850.

Furthermore, it should go without saying that, the GOOSE technology has brought several benefits to the power protection and communication systems in the field of substation automation. However, the lack of tools and knowledge to take advantage of the GOOSE messaging technology in IEC61850-based zone substations is tangible. For instance, in order to test an Intelligent Electronic Device (IED), isolating a GOOSE message from substation is a main industrial challenge for engineers. When an IED is isolated from live substation for test purposes, its GOOSE message is not isolated yet, and the IED under test is still publishing the GOOSE trip signal to other IEDs. In order to isolate the GOOSE trip signal for IED test purposes, each vendor implements its own method and they use their proprietary configurator tools. This means that, engineers are desperately dealing with a lack of comprehensive tool or method to isolate the GOOSE trip signal in a multi-vendor zone substation. These challenges led to the slow migration of the standard into substations.

Having acknowledged these difficulties and challenges the spotlight is seemingly in the path of developing a tool or program to be utilised for GOOSE isolation and GOOSE management in a multi-vendor relay environment. In doing that, a 66/22kV Distribution Terminal Zone Substation is implemented accompanied with a SCADA centre as a model of an IEC61850-based Substation. Two bays with separate 66kV sub-transmission lines, 66/22kV step down transformers, 22kV Bus 1 with Bus Tie Circuit Breaker and three 22kV feeders per bay have been considered for the simulation. In the construction of the Substation Simulator, the aim is to take advantage of the IEC61850 GOOSE messaging technology for protection, control, monitoring and communication purposes. Hence, the hardwire connections are replaced by GOOSE signals through optic cables as much as possible. This thesis will not only provide the design and configuration procedures of this substation, but also will cover the difficulties that engineers may encounter in IEC61850-based substations systems in terms of device configuration, testing and maintenance.

In order to fully understand the concept of the 66/22kV Distribution Terminal Zone Substation, it is very essential to be familiar with the structure of communication protocols and the IEC61850 Standard. This thesis starts by exploring a synopsis of communication protocols and their development over the time. It elucidates core elements of telemetry communications, structures of protocols and the significance of standards for communication protocols within substation automation systems. This is followed by a comprehensive exploration of the fundamentals of the IEC61850-based substations. In particular, it will cover the GOOSE messaging technology and interoperability in a multi-vendor substation environment. The author also addresses the difficulties that engineers may encounter in IEC61850-based substations systems in terms of device configuration, testing and maintenance.

Index Terms: *IEC61850; Configured IED Description (CID); Multi-vendor interoperability, Substation Configuration Language (SCL), Configured IED Description (CID); System Configuration Description (SCD); GOOSE Signal; Zone Substation, SCADA, PCM600; EnerVista, IET600; Substation Automation; IED Configurator Tools, GOOSE Isolation, Device testing.*

Chapter 1 - Thesis Overview

1.1 Introduction

For a number of decades there have been numerous research studies and examination on power protection systems due to the host of Intelligent Electronic Devices (IEDs) in Substation Automation System (SAS) [1, 2]. An appropriate and well-designed communication structure is required to make these IEDs interconnect and exchange data. This has categorised communication technology as one of the crucial contributing factors to guarantee unfailing, reliable and cost-effective protection systems. Therefore, development of a robust and reliable protocol for communication applications has grown into a foremost objective in power communication and protection systems [3-5]. The International Electrotechnical Committee (IEC) and Institute of Electrical and Electronic Engineers (IEEE) agreed to collaborate together to advance the existing communication protocols for SAS [6, 7]. The objectives were to achieve interoperability and free configuration in multi-vendor environment substations. The outcome of this agreement was to announce the first edition of the IEC61850 Standard as an international standard in 2004 [1, 7, 8]. The standard incorporates the use of logical nodes to resolve problems related to interoperability and interchangeability in multi-vendor zone substation systems. The standard also initiated a cost-effective Generic Object Oriented Substation Event (GOOSE) messaging technology to replace the traditional copper wiring [7].

The last few years have seen numerous studies pointing to the IEC61850 as a worthwhile international standard for substation automation systems [7-10]. However, there is still resistance from utilities to welcoming the IEC61850 implementation [7, 9, 11]. This may perhaps be due to the lack of knowledge that engineers have about the standard and/or because of several ambiguous topics that still are not addressed in detail in the context of IEC61850. Furthermore, it goes without saying that, the GOOSE technology has brought several benefits to the power protection and communication systems in the field of substation automation. However, the lack of tools and knowledge to take advantage of the GOOSE messaging technology in IEC61850-based zone substations is tangible [6, 7, 11-13].

This thesis provides the development of a program using a SCADA system to manage IEC61850 GOOSE messaging in a multi-vendor environment substation. In doing that, a 66/22kV Distribution Terminal Zone Substation (form now-on it will be referred to as - Substation Simulator) is implemented as a model of an IEC61850-based Substation. In the construction of the Substation Simulator, the aim is to take advantage of the GOOSE technology for protection, control, monitoring and communication purposes. Hence, the hardwired connections are replaced by GOOSE signals through optic cables as much as possible. This thesis will not only provide the design and configuration procedures of this substation, but will also cover the difficulties that engineers may encounter in IEC61850-based substation systems in terms of device configuration, testing and maintenance.

This chapter covers a brief introduction, the key objectives, the original contribution and methodologies of the research. It also provides insight into the research significance in the discipline of engineering.

1.2 Key Objectives

The key objectives of this research are synopsised as follows:

- Review and analysis of the most common traditional protocols such as Modbus, Distributed Network Protocol (DNP3), Utility Communication Architecture (UCA) and compare their functionality with the IEC61850 Standard;
- Design, establish and commission a 22/66kV IEC61850-based Distribution Terminal Zone Substation;
- Configure IEDs individually utilising vendor propitiatory tools namely PCM600 and EnerVista to create configured IED files for ABB and GE relays respectively;

- Create the System Description File (SCD) that contains GOOSE messaging between IEDs, using IET600 as a multi-vendor IED system configurator tool;
- Design a single line diagram to illustrate the communication paths of the GOOSE messages between publishers and subscribers;
- Draft a single line Protection Scheme of the Substation Simulator to represent the implementation of protection, control and monitoring functions;
- Test and validate the GOOSE communication between IEDs to ensure IEC61850-based interoperability achieved and all IEDs are capable of exchanging data using the peer-to-peer communication network model;
- Examine the application and the advantages of GOOSE messaging technology over traditional copper wiring by implementing different protection scenarios such as Circuit Breaker Failure Protection, Bus Tie Coupler and Busbar Protection Interlocking System;
- Design and develop a SCADA system to monitor and control the performance of the Substation Simulator remotely from SCADA control centre;
- Propose a novel GOOSE isolation method for a multi-vendor environment substation using PLC/SCADA programming;
- Remotely implement GOOSE isolation in a live substation for devices testing purposes through SCADA;
- Document a final report and of all wiring designs, in both AutoCAD and PDF format, which can be used for future research studies.

1.3 Design and Methodology

1.3.1 Literature Review

The IEC161850 Standard is under a dynamic environment and the research area is new [14, 15]. Therefore, a lack of academic resources, particularly literature relating to IEC61850 GOOSE messaging is evident. However, to control the quality, both IEC161850 standard and peer-reviewed papers from highly ranked journals are selected for review and analysis.

The literature review involves exploring of both conventional and existing communication protocols and their development over the time. Core elements of telemetry communications, structures of protocols and the significance of standards for communication protocols within substation automation system are studied. In addition, a comprehensive review and study to understand the fundamentals of the IEC61850-based substations, particularly the GOOSE messaging technology and interoperability in a multi-vendor substation environment is undertaken.

1.3.2 System Design

Due to lack of tools and knowledge to take advantage of the GOOSE messaging technology in IEC61850-based zone substation, the IEC61850 Standard has not seen a warm welcoming from utilities and companies over the last 10 years [7]. This thesis provides solutions to challenges dealing with IEC61850 GOOSE messaging in multi-vendor zone substations. A 66/22kV Distribution Terminal Zone Substation is implemented as a model of an IEC61850-based Substation.

1.3.2.1 *66/22kV Distribution Terminal Zone Substation*

The 66/22kV Distribution Terminal Zone Substation has been funded by industry partners namely: ABB, GE Digital Electric, Phoenix, Tricab, Australia Power Institution (API), AusNet Services, Omicron, Doble, Australian Strategic Technology Project with an overall funding of $1,700,000.00. Two bays with separate 66kV sub transmission lines, 66/22kV step down transformers, 22kV Bus 1 with bus tie circuit breaker and three 22kV feeders per bay have been considered for design of the Substation Simulator. In parallel, a control centre utilising SCADA system is stablished to make use of remote control in this project. The development of the Substation Simulator aims to take advantage of the IEC61850 GOOSE messaging technology for protection, control, monitoring and communication purposes. Hence, the hardwired connections are replaced by cost-effective GOOSE signals through optic cables. Copper cables are only used to connect circuit breakers to corresponding IEDs. Electrical Engineering AutoCAD software is deployed to draft the single line diagram of system which includes individual device connection, a communication single line diagram, AC wiring, DC Supply and input/output contacts of IEDs.

1.3.3 Analysis of Tests and Results

There are various types of testing and result analysis undertaken to ensure that the outcome of the project is compliant with the industry standard requirement and it satisfies the scope of the project.

1.3.3.1 *Interoperability Testing*

IEDScout and CMC356 Omicron Test Universe System are utilised though multiple test scenarios to show the interoperability between devices used in the Substation Simulator is achieved.

1.3.3.2 *GOOSE Isolation for IED Testing*

After completing PLC/SCADA system for GOOSE isolation, different IEDs of the Substation Simulator are injected simulated fault signals using CMC356 under live condition. Simultaneously, the GOOSE isolation method is examined for the IED under test from SCADA centre remotely.

1.4 Research Significance

IEC61850 is widely accepted around the globe due to the significant benefits that it provides compared with conventional hard-wired solutions. However, the wide spread development and implementation of IEC 61850-based substation protection, automation and control systems is raising multitude of issues and challenges related to the testing of IEC61850-based devices and systems. The foremost challenge is the replacement of the hardwired interfaces between the protection IEDs that work together in different protection, automation and control schemes with GOOSE messages.

The specialists involved in the testing of such schemes are used to a physical isolation of the test object based on the use of test switches that allows on one hand to open the circuit that trips the breaker and at the same time to replace the analogue signals from the secondary of the current and voltage transformers with signals coming from the test equipment.

The replacement of part or all of the hardwired interfaces with communication links requires the development and implementation of methods and tools that maintain the same level of security during the testing process, while at the same time takes advantage of all the benefits that IEC 61850 provides.

Therefore, engineers are dealing with a lack of comprehensive tool or method to manage the GOOSE trip signal in a multi-vendor zone substation. The significance of research is to develop a tool and software to isolate or manage GOOSE messages in a multi-vendor relay environment which is not resolved in any past researches. The research contributes to the knowledge by modelling a section of an IEC61850-based substation to meet the requirements of interoperability between vendor specific IEDs.

The achievement of this research project will enable engineers to test any IED, regardless of its manufacturer, without GOOSE interruption in an IEC61850-based zone substation.

1.5 Original Contribution

The research contribution to body of the knowledge is to endorse and publicise the IEC61850 protocol as the latest and improved communication standard opposed to other substation protocols like DNP and MODBUS by modelling a section of IEC61850-based substation. The modelling involved original designing and wiring the 22/66kV Distribution Terminal Zone Substation. In doing that, combination of both copper and fibre optics are utilised to interconnect devices. However, in order to take advantage of the GOOSE messaging technology, the amount of copper wiring is reduced by replacing GOOSE signals. The original work involved programming of GOOSE messages to accomplish interoperability between multi-vendor IEDs such as GE and ABB. This is the most complex and topmost challenging part of the project due to lack of tools [11, 16]. The Substation Simulator has a high potential to be upgraded to a complete model of an IEC61850-Based substation. It can also potentially be used for industrial training as well as academic and future research studies.

Furthermore, the study potentially contributes to engineering discipline by developing a novel method of GOOSE isolation in an energised multi-vendor based substation environment. Over the past decades, protection system operation has been given importance due to host of critical equipment known as “Intelligent Electrical Devices” in substation automation systems. In order to guarantee unfailing operation, these intelligent devices are required to be tested and serviced within their lifecycle. This involves different types of testing such as product manufacturing testing, commissioning testing and periodical maintenance testing during operation [9].

When an IED is isolated from live substation for test purposes, its GOOSE message is not isolated yet, and the IED under test is still publishing the GOOSE trip signal to others. In order to isolate the GOOSE trip signal for IED test purposes, each vendor implement its own method and they use their proprietary configurator tools [9, 11, 17].

Designing of GOOSE isolation method in a live substation without interrupting any other IEDs under operation originally developed through a PLC/SCADA system. All provided programming and design in this research are original and the most improved method of its kind which require knowledge of engineering protection and communication systems. Through several workshops and conferences [7, 11], the proposed novel method of isolation has been presented to industry partners and professionals who are leader in IEC615850. It has revived a high level of satisfaction and it also proved its conformant with the requirement of the IEC61850 Standard.

1.6 Thesis Organisation

The thesis comprises of seven chapters and is organised as follows:

- *Chapter 1:* covers a brief introduction of the key objectives, motivations and methodologies of the research, while providing insight into the research significance in the discipline of electrical engineering.
- *Chapter 2:* presents a comprehensive literature review exploring a synopsis of communication protocols and their development over the time. The chapter elucidates core elements of telemetry communications, structures of protocols and the significance of standards for communication protocols within substation automation systems.
- *Chapter 3:* describes the fundamentals of the IEC61850 Standard. In particular, it covers the GOOSE messaging technology and interoperability in multi-vendor environment substations. The concept of GOOSE isolation for IEC61850-based device testing purposes is outlined in in this chapter. Chapter 3 also addresses the difficulties that engineers may encounter in IEC61850-based substations systems in terms of device configuration, testing and maintenance.
- *Chapter 4:* provides hardware description and a detailed insight into the wiring layout of the 66/22kV IEC61850-Based Distribution Terminal Zone Substation and the connection diagram between the equipment.
- *Chapter 5:* provides the flow of the engineering process undertaken to design the IEC61850-Based 66kV/22kV Distribution Terminal Zone Substation. It outlines the required steps, individual device programming and substation configuration, and tools to establish the IEC61850 GOOSE communication between IEDs. It also addresses the challenges and issues that are encountered within the configuration process.

- Chapter 6: aims to use IEDScout and vendor proprietary tools to prove the interoperability achievement between ABB and GE devices in the established 22/66kV IEC61850-based Distribution Terminal Zone Substation. Furthermore, by utilising both isolator switch locally and the SCADA system remotely the GOOSE isolation is experimented and validated while the Substation Simulator is energised. CMC356 Omicron fault simulator is utilised as a fault simulator device to create different fault scenarios for further test validation and analysis. The test method and results that provided in this chapter potentially enable engineers to test any IED, regardless of its manufacturer, without GOOSE interruption in an IEC61850-based zone substation.
- *Chapter 7:* summaries the work in chapters 1-6 and provides recommendations for future research studies.

Chapter 2 - Literature Review

2.1 Introduction

The purpose of this chapter is to provide a synopsis of communication protocols and their development over the time. The chapter elucidates core elements of telemetry communications, structures of protocols and the significance of standards for communication protocols within substation automation systems.

2.2 The Importance of Power System Communication

Over the past decades power protection systems have seen numerous studies due to the host of critical equipment such as IEDs in Substation Automation System [2, 18]. An appropriate and well-designed communication structure is required to make these intelligent devices interconnect and exchange data. This has categorised communication technology as one of the crucial contributing factors to guarantee unfailing, reliable and cost-effective protection systems. Therefore, the development of a robust and reliable protocol for communication applications has grown into a foremost objective in power communication and protection systems [3-5, 19].

2.3 Protocols

When language is a media for communication, there is a need for systematic rules to follow in order to achieve the communication between parties [20]. A protocol plays the role of a rulebook prepared with a chain of instructions to help two or more communication parties talk to and understand each other [19-21].

Communication in a multi-vendor environment, a place where devices come from different vendors, often causes challenges due to the use of multi-language technologies in programming of vendors' devices [1, 3]. Overcoming to this problem requires an expensive interface for communication applications. The International Standard Organisation Network Model known as OSI (Open System Interconnection) introduced a 7 network-layered hierarchy to show how data is transferred from one communication platform to another end and vice versa (Fig. 2.1) [1, 19, 22].

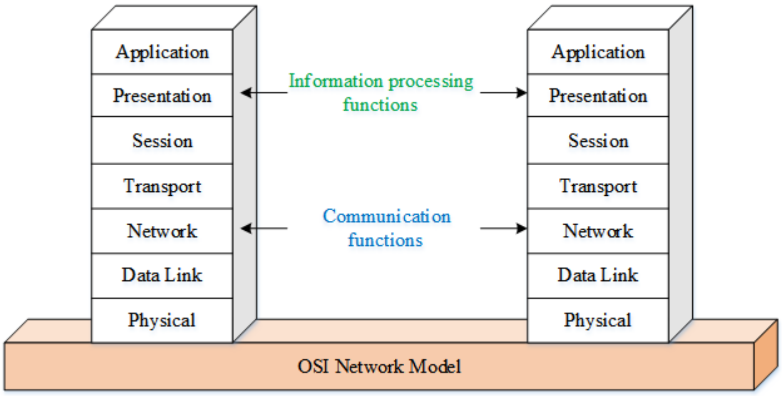


Fig. 2.1 OSI 7 network- layered hierarchy [1, 19]

- Application layer provides a cluster of interfaces to be utilised for getting access to network services.
- Presentation layer mainly transforms the data of application into a generic framework for network broadcasting and vice versa.
- Session layer allows two communication parties to maintain ongoing exchange of data across a network.
- Transport layer is to manage the data transmission over the network.
- Network layer converts logical network address into the format to be used within physical devices and also controls the addressing for message delivery.
- Data Link layer initiates specific data frames between the Physical layer and the Network.
- Physical layer converts data format from bit into signals to be sent as outgoing messages and vice versa.

2.3.1 Modbus

Modbus is a Client/Server massaging protocol located in the Application layer of the OSI Network Model [23]. It supports different types of Physical layers categorised in OSI. Modbus was originally introduced by Modicon (now Schneider Electric) in 1976 to support different fields of applications such as: industrial automation, infrastructure, and substation automation and transportation applications [24]. Modbus makes use of the Master/Slave structure to establish communication between devices connected together. One of the advantages of the Modbus protocol is that the flow of data exchange can be either from client to Server or vice versa [23].

Modbus, also known as Master/Slave protocol, works with the request/reply rule [23]. In order to perform the request/reply operation in Modbus based system, two different types of frames are initiated. These are: Application Data Unit (ADU) and Protocol Data Unit (PDU [25]. PDU contains a code specifying the function to be operated and ADU provides the information to be used for PDU operation. The process of exchanging data starts by initiating a command which contains both ODU and ADU frames and ends by receiving a response packet from the client (Fig. 2.2) [19].

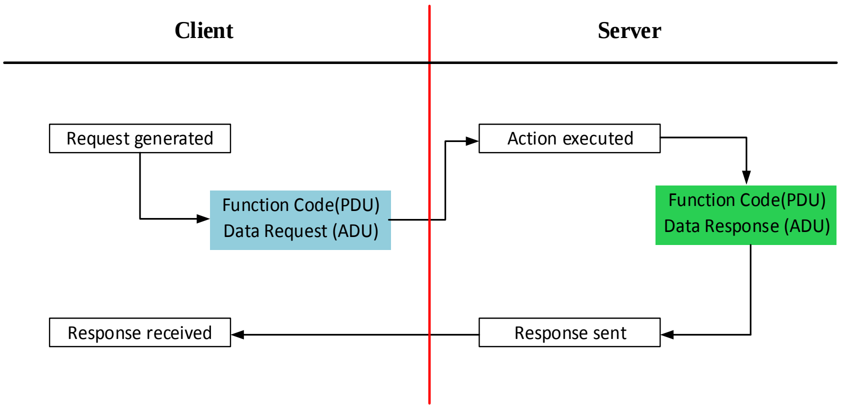


Fig. 2.2 Client/Server data exchange in Modbus protocol [19, 25]

Modbus is designed with a combination of layered protocols, such as Modbus RTU (Remote Terminal Unit) and Modbus TCP/IP (Transmission Control Protocol/Internet Protocol), to offer a trustworthy data exchange mechanism between microprocessor based devices. Modbus RTU operate within Physical layer using RS232 or RS485 serial, to transfer data between devices [26]. The disadvantage of Modbus RTU is its limit to transfer different types of information. The information packets that can be sent through Modbus RTU are only data. This means that Modbus RTU is not able to exchange other types of parameters such as units, resolution, point name, status value, etc. [3, 23, 27]. This type of information requires modern Ethernet-based protocols such as Ethernet/IP or IEC61850. Modbus protocol eliminated this drawback by introducing Modbus TCP/IP driver. Modbus TCP (Modbus Ethernet/IP) is a well-accepted industry protocol that utilises the Ethernet TCP/IP Physical layer, the top level of the Physical layer in OSI, to achieve the communication between devices [23]. Figure 2.3 illustrates the structure of the Modbus communication network which employs Modbus TCP, Modbus RTU and RS232 Modbus RTU485.

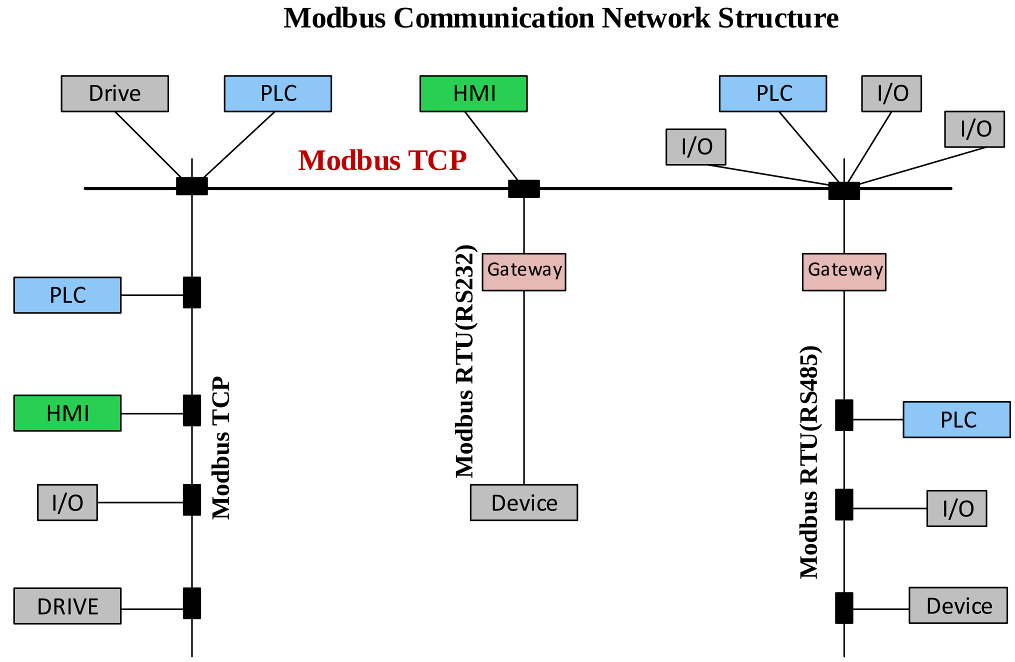


Fig. 2.3 Modbus communication architecture [19, 23]

One of the challenges with Modbus protocol is the upgrading of Modbus devices from Physical layer (RS232 or RS422) to Modbus TCP/IP (Ethernet layer). This requires a gateway device to convert the communication format from Physical layer to upper layer such as Ethernet layer. This conversion causes an unwanted time delay in the process of function's operations [27, 28].

In Modbus protocol based system, the Server employs a controller as a middleware to collect data from other devices and send it to the Master through a programming panel or a host processor. The controllers used by the Server also follow the Master/Slave communication architecture. The only difference between the controller and the Server of Modbus is that, the controller can only interact with one Master simultaneously, whereas the Server can interact with the Master and the controller at the same time.

Over the las decades Modbus TCP/IP has been deployed as one of the industry accepted standards to operate Client/Server based communication application [19, 23]. In the context of substation automation it is used to monitor, supervise and control the performance of the intelligent devices - IEDs, circuit breakers, transformers - through a middleware gateway and controller. Although interoperability was one of the targets to achieve in Modbus, still there are many challenges in a multi-vendor environment that Modbus fails to resolve [4, 6, 29].

2.3.2 DNP3

Distributed Network Protocol (DNP3) is another open[1] and public communication protocol originally introduced by Harris in 1993 at Distributed Automation [30]. DNP3 located in the second layer of OSI Network Model employing a series of communication protocols to achieve interoperability between devices as per IEC Technical Committee 57 [30]. The DNP3 protocol is compliant with IEC 62351-5 and is mainly established as a standard for utilities including electrical and water industries [19, 22]. DNP3 utilises SCADA to control and monitor the performance of intelligent devices through a Remote Terminal Unit (RTU), also known as gateway, under Master station/gateway/intelligent devices communication structure. One of the primary purpose of DNP3 was to provide a reliable protocol in terms of interoperability and long term stability [20, 27, 31]. Therefore, network security and cyber security issues were not initially considered in the development of DNP3 [32, 33]. This resulted in being easily attached and hacked by intruders in smart grid application. This is due to the fact that smart grid is a platform run by an IP interface and provides open admission to a third party to the IP infrastructure and physical network. Therefore failure to secure the IP infrastructure will cause series interruption and/or damage to the network. Therefore, DNP3 has been forced to resolve this drawback by adding secure authentication parameters to its architecture.

The DNP3 protocol has been widely utilised by companies due to its numerous proven merits such as its efficiency, robustness and better interoperability compared to Modbus or older protocols [3, 31]. For instance, from the point of OSI Network Model, DNP3 is a layer 2 protocol whereas it supports layer 4, layer 5 and layer 7 of the OSI Network Model. This gives it superiority over Modbus protocol, positioned in the Application layer. Furthermore; in contrast to Modbus or other older protocols, time synchronization is achieved for the first time using RTU in DNP3 protocol. It initiated a frame which contains a time stamped variation of data pulled out and transferred through the RTU [1]. In addition; despite Modbus protocol, DNP3 is capable of communicating with

[1] Open architecture is an expression that describes an interoperable networks between software and hardware interfaces and accordingly between vendors.

multiple Masters and pee-to-peer[2] communication simultaneously. Furthermore, DNP3 has the capacity of transferring different type of data in a single massage packet with a defined time frame [19, 20, 31].

2.3.3 IEC61850

It should go without saying that the developments of the Modbus and DNP3 protocols have been favourable achievements in the field of communication systems [3, 4]. Utilities have used these protocols applications free of exorbitant charge access to their license to implement their communication applications. However, the drawback of these protocols is their complexity in terms of substation and instrument configuration. Due to a convoluted structure used by these protocols, configuration of an interoperable system in a multi-vendor environment was an irresistible time consuming procedure [6]. Also they were unable to fully warrant different vendor IEDs to communicate with one another. Thus, in recent decades, to a great extend interoperability has been a topmost challenge for multi-vendor-based substation automation systems [4, 34-36].

The International Electrotechnical Commission (IEC) Technical Committee (TC) 57 was established in 1964 to produce international standard in the field of communications for electrical utilities. The IEC considered not only equipment aspects, but to a greater extent system parameters. This scope was modified to prepare standard for SCADA systems, Energy Management Systems (EMS), Distribution Management Systems (DMS), distributed automation, telemetry and associated communications [1, 6].

At the same time, the Electric Power Research Institute (EPRI), founded in 1973, was working towards drafting proposal for the implementation of a protocol within specific interfaces and data models. EPRI recognised the potential benefit of a unified scheme of data communication for all operating purposes across the entire utility enterprise. In 1980, EPRI commissioned the Utility Communications Architecture UCA project which identified the overall structure, requirement, technology and layer to implement such a scheme. It focused on the ease of combining a broad range of devices and systems; and the sharing of management and control information [1, 4, 6, 19].

By 1994, EPRI had combined substation control equipment and power apparatuses into the UCA scheme [1, 6]. EPRI launched Research Project 3599 to define, demonstrate

[2] Peer-to-peer communication refers to the exchange of data directly between two devices where their functionality come with same capacity. There is no Client/Server order in peer-to-peer communication.

and endorse an industry wide UCA compatible communications approach for the integration of substation IEDs [29]. The objective was to avoid expensive marketplace shakeout of incompatible systems.

Many utilities and IED manufacturers took an immediate interest in the UCA work and joined in the effort to produce a communications network stack. The forward-looking approach was intended to define the technical requirement for a system to control and monitor substations [6, 29]. The specification includes requirement for fast messaging amongs peer IEDs to achieve fault-related control over data communication systems. The objective was to use the substation Local Area Network (LAN) messaging to replace the mass of dedicated copper wiring between IEDs.

Another feature of the approach was to identify communication system layers which may have already existed in widespread use. This allowed EPRI researchers to buy commonly used hardware and software components for substation control. For lower layers of the system, the researchers looked at a variety of industrial field bus solution, as well as office-LAN technologies like Ethernet and Internet Protocol (IP) [4, 6]. These were not suited for fast substation control, but had the advantage of global usage to support a rich array of affordable system components that could be implemented within substations.

After detailed study by EPRI, a group of prominent utilities led by the American Electric Power (AEP) company forged ahead in a proposal to decide on specific layer. These users were developing project to equip a substation with the most modern LAN-based and standardised control schemes and pushed ahead to demonstrate a working result [4, 6]. The objective was to define a standard which could achieve interoperability and use fibre optic cable.

The call for an international standard intensified as different vendors introduced proprietary solutions into the market. Many manufacturers had already developed versions of integrated LAN-based systems. At the request of the users, several European suppliers worked together with the International Electrotechnical Commission (IEC) to create the communications standard IEC60870-5 [4, 6]. Subsection of IEC61870- 5 provided for basic information transfer and control between one vendor relay and the overall system of another vendor. The market where these manufactures sold their products tended to support more expensive, futuristic system as part of a major project [6, 29].

In 1995, the IEC commissioned a new project identified as IEC61850, to define the next generation of standardised high-speed substation control, protection and monitoring communication. The main objective was to have utilities and vendors collaborating with each other to develop the framework of the standard. The EPRI UCA 2.0 and IEC61850 joint task forces worked on the interoperability between Station, Bay and Process levels [6].

In October 1997, the Edinburgh TC57 Working Groups concluded that a single communications standard for Substation Automation Systems (SAS) will be suitable for the world market [1, 6]. The IEC61850 was officially launched after careful planning and development in the year 2004 [4, 6]. Major UCA model, data type and service were incorporated into the final standard.

During this struggle for standardisation, MODBUS and DNP3 became the de facto standards across all substations worldwide. While MODBUS and DNP3 are successful in providing standard-based intercommunications between station computers, Remote Terminal Units (RTUs) and IEDs; modern technology has surpassed the networking capabilities these standards were originally designed for. MODBUS and DNP3 are classed as tag-based protocols, where users access data by specifying a tag number [24, 31]. IEC61850 presents a common naming convention which removes the mapping processes of unknown tags and allocates them into specific power system functions. From a SCADA perspective, the IEC61850 is a true, high-speed, robust and interoperable protocol [6, 37].

2.4 Types of Devices Connections within OSI Network Model

The Data Link layer provides specific data frames between the Physical and the Network layers. There are two commonly used data link connections to establish communication between layered devices: direct and multi-drop connections [1].

2.4.1.1 *Direct Connect*

The direct connection is used to interconnect only two devices together by a network media including copper, wireless or fibre whereas in direct connect each device is able to manage its connection and communicate with the other end constantly. This enables IEDs, using several individual direct connections, to communicate at the same time. The direct connect initiated star network topology where several devices are connected to only one device as an origin device or network controller (Fig. 2.4). Most of the open architecture protocols support star connection. One of the advantages of star network topology is that it is a simple network connection and it allows many IEDs from different vendors to be connected to the network.

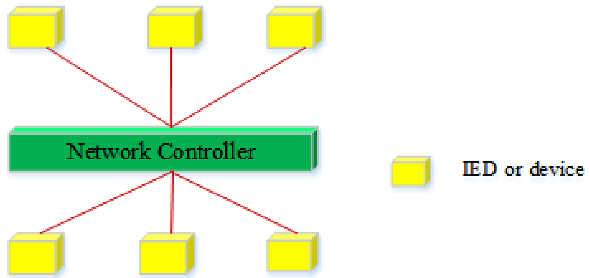


Fig. 2.4 Star network topology [1]

2.4.1.2 *Multi-drop Connect*

Multi-drop connection is also a common and robust type of data link connection model [1]. It allows multiple devices to be physically connected together through a ring or bus network topologies (Figures 2.6 and 2.7) [1]. In this kind of connection, only one device is able to communicate at a time. Therefore, peer-to-peer communication is not guaranteed in this type of connection [1, 38].

In the multi-drop connection, tagging and addressing devices are very essential. they enable devices to be recognised by the destination and the source of the data being exchanged [38].

Due to the complexity with the structure of the multi-drop connection, trouble shooting is a substantial challenge [38]. This is because in order to find the root of the problem in the network, messages from all sources need to be captured and analysed. In contrast, trouble shooting in direct connection can be easily executed by utilising indicators such as LEDs [38, 39]. Another drawback of the multi-drop connection is the possibility of failing entire communication system because of failing the network controller which is the source of controlling of data transmission [27, 39]. The nature of the network controller is determined by the topology of Ethernet Local Area Networks (LANs). The design of LAN is mainly dependant on a network topology selected. In the context of the communication network, the term ‘topology’ refers to the way the work-stations are interconnected with each other.

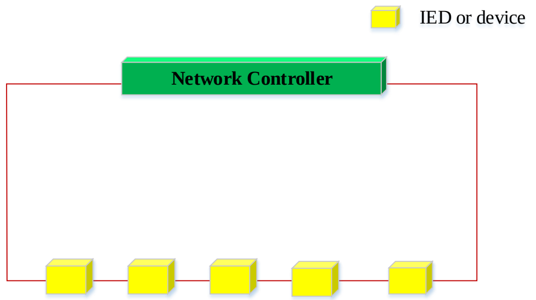


Fig. 2.6 Ring connection topology

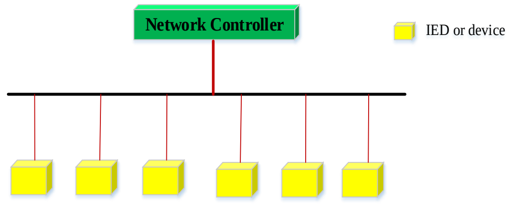


Fig. 2.5 Bus connection topology

In a bus network connection, a controller as a network Master is located in a control centre to control the communication between IEDs. It provides authorisation commands to IEDs to share the information together. An IED can only communicate when it detects the virtual token and passes the token when it is finished. The most important advantage of a bus network model through multi-drop connection is the possibility of achieving peer-to-peer communication between devices [1].

The benefit of the ring is that fault isolation and fault recovery are simpler than for the bus topology. Therefore, the ring topology is considered to be the most reliable topology. However, time delay for message transmission is almost same as bus topology, and hence this topology may not be suitable for time critical messages [1].

2.4.2 Star Ring Network Topology

Star ring network topology is a combination of star and ring network topology taken from direct and multi-drop connections respectively [1]. The advantage of star ring network topology is its capability for redundancy. It provides some level of redundancy if any of the ring connections should fail [40]. Normally, Ethernet switches do not support “loops” since messages would circulate indefinitely in a loop and eventually eat up all of the available bandwidth. However, ‘managed’ switches (i.e. those with a management processor inside) take into consideration the potential for loops and implement an algorithm called the Rapid Spanning Tree Protocol which is defined in the IEEE 802.1w Standard [1, 40]. This protocol allows switches to detect loops and internally block messages from circulating in the loop and also allows reconfiguration of the network during communication network fault within a sub-second. The star ring topology has the capacity to provide time delay within an acceptable scale and also offers more reliability compared to bus and ring topology. However, it is overpriced and complex to build and maintain compared to other topologies [1].

2.5 Conclusion

The developments of the Modbus and DNP3 protocols have been considerable an accomplishment for communication applications. However, due to convoluted structure used by these protocols, configuration of an interoperable system in a multi-vendor environment was an irresistible time consuming procedure. Furthermore, since they were unable to fully warrant different vendor IEDs to communicate with one another, the IEC61850 was introduced as an international standard for substation automation systems.

It has been a matter of course that the IEC61850 Standard is the first and ubiquitous international standard to warrant all communication requirements within SASs. The IEC61850 provides full interoperability and interchangeability capability between intelligent devices, regardless of their manufacturer. The IEC61850 has the capacity to co-operate with existing conventional protocols (i.e. Modbus or DNP3) given that Ethernet switches support both fibre and copper interconnections. The standard makes use of cost-effective GOOSE messaging technology to replace the traditional copper wiring.

Chapter 3 - IEC61850 and GOOSE Messaging

3.1 Introduction

The purpose of this chapter is to describe the fundamentals of the IEC61850 Standard. In particular, it will cover the GOOSE messaging technology and interoperability in a multi-vendor substation environment. The concept of GOOSE isolation for IEC61850-based device testing purposes is outlined. The chapter also addresses the difficulties that engineers may encounter in IEC61850-based substations systems in terms of device configuration, testing and maintenance.

3.2 IEC61850: a Lingua Franca for Substation Automation

In direct response to a lack of communication standards in Substation Automation Systems (SAS), the International Electro-technical Committee (IEC) was established in 1964 to remodel and advance the existing protocols [8]. At the same time IEEE was working on a similar project called Utility Communication Architecture (UCA). However, in 1997, both IEEE and IEC agreed to work together to create an international protocol as a Lingua Franca for substation automation systems [7, 41]. Therefore, the IEC61850 was introduced in 2004 as an international standard which incorporates the use of logical nodes to resolve problems related to interoperability and interchange ability [6]. The standard does not direct entire individual implementations and system particular functionalities. It instead focuses on the visible specifications of both primary and secondary equipment. The Second Edition of the IEC61850 Standard is published in 2014 which is encapsulated in a series of 20 documents spanning over ten parts as shown in Table 3.1 [6, 7, 11].

Table 3.1 IEC61850 Arrangement [6, 7]

Part	Content
1	**Introduction and overview:** Summary of the IEC61850 protocol using texts and figures from other parts of the standard.
2	**Glossary:** Collection of specific terminologies and definitions from other standards and terms defined in different parts of the IEC61850 protocol.
3	**General Requirements:** Basics of the IEC61850 protocol such as system availability, maintainability, reliability, security and more.
4	**System and Project Management**: Challenges in substation automation systems such as parameter classification, tools, documentation, factory tests, quality assurance responsibilities and system tests.
5	**Communication Requirements for Function and Device Models:** Communication requirements related to function and device models such as interoperability, logical nodes (LN) and piece of information for communication (PICOM).
6	**Substation Automation System Configuration Language:** Substation configuration language (SCL) based on XML file format.
7	**Basic Communication Structure For Substation and Feeder Equipment:** This part is divided into four subsections that define the details of the abstract model used in the IEC61850 to meet the requirements of all functions and applications in the substation and automation domain.
7-1	**Principles and Models:** Concepts of communication modelling.
7-2	**Abstract Communication Service Interface:** Models and services required by substation automation and protection systems.
7-3	**Common Data Classes:** Common data classes (CDC) necessary to implement the concepts of the hierarchical object model.
7-4	**Compatible Logical Mode Classes and Data Classes:** 92 logical node classes associated with basic substation functions.
7-5	**Technical Report:** Explain the Use of Logical Nodes to model functions of a specific domain
8	**Specific Communication Service Mapping (SCSM):** Mapping of abstract models to selected MMS and ISO/IEC 8802-3 protocol.
8-1	**Guideline For Mapping From IEC 61850 To IEC 60870-5-101/-104 (Technical Specification)**
9	**Process Bus Mapping:** This part is divided into two subsections that define different implementations of the IEC61850 Process Bus.
9-1	**Sample Values Over Serial Uni-directional Multi-Drop Point-To-Point Links:** Mapping of core elements from the model for transmission of sampled measured values in a point-to-point link.
9-2	**Sampled Values Over ISO/IEC 8002-3:** Mapping of the complete model for transmission of sampled measured values and the model for Generic Object Oriented System Events (GOOSE).
9-4	**Technical Report:** Use of IEC 61850 for monitoring of power equipment
9-5	**Technical Report:** Use of IEC 61850 for transmitting synchrophasor information according to IEEE C37.118.
10	**Conformance Testing:** Procedures for conformance testing of IEC61850 compliant devices such as documentation, device related conformance testing, validation of test equipment, and quality assurance.

3.2.1 IEC61850-based Substations' Architecture

IEC61850 has made use of the hierarchal substation automation structure to develop three levels namely: Enterprise or Station level, Bay level and Process level (Fig. 3.1).

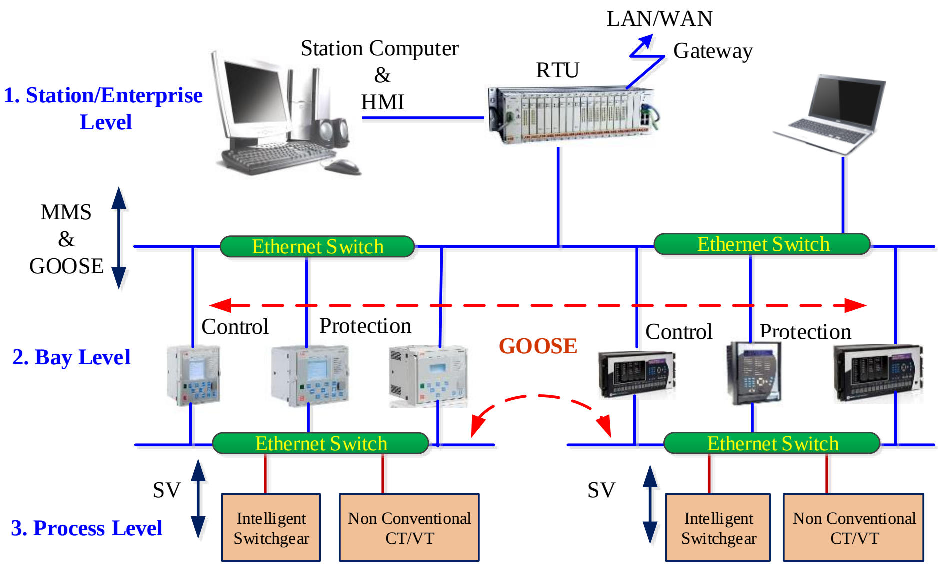


Fig. 3.1 Architecture of an IEC61850-based substation [11]

3.2.1.1 *Station Level*

Station level is used for the archiving, automation, data storage and management of countless Bay level devices through the use of dedicated software tools. The hardware necessary to carry out such tasks is sheltered in a separate room away from all switchgear equipment. The Station level allocates HMI computers, printers, modems, GPS receivers and Ethernet switches. The large storage capacity provided by these peripherals allow significant amounts of data files to be stored in real-time databases. These databases are continuously updated through Station level modems, which act as a communications gateway to the Network Control Centre (NCC). The modems require physical coupling of Wide Area Networks (WAN), but also demand the presence of protocol converters capable of decoding incoming software commands [6, 11].

3.2.1.2 *The Bay Level*

The Bay level connects a wide range of control and protections IEDs using Station level Ethernet switches. The serial connections of these devices isolate various substation objects (i.e. lines and transformers) from the rest of the substation. These digitally manufactured IEDs have in-built LCD screens, push buttons and LEDs for the indication of measured data [6, 11]. Depending on the communication commands received from the Station level, these IEDs are capable of performing functions such as bay control, bay protection, bay monitoring and fault recording. All Bay level automation systems are housed in stand-alone kiosks away from primary and secondary switchgear equipment [6, 11].

3.2.1.3 *The Process Level*

The Process level interlinks all primary and secondary switchgear equipment together with the substation automation systems located in the Bay level kiosks. A large quantity of serial communication links are essential to carry out such manipulation, especially when connecting countless number of actuators, sensors, voltage transformers (VTs) and Resistance Thermal Detectors (RTDs). The use of equipment that utilises both input and output (I/O) terminals is a clever way to reduce hardwiring in the Process level [6].

3.2.2 IEC61850 Components and Labelling

IEC61850 incorporates the use of sophisticated object model abstracts to achieve interoperability between devices from different vendors [6, 42]. The Server is connected to a physical device in which, a logical device is operating. Inside the logical device, there are different logical nodes [7]. Figure 3.2 illustrates the order of locating objects under Server.

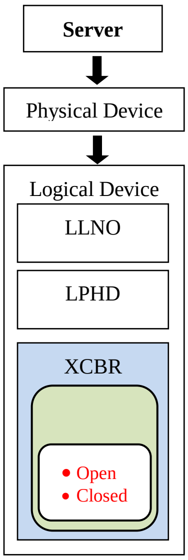


Fig. 3.2 Labelling of a circuit breaker according to IEC61850 [42]

3.2.2.1 *Server*

The Server represents the visible behaviour of a device using the network, such as the Ethernet or any other network systems, as well as the devices along with their functions.

A Server communicates with a Client (most service models in IEC61850 provide communication with Client devices) and sends information to peer devices [43].

3.2.2.2 *Physical device*

The physical device is defined as a communication media which connects the Server to logical devices such as the network, Ethernet or any other network. One physical device may have multiple Logical Devices working within it.

3.2.2.3 *Logical nodes*

The logical nod (LN) is an important object in the context of the IEC 61850 Standard. LNs are a virtual representation of the fundamental functions within a SAS and work as predefined groupings of data objects that serve specific functions (Table 3.2) [34].

Table 3.2 Categorising Logical Nodes

Logical Node Groups	Groups Designations	Logical Node Groups	Groups Designations
System LN	L	Metering	M
Protection	P	Control	C
Generic	G	Switchgear	X
Protection Related	R	Instrument transformers	T
Automatic Control	A	Power transformers	Y
Sensor and monitoring	S	Power system equipment	Z

LNs can be used as “bricks” to build the complete device as a simulation. Some examples of LNs include: the MMXU, which provides all electrical measurements in 3-phase systems (voltage, current, watts, vars, power factor, etc.) and the XCBR for the short circuit breaking capability of a circuit breaker (Table 3.3) [6]. LNs are described in details in Clause 5 of IEC 61850-7-4 [44, 45].

Table 3.3 Example of Logical Nodes used in IEC61850-based substations

LN Classes	**Description**	**LN Classes**	**Description**
XSWI	Circuit Switch	XCBR	Circuit breaker
MMTR	Metering	YPTR	Power transformer
RBRF	Breaker failure	MMXU	Measurement unit
PDIS	Distance protection	GGIO	Generic logical node
PDIF	Differential protection	PTOC	Time Overcurrent Protection

3.2.2.4 *Logical Devices*

The logical device (LD) model is composed of the relevant logical nodes required to provide the information necessary for a particular device. A LD presents functions that are to be performed by a physical device. For example, a circuit breaker could be composed of the following logical nodes: XCBR, XSWI, CPOW, CSWI, and SMIG. Logical devices are not defined in any of the documents due to the different products, implementations and combinations of logical nodes for the same logical device [45].

3.2.2.5 *Data objects or Data Classes*

Data objects (DOs) are predefined names of objects associated with one or more logical nodes. They are listed only within the logical nodes. Table 3.4 represents the data objects and their functionality in IEC61850-based substations [11].

Table 3.4 Different Types of Data Objects Imitated by IEC61850 [46]

Description	**Data objects Name**
Starting of a logical node	Str
Operation of a logical	Op
Trip activation	Tr
Switch position	Pos
Local operation	Loc
Status information	BlkCls
Phase to ground amps	A
Angle between phase current and voltage	Ang

3.2.2.6 *Data Attributes*

Data attributes are also predefined common attributes that can be reused by many different objects, such as the quality (q), general (General), status value (StVal) attributes. These common attributes are defined in Clause 6 of IEC 61850-7-3 [45].

3.2.2.7 *Standard data type*

Standard data type includes a wide variety of parameters such as Boolean, Coded Enum, integer, Bit String and floating point which are tabulated in table 3.5.

Table 3.5 Example of Two Data Type Used For CB in IEC61850 [11]

Enum Value	**Bit Pairs**	**Usual Meaning**
0	0 0	Transition
1	0 1	False or Open
2	1 0	True or Closed
3	1 1	Invalid

Accordingly, the practical example circuit breaker labelling in IEC61850 for feeder Bay A1 is shown in Figure 3.3.

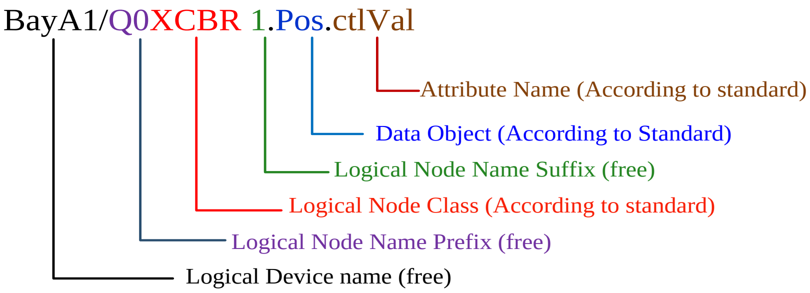


Fig. 3.3 Example of labelling of a circuit breaker in IEC61850 [11, 46]

3.3 Interoperability and SCL language

3.3.1 Substation Configuration Language (SCL)

Prior to the standardization of the IEC61850 protocol, it was impossible for different vendor IEDs to communicate with one another [1, 4, 6]. The reason behind this was that manufacturers purposely designed their products using their own proprietary tools, meaning customers had to favour one vendor more than another. In doing so, manufacturers practically configured their products in such a way that if one piece of equipment failed, then all or some accompanying devices required replacement. This was a major downfall for substations as a great deal of worthwhile international standard equipment which was rather expensive needed to be stockpiled [6].

IEC61850-6 introduces XML-based Substation Configuration Language (SCL) as a common language to accomplish interoperability between devices [7, 47]. Accordingly different form files using the common based language are brought together in part 6 of the IEC61850 standard. These files are as follows [7, 47, 48]:

- Description of Configured IED (CID)
- Capability Description of IED (ICD)
- Instantiated IED Description (IID)
- Description of System Exchange (SED)
- Description of Substation Configuration (SCD)
- System Specification Description (SSD)

The development process of an IEC61850-based project is subject to the accessibility of software tools that make use of these files in the process of IEC61850 devices configuration [7]. Two core steps need to be considered in the process of configuring

IEC61850 devices. These steps are known as "individual IED configuration" and "system configuration". For the individual IED configuration each vendor has its own proprietary tools to configure its IEDs. However, due to a wide variety of available vendor tools, being familiar with these configuration tools is a significant challenge for engineers and technicians [7, 35, 44].

In order to configure the IEC61850-based IEDs, the ICD file of an IED needs to be imported into the vendor proprietary tool to be programmed. After programming individual IEDs, multi-vendor substation configurator software is be used to create the System Configuration Description (SCD). The SCD file contains the GOOSE configuration and the mapping of IEDs [46]. However, due to the complexity of SCL language and SCD files, the lack of knowledge about SCL language structure and IEC61850 GOOSE messaging has caused substantial challenges for engineers and technicians in IEC61850-based substations. Figure 3.4 shows an example of IEC 61850 device configuration process [7, 11].

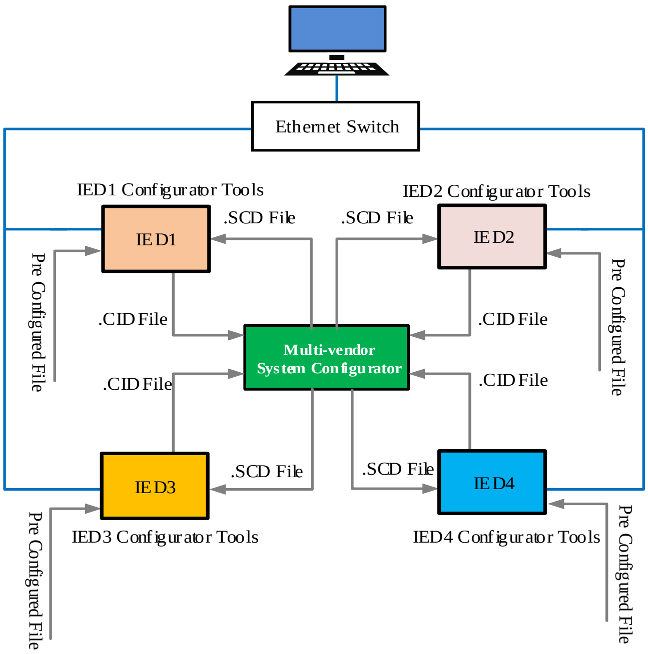


Fig. 3.4 Flow of individual IED and system configuration [7]

A further problem arises due to the version of software used for IED configuration and correspondingly for SCL language. For instance, in terms of IED replacement, if a CID file of an old IED is configured using an old version of the vendor proprietary tool, then that CID file will not be imported into the new IED using a new version of configurator tools. For instance, if an ABB relay was configured using PCM600 Version 2.4 as a configuration tool, the new IED will not accept the import of that CID file using a new version of configuration tools such as PCM600 version 2.6 [7, 11].

Moreover, most engineers and protection technicians are still unfamiliar with the IEC61850 Standard from the technical point of view such as IED testing in a multi-vendor IED environment substation. Vendors use their own proprietary tools to configure IED and they use their particular configuration tools to create SCL file and CID files. For example ABB uses PCM600 for IED configuration and IET600 for SCL language or GOOSE mapping, whereas, SEL IEDs need to be configured by their proprietary tools called Acselerator Quickset [49, 50]. This creates a problem when an IED needs to be tested in a live substation. Engineers are required to have comprehensive knowledge of all configurator tools.

Last but not the least challenge is related to the GOOSE isolation method in terms of IED testing. When simulating a fault for a particular IED under test, it is not desirable for other IEDs in the system to react and therefore there is a need for isolation [9, 11, 17]. IEC61850-8-1 defines a test mode for GOOSE isolation purposes by setting one bit of the data attributes of GOOSE quality in the test mode [11, 17]. This is known as "putting a flag on the IED" to show the IED subscribing or publishing a message is under test (Fig. 3.5). In this way other IEDs which are subscribing to the IED under test will ignore any command that is coming from that IED.

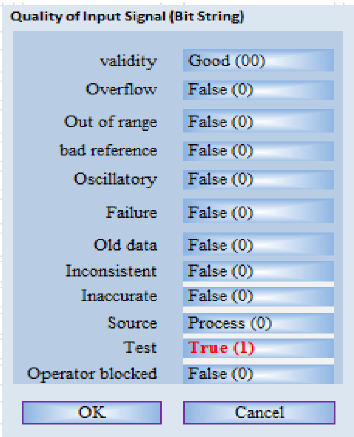


Fig. 3.5 Data attributes of a quality bit of GoCB [7]

3.4 GOOSE Messaging in IEC61850-based Substations

The GOOSE message is the most important and beneficial feature of the IEC61850 Standard [12]. The GOOSE is a time critical message which is directly mapped onto the Ethernet, to make it fast and efficient. GOOSE works on a publisher/subscriber model, which means that the devices that have subscribed for this service can send and publish it as well (Fig. 3.6) [7, 11].

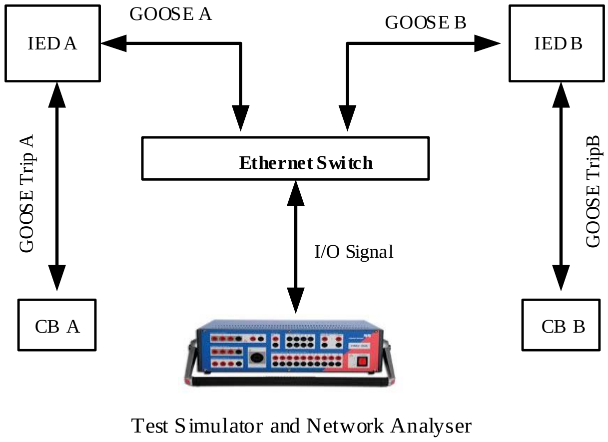


Fig. 3.6 Peer-to-peer communication between IEDs via GOOSE messaging [7]

Although GOOSE is already used in the UCA protocol, the IEC61850 GOOSE is a more advanced version of the UCA GOOSE message. The additional features are as follows [11, 16, 42]:

- High level of flexibility;
- Capability of either publishing or subscribing multiple messages from one IED;
- Containing much more data attribute types (Boolean, BitString, Coded Enum, Integer, floating, etc.);
- Exchange of data is much faster;
- Usage in protection and control;
- Messages are published by multicasting on the network;
- IEDs subscribe (or listen) to selected multicast messages;
- Messages are sent or published periodically (heartbeat or maximum transmission time of 60s, 10s, 1s, etc.) under normal conditions; and
- Messages are sent multiple times when an event occurs, following a transmission pattern until the maximum time is reached or until another event occurs.

IEC61850-8-1 defines the mapping and its syntax to manage a GOOSE message [6, 51]. A separate function block called GoCB (GOOSE Control Block) is introduced in IEC 61850. This block is a part of LLN0 (Logical Node of any Logical Device). This block holds different attributes which are defined in the standard [7, 46, 47]. A GOOSE message contains a GOOSE Control Block, Control Block Reference, Data Set Reference, GOOSE ID and communication details. In data reference, the dataset members or items which contain status information are defined such as relay trip, breaker status, quality, timestamp and etc. (Table 3.6) [7, 8].

Table 3.6 Components of GoCB [51]

Attribute Name	Attribute Type	FC	Value/value range/explanation
GoCBName	ObjectName	GO	Instance name of an instance of GoCB
GoCBRef	ObjectReference	GO	Path-name of an instance of GoCB
AppID	VISIBLE STRING65	GO	Attribute that allows a user to assign a system unique identification for the application that is issuing the GOOSE. Default GoCBRef
GoEna	BOOLEAN	GO	Enabled (TRUE) | disabled (FALSE)
DatSet	ObjectReference	GO	
ConfRev	INT32U	GO	
NdsCom	BOOLEAN	GO	
Services Send GOOSE Message Get Go Reference Get GOOSE Element Number Get GoCB Values Set GoCB Values			

3.5 Device Testing in IEC61850-based Substation Protection Systems

When dealing with IEC61850-based substation systems and their devices, there are two types of testing categorized according to the systems specification and testing purposes known as: Product Testing and Systems Testing. While the product testing involves all testing related to the devices and their functionality based on their technical specifications, such as Device Acceptance Testing; Device Interoperability Testing, Integration Testing and Factory Acceptance Testing, the Systems Testing includes all functionality and performance testing related to the configured IEC61850-based substation system and their compliance with the standard such as Commission Testing, Conformance testing, Site Acceptance Testing, and Maintenance Testing [9, 11, 17, 52].

3.5.1 Device Acceptance Test

The first step to validate the correct behaviour of a new device before being used in substation protection, automation and control system is known as a Device Acceptance Test (DAT) [9, 11]. This test ensures that the device truly meets all technical descriptions listed in the device documentation that are of interest to the user. In other words, DAT is a prerequisite for making the product acceptable for use in the protection scheme. Since the DAT is a laboratory based experiment, it essentially needs to be designed based on a number of test scenarios that, as practically as possible, emulate the user's substation environment.

3.5.2 Conformance Test

Manufacturers of IEDs are required to prove that their devices are capable of complying with the IEC61850 Standard mechanism [53]. Therefore the conformance testing is a laboratory based experiment to assure the user of a device that the device will meet the requirement of the IEC61850 Standard [11].

3.5.3 Device Interoperability Test

One of the foremost objectives of the IEC 61850 Standard is to achieve interoperability between different vendors' devices. In a peer to peer communication based platform, device interoperability test ensures that the device exchanges data correctly with other vendor's devices [9, 11, 17]. The interoperability test has been performed repeatedly to prove the correct behaviour of any device as an integrated part of a multi-vendor system. From the point of the requirement for virtual isolation, the majority parts of the device interoperability test needs to be performed under the normal operating condition and isolation is not required [11, 17]. However, there is an exception, when the capabilities of IEDs working together as a protection scheme need to be tested. In this case, the virtual isolation is required which will be discussed later on in this chapter.

3.5.4 System Integration Test

Besides the interoperability capability between devices, their performances need to be compliant with the protection system development requirement. Whilst the interoperability test ascertains that the IEDs communicate with each other, the integration test functions one phase further and verifies that they talk fast and efficiently enough. There is no need for virtual isolation during integration testing [9, 11].

3.5.5 Factory Acceptance Test

Another important customer agreed test is the Factory Acceptance Test (FAT) [11, 14]. It is an agreement between the final user and the system integrator to detect any possible potential problems existing in a device in an earlier stage of the project, when they are less costly and complicated to fix. Since during the factory acceptance test not all components of the system are available, the test system is required to be capable of simulating any device missing from the actual protection scheme.

Moreover, in a FAT all existing components of the system are required to be configured and programmed subject to the requirements of the real system application. Therefore, the configuration of all devices which are designed for the project in SCD files format needs to be available [11]. FAT is a laboratory based experiment and there is no need to use any isolation test on IEDs at this stage.

3.5.6 Commissioning Test

When the components of a designed application are properly configured and commissioned, the commissioning test needs to be performed to prove that the devices are configured appropriately, according to the requirement of the application [52]. Thus, for a commissioning test, all functional elements used for protection and control of the equipment are expected to be operating under normal condition. Consequently, there is no need for virtual isolation during the commissioning test [11].

3.5.7 Maintenance Test

In order to maintain a substation protection under normal operating conditions, and keep it up-to-date in response to the latest requirement of the industry standard, periodical maintenance testing needs to be performed. Its goals are therefore to detect and diagnose equipment problems, or to confirm whether all required actions taken to modify configuration, replace, repair or upgrade protection devices or other components of the fault clearing scheme, have been effective or not. The maintenance could be divided into two sub-categories [9, 11]:

3.5.7.1 *Scheduled Maintenance Test*

Scheduled Maintenance TEST is a part of the “Site Maintenance Proposed Plan” performed periodically to prove that the protection system and their devices meet all the requirements of the system. Moreover it examines whether all individual components work under normal conditions and in compliance with the configuration of the protection scheme. In IEC61850-based substations, a broad collection of monitoring function exists due to multi-functional protection devices such as IEDs. Equipment failure or human errors cause irreparable damages to the system and other equipment. Therefore, the scheduled maintenance test is highly crucial and recommended to be performed periodically to reduce any possible risks.

3.5.7.2 *Maintenance Test Due to Abnormal Protection System Performance*

This test is required when a device or its operation in the system are detected faulty: viz. in the context of fault detecting and clearing schemes, if a device operates when it is not supposed to, or it does not operate when is required. Therefore, the faulty device needs to be tested to identify the problem associated with it and to take effective action to stop any additional damage to the rest of the system. After resolving the device problems, different types of testing described earlier such as acceptance testing, interoperability testing and conformance testing are performed.

3.6 IED Isolation for Test Purposes (Virtual Isolation)

While acceptance and interoperability tests are laboratory based experiments and they do not require virtual isolation during testing, the maintenance test needs virtual isolation when the device or its functional elements are under the test in an energized substation. There are different levels of isolation for IEC61850-based substation devices based on the following testing objectives [9, 11, 17, 52]:

- Function element testing;
- Sub-function or function testing;
- Whole IED testing.

Therefore, the level of virtual isolation varies according to the objectives of the test. For instance, if a protection function such as PTOC (Overcurrent Protection) needs to be tested this test is categorized under the “isolation of sub-function or function testing”. Therefore, only PTOC function is required to be virtually isolated from the protection system. Correspondingly for whole IED testing, the complete IED should be isolated from energized substation.

The aforementioned isolation levels are not only required for consideration when a test plan is developed for a zone substation system, but the specific capability of the system to control and monitor the mode and behaviour of different functional elements is essential. This is only achievable in IEC61850-based substations that did not exist in traditional substation’s devices.

Edition 1 of IEC61850 mentioned a number of features to be used for testing of IEC 61850 devices. These features covered the possibility of setting [9, 11]:

- a mode of a function of logical node (LLN0) in TEST mode
- TEST flag on the quality of a particular data attribute that is being sent from a Server to other devices
- a GOOSE message as a TEST message being published for test purposes
- a control command in a TEST mode when it is being sent to other devices

Since Edition 1 did not explain in detail how to implement the above mentioned possible testing features, each vendor has put into operation its own proprietary tools and engineering methods to achieve test objectives [7, 11]. As a consequence, interoperability issues have been raised between vendors from the point of testing IEC61850-based substation devices. These problems are not only addressed and improved in Edition 2 of IEC61850, but also additional features and detailed specifications are added to the standard which enables engineers and utilities to achieve a seamless solution [7, 11]. These new features are as follows:

3.6.1 Using Test Flag for the Input Signal and/or Logical Node

3.6.1.1 *Normal Operating Condition*

a. The input signal[3] is set to FALSE for its Test mode and the Test mode of the logical node (LLN0) within physical device (IED) is FALSE [9, 11]

This is the normal maintenance testing of equipment located both primary and secondary side of the substation. The purpose of this scenario is to examine the operation of the devices such as IED and its circuit breaker under normal condition. This test executes all operating commands and functions designed in test scenario. This state represents the normal operation condition of the protection system (Fig 3.7 and Table 3.7) [9, 11, 17, 52]. However, this test is hardly exercised in a substation due to any possible interruption may occur to the zone substation. It only happens when there is really fault in the substation or transmission lines.

[3] In IEC61850-based substation systems, devices are operated through either control service command or by GOOSE signal which are subscribed to. For simplicity therefore, instead of using both GOOSE and control service command, the term “input signal” is used in this chapter.

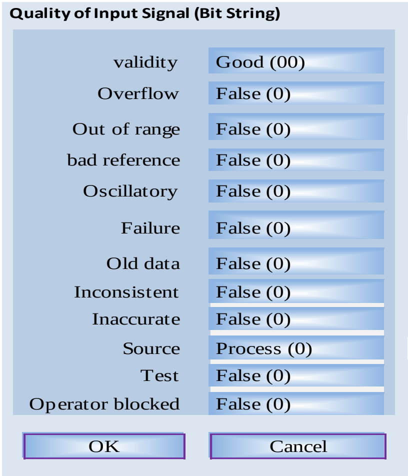


Fig. 3.7 TEST bit is set to False [7, 11]

b. The TEST flag of the input signal is set to FALSE and the IED is set to TEST mode [9, 11]

When an IED is being tested; any interruption and unnecessary reaction in substation should be eliminated. Therefore, in order to make the IED under test to discard and bypass all live GOOSE messages coming from the other IEDs without any response, the IED needs to be set in a TEST mode (Table I).

c. *The Input signal is set to TEST flag, whereas the TEST mode of the logical node is set to FALSE [9, 11]*

If the TEST mode of the input signal is set to FALSE and the TEST mode of logical node (LLN0) within physical device (IED) is set TRUE, then the receiving command will not be accepted, the IED receives the GOOSE signal from other IEDs and ignores that (Fig. 3 8).

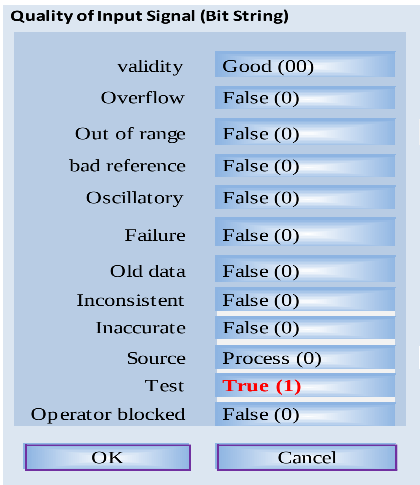


Fig. 3.8 IED under test publishes GOOSE with TEST flag [7, 11]

This scenario is used when other IEDs are operating in energized substation, under normal condition, and are required to discard the signal with a TEST flag coming from IEDs under test. For instance, when an IED needs to be replaced or upgraded, all signals publishing from that IED must be set in TEST mode. This means the other IEDs and devices do not react to its messages and ignore them (Table 3.7).

As Figure 3.9 depicts, the IED (C) is under test and it publishes a GOOSE signal (GOOSE C) with TEST flag. At the same time the modes of the IED (A) and IED (B) are ON which means that the IED (A) and IED (B) are working in normal condition, and they discard the GOOSE coming from IED (C). Similarly, because the function of the IED (C) is set to TEST mode, it will discard the GOOSE B coming from the IED (B).

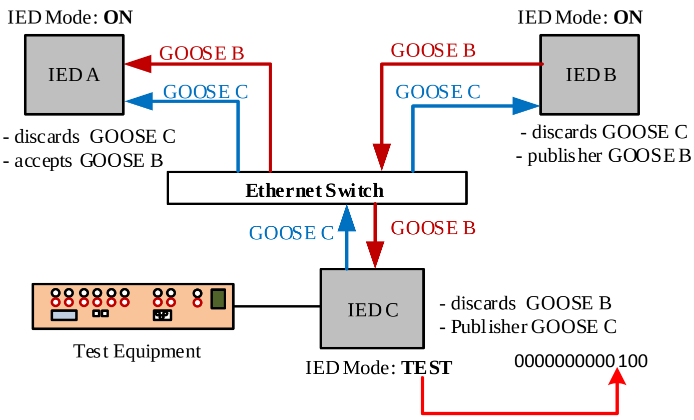


Fig. 3.9 Reaction from IEDs for a GOOSE signal with TEST flag [11]

d. Both input signal and logical node (LLN0) within physical device (IED) are set to TEST mode [9, 11, 17]

This scenario is used for maintenance test purposes without having any reaction from primary side equipment. All Bay level and Process level devices are required to be tested periodically to make sure that they fulfil the requirement of the protection system. When an IED is set to TEST mode, and an input signal with a flag test TRUE is injected to IED, it is expected the IED and other contributing testing devices operate as if there is a real fault in the system. It means the command will be executed, and a wired output will be initiated. Consequently the breakers will be energized. This state obviously is a complete and comprehensive testing process, which could be performed on both bay and Process levels devices, in an energized substation (Table 3.7).

e. The test bit of input signal is set TRUE, and the logical node is set to "TEST-BLOCKED" mode [9, 11, 17]

The mode "TEST-BLOCKED" is the feature initiated in Edition 2 of the IEC61850 Standard. It is effectively practical when performing a test in an energized substation without any intention of having a real reaction in the process bus. When the input signal has the test flag TRUE and a logical node of a physical device is set to TEST-BLOCK, the command will be processed and all the reactions (e.g. sending and receiving command confirmation, time stamp) will be generated. However, the wired output will not send any command to the Process level devices such as breakers. To set an example, when an IED is replaced, changed or upgraded, its performance needs to be verified over the substation. It should prove that its new configuration and firmware complies with the original requirement of the whole system, and it is capable of interoperating with other IEDs in a live substation [11].

Table 3.7 IED Protection and Control Modes for Test Purposes [11]

TEST Quality of Input Signal	Test Mode of Logical Device	Test Mode of Logical Node	Command Execution	Wired Output
FALSE	ON	ON	√	√ (normal condition, it will trip if fault occure)
FALSE	TEST	TEST	×	×
TRUE	ON	ON	×	×
TRUE	TEST	TEST	√	√
TRUE	TEST	TEST-BLOCK	√	×

3.6.2 GOOSE and Sampled Value Messages Simulation

The possibility of subscribing physical devices, such as IEDs to simulated messages (GOOSE and Sampled Value) are sent from test equipment, is another important feature which is addressed in Edition 2 of the IEC61850 Standard [54, 55]. This feature enables test engineers to simulate both GOOSE and Sampled Value messages by test equipment and send them to devices, by putting a flag known as ”Sim Flag”. This indicates whether the messages are original from energized devices or simulated. In order to take advantage of the “Sim flag” mode for messages, the Edition 2 of the IEC61850 Standard added another status called “Sim” mode to the logical node within the physical device to increase the device testing functionality and capability in IEC61850-based substations. If the mode of the logical node (LLN0) is set to “Sim”, it will only accept the message when the GOOSE quality bit is set to simulation mode. If the GOOSE is not flagged as simulated and is original message, the IED flagged to “Sim" mode will discard that message [9, 11, 17, 53].

An example of using the above feature is shown in Figure 3.10. For simplicity, among numerous GOOSE messages published in the network, only two GOOSE messages are chosen namely: GOOSE C and GOOSE D. While GOOSE D is a simulated message being sent from test equipment, GOOSE C is an original message being published in the network from the live IED (C). Figure 3.10 shows that the logical mode of the IED (B) is set to "Sim" mode. Thus, it receives and accepts the simulated message (GOOSE C) coming from test equipment. The IED (A) working under normal condition, and its data object "Sim" mode is set to FALSE. This enables the IED (A) only accepts the original message published from IED (C), GOOSE C, and ignores the simulated message, GOOSE D, coming from test equipment [11]. Therefore, the IED (B) can be tested using simulated message from test equipment without any interruption in the system or causing unnecessary signals to the other devices.

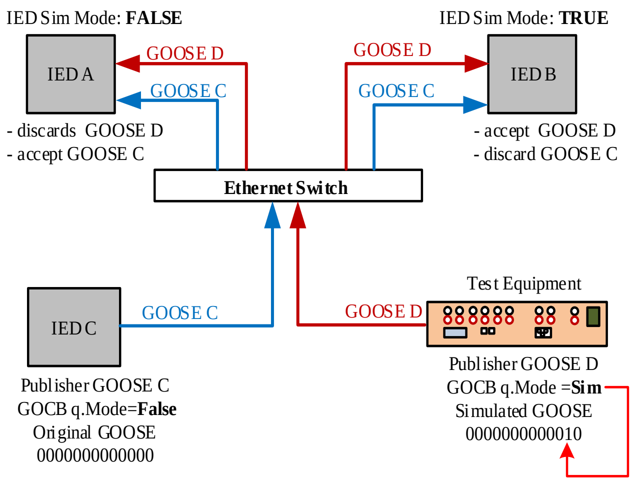


Fig. 3.10 IEDs responses for a simulated message being published from test equipment [11]

3.6.3 Monitoring and Measuring of Control Functions Performance

Another highly crucial characteristic introduced in Edition 2 of the IEC61850 Standard is the possibility of monitoring the control performance of the device under test condition while it is connected to an energized substation [9, 11, 17, 53].

When an IED receives a control command through the input signal, the related data object confirms the receiving of that signal by activating data attribute opRvd. Then, this control command is needed to be accepted and processed. If the device accepts and executes the command, the data attribute opOK will be activated to confirm that the command is processed. At the same time, the data attribute named "tOpOk" will be started to monitor the time stamp of wired output. These data attributes are activated independently of whether the wired output is generated or not. As Figure 3.11 illustrates, the function mode of the circuit breaker switch (CSWI) is set to "TEST-BLOCKED" mode. Thus, the output will not energize the coil of circuit breaker. However, the evaluation of the control function performance could be monitored "using opOk" and "tOpOk" data attributes [9, 11].

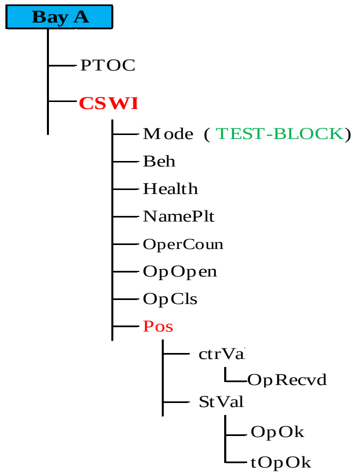


Fig. 3.11 Mirroring of a control block through "ctrVal and stVal" data attributes [11]

3.6.4 An Example of Device Isolation for Maintenance Test

By implementing new features of Edition 2 of the IEC61850 Standard that are already described in this chapter, both partial isolation (isolation of only Bay level devices) and complete isolation (isolation of Bay level and Process level devices) are achievable during the maintenance test [10, 11, 17, 52]. Figure 3.12 shows the schematic diagram of complete isolation steps to be completed in an energised IEC561850-based substation.

In this example, a test unit is used instead of a merging unit to send the sampled value message from Process level. The procedure of devices isolation is approachable as follows [9, 11]:

I. Both Protection and Control function modes of the physical device (LPHD) is set to "TEST" mode. This is the mandatory step of the IED isolation or the IED testing. If the IED is supposed to accept the input signal, this TEST mode makes possible the protection and the control functions of the IED to execute the command.

II. The logical node within the IED for protection purposes, Distance Protection 1(PDIS1) is set to "Sim" mode. The "Sim" mode enables the IED under test to identify, receive and accept only the simulated sampled value message coming from the test equipment. Therefore, as soon as it receives the message, the data attribute called opRcvd will be activated.

III. The input signal will be operated and correspondingly the data attribute “opOk” will be activated.

IV. The logical node for control purpose, Circuit Breaker Switch 2 (CSWI2), is set to “TEST-BLOCK” mode. Therefore the initiated trip function which is

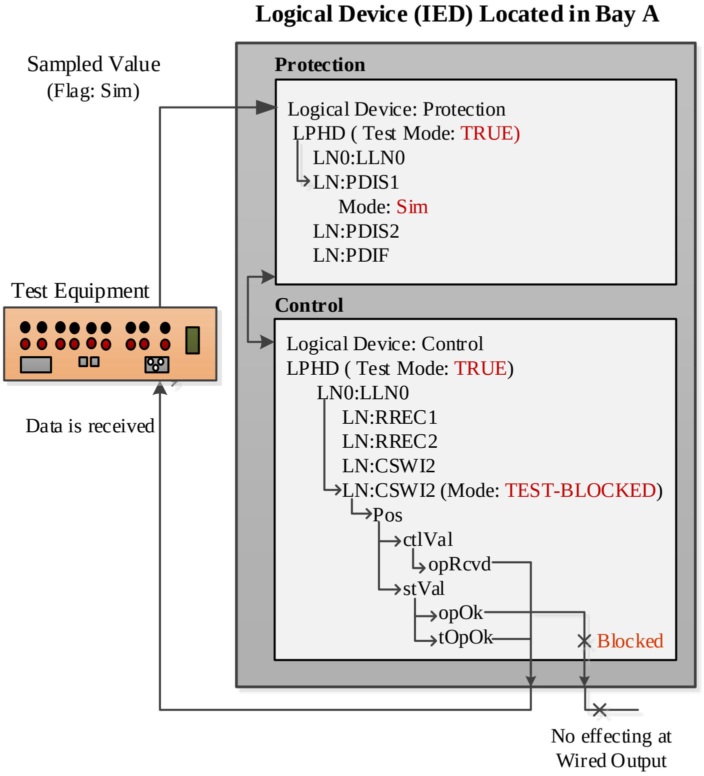


Fig. 3.12 Insight view of device isolation for maintenance test [11, 17]

3.7 Testing Tools and Interoperability Issues

When dealing with virtual isolation for test purposes, there are two steps to be performed: configuring IED for test function -setting IED mode to TEST mode and configuring the test equipment based on the test plan. Therefore, it is clear that both IED and test equipment must comply with the standard requirement [9, 11, 46].

From the perspective of IED configuration for test purposes, there are still considerable challenges facing power utilities due to lack of seamless IED configuration tools. Vendors use their own proprietary tools to configure IED and they use their particular configuration tools to create or modify SCL file and CID files. For example ABB uses PCM600 for IED configuration, whereas, GE IEDs need to be configured by their proprietary tools called “EnerVista”. This creates problems when an IED needs to be set up for testing in a live substation. Engineers are required to have comprehensive knowledge of all configurator tools. A further problem arises due to the version of software used for IED configuration and correspondingly for SCL language. For instance, in terms of IED isolation for replacement purposes, if a CID file of an old IED is configured using an old version of the vendor proprietary tool, then that CID file will not be imported into the new IED using a new version of configurator tools. For instance, if an ABB relay was configured using PCM600 Version 2.4 as a configuration tool, the new IED will not accept the import of that CID file using a new version of configuration tools such as PCM600 version 2.6 [11, 50].

3.8 Conclusion

The IEC61850 protocol is an engineering process capable of achieving interoperability in Substation Automation Systems. The GOOSE messaging is one of the most important achievements of IEC61850 that enables the devices located in the Bay level of IEC61850 substation to transform data for supervision and protection purposes. However, neither owing to lack of understanding of the IEC61850 Standard nor lack of tools, the GOOSE messaging technology and IEC61850 is being abandoned rather than being substituted by traditional substation automation systems. This chapter has tried to show that how the Edition 2 of the IEC61850 Standard addresses these issues and solves problems relating IEC61850 GOOSE messaging and IED isolation. Different approaches are presented in terms of IED isolation for test purposes in an IEC61850-based substation. However, if utilities have already built their substations using devices that are compliant with the first edition of the IEC61850 Standard, there is still a tangible lack of tools to fully take the advantage of the interoperability and the GOOSE messaging technology in their substations.

Chapter 4 - Hardware Installation and Wiring Layout

4.1 Introduction

The objective of this chapter is to provide hardware description and a detailed insight into the wiring layout of the 66/22kV IEC61850-Based Distribution Terminal Zone Substation and the connection diagram between equipment. The Substation Simulator is founded by industry partners namely: ABB, GE Digital Electric, Phoenix, Ticab, Australia Power Institution (API), AusNet Services, Omicron, Doble, Australian Strategic Technology with an overall funding of $1,700,000.00.

The development of the Substation Simulator aims to take advantage of the IEC61850 GOOSE messaging technology for protection, control, monitoring and communication purposes. Hence, the hardwire connections are replaced by cost effective GOOSE signals through optic cables. Copper cables are only deployed to connect circuit breakers to corresponding IEDs. Electrical Engineering AutoCAD software is utilised to draft the single line diagram of the wiring schematic which includes individual device connection, a communication single line diagram, AC wiring, DC Supply and Aux DC wiring.[4]

[4] Design and construction of the 66/22kV Distribution Terminal Zone Substation including hardwire installation and wiring layout are documented in a report over 250 pages. Due to the word limitation, this chapter only provides a synopsis of the most important documents are addressed to make ease for the understanding of the thesis.

4.2 Equipment Details and Hardware Installation[5]

Interoperability and peer-peer-communication in a multi-vendor zone substation environment is much more than simply transferring information between devices [6]. When a device publishes a signal, the subscriber needs to be familiar with syntax and the language structure of the receiving data. This means these two devices need to be interoperable. Therefore, the selection of equipment to be interoperable in an IEC61850-based substation is a complex procedure that requires a high level of protection and communication engineering skills. The 66/22kV Distribution Terminal Zone Substation is modelling a section of an IEC61850-based zone substation system. Two bays with separate 66kV sub transmission lines, 66/22kV step down transformers, 22kV Bus 1 with bus tie circuit breaker and three 22kV feeders per bay have been considered for the simulation. The protection equipment, i.e. CTs, VTs and Protective devices are employed to simulate the Bay level and Process level of the Substation Simulator. Figure 4.1 shows the schematic single line diagram of the system executed according to the current industry standard and utilities requirement.

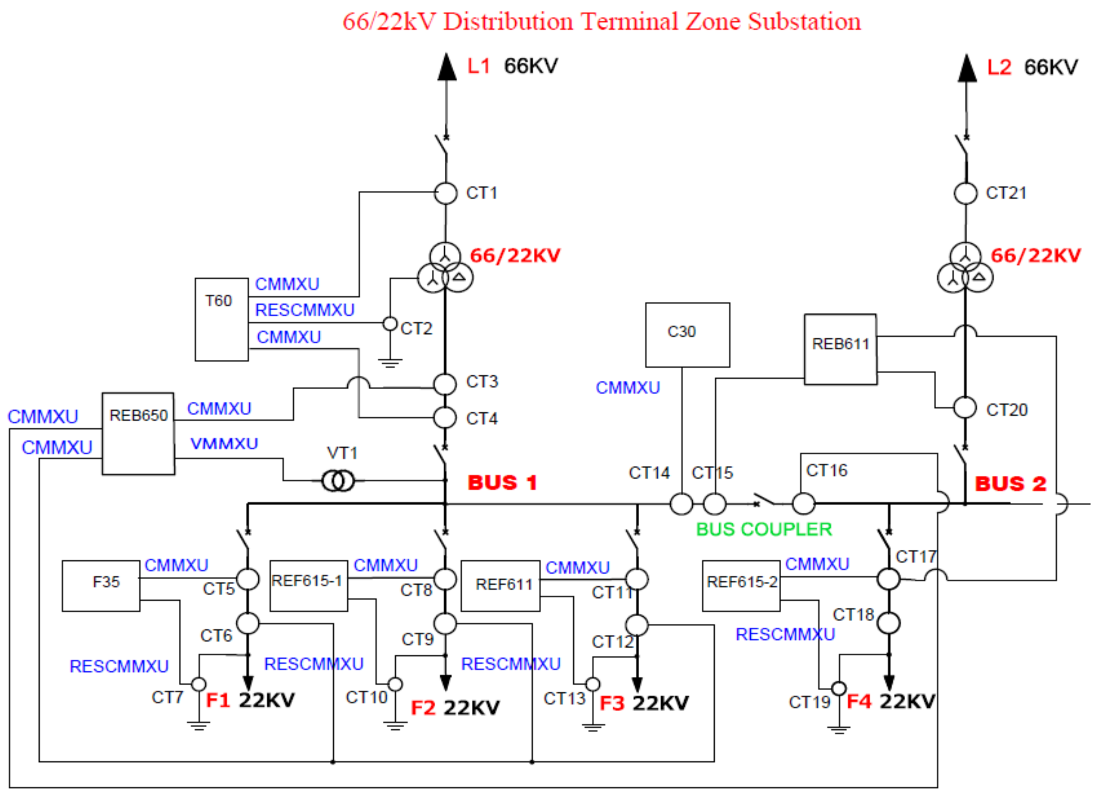


Fig. 4.1 Schematic single line diagram of CTs/VTs of the Substation Simulator

[5] Throughout the establishment of the Distribution Terminal Zone Substation, all OH&S issues and safety hazards as well as technical standards are noted and complied with to ensure no injuries occur for people who are involved in the implementation.

The core of the 66/22kV Distribution Terminal Zone Substation comprises eight protection IEDs (from ABB and GE vendors), DC Power Supply, MCBs, a Managed Ethernet switch, a PLC SLC500 controller and a Citect SCADA system. Table 4.1 provides the specification and details of the equipment used in the Substation Simulator.

Table 4.1 Details of the devices used for 66/22kV Substation Simulator

Device Name	Vendor	Function
RSG2100	Siemens	Managed Ethernet Switch
T60	GE	Transformer Protection IED
REB650	ABB	Busbar Protection*
F35	GE	Feeder Protection System**
REF615-1	ABB	Feeder Protection and Control **
REF611	ABB	Feeder Protection and Control***
C30	GE	Control and Monitoring
REB611	ABB	Busbar Protection and Control***
REF615-2	ABB	Feeder Protection and Control**
SLC500	Allen Bradley	Controller
Citect Vijio	Schneider	SCADA System
CMC356	OMICRON	Test Simulator
Transformer	Voltron	DC Power supply

*Busbar multipurpose differential protection and control

**Non-Directional O/C, Non-directional E/F, voltage & frequency based protection, synchro check and CB condition monitoring

***Non-Directional O/C, Non-directional E/F

An industry standard CMC356 test simulator is utilised to emulate the CTs and VTs of the Substation Simulator. Table 4.2 summarises the lists and allocation of the CTs and VTs, according to the IEC61850 Standard labelling, which are illustrated in Figure 4.2.

Table 4.2 Allocation and functionality of CTs and VTs

Name	Protection Zone	Measurement	IEC61850	ANSI	IEC-60617
CT_1, CT_4	Transformer	3-phase current	CMMXU	I_A, I_B, I_C	3I
CT_2	Transformer	Residual current	RESCMMXU	I_G	Io
VT1	Transformer	3-phase voltage	VMMXU	V_A, V_B, V_C	3U
CT_3, CT_6, CT_9, CT_{12}, CT_{16}	Bus 1	3-phase current	CMMXU	I_A, I_B, I_C	3I
CT_5	Feeder 1	3-phase current	CMMXU	I_A, I_B, I_C	3I
CT_7	Feeder 1	Residual current	RESCMMXU	I_G	Io
CT_8	Feeder 2	3-phase current	CMMXU	I_A, I_B, I_C	3I
CT_{10}	Feeder 2	Residual current	RESCMMXU	I_G	Io
CT_{11}	Feeder 3	3-phase current	CMMXU	I_A, I_B, I_C	3I
CT_{13}	Feeder 3	Residual current	RESCMMXU	I_G	Io
CT_{14}	Bus Coupler	3-phase current	CMMXU	I_A, I_B, I_C	3I

4.2.1 RSG2100

Traditional substations have utilised copper cables to interconnect equipment to each other, whereas in a modern substation, in particular IEC61850-based substations, Ethernet TCP/IP media is used to send and receive data between devices [56]. In the construction of the Substation Simulator, the IEC61850 GOOSE is used for protection, control, monitoring and communication purposes by optic cables connected to an Ethernet switch. In doing that, a Ruggedcom 2100, 12-Port modular Ethernet is used to establish a Virtual Local Area Network (VLAN) to bring all intelligent IP dependant devices under a specific sub network.

Ruggedcom RSG2100 is a popular industry standard fully managed Ethernet switch with: 128-bit encryption; up to 3 gigabit Ethernet ports, either copper and/or fibre; 2 fast Ethernet ports copper, 10 LC/ST fibre port; two port modules for tremendous flexibility; non-blocking, with store and forward switching [57].

Four types of communication ports namely: ST-type glass fibre serial, optical LC Ethernet, galvanic RJ-45 Ethernet and 232 serial connections are used to connect devices to the RSG2100 [57]. All IEDs employed by 66/22kV Distribution Terminal Zone Substation not only support traditional protocols such as IEC60870-5-103, DNP3 and Modbus, but also are fully compliant with the IEC61850 Standard and GOOSE messaging [50, 58-61]. They have already passed the Acceptance and Conformance Test for interoperability and peer-to-peer communication required between multi-vendor devices in an IEC61850-based substation. However, these protocols cannot be in service simultaneously. Activating one of them will disable the connectivity of the other protocols [57].

- RS-232/RS-485 serial connection allows the devices to communicate with each other through Modbus or DNP3 protocol [23, 31]. When RS232 is required to be activated, the baud rate needs to be set to19.2kbps [57].
- The Ethernet-based communication system via the RJ-45 connector (100BASE-TX) enables the operator to directly connect to the IEDs for Web HMI browsing, Individual IED configuration, resetting and/or changing the IED hardware setup. RJ-45 is also used for the programming of the Ethernet Switch as an Administrator. The PLC controller, the station computer and Omicron CMC356 are using the TC/IP RJ-45 Ethernet connection to communicate with other devices [24, 57, 62].
- Fibre-optic LC/ST connectors (100BASE-FX) are utilised to interconnect the protection relays to the Ethernet switch. This enables the IEDs to send and/or receive information through GOOSE signal as a horizontal communication between other IEDs located in the Bay level [63]. Figure 4.2 shows the connection of devices to the Ruggedcom RSG2100.

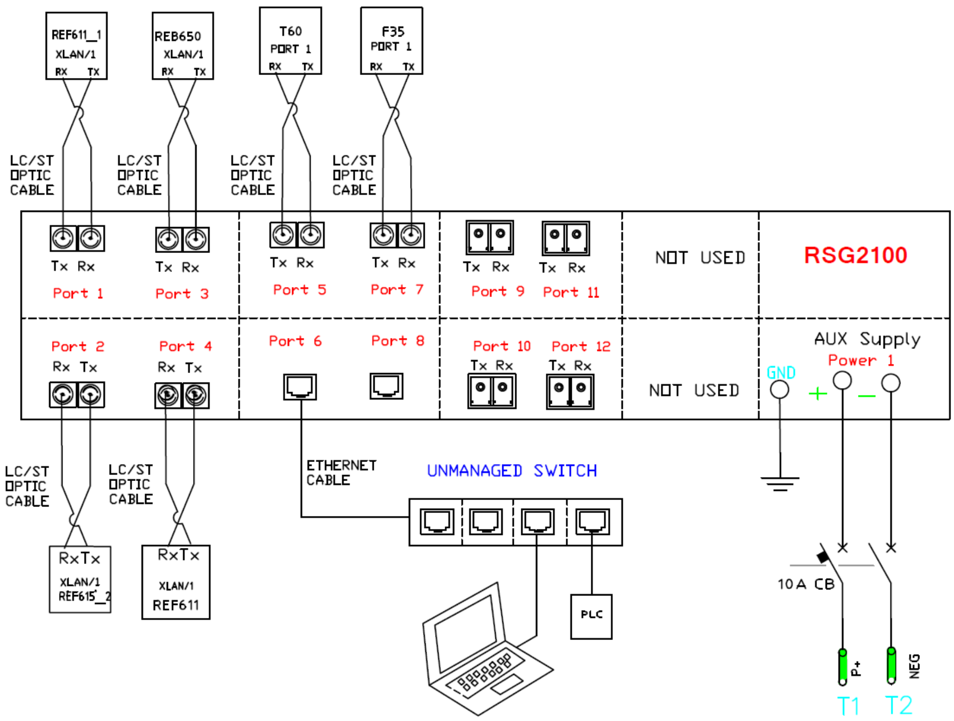


Fig. 4.2 Wiring layout and physical connection of the Ethernet switch

4.2.2 T60

T60 is a Transformer Protection relay from GE Multilin Universal Relays (Multilin URs) [60]. It is a microprocessor based IED which can be employed for multi-level protection systems such as low voltage transformers or large three-phase high voltage transformers. T60 is capable of measuring six three-phase current inputs and six ground current inputs simultaneously (Figure 4.3). T60 supports the transformer windings connection between two breakers in different types of application: in breaker-and-a-half configurations or in a ring bus connection [60]. In the arrangement of the 66/22kV Distribution Terminal Zone Substation, T60 is located in Line 1 to protect Transformer 1 and all equipment associated with the transformer zone within Line 1 using the following protection schemes:

- Three 3-phase low impedance differential protection
- Back up for Busbar protection
- Bus Tie Circuit Breaker control
- Phase and Earth Fault Overcurrent Protection
- Overvoltage and Under voltage protection

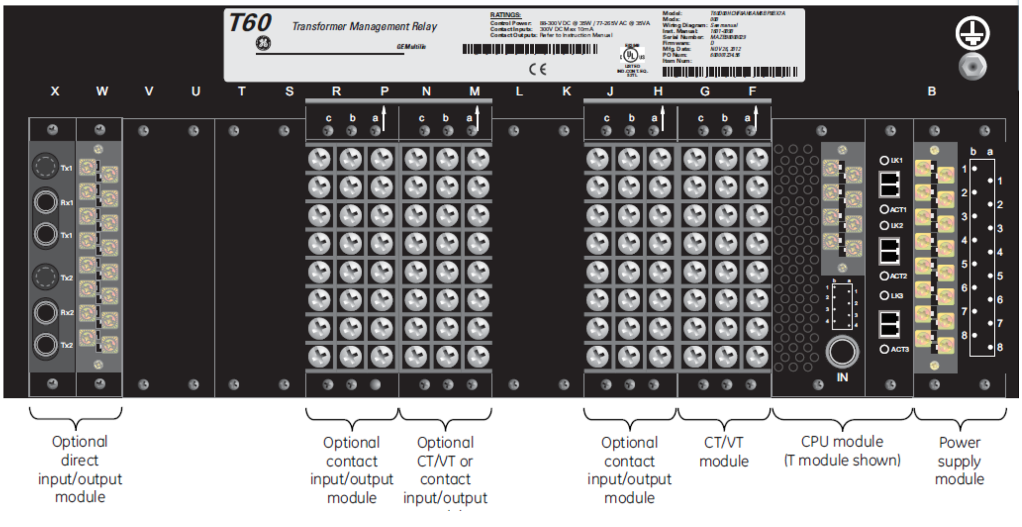


Fig. 4.3 Rear view of T60 connection channels [60]

T60 relay provides two programmable options, 1A and 5A, for secondary current measurements. As Figure 4.4 shows, channels 1 to 4 are selected for CT_1 measurements and Channels 5 to 8 are selected for CT_3 measurements. This composition intends to measure differential current for transformer protection in Line 1. In order to ensure compliance with the safety standards in the construction of the Substation Simulator, 2.5mm^2 wires are selected for CT and VT connections.

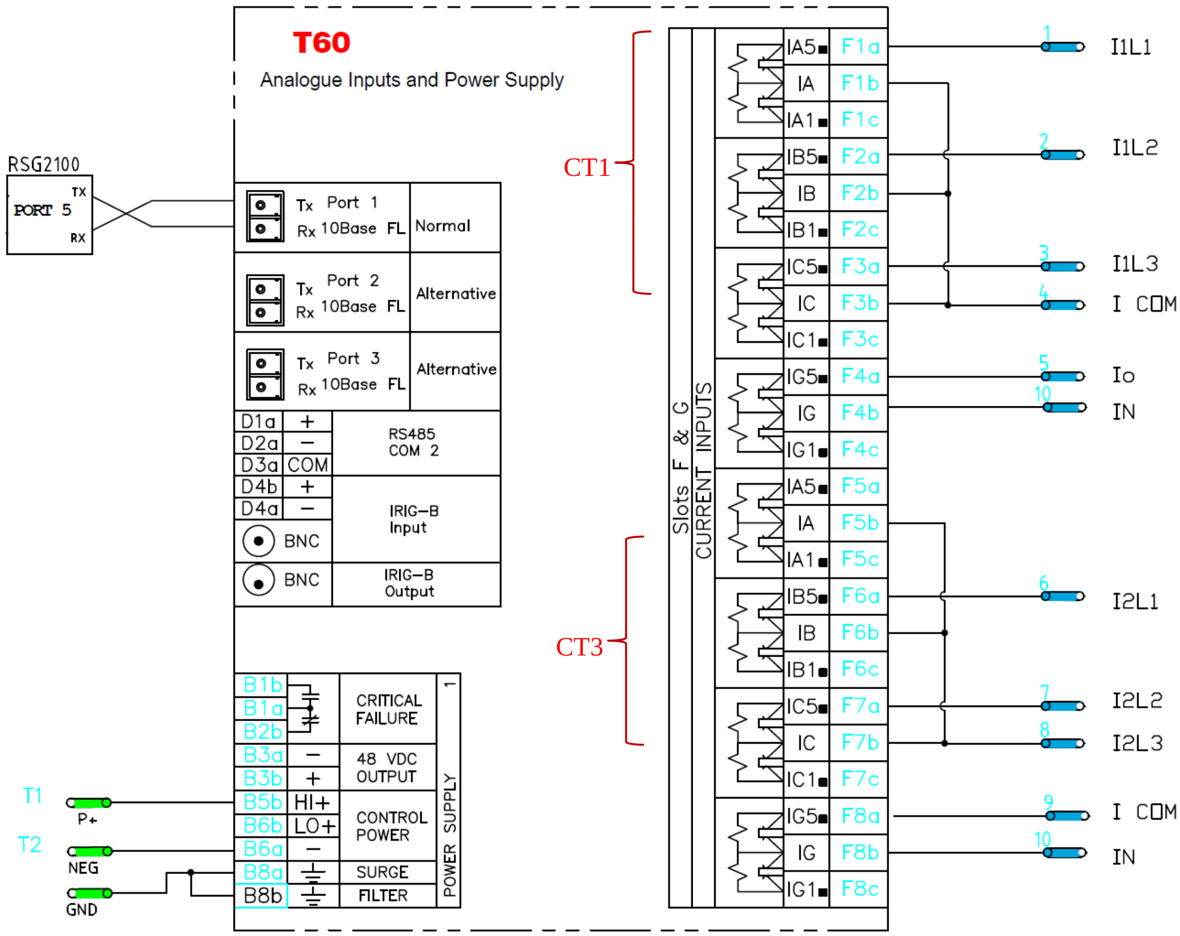


Fig. 4.4 T60 analogue inputs wiring diagram

T60 is built in two Modules, 6N and 67, for binary inputs and outputs contacts. Module 6N is used for binary input signal, for monitoring and measurement, whereas Module 67 is used for binary output contacts to relay protection and control commands. Both 6N and 67 Modules come with 24 terminal connections designed in eight rows by three columns [60]. Figure 4.5 shows the wiring layout of digital contact input/output used for T60.

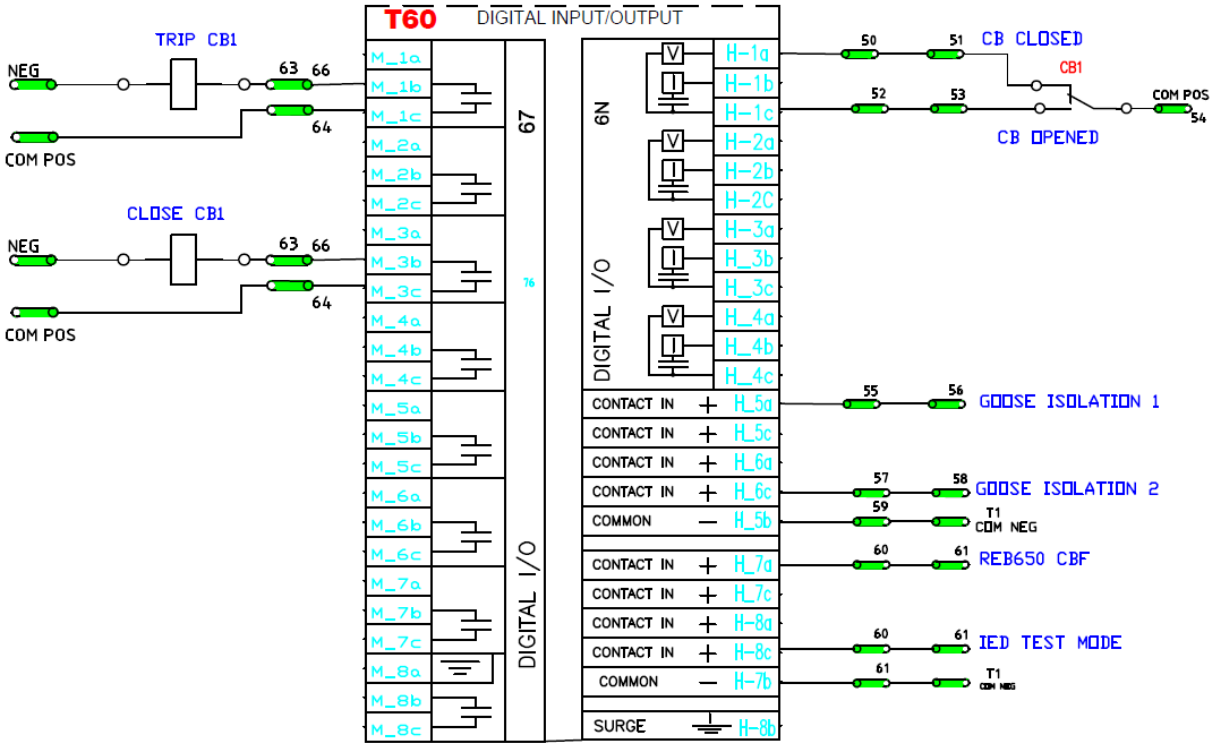


Fig. 4.5 T60 digital input/output connection layout

Figure 4.5 illustrates that channels M-1a and H-1c are used to monitor the status of the Circuit Breaker 1, whereas the channels M-1b and M-3c are controlling the position of the Circuit Breaker 1 by sending either TRIP or CLOSE command to the coil of CB1.

Since Transformer 1 requires a periodical maintenance test, it needs to be isolated from the 66/22kV Line 1. In order to avoid this interruption due to GOOSE sending from T60 during the test condition, H-5a an H-6c channels are used to isolate T60's GOOSE signals from the network. Furthermore, when IED demands an upgrading or testing, it ought to ignore or bypass all GOOSE signals subscribed to. This can be executed by activating the IED Test Mode through channel H-8c. The design and philosophy of the GOOSE isolation and IED Test mode is discussed in detail in Chapters 3 and 5 of this thesis.

4.2.3 REB650

REB650 is a numerical busbar relay that offers a wide variety of protection and control functions [58]. It is mainly designed for the protection of single busbars in high impedance-based applications. It also offers High Impedance Differential Protection for generators, autotransformers, shunt reactors and capacitor banks [58].

In designing of the Substation Simulator, REB650 is used for the following protection and control functions:

- Three 3-phase High Impedance Differential Protection,
- Back up for Feeder Protection
- Bus Tie Circuit Breaker Control
- Phase and Earth Fault Overcurrent Protection
- Overvoltage and Undervoltage Protection.

Figure 4.6 shows the analogue input, CTs and VTs, terminal connection of the REB650.

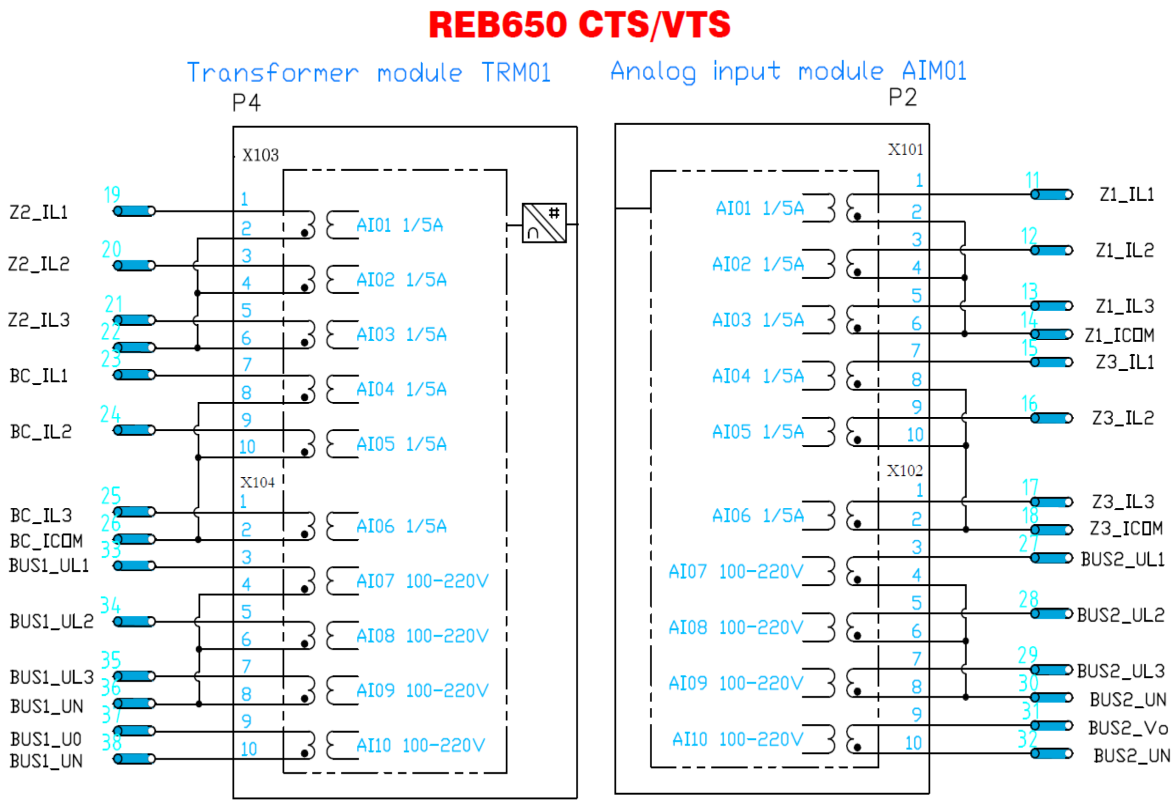


Fig. 4.6 Analogue inputs wiring diagram

REB650 is integrated with X317, digital inputs/outputs, to protect and control three different zones at the same time via High Impedance Differential Current Measurement. It sends Trip Circuit Supervision signals (TCSs) to CB1, CB3, CB4 and CB5at the same time by synchronising their circuit breaker position (Fig 4.7).

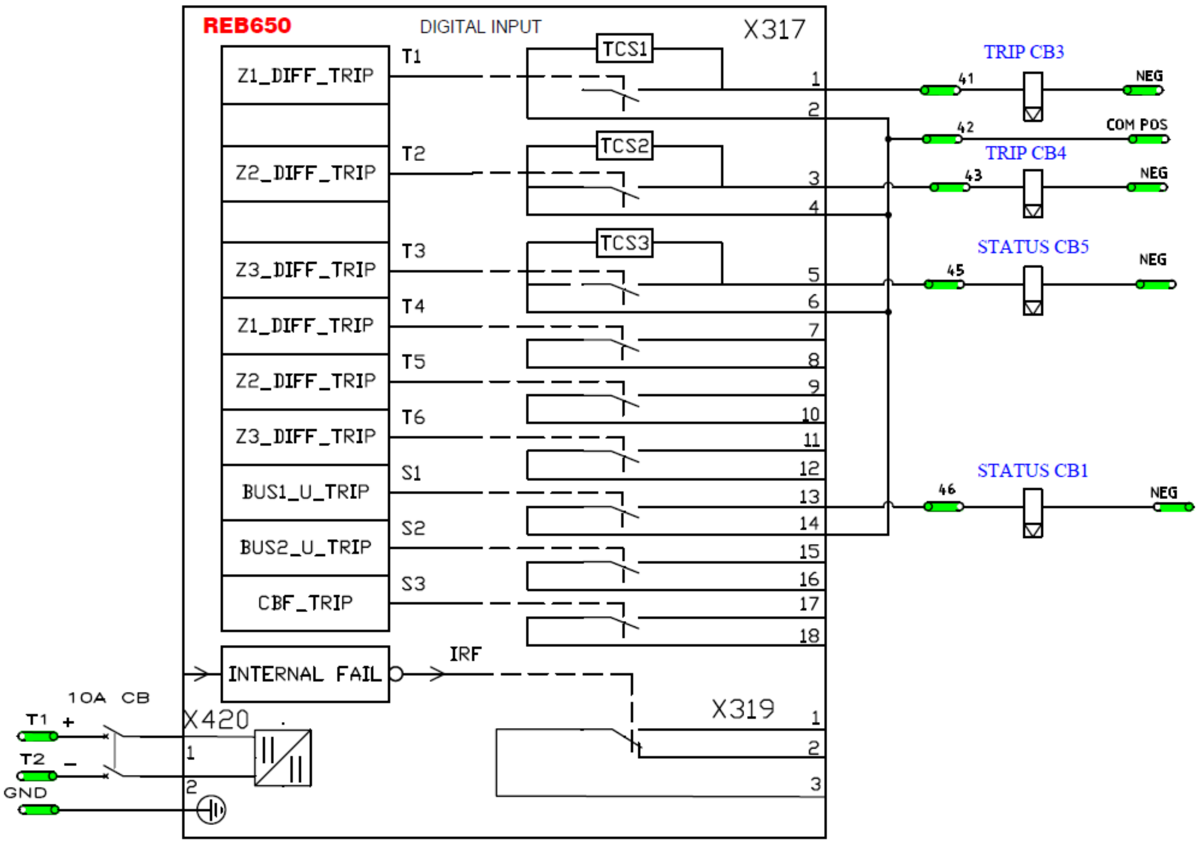


Fig. 4.7 REB650 digital input/output connection layout

4.2.4 F35

F35 is a feeder protection relay that belongs to the Multilin Universal family. It can be utilised for feeder supervision including control, protection and monitoring functions within a zone substation [61].

One of the advantages of the F35 over the other GE feeder protection relays is its flexibility and its capacity to be employed for a wide range of protection schemes. It can be programmed to control up to six feeder zones or protect up to five feeders accompanied by bus voltage measurement. It also provides high-speed performance of logical function, which is a vital issue within substation automation protection systems [61]. F35 is employed as a feeder protection IED in Feeder 1 connected to the Bus 1 (Fig. 4.1). It provides multiple protections relaying to protect and control all equipment located within Feeder 1 zone. These protection schemes are as follows:

- Instantaneous (Directional) Phase Overcurrent Protection
- Time phase (Non-directional) Overcurrent Protection
- Phase and Earth Fault Overcurrent Protection.

F35 relay provides two programmable options, 1A and 5A, for secondary current measurements. Channels F 1-4 are selected for CT4 measurements to measure Residual Current and Three-phase Current (Figure 4.8).

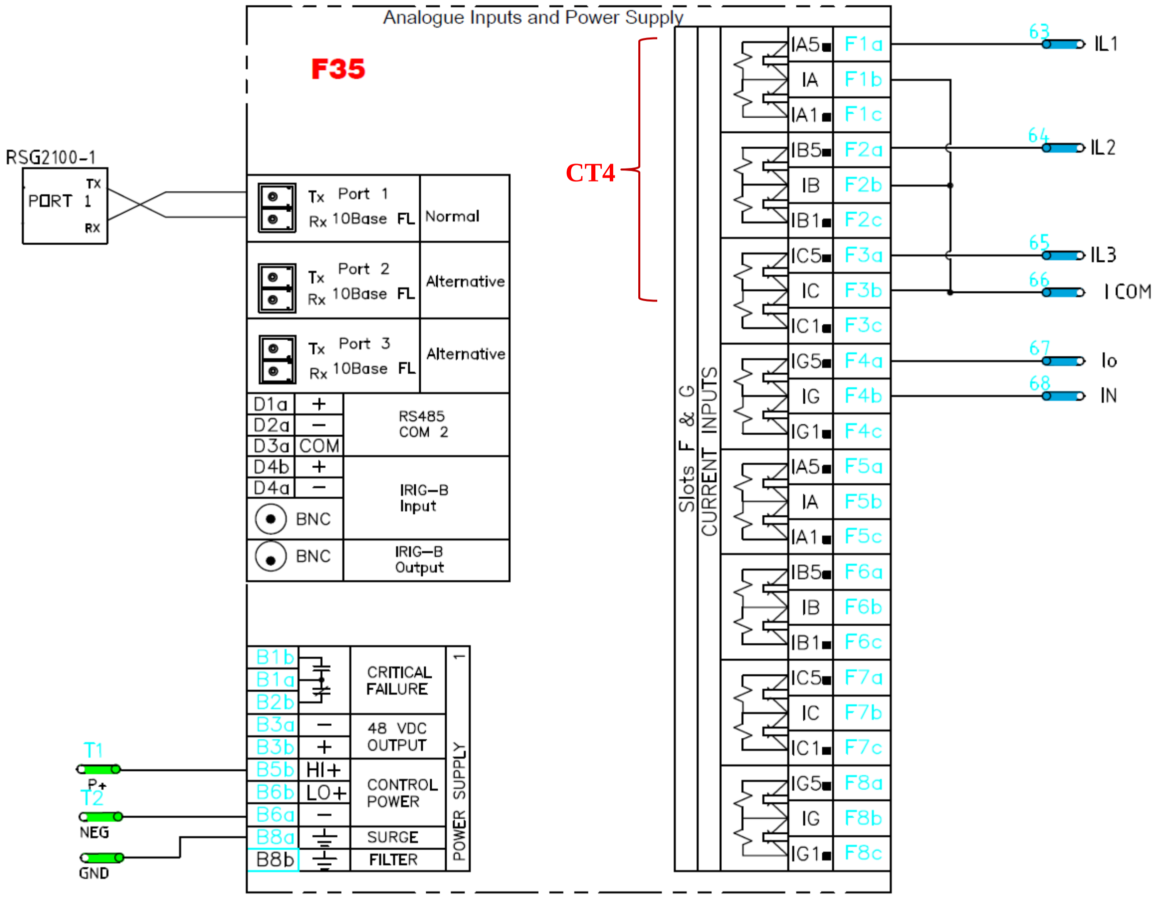


Fig. 4.8 F35 Analogue inputs wiring diagram

F35 is built in two Modules, 6N and 67, for binary inputs and outputs contact. Module 6N is used for binary input signal, for monitoring and measurement, whereas Module 67 is used for binary output contacts to relay protection and control commands. Both 6N and 67 Modules come with 24 terminal connections designed in eight rows by three columns. Figure 4.9 displays the wiring layout of digital contact input/output used for F35 [61].

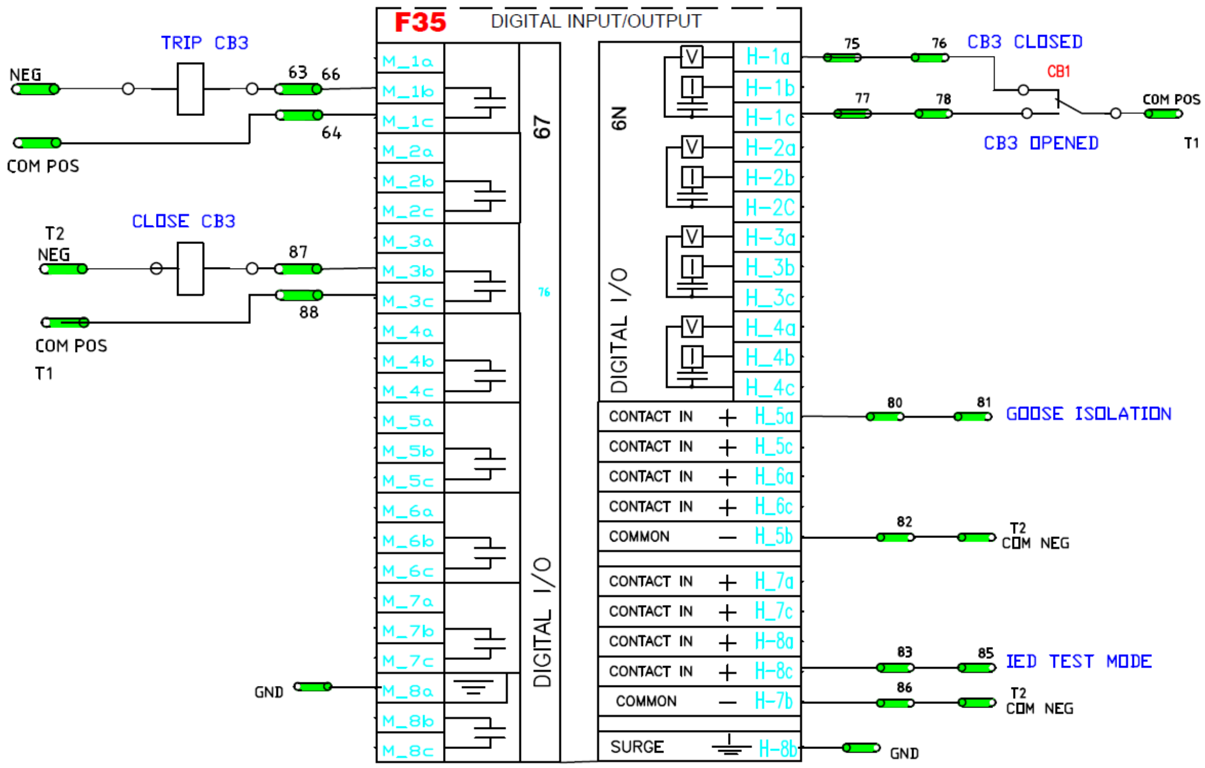


Fig. 4.9 F5 Digital input/output connection layout

4.2.5 REF615-1

REF615 is a part of the ABB Relion relays to be utilised for protection and control particularly for medium voltage feeder applications [50]. In the construction of IEC61850-Based 66/22kV Distribution Terminal Zone Substation, REF615-1 is used as a 22kV feeder relay for protection and control of the equipment located within its zone (Fig. 4.1). It has the functionality of Non-Directional Overcurrent Protection, Non-directional Earth Fault Protection, Voltage & Frequency based Protection, Synchro Check and CB Condition Monitoring [50]. Figure.4.10 shows the wiring layout and physical connection of the REF615-1.

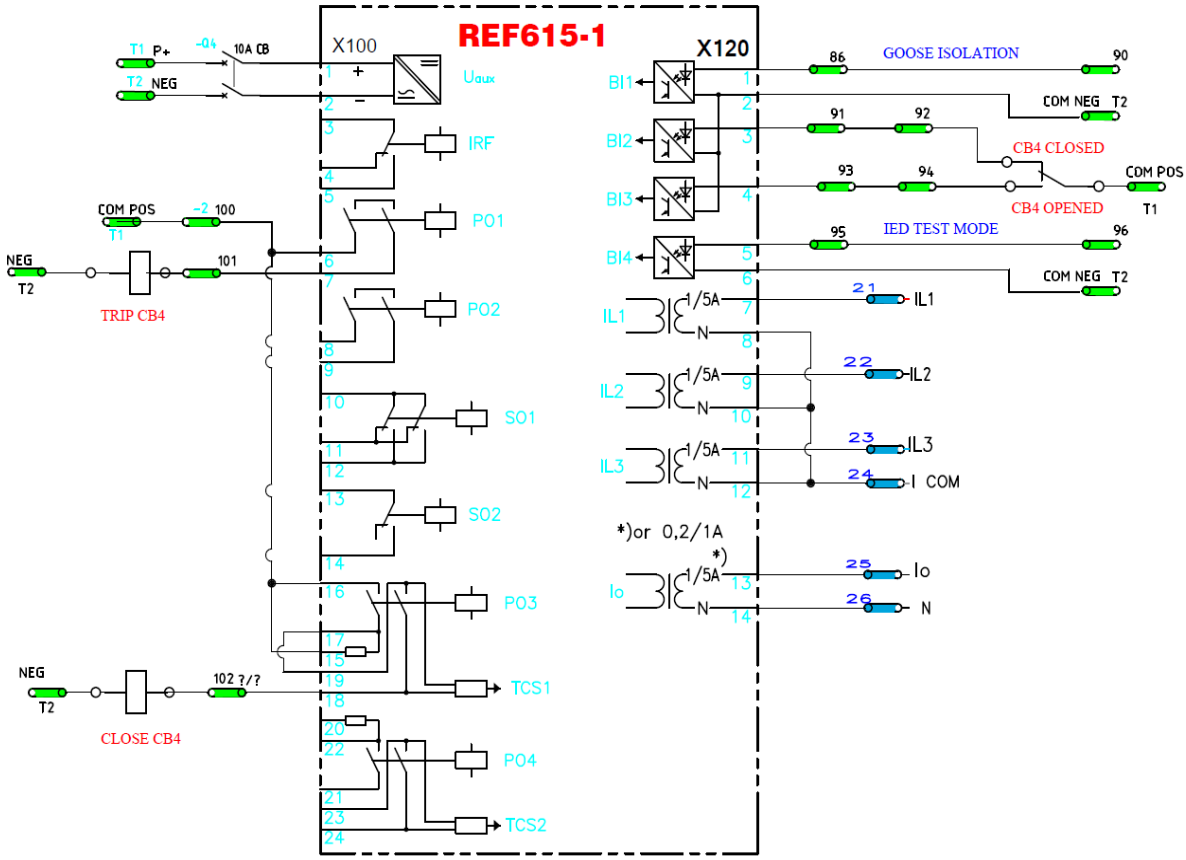


Fig. 4.10 REF615-1 wiring diagram

The CT measurements are injected into the REF615-1 through the analogue input channel (X120). The signal marked with IL1, IL2 and IL3 represents the three phase currents. And I_o represents the ground current (Fig. 4.10).

REF615-1 provides up to four multifunction setting groups for protection and control. Each group can, then, be activated or deactivated by using the Setting Group option available in REF615-1. Table 4.3 tabulates the connection for analogue inputs used for this thesis:

Table 4.3 REF615-1 Analogue Inputs Connection

Analog Input	Measurement	Connector Pins
IL1	Phase A current	X120-7, 8
IL2	Phase B current	X120-9, 10
IL3	Phase C current	X120-11, 12
I0	Ground current	X120-13, 14

REF615-1 provides 4 binary input and 10 binary output channels to be used for digital contact inputs/outputs. The binary inputs (X120: BI2-4) are used to monitor the position of CB4 and the binary outputs are used to control the CB4 position by either tripping or closing the coil (Tables 4.4).

Table 4.4 Binary Input/Output Connections

Signal	Binary Type	Functionality	Connector Channels and Pins
PO1	Output	Close circuit breaker	X100-6, 7
PO3	Output	Open circuit breaker/Master Trip -1	X100 -16, 17, 18, 19
BI1	Input	GOOSE isolation	X120-1, 2
BI2	Input	Circuit breaker closed position	X120-3, 2
BI3	Input	Circuit breaker open position	X120-4, 2
BI4	Input	IED Test mode	X120-5, 6

4.2.6 REF611

REF611 is a Multi Management Feeder protection and control relay from ABB Relion series [59]. It is designed for the protection, control, measurement and supervision of utility substations and industrial power systems including: radial, looped and meshed distribution networks with or without distributed power generation. It is well known for its simplified design but powerful performance in protection systems [59]. REF611 used in 66/22kV Distribution Zone Substation Simulator is fully compatible with the IEC61850 Standard. It is located in Feeder 3 connected to the Bus 1 (Fig. 4.1). It provides multiple relaying schemes to protect its protection zone. These protection schemes are as follows:

- Instantaneous (Directional) Phase Overcurrent Protection
- Time Phase (Non-directional) Overcurrent Protection
- Phase and Earth Fault Overcurrent Protection.

Figure 4.11 illustrates the schematic wiring diagram of the REF611.

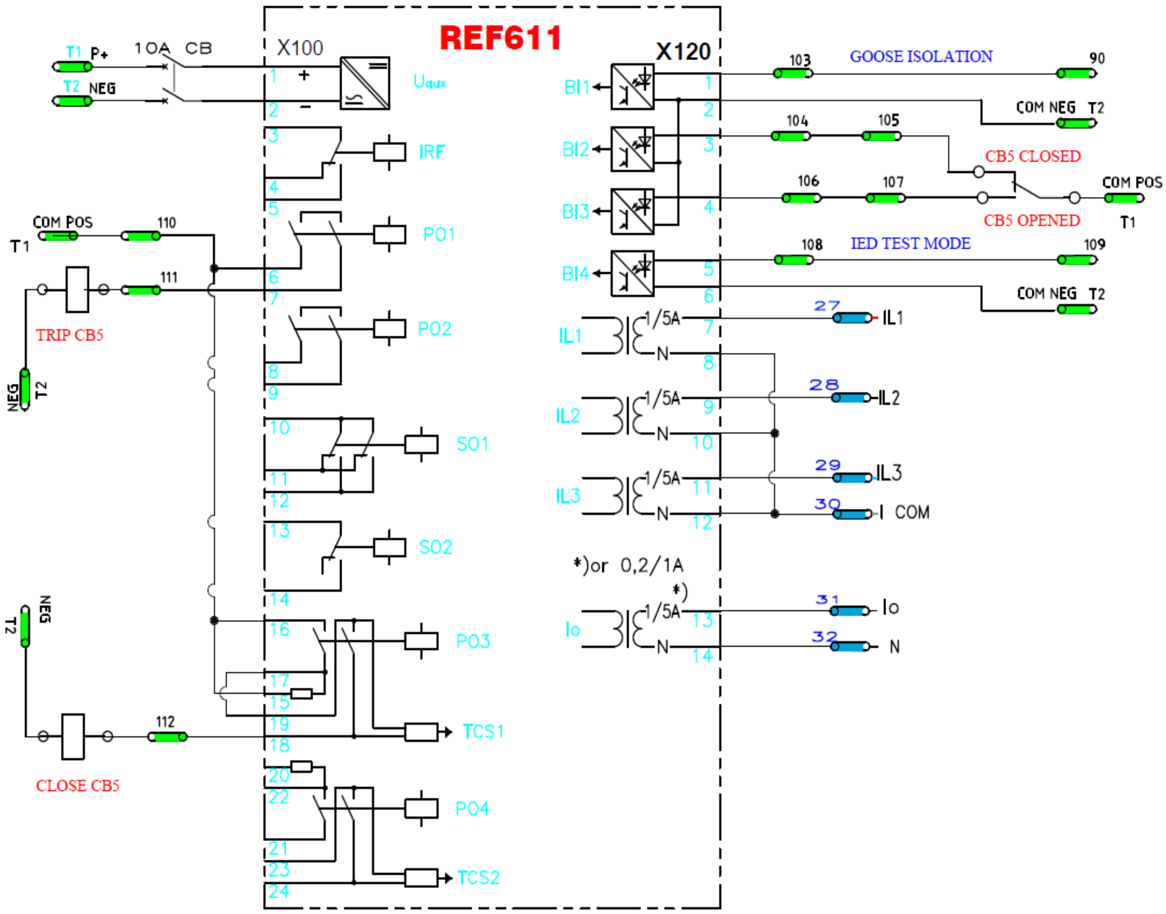


Fig. 4.11 REF611 wiring diagram

4.2.7 REF615-2

As mentioned in Section 4.2.5, REF615 is a part of Relion series relays intended for protection and control particularly for Medium Voltage applications. Despite the fact that REF615-1 is used for feeder protection, REF615-2 implemented a bus tie coupler IED between Line 1 and Line 2 of the Substation Simulator (Fig. 4.1). The performance and application of this IED will be discussed in detail in Chapter 5. This IED not only controls and monitors the position of the Bus Coupler Circuit Breaker, but it also operates as Non-directional Overcurrent Protection, Non-directional Earth Fault Protection, Voltage & Frequency based protection and Synchro Check within busbar zone protection between Bus 1 and Bus 2.

REF615-2 employs channel X120 for analogue signals measurements. The signals marked with IL1, IL2 and IL3 represents the three phase currents and I_o represents the ground current.

REF615-2 also provides up to four multifunction setting groups for protection and control systems [50]. Each group can then be activated/deactivated by using the setting group settings available in REF615-2. The wiring diagram of REF615-2 is depicted in Figure 4.12.

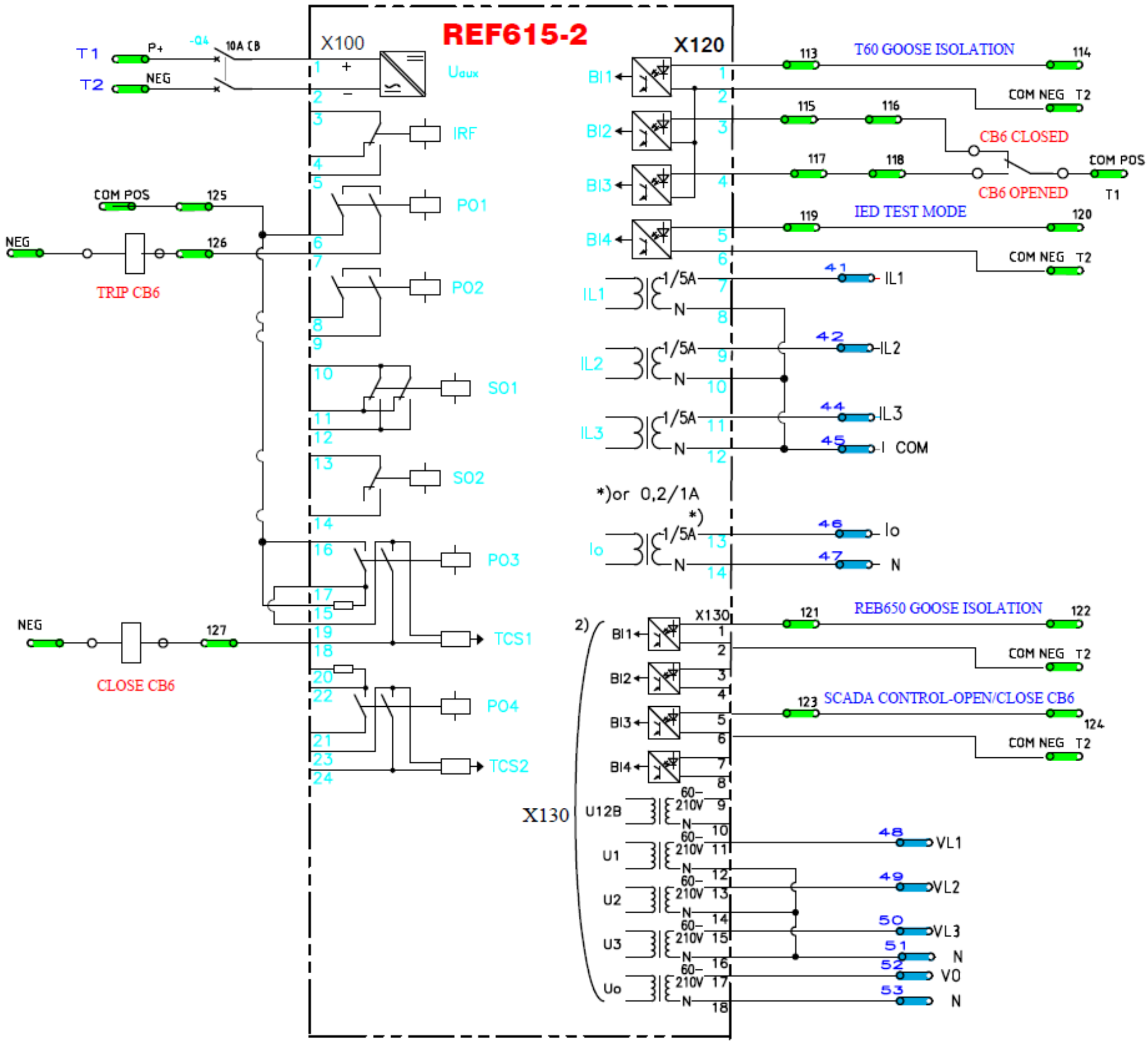


Fig. 4.12 REF615-2 wiring diagram

4.2.8 PLC SLC500

An Allen Bradley SLC500/05 is used as a controller to run the SCADA system in the Station level [3]. The PLC machine provides 24V DC input/output contacts. It has both DH-585 and galvanised RJ-45 Ethernet interface for communication. The DH-485 is to be used for the basic and preliminary configuration such as device IP set up and reading the PLC input/output channels configuration. RJ-45 Ethernet port is, therefore, used for fast communication between devices and PLC [64]. It also enables the administrator to mimic, monitor and control the devices performance through the SCADA system.

SLC500 is built in two channels for the binary inputs (channels 2 and 3) and two channels for the binary outputs (channels 4 and 5). Chanel 1 is occupied by CPU of the PLC.

4.2.9 Power Supply

In order to energise the devices of the Substation Simulator safely, it is highly crucial to supply the power to the equipment within their control power supply range. Most of the IEDs have three options: Low Range (24 to 48V DC only), Medium Range (48 to 1125V DC only) and High Range (125 to 250V DC and AC) [50, 59-61]. Since the Substation Simulator is meant to be utilised for research purposes in the laboratory environment, the Medium Range option is selected to power up the IEDs and auxiliary circuit breakers. Only SCADA HMI, PLC controller, Door Lamp and Cooling fan are connected to 240 AC (Fig. 4.13).

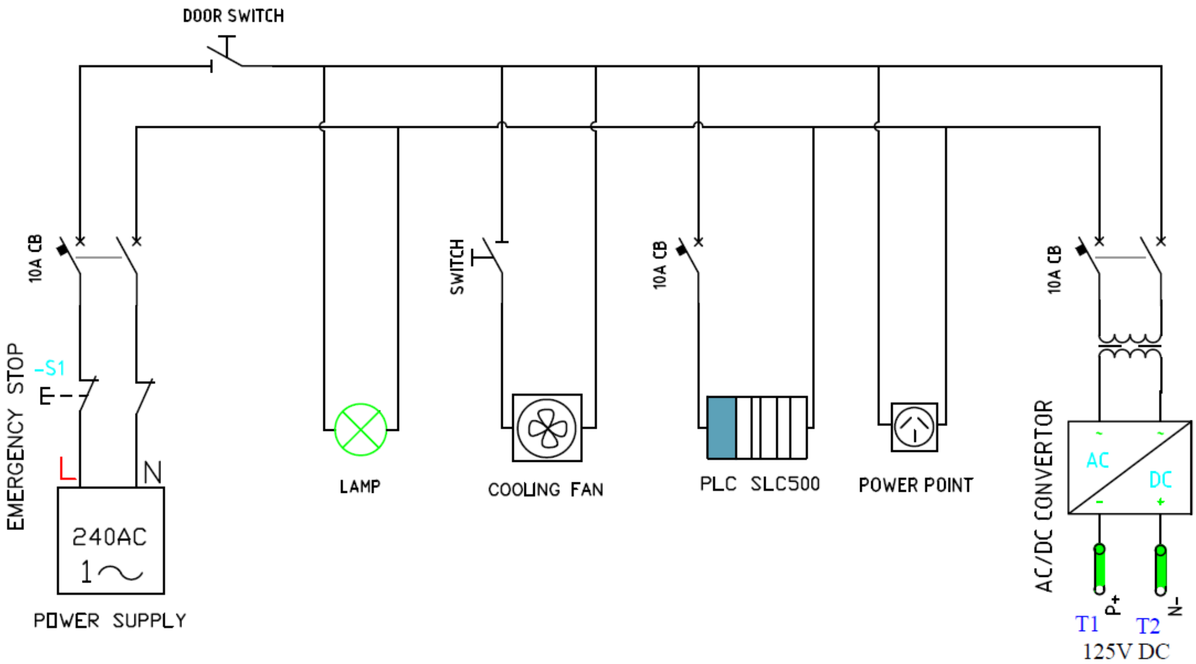


Fig. 4.13 Single line diagram of DC and AC supply of the Substation Simulator

A 240/90V AC Voltron step down transformer is selected to build the customised 125V DC power supply. A full wave diode bridge rectifier is employed to convert the 90V AC output from the transformer to DC voltage. According to the full wave diode bridge rectifier performance, the output is governed using the following equation [65]:

$$V_{DC\ Output} = 90 \times 1.35 = 125V \pm 5V$$

It is very important to ensure that the DC output from power supply to be filtered. Since all IEDs are built in electrolytic capacitors, if the output DC voltage from transformer is not filtered, these capacitors play the role of the filter and reduce the ripples associated with DC output from the transformer. Consequently there will be a voltage drop in the DC source [65]. Three sets of 600 µF capacitors are connected in series to the DC output of the diode bridge to apply filtering and to smooth the ripples. According to Figure 4.13, the terminals T1 and T2 are selected as 125V DC power supply. Thus in all wiring layout used in Chapter 5, these terminal represent the DC control power supply to energise the devices.

4.2.10 Main Circuit Breakers (MCBs)

Six sets of 3-pole Normally Closed SKBMT contact relays are used to simulate the performance of MCBs located in the simulated switchyard of the substation. Figure 4.14 shows the contact arrangement of the 12-pin SKBMT latching relays used as a dummy circuit breaker.

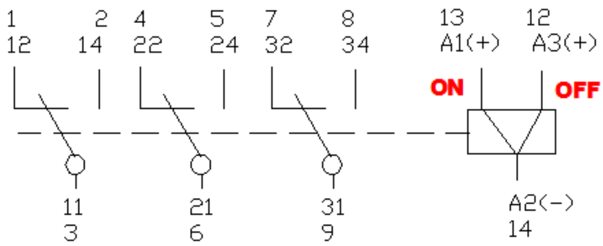


Fig. 4.14 Normally Closed 12-pin MCB used as a dummy circuit breaker [66]

4.3 Conclusion

This chapter provided the details, specification and wiring circuit diagram of hardware inventory used throughout the construction of the IEC61850-Based 66/22kV Distribution Terminal Zone Substation. The Substation Simulator is established mainly through Ethernet and fibre optic technologies as opposed to conventional hardwired copper. This enables advantage to be taken of cost-effective GOOSE messaging technology for peer-to-peer communication between devices of the Substation Simulator.

Chapter 5 - Substation Design and System Configuration

5.1 Introduction

This chapter provides the flow of the engineering process undertaken to design the IEC61850-Based 66kV/22kV Distribution Terminal Zone Substation. It outlines the required steps, induvial device and system configuration, and tools to establish the IEC61850 GOOSE communication between IEDs. It also addresses the challenges and issues that are encountered within the configuration process.

5.2 Individual Device Configuration

Two core steps need to be considered in the process of configuring IEC61850 devices and substations. These steps are known as “individual IED configuration” and “system configuration”. The development process of an IEC61850-based project is subject to the accessibility of software tools that make use of these files in the process of IEC61850 devices configuration. For the individual IED configuration each vendor has its own proprietary tools to configure its IEDs. However, due to a wide variety of available vendor tools, being familiar with these configuration tools is a significant challenge for engineers and technician.

Design and configuration of the 66/22kV Distribution Terminal Zone Substation is started with individual device configuration by programing all IED’s protection and control functions, depending on the protection schemes. This step requires the vendor proprietary tool to configure the IEDs’ parameters, create GOOSE publishing signals and export CID files of the IEDs. Vendor proprietary tools namely PCM600 and

EnerVista are used to program ABB and GE relays respectively. Once CID files of all IEDs are obtained, they are imported into IET600, a multi-vendor IEC61850-based substation configurator tool, to create a SCD file of the substation. The flow of IEC61850-based individual device and substation configuration by utilizing required tools is depicted in figure 5.1.

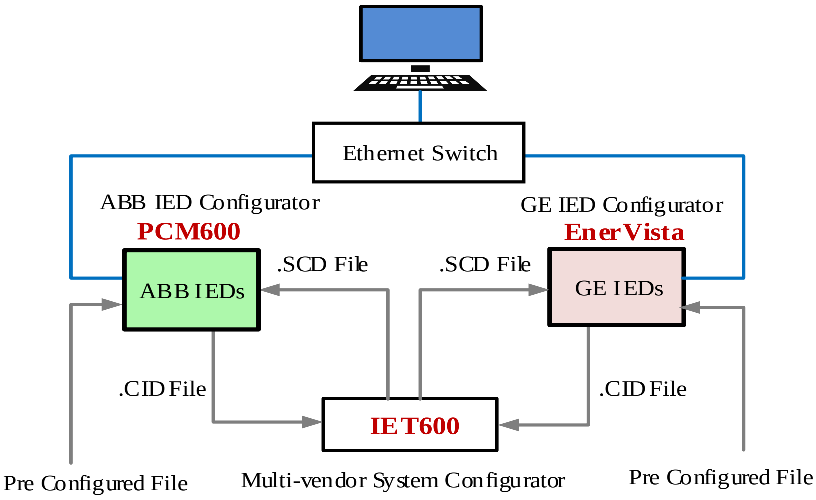


Fig. 5.1 The process and tools used for Individul IED and substation configuration

5.2.1 RSG2100

Ruggedcom 2100 is one of the core devices of 22/66kV Distribution Terminal Zone Substation utilised to establish a Virtual Local Area Network (VLAN). This enables the user to bring all intelligent IP dependant devices under a subnetwork. Thus, prior to configuring the devices of the 66/22kV Distribution Terminal Zone Substation, the Ethernet Switch is programmed according to the requirement of the system. The first initial connection between PC and the Ethernet Switch is stablished through RS232 console (DB9 female connector) of the switch to RJ45 port of the PC. This provides a temporary access to the switch for initial setup including: IP configuration, generating user name and password, trouble shooting and resetting the device to the factory setting. The parameters for serial connection are chosen, 57600 no parity bits, 8 data bits and stop bits, according to the RSG2100 Configuration Manual [57]. Once the connection is established, the following details are set for the switch:

- User Name: Sajad Amjadi
- Password: ************
- IP Address: 192.168.2.50

Setting the IP for RSG2100 allows the user to program the switch using a Rugged Operating System (ROS) Web Server interface. It also provides a permanent communication connection between switch and other devices through TCP/IP layers. In order to work with ROS interface, a web browsing Server, preferably Internet Explorer 9 is launched and the created User Name and Password are entered as shown in Figure 5.2.

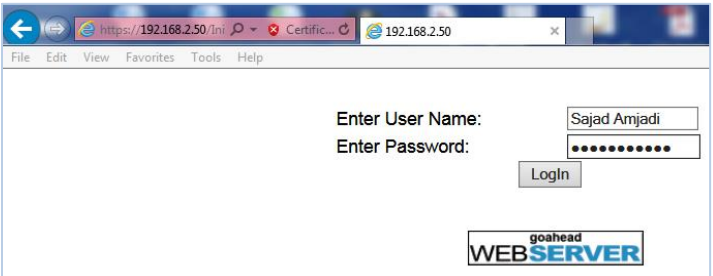


Fig. 5.2 Login page using IP: 192.168.2.68 to enter ROS Web Interface

The ROS interface is encapsulated with a series of linked web pages. Figure 5.3 shows The Main Menu of ROS Web browser at the high level of the menu hierarchy expanded into lower level sub-menus:

- Administration
- Ethernet Ports
- Virtual LANs.

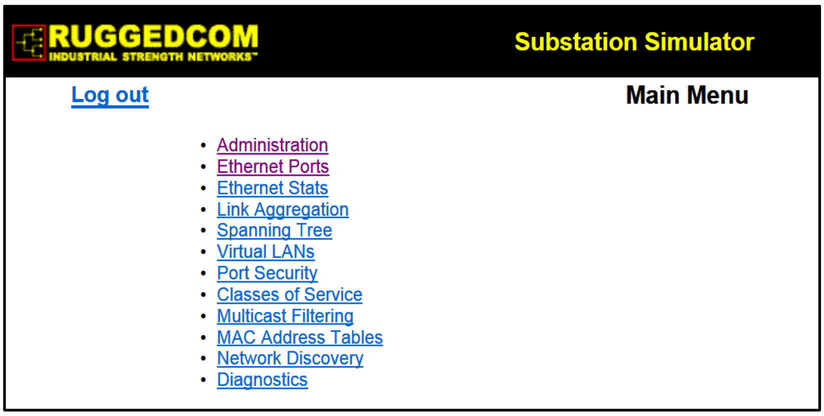


Fig. 5.3 ROS Web Interface Main Menu

5.2.1.1 *Administration*

The Administration menu enables the user to create the preliminary network and administration parameters including IP interface, System identification, User Name and Password (Fig. 5.4).

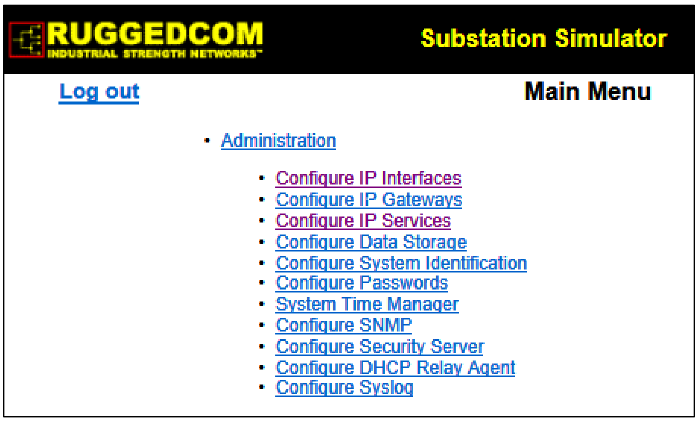


Fig. 5.4 Administration menu and its links

Access restriction to the switch is highly crucial to avoid any cyber security network issues. RSG2100 provides three levels of access:

- Guest
- Operator
- Admin

The highest level of the authority is given for the Administrator who has the full authority of configuring, setting and/or resetting the switch according to the requirement of the system (Fig. 5.5).

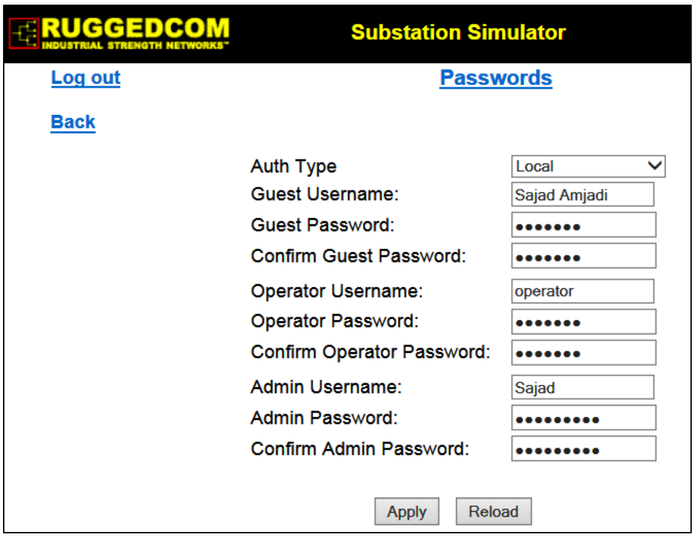


Fig. 5.5 Password and Username setup for RSG2100

RSG2100 enables the user to create up to fifteen IP interfaces provided that they do not overlap with each other in terms of VLAN ID and subnet mask parameters. The default VLAN ID for management port of the switch is set to 1 by default. It is highly recommended to keep the VLAN ID and subnet mask as default values for the management IP interface. All other IEDs and Devices connected to the switch are assigned to the VLAN ID 1 through managed ports to play the role of Client to the Ethernet switch (Fig. 5.6).

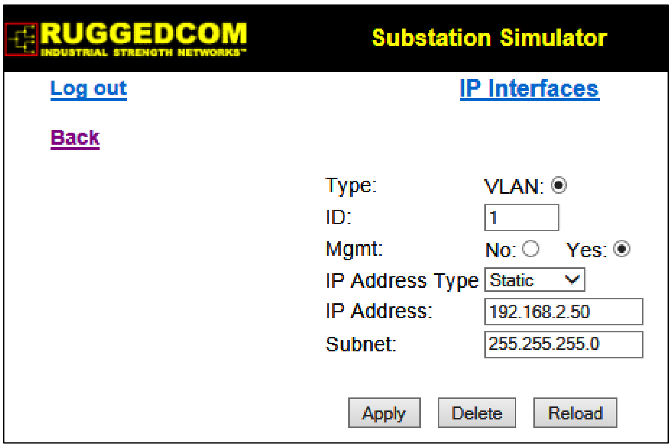


Fig. 5.6 Configuration of Management Port with VLAN ID set to 1

5.2.1.2 *Ethernet Ports*

The Ruggedcom 2100 provides 11 modular Ethernet ports to connect intelligent IP dependant devices using a specific VLAN ID. This enables these intelligent devices to interoperate with each other over a multi-casting communication model. The Ethernet ports provide the following configuration links:

- Configure port parameters
- Configure port rate limiting
- Configure port mirroring
- Configure link detection
- View port status
- Reset ports

The Ethernet Port Menu allows the user to physically arrange the connection of the devices. Figure 5.7 shows an example of port parameters configuration used for REF611 IED.

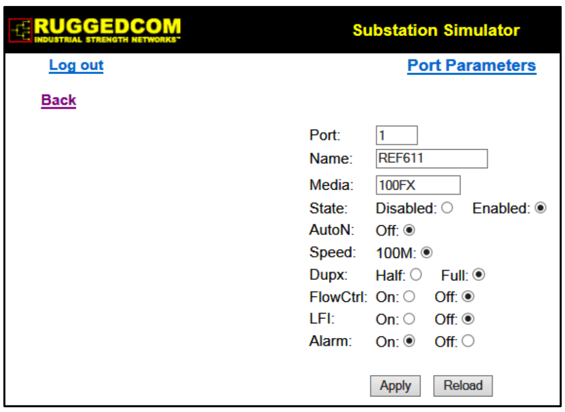
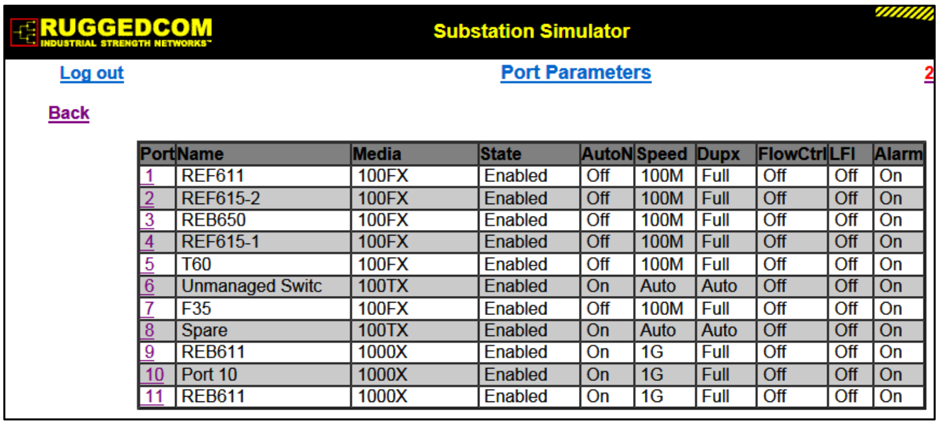


Fig. 5.7 Snap shot of port parameters setting for REF611 IED

Subject to the type of the connectors used to connect the devices to the Ethernet switch- LC, ST, RS232 and RJ45- RSG2100 provides different media to transfer data: 100M, 100TX, 100FX and 1000T.

During the configuration procedure the copper Ethernet cable is used, the port speed is selected as 100M. By doing that, the Auto-Negotiation parameter is automatically forced 'ON'. Once the IEDs are energised and physically connected to the switch through optic cables, the port speed will be changed to 1G and correspondingly the Auto-Negotiation parameters will be changed to 'OFF'. The 'State' parameter is enabled to prevent frames from being sent and received during link detection. In order to avoid losing data under heavy network traffic, due to publishing and receiving multiplex GOOSE messages, the Full Duplex parameter is selected. However, it should be noted that the other end connected device has to be set to Full Duplex mode as well. Figure 5.8 depicts the specification of the ports used to connect the IEDs of the 66/22kV Distribution Terminal Zone Substation to RSG2100.



Port	Name	Media	State	AutoN	Speed	Dupx	FlowCtrl	LFI	Alarm
1	REF611	100FX	Enabled	Off	100M	Full	Off	Off	On
2	REF615-2	100FX	Enabled	Off	100M	Full	Off	Off	On
3	REB650	100FX	Enabled	Off	100M	Full	Off	Off	On
4	REF615-1	100FX	Enabled	Off	100M	Full	Off	Off	On
5	T60	100FX	Enabled	Off	100M	Full	Off	Off	On
6	Unmanaged Switc	100TX	Enabled	On	Auto	Auto	Off	Off	On
7	F35	100FX	Enabled	Off	100M	Full	Off	Off	On
8	Spare	100TX	Enabled	On	Auto	Auto	Off	Off	On
9	REB611	1000X	Enabled	On	1G	Full	Off	Off	On
10	Port 10	1000X	Enabled	On	1G	Full	Off	Off	On
11	REB611	1000X	Enabled	On	1G	Full	Off	Off	On

Fig. 5.8 Ports parameters setting for IEDs used in Substation Simulator

5.2.1.3 *Virtual LANs*

A Virtual Local Area Network or VLAN is a cluster of IP dependant devices, within a distinctive LAN section, that exchanges the information provided that they were attached to the same physical LAN section [3, 22]. RSG2100 provides up to 245 VLANs with free configuration connectivity packages for multiple scenarios which are used in the development of the 66/22kV Distribution Terminal Zone substation. It has also the capacity for operating both tagged and untagged operation on the multicasting network. In a multi-vendor multicasting network, VLAN tag is used as identification information to warrant VLAN operation.

Tagged frames are categorised under the IEEE 802.1Q standard. They contain a particular VLAN identifier (VID), whereas untagged frames do not carry tags and only encompassing prioritised information with a VID of 0 according to the IEEE 802.1p (Priority Levels and Egress Priority Queues) standard. Interoperability in a multi-vendor common-based-language environment is achievable when a switch receives a tagged frame; it recognises and identifies the VID and forwards the frame to other ports in the identical VLAN. If any intelligent device is connected to this port, it will receive and detect the frame [57].

In the context of the IEC61850, since each GOOSE control block is configured by vendor’s proprietary tools it is unlikely to be recognised by the other vendor’s devices. This raises some interoperability issues between multi-vendor devices. In order to tackle this problem, the standard implements the GOOSE VLAN tagging. The GOOSE published in the network, must be tagged with the same VLAN ID that is used by the receiver IED. If so, then the subscriber IED will receive the incoming GOOSE by detecting its VLAN ID [48].

ROS Web Server Interface provides a configuration menu to configure VLAN and its ID for frame tagging in the network. Figure 5.9 is an example of configuring port VLAN parameters setting for Port 1 which is assigned to REF611.

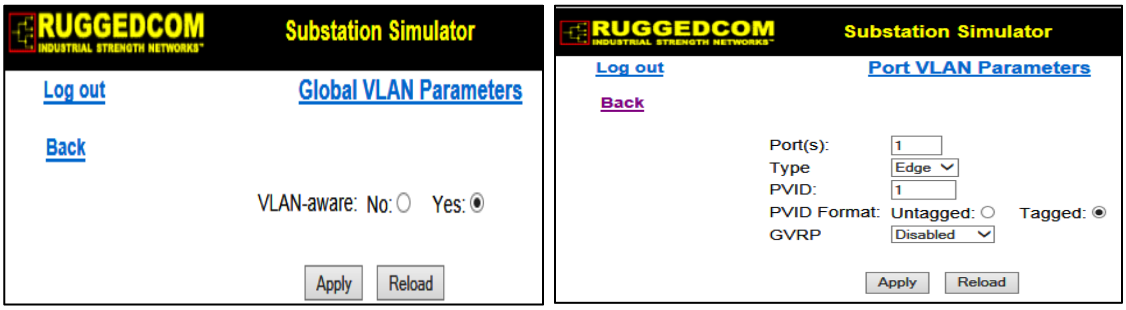


Fig. 5.9 An example of creating VLAN ID in RSG2100

5.2.2 T60

T60 is a Transformer Protection IED from GE Multilin Universal Relays (Multilin UR) programmable using EnerVista software [60]. It protects, controls, and monitors Transformer 1 and all equipment associated with transformer zone within Line 1 of the 66/22kV Distribution Terminal Zoe Substation. For configuring and calibrating GE Multilin Universal relays, EnerVista has been employed as an IED programming tool. EnerVista Launchpad is the first page to run to configure T60 (Fig. 5.10).

Fig. 5.10 EnerVista Launchpad (Main Menu)

EnerVista Launchpad allows the users to download the latest firmware, manuals and other supporting documents free of charge [60]. After loading EnerVista Launchpad, T60 and its documents including the latest firmware, Version 7.1, are downloaded from the GE centralised library website shown in Figure 5.11.

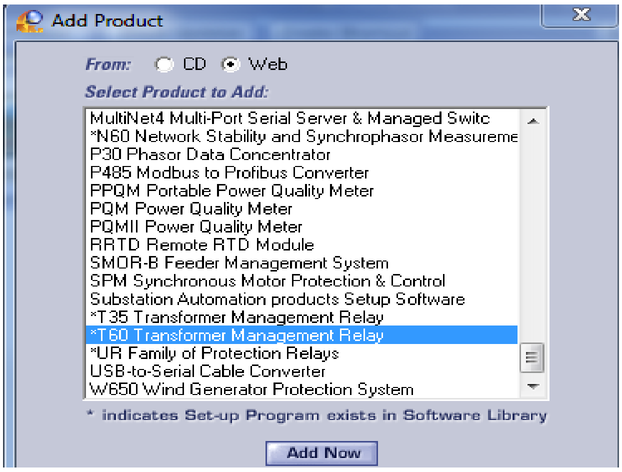


Fig. 5.11 EnerVista central free online software and document library

Communication between PC and T60 is achievable via either Ethernet port (RJ-45 Connector) or RS485 serial over F485 connector. However, it is recommended to use the front RS485 port for the first connection. This enables the user to set up the IP address for an IED, upgrade the firmware and reset the device. Figure 5.12 demonstrates how to enter the required setting in the Device Setup window to establish the communication.

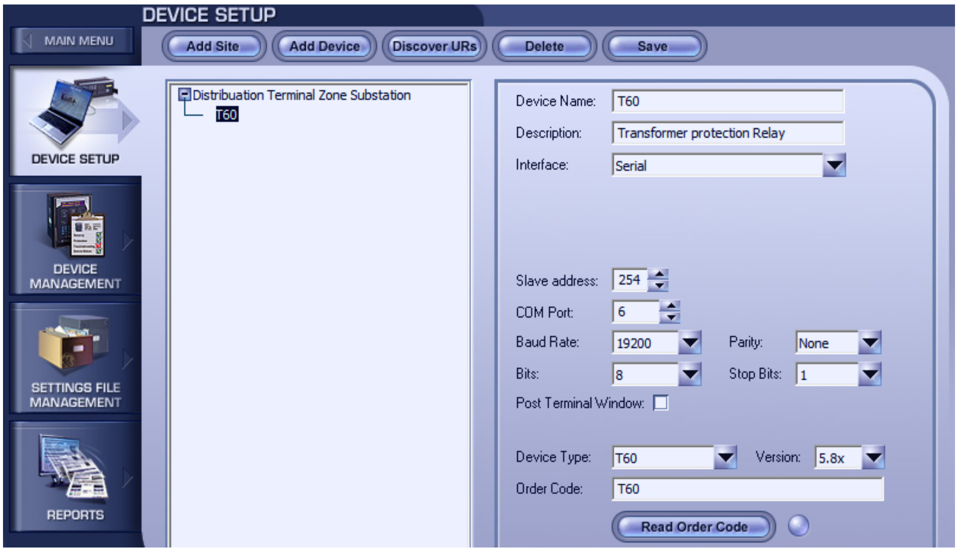


Fig. 5.12 Connection setup between RSG2100 and T60 using RS485 serial port.

By clicking the "Read Order Code" tab in the bottom of the Device Setup window, the T60 IED will be connected to PC. It will then, read and copy the factory setting of the IED to EnerVista. Since communication with IED over RS485 is slightly slow compared to the Ethernet port [3], after setting up the IP for T60 through RS485 (shown in Fig. 5.13), the serial connection is replaced by the Ethernet connection.

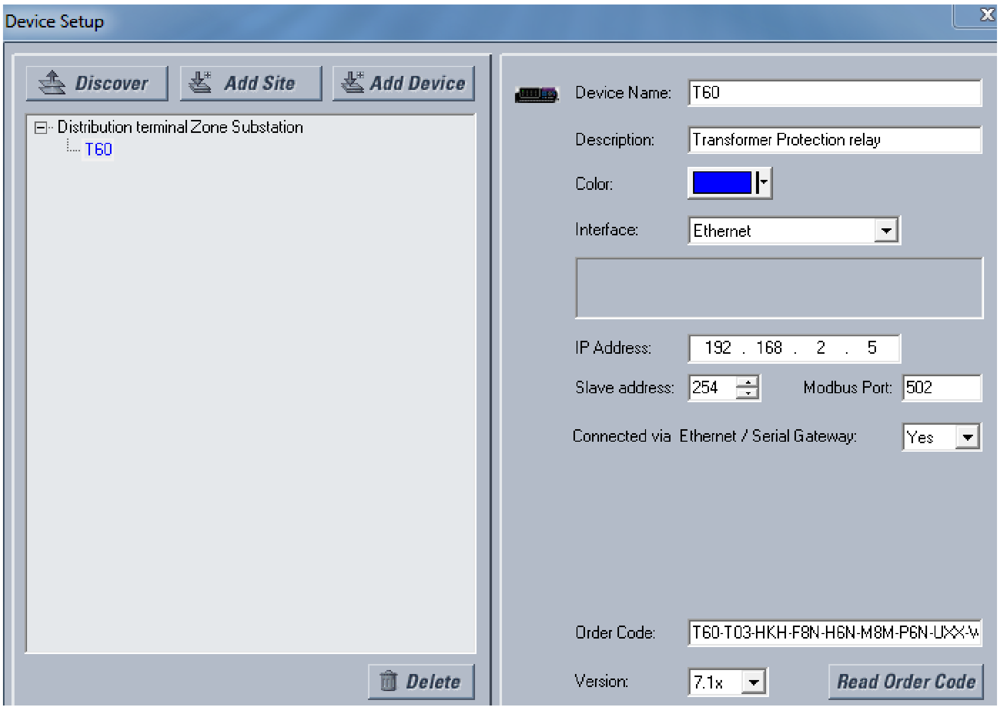


Fig. 5.13 IP parameters setting through serial connection for T60

EnerVista Launchpad provides starts with Main Menu, EnerVista UR Setup, with a series of dropdown expandable submenus to configure all physical and logical components of T60 individually. Clicking the “+” tab will expand each section’s parameters in detail and will open a new window to enter the information according to the system design (Fig. 5.14). The EnerVista UR Setup provides two options: Online or Offline, to work with.

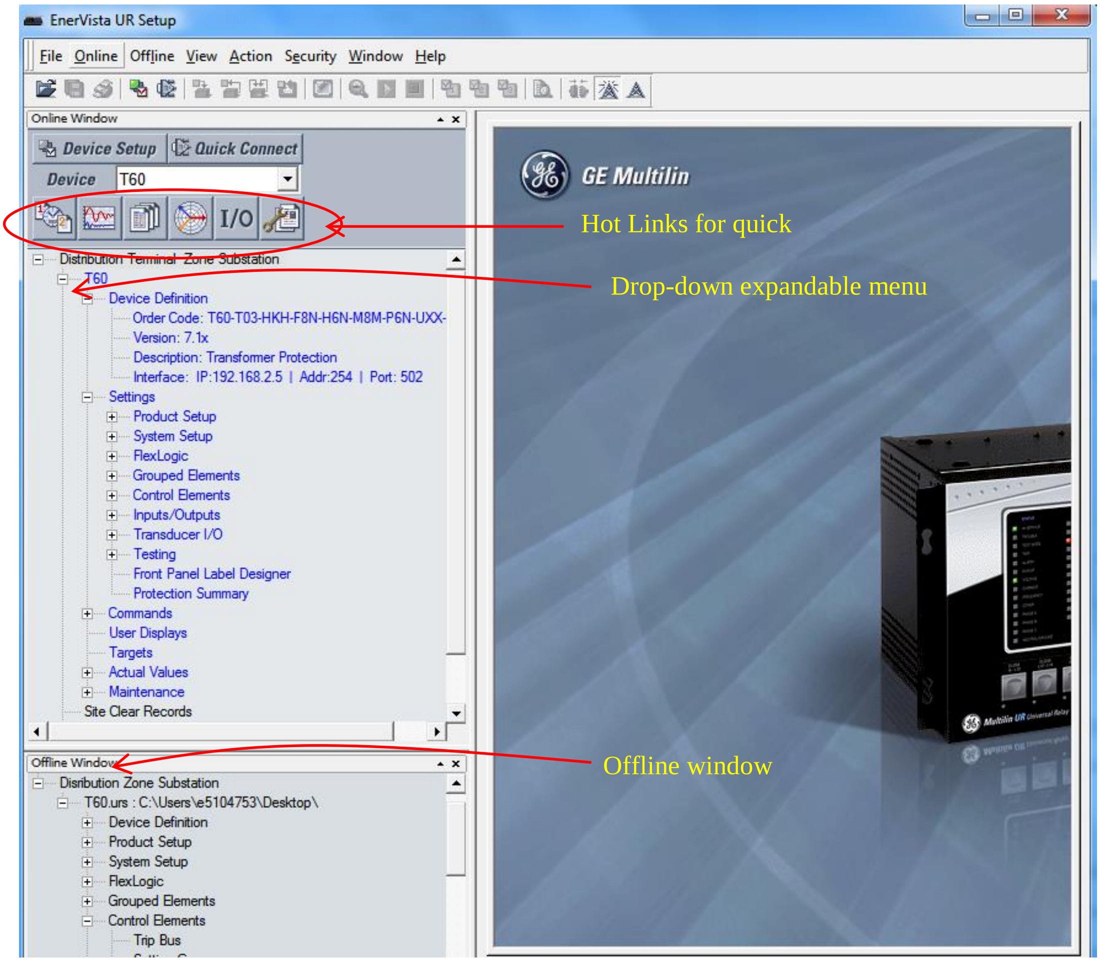


Fig. 5.14 EnerVista UR Setup menu and its linked submenus

The latest oscillography records, service reports and protection summary can be captured though Hot Links directly. Hot Links enable the user to monitor the updates status of inputs and outputs of T60 [3].

From the EnerVista Setup menu, Device Definition link provides technical details of the IED which are read through the RS485 serial connection [3]. For instance, T60 operates with 7.1 firmware version and the IP address of 192.168.2.5 (Fig. 5.14). These details cannot be altered or reset through the Ethernet connection and requires the RS485 serial connection.

Product Setup, Systems Setup, Flex Logic, Control Elements and Input/s/Outputs links are located under the Setting menu. Control Elements is designed with a series of links to program the protection functions for T60. The list of protection and control functions employed by T60 is tabulated in Table 5.1 according to three common indusrty standards namely: IEC61850, ANSI and IEC60617 [3].

Table 5.1 Functions Used for Protection and Control of Transformer Zone

Standard	**IEC61850**	**ANSI**	**IEC60617**
Three-phase Timed Non-directional Overcurrent Protection Stage 1	PHLPTOC	51P	3I>>>
Three-phase Instantaneous Directional Overcurrent Protection	DPHHPDOC	50P	3I>>→
Non-directional Instantaneous Earth Fault Protection	EFHPTOC	50N	Io>>
High Impedance Differential Protection	HZPDIF	87	I_d
Residual Overvoltage Protection,	ROVPTOV	59N	Uo>
Three-phase Undervoltage Protection,	PHPTUV	27	3U<
Three-phase Overvoltage Protection,	PHPTOV	59	3U>
Master Trip	TRPPTRC1	86/94	MT
Circuit Breaker Control,	CBXCBR	52	I <->O CB

Figure 5.15 shows the snapshot of the Trip Bus window, the place under the Setting menu within the Control Element link used to initiate the functions mentioned in Table 5.1. This window is launched through the following path:

EnerVista → UR Setup → Setting → Control Elements → Trip Bus

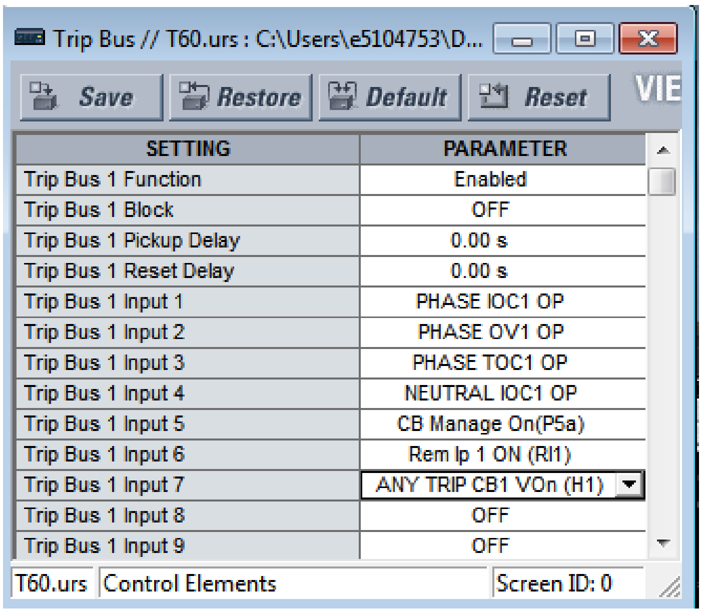


Fig. 5.15 Trip Bus window configuration for T60

T60's input and output contacts are configurable under the Product Setup section. As Figure 5.16 depicts, the channels H5A and H5C are selected to monitor the position of the Circuit Breaker 1. H6A contact is used to receive the CBF signal from REB650. H6C and H7C contacts are used to enable T60 to bypass any subscribed GOOSE message during the maintenance test condition. H7A is used to ontrol the position of Bust Tie Circuit Breaker (CB6) from the SCADA contol room remotly.

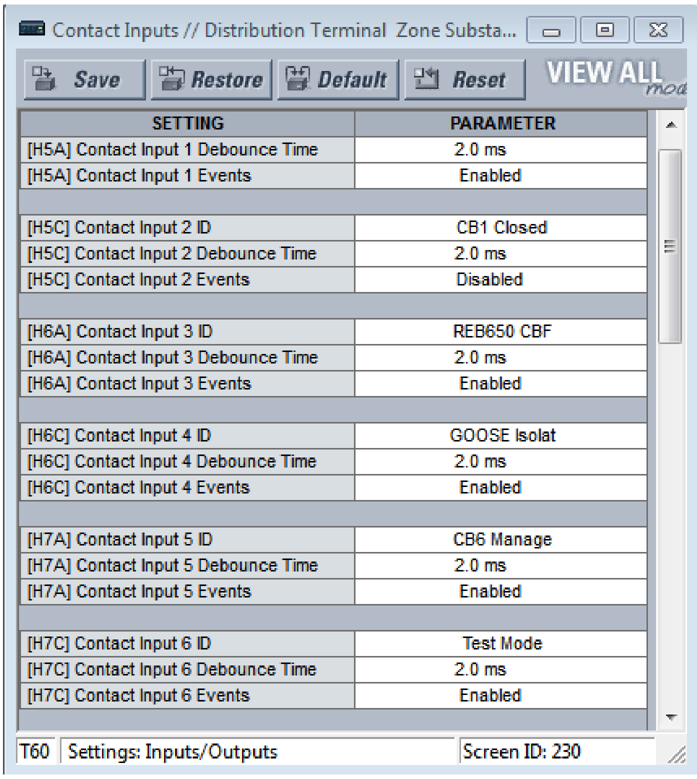


Fig. 5.16 T60's input and output contacts configuration

T60 employes only two contacts, H1 and H2, to send its output signals through wire cable. These two contacts control the position of CB1 by sending Open/Close commands (Fig. 5.17). This is due to the fact that in the construction of 66/22kV Distribution Terminal Zone Substation the amount of copper wiring is reduced and replaced by GOOSE signals. Saying that, all remaining signals are published through GOOSE message.

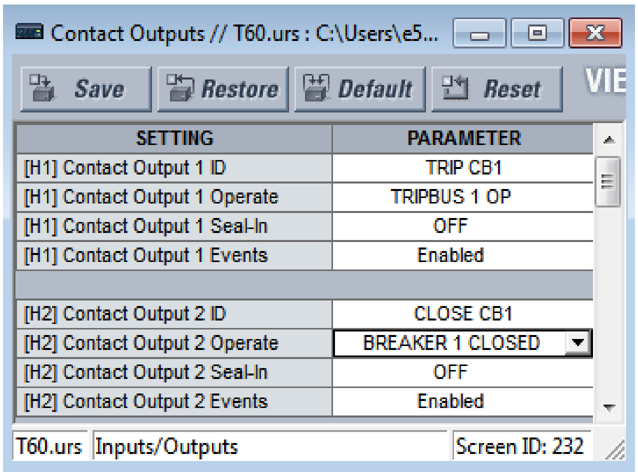


Fig. 5.17 Output contacts configuration for T60

Another useful submenu under EnerVista Setup is Product Setup. It is intended to create a GOOSE Control Block using the IEC61850 GOOSE Configurator launchpad. However, prior to start working with this launchpad, its engineering mode has to be enabled within the Server Configuration window located under Product Setup Menu.

GE Universal Relays, including T60, make a use of the TxGOOSE element to publish the GOOSE Control Block signal in the network. Each TxGOOSE consists of standardised information to make its GOOSE signal recognisable in the network. Figure 5.18 shows the configuration of GOOSE Control Block 1 for T60 (GCB1_T60) using Tx Configurable GOOSE launchpad. In the configuration of GCB1_T60, it is mandatory to choose a unique name and number for GOOSE ID and ETYPE APPID respectively.

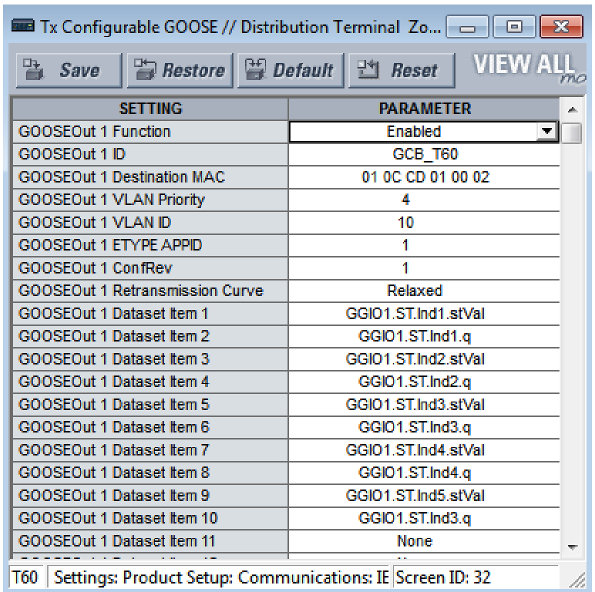


Fig. 5.18 Configuration of GCB1_T60

T60 publishes a GOOSE signal consists of five pairs of datasets. Each pair transfers Quality and StVal data attributes of the GOOSE Control block. These datasets contain protection, control and supervision information to the subscriber IED which is provided as a Signal Matrix in Table 5.2.

Table 5.2 GOOSE Signal Matrix of T60

IEDs			IP	Subscriber						
				T60						
T60 .... 192.168.2.5 REB650 .... 192.168.2.10 F35 .... 192.168.2.15 REF615_1 .... 192.168.2.20 REF611 .... 192.168.2.25 REF615_2 .... 192.168.2.30				GGIO3.ST.Ind1.stval	GGIO3.ST.Ind2.stval	GGIO3.ST.Ind3.stval	GGIO3.ST.Ind4.stval	GGIO3.ST.Ind5.stval	GGIO3.ST.Ind6.stval	GGIO3.ST.Ind7.stval
	IED	GOOSE Details	GOOSE ID.Logical Devce.GCB.Dataset.Data Attribute							
Publisher	REB650	Master Trip	GCB1_REB650.LD0.TRPPTRC.stVal							
Publisher	REB650	CB2 fail	GCB1_REF650.LD0.CCBRBRF.stVal	×						
Publisher	REB650	CB2 Status 1	GCB1_REF650.LD0.CBSWI.PosCls.stVal		×					
Publisher	REB650	CB2 Status 2	GCB1_REF650.LD0.CBSWI.PosOpn.stVal			×				
Publisher	REF615_2	CB6 Fail	GCB1_REF615_2.LD0.CCBRBRF.stVal				×			
Publisher	REF615_2	CB6 Status 1	GCB1_REF615_2.LD0.CBSWI.PosCls.stVal					×		
Publisher	REF615_2	CB6 Status 2	GCB1_REF615_2.LD0.CBSWI.PosOpn.stVal						×	
Publisher	REF615_2	CB6 Control	GCB1_REF615_2.LD0.CBSWI.PosOpn.stVal							×

After configuring GOOSE Control Blocks using Tx Configurable windows, they are assigned to GGIO function blocks to be published in the network. Figure 5.19 illustrates the composition and arrangement of GGIO function blocks for GCB1_T60.

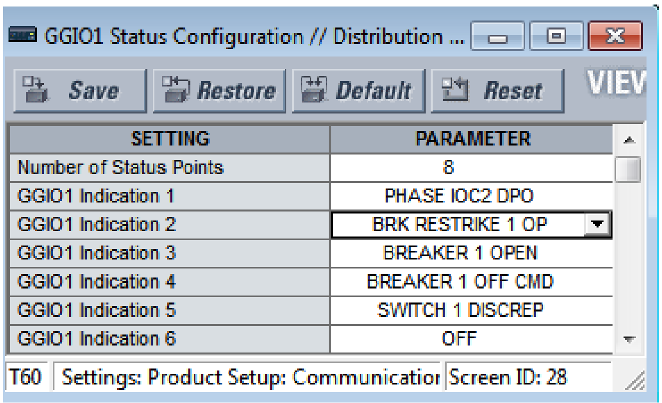


Fig. 5.19 Information of T60’s GGIO function blocks

From the point of subscribing to a GOOSE signal, the standard has not initiated any receiving GOOSE Control Block. Thus, vendors implemented their own way to receive and store the receiving GOOSE signal in their device. For instance, GE Universal Relays provide a RxGOOSE element to receive an incoming GOOSE signal and extract its information. This is achievable providing that the details of the incoming GOOSE signal, GOOSE ID, VLAN ID and GOOSE Reference Number, are already specified to T60. These details are given to T60 within two separate windows called:

- Remote Devices
- Remote Inputs

Remote Devices represent the details of GOOSE publisher IEDs and Remote Device represents the details of incoming GOOSE control Block.

If the details of Remote Devices and Remote Inputs inside T60 do not match with the details of the publisher device and its GOOSE signals, the GOOSE message will neither be detected nor executed by T60. Figure 5.20 shows the configuration of Remote Inputs and Remote Devices for T60 relay. It depicts that T60 is subscribed to two IEDs namely: REB650 and REF615-2. It also provides details of the IEDs and their GOOSE messages detail that T60 is subscribed to.

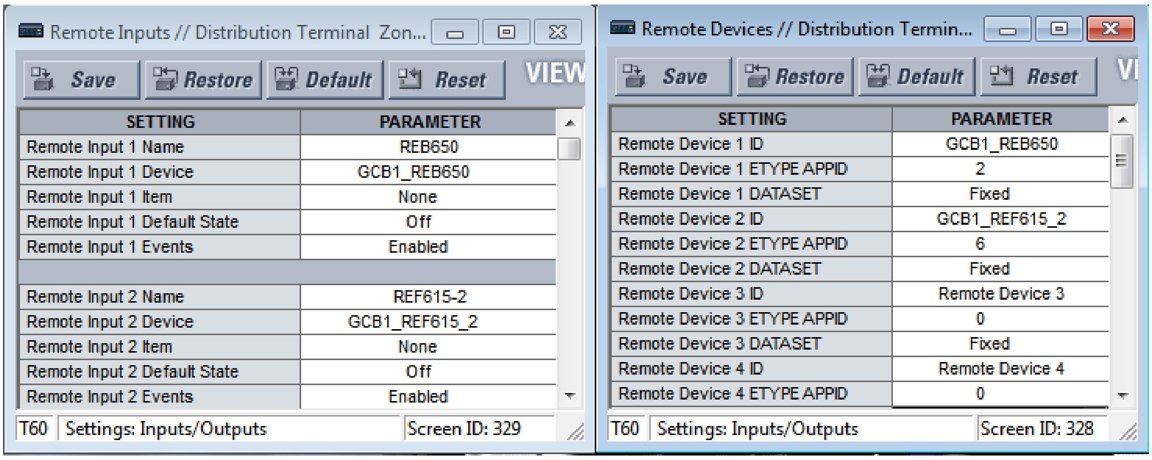


Fig. 5.20 Introducing the detail of subscribed GOOSE to T60

5.2.3 REB650

REB650 is a multi-management busbar relay from the ABB Relion family programmable using PCM600 software. In the designing of the 66/22kV Distribution Terminal Zone Substation, REB650 is utilised for the protection of Bus1 connected to Line 1 to perform as:

- Three-phase High Impedance Differential Protection
- Back up for Feeders 1, 2 and 3 protections
- Bus Tie Circuit Breaker 1 Control
- Phase/Earth Overcurrent Protection
- Overvoltage/Undervoltage Protection

The details of protection and control functions implemented by REB650 are listed in Table 5.3 according to three common indusrty standards namely: IEC61850, ANSI and IEC60617 [67].

Table 5.3 Functions Used for Protection and Control of Bus 1 [45, 51, 61]

Standard	IEC61850	ANSI	IEC 60617
Three-phase Instantaneous Directional Overcurrent Protection	DPHHPDOC	50P	3I>>→
Three-phase Non-directional Overcurrent Protection Stage 1	PHIPTOC	50P	3I>>>
High Impedance Differential Protection	HZPDIF	87	Id
Three-phase Undervoltage Protection,	PHPTUV	27	3U<
Three-phase Overvoltage Protection,	PHPTOV	59	3U>
Non-directional Instantaneous Earth Fault Protection	EFHPTOC	50N/51N	Io>>>
Master Trip	TRPPTRC	86/94	MT
Circuit Breaker Control	CBXCBR	52	I <->O CB
Circuit Breaker Failure	CCBRBRF	50BF	3I>/Io>B F

Individual configuration of REB650 requires a vendor proprietary software tool. PCM600 is employed as the ABB IED configurator tool to program the REB650 relay. After installing PCM600 V2.6, the connectivity package of REB650 is downloaded from the ABB protection Library using Update Manager windows. This connectivity package contains a different version of REB650 firmaware and entire documents related to its configuration (Fig. 5.21).

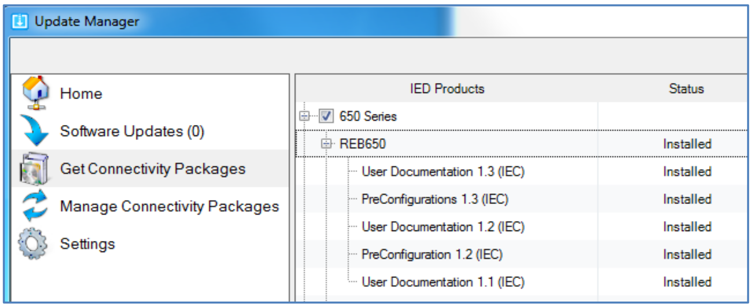


Fig. 5.21 Using Update Manager as the ABB central software library

Communication between PC and REB650 is achievable either via the rear Ethernet port VLAN 1 or the RJ-45 front port using the HMI Web Browser [67]. The HMI Web Browser is only designed to set up basic parameters of the IED. It has limited capacity to configure the IED’s protection and control functions’ parameters. Thus, the rear port is approached as a communication media between PC and REB650. After launching PCM600, a new project named 66/22kV Distribution Terminal Zone substation is created in PCM600 and REB650 is added to the project. This is followed by scanning the serial number and IP address from IED to PCM600 through the straightforward procedures illustrated in Figure 5.22.

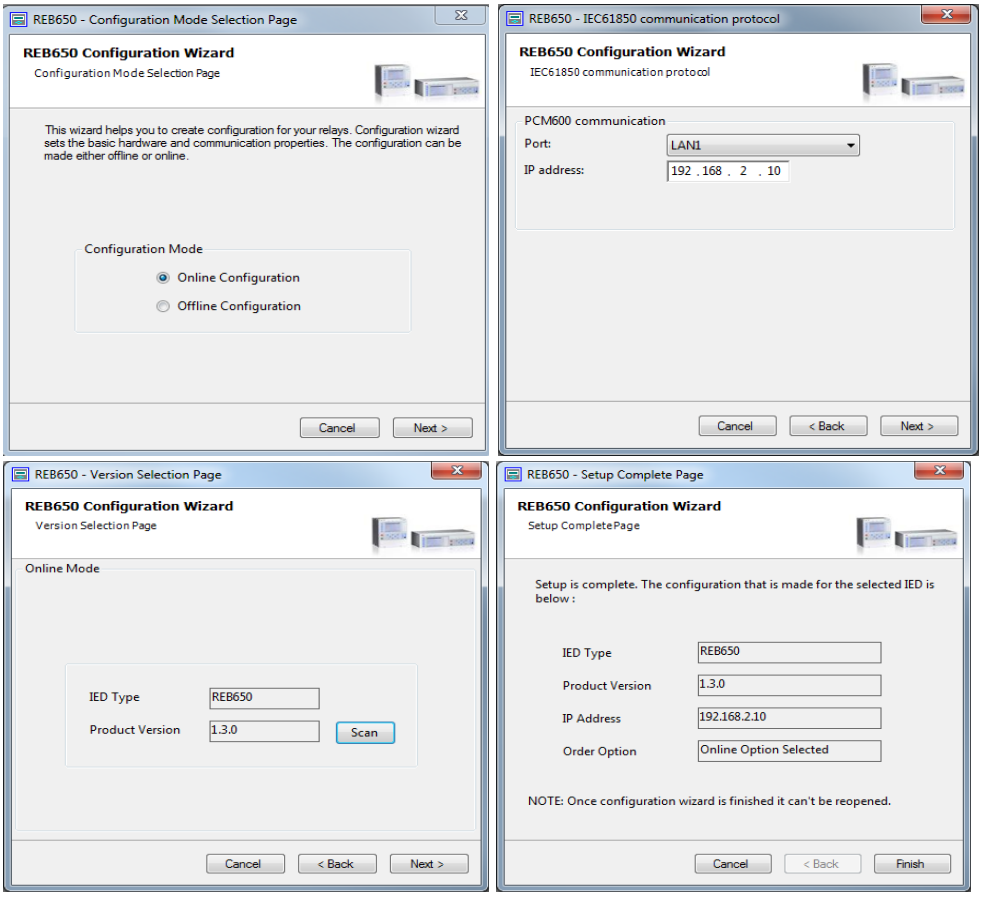


Fig. 5.22 REB650's communication and IP set up using PCM600

When the scanning is accomplished, REB650 will appear in the project file created in PCM600. The next step is to read the IED setting. The Reading process enables the user to read all preconfigured file of the IED into project file created in PCM6600. The preconfigured file contains all information about Hardware Configuration (HW Configuration), input/output contacts, Application Configuration, IEC65850 Configuration and protection functions configurations. HW Configuration describes how and which channels are installed in REB650. Application Configuration provides details of the protection and control functions which can be utilised by REB650. Figure 5.23 shows snapshot from the main menu and submenus within PCM600. For instance, it shows the setting of analogue inputs used for CTs measurements.

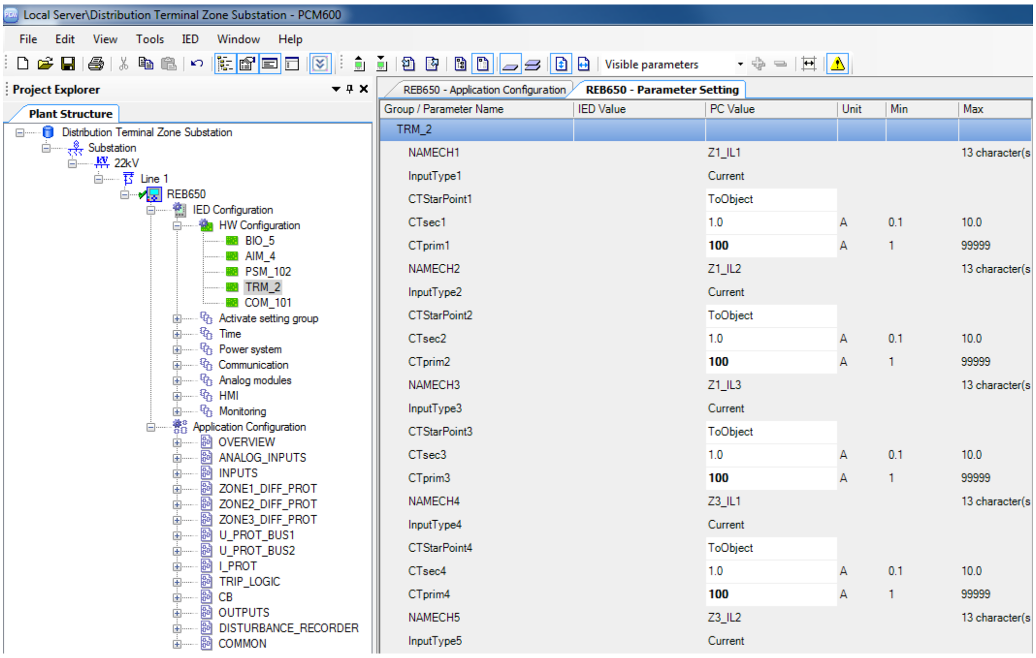


Fig. 5.23 snapshot of the PCM600 used for REB650

The programmable and flexibility of REB650 enables the user to alter/change the setting of the IED subject to the requirement of the system at any time [67]. For instance, if all the inputs are already occupied in pre-configured setting and an external signal is required to be connected to the IED for logic programing, PCM600 allows the user to add/insert additional hardware module. Figure 5.24 shows an example of adding a hardware module, BIO-5 to the application configuration page of PCM600. The GOOSE Isolation signal is injected to REB650 via BI1 contact under BIO_5 module.

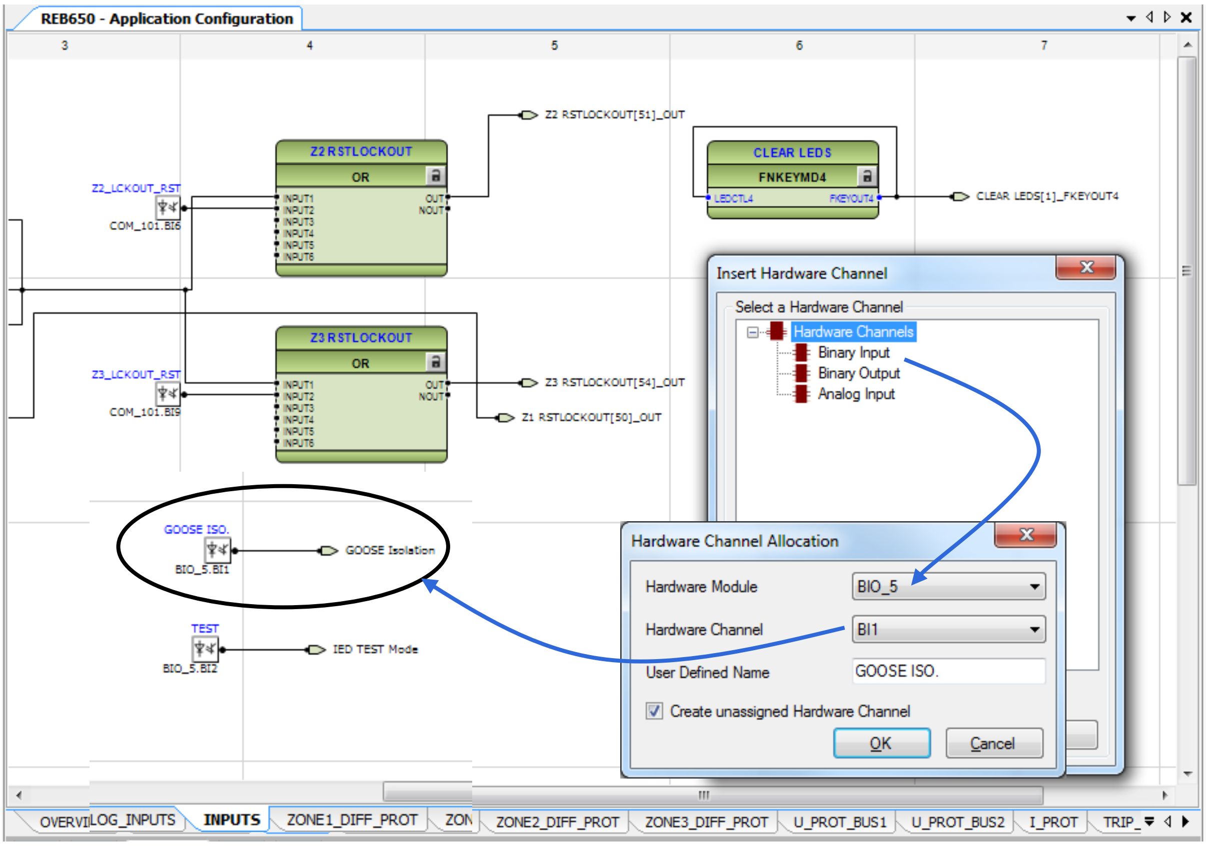


Fig. 5.24 Inserting additional hardware contact input to REB650

PCM600 make use of an internal IEC61850 Configurator tool to configure GOOSE Control Block of REB650 and export its CID file. Prior to start working with GOOSE configurator, the IEC61850 Engineering mode of REB650 needs to be activated. This allows the user to lunch the IEC61850 Configurator window. Then a new data set is created by right-clinking in the empty space of the GOOSE Configurator window. According to the standard [45, 67], all data sets have to be located under LLN0. This is a specific logical node provides functionality of the logical device that belongs to. After creating data set and data attribute, GOOSE Control Block is generated and mapped to subscriber IEDS. Figure 5.25 exemplifies a flow of creating one of the REB650 GOOSE Control Blocks.

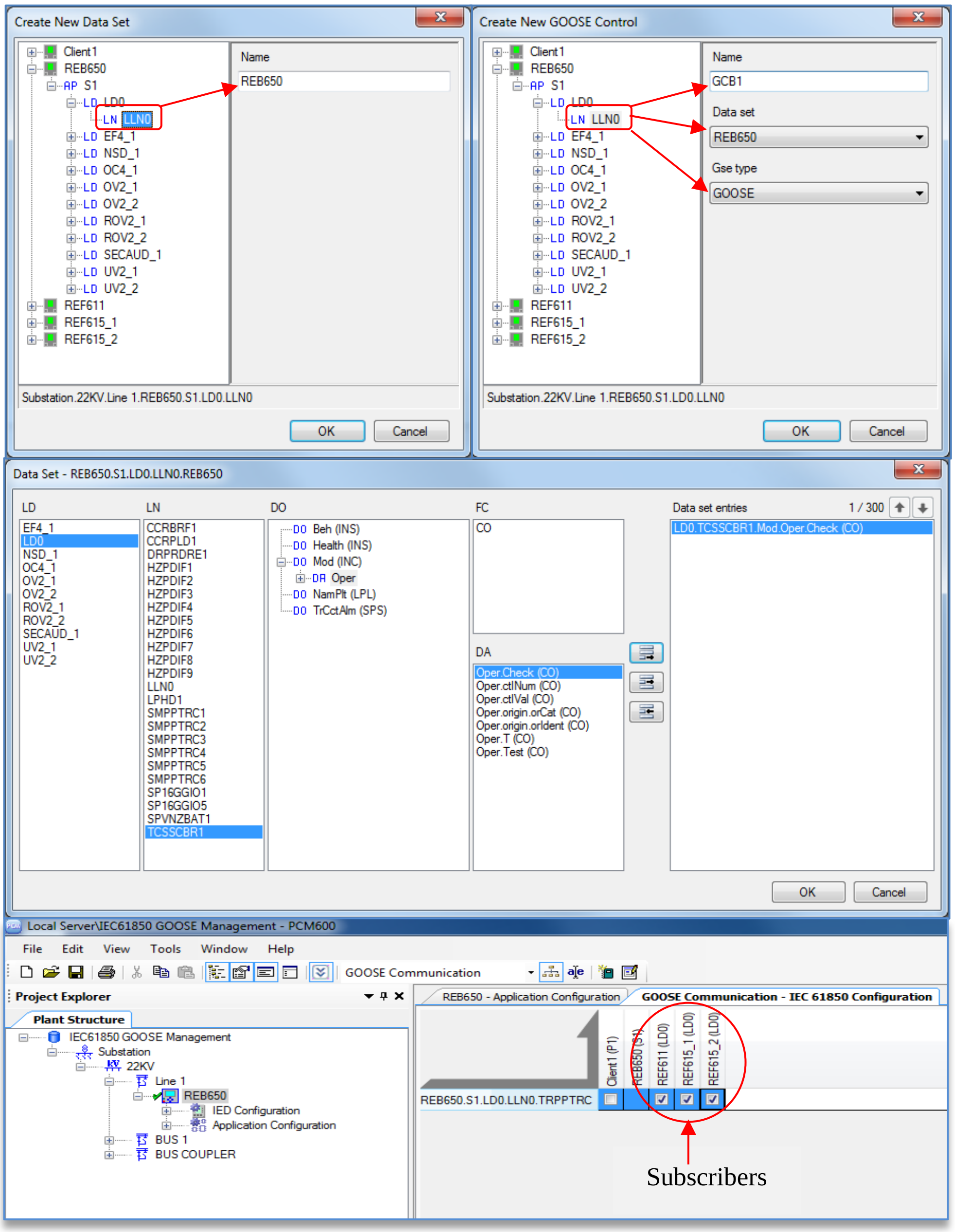


Fig. 5.25 Procedures to create GCB1_REB650

REB650 publishes GCB1-REB650 signal which consists of five pairs datasets. Each pair transfers different data attributes, Quality and StVal, of the GOOSE Control block. These datasets contain protection, control and supervision information to subscriber IEDs. REB650 is also subscribed to nine GOOSE signals being published from F35, REF615-1 and REF611 (Table 5.4).

Table 5.4 GOOSE Signal Matrix of REB650

		IEDs	IP	Subscriber																							
		T60 . . . . .192.168.2.5 REB650 . . . . .192.168.2.10 F35 . . . . .192.168.2.15 REF615_1 . . . . .192.168.2.20 REF611 . . . . .192.168.2.25 REF615_2 . . . . .192.168.2.30		T60			REB650									F35		REF615			REF611			REF615-2			
				GGIO3.ST.Ind1.stval	GGIO3.ST.Ind2.stval	GGIO3.ST.Ind3.stval	GOOSE Binary Recived 1	GOOSE Binary Recived 2	GOOSE Binary Recived 3	GOOSE Binary Recived 4	GOOSE Binary Recived 5	GOOSE Binary Recived 6	GOOSE Binary Recived 7	GOOSE Binary Recived 8	GOOSE Binary Recived 9	GGIO3.ST.Ind1.stval	GGIO3.ST.Ind2.stval	GOOSE Binary Recived 1	GOOSE Binary Recived 2	Not Used	GOOSE Binary Recived 1	GOOSE Binary Recived 2	Not used	GOOSE Binary Recived 1	GOOSE Binary Recived 2	GOOSE Binary Recived 3	GOOSE Binary Recived 4
Publisher	REB650	Master Trip	GCB1_REB650.LD0.TRPPTRC.stVal													×		×			×			×			
		CB2 fail	GCB1_REF650.LD0.CCBRBRF.stVal	×																							
		CB2 Status 1	GCB1_REF650.LD0.CBSWI.PosCls.stVal		×																						
		CB2 Status 2	GCB1_REF650.LD0.CBSWI.PosOpn.stVal			×																					
	F35	CB3 Fail	GCB1_F35.LD0.GGIO1.ST.Ind1.stVal				×																				
		CB3 Status 1	GCB1_F35.LD0.GGIO1.ST.Ind2.stVal					×																			
		CB3 Status 2	GCB1_F35.LD0.GGIO1.ST.Ind3.stVal						×																		
	REF615-1	CB4 Fail	GCB1_REF615_1.LD0.CCBRBRF.stVal							×																	
		CB4 Status 1	GCB1_REF615_1.LD0.CBSWI.PosCls.stVal								×																
		CB4 Status 2	GCB1_REF615_1.LD0.CBSWI.PosOpn.stVal									×															
	REF611	CB5 Fail	GCB1_REF611.LD0.CCBRBRF.stVal										×														
		CB5 Status 1	GCB1_REF611.LD0.CBSWI.PosCls.stVal											×													
		CB5 Status 2	GCB1_REF611.LD0.CBSWI.PosOpn.stVal												×												

5.2.4 F35[6]

F35 is a GE relay employed in Feeder 1 connected to the Bus 1. It provides multiple relaying functions to protect and control all equipment located within Feeder 1 zone. EnerVista IED configurator tool is the vendor proprietary tool to configure F35. Similar to the other IEDs, RS485 Serial is used to make a connection between F35 and PC to set up the IP: 192.168.2.15 for F35.

F35 operates with a timed directional Overcurrent Protection element in three stages: High (Stage 1), Medium (Stage 2) and Low (Stage 3). Subject to the protection scheme, these stages are chosen between definite time and inverse definite minimum time characteristics. F35 is also configured for non-directional Overcurrent without time-dependant delay properties. F35 also performs the Residual Current Measurement to operate the Earth Fault Protection element in Feeder 1. According to the default setting of the F35 [61], the Residual Current is governed by summation of three-phase currents.

The details of protection and control functions utilised by F35 are listed in Table 5.5 according to three common indusrty standards namely: IEC61850, ANSI and IEC60617.

[6] Since F35 belongs to GE UR Multilin relays and the snapshots of UR configuration instructions are already provided in detail in Section 5.2.2, the snapshots related to F35 configuration are not presented in this section and are presented in Appendix A.

Table 5.5 Functions Used for Protection and Control of Feeder1 by F35 [45, 51, 61]

Standard	IEC61850	ANSI	IEC 60617
Three-phase Timed Non-directional Overcurrent Protection Stage 3	PHLPTOC	51P	3I>
Three-phase Timed Non-directional Overcurrent Protection Stage 2	PHHPTOC	51P	3I>>
Three-phase Timed Non-directional Overcurrent Protection Stage 1	PHIPTOC	50P	3I>>>
Three-phase Instantaneous Directional Overcurrent Protection	DPHHPDOC	50P	3I>>→
Non-directional Instantaneous Earth Fault Protection	EFHPTOC	50N/51N	Io>>>
Master Trip	TRPPTRC	86/94	MT
Circuit Breaker Control	CBXCBR	52	I <->O CB
Circuit Breaker Failure	CCBRBRF	50BF	3I>/Io>B F

Similar to T60, input and output contacts of F35 are configured using EnerVista Launchpad menu. The channels H-1a and H-1c are selected to monitor the position of Circuit Breaker 3. H1-a will be energised when CB3 is closed, whereas H-1c will be trigged when CB3 is open. If F35 requires periodical maintenance test or IED upgrading, it needs to put in TEST mode to ignore other IEDs publishing signals. H-8a is used to set F35 to the TEST mode. At the same time, if the GOOSE being published from F35 needs to be bypassed by other subscribed IEDs, input H-8c will be energised to isolate GOOSE signals publishing from F35. H-5a and H-8c are controllable either locally via a manual switch or remotely from SCADA control centre.

Tripping and closing the Circuit Breaker 3 is managed through output contacts of F35. While H-1a initiates the Trip/Open command to energise the coil of CB3, H-1c is used to close the contactor of CB3. Table 5.6 represents the details of F35's input/output contacts configuration using EnerVista Launchpad.

Table 5.6 Configuration of Input/output Contacts of F35

Channels	Contact Type	Parameter
H-1a	Input	CB3 is Closed
H-1c	Input	CB3 is Open
H-5a	Input	GOOSE Isolation
H-8c	Input	IED Test Mode
M-1a	Output	Trip/Open CB3
M-3b	Output	Close CB3

Similar to other IEDs, in the construction of the 66/22kV Distribution Terminal Zone Substation the amount of copper wiring is reduced and replaced by taking advantage of GOOSE signals. F35 utilises only two contacts to control the position of CB3. Other output signals such as upstream CBF command are transmitted through GOOSE message to other IEDs.

According to Table 5.6, one of the protection functions considered for F35 is Circuit Breaker Failure (CCBRBRF). This function generates a trip signal to be sent to the upstream IED, REB650, to clear the fault in Feeder 1 zone if F35 fails to operate.

Figure 5.26 shows the logic diagram of the CBF trip signal created using Flex Logic program through EnerVista used to create CBF signal being sent from F35.

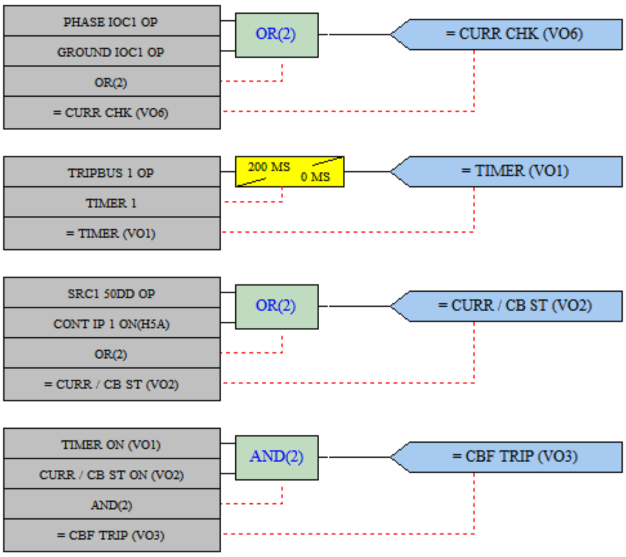
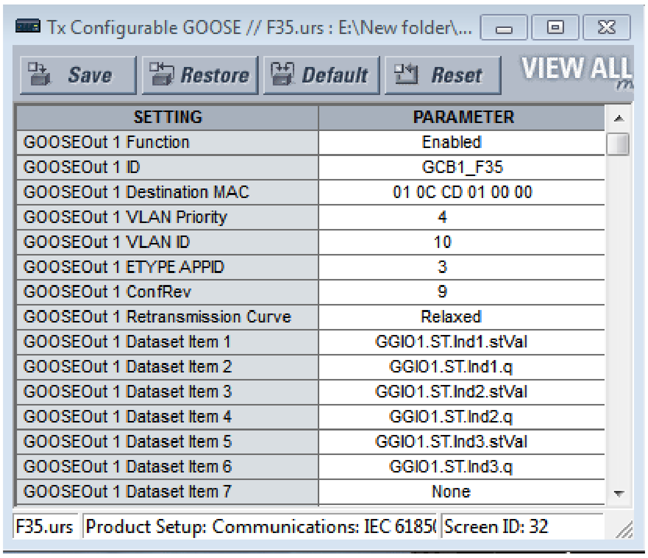


Fig. 5.26 Logic diagram of CBF trip signal used for F35

The Product Setup within EnerVista Launchpad window is the link to create GOOSE Control Blocks using IEC61850 GOOSE Configurator. However, prior to start working with IEC61850 configurator lunch pad, its engineering mode has to be enabled within Server Configuration window located in Product Setup Menu.

GE F35 provides TxGOOSE element, programmable using Tx Configurable GOOSE Launchpad, to publish the GOOSE Control Block signal in the network. This TxGOOSE consists of standardised information to make it recognisable in the network. Figure 5.27 is a snapshot of Tx Configurable GOOSE window which provides details of the GCB1_F35 including GOOSE ID, VLAN ID and GOOSE Destination MAC Address.



Tx Configurable GOOSE // F35.urs : E:\New folder\...

SETTING	PARAMETER
GOOSEOut 1 Function	Enabled
GOOSEOut 1 ID	GCB1_F35
GOOSEOut 1 Destination MAC	01 0C CD 01 00 00
GOOSEOut 1 VLAN Priority	4
GOOSEOut 1 VLAN ID	10
GOOSEOut 1 ETYPE APPID	3
GOOSEOut 1 ConfRev	9
GOOSEOut 1 Retransmission Curve	Relaxed
GOOSEOut 1 Dataset Item 1	GGIO1.ST.Ind1.stVal
GOOSEOut 1 Dataset Item 2	GGIO1.ST.Ind1.q
GOOSEOut 1 Dataset Item 3	GGIO1.ST.Ind2.stVal
GOOSEOut 1 Dataset Item 4	GGIO1.ST.Ind2.q
GOOSEOut 1 Dataset Item 5	GGIO1.ST.Ind3.stVal
GOOSEOut 1 Dataset Item 6	GGIO1.ST.Ind3.q
GOOSEOut 1 Dataset Item 7	None

F35.urs | Product Setup: Communications: IEC 6185(| Screen ID: 32

Fig. 5.27 Configuration of GCB1_F35 using Tx Configurable GOOSE Launchpad

F35 publishes a GOOSE signal which contains three pairs of datasets. Each pair transfers Quality and StVal data attributes belongs to its GCB (Fig. 5.26). These data attributes contain protection, control and supervision information to subscriber IEDs. Table 5.7 provides the GOOSE mapping between F35 and other IEDs. It shows the details of publishing GOOSE from F35 as well as details of GOOSE signals that F35 is subscribed to.

Table 5.7 GOOSE Signal Matrix for F35

IEDs	IP
T60	192.168.2.5
REB650	192.168.2.10
F35	192.168.2.15
REF615-1	192.168.2.20
REF611	192.168.2.25
REF615-2	192.168.2.30

Publisher	IED	GOOSE Details	GOOSE ID.Logical Devce.GCB.Dataset.Data Attribute	Subscriber REB650 GOOSE Binary Recived 1	Subscriber REB650 GOOSE Binary Recived 2	Subscriber REB650 GOOSE Binary Recived 3	Subscriber F35 GGIO3.ST.Ind1.stval
Publisher	REB650	Master Trip	GCB1_REB650.LD0.TRPPTRC.stVal				×
		CB2 fail	GCB1_REF650.LD0.CCBRBRF.stVal				
		CB2 Status 1	GCB1_REF650.LD0.CBSWI.PosCls.stVal				
		CB2 Status 2	GCB1_REF650.LD0.CBSWI.PosOpn.stVal				
	F35	CB3 Fail	GCB1_F35.LD0.GGIO1.ST.Ind1.stVal	×			
		CB3 Status 1	GCB1_F35.LD0.GGIO1.ST.Ind2.stVal		×		
		CB3 Status 2	GCB1_F35.LD0.GGIO1.ST.Ind3.stVal			×	

In order to map GOOSE signals between F35 and other IEDs there are two available approaches: using EnerVista Simplified IEC61850 GOOSE Configurator or using a multi-vendor IEC61850-based IED configurator tool such as IET600.

The EnerVista Simplified IEC61850 GOOSE Configurator is applicable when mapping is required between GE IEDs. This means there are no third party vendor IEDs and tools are contributed. An example of using Simplified GOOSE Configurator is demonstrated in Figure 5.28. (**Note:** in the development of the 66/22kV Distribution Terminal Zone Substation, there is no GOOSE signal used to be transferred between F35 and T60. Thus, Figure 5.28 is provided as an example to illustrate how two GE IEDs can be mapped to each other). The second approach, using multi-vendor system configurator tool, is selected as a solution to map GOOSE signal between F35 and ABB relay. This step will be explained in detail in Section 5.3.

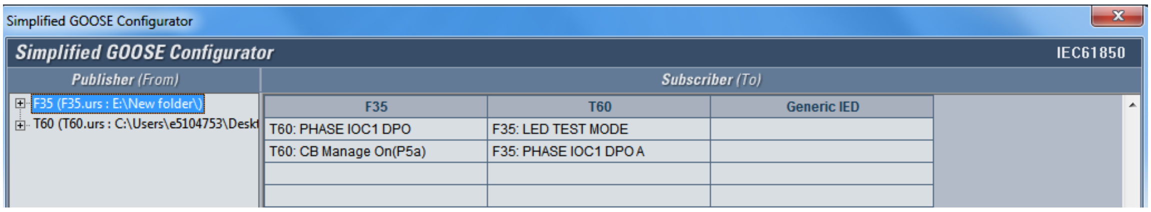


Fig. 5.28 Example of GOOSE mapping between F35 and T60 using vendor tool

5.2.5 REF615-1

REF615-1 is an ABB relay employed as a feeder protection IED in Feeder 2 connected to the Bus 1 (Fig. 4.1 in chapter 4). It is utilised to protect and control all equipment located within the Feeder 2 zone using different protection schemes such as: timed directional Overcurrent Protection element in three stages: High (Stage 1), Medium (Stage 2) and Low (Stage 3). Subject to the protection scheme, these stages have combined with Definite Time (DT) and Inverse Definite Minimum Time (IDMT) characteristics. REF615-1 is also configured for non-directional Overcurrent Protection without time delay properties. REF615-1 performs the Residual Current Measurement to operate the Earth Fault Protection element in Feeder 1. According to the default setting of the REF615-1 [59], the Residual Current is governed from the summation of three-phase currents. The details of protection and control functions utilised by REF615-1 are listed in Table 5.8 according to three common industry standards namely: IEC61850, ANSI and IEC60617.

Table 5.8 Protection and control functions employed by REF615-1 [45, 51, 61]

Standard	IEC61850	ANSI	IEC 60617
Three-phase Timed Non-Directional Overcurrent Protection Stage3	PHLPTOC	51P	3I>
Three-phase Timed Non-directional Overcurrent Protection Stage 2	PHHPTOC	51P	3I>>
Three-phase Timed Non-directional Overcurrent Protection Stage 1	PHIPTOC	50P	3I>>>
Three-phase Instantaneous Directional Overcurrent Protection	DPHHPDOC	50P	3I>>→
Non-directional instantaneous Earth Fault Protection	EFHPTOC	50N/51 N	Io>>>
Master Trip	TRPPTRC	86/94	MT
Circuit Breaker Control,	CBXCBR	52	I <->O CB
Circuit Breaker Failure	CCBRBRF	50BF	3I>/Io>B F

All the aforementioned protection and control functions are configured and set up by PCM600. An example of creating circuit breaker failure function for REF615-1 using the Application Configuration window of PCM600 is shown in Figure 5.29. The CBF sends a trip signal to the upstream IED, REB650, to clear the fault in Feeder 1 if REF615-1 fails to operate (Fig. 5.30). More detail and explanation of implementing CBF protection is provided in Chapter 6.

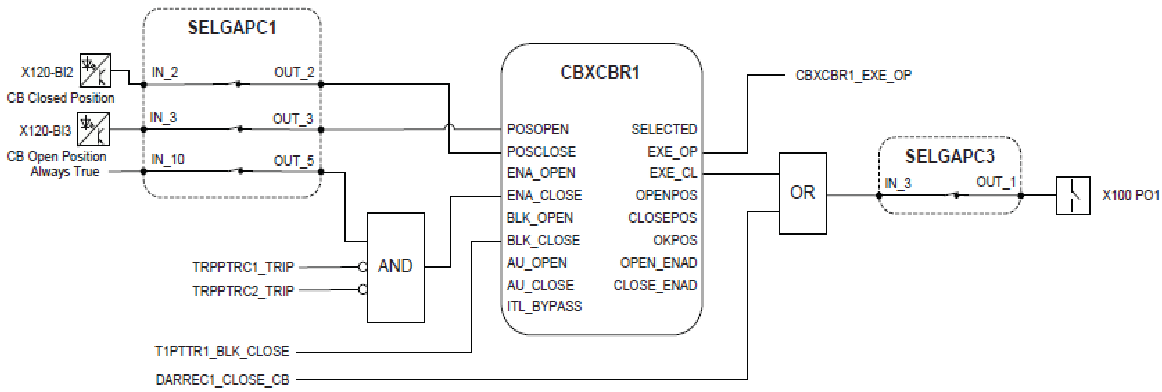


Fig. 5.29 REF615-1 CBXCCBR1 logic operation controlled by different signals

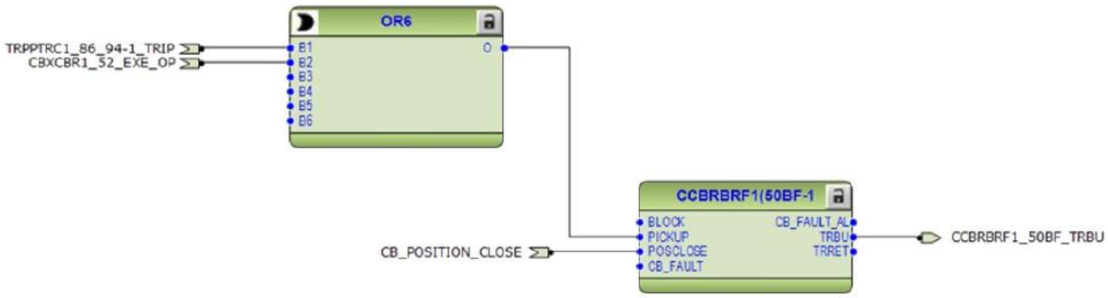


Fig. 5.30 CBF function block created in Application Configuration of REF615-1

REF615-1 has a Signal Monitoring option which allows the user to monitor and capture the latest status and record of inputs and outputs of the IED. Figure 5.31 shows the details and parameters which can be captured through Signal Monitoring within PCM600.

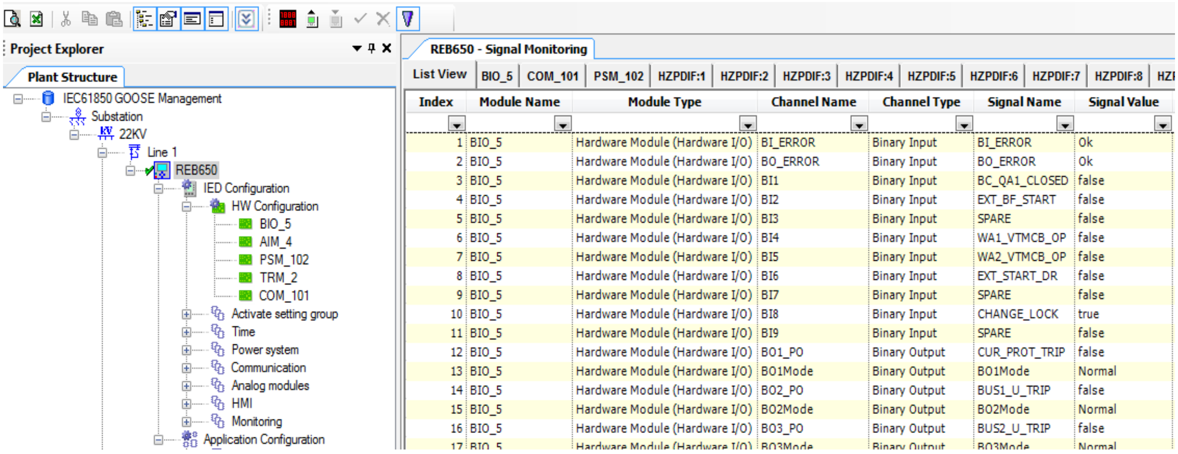


Fig. 5.31 Signal Monitoring window in PCM600

Similar to other IED used in Substation Simulator, copper wiring between REF6151 and other IEDs is replaced by GOOSE messaging technology. REF615-1 publishes a GOOSE signal to REB650 and is subscribed to GOOSE message coming from REB650. In order to configure GOOSE Control Block of REF615-1, the IEC61850 Engineering mode in PCM600 is enabled and GOOSE Configurator is used to create the datasets and CGB of REF615-1. The details of GOOSE messages mapped between REF615-1 and REB650 is provided as REF615-1 GOOSE Signal Matrix in Table 5.9.

Table 5.9 GOOSE Signal Matrix of REF615-1

IEDs	IP
T60	192.168.2.5
REB650	192.168.2.10
F35	192.168.2.15
REF615-1	192.168.2.20
REF611	192.168.2.25
REF615-2	192.168.2.30

				Subscriber					
				REB650			REF615-1		
	IED	GOOSE Details	GOOSE ID.Logical Devce.GCB.Dataset.Data Attribute	GOOSE Binary Recived 1	GOOSE Binary Recived 2	GOOSE Binary Recived 3	GGIO3.ST.Ind1.stval	GGIO3.ST.Ind2.stval	GGIO3.ST.Ind3.stval
Publisher	REB650	Master Trip	GCB1_REB650.LD0.TRPPTRC.stVal						×
		CB2 fail	GCB1_REF650.LD0.CCBRBRF.stVal						
		CB2 Status 1	GCB1_REF650.LD0.CBSWI.PosCls.stVal						
		CB2 Status 2	GCB1_REF650.LD0.CBSWI.PosOpn.stVal						
	REB615-1	CB3 Fail	GCB1_F35.LD0.GGIO1.ST.Ind1.stVal	×					
		CB3 Status 1	GCB1_F35.LD0.GGIO1.ST.Ind2.stVal		×				
		CB3 Status 2	GCB1_F35.LD0.GGIO1.ST.Ind3.stVal			×			

5.2.6 REF615-2

In designing of the 66/22kV Distribution Terminal Zone Substation, REF615-2 is deployed as a Bus Tie Coupler IED between Line 1 and Line 2 of the substation (Fig. 4.1 in chapter 4). Its primary task is to monitor and control the position of the Bus Coupler Circuit Breaker (CB6). It operates different elements such as non-directional Overcurrent Protection, non-directional Earth fault Protection, Voltage & Frequency based Protection and Synchro Check within busbar zone protection between Bus 1 and Bus 2. The performance and operation of REF615-2 is analysed in detail in Chapter 6.

From the point of IEC61850 GOOSE messaging, REF615-2 is subscribed to receive GOOSE signals from REB650 and T60 relays. In order to assign the incoming GOOSE signals from REB650 and T60, a GOOSE binary input as a virtual input needs to be created. Form the Insert Function Block library a “GOOSERCV_BIN” as an input signal is inserted in Application Configuration page of PCM600. After giving name and details to the signal it can be connected to any other logic functions. Once the GOOSERCV_BIN input is connected to a logic function loop, its colour will change from grey to green. The flow of creating binary GOOSE input signal is shown in Figure 5.32. It shows that GOOOSERCV_BIN signal is connected to OR6 logic function which has a MASTER TRIP output. REF615-2 will send the trip signal to its circuit breaker as soon as it detects the GOOSE signal from REB650 or T60 (Fig. 5.32)

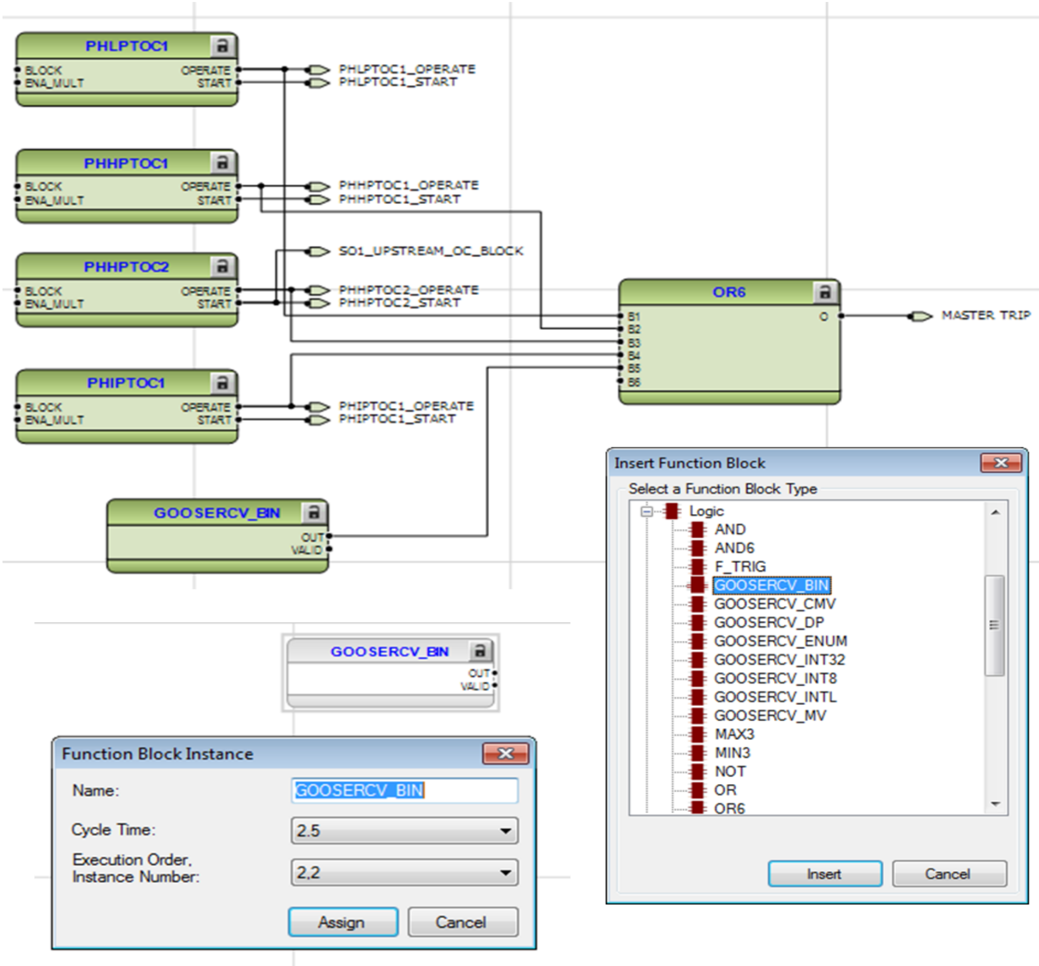


Fig. 5.32 The flow of connecting GOOSE input signal to protection functions of REF615-2

The details of GOOSE messages mapped between REF615-2, REB650 and T60 is provided as REF615-2 GOOSE Signal Matrix in Table 5.9.

Table 5.10 GOOSE Signal Matrix of REF615-2

IEDs			IP	Subscriber																								
				T60							REB650									REF615_2								
				GGIO3.ST.Ind1.stval	GGIO3.ST.Ind2.stval	GGIO3.ST.Ind3.stval	GGIO3.ST.Ind4.stval	GGIO3.ST.Ind5.stval	GGIO3.ST.Ind6.stval	GGIO3.ST.Ind7.stval	GOOSE Binary Recived 1	GOOSE Binary Recived 2	GOOSE Binary Recived 3	GOOSE Binary Recived 4	GOOSE Binary Recived 5	GOOSE Binary Recived 6	GOOSE Binary Recived 7	GOOSE Binary Recived 8	GOOSE Binary Recived 9	GOOSE Binary Recived 1	GOOSE Binary Recived 2	GOOSE Binary Recived 3	GOOSE Binary Recived 4	GOOSE Binary Recived 5	GOOSE Binary Recived 6	GOOSE Binary Recived 7	GOOSE Binary Recived 8	GOOSE Binary Recived 4
		T60 .... .192.168.2.5 REB650 .... .192.168.2.10 F35 .... .192.168.2.15 REF615-1 .... .192.168.2.20 REF611 .... .192.168.2.25 REF615-2 .... .192.168.2.30																										
Publishers	T60	Master Trip	GCB1_T60.LD0.GGIO1.ST.Ind1.stVal																	×								
		CB1 Interlocking	GCB1_T60.LD0.GGIO1.ST.Ind2.stVal																		×							
		CB1 is Open	GCB1_T60.LD0.GGIO1.ST.Ind5.stVal																			×						
		CB1 is Closed	GCB1_T60.LD0.GGIO1.ST.Ind6.stVal																				×					
		Switch Monitoring	GCB1_T60.LD0.GGIO1.ST.Ind7.stVal																					×				
	REB650	Master Trip	GCB1_REB650.LD0.TRPPTRC.stVal																									
		CB2 fail	GCB1_REF650.LD0.CCBRBRF.stVal	×																								
		CB2 Status 1	GCB1_REF650.LD0.CBSWI.PosCls.stVal		×																							
		CB2 Status 2	GCB1_REF650.LD0.CBSWI.PosOpn.stVal			×																						
	REF615_2	CB6 Fail	GCB1_REF615_2.LD0.CCBRBRF.stVal				×									×									×			
		CB6 Status 1	GCB1_REF615_2.LD0.CBSWI.PosCls.stVal					×									×									×		
		CB6 Status 2	GCB1_REF615_2.LD0.CBSWI.PosOpn.stVal						×									×									×	
		CB6 Control	GCB1_REF615_2.LD0.CBSWI.PosOpn.stVal							×									×									×

5.2.7 PLC SLC500

Allen Bradley SLC500/05 is employed as a middleware in the Station Level of the 22/66kV Distribution Terminal Zone Substation to control the operation of equipment both remotely and locally. This controller enables the operator to interact with IEDs and other devices through physical switches, locally, or via SCADA HMI, remotely. Configuration of SLC500 requires two main software interfaces: RSLinx and RSLogix 500. RSLinx operates a gateway to link the RSLogix500 to the PLC controller, where the RSLogix provides a ladder based programming interface to develop a program for PLC [64]. To begin, the RSLinx window is run and SLC500/05 is added to its library. Once the PLC SLC500 appears in the devices list of RSLinx, the RSLogix500 is launched. It is recommended to read the inputs/outputs and channels configuration of the PLC machine and copy them to the RSLogix500 memory (Fig. 5.33).

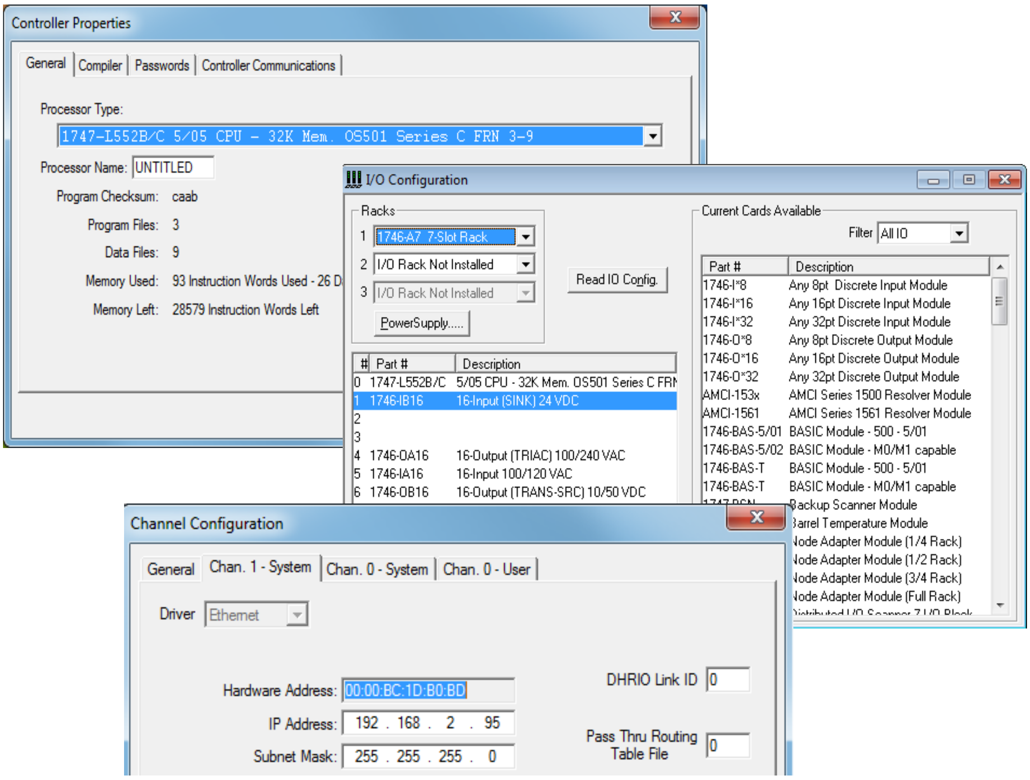


Fig. 5.33 Reading the channels configuration of SLC500

SLC500 used in Substation Simulator has 5 channels, two for the binary inputs (channels 1 and 5), two for the binary outputs (channels 4 and 6) and channel 0 is occupied by CPU of the PLC (Fig 5.33). Table 5.11 tabulates a list of inputs/outputs used in the ladder program of PLC SLC500 to monitor and control the IEDs, circuit breakers, isolators and earth switches utilised in Substation Simulator.

- **Note:** The RSLogix program is written over 120 lines using 65 I/O variables. Table 5.11 and Figure 5.34 only provide a section of PLC program and its details. The omplete ladder program and input/output details are provided in Appendix B.

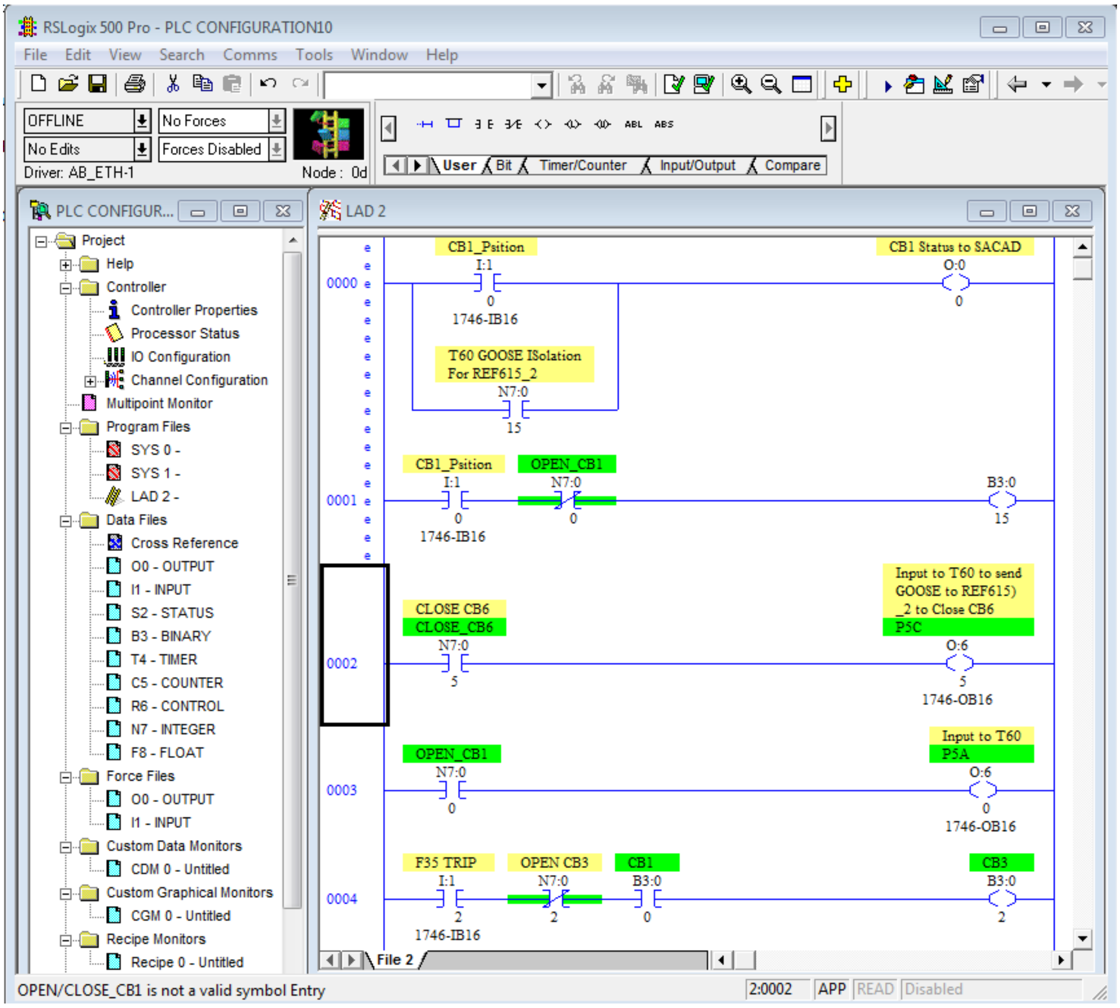


Fig. 5.34Snapshot of the logical ladder program of RSLogix500

Table 5.11 List of Inputs/Outputs Used in PLC SLC500

PLC I/O	Data Type	Addresses Used for Ladder Program	Comment
CB1_Position	Digital	I1:0/0	Status of CB1 as an input to PLC
CB2_Position	Digital	I1:0/1	Status of CB2 as an input to PLC
CB3_Position	Digital	I1:0/2	Status of CB3 as an input to PLC
CB4_Position	Digital	I1:0/3	Status of CB4 as an input to PLC
CB5_Position	Digital	I1:0/4	Status of CB5 as an input to PLC
CB6_Position	Digital	I1:0/5	Status of CB6 as an input to PLC
Cb1_Position	Digital	O4:0/0	Status of CB1 as an output to be sent to SCADA
CB2_Position	Digital	O4:0/1	Status of CB2 as an output to be sent to SCADA
CB3_Position	Digital	O4:0/2	Status of CB3 as an output to be sent to SCADA
CB4_Position	Digital	O4:0/3	Status of CB4 as an output to be sent to SCADA
CB5_Position	Digital	O4:0/4	Status of CB5 as an output to be sent to SCADA
CB6_Position	Digital	O4:0/5	Status of CB6 as an output to be sent to SCADA
CB1-Control	Digital	I1:0/6	Switch to Open/Close CB1 locally
CB2-Control	Digital	I1:0/7	Switch to Open/Close CB2 locally
CB3-Control	Digital	I1:0/8	Switch to Open/Close CB3 locally
CB4-Control	Digital	I1:0/9	Switch to Open/Close CB4 locally
CB5-Control	Digital	I1:0/10	Switch to Open/Close CB5 locally
CB6-Control	Digital	I1:0/11	Switch to Open/Close CB6 locally
CB1-Control	Digital	N7:0/0	Open/Close CB6 through SCADA HMI
CB2-Control	Digital	N7:0/1	Open/Close CB2 through SCADA HMI
CB3-Control	Digital	N7:0/2	Open/Close CB3 through SCADA HMI
CB4-Control	Digital	N7:0/3	Open/Close CB4 through SCADA HMI
CB5-Control	Digital	N7:0/4	Open/Close CB5 through SCADA HMI
CB6-Control	Digital	N7:0/5	Open/Close CB6 through SCADA HMI
T60	Digital	I1:0/12	Switch to put T60 in TEST mode locally
REB650	Digital	I1:0/13	Switch to put REB650 in TEST mode locally
F35	Digital	I1:0/14	Switch to put F35 in TEST mode locally
REF615-1	Digital	I1:0/15	Switch to put REF615-1 in TEST mode Locally
REF611	Digital	I5:0/0	Switch to put REF611 in TEST mode locally
REF615-2	Digital	I1:0/1	Switch to put REF615-2 in TEST mode locally
F35	Digital	N7:0/8	SCAD HMI command to put F35 in TEST mode
REF615-1	Digital	N7:0/9	SCAD HMI command to put REF615-1 in TEST mode
REF611	Digital	N7:0/10	SCAD HMI command to put REF611 in TEST mode
REF615-2	Digital	N7:0/11	SCAD HMI command to put REF615-2 in TEST mode

5.2.8 The SCADA System

The 22/66kV Distribution Terminal Zone Substation makes use of the SCADA system to monitor and control operation of equipment, earth switches isolators and circuit breakers, without need of physical access to the substation. Citect Vijio software is employed to develop the SCADA system which is driven by an external controller, PLC SLC500.

Development of the SCADA system is started by linking a PLC controller as an External I/O Device to the I/O Server of SCADA. The IO Server is the processor of the SCADA which operates as a gateway between PLC controller and SCADA [68, 69]. Figure 5.35 shows the configuration of I/O Server and External I/O Device within Express Communication Wizard windows. The PLC SLC500 Allen Bradley is selected as an external I/O Device for SCADA system with TCP/IP option to communicate with.

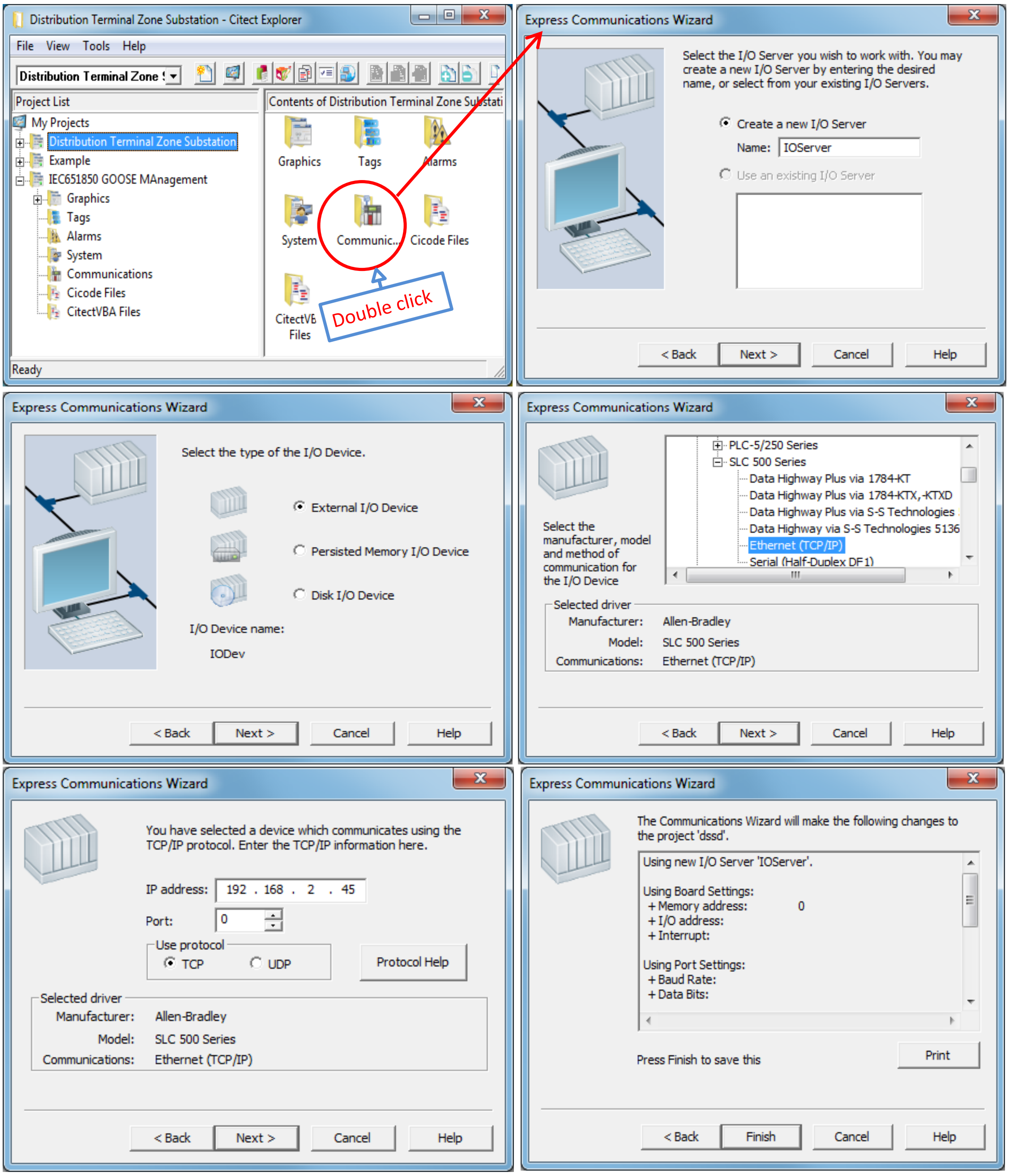


Fig. 5.35 Configuration of IO Server and IP for SCADA

I/O Sever of SCADA contains multiple sub-servers, Cluster, Trend, Report, Alarm and Network servers. These servers extract information from PLC through I/O Server to process and analyse [69]. They also interact with other SCADA servers under redundancy condition [64]. For instance, if the SCADA system is redundant from the substation, these servers update the I/O Server information through other SCADA servers.

The next step is to define the above mentioned sub-servers. The Project Editor page is lunched to create Cluster, Network, Report, Trend and Alarm servers by choosing a unique name and details for them. Figure 5.36 shows the steps of creating these servers.

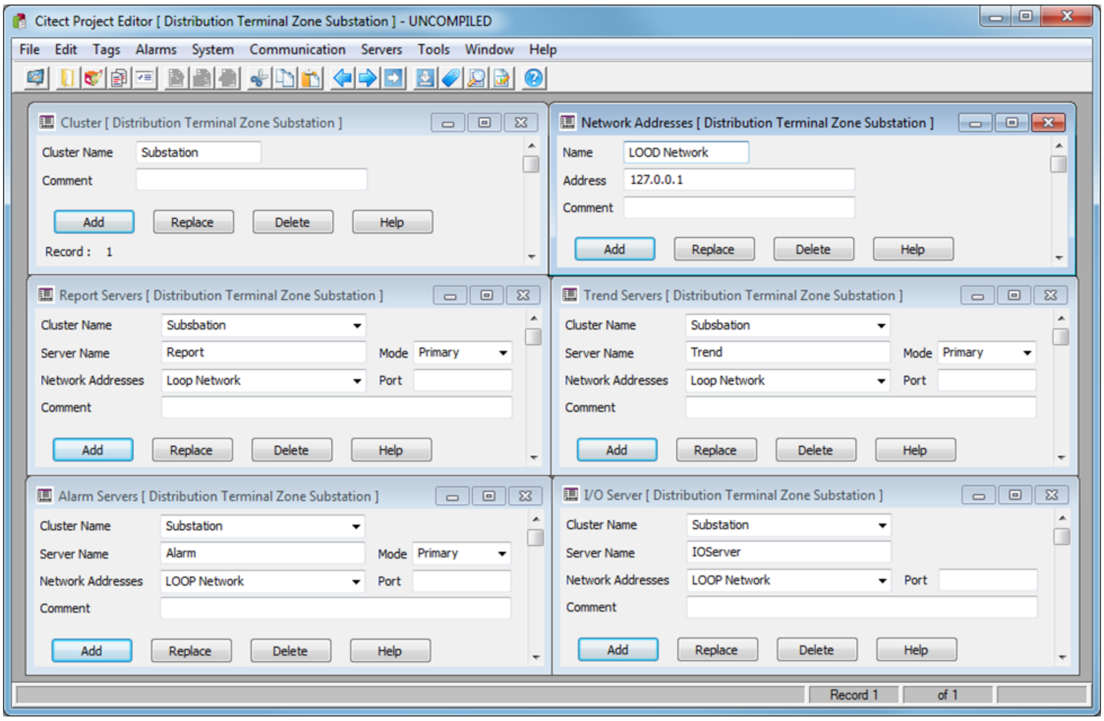


Fig. 5.36 Steps to create Cluster, Report, Alarm, Network and Trend servers

SCADA systems utilise an HMI (Human Machin Interface) as a middleware between SCADA operator and equipment. The HMI enables the operator to run the SCADA program through a touch screen display. Therefore, the next step is to create the HMI graphic page. But prior to starting design of the graphic page, inputs/outputs of the PLC must be linked to the virtual components, push buttons and switches which will be used in the graphic page. This step is called: Creating Variable Tags. Each tag has two main identities: Address and Tag Name. They represent the inputs/outputs addresses used in the PLC and SCADA respectively. Figure 5.37 shows an example of creating a variable tag, CB1_Position, in SCADA. CB1_Position is a variable used to capture the status of Circuit Breaker 1 from substation using SLC500, via N7:0/0 channel, and transfer it to the HMI page (Figures 5.37 and 5.38).

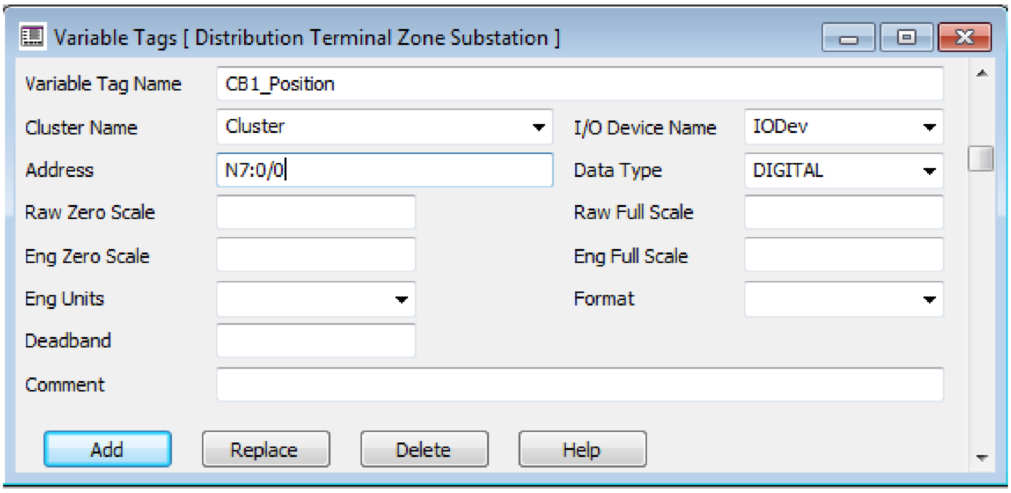


Fig. 5.37 Example of creating a variable tag in SCADA

Table 5.12 provides a list of input/output variable tags created between PLC and SCADA.

- **Note:** As it is explained in section 5.3.1, the RSLogix program and SCADA is written over 120 lines using 65 I/O variables. Table 5.12 only provides details of only couple of components used in SCADA programming. Full list of variable tags is provided in Appendix B.

Table 5.12 List of Variables Tags Used between PLC and SCADA

SCADA Tag Name	Data Type	PLC I/O	Comment
CB1_Position	Digital	O4:0/0	Monitors the status of CB1
CB2_Position	Digital	O4:0/1	Monitors the status of CB2
CB3_Position	Digital	O4:0/2	Monitors the status of CB3
CB4_Position	Digital	O4:0/3	Monitors the status of CB4
CB5_Position	Digital	O4:0/4	Monitors the status of CB5
CB6_Position	Digital	O4:0/5	Monitors the status of CB6
CB1-Control	Digital	N7:0/0	Switch to Open/Close CB1
CB2-Control	Digital	N7:0/1	Switch to Open/Close CB2
CB3-Control	Digital	N7:0/2	Switch to Open/Close CB3
CB4-Control	Digital	N7:0/3	Switch to Open/Close CB4
CB5-Control	Digital	N7:0/4	Switch to Open/Close CB5
CB6-Control	Digital	N7:0/5	Switch to Open/Close CB6
T60	Digital	N7:0/6	Switch to put T60 in TEST mode
REB650	Digital	N7:0/7	Switch to put REB650 in TEST mode
F35	Digital	N7:0/8	Switch to put F35 in TEST mode
REF615-1	Digital	N7:0/9	Switch to put REF615-1 in TEST mode
REF611	Digital	N7:0/10	Switch to put REF611 in TEST mode
REF615-2	Digital	N7:0/11	Switch to put REF615-2 in TEST mode
IS1	Digital	N7:0/12	Switch to Open/Close Isolator 1
IS2	Digital	N7:0/13	Switch to Open/Close Isolator 2
ES1	Digital	N7:0/14	Switch to Open/Close Earth Switch 1
ES2	Digital	N7:0/15	Switch to Open/Close Earth Switch 2
ES3	Digital	N7:1/0	Switch to Open/Close Earth Switch 3
ES4	Digital	N7:1/1	Switch to Open/Close Earth Switch 4
ES5	Digital	N7:1/2	Switch to Open/Close Earth Switch 5
ES6	Digital	N7:1/3	Switch to Open/Close Earth Switch 6

Once all variable tags are created, design of a single line diagram for the 22/66kV Distribution Terminal Zone Substation is started by inserting all components from Graphic Builder library into the HMI graphic page. The process of inserting two components, a switch: CB1 Open/Close and an indicator: CB1, to control and monitor the Circuit Breaker 1 located in substation is shown in Figure 5.38.

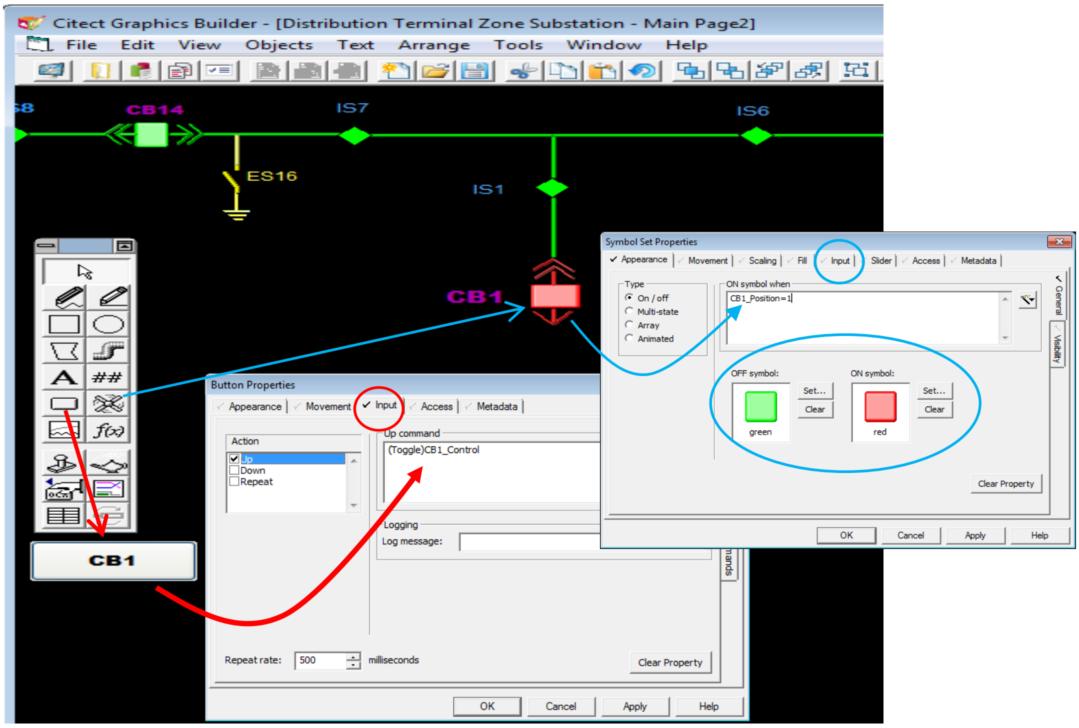


Fig. 5.38 Inserting a component in the SCADA graphic page

Table 5.12, Figures 5.38 and 5.39 illustrates that the SCADA variable tag, CB1-Position, captures the status of the Circuit Breaker 1 from substation through PLC, using N7:0/0 channel, and transfers it to the HMI component, CB1. If the operator decides to change the position of CB1, an open/close command will be sent from SCADA to the substation through PLC SLC500 (Figures 5.38 and 5.39).

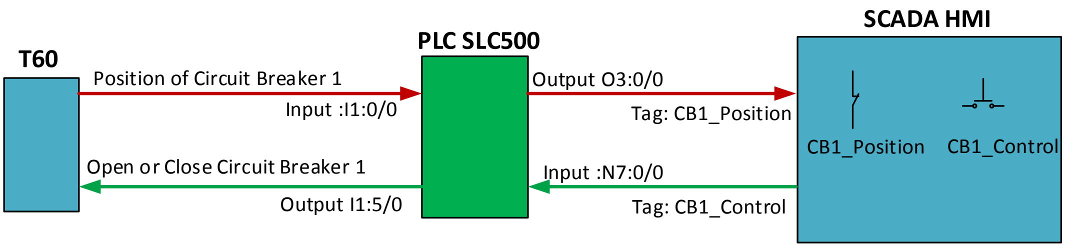


Fig. 5.39 Communication path between SCADA HMI and T60 through PLC

A complete version of the 22/66kV Distribution Terminal Zone Substation SCADA HMI is depicted in Figure 5.40. The HMI page contains all IEDS, earth switches, isolators and circuit breakers of Substation Simulator which can be controlled and monitored from the SCADA control room.

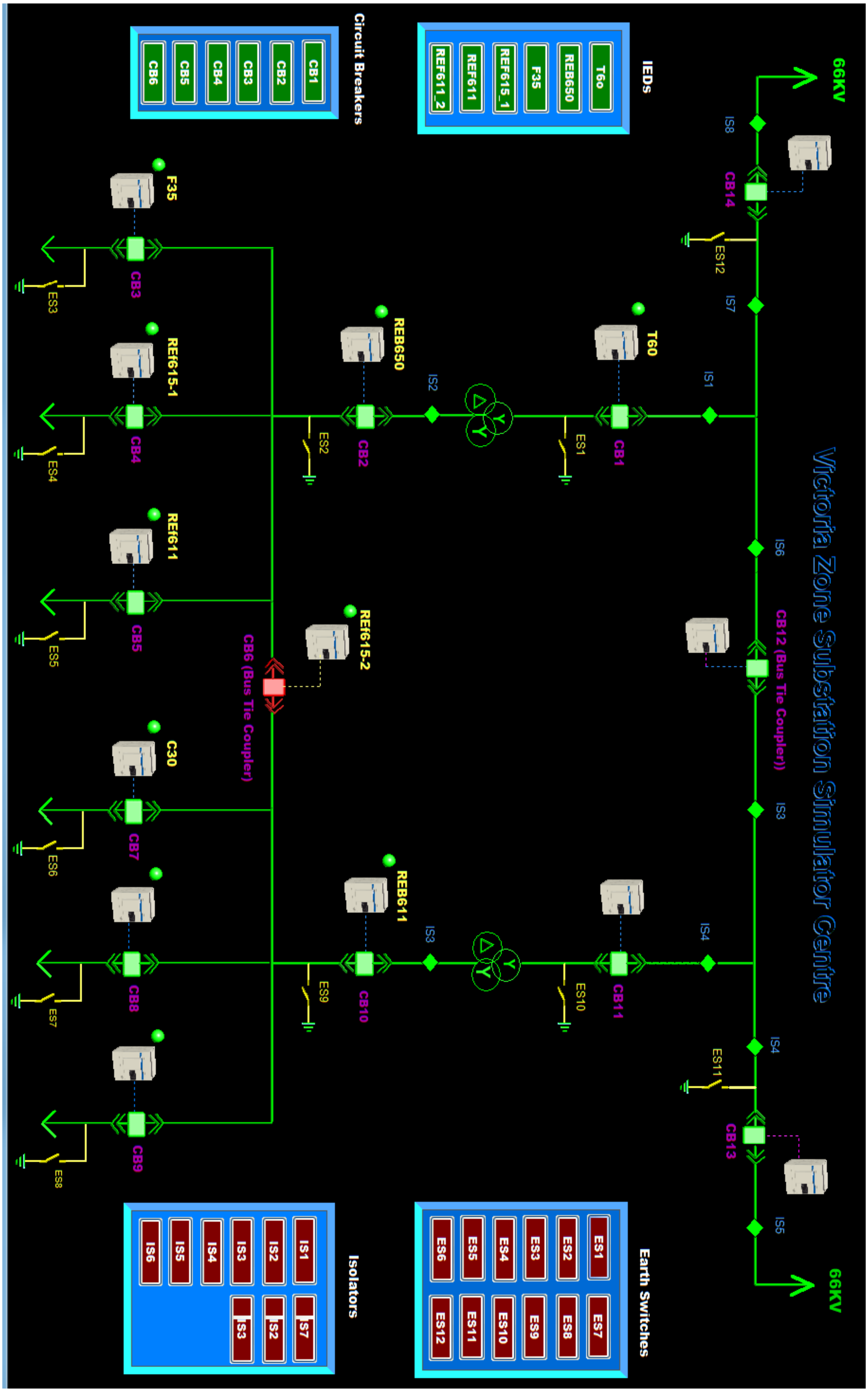


Fig. 5.40 Snapshot from HMI of the SCADA system used for Substation Simulator

5.3 System Configuration and GOOSE Mapping

System configuration and GOOSE mapping is the last but not the least important part of design and development of the 66/22kV Distribution Terminal Zone Substation. Due to the interoperability issues between multi-vendor devises, this step is very challenging for Protection Engineers. For instance, in terms of IEC61850 edition, it is highly crucial to have all CID files written based on one version of the IEC61850 Standard. If one of the CID files is configured according to the second edition and others are compliment with only the first edition, the interoperability will be unachievable. Furthermore, vendor IED proprietary configurator tools and multi-vendor IEC61850-based substation configurator software need to have same version of the IEC61850 firmware.

Once the process of individual IED configuration is accomplished, IED’s configured files are exported from devices. These files, then, are imported into IET600 to create a SCD file of the substation.

The process is started by creating a new project named: Distribution Terminal Zone Substation in IET600. One of the requirements to achieve the peer-to-peer communication through GOOSE message is to assign all IEDs to a unique and an identical sub-network. Therefore a sub-network, WF1, is created as the IET600 default sub-network to locate all IEDs under this sub-network. The next step is to import the CID, SCL format, files of ABB relays from PCM600 into IET600. These files contain the configured but unmapped GOOSE Control Blocks of the REB650, REF615-1, REF611 and REF615-2 relays. Since these IEDs are configured through the ABB software and IET600 is also an ABB proprietary software, these IEDs will be recognised by IET600 and are assigned to the WF1 automatically. Figure 5.41 shows the flow of creating project file and subnetwork in IET600 followed by importing the SCL files.

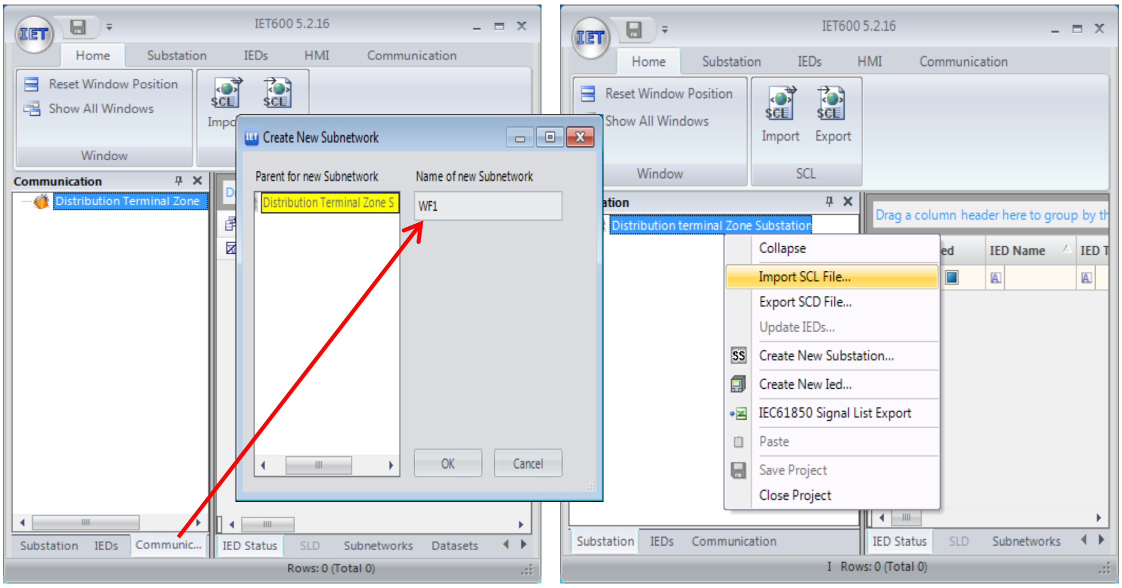


Fig. 5.41 Importing SCS files into IET600 project file

After imprting the CID files of the ABB relays, there will be two groups of IEDs in IET600 which can be seen in Figure 5.42. Group 1 is bounded by the red line and contains Clients 1-5 and the other group is circled in a green colour which consists of all ABB IEDs.

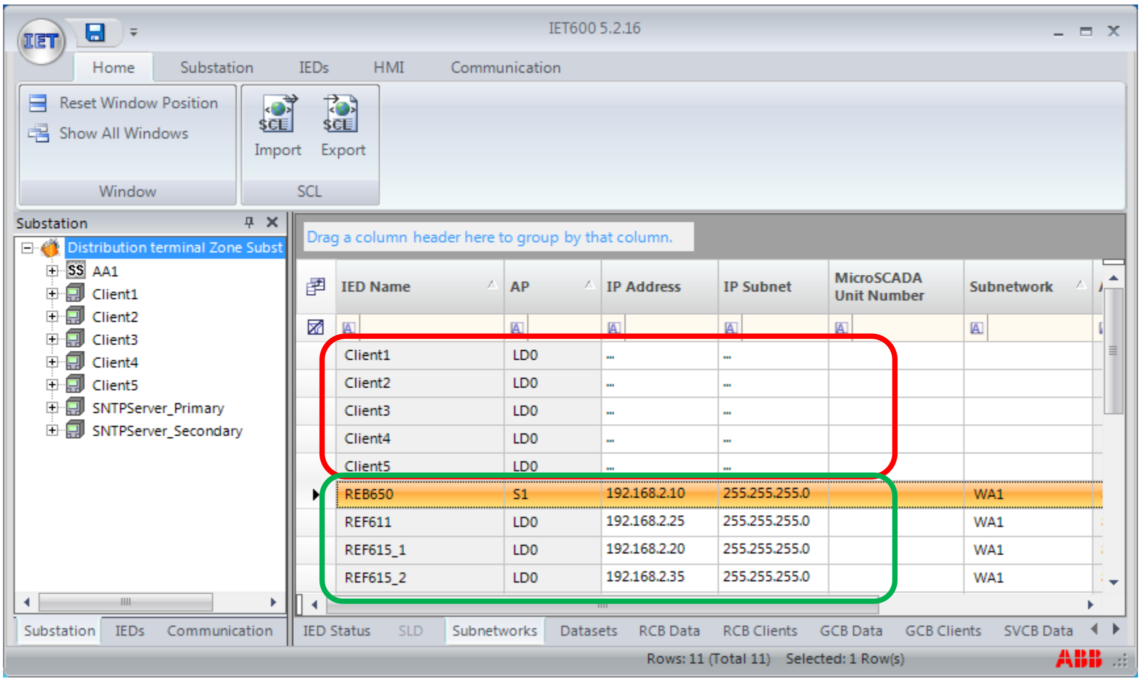


Fig. 5.42 Importing the CID files of ABB relays into IET600

The Clients 1-5 represent the generic IEC61850-based IEDs without any configuration. CID files of IEDs from other vendors can be imported into these generic IEDs. For instance, by right clinking on Client 1 and selecting the Update IED option, the CID file of T60 relay is imported into IET600 and is copied to Client 1. Since T60 is not an ABB relay, it needs a slight manipulation to make it compatible with IET600. For instance, it does not have any sub-network identity which has to be specified manually in IET600 (Fig. 5.43).

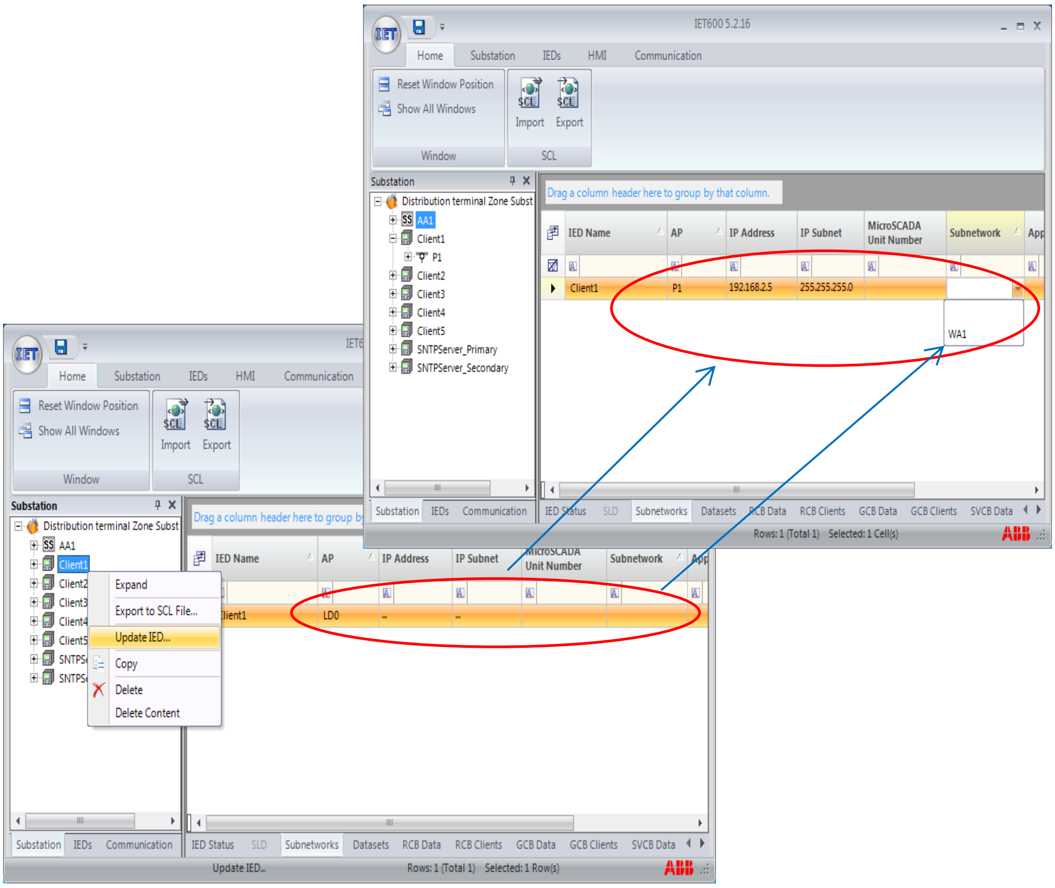


Fig. 5.43 Updating Client1 by importing the CID file of T60

The GCB Data window in IET600 allows the user to check whether the CID file is imported as it should be or not. It provides the details of GCB1-T60 Dataset which is already created for T60 using EnerVista software in Section 5.2.2 (Fig. 5.44).

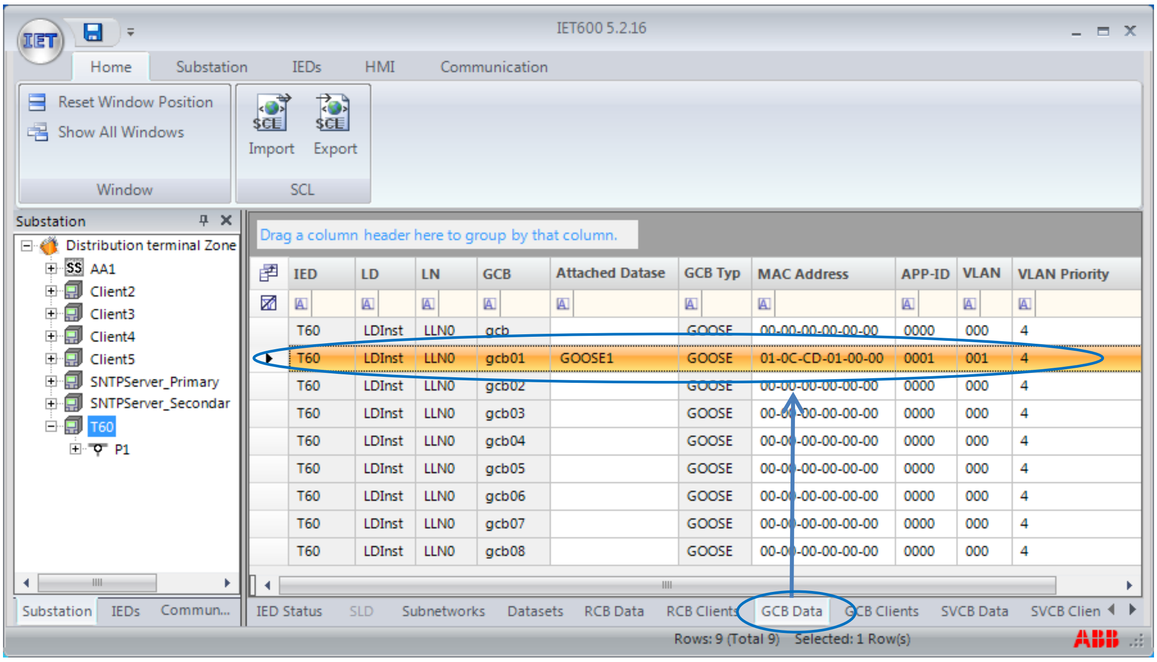


Fig. 5.44 Checking the content of CGB1_T60 after importing into IET600

After checking the content of GCBs through GCB DATA window, and making sure that CID files are imported successfully into IET600, all IEDs and their GOOSE Control Blocks are mapped to each other within the GCB Client window in IET600. Figure 5.45 shows an example of mapping REB650 to REF615-1, REF615-2, REF611 and T60 relays. These IEDs are selected as subscribers to the Trip Circuit Supervision Signal being published from REB650. The final step is to export the SCD file of the substation and write this file into all IEDs individually.

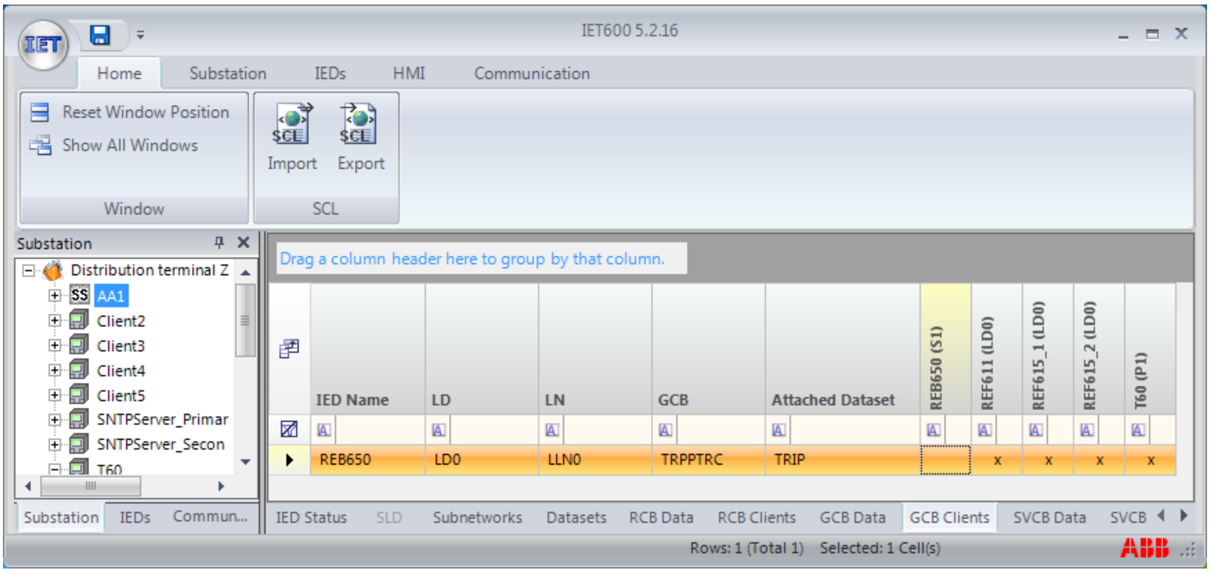


Fig. 5.45 Example of GOOSE mapping between REB650 and other subscriber IEDs

The completed view of the IEC61850-Based 66kV/22kV Distribution Terminal Zone Substation is presented in Figure 5.46.

Fig. 5.46 Front and rear view of the 22/66kV Distribution Terminal Zone Substation

5.4 Conclusion

Chapter 5 provided the configuration procedure of the IEC61850-based devices through vendor proprietary tools. This was followed by system configuration and GOOSE mapping between devices. Signal Matrices of all IEDs (subscribers and publishers) were provided to enable users to simply track the functionality of GOOSE messages between IEDs. Most of the control and protection blocks such as CBF, Tie Bus Coupler, and Busbar Protection were programmed through IEDs' vendor proprietary tools. A Citect SCADA system was programmed to use as a middleware to administer GOOSE isolation and GOOSE messaging from the control centre remotely. All the CID files and the SCD file of the system were saved as a project file to be used for training and future system upgrading.

Chapter 6 - Analysis of Tests and Results

This chapter aims to use IEDScout and vendor proprietary tools to prove the interoperability achievement between ABB and GE devices in the established 22/66kV IEC61850-based Distribution Terminal Zone Substation. Furthermore in this chapter, by utilising both the isolator switch locally and the SCADA system remotely the GOOSE isolation will be proposed and examined while the Substation Simulator is energised. The CMC356 Omicron fault simulator is utilised as a fault simulator device to create different fault scenarios for further test validation and analysis.

6.1 Introduction

In order to capture the GOOSE massages which are being transferred between IEDs and to validate the GOOSE isolation in Substation Simulator, the CMC356 fault simulator test unit is employed with IEDScout as a network analyser. CMC356 enables users to simulate and inject the following signals into IEDs:

- Secondary analogue voltage and current signals
- Binary simulated GOOSE signals
- Binary sampled value.

CMC356 provides the injection of up to six voltage and/or current sources which can be either single phase or three-phase. The communication between CMC356 and PC is achievable through an in built RJ45 port which provides TCP/IP connectivity. Figures 6.1 and 6.2 show the front and rear view of the CMC356 Test Unit.

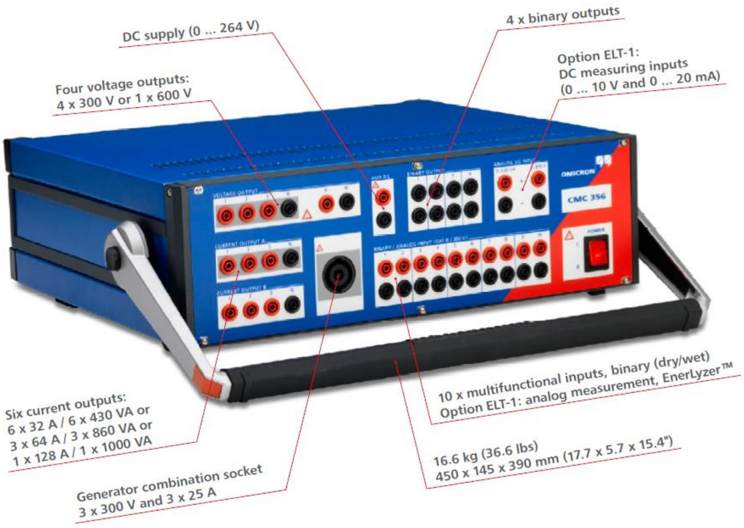


Fig. 6.1 Front view of the CMC356 Test Unit

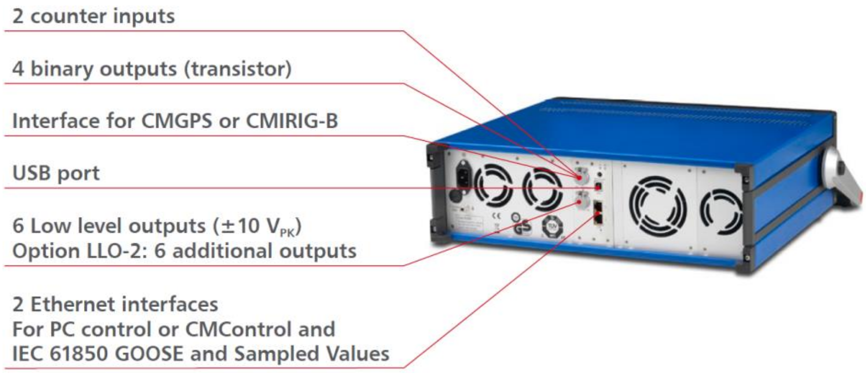


Fig. 6.2 Rear view of the CMC356 Test Unit

The CMC356 Test Simulator is run by Omicron Test Universe Software. It provides several protection testing and monitoring modules such as Differential Protection, Distance Protection, Overcurrent Protection testing as well as IEC61850 Modules configuration (Fig. 6.3).

After running the Test Universe launch pad, it is highly important to make sure that the wiring connections between CMC356 and IEDs are correct and there is no risk of injecting wrong signals into the IEDs. This can be validated via the QuickCMC module which is located within test modules of the CMC356 Test Universe Software. Thus, the primary test starts with injecting the single phase fault values 57.73 V and 2 A into one of the IEDs and capturing the output from the IED and the corresponding circuit breaker. This is done between CMC356, F35 and CB3 and the results are shown in Figure 6.4. Since a proper response is received from F35 and its circuit breaker, it is then assured that the wiring connections between the Test Unit and IEDs are correct.

Fig. 6.3 Omicron Test Universe launch pad and its different modules

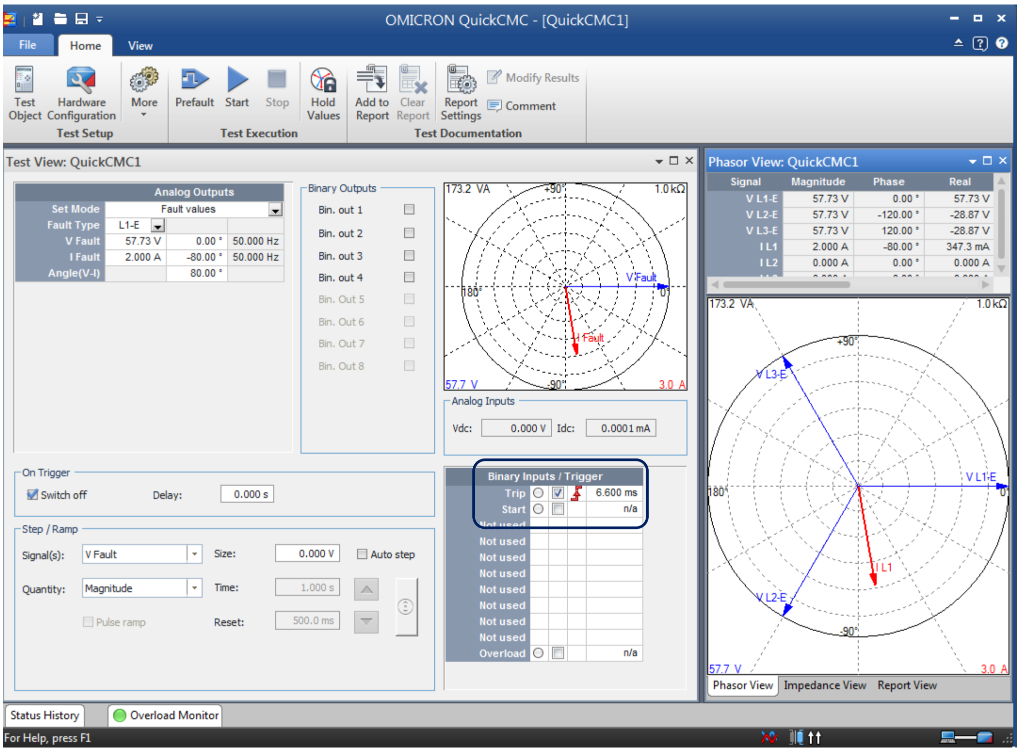


Fig. 6.4 QuickCMC test module and wiring validation check test

6.2 GOOSE Communication and Interoperability

6.2.1 IEDScout and GOOSE Capturing From the Network

After validating the wiring connections between the IEDs and the CMC356 through the QuickCMC Test, the IEDScout software is used to capture the GOOSE signals that are being transferred between devices. The IEDScout is capable of sniffing in the network to obtain the GOOSE Control Blocks and their details including GOOSE Reference Numbers, App IDs and all associated data sets. It also enables the user to check whether other IEDs are detecting and responding to the publishing GOOSE signals in the network or not. Figures 6.5 shows the procedure of sniffing in the network through IEDScout to capture GOOSE signals.

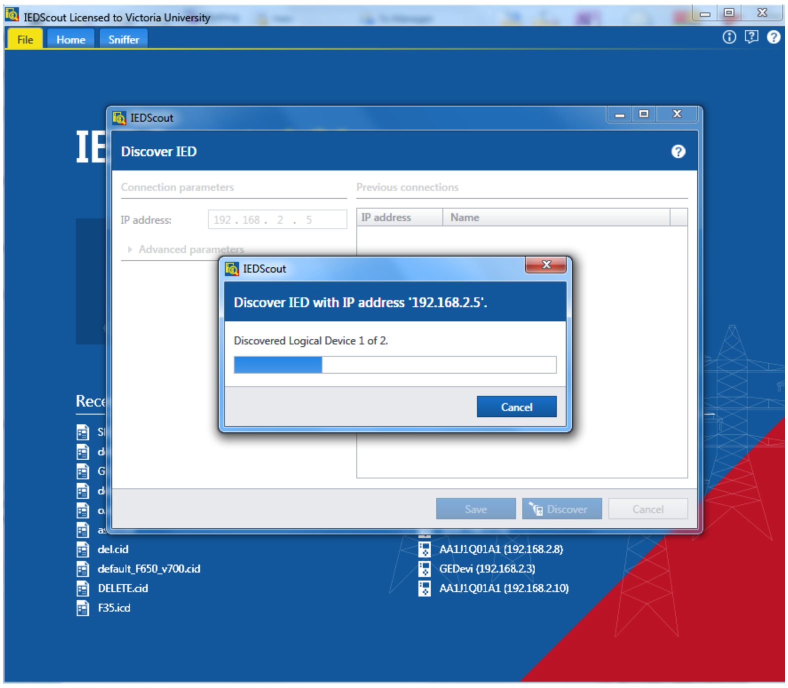


Fig. 6.5 Discovering GOOSE signal in the network using IEDScout

Once the discovery (sniffing) of the GOOSE messages is finished, all the IEDs and their GOOSE Control Blocks appeare in the IEDScout Subscribe Window. This window provides more details about the captured GOOSE Control Blocks such as their GOOSE IDs, APP IDs and Data sets as illustrated in Figure 6.6.

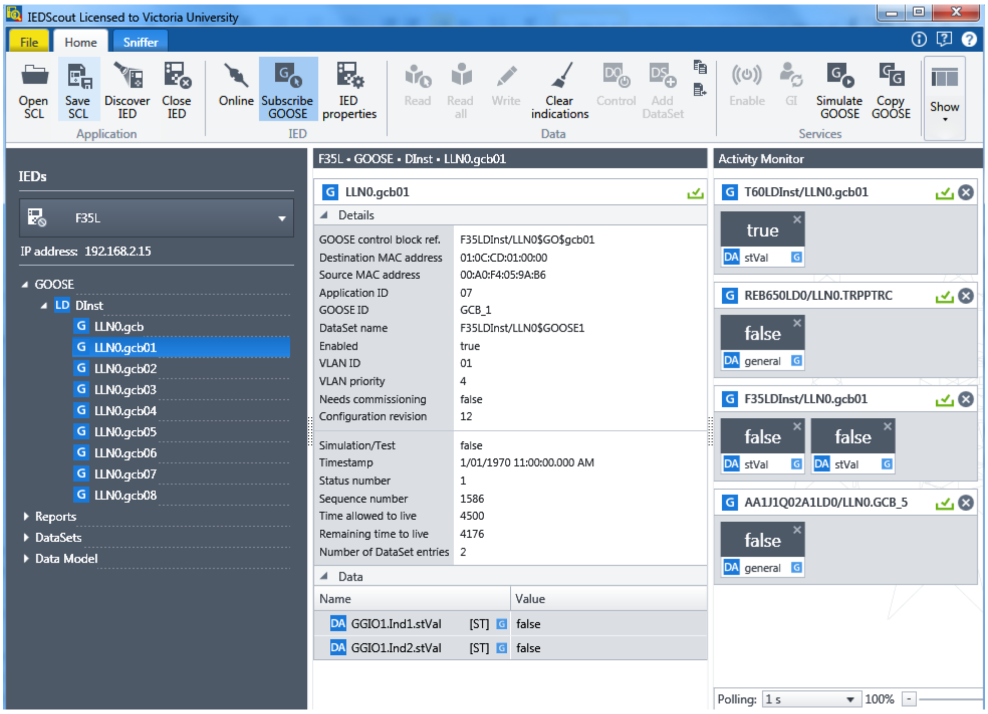


Fig. 6.6 Employing IEDScout to prove GOOSE interoperability between IEDs

Wireshark is another type of network analyser software which can be used to capture and analyse the GOOSE communication in IEC61850-based substation network.

The GOOSE interoperability can also be examined and validated through IEDs. While Figure 6.7 shows the configuration of the Remote Device (REB650 IED) and the Remote Input(GOOSE signal coming from REB650) of F35, Figure 6.8 shows the status of Remote Device and Remote Input of F35 which are online. That means F35 is receiving the GOOSE signal from REB650.

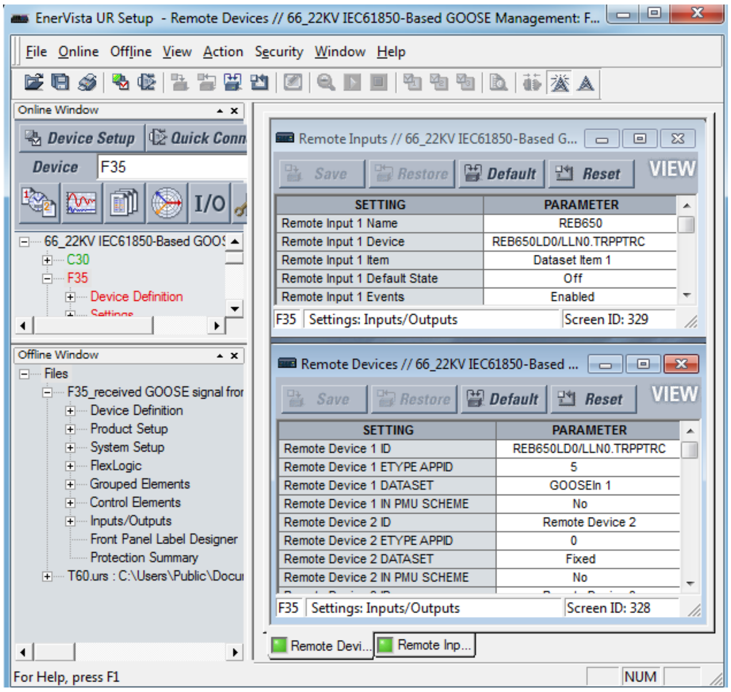


Fig. 6.7 Configuration of Remote Device and Remote Input for F35

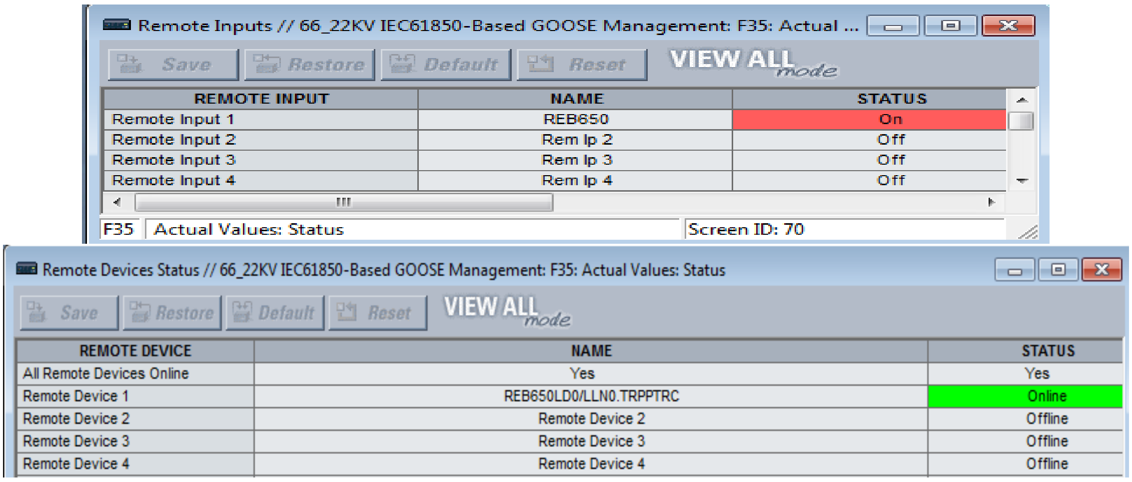


Fig. 6.8 Status of the Remote Device and the Remote Input of F35

6.2.2 Comparison of Wired and GOOSE Trip Signal

This section demonstrates the time performance comparison between GOOSE and wired analog signals. For this purpose, the CMC356 test unit is used to inject the current into one of the IEDs. Then the trip signals coming via GOOSE and through cable are captured and compared. After a pre-fault condition, there is no fault injection for about 1 second, then 6 A (as a fault current) is injected into the REF615-1 IED. It is expected that the REF615-1 IED detects the fault after a short delay. The trip signal is detected via a GOOSE signal is about 2.6 ms faster than the signal detected through cable.

Therefore, the aforementioned delay could be reduced using GOOSE communication in protection systems (Fig.6.9).

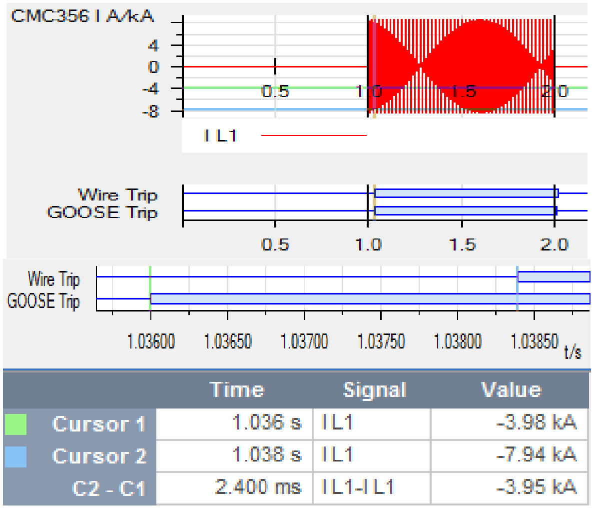


Fig. 6.9 Comparison of GOOSE and wired signal from the point of traveling time in the network

6.2.3 Circuit Breaker Failure (CCBRBRF) Testing Using GOOSE Message

Circuit Breaker Failure (CBF) is one of the primary Protection and Control functions that needs to be considered in substation protection design. When any of the IEDs detects a fault within its zone, it trips and initiates the upstream CBF function simultaneously. After a certain delay, if the fault is not cleared by the primary IED, the back-up IED will trip to clear the fault. In the Substation Simulator all the IEDs employ a GOOSE control block, CCBRBRF, to send the CBF signal to the back-up IED instead of using a hardwired connection. The upstream IED continuously monitors the status and position of the circuit breaker located in the fault zone by receiving the GOOSE monitoring block, SSCBR. If the fault is cleared and the CB is opened, then it will block the CBF function. Otherwise, it will execute the trip function (Fig. 6.10).

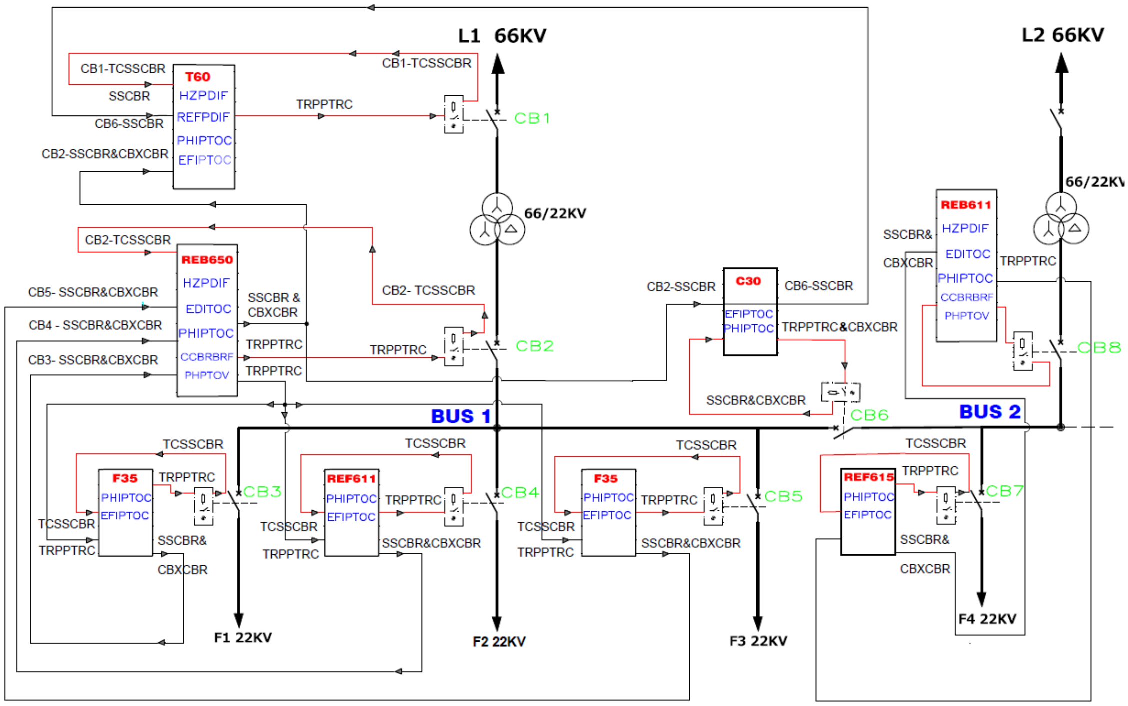


Fig. 6.10 Overview of all protection, control and monitoring function is used for Substation Simulator

Figures 6.11 and 6.12 show the breaker failure scheme used in the design of the Substation Simulator between REB650, F35, REF615-1 and REF611.

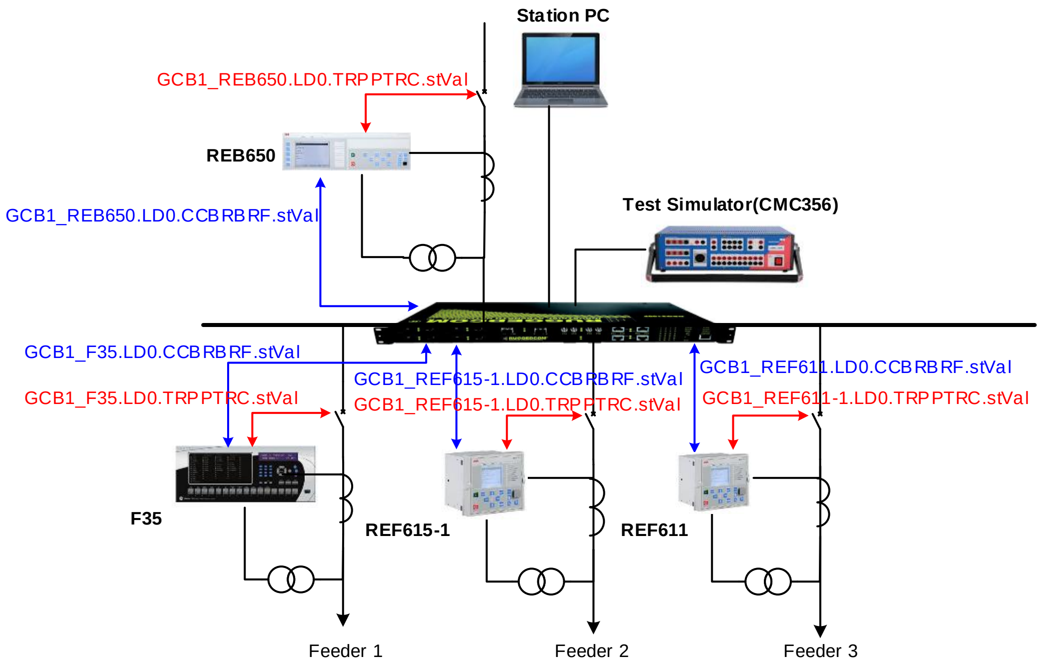


Fig. 6.11 Breaker failure design through GOOSE communication

According to the configuration of the F35 IED, once it detects the fault in Feeder 1, it should clear the fault in 200ms (Fig. 6.12). However, in case of failure to clear the fault, there is a GOOSE Breaker Failure signal (GCB1_F35.LD0.CCBRBRF.stVal) sending from F35 to REB650 to initiate its breaker failure protection function.

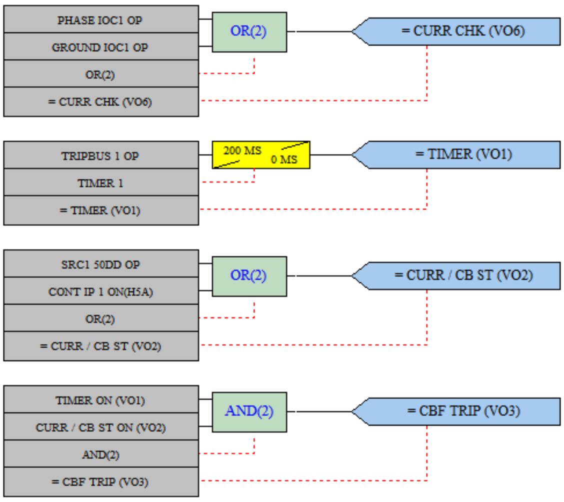


Fig. 6.12 Logic used for F35 GE IED to initiate the CBF signal

Similar to the previous section, after applying a stable pre-fault condition, i.e. there is no fault current, a single phase fault current of 6A is injected into the F35 using CMC356. Figure 6.13 shows that the trip signal is initiated, and correspondingly the F35 IED expects the fault current to be disconnected; if not it initiates the breaker failure function within 200ms through both analogues output and GOOSES to activate the REB650 as a backup protection. In order to test the breaker failure function using GOOSE message, the fault is kept on the F35 after the initial trip, therefore breaker failure is issued and REB650 issues a trip command to clear the fault by receiving both GOOSE and wired CBF signal.

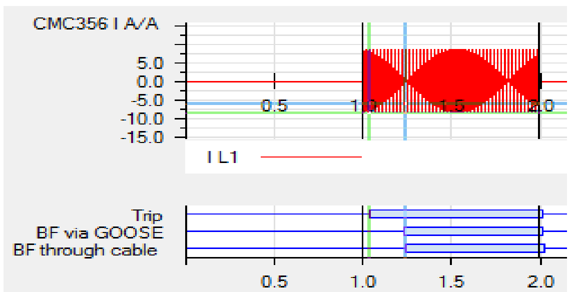


Fig. 6.13 Breaker Failure testing through both GOOSE and cable

In Figure 6.14 results are zoomed and it's clearly shown that the GOOSE signal for BF, received by the REB650, is about 7.685 ms faster than the signal that travels through the cable.

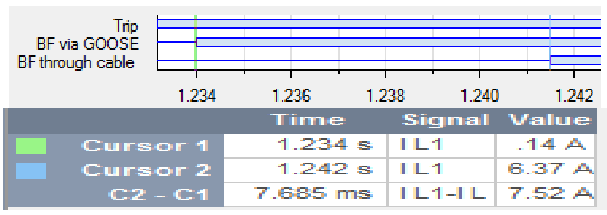


Fig. 6.14 Zoomed in photo showing CBF signal traveling time difference between GOOSE and Cable

Although Section 6.2.2 addressed the comparison of GOOSE and wired signals from the point of travelling time in the network in detail, the CBF experiment also clearly illustrates that GOOSE technology is much superior to traditional methods of power communication when signals or control commands need to travel long distances in the network.

6.2.4 Sending Different Data Attribute Such as a Boolean Number through GOOSE Signal

As already explained in Chapter 3, the IEC61850 Standard defines a GoCB which is a part of a Logical Node of any Logical Device, and it is capable of carrying different attributes. These data sets and their attributes are able to play a crucial role in the protection and communication systems in IEC61850 based substations. For instance, IED trip signal, breaker status, quality and timestamp could be transferred within GoCB and its data sets.

In this section, the GoCB, which has already been used in Section 6.2.3 for CBF testing will be used to transfer several Boolean numbers within its standard dataset format to turn on the LED of the subscriber IEDs. Figure 6.15 illustrates that when the F35 and REF615-1 receive GCB1_REB650.LD0.TRPPTRC.stVal- coming from REB650 - their LEDs are turned on. This LED can be used to send a specific warning or alarm to the control rooms such as trip condition, CB monitoring and other IEDs Status. This is a further significant advantage of IEC61850 GOOSE message capability which is used for transferring data, reports, control and protection command both vertically and horizontally within three levels of the IEC61850-based substation.

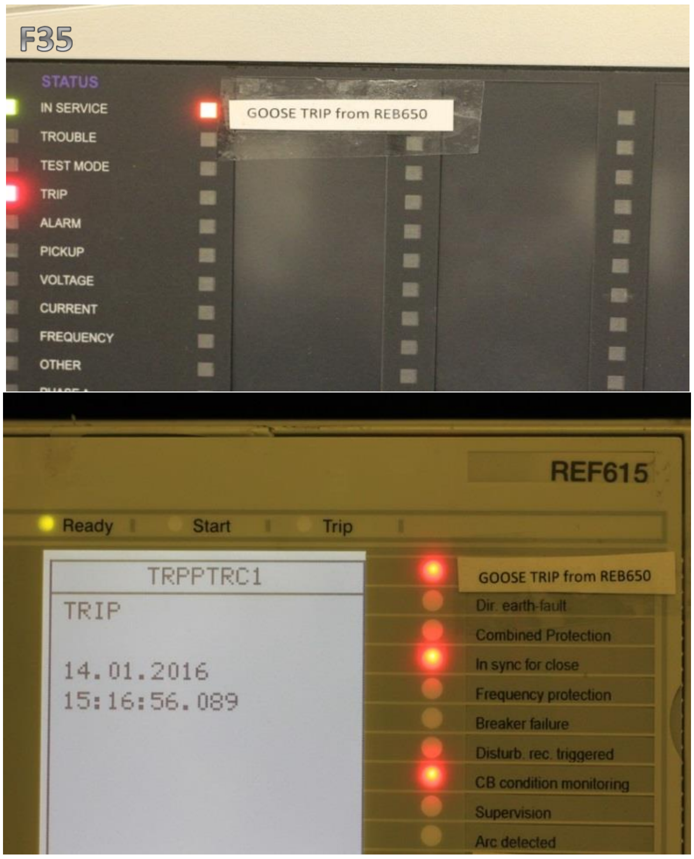


Fig. 6.15 LEDs of F35 and REF615-1 turn on once receive the trip signal from REB650

6.2.5 Busbar Protection

When there is a fault in a busbar, connected to feeders, all IEDs located within that area must trip to open their CBs. In a traditional substation, there is a hardwired connection between Busbar IED and other IEDs located within the Bus protection zone. In the design of BUS 1 of the Substation Simulator, all the hardwire connections between REB650, F35, REF615-1, REF611 and REF615-2 are removed and the communication and data transfer between these IEDs is achieved by GOOSE messaging (Fig. 6.10 in Section 6.2.3).

Using the State Sequencer test module of the CMC356, a three-phase fault current of 4A is applied in BUS 1 which is protected by REB650, F35, REF615-1, REF611 and REF6150-2 (Fig. 6.16).

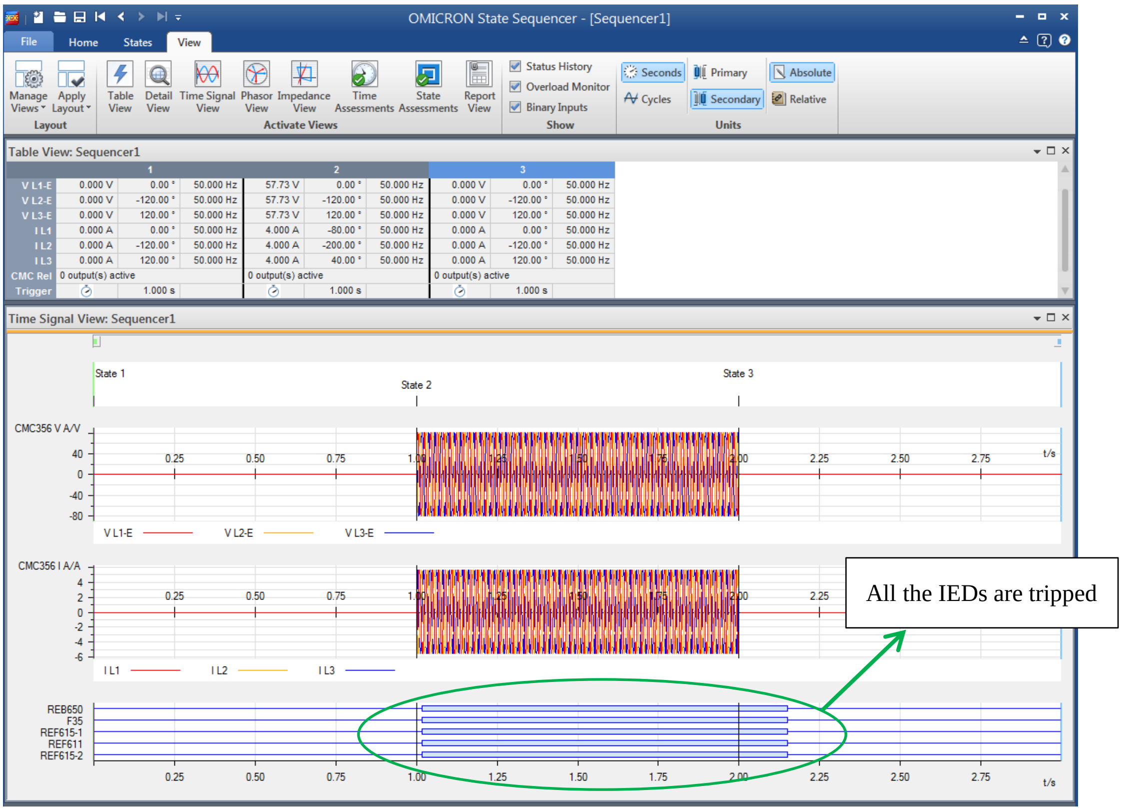


Fig. 6.16 Fault injection to Bus 1 and corresponding IEDs' responses

Once REB650 detects the fault, it will trip CB2 and simultaneously sends the Master Trip GOOSE signal (TRPTRC) to F35, REF615-1, REF611 and REF615-2 to trip their circuit breakers: CB2, CB3, CB4, CB5 and CB66 respectively.

Figures 6.16 - 6.18 show how REB650 and other IEDs located within the BUS 1 zone communicate with each other using GOOSE messages to clear the fault located in their zone.

- **Note:** as can be seen from Figures 6.17 and 6.18, the REF615-2 IED is also tripped. However, since its circuit breaker, CB6, is a normally closed circuit breaker, there is no change in the position of CB6 in the SCADA screenshot.

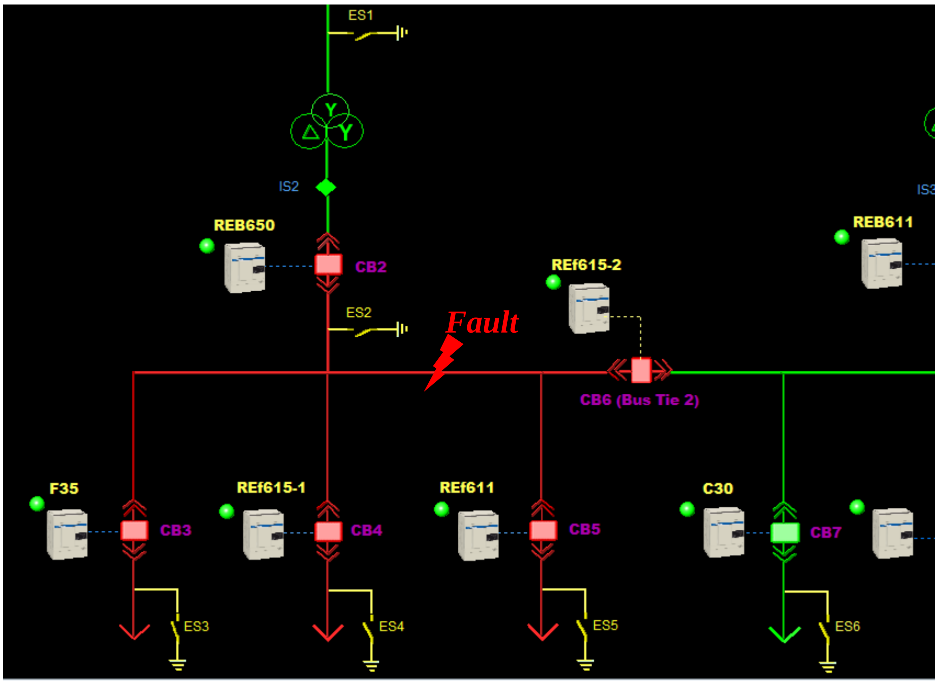


Fig. 6.17Screenshot from the SCADA system while the fault is applied within Bus 1 and all corresponding IEDs are tripped through GOOSE signal coming from REB650

Fig. 6.18 Snapshot from the Substation Simulator while the fault is applied within Bus 1 and all corresponding IEDs are tripped through GOOSE signal coming from REB650

6.2.6 Bus Tie Circuit Breaker

The Bus Tie Circuit Breaker, BTCB, or Bus Coupler Switching is used when it is required to switch the in-service transformer between buses in case of any failure in one of the transformers or conducting a regular maintenance service. For instance, if

Transformer 1 requires a periodical maintenance test, it needs to be isolated from 66/22kV Line 1. This will cause a total power interruption for the Feeders 1, 2 and 3 which are supplied by the energised 66/22 kV transformer in Line 1. In order to avoid this interruption in the Substation Simulator Distribution Feeders, a Normally Open CB is used as BTCB between Bus 1 and Bus 2 to switch Transformer 1 and Transformer 2. The BTCB will be closed through control GOOSE Signal, CBXCBR, which comes from T60. The drawback of this scheme is that, by closing CB5, there will be a huge amount of current flowing back toward Transformer 1 if there is a fault within the transformer zone. This shortfall is resolved by interlocking CB1, CB2 and CB6. If CB6 is closed, tripping either CB1 or CB2 will open CB6 as well. Therefore REF615_2 is continuously monitoring CB1 and CB2 status through GOOSE signals, CBSWI.Pos, being published from T60 and REB650. Figures 6.19 and 6.20 show the status of Isolator Switch 1, Isolator Switch 2, CB1 and CB6 (BTCB) before and after isolation of the 66/22 kV transformer of the Line 1.

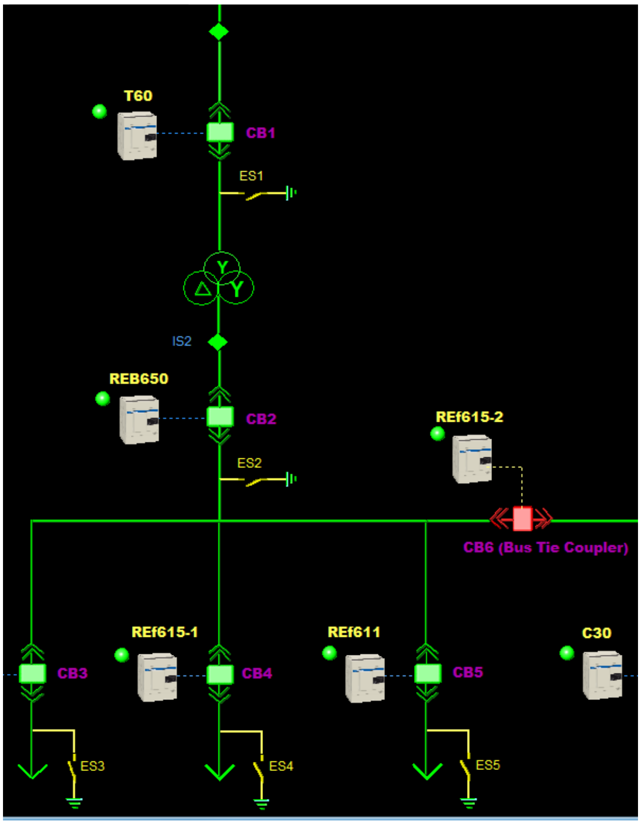


Fig. 6.19 Status of CB1 & CB6 under normal operation condition

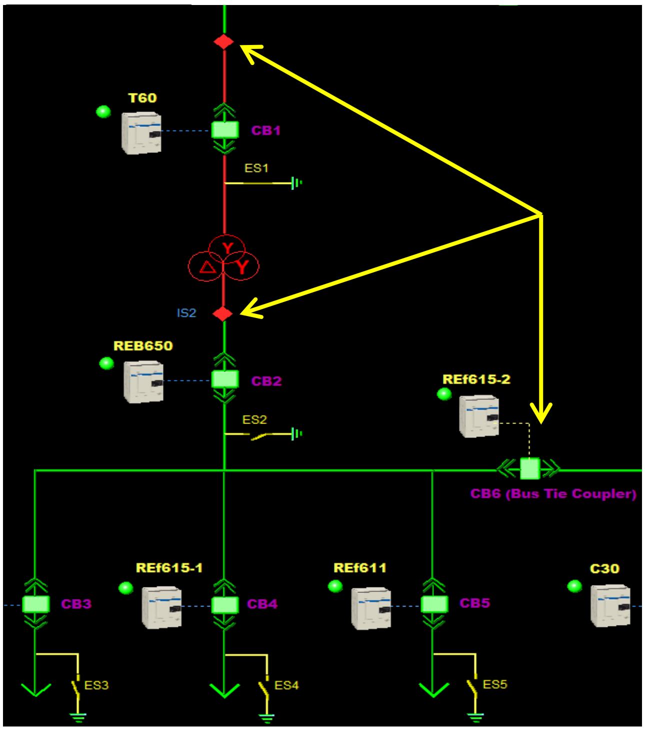


Fig. 6.20 CB1 & CB6 after the isolation of Transformer 1 using IS1 & IS2

Figure 6.20 depicts that when Isolator Switch 1 and 2 are opened, REF615-2 receives a GOOSE signal, GCB1_T60.LD0.CBSWI.PosCls.stVal, from T60 to close CB6 to prevent power supply interruption in Feeders 1, 2 and 3.

➢ **Note:** CB1, CB2 and CB6 are interlocked with each other through the GOOSE signals: TRPTRC and SSCBR for safety and protection of Bus 1. It means, if REB650 trips, REF615-1 will trip regardless of the status of the T60 IED and Transformer 1.

6.3 GOOSE Isolation for Maintenance Service Purposes

In order to maintain a substation protection under normal operating conditions, and keep it up-to-date in response to the latest requirement of the industry standard, periodical maintenance testing needs to be performed. Its goals are therefore to detect and diagnose equipment problems, or to confirm whether all required actions taken to modify configuration, replace, repair or upgrade protection devices or other components of the fault clearing scheme, have been effective or not. The maintenance could be divided into two sub-categories as follows:

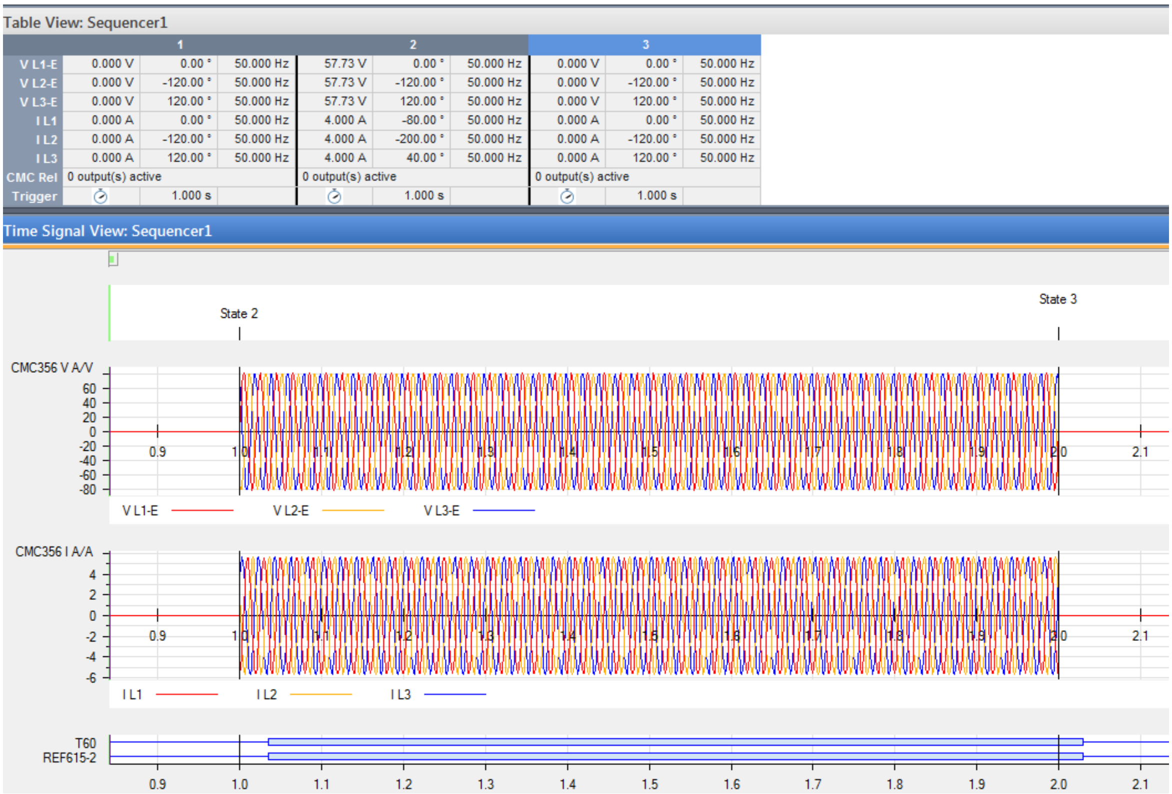
- Scheduled Maintenance Test
- Maintenance Test Due to Abnormal Protection System Performance

In this chapter, two types of maintenance test are carried and the results are validated.

6.3.1 Scheduled Maintenance Test

Scheduled Maintenance Test is a part of the “Site Maintenance Proposed Plan”, performed periodically to prove that the protection system and their devices meet all the requirements of the system. Moreover it examines whether all individual components work under normal conditions in compliance with the configuration of the protection scheme. In this section, the T60 transformer IED is isolated for the Maintenance Test. Before doing any test and injecting simulated fault signals into T60, Isolator Switches 1 and 2 are opened to isolate the 22/66kV transformer Line 1. By doing that, the CB6, Bus Tie Circuit Breaker, is closed automatically, due to interlocking with the Isolator Switches, to supply power to the Feeders 1, 2 and 3 through 66/22kV line 2 (Fig. 6.20 in Section 6.2.6).

.After isolation of the Transformer 1 from Line 1 and closing of the CB6, the T60 IED can be tested for maintenance services. A three-phase 4A and 57.73V, fault values, are injected into the T60 IED after applying a pre-fault condition; there is no fault injection for about 1 second. Without doing any GOOSE isolation, T60 will be tripped in 70 ms. Due to interlocking between CB1 and CB6, T60 sends the GOOSE trip signal, GCB1_T60.LD0.GGIO1.ST.Ind1.stVal, to the REF615-2 to open the CB6 (Figures 6.21 and 6.22).



	1			2			3		
V L1-E	0.000 V	0.00 °	50.000 Hz	57.73 V	0.00 °	50.000 Hz	0.000 V	0.00 °	50.000 Hz
V L2-E	0.000 V	-120.00 °	50.000 Hz	57.73 V	-120.00 °	50.000 Hz	0.000 V	-120.00 °	50.000 Hz
V L3-E	0.000 V	120.00 °	50.000 Hz	57.73 V	120.00 °	50.000 Hz	0.000 V	120.00 °	50.000 Hz
I L1	0.000 A	0.00 °	50.000 Hz	4.000 A	-80.00 °	50.000 Hz	0.000 A	0.00 °	50.000 Hz
I L2	0.000 A	-120.00 °	50.000 Hz	4.000 A	-200.00 °	50.000 Hz	0.000 A	-120.00 °	50.000 Hz
I L3	0.000 A	120.00 °	50.000 Hz	4.000 A	40.00 °	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		1.000 s			1.000 s			1.000 s	

Fig. 6.21injection of a three phase fault into T60 using CMC356 and trip response from REF615-2

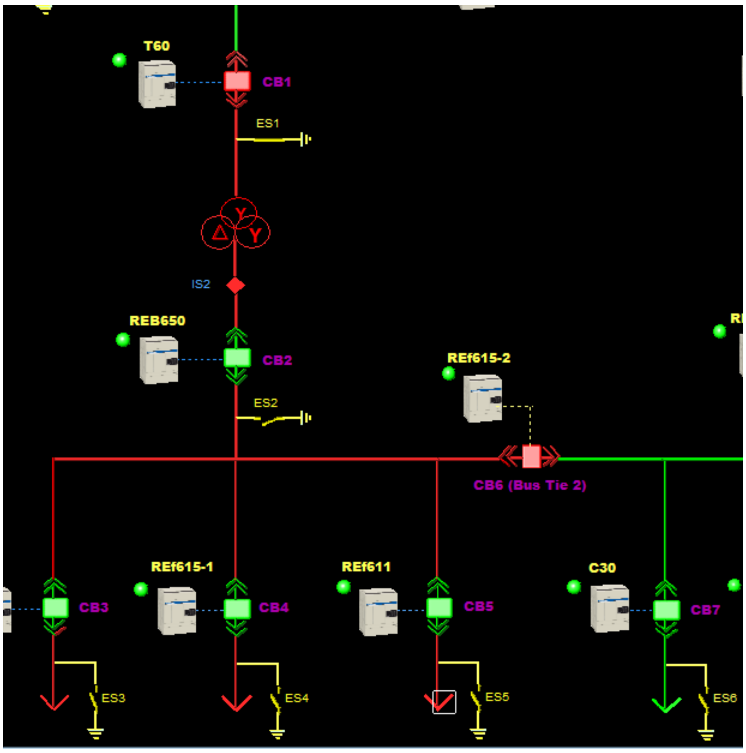


Fig. 6.22 Screenshot from the SCADA system while fault is applied to T60

Since the fault that is applied to the T60 is only simulated for the test purposes, sending a trip signal to CB6 and opening CB6 is an unwanted reaction that needs to be prevented. Therefore, T60 is set to the Test mode through PLC program and the SCADA system from the control centre to avoid sending GOOSE trip signal to CB6 (Fig. 6.23). By doing this, all signals which are published from T60 under test conditions are blocked and will not be sent to other IEDs. Thus by redoing the test scenario, REB615_2 will not be tripped because of the absence of incoming trip signal which can be seen in Figure 6.24.

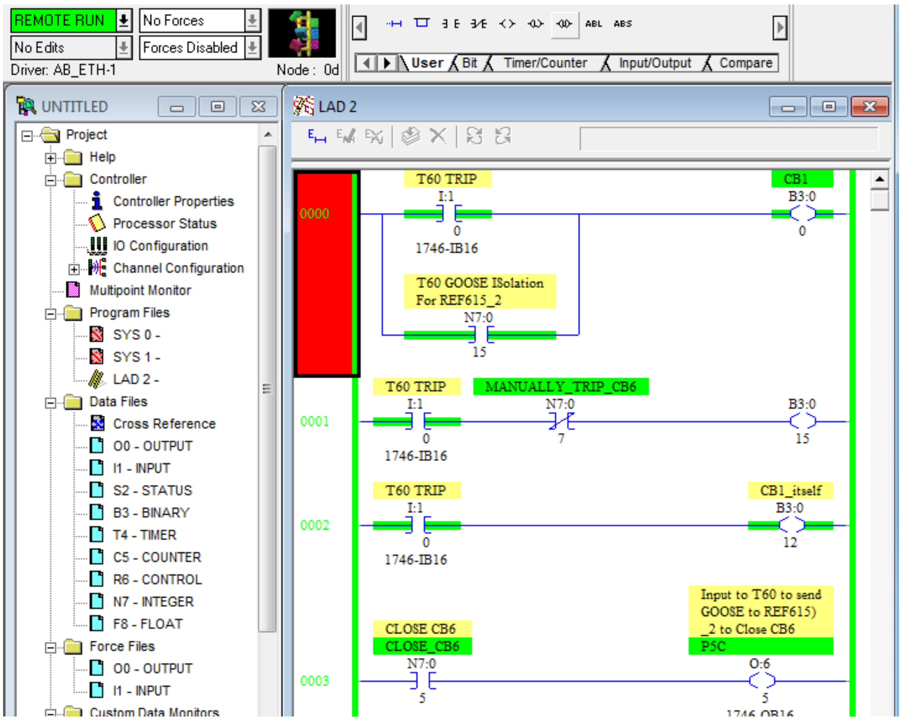


Fig. 6.23 Isolation of T60 via PLC/SCADA by trigging the Input: N7:0/15

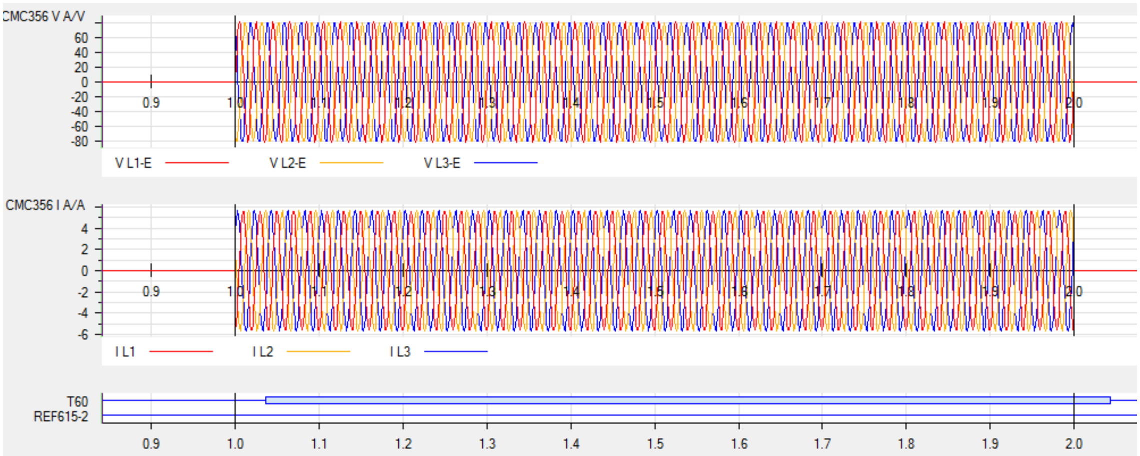


Fig. 6.24 as T60 is set to Test mode, it did not send trip signal to REF615-2

In order to assure the administrator in the control centre that T60 is under test and its signals are isolated, a flashing light, TEST MODE, is designed in the SCADA screen which can be seen in Figure 6.25.

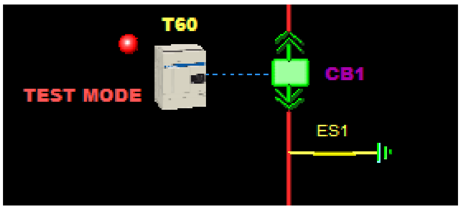


Fig. 6.25 Once T60 is set to Test mode, it starts to flash the TEST MODE indicator in the SCADA screen

In this test, although there is no output trip or any other control signals from T60 to other IEDs, its performance and CB trip time can be captured internally through CMC356 which is the aim of the maintenance Test (Fig. 6.26).

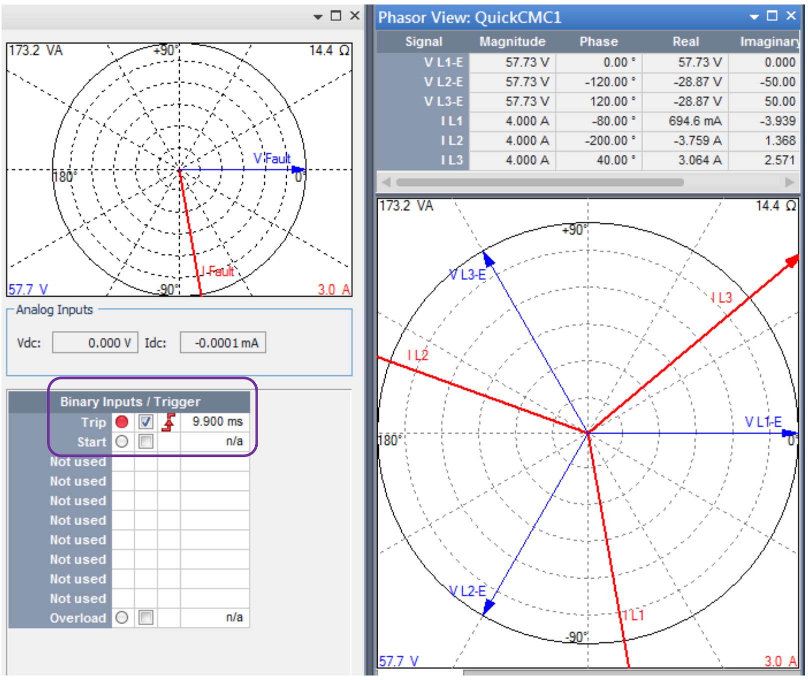


Fig. 6.26 Time performance of T60 captured by CMC356

6.3.2 Maintenance Test Due to Abnormal Protection System Performance

This test is performed when a device or its operation in the system are detected faulty: viz. in the context of fault detecting and clearing schemes, if a device operates when it is not supposed to, or it does not operate when is required. Therefore, the faulty device needs to be isolated and tested to identify the problem associated with it and to take effective action to stop any additional damage to the rest of the system. When an IED is being fixed, upgraded and tested; any interruption and unnecessary reaction in substation should be eliminated. Therefore, in order to make the IED under test to discard and bypass all live GOOSE messages coming from the other IEDs without any response, the IED is set to the TEST mode. As already explained in Section 6.2.5; when there is a fault in Bus 1, connected to Feeders 1, 2 and 3, all IEDs located within that area must trip to open their CBs. In a traditional substation, there is a hardwired connection between Busbar IED and other IEDs located within Bus protection zone. In the design of BUS 1 of the Substation Simulator, all the hardwire connection between REB650, F35, REF615-1 and REF611 are removed. The communication and data transfer between these IEDs is achieved by GOOSE messaging. This means, if REB650 detects any fault, it will trip CB2 through hardwire connection and simultaneously sends the master Trip GOOSE trip signal (TRPTRC) to F35, REF615-1, REF611 to trip their circuit breaker indirectly. If one of the IED for instance, REF615-1 is faulty and needs to be fixed or upgraded, it should ignore any signal coming from Busbar REB650 IED during the service. A method of device isolation is used with combination of PLC programming and SCADA system to isolate REF615-1 from the substation (Fig. 6.27). By doing that, REF615-1 will basically bypass any signals receiving from other IEDs and will not trip because of the trip signal that is coming from REB650.

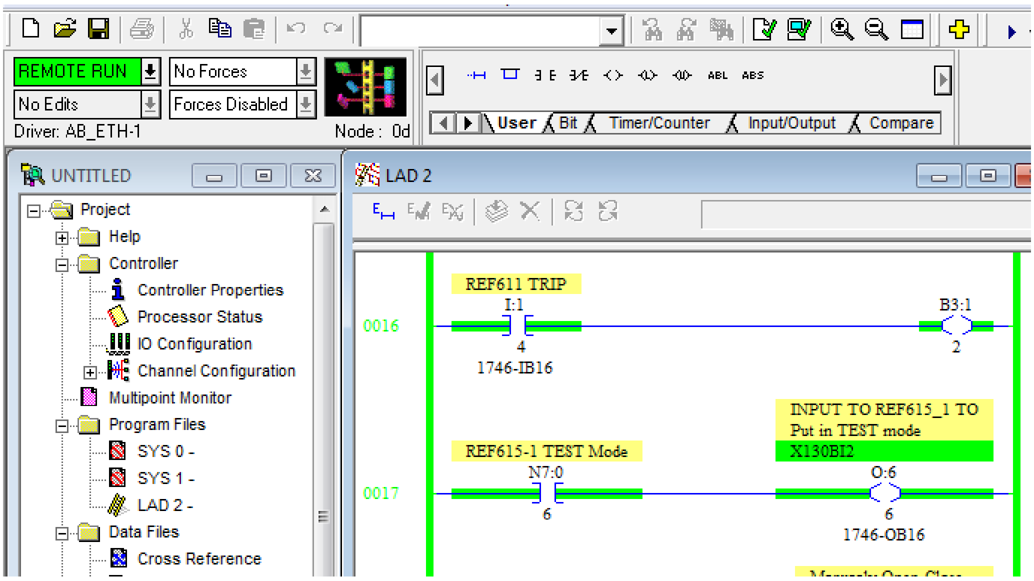


Fig. 6.27 REF615-1 is set to TEST mode via PLC/SCADA by trigging the Input: N7:0/6

Using CMC356, three phase fault values: 4A and 57.73V as secondary side values are injected into REB650 and it is expected all IEDs namely: REB650, REF615-1, F35 and REF611 are tripped. But as can be seen from Figures 6.28 - 6.30 the REF615-1 which is set to TEST Mode and isolated from the network does not react to the incoming trip signal and ignore it.

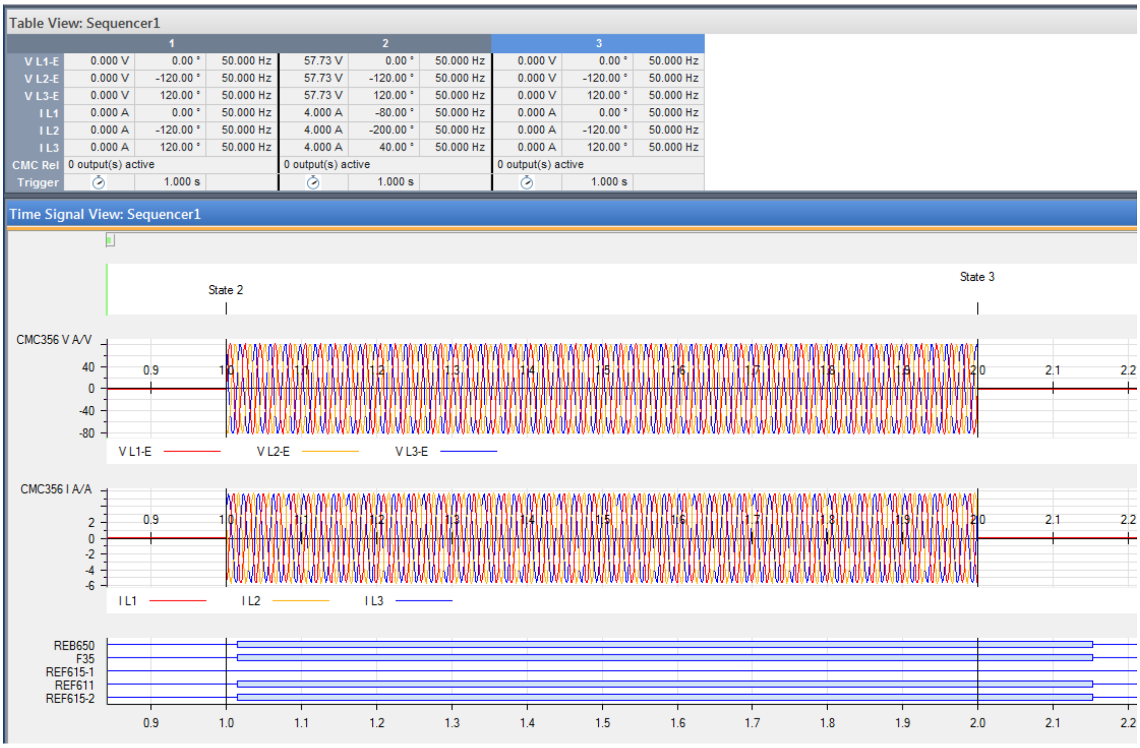


Fig. 6.28 Injection of fault values into REB650, F35, REF615-1, REF611 and REF615-2 and trip response of them(all tripped except REF615-1)

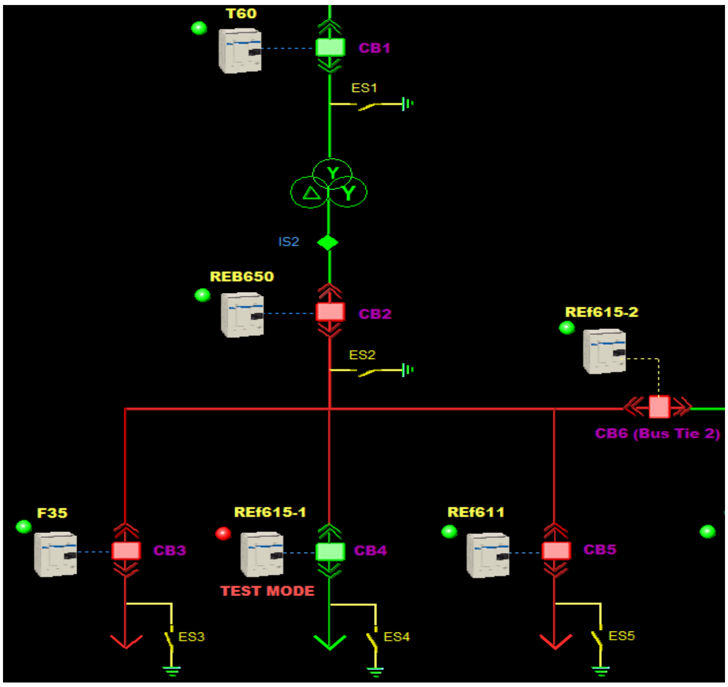


Fig. 6.29 Screenshot from the SCADA system while REF615-1 is in test mode and its ignorance to incoming trip signal from REB650

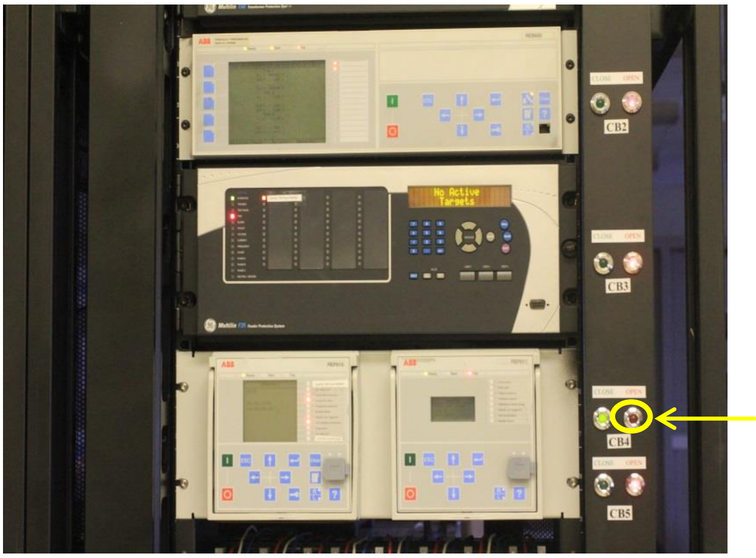


Fig. 6.30 Snapshot from the Substation Simulator while REF615-1 is in test mode and its ignorance to incoming trip signal from REB650

- **Note:** In section 6.3.1 the publisher IED (T60) and its publishing GOOSE signals are isolated from the network, whereas in Section 6.3.2 the receiver IED (REF615-1) is isolated from network.

The methods of isolation that are provided in this chapter are completely independent from vendor tools and vendor devices. It is only programmable and manageable though PLC and the SCADA system. Therefore, the multi-vendor interoperability issues for IED testing which is currently one of the topmost challenges that protection engineers are dealing with in IEC61850-based substations when IED isolation and testing is required is resolved.

6.4 Conclusion

This chapter demonstrated the IEC61850 interoperability and GOOSE communication between ABB and GE IEDs using both IEDScout and vendor proprietary tools. By examining different protection test schemes such as Circuit Breaker Failure Protection system, it is proved that GOOSE technology is much superior to traditional methods of power communication when signals or control commands need to travel long distances in the network. In this chapter, a novel method of GOOSE isolation was revealed and validated through the SCADA system under device testing condition using multiple scenarios such a Busbar Protection, Transformer Maintenance and Feeder Relay Maintenance. The test method and results that provided in this chapter potentially enable engineers to test any IED, regardless of its manufacturer, without GOOSE interruption in an IEC61850-based zone substation.

Chapter 7 - Conclusion

7.1 Introduction

In recent decades, to a great extent interoperability has been a topmost challenge in multi-vendor substations [5, 37-39]. Existing protocols were unable to fully warrant different vendor IEDs to communicate with one another [5, 6]. The reason behind this was that manufacturers purposely designed their products using their own proprietary tools, meaning customers had to favour one vendor more than another [2, 40]. In doing so, manufacturers practically configured their products in such a way that if one piece of equipment failed, then all or some accompanying devices required replacement. This was a major downfall for substations as a great deal of auxiliary equipment which was rather expensive needed to be stockpiled. Therefore, an urgent need for an international communication protocol as a Lingua Franca has become an essential but hot topic for power protection and substation automation systems [8, 41]. The International Electrotechnical Committee (IEC) and IEEE worked together to produce a systematic communication structure for utilities in 1990 [1, 6]. The objective of this collaboration was to make use of all "off-the shelf" existing protocols to achieve a friendly, reliable, flexible and robust protocol capable of fully supporting interoperability in a multi-vendor environment. The idea of splitting a massive problem into small pieces with defined detailed solution for each segment was used as an object-oriented model [9, 16]. As a consequence, the first version of IEC61850 was announced in 2004 as an international standard which provided a detailed specification of layered substation automation architecture [8]. The communication architecture is composed of an abstract definition of classes and services which are independent of underlying concrete protocol stacks and deployment platforms [14]. The IEC61850 Standard incorporates the use of logical nodes to resolve problems related to interchangeability, but also physical character mappings to overcome IED proprietary restrictions. The protocol does not describe any individual implementations, communication architectures or product functionalities. It instead focuses on the visible specifications of both primary and secondary equipment [7].

The IEC61850 Standard is the first and ubiquitous international standard to warrant all communication requirements within SASs. The IEC61850 Standard provides full interoperability and interchangeability capability between intelligent devices, regardless of their manufacturer. The IEC61850 has the capacity to co-operate with existing conventional protocols (i.e. Modbus or DNP3) given that Ethernet switches support both fibre and copper interconnections. The standard makes use of cost-effective GOOSE messaging technology to replace the traditional copper wiring.

Although IEC61850 is widely accepted around the globe due to the significant benefits that it provides compared with conventional hard-wired solutions, there is still resistance from utilities to welcoming the IEC61850 implementation. This may perhap be due to the lack of knowledge that engineers have about the standard and/or because of several ambiguous topics that are still not addressed in detail in the context of IEC61850.

This chapter summarises the final remarks and future work of this PhD research.

7.2 Major Accomplishments and Benefits

The IEC 61850 standard has defined various ways of implementing a test bit for testing purpose. However, there is not yet a standardised GOOSE isolation procedure in the standard that all vendors comply to. Three major accomplishments have been satisfied throughout the research including the construction of the 66/22kV IEC61850-based Distribution Terminal Zone Substation, GOOSE interoperability between GE and ABB IEDs, and the development of a novel method of GOOSE isolation for IED testing purposes in an energised multi-vendor substation.

Chapter 2 provided a comprehensive literature review of the traditional and the existing standards such as Modbus and DNP3. It proposed that the IEC61850 Standard is the first and ubiquitous international standard to warrant all communication requirements within SASs. In Chapter 2 it is explained in theory how IEC61850 provides full interoperability and interchangeability capability between intelligent devices, regardless of their manufacturer.

A detailed description of the hardware inventory and wiring layout of the Substation Simulator and the connection diagram between equipment was provided in Chapter 4. The constructed Substation Simulator was modelled in section of an IEC61850-based zone substation system. It was shown that the selection of equipment to be interoperable in an IEC61850-based substation is a complex procedure that requires a high level of protection and communication engineering skills. In the design of the Substation Simulator, copper wiring is reduced considerably to only a few copper links between CBs and IEDs. GOOSE messages have been sent across fibre optic cables to other IEDs for the majority of protection, control and monitoring functions. This upgrade offers several benefits including reduced wiring costs, higher data performance and automated link status. All the wiring and hardware installation design can be used as references for training and future development purposes.

Chapter 5 provided the flow of the individual IEC61850-based devices configuration through their vendor proprietary tools. This was followed by system configuration and GOOSE mapping between devices. Signal Matrices of all IEDs (subscribers and publishers) were provided to enable users to simply track the functionality of GOOSE messages between IEDs. Most of the control and protection blocks such as CBF, Tie Bus Coupler, and Busbar Protection were programmed through IEDs' vendor proprietary tools. A Citect SCADA system was programmed to use as a middleware to administer GOOSE isolation and GOOSE messaging from the control centre remotely. All the CID files and the SCD file of the system were saved as a project file to be used for training and future system upgrading.

In Chapter 6 demonstration of GOOSE interoperability and GOOSE management in a multi-vendor substation was revealed. The GOOSE interoperability and peer-to-peer communication between ABB and GE IEDs fully were achieved and demonstrated using IEDScout as a network analyser. GOOSE isolation which has been the main challenge in IEC61850-based substations, was resolved through the SCADA system under device testing condition using multiple scenarios such a Busbar Protection, transformer maintenance and feeder relay maintenance. The achievement of this research project will potentially enable engineers to test any IEDs, regardless of its manufacturer, without GOOSE interruption in an IEC61850-based zone substation.

Overall, several reasons such as trained workforce, budget concerns, lack of tools and knowledge have led to the slow migration of the IEC61850 Standard into substations. Therefore, the mainstream engineers have either never or only vaguely been exposed to the intricacies of the IEC61850 Standard. Those who have had some experience usually are forced to learn 'on the job'. This enforces utilities to manage their networks using traditional hardwired solutions, even though alternative and far more cost- effective Ethernet and fibre optic technologies in the form of the IEC61850 Standard are available. The 22/66kV IEC61850-based Distribution Terminal Zone Substation has been developed using all the latest technology and equipment, and is considered state of the art. It can be utilised as a platform for the development, research and training of university graduates and power system personnel.

7.3 Future Work and Recommendation

Even though substantial accomplishments have been made through this research study, there are still several ambiguous topics in IEC61850-based substation automation systems that required further investigation, clarification and development in future work. Whereas Station, Bay and Process levels are part of the IEC61850 Standard architecture, much of the progress till date on IEC61850 has been based on Station and Bay level communications between HMI computers, Ethernet switches and IEDs. This means the IEC61850-9-2 has been largely unexplored and abandoned by utilities and academics. IEC61850-9-2 initiates Non-Conventional Instrument Transformer Technology (NCITT) into the Process level, breaking the constraints of conventional CTs and VTs. Future work is required to improve synchronisation between digital sources and switchgear that transmit sampled data over the network using IEEE 802. This includes management of these SVs in IEC61850-based substation in terms of device testing. When switchgear or a NCIT requires an isolation for testing purposes, its SVs need to be isolated to avoid any unwanted interruption between Bay level devices. This is a challenge due to the fact that the IEC61850 Standard has not been addressed clearly and in detail.

Furthermore, nowadays smart grid makes use of technologies, such as state estimation, that improve fault detection and allow self-healing of the network without the intervention of technicians. This ensures more reliable supply of electricity and reduced vulnerability to natural disasters or attack. Since, smart grid is a platform run by IP interfaces and provides open admission to a third party to the IP infrastructure and physical network, failure to secure the IP infrastructure will cause series interruption and/or damage in the network. “On December 23, 2015, the Ukrainian Kyivoblenergo, a regional electricity distribution company, reported service outages to customers. The outages were due to a third party’s illegal entry into the company’s computer and SCADA systems: Starting at approximately 3:35 p.m. local time, seven 110 kV and 23 35 kV substations were disconnected for three hours. Later statements indicated that the cyber-attack impacted additional portions of the distribution grid and forced operators to switch to manual mode. The outages were originally thought to have affected approximately 80,000 customers, based on the Kyivoblenergo’s update to customers. However, later it was revealed that three different distribution companies were attacked, resulting in several outages that caused approximately 225,000 customers to lose power across various areas” [70]. Recently a great deal of importance has been given to the theoretical and practical aspects of security in IEC61850-based systems [32, 71-73], however, cyber security for SCADA systems and IT networks with VLAN infrastructure is still a grey area for utilities that need to be further explored in future research works.

In addition, a modern power system automation and application of intelligent protection system can be designed based on the IEC61850 Standard where “read and write” services can be used to update protection settings. This can be a potential research area for design and development of Multi-Agent Systems (MAS) which is becoming a promising industrial research approach in dealing with the complexities in the future power system networks. Thus, research on IEC61850 standard and existing communication services for real-time adjustment in the settings of the relays will highlight possibilities in deployment of MAS using IEC61850 standard.

References

[1] A. Kalam and D. P. Kothar, Power systems protection and communications, First ed. Kent, UK: New Age Science Limited, 2010.

[2] P. Zhang, L. Portillo, and M. Kezunovic, "Reliability and component importance analysis of all-digital protection systems," in Power Systems Conference and Exposition, 2006. PSCE'06. 2006 IEEE PES, 2006, pp. 1380-1387.

[3] S. Mohagheghi, J. Stoupis, and Z. Wang, "Communication protocols and networks for power systems-current status and future trends," in Power Systems Conference and Exposition, 2009. PSCE'09. IEEE/PES, 2009, pp. 1-9.

[4] E. Udren, S. Kunsman, and D. Dolezilek, "Significant substation communication standardization developments," in 2nd Annual Western Power Delivery Automation Conference (WPDAC) Proceedings, 2000.

[5] I. Bermudez, A. Tongaonkar, M. Iliofotou, M. Mellia, and M. M. Munafò, "Towards automatic protocol field inference," Computer Communications, vol. 84, pp. 40-51, 2016.

[6] B. Stojcevski, "Implementation of the IEC61850 international protocol for accurate fault location in overhead transmission lines," College of Engineering and Science, Victoria University, Australia, 2013.

[7] S. Amjadi and A. Kalam, "IEC61850 GOOSE Performance in Real Time and Challenges Faced by Power Utilities," in PowerTech, 2015 IEEE Eindhoven, 2015, pp. 1-6.

[8] R. Mackiewicz, "Overview of IEC 61850 and Benefits," in Power Systems Conference and Exposition, 2006. PSCE'06. 2006 IEEE PES, 2006, pp. 623-630.

[9] A. Apostolov, "Isolation of IEDs for testing in IEC61850 Based Substation Power Protection," in Australi Protection Symposium, 2014. APS, Sydney, 2014, pp. 201-211

[10] M. G. Kanabar and T. S. Sidhu, "Performance of IEC 61850-9-2 Process Bus and Corrective Measure for Digital Relaying," Power Delivery, IEEE Transactions on, vol. 26, pp. 725-735, 2011.

[11] S. Amjadizeynalhajelo and A. Kalam, "Device Isolation in IEC61850 Based Substation Protection Systems," International Journal on Recent Technologies in Mechanical and Electrical Engineering (IJRMEE), pp. 43-48, 2015.

[12] A. Apostolov, "To GOOSE or not to GOOSE?-that is the question," in Protective Relay Engineers, 2015 68th Annual Conference for, 2015, pp. 583-596.

[13] P. Rietmann and P. Reinhardt, "Applying IEC 61850 to substation automation systems," in PSP,(2006) Power System Protection Conference, Bled. Slovenia, 2006, pp. 6-8.

[14] F. Clavel, E. Savary, P. Angays, and A. Vieux-Melchior, "Integration of a new standard: A network simulator of IEC 61850 architectures for electrical substations," Industry Applications Magazine, IEEE, vol. 21, pp. 41-48, 2015.

[15] P. Pruthvi, H. Bhuvaneswari, and L. Sudheendran, "Analysis of utility communication protocol IEC 61850 for substation automation systems," in Research & Technology in the Coming Decades (CRT 2013), National Conference on Challenges in, 2013, pp. 1-8.

[16] J.-x. WU, M.-q. HU, Z.-j. WU, G.-f. XI, and Y.-s. DU, "Testing of IEC 61850 based intelligent electronic device and substation automation system," Power System Technology, vol. 2, p. 017, 2007.

[17] A. Apostolov and B. Vandiver, "Virtual isolation of IEDs for testing in IEC 61850 based substation protection systems," in Protective Relay Engineers, 2014 67th Annual Conference for, 2014, pp. 552-563.

[18] K.-P. Brand, V. Lohmann, and W. Wimmer, Substation automation handbook: Utility Automation Consulting Lohmann Bremgarten, 2003.

[19] S. Amjadi and A. Kalam, "IEC61850: a Lingua Franca for Substation Automation " International Journal of Technical Research & Science (IJTRS) vol. 1, pp. 28-34, 2016.

[20] J. Espina, T. Falck, A. Panousopoulou, L. Schmitt, O. Mülhens, and G.-Z. Yang, "Network topologies, communication protocols, and standards," in Body sensor networks, ed: Springer, 2014, pp. 189-236.

[21] T. P. Peixoto and S. Bornholdt, "Evolution of robust network topologies: Emergence of central backbones," Physical review letters, vol. 109, p. 118703, 2012.

[22] G. Bora, S. Bora, S. Singh, and S. M. Arsalan, "OSI reference model: An overview," International Journal of Computer Trends and Technology (IJCTT), vol. 7, pp. 214-218, 2014.

[23] I. Modbus, "Modbus application protocol specification v1. 1a," North Grafton, Massachusetts (www. modbus. org/specs. php), 2004.

[24] A. Swales, "Open Modbus/TCP Specification," Schneider Electric, vol. 29, 1999.

[25] M. Mallouhi, Y. Al-Nashif, D. Cox, T. Chadaga, and S. Hariri, "A testbed for analyzing security of SCADA control systems (TASSCS)," in Innovative Smart Grid Technologies (ISGT), 2011 IEEE PES, 2011, pp. 1-7.

[26] W. S. Going, B. Thigpen, P. Chok, A. B. Anderson, and G. Vachon, "Intelligent Well Technology: Are we ready for closed loop control?," in Intelligent Energy Conference and Exhibition, 2006.

[27] K. Zimmerman and E. O. Schweitzer III, "Substation Communications: When Should I Use EIA-232, EIA-485, And Optical Fiber?," in Western Protective Relay Conference, 1996.

[28] R. MEI and Y.-m. MU, "Realization of communication between automatic devices based on Modbus protocol," Journal of Beijing Institute of Machinery, vol. 1, p. 014, 2006.

[29] A. Bakhtar and M. Kooshavar, "Implementation of UCA Based Inter and Intra Substation Communication Architecture."

[30] A. W. Blackett, B. J. Gilbert, and M. A. Hancock, "Method and system for master slave protocol communication in an intelligent electronic device," ed: Google Patents, 2004.

[31] M. ALI, "DNP3 analysis and implementations," 2014.

[32] W. Wang and Z. Lu, "Cyber security in the Smart Grid: Survey and challenges," Computer Networks, vol. 57, pp. 1344-1371, 2013.

[33] V. M. Igure, S. A. Laughter, and R. D. Williams, "Security issues in SCADA networks," Computers & Security, vol. 25, pp. 498-506, 2006.

[34] M. Childers and M. Borrielli, "IEC61850 substation experiences DPSP 2012," in Developments in Power Systems Protection, 2012. DPSP 2012. 11th International Conference on, 2012, pp. 1-5.

[35] T. Kostic and C. Frei, "Modelling and using IEC 61850-7-2 (ACSI) as an API," in Power Tech, 2007 IEEE Lausanne, 2007, pp. 713-719.

[36] B. Stojcevski and A. Kalam, "Multi-vendor portable IEC61850 testing unit," in Innovative Smart Grid Technologies Asia (ISGT), 2011 IEEE PES, 2011, pp. 1-8.

[37] D. Hou and D. Dolezilek, "IEC 61850–what it can and cannot offer to traditional protection schemes," Schweitzer Engineering Laboratories, Inc, vol. 20080912, 2008.

[38] M. J. Erickson, D. V. Zilavy, and E. A. Cross, "Multi-drop ethernet," ed: Google Patents, 2010.

[39] P. H. Sutterlin, W. R. Bemiss, and G. M. Hey, "Data communication network providing power and message information," ed: Google Patents, 1992.

[40] R. C. Dixon, N. C. Strole, and J. D. Markov, "A token-ring network for local data communications," IBM Systems Journal, vol. 22, pp. 47-62, 1983.

[41] A. Esterline, W. Wright, and M. Sundaresan, "A wireless multiagent architecture for structural health monitoring that incorporates web services," in Proceedings of AIAA Infotech@ Aerospace 2010 Conference, 2010.

[42] R. Aguilar and J. Ariza, "Testing and configuration of IEC 61850 multivendor protection schemes," in Transmission and Distribution Conference and Exposition, 2010 IEEE PES, 2010, pp. 1-8.

[43] B. Stojcevski and A. Kalam, "Fault Location in Overhead Power Lines Using the IEC61850 International Protocol," International Review on Modelling and Simulations (IREMOS), vol. 3, pp. 888-899, 2010.

[44] J. Park, E. In, S. Ahn, C. Jang, and J. Chong, "IEC 61850 Standard Based MMS Communication Stack Design Using OOP," in Advanced Information Networking and Applications Workshops (WAINA), 2012 26th International Conference on, 2012, pp. 329-332.

[45] IEC61850-7, Basic Communication Structure for Substation and Feeder Equipment, 2 ed.: International Electrotechnical Committee 2012.

[46] T. Sidhu, M. Kanabar, and P. Parikh, "Configuration and performance testing of IEC 61850 GOOSE," in Advanced Power System Automation and Protection (APAP), 2011 International Conference on, 2011, pp. 1384-1389.

[47] E. Atienza, "Testing and troubleshooting IEC 61850 GOOSE-based control and protection schemes," in Protective Relay Engineers, 2010 63rd Annual Conference for, 2010, pp. 1-7.

[48] P. Jongjoo, I. Eunkyu, A. Sangwoo, J. Cheoljon, and C. Jonghwa, "IEC 61850 Standard Based MMS Communication Stack Design Using OOP," in Advanced Information Networking and Applications Workshops (WAINA), 2012 26th International Conference on, 2012, pp. 329-332.

[49] SEL. (2010, Relay Configuration Tools Manual available at. [https://www.selinc.com/SEL-5030/]. 2013(10/06/2013).

[50] ABB. (2016). REF615 Feeder Protection and Control Relay Application Manual. Available: https://library.e.abb.com/public/ca0cdd3d79e543e1b5e5227eba428a8d/REF615_appl_756378_ENr.pdf

[51] IEC61850-8-1, "Specific Communication Service Mapping (SCSM) – Mappings to MMS," in Part 8-1, ed: International Electrotechnical Committee 2014.

[52] S. Nick, G. Nourbakhsh, A. Ghosh, and N. Ghasemi, "A technique for analysing GOOSE packets when testing relays in an IEC 61850-8-1 environment," in Proceedings of the 2015 South East Asia Protection and Automation Conference, SEAPAC 2015, 2015, pp. 1-12.

[53] J. Jiang, H. Gou, Z. Liu, D. Liu, J. Bu, and X. Ji, "A conformance testing device for an IEC 61850 configuration file based on an NICRIO platform," in Future Communication Technology and Engineering: Proceedings of the 2014 International Conference on Future Communication Technology and Engineering (FCTE 2014), Shenzhen, China, 16-17 November 2014, 2015, p. 199.

[54] Y. Liu, "Generic substation event monitoring based on IEC 61850 and IEEE 1588 standards," 2015.

[55] IEC61850-9-2, "Sampled Values over ISO/IEC 8002-3," in IEC61850 Standar, 2 ed: International Electrotechnical Committee 2012.

[56] J. Zhao, K. Qian, J. Yao, S. Wang, Z. Yang, Z. Gao, et al., "A network scheme for process bus in smart substations without using external synchronization," International Journal of Electrical Power & Energy Systems, vol. 64, pp. 579-587, 2015.

[57] RUGGEDCOM. 2100 Rugged Operating System User Guide [Online]. Available: http://inlsystem.se/doc/ManualRSG2100.pdf

[58] ABB. (2015). Busbar Protection REB650 Application Manual. Available: https://library.e.abb.com/public/aec0e41f928a5c15c125783a00453fe7/1MRK505262-UEN_-_en_Application_manual__Busbar_protection_REB650__IEC.pdf

[59] ABB. (2015). REF611 Feeer Protection and Control Relay Application Manual. Available: https://library.e.abb.com/public/7e273b09430b440db4bba317b374ecdd/REF611_appl_757456_ENb.pdf

[60] GE. (2016). T60 Transformer Protection Relay Manual. Available: http://www.gegridsolutions.com/products/manuals/t60/t60man-s5.pdf

[61] GE. (2016). F35 Multiple Feeder Management Relay Manual. Available: https://www.gegridsolutions.com/products/manuals/f35/f35man-ab2.pdf

[62] M. Majdalawieh, F. Parisi-Presicce, and D. Wijesekera, "DNPSec: Distributed network protocol version 3 (DNP3) security framework," in Advances in Computer, Information, and Systems Sciences, and Engineering, ed: Springer, 2007, pp. 227-234.

[63] IEC61850-8-1, "Specific Communication Service Mapping (SCSM) – Mappings to MMS," in Part 8-1, ed: International Electrotechnical Committee 2012.

[64] A. Scott, Learning RSLogix 5000 Programming: Packt Publishing Ltd, 2015.

[65] I. D. Mayergoyz and P. McAvoy, Fundamentals of Electric Power Engineering: World Scientific, 2015.

[66] C. RELECO, "MRC Series C5-A3x," C. RELECO, Ed., ed. USA: RELECO, 2016.

[67] ABB. 650 Series, IEC61850 Engineering Guide [Online]. Available: https://library.e.abb.com/public/552aab389ceb41658a7668d89898a662/RE_611_iec61850eng_757465_ENb.pdf

[68] E. Diaconescu and F. M. Enescu, "A laboratory infrastructure for the evaluation of the use of multi-agent technologies in industrial SCADA systems," in Applied Mechanics and Materials, 2014, pp. 432-441.

[69] S. Electric, "Citect SCADA " in V.2, S. Electric, Ed., ed. USA: Schneider Electric, 2013.

[70] M. Robert and L. SANS, "Analysis of the Cyber Attack on the Ukrainian Power Grid," ed. USA: Electricity Information Sharing and Analysis Centre (E-ISAC), 2016.

[71] E. D. Knapp and R. Samani, Applied cyber security and the smart grid: implementing security controls into the modern power infrastructure: Newnes, 2013.

[72] J. Liu, Y. Xiao, S. Li, W. Liang, and C. Chen, "Cyber security and privacy issues in smart grids," Communications Surveys & Tutorials, IEEE, vol. 14, pp. 981-997, 2012.

[73] N. Moreira, E. Molina, J. Lázaro, E. Jacob, and A. Astarloa, "Cyber-security in substation automation systems," Renewable and Sustainable Energy Reviews, vol. 54, pp. 1552-1562, 2016.

Appendix A - List of Equipment and Technical Specifications

Table A.1 IEDs and Devices Specifications Used for 66/11 kV Substation

Device Name	Vendor	Function	IP Address	Model Number
RSG2100_1	Siemens	Managed Ethernet Switch	192.168.0.1 192.168.2.100	FX01FX01FX01TX01FG011FG01
RSG2100_2	Siemens	Managed Ethernet Switch	192.168.0.2 192.168.2.300	FX01FX01FX01TX01FG011FG01
T60	GE	Transformer Protection Relay	192.168.2.5	T03-HKH-F8N-H6N-M8M-P6N-UXX-WXX
REB650	ABB	Busbar protection	192.168.2.10	Version 1.3 A03X00-X---B1X0-DH-SB-E
F35	GE	Feeder Protection System	192.168.2.15	T03-HKH-F8N-H6N-M67-P67-UXX
REF615-1	ABB	Feeder Protection and Control: Non-Directional O/C, Non-directional E/F, voltage & frequency based protection, synchro check and CB condition monitoring (RTD option)	192.168.2.20	HBFHAEAGBEH1BCN11G
REF611	ABB	Feeder Protection and Control : Non-directional O/C and non-directional E/F	192.168.2.25	HBBAAA1AN1XE
C30	GE	Feeder Protection	192.168.2.30	N-A-D-F-2-G-5-HI-6E
F650_1	GE	Feeder Protection	192.168.2.35	N-A-D-F-2-G-5-HI-6E
REB611	ABB	Busbar and multipurpose differential protection and control Relay	192.168.2.40	HBAAAA1NN1XE
REF615_2	ABB	Feeder Protection and Control: Non-Directional O/C, Non-Directional E/F, voltage & frequency based protection, synchro-check and CB condition monitoring (RTD option)	192.168.2.45	HBFHAEAGBEH1BCN11G
PLC SLC500	Allen Bradley	Programmable Logic Controller	192.168.2.95	SLC/05-CX/101
CMC35	Omicron	Fault Simulator Unit	192.168.2.50	CMC356.3 U.T76

MRC series

C5-A3x

11-pin, power relay, 3-pole, plug-in, faston

Type	**C5-A3x/ ... V** Power relays, 3 change-over contacts
Maximum contact load	**16 A/400 V AC-1 0,5 A/110 V DC-1** **16 A/30 V DC-1 0,2 A/220 V DC-1**

Contacts	
Material Standard Code 0	AgNi
Rated current	16 A
Switch-on current max. (20 ms)	40 A
Switching voltage max.	400 V
AC load (Fig 1)	4 kVA
DC load	see Fig. 2

Coil	
Coil resistance	see table; tolerance ± 10 %
Pick-up voltage	≤ 0,8 x U_N
Release voltage	≥ 0,1 x U_N
Nominal power	2,4 VA (AC)/1,4 W (DC)

Coil table

VAC	Ω	mA	VDC	Ω	mA
24	65	100	24	414	58
48	286	50	48	1K6	30
115	1K7	21	110	8K1	13
230	6K8	10	220	35K6	6,2
400	18K8	6			

Insulation	Volt rms, 1 min
Contact open	1000 V
Contact/contact	4 kV
Contact/coil	4 kV
Insulation resistance at 500 V	≥3 GΩ
Insulation, IEC 61810-1	4 kV/3

Specifications	
Ambient temperature operation/storage	-40 (no ice)....60 °C /-40 ... 80 °C
Pick-up time/bounce time	20 ms/≤ 3 ms
Release time/bounce time	10 ms/≤ 1 ms
Mechanical life ops	AC: 10 Mill./DC: 20 Mill.
DC voltage endurance at rated load	≥100000 switching cycles
Switching frequency at rated load	≤ 1200/h
Protection class	IP40
Weight	95 g

Standard types	
VAC 50 Hz/60 Hz: 24, 48, 115, (120), 230, (240)	**C5-A30/AC ... V**
LED	**C5-A30X/AC ... V**
RC suppresor (max 250 V)	**C5-A30R/AC ... V**
VDC 24, 48, 110, 220	**C5-A30/DC ... V**
LED	**C5-A30X/DC ... V**
Free wheeling diode	**C5-A30DX/DC ... V**
Polarity and free wheeling diode	**C5-A30FX/DC ... V**
AC/DC bridge rectifier 24 V, 48 V, 60 V	**C5-A30BX/UC ... V**

"..." Enter the voltage for full type designation

Accessories	
Socket:	**S5-S, S5-L, S5-P, S5-P0, S5-M**
Optional accessories (blanking plug):	**SO-NP, SO-OP**

Connection diagram

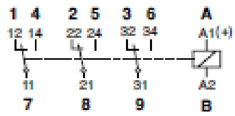


Fig. 1 AC voltage endurance

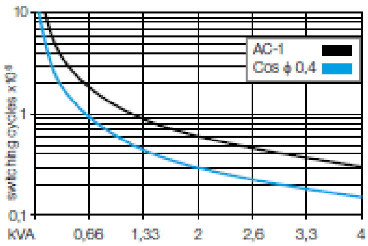
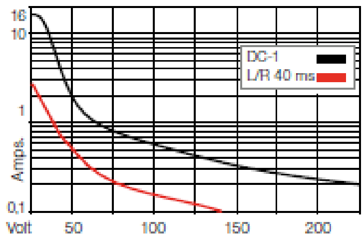
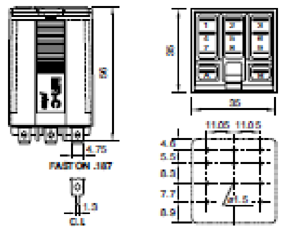


Fig. 2 DC load limit curve



Dimensions [mm]



Technical approvals, conformities

Fig. A.1 Technical specifications of dummy circuit breakers

Table A.2.a Order Code instruction for ABB IEDs

H B F **F A E A G** B C C 1 B B A 1 X D

#	DESCRIPTION	
4-8	**Standard configurations, analog and binary I/O options**	
	Standard configuration descriptions in short: **A** = Non-directional O/C and directional E/F protection. **B** = Non-directional O/C and directional E/F protection, CB condition monitoring **C** = Non-directional O/C and non-directional E/F protection **D** = Non-directional O/C and non-directional E/F protection, CB condition monitoring **E** = Non-directional O/C and directional E/F protection with phase-voltage based measurements, CB condition monitoring **F** = Directional O/C and directional E/F protection with phase-voltage based measurements, undervoltage and overvoltage protection, CB condition monitoring **G** = Directional O/C and directional E/F protection, phase-voltage based protection and measurement functions, CB condition monitoring, (sensor inputs) **H** = Non-directional O/C and non-directional E/F protection, voltage and frequency based protection and measurement functions, synchro-check and CB condition monitoring	
	Std. conf **A**: 4I + Uo (Io 1/5 A) + 3 BI + 6 BO	**AAAAA**
	Std. conf **A**: 4I + Uo (Io 0.2/1 A) + 3 BI + 6 BO	**AABAA**
	Std. conf **B**: 4I +Uo (Io 1/5 A) + 11 BI + 10 BO	**BAAAC**
	Std. conf **B**: 4I +Uo (Io 1/5 A) + 17 BI + 13 BO	**BAAAE**
	Std. conf **B**: 4I +Uo (Io 0.2/1 A) + 11 BI + 10 BO	**BABAC**
	Std. conf **B**: 4I +Uo (Io 0.2/1 A) + 17 BI + 13 BO	**BABAE**
	Std. conf **C**: 4I (Io 1/5 A) + 4 BI + 6 BO	**CACAB**
	Std. conf **C**: 4I (Io 0.2/1 A) + 4 BI + 6 BO	**CADAB**
	Std. conf **D**: 4I (Io 1/5 A) + 12 BI + 10 BO	**DACAD**
	Std. conf **D**: 4I (Io 1/5 A) + 18 BI + 13 BO	**DACAF**
	Std. conf **D**: 4I (Io 0.2/1 A) + 12 BI + 10 BO	**DADAD**
	Std. conf **D**: 4I (Io 0.2/1 A) + 18 BI + 13 BO	**DADAF**
	Std. conf **E**: 4I (Io 1/5 A) + 5U + 16 BI + 10 BO	**EAEAG**
	Std. conf **E**: 4I (Io 0.2/1 A) + 5U + 16 BI + 10 BO	**EAFAG**
	Std. conf **F**: 4I (Io 1/5 A) + 5U + 16 BI + 10 BO	**FAEAG**
	Std. conf **F**: 4I (Io 0.2/1 A) + 5U + 16 BI + 10 BO	**FAFAG**
	Std. conf **G**: 3Is + 3Us +Io (Io 0.2/1 A) + 8 BI + 10 BO	**GDAAH**
	Std. conf **H**: 4I (Io 1/5 A) + 5U + 16 BI + 10 BO	**HAEAG**
	Std. conf **H**: 4I (Io 0.2/1 A) + 5U + 16 BI + 10 BO	**HAFAG**

Table A.2.b Order Code instruction for ABB IEDs

HBFFAEAGBC**C**1BBA1XD

#	DESCRIPTION	
11	**Communication protocols**	
	IEC 61850 (for Ethernet communication modules and IEDs without a communication module)	**A**
	Modbus (for Ethernet/serial or Ethernet + serial communication modules)	**B**
	IEC 61850 + Modbus (for Ethernet or serial + Ethernet communication modules)	**C**
	IEC 60870-5-103 (for serial or Ethernet + serial communication modules)	**D**
	DNP3 (for Ethernet/serial or Ethernet + serial communication modules)	**E**

Table A.2. c Order Code instruction for ABB IEDs

HBFFAEAG**BC**C1BBA1XD

#	DESCRIPTION	
9 - 10	**Communication modules (Serial/Ethernet)**	
	Serial RS-485, incl. an input for IRIG-B + Ethernet 100Base-FX (1 x LC)	**AA**
	Serial RS-485, incl. an input for IRIG-B + Ethernet 100Base-TX (1 x RJ-45)	**AB**
	Serial RS-485, incl. an input for IRIG-B	**AN**
	Serial glass fibre (ST), incl. an RS-485 connector and an input for IRIG-B (cannot be combined with arc protection)	**BN**
	Serial glass fibre (ST) + Ethernet 100Base-TX (1 x RJ-45) + Serial RS-485 connector, RS-232/485 D-Sub 9 connector + input for IRIG-B (cannot be combined with arc protection)	**BB**
	Serial glass fibre (ST) + Ethernet 100Base-TX (3 x RJ-45)	**BD**
	Serial glass fibre (ST) + Ethernet 100Base-TX and -FX (2 x RJ-45 + 1 x LC)	**BC**
	Ethernet 100Base-FX (1 x LC)	**NA**
	Ethernet 100Base-TX (1 x RJ-45)	**NB**
	Ethernet 100Base-TX (2 x RJ-45 + 1 x LC)	**NC**
	Ethernet 100Base-TX (3 x RJ-45)	**ND**
	No communication module	**NN**

Table A.2. d Order Code instruction for ABB IEDs

H B F F A E A G B C C 1 B B A 1 X D

#	DESCRIPTION	
12	**Language**	
	English	1
	English and German	3
	English and Swedish	4
	English and Spanish	5
	English and Russian	6
	English and Portuguese (Brazilian)	8
13	**Front panel**	
	Small LCD	A
	Large LCD with single line diagram (SLD)	B
14	**Option 1**	
	Auto-reclosing	A
	Arc protection (requires a communication module, cannot be combined with communication modules BN or BB)	B
	Arc protection and auto-reclosing (requires a communication module, cannot be combined with communication modules BN, BB)	C
	None	N
15	**Option 2**	
	Directional earth-fault protection (only for std configuration: A, B, E, F, G)	A
	Admittance based earth-fault protection (only for std configuration: A, B, E, F, G)	B
	None	N
16	**Power supply**	
	48...250 V DC, 100...240 V AC	1
	24...60 V DC	2
17	**Vacant digit**	
	Vacant	X
18	**Version**	
	Version 3.0	D

Example code: H B F F A E A G B C C 1 B B A 1 X D

Your ordering code:

Digit (#)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Code																		

Table A.3 Order code instruction for GE IEDs

	F35	- *	**	- H	*	*	- F**	- H**	- M**	- P**	- U**	- W	*	For Full Sized Horizontal Mount
Base Unit	F35													Base Unit
CPU		E												RS485 + RS485 (IEC 61850 option not available)
		J												RS485 + multimode ST 100BaseFX
		K												RS485 + multimode ST Redundant 100BaseFX
		N												RS485 + 10/100 BaseT
		T												RS485 + three multimode SFP LC 100BaseFX. Req FW v7xx or higher
		U												RS485 + two multimode SFP LC 100BaseFX + one SFP RJ45 100BaseT. Req FW v7xx or higher
		V												RS485 + three SFP RJ45 100BaseT. Req FW v7xx or higher
Software Options			00											No Software Options
(see note 1 below)			03											IEC 61850
			A0											CyberSentry UR Lvl 1. Req UR FW 7.xx or higher
			B0											IEEE 1588. Req UR FW 7.xx or higher
			C0											PRP
			D0											IEEE 1588 + CyberSentry UR. Req UR FW 7.xx or higher
Mount / Coating				H										Horizontal (19" rack) - Standard
				A										Horizontal (19" rack) - Harsh Chemical Environment Option
				V										Vertical (3/4 size) - Standard
				B										Vertical (3/4 size) - Harsh Chemical Environment Option
User Interface					F									Vertical Front Panel with English Display
					I									Enhanced German Front Panel
					J									Enhanced German Front Panel with User-Programmable Pushbuttons
					K									Enhanced English Front Panel
					L									Enhanced English Front Panel with User-Programmable Pushbuttons
					M									Enhanced French Front Panel
					N									Enhanced French Front Panel with User-Programmable Pushbuttons
					Q									Enhanced Russian Front Panel
					T									Enhanced Russian Front Panel with User-Programmable Pushbuttons
					U									Enhanced Chinese Front Panel
					V									Enhanced Chinese Front Panel with User-Programmable Pushbuttons
					W									Enhanced Turkish Front Panel
					Y									Enhanced Turkish Front Panel with User-Programmable Pushbuttons
Power Supply						H								125 / 250 V AC/DC
(see note 2 below)						H						RH		125/250 V AC/DC with redundant 125/250 V AC/DC power supply
						L								24 - 48 V (DC only)
CT/VT DSP							8F		8F		8F			Standard 4CT/4VT
							8G		8G		8G			Sensitive Ground 4CT/4VT
							8H		8H		8H			Standard 8CT
							8J		8J		8J			Sensitive Ground 8CT
							8L		8L		8L			Standard 4CT/4VT w/ enhanced diagnostics
							8M		8M		8M			Sensitive Ground 4CT/4VT w/ enhanced diagnostics
							8N		8N		8N			Standard 8CT w/ enhanced diagnostics
							8R		8R		8R			Sensitive Ground 8CT w/ enhanced diagnostics
IEC 61850 Process Bus								81						8 Port IEC 61850 Process Bus Module
Digital I/O								XX	XX	XX	XX	XX		No Module
								4A	4A	4A	4A	4A		4 Solid State (No Monitoring) MOSFET Outputs
								4C	4C	4C	4C	4C		4 Solid State (Current w/opt Voltage) MOSFET Outputs
								4D	4D	4D	4D	4D		16 Digital Inputs with Auto-Burnish
								4L	4L	4L	4L	4L		14 Form-A (No Monitoring) Latchable Outputs
								67	67	67	67	67		8 Form-A (No Monitoring) Outputs
								6C	6C	6C	6C	6C		8 Form-C Outputs
								6D	6D	6D	6D	6D		16 Digital Inputs
								6E	6E	6E	6E	6E		4 Form-C Outputs, 8 Digital Inputs
								6F	6F	6F	6F	6F		8 Fast Form-C Outputs
								6K	6K	6K	6K	6K		4 Form-C & 4 Fast Form-C Outputs
								6L	6L	6L	6L	6L		2 Form-A (Current w/ opt Voltage) & 2 Form-C Outputs, 8 Digital Inputs
								6M	6M	6M	6M	6M		2 Form-A (Current w/ opt Voltage) & 4 Form-C Outputs, 4 Digital Inputs
								6N	6N	6N	6N	6N		4 Form-A (Current w/ opt Voltage) Outputs, 8 Digital Inputs
								6P	6P	6P	6P	6P		6 Form-A (Current w/ opt Voltage) Outputs, 4 Digital Inputs
								6R	6R	6R	6R	6R		2 Form-A (No Monitoring) & 2 Form-C Outputs, 8 Digital Inputs
								6S	6S	6S	6S	6S		2 Form-A (No Monitoring) & 4 Form-C Outputs, 4 Digital Inputs
								6T	6T	6T	6T	6T		4 Form-A (No Monitoring) Outputs, 8 Digital Inputs
								6U	6U	6U	6U	6U		6 Form-A (No Monitoring) Outputs, 4 Digital Inputs
								6V	6V	6V	6V	6V		2 Form-A (Cur w/ opt Volt) 1 Form-C Output, 2 Latching Outputs, 8 Digital Inputs
Transducer I/O								5A	5A	5A	5A	5A		4 dcmA Inputs, 4 dcmA Outputs
								5C	5C	5C	5C	5C		8 RTD Inputs
								5D	5D	5D	5D	5D		4 RTD Inputs, 4 dcmA Outputs
								5E	5E	5E	5E	5E		4 dcmA Inputs, 4 RTD Inputs
								5F	5F	5F	5F	5F		8 dcmA Inputs
Inter-Relay Communications												7A		820 nm, multimode, LED, 1 Channel
												7B		1300 nm, multimode, LED, 1 Channel
												7C		1300 nm, singlemode, ELED, 1 Channel
												7H		820 nm, multimode, LED, 2 Channels
												7I		1300 nm, multimode, LED, 2 Channels
												7J		1300 nm, singlemode, ELED, 2 Channels
												7S		G.703, 2 Channels
												7T		RS422, 1 Channel
												7W		RS422, 2 Channels
												76		IEEE C37.94, 820 nm, multimode, LED, 1 Channel
												77		IEEE C37.94, 820 nm, multimode, LED, 2 Channel

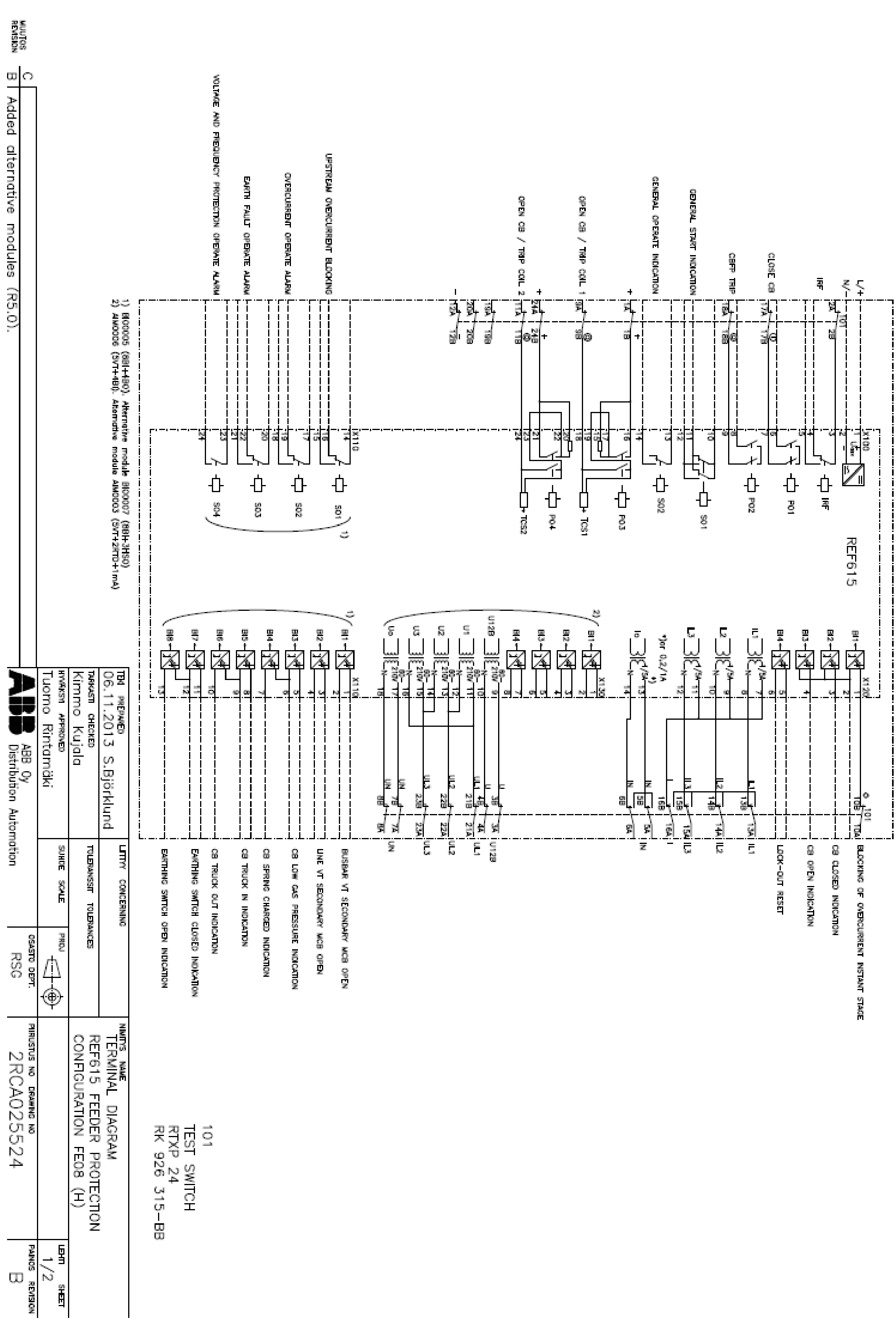


Fig. A.1.2 Default wiring diagram for REF615 ABB IED

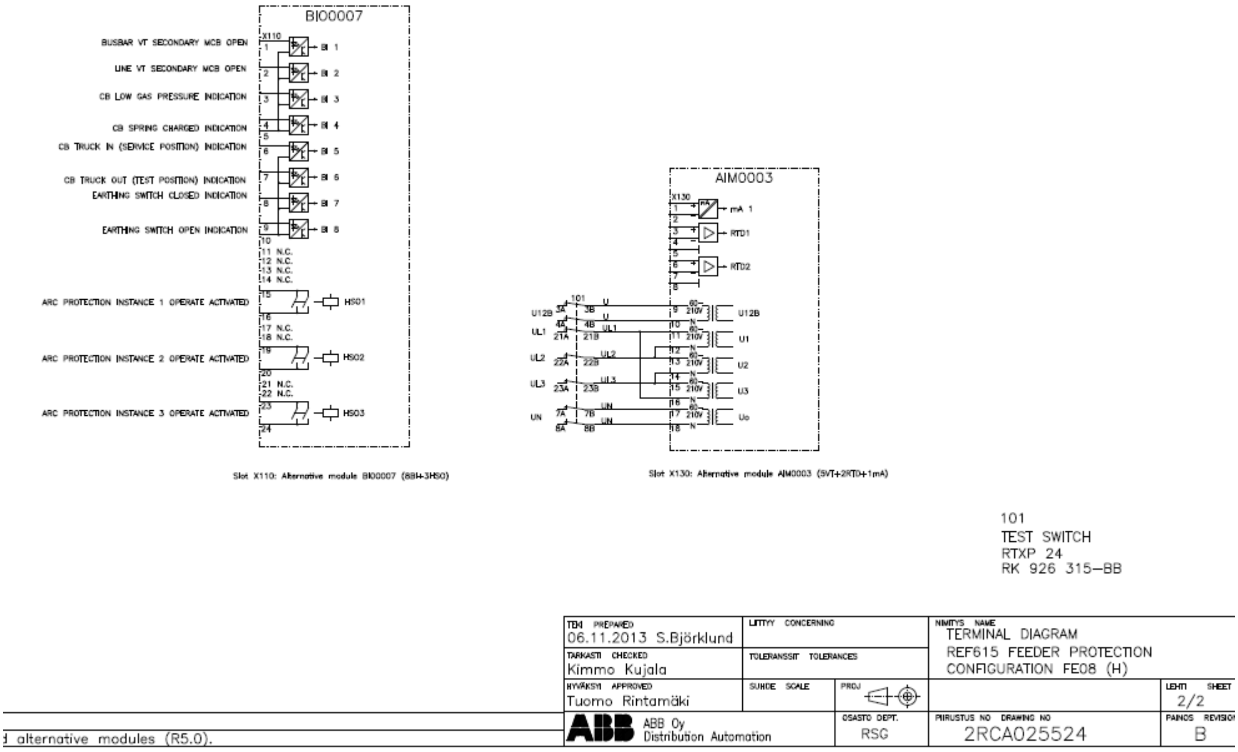
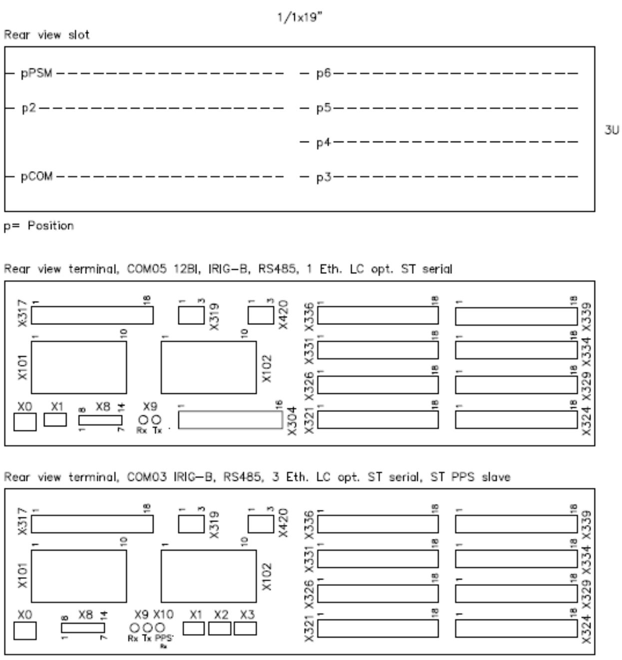


Fig. A.1.3 Default wiring diagram for REF611 ABB IED



Designation for 3U, 1/1x19" casing with 1 TRM

Module	Slot	Terminal
COM05	pCOM	X0, X1, X8, X9, X304
COM03	pCOM	X0, X8, X9, X10, X1, X2, X3
TRM01	p2	X101, X102
PSM01 PSM02 PSM03	pPSM	X317. X319, X420
BIO01	p3	X321, X324
BIO01	p4	X326, X329
BIO01	p5	X331, X334
BIO01	p6	X336, X339

Compression or ringlug terminals

Fig. A.1.5.a Default wiring diagram for REF650 ABB IED

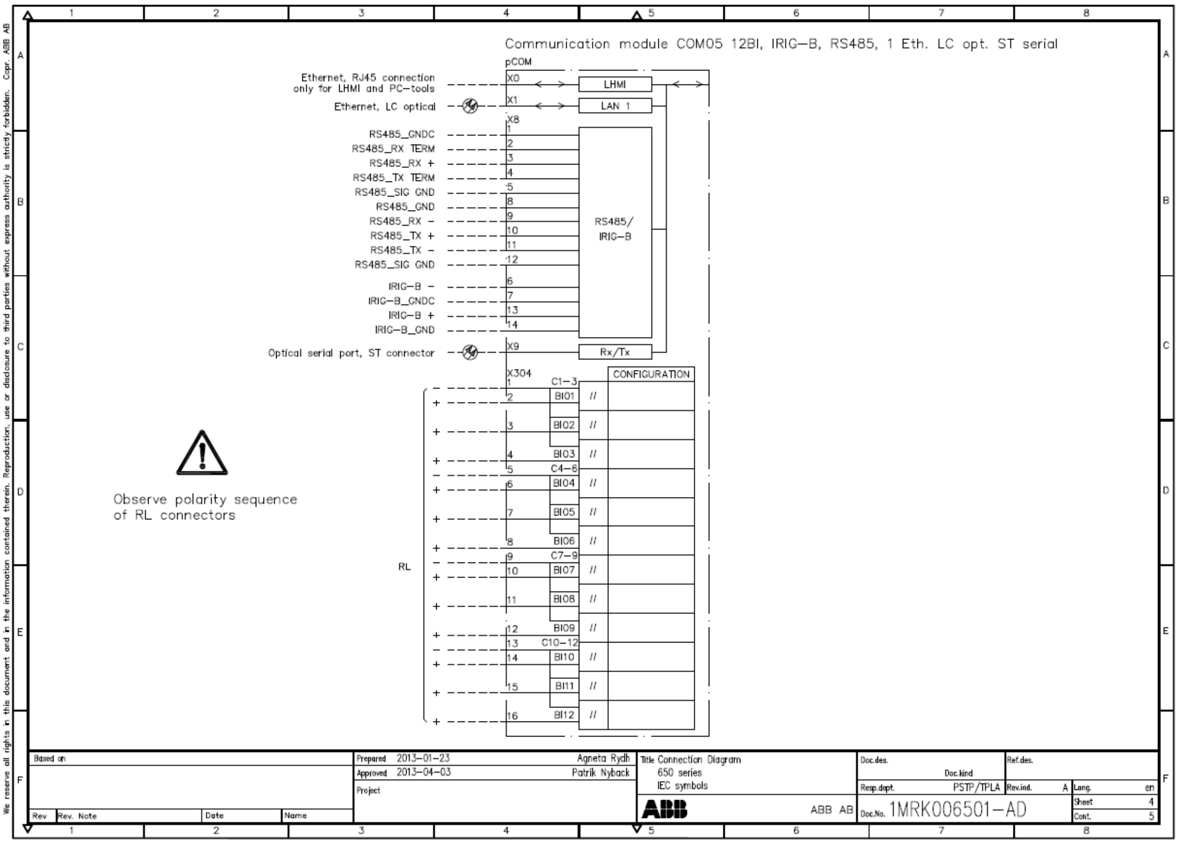
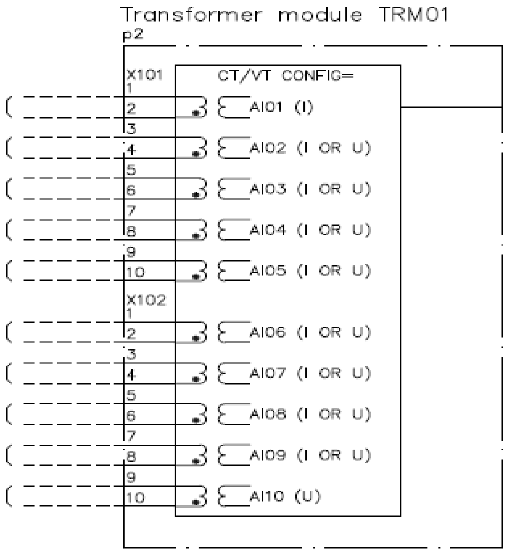
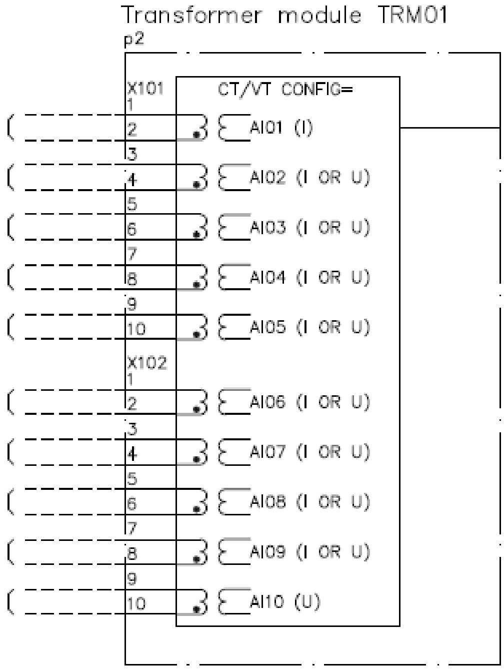


Fig. A.1.5.b Default wiring diagram for REF650 ABB IED



Designation corresponding to Transformer module				
CT/VT input designation	Current/voltage configuration			
	6I+4U	8I+2U	4I+1I+5U	4I+6U
AI01	**1/5A**	1/5A	1/5A	1/5A
AI02	1/5A	1/5A	1/5A	1/5A
AI03	1/5A	1/5A	1/5A	1/5A
AI04	1/5A	1/5A	1/5A	1/5A
AI05	1/5A	1/5A	0.1/0.5A	100–220V
AI06	1/5A	1/5A	100–220V	100–220V
AI07	100–220V	1/5A	100–220V	100–220V
AI08	100–220V	1/5A	100–220V	100–220V
AI09	100–220V	100–220V	100–220V	100–220V
AI10	100–220V	100–220V	100–220V	100–220V

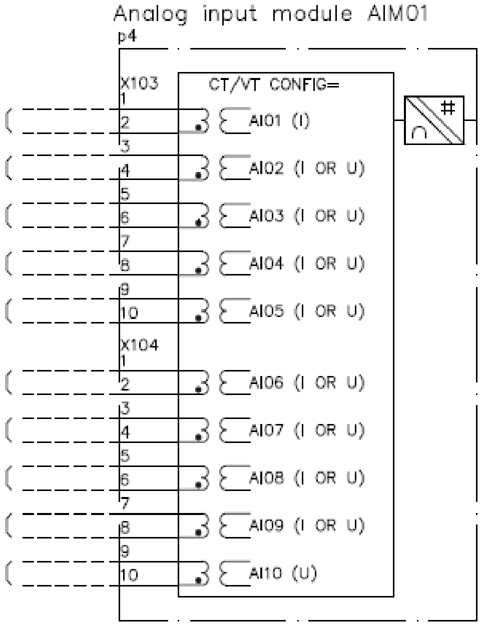
- Indicates high polarity. Note that internal polarity can be adjusted by setting of analog input CT neutral direction and or on SMAI pre–processing function blocks.



Designation corresponding to Transformer module				
CT/VT input designation	Current/voltage configuration			
	6I+4U	8I+2U	4I+1I+5U	4I+6U
AI01	**1/5A**	1/5A	1/5A	1/5A
AI02	1/5A	1/5A	1/5A	1/5A
AI03	1/5A	1/5A	1/5A	1/5A
AI04	1/5A	1/5A	1/5A	1/5A
AI05	1/5A	1/5A	0.1/0.5A	100–220V
AI06	1/5A	1/5A	100–220V	100–220V
AI07	100–220V	1/5A	100–220V	100–220V
AI08	100–220V	1/5A	100–220V	100–220V
AI09	100–220V	100–220V	100–220V	100–220V
AI10	100–220V	100–220V	100–220V	100–220V

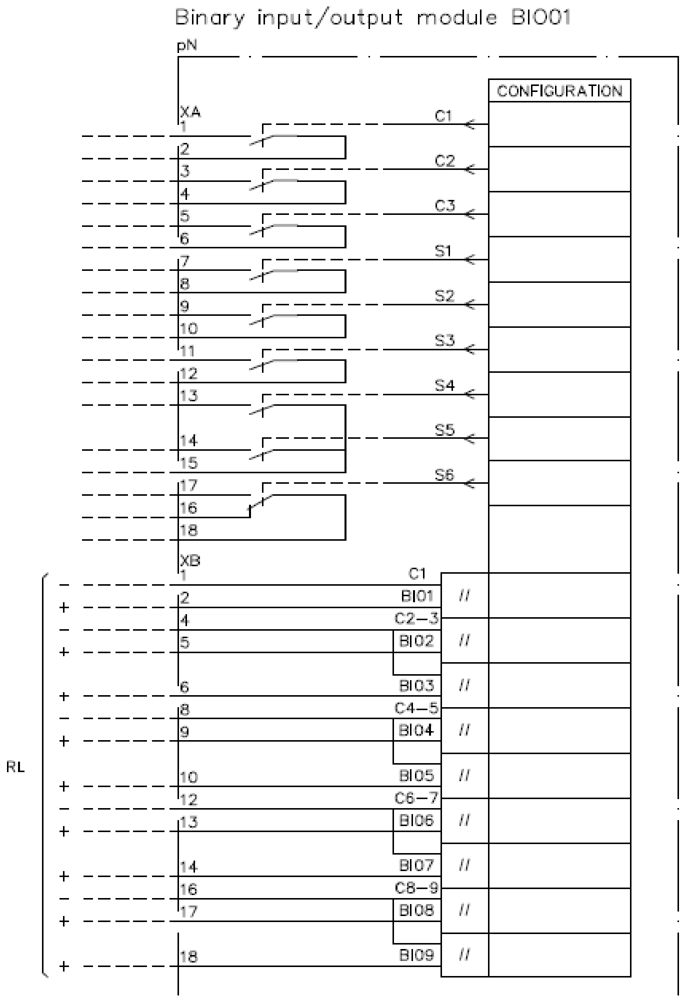
- Indicates high polarity. Note that internal polarity can be adjusted by setting of analog input CT neutral direction and or on SMAI pre–processing function blocks.

Fig. A.1.5.c Default wiring diagram for REF650 ABB IED



Designation corresponding to Analog input module		
CT/VT input designation	Current/voltage configuration	
	6I+4U	4I+1I+5U
AI01	1/5A	1/5A
AI02	1/5A	1/5A
AI03	1/5A	1/5A
AI04	1/5A	1/5A
AI05	1/5A	0.1/0.5A
AI06	1/5A	100–220V
AI07	100–220V	100–220V
AI08	100–220V	100–220V
AI09	100–220V	100–220V
AI10	100–220V	100–220V

• Indicates high polarity. Note that internal polarity can be adjusted by setting of analog input CT neutral direction and or on SMAI pre–processing function blocks.



Designation in correspondance to the local in the rack		
pN=	XA=	XB=
p3	X321	X324
p4	X326	X329
p5	X331	X334
p6	X336	X339

Fig. A.1.5.d Default wiring diagram for REF650 ABB IED

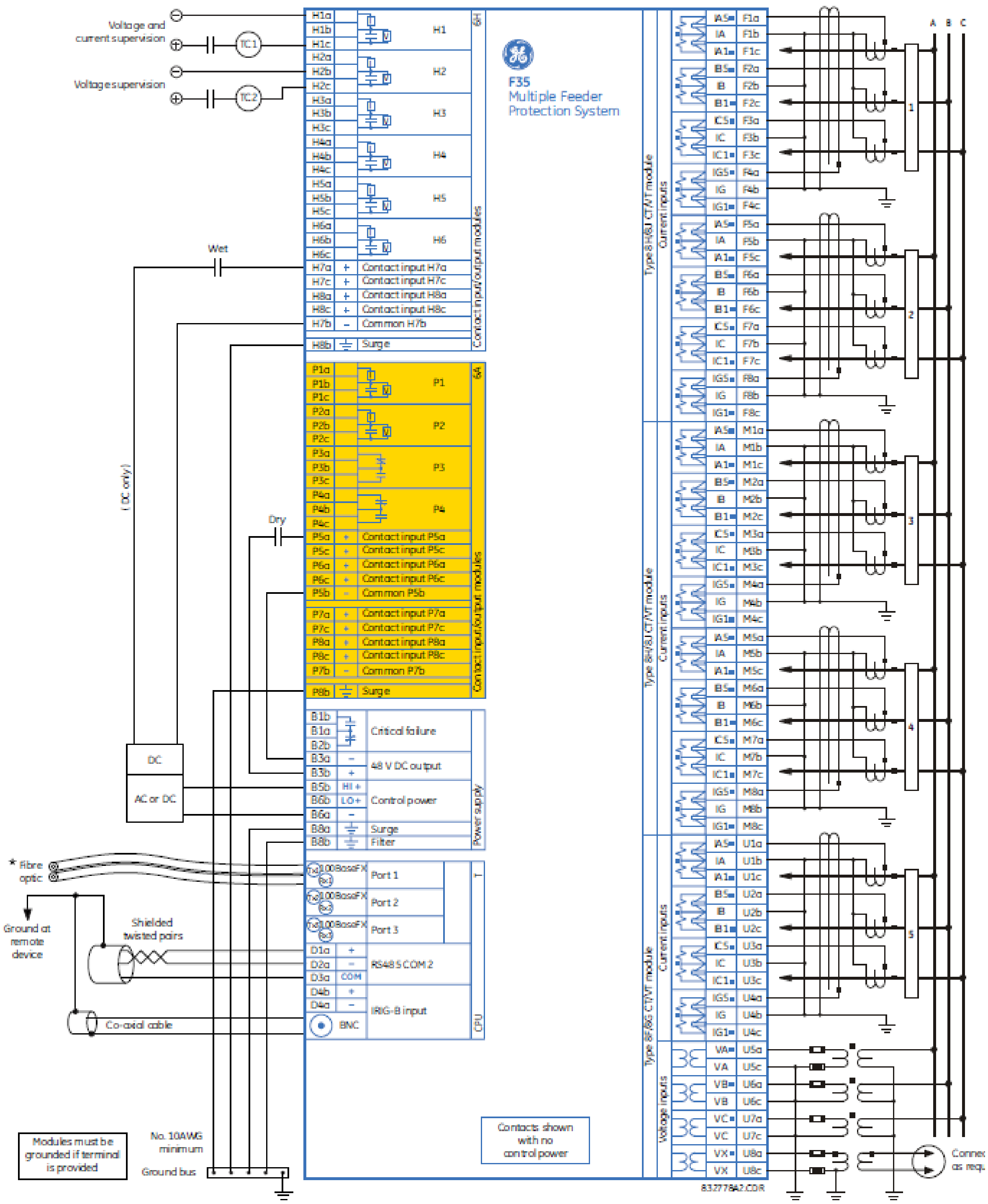


Fig. A.1.6 Typical wiring diagram for REF611 ABB IED

Specifications

- **Maximum Watts:** 2000Watts
- **Frequency:** 50/60 Hz (dual compatibility)
- **Input Voltage:** AC 200-240V
- **Output Voltage:** AC 100V-120V

IN THE BOX

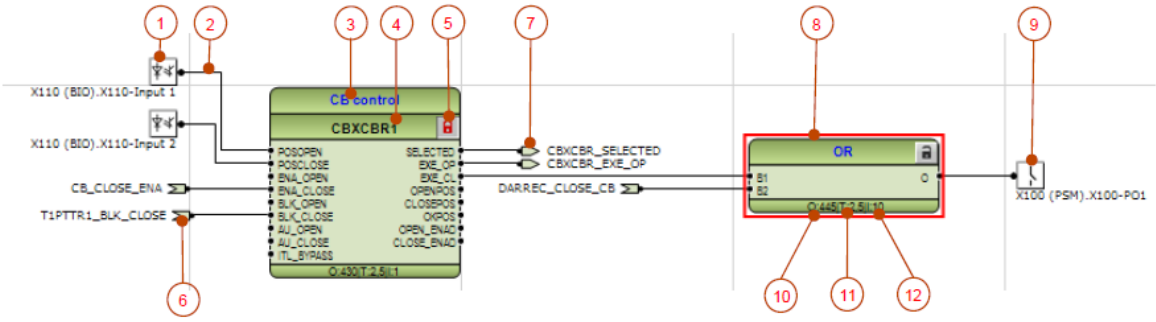
- **1x** Step Down Transformer
- **1x** User's Manual

SIZE & WEIGHT

- **Product Dimensions (L x W x H):** 21 x 22.5 x 16.5cm
- **Package Dimensions (L x W x H):** 24.5 x 29.5 x 19cm
- **Net Weight:** 10.45kg
- **Gross Weight:** 11kg

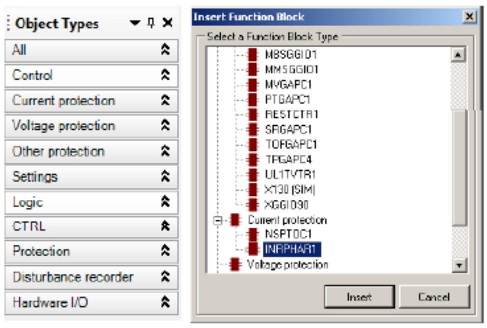
Fig. A.1.6 Technical specifications of step down Transformer

Appendix B - Devices Configurations

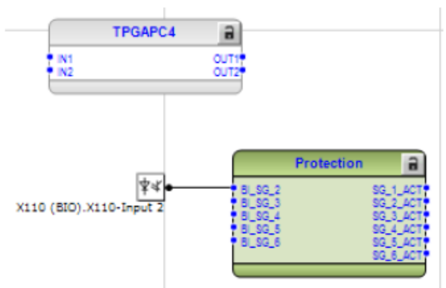


1. Hardware, binary input channel
2. Connection(s)
3. User defined function block name (blue)
4. Function block name
5. Function block, locked
6. Variable output
7. Variable input
8. Function block, selected (red)
9. Hardware, binary output channel
10. Execution order
11. Cycle time (unused in RBX615)
12. Instance number

Fig. B.1 Application Configuration tool (Symbols)

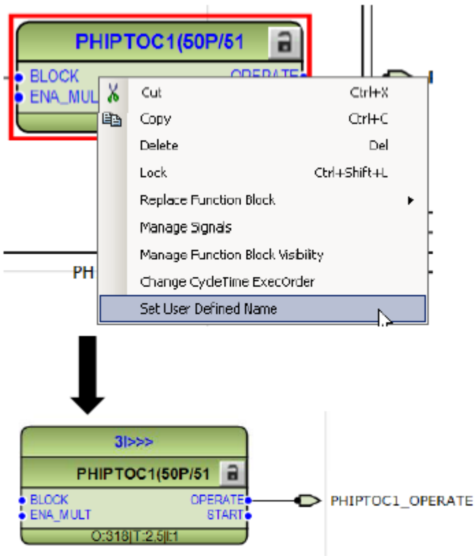


- Function blocks are the main elements of an application configuration
- Organized into type groups in Object Types view



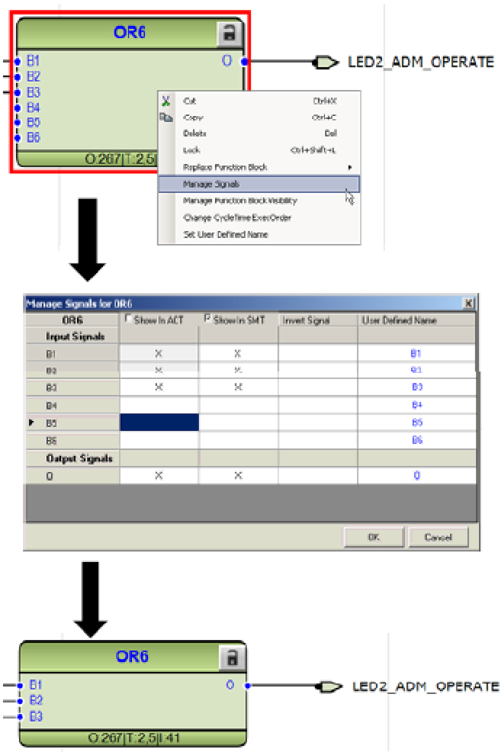
- Function block without connection – grey
- Function block with at least one input connected - green

Fig. B.2 Application Configuration tool (Function blocks)



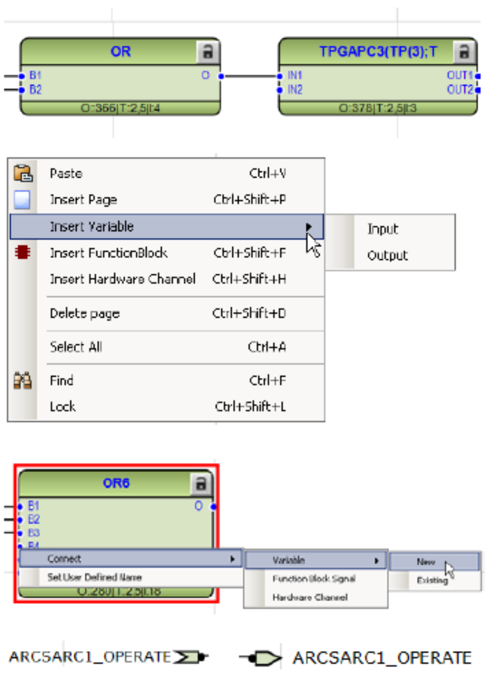
- User defined names can be added to the function blocks.
- User names are visible in Parameter Setting tool if the IED configuration is first written to the IED and then read back to PCM600.

Fig. B.3 Application Configuration tool (Function block naming)



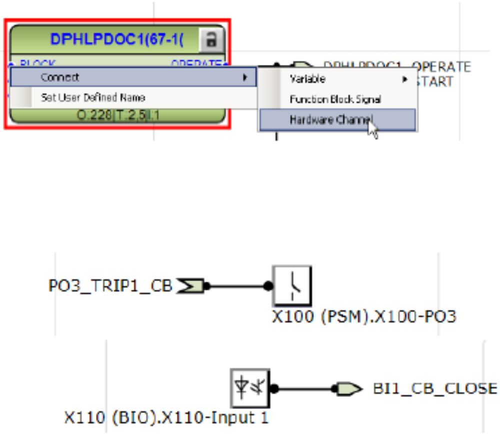
- Unused inputs and outputs can be hidden in ACT:
  - Select a function block and right click. Select Manage signals.
  - Hide inputs / outputs which are not needed.

Fig. B.4 Application Configuration tool (Function block management)



- To make a connection:
  - Click & drag a line between two signals
  - Link two signals by using variables
- New variables can be created several ways
  - Right-click in some empty place in ACT and select ”Insert Variable”
  - Right-click on the function input and select *Connect – Variable – New*
  - Open Variable list and click Add
- Input variable and output variable has different symbols in ACT

Fig. B.5 Application Configuration tool (Connecting variables)



- A hardware connection (inputs, outputs, LEDs) can be added similar way as variables.
- Hardware input channels can be used as often as needed.
- Hardware binary output channels and LEDs can be used only once.
- Hardware channels have their own graphical symbols in the Application Configuration tool.
- It is not allowed to leave unconnected hardware channels in ACT.
- Hardware channels can only be connected to a function block input or output

Fig. B.6 Application Configuration tool (Hardware channels)

Table B.1 Data details and their addresses used in SCADA

SCADA Tag Name	Data Type	Allen Bradley Address	Comment
CB1_Position	Digital	O3:0/0	Monitors the status of CB1
CB2_Position	Digital	B3:0/1	Monitors the status of CB2
CB3_Position	Digital	B3:0/2	Monitors the status of CB3
CB4_Position	Digital	B3:0/3	Monitors the status of CB4
CB5_Position	Digital	B3:0/4	Monitors the status of CB5
CB6_Position	Digital	B3:0/5	Monitors the status of CB6
CB1-Control	Digital	N7:0/0	Switch to Open/Close CB1
CB2-Control	Digital	N7:0/1	Switch to Open/Close CB2
CB3-Control	Digital	N7:0/2	Switch to Open/Close CB3
CB4-Control	Digital	N7:0/3	Switch to Open/Close CB4
CB5-Control	Digital	N7:0/4	Switch to Open/Close CB5
CB6-Control	Digital	N7:0/5	Switch to Open/Close CB6
T60	Digital	N7:0/6	Switch to put T60 in TEST mode
REB650	Digital	N7:0/7	Switch to put REB650 in TEST mode
F35	Digital	N7:0/8	Switch to put F35 in TEST mode
REF615-1	Digital	N7:0/9	Switch to put REF615-1 in TEST mode
REF611	Digital	N7:0/10	Switch to put REF611 in TEST mode
REF615-2	Digital	N7:0/11	Switch to put REF615-2 in TEST mode
IS1	Digital	N7:0/12	Switch to Open/Close Isolator 1
IS2	Digital	N7:0/13	Switch to Open/Close Isolator 2
IS3	Digital	N7:0/14	Switch to Open/Close Earth Switch 1
IS4	Digital	N7:0/15	Switch to Open/Close Earth Switch 1
ES1	Digital	N7:1/0	Switch to Open/Close Earth Switch 1
ES2	Digital	N7:1/1	Switch to Open/Close Earth Switch 2
ES3	Digital	N7:1/2	Switch to Open/Close Earth Switch 3
ES4	Digital	N7:1/3	Switch to Open/Close Earth Switch 4
ES5	Digital	N7:1/4	Switch to Open/Close Earth Switch 5
ES6	Digital	N7:1/5	Switch to Open/Close Earth Switch 6

Table B.2 Data details and their addresses used in PLC configuration

PLC I/O	Data Type	Addresses Used for Ladder Program	Comment
CB1_Position	Digital	I1:0/0	Status of CB1 as an input to PLC
CB2_Position	Digital	I1:0/1	Status of CB2 as an input to PLC
CB3_Position	Digital	I1:0/2	Status of CB3 as an input to PLC
CB4_Position	Digital	I1:0/3	Status of CB4 as an input to PLC
CB5_Position	Digital	I1:0/4	Status of CB5 as an input to PLC
CB6_Position	Digital	I1:0/5	Status of CB6 as an input to PLC
Cb1_Position	Digital	O4:0/0	Status of CB1 as an output to be sent to SCADA
CB2_Position	Digital	O4:0/1	Status of CB2 as an output to be sent to SCADA
CB3_Position	Digital	O4:0/2	Status of CB3 as an output to be sent to SCADA
CB4_Position	Digital	O4:0/3	Status of CB4 as an output to be sent to SCADA
CB5_Position	Digital	O4:0/4	Status of CB5 as an output to be sent to SCADA
CB6_Position	Digital	O4:0/5	Status of CB6 as an output to be sent to SCADA
CB1-Control	Digital	I1:0/6	Switch to Open/Close CB1 locally
CB2-Control	Digital	I1:0/7	Switch to Open/Close CB2 locally
CB3-Control	Digital	I1:0/8	Switch to Open/Close CB3 locally
CB4-Control	Digital	I1:0/9	Switch to Open/Close CB4 locally
CB5-Control	Digital	I1:0/10	Switch to Open/Close CB5 locally
CB6-Control	Digital	I1:0/11	Switch to Open/Close CB6 locally
CB1-Control	Digital	N7:0/0	Open/Close CB6 through SCADA HMI
CB2-Control	Digital	N7:0/1	Open/Close CB2 through SCADA HMI
CB3-Control	Digital	N7:0/2	Open/Close CB3 through SCADA HMI
CB4-Control	Digital	N7:0/3	Open/Close CB4 through SCADA HMI
CB5-Control	Digital	N7:0/4	Open/Close CB5 through SCADA HMI
CB6-Control	Digital	N7:0/5	Open/Close CB6 through SCADA HMI
T60	Digital	I1:0/12	Switch to put T60 in TEST mode locally
REB650	Digital	I1:0/13	Switch to put REB650 in TEST mode locally
F35	Digital	I1:0/14	Switch to put F35 in TEST mode locally
REF615-1	Digital	I1:0/15	Switch to put REF615-1 in TEST mode Locally
REF611	Digital	I5:0/0	Switch to put REF611 in TEST mode locally
REF615-2	Digital	I1:0/1	Switch to put REF615-2 in TEST mode locally
F35	Digital	N7:0/8	SCAD HMI command to put F35 in TEST mode
REF615-1	Digital	N7:0/9	SCAD HMI command to put REF615-1 in TEST mode
REF611	Digital	N7:0/10	SCAD HMI command to put REF611 in TEST mode
REF615-2	Digital	N7:0/11	SCAD HMI command to put REF615-2 in TEST mode

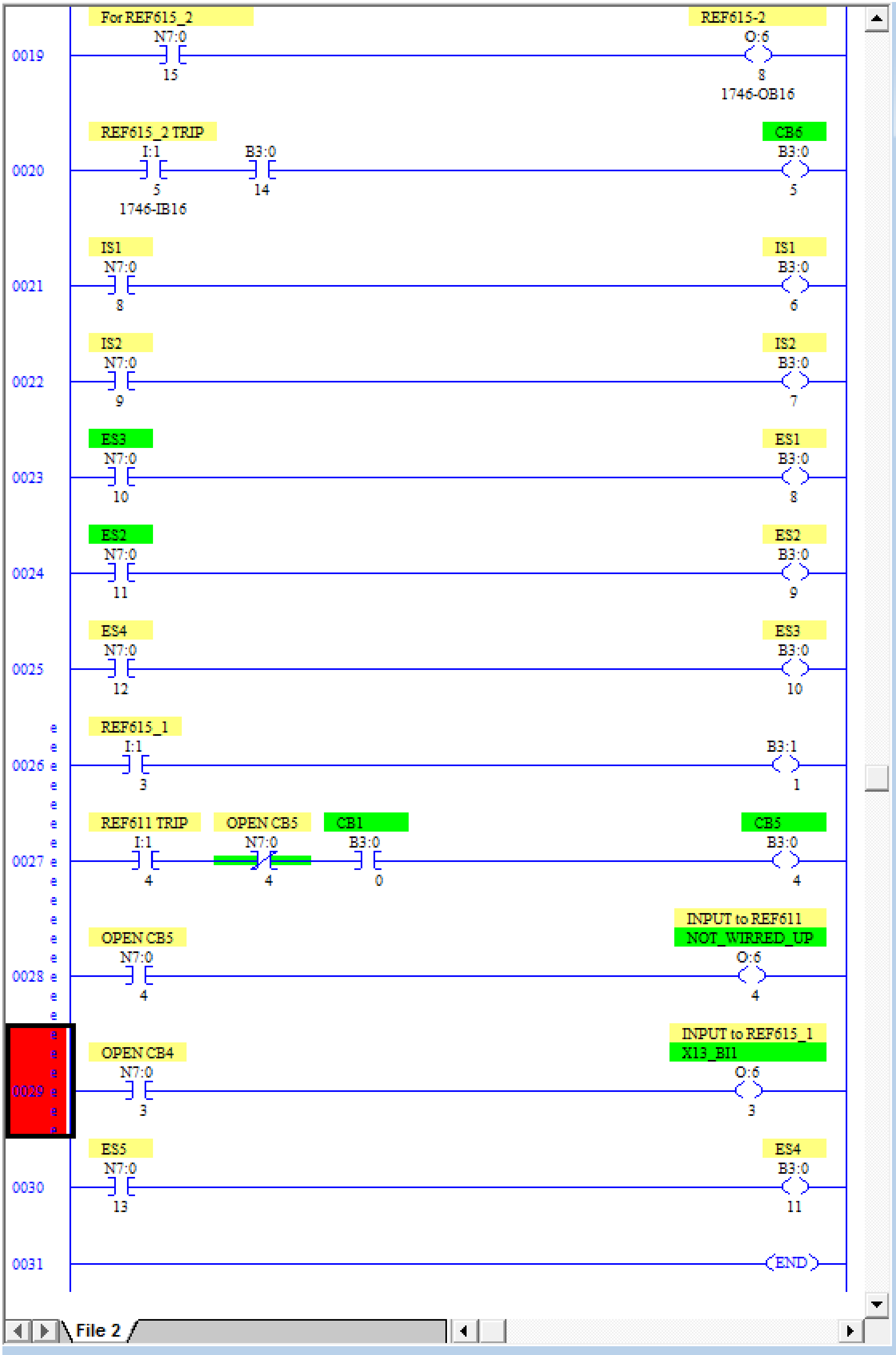


Fig B.7. a Ladder program written in PLC SLC500

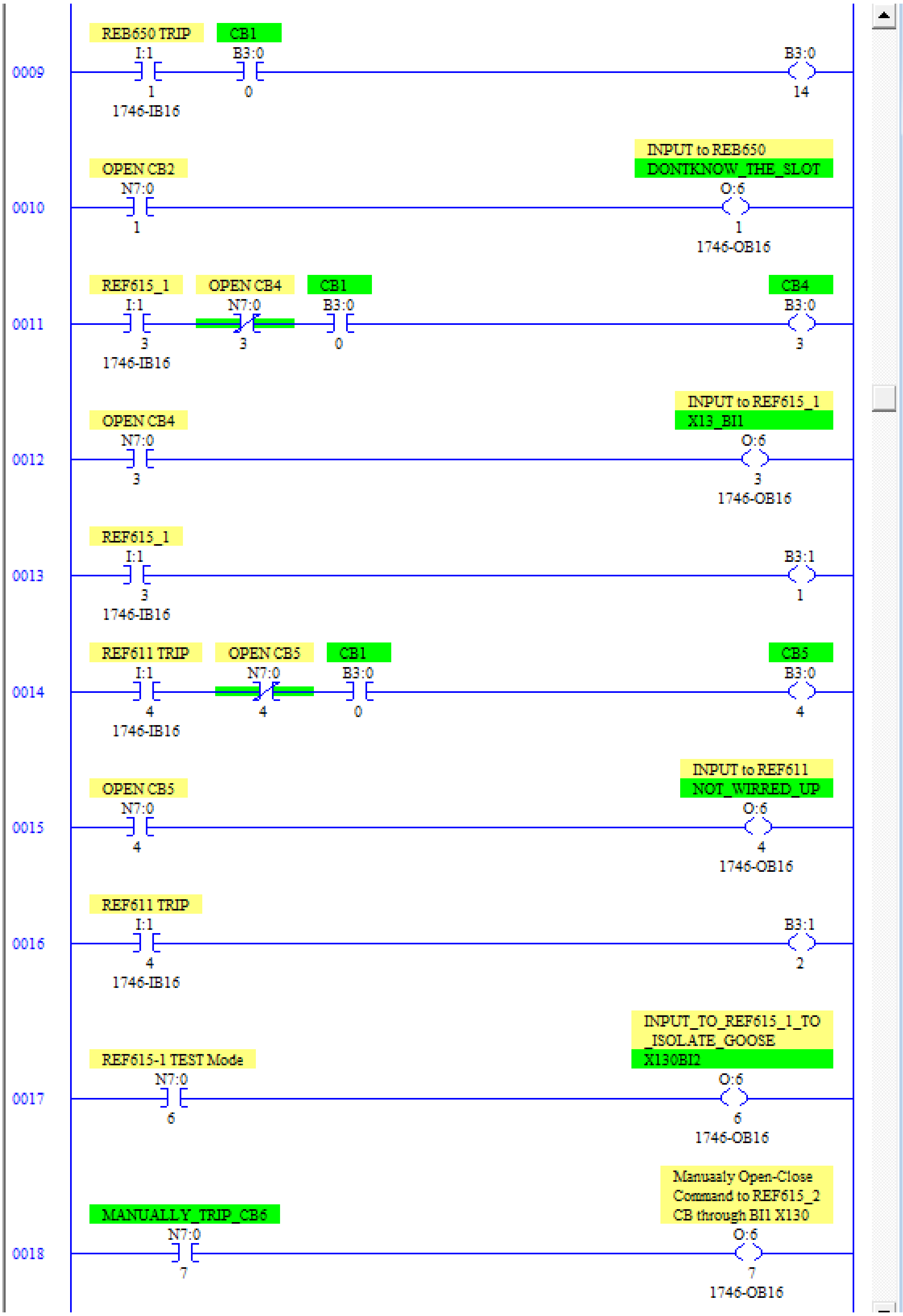


Fig B.7. b Ladder program written in PLC SLC500

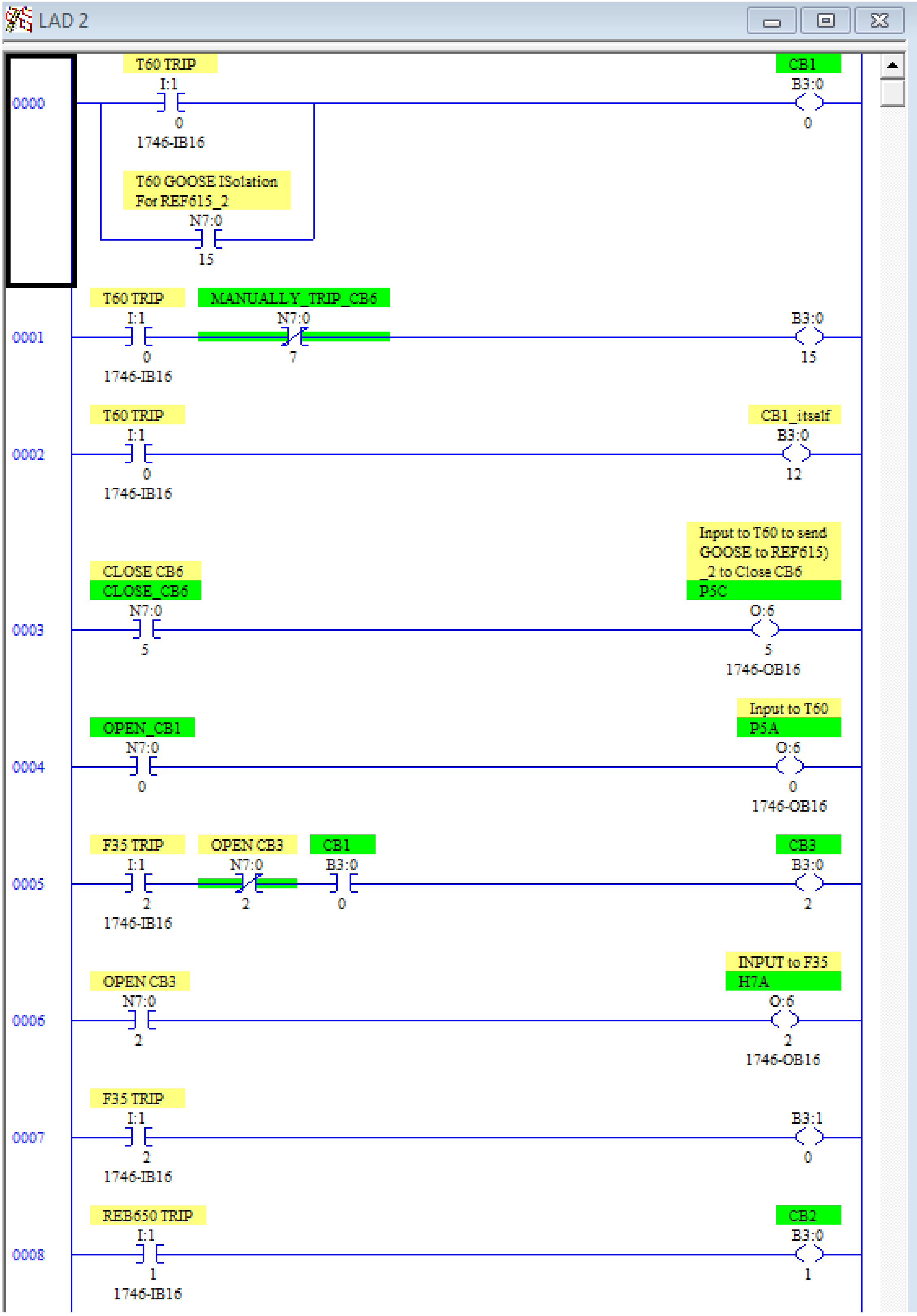


Fig B.7. c Ladder program written in PLC SLC500

Table B.3.a Protection and control functions according to three common industry standards

Function	IEC 61850	IEC 60617	IEC-ANSI
	NSPTOC2	I_2> (2)	46 (2)
Phase discontinuity protection	PDNSPTOC1	I_2/I_1>	46PD
Residual overvoltage protection	ROVPTOV1	U_0> (1)	59G (1)
	ROVPTOV2	U_0> (2)	59G (2)
	ROVPTOV3	U_0> (3)	59G (3)
Three-phase undervoltage protection	PHPTUV1	3U< (1)	27 (1)
	PHPTUV2	3U< (2)	27 (2)
	PHPTUV3	3U< (3)	27 (3)
Three-phase overvoltage protection	PHPTOV1	3U> (1)	59 (1)
	PHPTOV2	3U> (2)	59 (2)
	PHPTOV3	3U> (3)	59 (3)
Positive-sequence undervoltage protection	PSPTUV1	U1<	47U+
Negative-sequence overvoltage protection	NSPTOV1	U2>	47O-
Three-phase thermal protection for feeders, cables and distribution transformers	T1PTTR1	3Ith>F	49F
Three-phase thermal overload protection for power transformers, two time constants	T2PTTR1	3Ith>T	49T
Negative-sequence overcurrent protection for motors	MNSPTOC1	I2>M (1)	46M (1)
	MNSPTOC2	I2>M (2)	46M (2)
Loss of load supervision	LOFLPTUC1	3I<	37
Motor load jam protection	JAMPTOC1	Ist>	51LR
Motor start-up supervision	STTPMSU1	Is2t n<	49,66,48,51LR
Phase reversal protection	PREVPTOC	I_2>>	46R
Thermal overload protection for motors	MPTTR1	3Ith>M	49M
Binary signal transfer	BSTGGIO1	BST	BST
Stabilized and instantaneous differential protection for 2W-transformers	TR2PTDF1	3dI>T	87T
Line differential protection and related measurements, stabilized and instantaneous stages	LNPLDF1	3dI>L	87L
Numerical stabilized low impedance restricted earth-fault protection	LREFPNDF1	dI0Lo>	87NL
High impedance based restricted earth-fault protection	HREFPDIF1	dI_0Hi>	87NH
Circuit breaker failure protection	CCBRBRF1	3I>/I_0>BF	51BF/51NBF
Three-phase inrush detector	INRPHAR1	3I2f>	68
Master trip	TRPPTRC1	Master Trip (1)	94/86 (1)
	TRPPTRC2	Master Trip (2)	94/86 (2)
Arc protection	ARCSARC1	ARC (1)	50L/50NL (1)
	ARCSARC2	ARC (2)	50L/50NL (2)
	ARCSARC3	ARC (3)	50L/50NL (3)

Table continues on next page

Table B.3.b Protection and control functions according to three common industry standards

Function	IEC 61850	IEC 60617	IEC-ANSI
Protection			
Three-phase non-directional overcurrent protection, low stage	PHLPTOC1	3I> (1)	51P-1 (1)
	PHLPTOC2	3I> (2)	51P-1 (2)
Three-phase non-directional overcurrent protection, high stage	PHHPTOC1	3I>> (1)	51P-2 (1)
	PHHPTOC2	3I>> (2)	51P-2 (2)
Three-phase non-directional overcurrent protection, instantaneous stage	PHIPTOC1	3I>>> (1)	50P/51P (1)
	PHIPTOC2	3I>>> (2)	50P/51P (2)
Three-phase directional overcurrent protection, low stage	DPHLPDOC1	3I> → (1)	67-1 (1)
	DPHLPDOC2	3I> → (2)	67-1 (2)
Three-phase directional overcurrent protection, high stage	DPHHPDOC1	3I>> →	67-2
Non-directional earth-fault protection, low stage	EFLPTOC1	I_0> (1)	51N-1 (1)
	EFLPTOC2	I_0> (2)	51N-1 (2)
Non-directional earth-fault protection, high stage	EFHPTOC1	I_0>> (1)	51N-2 (1)
	EFHPTOC2	I_0>> (2)	51N-2 (2)
Non-directional earth-fault protection, instantaneous stage	EFIPTOC1	I_0>>>	50N/51N
Directional earth-fault protection, low stage	DEFLPDEF1	I_0> → (1)	67N-1 (1)
	DEFLPDEF2	I_0> → (2)	67N-1 (2)
Directional earth-fault protection, high stage	DEFHPDEF1	I_0>> →	67N-2
Transient / intermittent earth-fault protection	INTRPTEF1	I_0> → IEF	67NIEF
Non-directional (cross-country) earth fault protection, using calculated I_0	EFHPTOC1	I_0>>	51N-2
Negative-sequence overcurrent protection	NSPTOC1	I_2> (1)	46 (1)

Table continues on next page

Table B.3.c Protection and control functions according to three common industry standards

Function	IEC 61850	IEC 60617	IEC-ANSI
Control			
Circuit-breaker control	CBXCBR1	I ↔ O CB	I ↔ O CB
Disconnector position indication	DCSXSWI1	I ↔ O DC (1)	I ↔ O DC (1)
	DCSXSWI2	I ↔ O DC (2)	I ↔ O DC (2)
	DCSXSWI3	I ↔ O DC (3)	I ↔ O DC (3)
Earthing switch indication	ESSXSWI1	I ↔ O ES	I ↔ O ES
Emergergency startup	ESMGAPC1	ESTART	ESTART
Auto-reclosing	DARREC1	O → I	79
Tap changer position indication	TPOSSLTC1	TPOSM	84M
Condition monitoring			
Circuit-breaker condition monitoring	SSCBR1	CBCM	CBCM
Trip circuit supervision	TCSSCBR1	TCS (1)	TCM (1)
	TCSSCBR2	TCS (2)	TCM (2)
Current circuit supervision	CCRDIF1	MCS 3I	MCS 3I
Fuse failure supervision	SEQRFUF1	FUSEF	60
Protection communication supervision	PCSRTPC1	PCS	PCS
Motor runtime counter	MDSOPT1	OPTS	OPTM
Measurement			
Disturbance recorder	RDRE1	-	-
Three-phase current measurement	CMMXU1	3I	3I
	CMMXU2	3I(B)	3I(B)
Sequence current measurement	CSMSQI1	I_1, I_2, I_0	I_1, I_2, I_0
Residual current measurement	RESCMMXU1	I_0	I_n
	RESCMMXU2	I_0(B)	I_n(B)
Three-phase voltage measurement	VMMXU1	3U	3U
Residual voltage measurement	RESVMMXU1	U_0	V_n
Sequence voltage measurement	VSMSQI1	U_1, U_2, U_0	U_1, U_2, U_0
Three-phase power and energy measurement	PEMMXU1	P, E	P, E

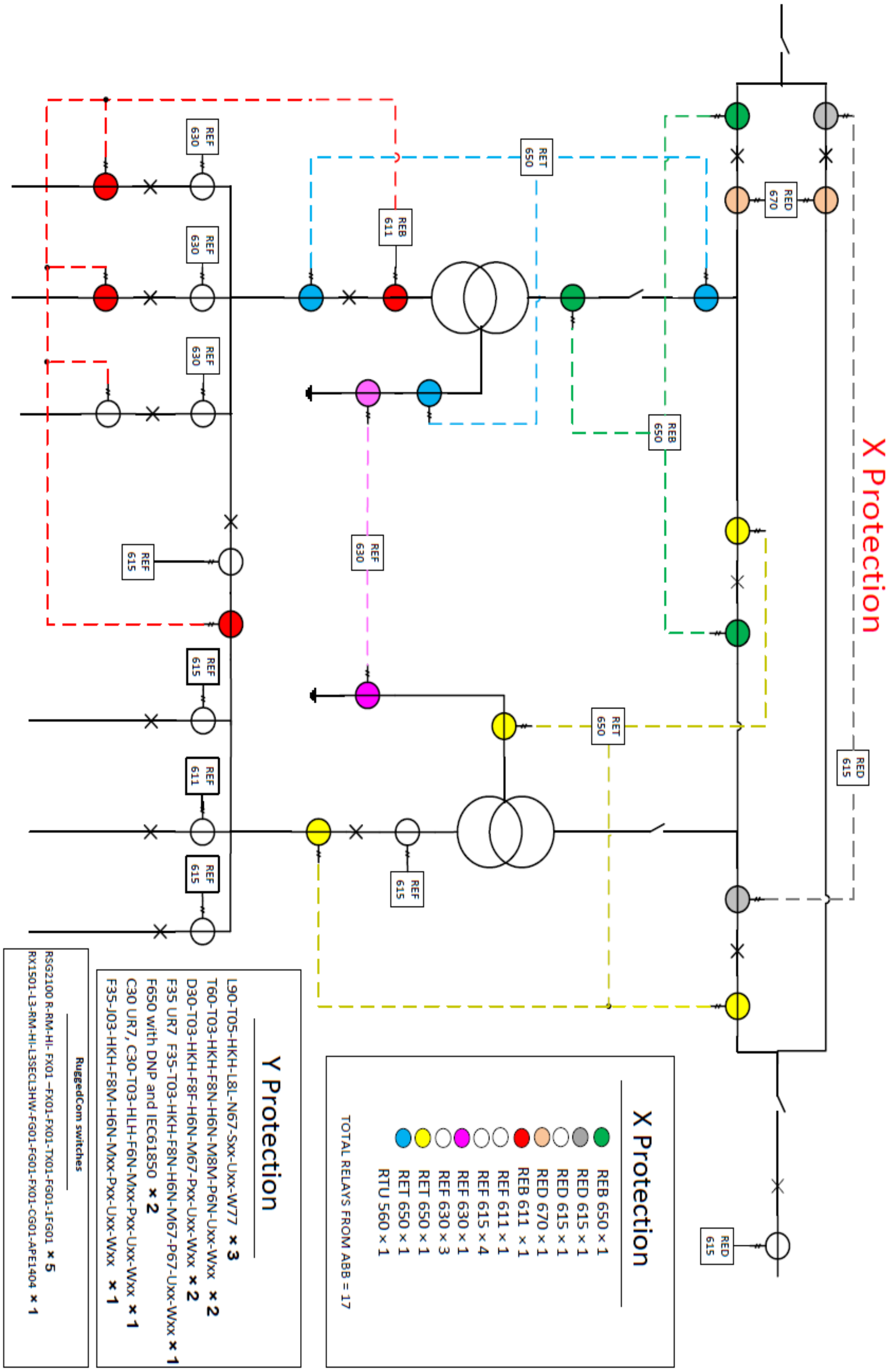


Fig. B. 8 Preliminary design of the X- Protection of Substation Simulator

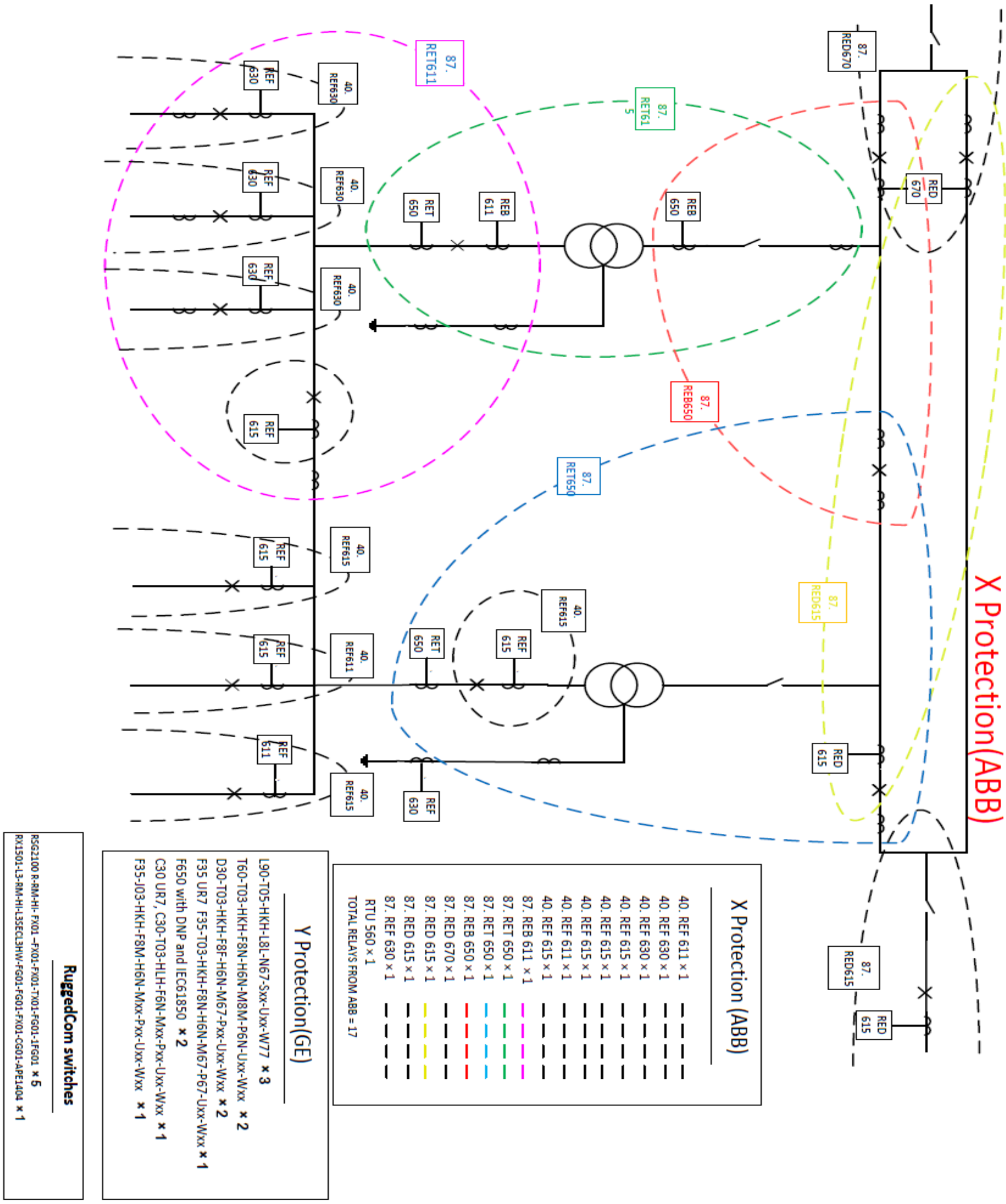


Fig.B.9 Preliminary design of the X- Protection of Substation Simulator