

Development of a Laboratory Facility and Experiments
to Support Learning IEC 61850 Based Substation Automation

by

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Abstract

IEC 61850 is rapidly becoming the internationally recognized standard for substation automation systems making it an indispensable element in power system protection and automation education. In order to facilitate teaching this very practical subject, a laboratory setup was developed to demonstrate IEC 61850 station bus inter Intelligent Electronic Device (IED) communication. In this setup, an electrical substation was implemented in a real time digital simulator (RTDS) and protection schemes were implemented in IEC 61850 station bus compliant IEDs from different vendors. Trip signals and breaker statuses were exchanged between RTDS and IEDs using GOOSE (Generic Object Oriented Substation Event) messages. Several protection applications including a novel backup bus protection scheme were developed based on the setup to demonstrate the use of GOOSE messages in time critical applications. The developed test setup along with the designed laboratory exercises will undoubtedly enhance teaching, training and research in this important field.

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Finally I would like to offer my sincere thanks to my parents and my wife for supporting and encouraging me to reach my target successfully.

Boosabaduge Achintha Hiruwan Wickremasuriya

Dedication

Affectionately dedicated to my dear wife and my loving parents.

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List of Abbreviations

CID	Configured IED Description
CT	Current Transformer
DA	Data Attribute
DO	Data Object
FC	Functional Constraint
FCDA	Functionally Constrained Data Attribute
GoCB	GOOSE Control Block
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
GTAO	Giga Transceiver Analog Output
GTDI	Giga Transceiver Digital Input
GTNET	Giga Transceiver Network Interface Card
GTSYNC	Giga Transceiver Synchronization Card

HMI	Human Machine Interface
ICD	IED Capability Description
ID	Identifier
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IID	Instantiated IED Description
IOU	Input Output Unit
IP	Internet Protocol
IPGL	Intelligent Power Grid Laboratory
LAN	Local Area Network
LD	Logical Device
LN	Logical Node
MAC	Media Access Control
MMS	Manufacturing Messaging Specification
OSI	Open System Interconnection
PD	Physical Device
RTDS	Real Time Digital Simulator

RTU	Remote Terminal Unit
SA	Substation Automation
SAS	Substation Automation System
SCD	Substation Configuration Description
SCL	System Configuration description Language
SED	System Exchange Description
SEL	Schweitzer Engineering Laboratories
SSD	System Specification Description
SMV	Sample Measured Values
SV	Sampled Values
UCA	Utility Communication Architecture
UTC	Universal Time Coordinated
VID	VLAN Identifier
VLAN	Virtual LAN
VT	Voltage Transformer
XML	Extensible Markup Language

Chapter 1

Introduction

1.1 Background

Electrical Substation Automation (or power system automation) refers to the automatic real time operation and control of the power system using its instrumentation and control devices. The main objective of the substation automation (SA) is to minimize the required resources for power system operation and maintenance while maintaining a highly reliable electricity supply. Some of the key tasks involved in substation automation are data acquisition, central control, and inter Intelligent Electronic Device (IED) communication required for power system monitoring and control [1].

The early substation automation systems (SAS) had master-slave architecture with vendor specific communication protocols. Single point of failure, no slave to slave communication, and master creating a bottleneck are some of the disadvantages of the early substation architecture. In addition to above mentioned disadvantages, these early SA systems lacked interoperability due to use of vendor specific communication protocols. Therefore, the user had no choice but to use

all devices in the SA system from one vendor, or use protocol converters which were very expensive. The main function of these first SA solutions was obtaining operational data such as voltage, current and the status of switching devices to a control center. However, they did not provide the complete and precise overview of the whole system [2].

In the early substations, copper wires were used to transfer signals between mainly electromechanical protection and control devices, as shown in Figure 1-1 [3], [4] and [5]. Configurations of these substations were inflexible, expensive and time consuming. With the introduction of electronics and digital technology, users expected more flexible and reliable SA systems with reduced settings and configuration efforts, lower installation costs, and interoperability between devices from different vendors [2], [6]. The legacy SAS with serial communication using vendor specific communication protocols were able to achieve some of the expectations, but lack of interoperability was a major issue. From time to time, several standardized protocols such as Modbus and DNP3 [6] were introduced but many of them required vendor depended extensions and weren't able to provide complete interoperability in complex systems [6]. Due to these reasons, substation automation systems required a standardized and interoperable communication system.

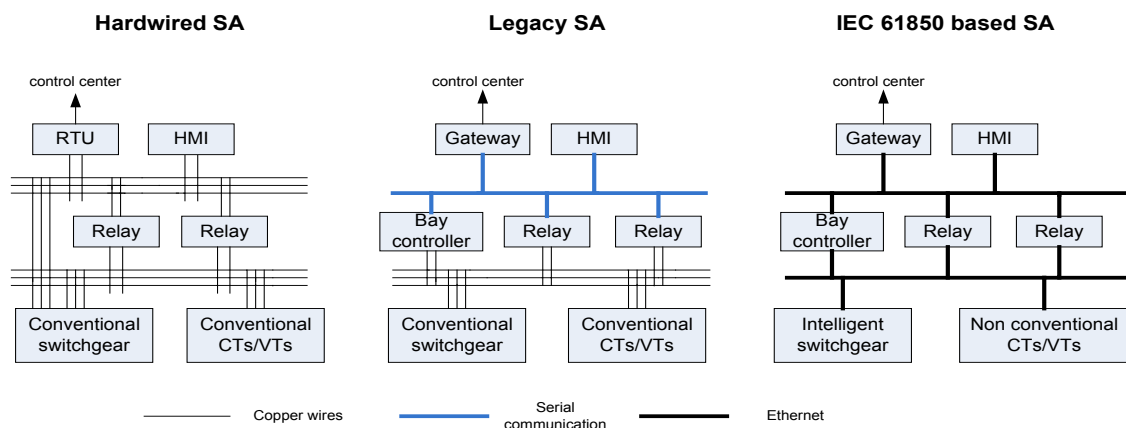


Figure 1-1: Substation Automation (SA) from early architecture to modern architecture (left to right) [3], [4], [5]

IEC (International Electrotechnical Commission) 61850 standard, first introduced in 2003 [7], not only be able to provide the required interoperability, but also provides reliability, flexibility, easy configuration and all the additional requirements important for a SAS. It standardizes the communication services between process level equipment (intelligent switchgears, sensors, etc.) and bay level protection and control devices (IEDs), an inter IED communication as well as the communication between bay level IEDs and the computers and computer equipment such as Human Machine Interface (HMI) at the station level [5]. The IEC 61850 standard has been designed to be future proof (i.e. the standard is capable of adapting to advancement in technology without changing its core modeling parts). Thus, this standard is expected to be used in almost all the SASs in the future for a long period of time.

1.2 Motivation

IEC 61850 standard is gradually becoming the leading international standard for substation automation systems. Hence it is crucial for today's engineers as well as engineering students aspiring to work in this technical area to be familiarized with this concept. In addition to including topics on modern substation automation in undergraduate and graduate power system engineering curricula, providing of appropriate practical skills to engineering students as well as to current engineers is important for successful implementation of this new concept. Importance of practical training in retaining theoretical knowledge and linking the knowledge with engineering practice is well recognized [8]. In this respect, there is an imperative need for an appropriate laboratory setup and associated experiments for providing essential hands on experience for students and practicing engineers to understand various practical aspects of this concept. Such a laboratory setup can also facilitate research into development of new power

system protection concepts utilizing the fast communication methods introduced in the standard.

1.3 Objectives

The main goal of the research is to demonstrate the IEC 61850 station bus concept for education, training and research purposes. Objectives that are essential to achieve this goal are:

1. Development of a laboratory setup using suitable hardware and software, including real-time simulation facilities. The laboratory development requires selection and implementation of a suitable power system model including switching, protection and control devices in a real-time simulator, calculation of protection settings and application of them to protection relays, configuration of communication between various intelligent electronics devices (IEDs) using IEC 61850 station bus, and documentation of all the details of the laboratory development process.
2. Implementation of low level interface between the real-time simulator and various protection and control devices for analog and digital signals. The conventional approach of connecting simulators to hardware through voltage and current amplifiers is costly and impractical when a large number of devices are involved. Design of this interface is an important requirement in the development of the test setup.
3. Performance evaluation of the laboratory setup by performing various communication and automation tasks with respect to requirements stated in the standard to verify the functionality. A methodology needs to be developed to compare the conventional hardwired signal communication and IEC 61850 based fast communication.

4. Implementation of test cases and applications to illustrate interoperability between IEDs of different suppliers and the effectiveness of new communication services proposed in the standard (such as Generic Object Oriented Substation Event – GOOSE – messages) in critical protection applications. These test cases need to be design in a way to illustrate features, advantages, and shortcoming (if any) in IEC 61850 station bus communication.
5. Development of laboratory exercises and instruction sheets based on the developed laboratory setup to provide hands on training for senior undergraduate and graduate students specializing in power systems area.

1.4 Scope

The experimental setup will be developed in the Intelligent Power Grid Laboratory (IPGL) of the University of Manitoba, Canada. The research will utilize the available real-time simulation facilities, software, and protection relays available in the laboratory whenever possible. The laboratory currently possesses five protection relays from two vendors: a line protection relay (LPRO 4000), a transformer protection relay (TPRO 4000) and a bus protection relay (BPRO 4000) from ERL Phase Power Technologies, and a line protection relay (SEL 421) and a transformer protection relay (SEL 487E) from Schweitzer Engineering Laboratories (SEL). Therefore, the power network model will be developed in such a way that available equipment and simulation capabilities can be utilized to the fullest extent. Furthermore, the test setup will be developed in an easily expandable manner to add more relays and equipment in the future.

1.5 Organization of the Thesis

Chapter 1 presents the introduction by explaining the background, motivation and objectives of the research. Main features of the IEC 61850 standard, its architecture, System Configuration description Language (SCL), the message format used for station bus communication and currently available IEC 61850 training programs and laboratory facilities are discussed under literature review in Chapter 2. Chapter 3 presents the development of the laboratory setup with the information of relay setting and GOOSE configuration. It also explains the tests conducted to verify the configuration and relevant test results. Chapter 4 discusses three applications which demonstrate the features and use of GOOSE messages. In Chapter 5, three laboratory exercises developed to familiarize students with the IEC 61850 station bus functionalities are presented. Finally, the conclusion and future research are presented in Chapter 6.

Chapter 2

Literature Review

2.1 Introduction

In this chapter, introduction to IEC 61850 standard is presented and its key features are explained. Also, substation architecture envisaged in IEC 61850 standard, System Configuration description Language (SCL) used in the standard and different SCL file types used in the engineering process are described. Moreover, introduction of GOOSE messages, its benefits and GOOSE publication and subscription process are discussed. The chapter is concluded with a summary of currently available IEC 61850 training programs and laboratory facilities.

2.2 Introduction of IEC 61850 Standard

Communication can be considered as a key component in real time operation of the power system. For substation automation applications, high speed IED to IED communication, high availability, guaranteed delivery times, standards based, multi-vendor interoperability and support for file transfer [9] arise as some of the key requirements for a communication system.

The Utility Communication Architecture (UCA) started to develop communication architecture to fulfill these requirements. The IEC Technical Committee Number 57 (TC57) Working Group 10 (WG10) used the concepts and work of UCA as foundation and introduced the IEC 61850 International Standard – Communication Networks and Systems in Substations to standardize the substation automation practices [9].

2.2.1 Structure of the IEC 61850 Standard

The IEC 61850 standard consists of 10 parts and the part numbers and the topics are listed in Table 2-1. The first five parts of the standard explain the general communication requirements in a substation. An XML (Extensible Markup Language) based System Configuration description Language (SCL) is described in part 6 for the configuration of electrical substation IEDs. Following the specifications and definitions of this part provide multi-vendor interoperability by allowing IEDs of any vendor to exchange information with IEDs of different manufacturers [10]. The part 7 explains the core communication structure for substation by providing the definition of objects such as data objects, datasets, report control and log control. It also explains the services provided by those objects such as getting object, creating object and reporting object [7]. Part 8 and 9 describe mapping of the data object and services into protocols. Part 8 – 1 explains mapping into Manufacturing Messaging Specification (MMS) and GOOSE whereas part 9 – 1 and 9 – 2 define mapping into SMV (Sample Measured Value) protocols. The final part of the standard (part 10) describes the testing methods [9].

Table 2-1: Structure of the IEC 61850 Standard [7], [9]

Part Number	Topic
IEC 61850 – 1	Introduction and Overview
IEC 61850 – 2	Glossary of terms
IEC 61850 – 3	General Requirement
IEC 61850 – 4	System and Project Management
IEC 61850 – 5	Communication Requirements for Functions and Device Models
IEC 61850 – 6	Configuration Description Language for Communication in Electrical Substations Related to IEDs
IEC 61850 – 7	Basic Communication Structure for Substation and Feeder Equipment
IEC 61850 – 7 – 1	Principles and Models
IEC 61850 – 7 – 2	Abstract Communication Service Interface (ACSI)
IEC 61850 – 7 – 3	Common Data Classes (CDC)
IEC 61850 – 7 – 4	Compatible logical node classes and data classes
IEC 61850 – 8	Specific Communication Service Mapping (SCSM)
IEC 61850 – 8 – 1	Mappings to MMS (ISO/IEC 9506 – Part 1 and Part 2) and to ISO/IEC 8802-3
IEC 61850 – 9	Specific Communication Service Mapping (SCSM)
IEC 61850 – 9 – 1	Sampled Values over Serial Unidirectional Multidrop Point-to-Point Link
IEC 61850 – 9 – 2	Sampled Values over ISO/IEC 8802-3
IEC 61850 – 10	Conformance Testing

2.2.2 Key Features of IEC 61850

IEC 61850 standard offers some significant advantages compared to the earlier substation automation systems.

Enhanced Interoperability

According to the IEC 61850-5, interoperability is defined as the capability of two or more IEDs of same or different manufacturers to exchange information among each other and to apply that information to acquire the desired coordination [7]. One of the key features of the IEC 61850 standard is the interoperability between the IEDs of the different manufacturers. Before the introduction of the IEC 61850 standard, one of the biggest challenges was the interoperability mainly due to the use of proprietary protocols. Therefore, the user was limited to one vendor or had to find ways to convert protocols. But with the introduction of the IEC 61850 standard and its standardized protocols (MMS, GOOSE, and SMV), the limitation of bounding to one vendor was removed. This allows a greater flexibility for users to choose their equipment based on merit rather than the compatibility.

Simplification of the hardware implementations

In the early substation automation architecture, the copper wires were used to connect switchgears to IEDs and IEDs to control boards. But with the development of serial communication, serial communication replaced copper wires used for communication between IEDs and between IEDs and Human Machine Interface (HMI). But still the switchgear and instrument transformers were connected with IEDs using copper wires. With IEC 61850, all the copper wire connections between intelligent switchgears to IEDs, IEDs to IEDs and IEDs to HMI were replaced by Ethernet network connection [4]. Also, due to the fact the IEC 61850 replaced the proprietary protocols with standardized protocols; the users were relieved from having to buy all SA equipment from one vendor. Not only these changes simplify the hardware implementation, but also reduce the installation and maintenance costs.

Object Oriented Data Representation

Object oriented data representation is another key feature of the IEC 61850 standard. The entire IEC 61850 data elements have descriptive data names which are standardized and defined in a power system context [9]. For an example, if the user requires to get the differential protection trip signal from a relay, the user has to go to Protection Device (Physical Device) → Relay1 (Logical Device) → PDIF (differential protection Logical Node) → Op (Data for operation) → general (Data Attribute represents any phase element). This makes the identification, configuration and mapping much easier compared to legacy protocols which use index numbers or register numbers to describe its data [9].

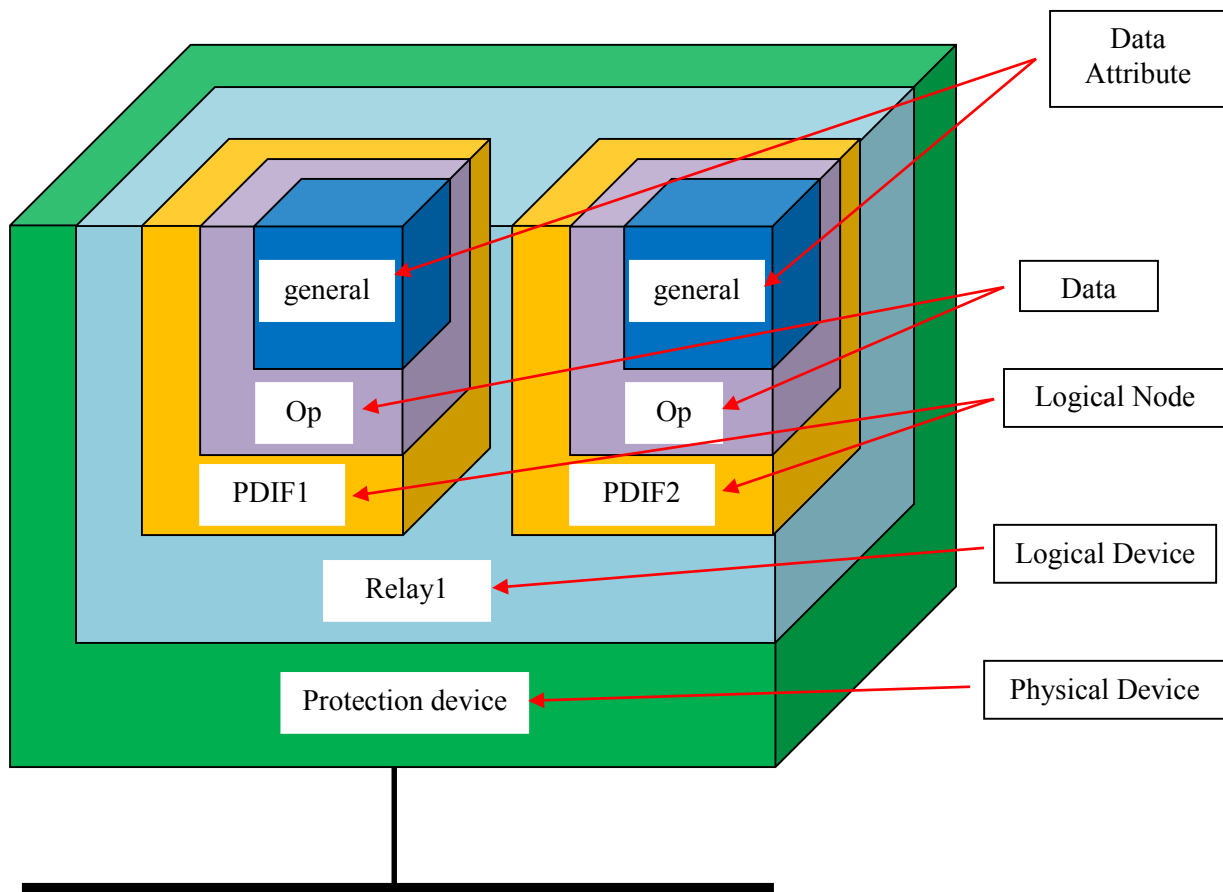


Figure 2-1: Object oriented data representation of IEC 61850 [11]

Long term stability

All the parts in the IEC 61850 standard are created in such a way that a change to one part does not require complete recreation of rest of the parts. Parts 1 to 4 of the standard describe the general parts of the standard whereas part – 5 describes the communication requirement specification and part – 7 – x explains modeling requirements. These parts are not going to change due to the changes in implementation parts. IEC 61850 – 8 – x and IEC 61850 – 9 – x describes specific communication service mapping based on the current technology and with the development of the communication technology; these sections might get modified in the future (these sections of the standard are designed to be modified with the future developments). But these modifications will not make significant changes to requirement specification and modeling parts (part 5 and existing part 7 subsections) which allow the IEC 61850 standard to be stabilized in the long run [7].

2.3 Substation Architecture

Figure 2-2 shows a typical IEC 61850 substation architecture which is mainly divided in to three logical levels. The top most level is the station level follows by the bay or unit level. The bottom most level is the process level. The Ethernet network switch that connects the station level and bay level is called as the station bus whereas the Ethernet network switch that connects the bay level and process level is called the process bus [12].

The process level includes devices such as merging units (MUs), Input Output units (IOUs), sensors and actuators. The merging unit takes voltage and current signals from instrument transformers, convert the analog signals into digitized samples and transmit to IEDs through the

process bus using SMV. The IO units process status inputs, generate status data and multicast it through process bus [13].

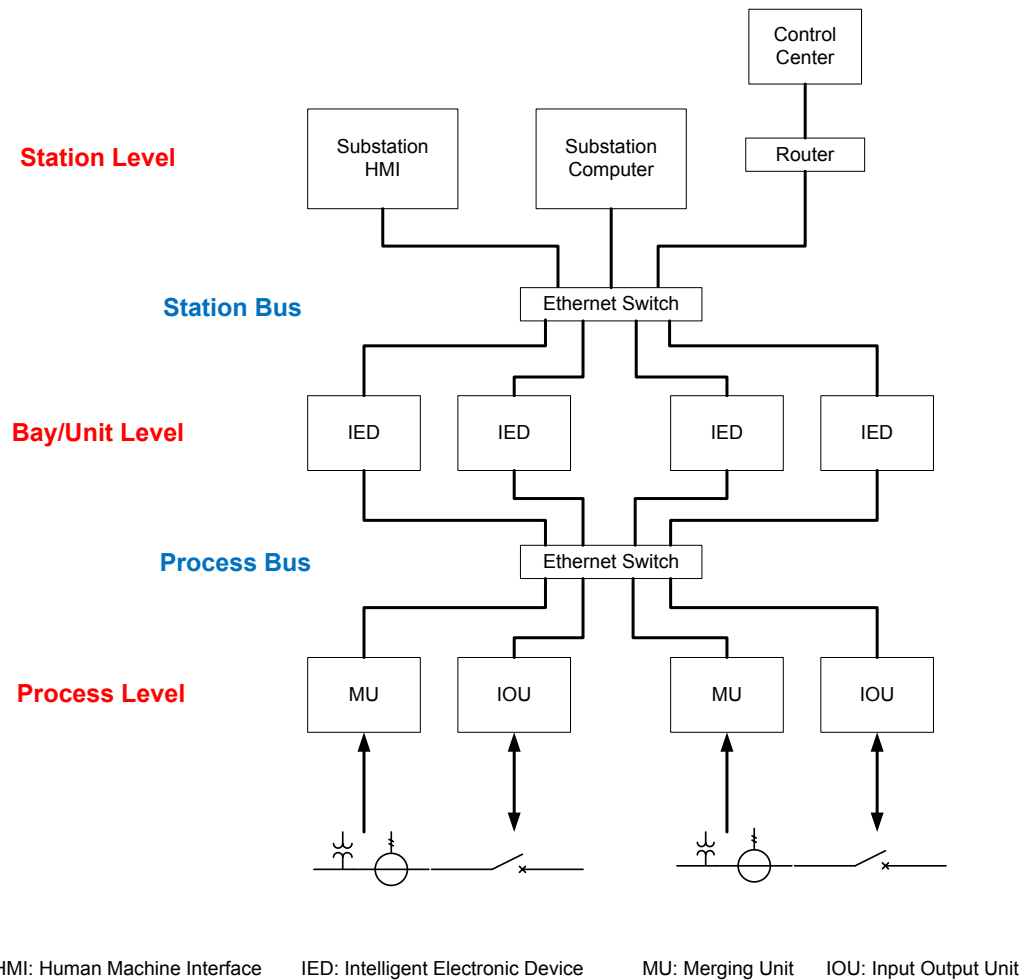


Figure 2-2: IEC 61850 Substation Architecture [4], [11]

The bay or unit level mainly consists of IEDs which are capable of operating multi functions such as protection, control, measurement and recordings. All the IEDs in the system receive the SMV messages and binary status messages sending from MUs and IOUs respectively through process bus. But each IED will only acquire the subscribed messages. The IEDs process the data of subscribed messages and take decisions based on the data. If an IED detects a fault, it will send a GOOSE message to the IO unit to trip the breaker [13]. So the process bus can be used not only to send SMV messages but also to send GOOSE messages.

The station level usually consists of a substation HMI, a substation computer and remote communication interfaces. As mentioned before, the station bus facilitates communication between bay level and station level. According to IEC 61850 – 5, it is called interface related station level function [7]. In addition to communication between station level and bay level, the station bus also facilitates the inter IED communication which is mentioned as process related station level function in IEC 61850 – 5 [7]. The main protocol used for inter IED communication is GOOSE messages which will be described later in this chapter.

2.4 System Configuration description Language (SCL)

System Configuration description Language (SCL) (a.k.a. Substation Configuration Language) is a description language for IED configurations and communication systems of electrical substation. It is based on the Extensible Markup Language (XML). The main purpose of the SCL is to have complete interoperability by exchanging system configuration data between IED configuration tools and system configuration tools of different vendors [10].

IED Configuration Tool

The IED configuration tool (a.k.a. IED configurator) is a tool capable of transferring IED configuration into IEDs, providing IED specific settings and generating IED specific configuration files. Each vendor has its own IED configuration tool for its IEDs. In addition to above mentioned capabilities, IED configuration tool can be used for following tasks [10],

- Import/export SCL files.

- Create CID (Configured IED Description) files.
- Create, edit and delete datasets, report control blocks, SMV and GOOSE control blocks.
- Subscription mapping with other IEDs of same or different vendors.
- Responsible for data model and all its configuration values [10].

In this research, IED configuration tools of three vendors are used to configure GOOSE subscription process of its own IEDs based on the SCD (System Configuration Description) file imported from the system configuration tool. In the later applications, IED configuration tools of three vendors are also used to configure GOOSE publication process of its own IEDs using their ICD (IED Capability Description) files.

System Configuration Tool

The system configuration tool (a.k.a. system configurator) is an IED independent system level tool which is capable of importing configuration files from several IEDs and adds system information shared by different IEDs. Based on the information, it generates a substation related configuration file and sends it to IED configuration tools for system related IED configuration. In addition to above mentioned capabilities, system configuration tool can be used for following tasks [10],

- Import/export SCL files.
- Create SCD (System Configuration Description) files.
- Responsible for communication addressing and the data flow between the IEDs [10].

In this research, a system configuration tool is used to configure GOOSE publication process of all the IEDs in laboratory setup using ICD files imported from the relevant IED configuration tools.

2.4.1 SCL description File Types

As shown in Figure 2-3, there are six types of SCL description files that are used to exchange configuration data between configuration tools of the same or different vendors. Even though each of the six files is used for different type of data exchanges, all of them follow the SCL rules. There are version and revision number for each file, which will be updated each time a modification occurs. Therefore, configuration tools are required to maintain the version and revision number information of imported and exported files to distinguish the new files from the old ones [10].

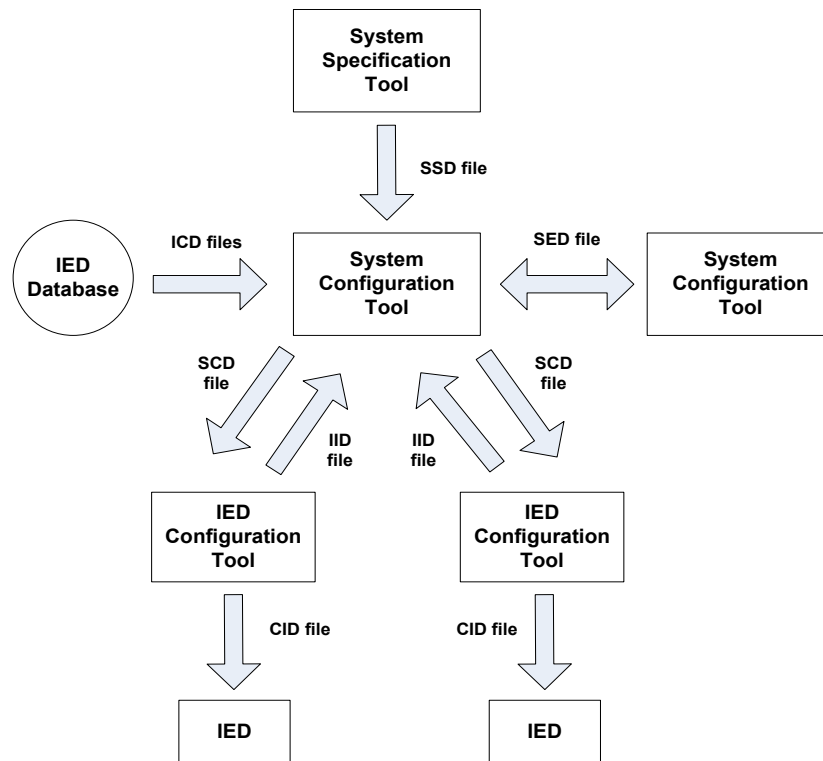


Figure 2-3: Information flow in the configuration process [10]

ICD (IED Capability Description) file

The IED capability description file describes the functional and engineering capabilities of an IED. It includes logical devices (LD), logical nodes (LN), data objects (DO) and data attribute (DA) information. In addition, it may contain preconfigured data model of the IED such as predefined datasets, GOOSE or SMV control blocks, etc. as well as communication section defining default address of the IED. It is usually provided by the manufacturer of the respective IED. ICD files can be found from the IED database or in the respective vendor's IED configuration tool. The file extension of this file is .icd for IED Capability Description [10], [14].

IID (Instantiated IED Description) file

The instantiated IED description (IID) file is used to exchange data of a project specific preconfigured IED (e.g. to include a preconfigured instance file, IED instance value changes, data model modifications) from the IED configuration tool to the system configuration tool. The IID file may contain project specific name, addresses, data models and preconfigured datasets and control blocks of the project. Also, it might contain binding IED logical nodes to a project specific single line diagram. IED configuration tool can modify the IID file based on the SCD file exported from the system configuration tool. The file extension of this file is .iid for Instantiated IED Description [10].

SSD (System Specification Description) file

The system specification description (SSD) file is used to exchange data from the system specification tool to the system configuration tool. It contains information about the single line diagram and the substation functionality using the required logical nodes. It may contain

explanation about the substation, data type templates and logical node type definitions. The file extension of this file is .ssd for System Specification Description [10], [14].

SCD (System Configuration Description) file

The system configuration description (SCD) file is used to exchange data from the system configuration tool to the IED configuration tool. It contains complete substation configuration including single line diagram, all the IEDs and their configurations, communication configuration and the substation description. The file extension of this file is .scd for System Configuration Description [10], [14].

CID (Configured IED Description) file

The configured IED description (CID) file is used to transfer data from the IED configuration tool to the IED. It contains device specific configuration data and communication information (such as address of the IED) of an instantiated IED within a project. IED configuration tool creates the CID file using the SCD file. The file extension of this file is .cid for Configured IED Description [10], [14].

SED (System Exchange Description) file

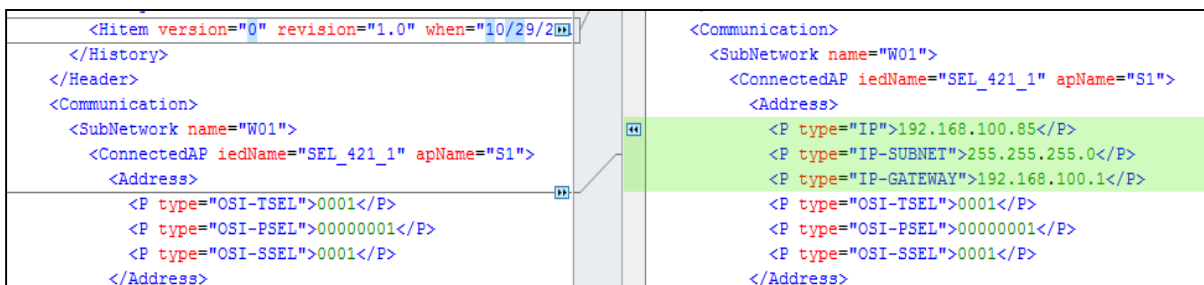
The system exchange description (SED) file is used exchange data from the system configuration tool of one project to the system configuration tools of other projects. It contains information about how to use one project in other projects and vice versa. The SED file is a subset of a SCD file and includes the already defined connections of the IEDs so that the importing project understands what it can change and what it cannot. The file extension of this file is .sed for System Exchange Description [10].

2.4.2 Difference between an ICD file and an CID file

ICD and CID files are the two main SCL files types used in this thesis. IED configuration tool of each vendor is used to create CID files from the ICD files located in their IED database (or from the SCD file imported from the system configuration tool). This section explains the additional XML codes that are added into an ICD file when it changes into a CID file.

Communication section

The first change is in the communication section of the code. When an IED included into a project, the IED configuration tool requests user to complete the properties of the IED which includes IP address, subnet mask and gateway. This information is required to transfer the CID file to the physical IED.



```
<Hitem version="0" revision="1.0" when="10/29/2011" />
</History>
</Header>
<Communication>
  <SubNetwork name="W01">
    <ConnectedAP iedName="SEL_421_1" apName="S1">
      <Address>
        <P type="OSI-TSEL">0001</P>
        <P type="OSI-PSEL">00000001</P>
        <P type="OSI-SSEL">0001</P>
      </Address>
    </ConnectedAP>
  </SubNetwork>
</Communication>
```

```
<Communication>
  <SubNetwork name="W01">
    <ConnectedAP iedName="SEL_421_1" apName="S1">
      <Address>
        <P type="IP">192.168.100.85</P>
        <P type="IP-SUBNET">255.255.255.0</P>
        <P type="IP-GATEWAY">192.168.100.1</P>
        <P type="OSI-TSEL">0001</P>
        <P type="OSI-PSEL">00000001</P>
        <P type="OSI-SSEL">0001</P>
      </Address>
    </ConnectedAP>
  </SubNetwork>
</Communication>
```

Figure 2-4: IED properties in communication section of the ICD file (left) and the CID file (right)

Another change in the communication section occurs due to GOOSE publication. GOOSE publication requires creation of datasets and inclusion of those datasets in GOOSE control blocks. When defining GOOSE control blocks, user has to provide information such as GOOSE control block name, MAC address, APP ID, VLAN ID, VLAN priority, minimum time and maximum time which are required for communication purposes (more explanation about these terms will be discussed in the GOOSE Messages section). These information can be found in the communication section as well. These information may already be included in the ICD file if it

contains predefined GOOSE control blocks. But if the user creates new GOOSE control blocks, then those information will be added to communication section. The ICD file used in Figure 2-5 does not include any predefined GOOSE control blocks.

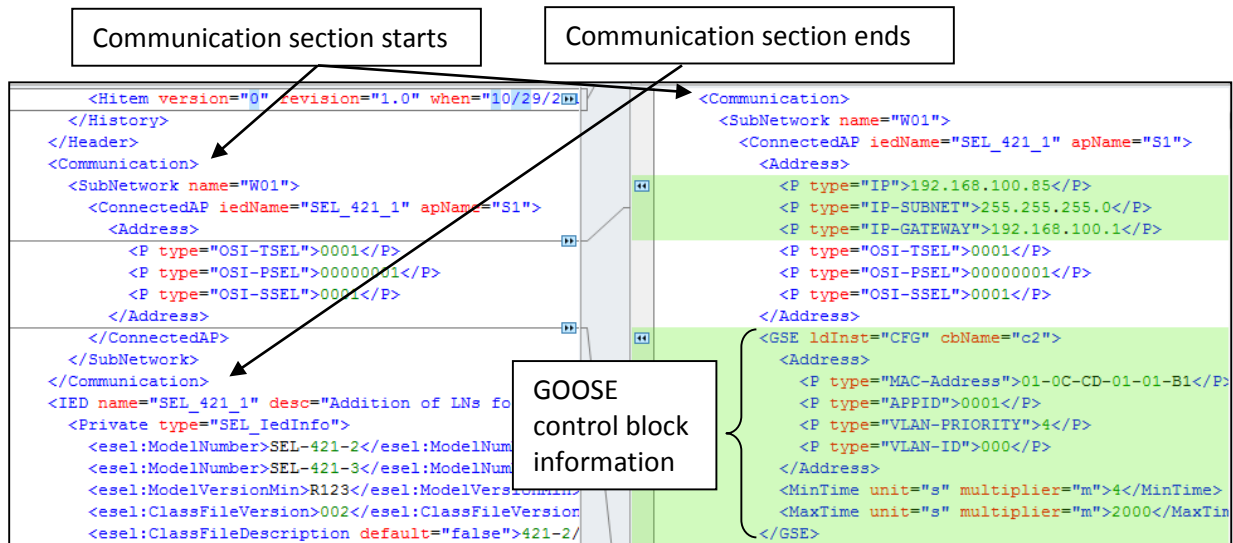


Figure 2-5: GOOSE control block information in communication section of the ICD file (left) and the CID file (right)

IED section

The IED section includes rest of the changes such as GOOSE subscription mapping, datasets, GOOSE control blocks and report control blocks information.

The GOOSE subscription mapping is a local issue. This means that each vendor has their own way of including it in the code. This vendor specific information can be included in the code by adding “Private” sections. Even though the subscription mapping of the code is different from vendor to vendor, the information in that section remains same.

```

<esel:Originator category="0" allowed="1"
<esel:Originator category="1" allowed="1"
<esel:Originator category="2" allowed="1"
<esel:Originator category="3" allowed="1"
<esel:Originator category="4" allowed="1"
<esel:Originator category="5" allowed="1"
<esel:Originator category="6" allowed="1"
<esel:Originator category="7" allowed="1"
<esel:Originator category="8" allowed="1"
</Private>
<Private type="SEL_GooseSubscription" />
<Services>
<DynAssociation />
<GetDirectory />
<GetDataObjectDefinition />
<DataObjectDirectory />
<GetDataSetValue />
<SetDataSetValue />
<DataSetDirectory />
<ConfDataSet max="21" maxAttributes="200"
<ReadWrite />
<ConfReportControl max="12" />
<GetCBValues />
<ReportSettings cbName="Conf" dataSet="Co
<GSESettings cbName="Conf" dataSet="Conf"
</Private>
</Private>
<Private type="SEL_GooseSubscription">
<esel:GooseSubscription iedName="SEL_487E_1" ldInst="CFG" cbName="c8" dataSet="d8" confRev="1" mAddr="01-0C-CD-01-01-B2" APPID="0002" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN009)Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="RTDS" ldInst="CTRL" cbName="Gcb01" dataSet="GOOSE_outputs_1" confRev="1" mAddr="01-0C-CD-01-01-B3" APPID="0001" VLAN-ID="000"
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="(CCIN001)Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="(CCIN004)Bool" />
<esel:GooseRxEntry tdlString="Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="LPRO_1" ldInst="Protection" cbName="cb" dataSet="bd" confRev="1" mAddr="01-0C-CD-01-01-B5" APPID="0007" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN005)Bool" />
<esel:GooseRxEntry tdlString="(CCIN006)Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="TPRO_1" ldInst="Protection" cbName="ct" dataSet="dt" confRev="1" mAddr="01-0C-CD-01-01-B4" APPID="0004" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN008)Bool" />
</esel:GooseSubscription>
</Private>

```

Figure 2-6: Subscription mapping information in IED section of the ICD file (left) and the CID file (right)

The complete information of the publisher such as IED name, GOOSE control block information (GOOSE control block name, MAC address, etc.) and dataset information (dataset name, logical device, logical node, data object, etc.) as well as subscriber information (GOOSE input, etc.) are included in the subscription mapping section. The Figure 2-7 and Figure 2-8 show the subscription mapping information extracted from the SEL 421 and LPRO 4000 CID files used in this research.

Different publishing IED information

```

</Private>
<Private type="SEL_GooseSubscription">
<esel:GooseSubscription iedName="SEL_487E_1" ldInst="CFG" cbName="c8" dataSet="d8" confRev="1" mAddr="01-0C-CD-01-01-B2" APPID="0002" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN009)Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="RTDS" ldInst="CTRL" cbName="Gcb01" dataSet="GOOSE_outputs_1" confRev="1" mAddr="01-0C-CD-01-01-B3" APPID="0001" VLAN-ID="000"
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="(CCIN001)Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="Bool" />
<esel:GooseRxEntry tdlString="(CCIN004)Bool" />
<esel:GooseRxEntry tdlString="Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="LPRO_1" ldInst="Protection" cbName="cb" dataSet="bd" confRev="1" mAddr="01-0C-CD-01-01-B5" APPID="0007" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN005)Bool" />
<esel:GooseRxEntry tdlString="(CCIN006)Bool" />
</esel:GooseSubscription>
<esel:GooseSubscription iedName="TPRO_1" ldInst="Protection" cbName="ct" dataSet="dt" confRev="1" mAddr="01-0C-CD-01-01-B4" APPID="0004" VLAN-ID="000"
<esel:GooseRxEntry tdlString="(CCIN008)Bool" />
</esel:GooseSubscription>
</Private>

```

4th variable is mapped to GOOSE input 1 (CCIN001)

All the variables in the specified GOOSE control block

Figure 2-7: Subscription mapping of SEL 421 CID file

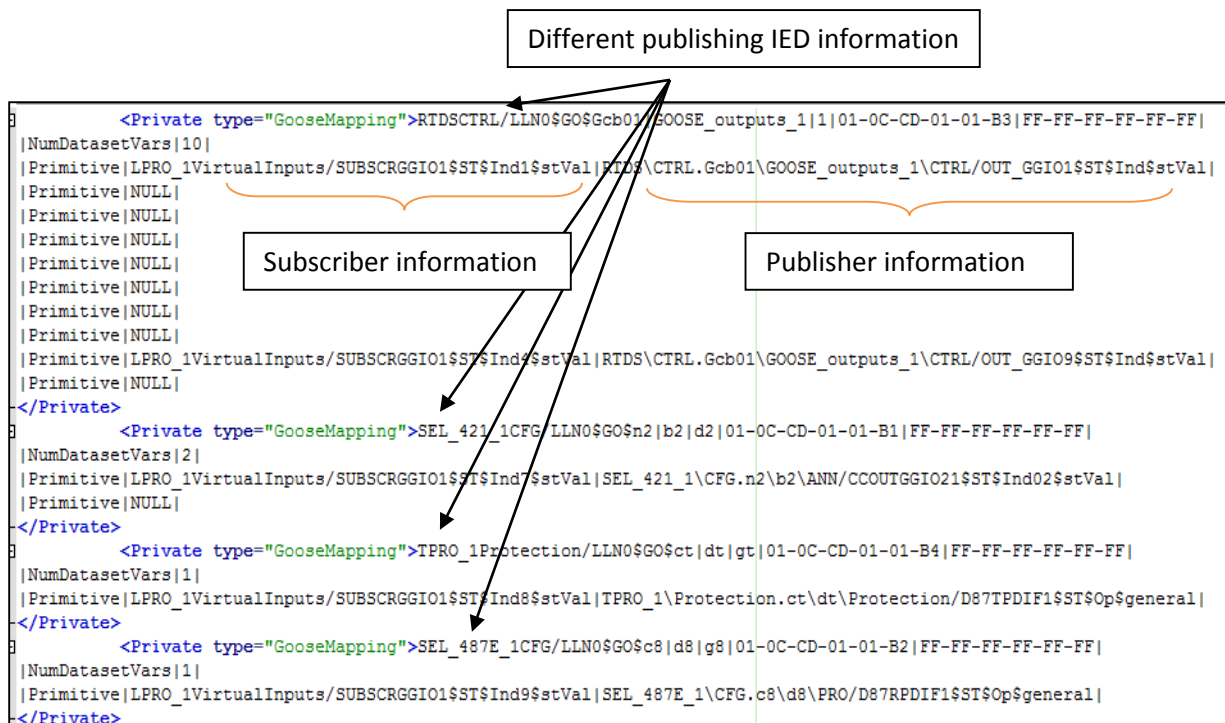


Figure 2-8: Subscription mapping of LPRO 4000 CID file

Dataset information is also included in the IED section and it is normally included after the subscription mapping. Even though inclusion of dataset name and functionally constrained data attributes (FCDA) (i.e. logical device, logical node, functional constraint, data object and data attribute) are standardized, the order they are presented can be changed from vendor to vendor. These can be included in the ICD file if they are predefined.

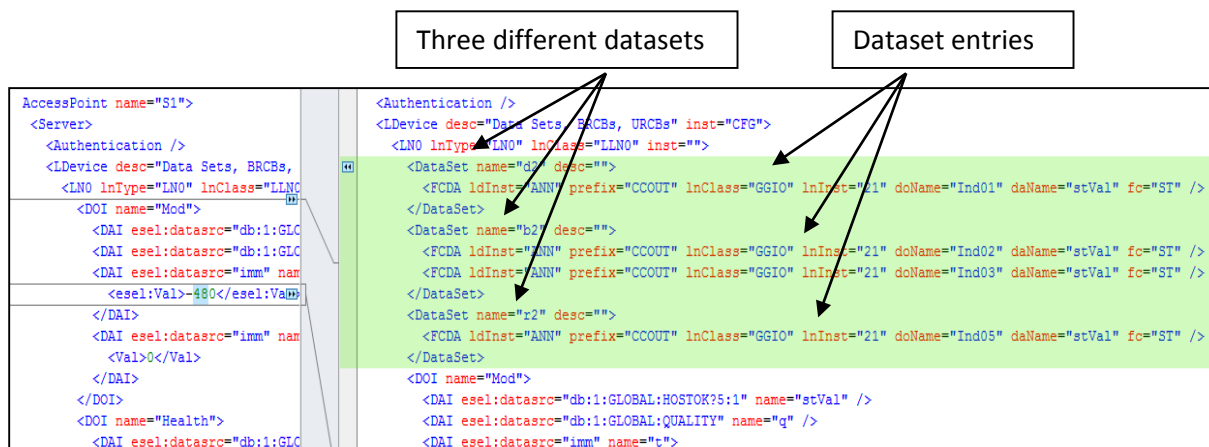


Figure 2-9: Dataset information in IED section of the ICD file (left) and the CID file (right)

Last part is the basic GOOSE and report control block information (i.e. control block name, configuration revision, application ID and description) which are normally included after the dataset information. Similar to the dataset information, the order of the information presentation can be different from manufacturer to manufacturer, but the content are the same. Some manufacturers tend to put rest of the control block information such as MAC address, VLAN ID, etc. (which are already provided under communication section) underneath the basic information by including a private section. Again, GOOSE and report control block information can be included in the ICD file if they are predefined.

Basic GOOSE control block information

<pre> <DOI name="NamPlt"> <DAI esel:datasrc="imm" name="vendor"> <Val>SEL</Val> </DAI> <DAI esel:datasrc="dbi:1:LOCAL:FID" name="swf"> <DAI esel:datasrc="imm" name="d"> <Val>Configuration</Val> </DAI> <DAI esel:datasrc="imm" name="configRev"> <Val>0</Val> </DAI> <DAI esel:datasrc="imm" name="ldNs"> <Val>IEC61850-7-4:2003</Val> </DAI> </DOI> </LNO> <LN lnType="LPHD1" lnClass="LPHD" inst="1" prefix="1"> <DOI name="PhyNam"> <DAI esel:datasrc="imm" name="vendor"> <Val>SEL</Val> </DAI> <DAI esel:datasrc="dbi:1:LOCAL:SER_NUM" name="serNum"> <DAI esel:datasrc="dbi:1:LOCAL:PART_NUM" name="partNum"> </DOI> <DOI name="PhyHealth"> <DAI esel:datasrc="db:1:GLOBAL:HOSTOK?3:1" name="hostOk"> <DAI esel:datasrc="db:1:GLOBAL:QUALITY" name="quality"> </DOI> <DOI name="Proxy"> <DAI esel:datasrc="imm" name="stVal"> <Val>0</Val> </DAI> </DOI> </LN> </pre>	<pre> <GSEControl name="c2" desc="" dataSet="d2" confRev="1" appID="g2"> <Private type="SEL_GOOSETXAddress"> <esel:Address> <esel:P type="MAC-Address">01-0C-CD-01-01-B1</esel:P> <esel:P type="APPID">0001</esel:P> <esel:P type="VLAN-ID">000</esel:P> <esel:P type="VLAN-PRIORITY">4</esel:P> </esel:Address> </Private> <Private type="SEL_GOOSETXMinTime"> <esel:MinTime>4</esel:MinTime> </Private> <Private type="SEL_GOOSETXMaxTime"> <esel:MaxTime>2000</esel:MaxTime> </Private> </GSEControl> <GSEControl name="n2" desc="" dataSet="b2" confRev="1" appID="d2"> <Private type="SEL_GOOSETXAddress"> <esel:Address> <esel:P type="MAC-Address">01-0C-CD-01-01-B1</esel:P> <esel:P type="APPID">0002</esel:P> <esel:P type="VLAN-ID">000</esel:P> <esel:P type="VLAN-PRIORITY">4</esel:P> </esel:Address> </Private> <Private type="SEL_GOOSETXMinTime"> <esel:MinTime>4</esel:MinTime> </Private> <Private type="SEL_GOOSETXMaxTime"> <esel:MaxTime>2000</esel:MaxTime> </Private> </GSEControl> </pre>
---	--

Additional information

Figure 2-10: Control block information in IED section of the SEL 421 ICD file (left) and the CID file (right)

Only includes the basic GOOSE control block information

<pre> <GSEControl name="c1" appID="g1" dataSet="d1" confRev="1" desc="" /> <GSEControl name="cr" appID="gr" dataSet="rd" confRev="1" desc="" /> <GSEControl name="cb" appID="gb" dataSet="bd" confRev="1" desc="" /> </LNO> </pre>	<div style="font-size: 2em;">}</div>
--	--------------------------------------

Figure 2-11: Control block information in IED section of the LPRO 4000 CID file

2.5 GOOSE Messages

Modern power systems are equipped with IEDs which are capable of power system functions such as protection, control, monitoring and recording. These devices are responsible for reliability and quality of the power system and thus, fast and reliable inter IED communication is important to achieve these abilities. The client – server communication offers guarantee of delivery but is too slow for time critical messages such as trip signals. IEC 61850 standard introduced a high speed peer-to-peer Generic Object Oriented Substation Event (GOOSE) messages for fast and reliable communication. In addition, GOOSE is standardized to achieve the interoperability between the IEDs from different vendors [15]. GOOSE messages are mapped directly to the link layer to increase the speed [16], [17]. GOOSE messages are multicast messages and can carry both binary, integer and analog values [18]. GOOSE message carry information such as occurring of a new event, information about the event and the time of the event. But it does not carry command information. It is a responsibility of the receiving device to take the action based on the information of the GOOSE message [19].

2.5.1 GOOSE Benefits

GOOSE messages present some great advantages to the substation communication compared to the typical hardwired connections and other communication protocols [20].

- Improved interoperability – One of the main disadvantages of the earlier communication protocols is the lack of interoperability. The vendors use their own communication protocols to communicate with other devices. So the substation was designed either using the devices of the same manufacturer or protocol converters were used for

communicating with the devices of other manufacturers. This method was really expensive. Standard communication interface of GOOSE messages provide seamless interoperability between devices of different manufacturers [20].

- Improved flexibility – Updating substation configuration in early substations was considered as a major issue as it needs lot of physical work such as removing existing connections and adding new connections. But with the use of GOOSE messages, these updating can be done by only using configuration tools. A new device can be easily added to the current substation by connecting it to Ethernet switch. The rest of the configuration does not require any physical connections [20].
- Reduced cost – IEC 61850 station bus concept and GOOSE messages can reduce cost by replacing lot of wires between IEDs by fiber optics connecting each IED to the Ethernet switch. It also reduces the complexity of the connections. In addition, it saves time and money for scheduled maintenance compared to hardwired connections. Moreover, GOOSE based systems can easily be improved or expanded by using software configuration which reduces installation, testing and commissioning cost [15].
- Speed – The IEC 61850 data model objects and services are built above the application layer of the Open System Interconnection (OSI) model. GOOSE messages are used to send the type 1 (fast messages) and type 1A (trip) messages [21], which are time critical. Mapping of GOOSE messages directly to the data link layer (Ethernet link layer) skipping application, presentation, session, transport and network layers, makes GOOSE messages faster than the other existing communication protocols [16], [17]. The performance requirement of GOOSE messages is very tight: the GOOSE transfer time

(total peer-to-peer time) should not exceed 4 milliseconds [18], [19].

- Reliability – GOOSE messages are multicast messages and subscriber does not provide acknowledgement. Therefore, GOOSE messages are repeated until a new event occurs. When a new event happens, GOOSE message is issued instantly and the next message is issued in few milliseconds after. Time duration between repeated GOOSE messages increases (normally twice the previous time period) until it reaches a predefined maximum time interval and remains at this maximum time interval. Minimum time, maximum time and specific intervals are local parameters and therefore decide by the GOOSE publisher. GOOSE messages also contain time allowed to live parameter which informs subscriber the maximum time interval it has to wait until it receives the next message. This increases the dependability and security of GOOSE messages [18], [21].

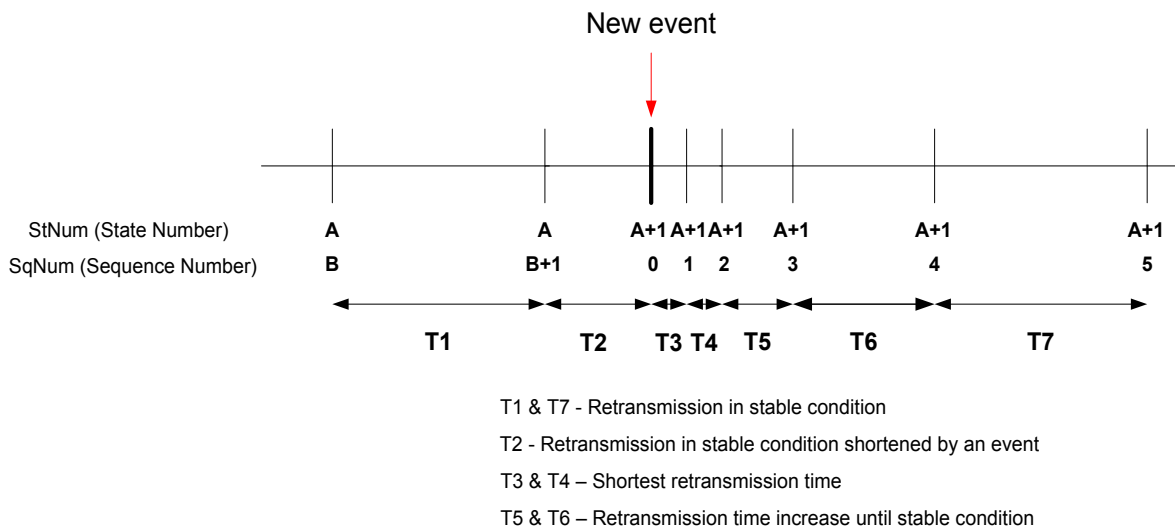


Figure 2-12: Time of transmission [21]

Receiver can recognize the GOOSE messages by checking the StNum (state number) and SqNum (sequence number) parameters. StNum only increases when a new event is occurred. SqNum continuously increases and it resets to zero when a new event is occurred.

2.5.2 GOOSE Publication and Subscription Configuration Processes

IED configuration tool of the manufacturer is required to configure an IED as a GOOSE subscriber due to the fact that it is a local issue. But GOOSE publication configuration of an IED can be done using its IED configuration tool or a system configuration tool.

GOOSE Publication Configuration Process

GOOSE publication process consists of two steps. The first step is to create a dataset including publishing information (i.e. including functionally constrained data attributes (FCDAs)). The next step is to create a GOOSE control block by including the created dataset.

Initial step of creating a dataset is to assign a name to it. FCDAs can be added to the dataset by following the object hierarchy shown in Figure 2-13.

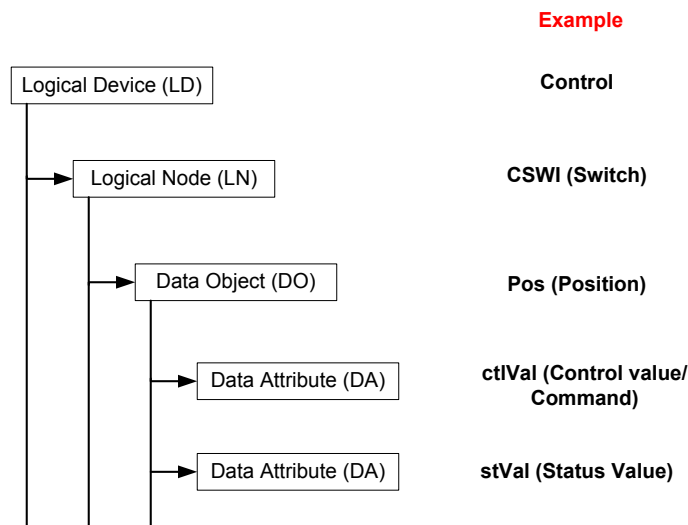


Figure 2-13: Object hierarchy [16]

Each of the dataset may consist number of LDs and each LDs may consist number of LNs. Similarly, each of the LNs may consist number of DOs and each DOs may consist number of

DAs. IEC 61850 defines above objects as follows [21],

- Logical device (LD) – “entity that represents a set of typical substation functions” [21].
- Logical Node (LN) – “entity that represents a typical substation function” [21]. A LN normally represents either the intelligent body of a substation entity (such as a switch) or a specific IED functionality (such as a differential protection scheme).
- Data Object (DO) – “meaningful structured information of applications located in an automation device which can be read or written” [21].
- Data Attribute (DA) – “named element of data object which has a specific type” [21].

Please note that the above definitions are directly taken from the IEC 61850-8-1 standard [21]

The next step is to create GOOSE control blocks to include the created datasets so that the information can be published as GOOSE messages. The GOOSE control blocks consist following fields which are to be completed by the user [21],

- GOOSE control block name – a valid name for the GOOSE control block.
- Dataset name – name of the dataset that is included in this control block.
- GOOSE ID – identifier of the GOOSE. It should be a string.
- ConfRev (configuration revision) – integer value between 0 to 4,294,967,295.
- Min time – shortest retransmission time interval in milliseconds.
- Max time – longest (at stable condition) retransmission time interval in milliseconds.

- MAC address – multicast address of the GOOSE control block and should be defined as 01-0C-CD-xx-xx-xx (x can be replaced by characters from 0 to 9 or A to Z) [21], [22].
- APP ID (application identifier) – it is a four digit hexadecimal number. It is used to differentiate applications associate with it. It is a combination of APPID type (two most significant bits) and the actual ID. If the two most significant bits are 00, it is a GOOSE type 1 message (fast messages) and if they are 10, it is a GOOSE type 1A message (trip). Therefore, 0x0000 to 0x3FFF are reserved for GOOSE type 1 messages whereas 0x8000 to 0xBFFF are reserved for GOOSE type 1A messages [21].
- VLAN ID (virtual LAN ID) – it is a three digit hexadecimal number. This is an optional field. If this option is used, the configuration should set the value. If it is not used, the value should be set to zero [22].
- VLAN Priority – This will be useful if the VLAN option is used. For higher priorities, this value should be between 4 to 7 and for lower priorities, this value should be between 1 to 3.

A new event will occur every time a dataset entry changes its value and sends GOOSE messages repetitively until a new event occurs.

GOOSE Subscription Configuration Process

Initial step of the subscription process is to import the CID file of the GOOSE publisher or the SCD file from the system configuration tool into the IED configuration tool of the subscriber. IED configuration tool is capable of extracting all the publishing information from the imported file. Select the required data attribute from the GOOSE publisher following the object hierarchy

shown in Figure 2-13 and map it to the suitable GOOSE input of the subscriber.

2.6 Training Programs and Laboratory Facilities

At present there is lack IEC 61850 courses and laboratory setups at the universities offering power engineering graduate and undergraduate programs. There are several university IEC 61850 laboratories, but most of them are mainly dedicated to research [23]. There are many independent test facilities developed by industry [24] but they are mainly used for conformal testing and certification. In addition, there are several commercial IEC 61850 research facilities developed by equipment manufacturers for their own research and development purposes [25]. Most equipment manufacturers provide IEC 61850 training programs for outsiders, mainly to demonstrate IEC 61850 capabilities of their devices.

General Electric (GE) conducts a three day IEC 61850 training program. It covers protocol fundamentals, Ethernet fundamentals, TCP/IP fundamentals, substation security, MMS overview, peer-to-peer communication and IEC 61850 applications in first two days and a lab session on third day [26].

Siemens also provides a training course regarding IEC61850 and GOOSE configuration. It covers basic of communication networks and systems with Ethernet and IEC 61850, structure of substation and Ethernet communication networks, implementation of IEC 61850 with DIGSI4, some applications of GOOSE and practical exercises [27].

ABB university of ABB corporation offers 30 minutes web based IEC 61850 technical course. This course provides very basics about the standard, key features, benefits, data modeling, GOOSE and Ethernet [28]. It also offers a two and a half day course in IEC 61850 for protection

and control which covers topics such as overview of IEC 61850 protocol suite, information on IEC 61850-7-3, hands-on configuration practice on ABB Relion relay and monitoring and decoding of IEC 61850 [29].

Schweitzer Engineering Laboratories (SEL) also offers an IEC 61850 training program which covers overview of network protocols and communication, applications, GOOSE and VLANs, AcSELERator Architect software, GOOSE and MMS report configuration, logic, importing ICD and CID files, VLAN configuration, etc. [30].

RTDS Technologies Inc. conducts an IEC 61850 and PMU applications training course and the topics covered relevant to IEC 61850 are; IEC 61850 fundamentals, use of RTDS Simulator hardware and software to assemble cases for IEC-61850 based applications, connection of IEC-61850 GOOSE and IEC-61850-9-2 LE enabled relays to the RTDS Simulator and introduction to RTDS 61850 MMS Voyager [31]. The courses offered by manufacturers generally focus on their own products and software tools.

A more general training program is offered by Kinectrics, which has a good laboratory facility. Their three day theory and workshop based IEC 61850 training program covers topics such as introduction to IEC 61850, Ethernet architecture, station bus applications, process bus applications, modeling approach and naming convention, integration and testing of multi-vendor IEDs for GOOSE applications, etc. [32].

All IEC 61850 training programs are expensive and mostly offer once or twice a year. Also, the number of participants for a course is limited. In addition, the company that offers the training program usually use its own IEDs and IED configuration tool for training. Therefore, participants experience multi-vendor interoperability only in a limited sense. Also, most of the

training programs use IED configuration tools for GOOSE configuration. Therefore, users are not exposed to the IEC 61850 SA system design process and system configuration tools. Due to time limitation, most of these courses lack information regarding SCL files, their usage, differences between SCL file types, information flow in the configuration process, performance testing of GOOSE (such as transfer time) and comparison between GOOSE and hardwired connection.

2.7 Chapter Summary

IEC 61850 standard, system configuration description language and its file types, GOOSE messages, GOOSE configuration process and some of the available IEC 61850 training programs and laboratory facilities were introduced. This introduction is important to understand the laboratory setup, applications and laboratory experiments described in the upcoming chapters.

Chapter 3

Laboratory Setup

3.1 Introduction

In this chapter, a laboratory setup of an IEC 61850 station bus compliant substation is presented in order to fulfill the objective 1. First, the structure of the experimental setup is explained. Second, the implementation of the electrical substation in RTDS is discussed. This includes detailed information of the power system implemented in RTDS, description of RTDS inputs and outputs used to communicate with the actual IEDs and implementation of low level interface between the real-time simulator and protection IEDs (objective 2). Third, configuration details of all the relays which are used to protect the power system are explained. Fourth, configuration steps to publish and subscribe GOOSE messages from RTDS and all of the relays are presented. This section consists of a systematic approach to configure the RTDS simulator and relays to publish and subscribe GOOSE messages. Finally, performance evaluation of the laboratory setup is presented (objective 3). This includes GOOSE performance testing results of the complete setup for different types of faults, GOOSE round trip time and GOOSE transfer time. Traditional

hardwired results are obtained as well for the comparison purposes.

3.2 Structure of the Test Setup

Figure 3-1 shows the basic structure of the laboratory test setup.

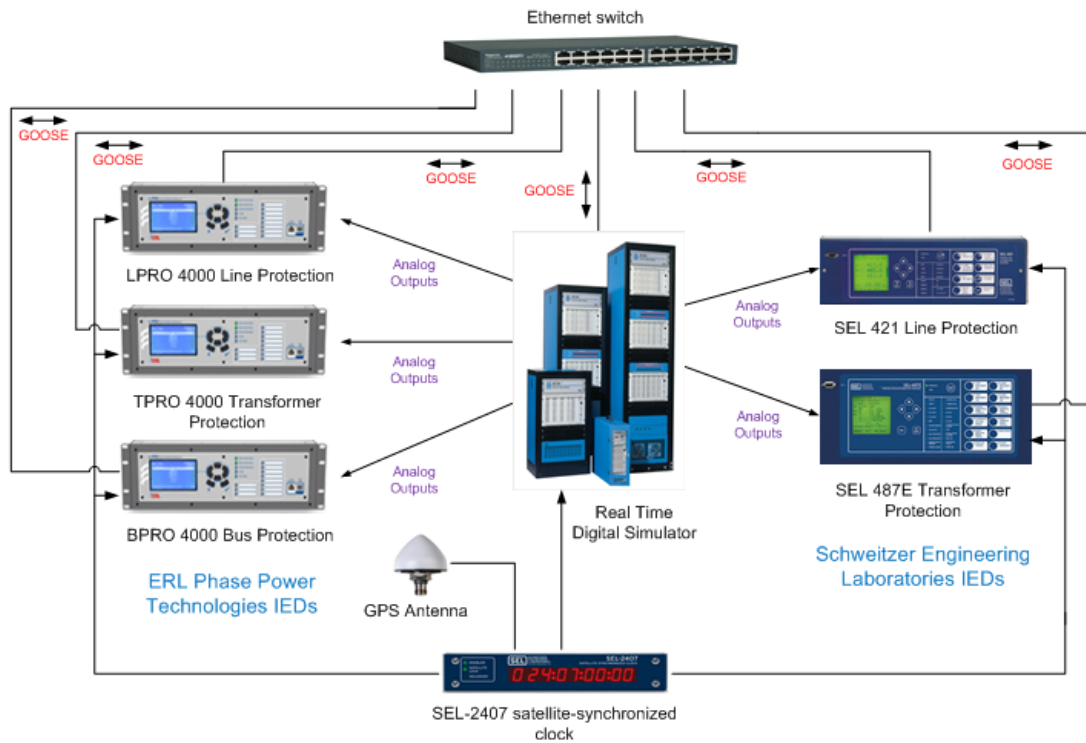


Figure 3-1: Basic structure of the laboratory test setup

The main components of the laboratory test setup are;

- Real Time Digital Simulator: RTDS Technologies' real time digital simulator is used to implement and simulate the power system. The simulated voltage and current signals of the power system are fed to protection relays through the analog outputs (GTAO) of the simulator.
- Protection relays: Five protection relays are used to protect the electrical substation. Three out of five protection relays are manufactured by the ERL Phase Power

Technologies whereas the rest of the two relays are from Schweitzer Engineering Laboratories (SEL). There are two line protection relays, two transformer protection relays and one bus protection relay. Each relay takes voltage and current signals from RTDS through analog outputs. GOOSE messages are used to send trip signal to RTDS as well as to receive the circuit breaker statuses from RTDS.

- Ethernet switch: IEC 61850 station bus uses Ethernet to transmit GOOSE messages. All the relays and the RTDS are connected to the Ethernet switch manufactured by Ruggedcom using 100 Mbps communication links which facilitates GOOSE message communication.
- Satellite synchronized clock: SEL-2407 satellite-synchronized clock manufactured by Schweitzer Engineering Laboratories is used to time synchronize the RTDS (through GTSYNC card) and all five relays. Demodulated IRIG-B outputs with an accuracy of ± 100 ns [33] are used to connect the devices.

3.3 Implementation of Power System in RTDS

3.3.1 Real Time Digital Simulator (RTDS)

The real time digital simulator (RTDSTM) available in the laboratory is manufactured by the RTDS Technologies Inc. Its hardware and software are specifically designed and optimized for power system electromagnetic transient simulations. It contains a user friendly graphical user interface and a component library with large number of power systems, control systems and protection and automation system models. It also allows users to create their own models.

Because of the real time operation, RTDS can be used to perform closed-loop testing with protection relays [34].

RSCAD is the simulation software of RTDS. RSCAD consists of two modules which are DRAFT module and RUNTIME module. The user can use DRAFT module to design the power system using the available library components or user defined components. Once the power system is completed, the user can compile the case in DRAFT module and run the case in RUNTIME module. User can add meters and plots to the RUNTIME module to monitor the power system, during the simulation. Moreover, user is able to interact with the simulation by applying faults or changing breaker positions using push buttons, sliders and switches [34].

Interface cards, analog and digital input and output cards of RTDS can be used to connect RTDS with protection relays [35]. In this research, analog output cards (GTAOs) of RTDS are used to feed simulated voltage and current signals to relays. The digital input card (GTDI) is used to receive trip signals from relays and network interface card (GTNET) is used for GOOSE communication with relays.

3.3.2 Electrical Power System and the Substation

Figure 3-2 shows the single line diagram of the power system which is simulated in the real time digital simulator (RTDS). The substation, which is highlighted in pink color, consists of a 230 kV bus bar connecting two overhead transmission lines, two transformers and 230 kV equivalent generator. This arrangement of the substation allows demonstration of line, transformer and bus protection schemes and could be implemented with the relays available in the laboratory. Furthermore, the 230 kV equivalent generator directly connected to the 230 kV bus bar in the

substation allows expansion of the laboratory setup to include generator protection in the future.

The two 230 kV overhead transmission lines are 200 km long, and connected to 230 kV system equivalent sources at remote ends. Two parallel connected step down transformers deliver power to a constant power load.

SEL 421 and SEL 487E relays manufactured by Schweitzer Engineering Laboratories are used to protect a transmission line and a transformer respectively. The remaining transmission line and the transformer are protected by LPRO 4000 and TPRO 4000 relays, respectively manufactured by ERL Phase Power Technologies. The 230 kV bus bar is protected by BPRO 4000 relay, which is also manufactured by ERL Phase Power Technologies.

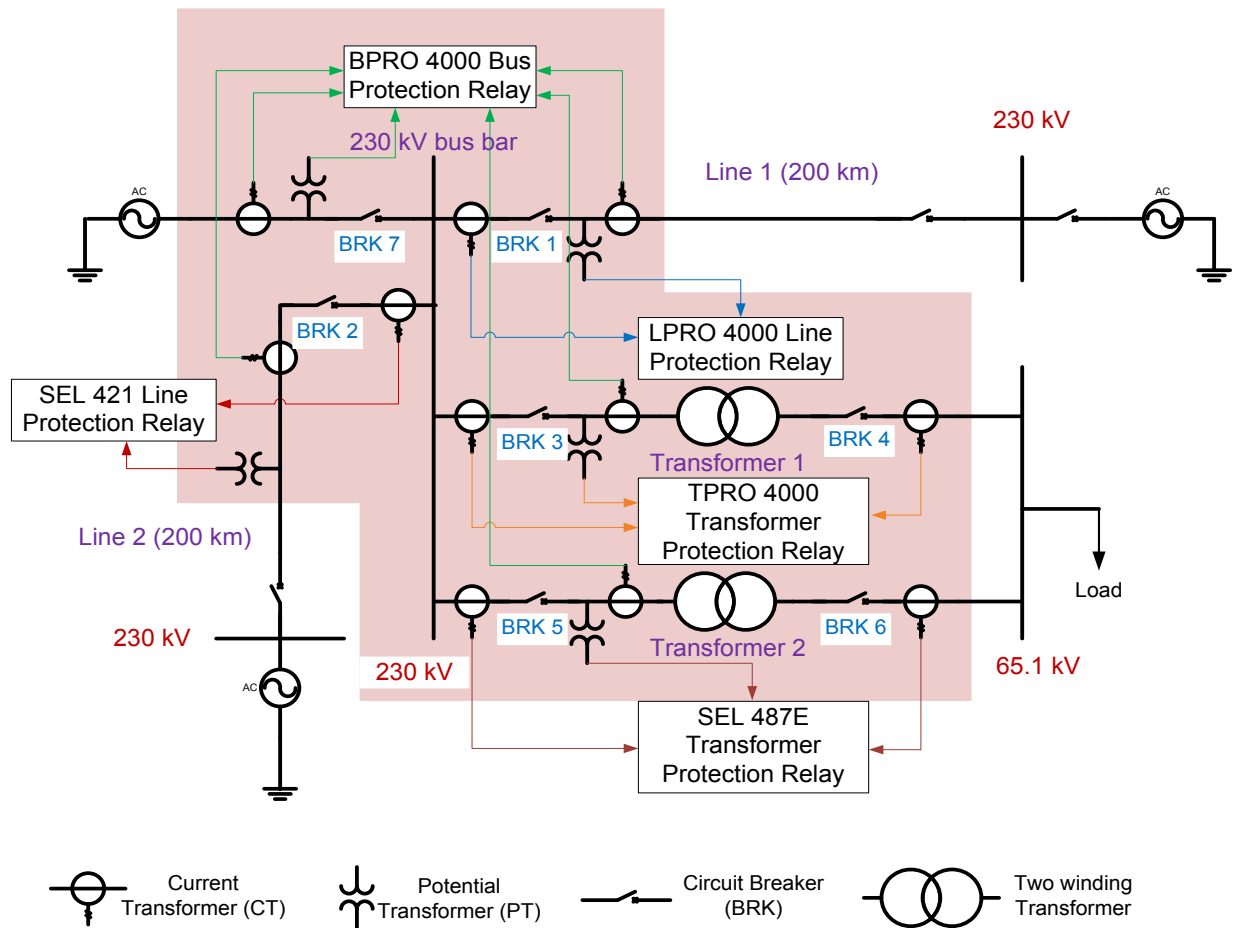


Figure 3-2: Single line diagram of the substation simulated in RTDS [36]

Table 3-1, Table 3-2, Table 3-3 and Table 3-4 show the data for the transmission lines, transformers and the load.

Table 3-1: Parameters of Transmission line 1

Number of Phases	3
Positive Sequence Series Resistance	0.0200 Ω /km
Positive Sequence Series Ind. Reactance	0.1708 Ω /km
Positive Sequence Shunt Cap. Reactance	0.2279 M Ω *km
Zero Sequence Series Resistance	0.7115 Ω /km
Zero Sequence Series Ind. Reactance	1.6961 Ω /km
Zero Sequence Shunt Cap. Reactance	0.3451 M Ω *km
Line Length	200 km

Table 3-2: Parameters of Transmission line 2

Number of Phases	3
Positive Sequence Series Resistance	0.0169 Ω /km
Positive Sequence Series Ind. Reactance	0.1473 Ω /km
Positive Sequence Shunt Cap. Reactance	0.2279 M Ω *km
Zero Sequence Series Resistance	0.0876 Ω /km
Zero Sequence Series Ind. Reactance	0.3695 Ω /km
Zero Sequence Shunt Cap. Reactance	0.3451 M Ω *km
Line Length	200 km

Table 3-3: Parameters of both transformers

Winding 1 Connection	Wye
Winding 2 Connection	Delta
Delta Lags or Leads Wye	Lags
Transformer Rating (3 Phase)	93.7 MVA
Base Frequency	60 Hz
Leakage Inductance of Tx	0.1715 pu
Base Primary Voltage (L-L RMS)	230 kV
Base Secondary Voltage (L-L RMS)	65.1 kV

Table 3-4: Data of the constant power load

Real Power	6.303 MW
Reactive Power	1.11 Mvar

3.3.3 Analog Outputs

Both the SEL and ERL Phase Power Technologies relays require analog voltage and current signals as inputs. The Gigabit Transceiver Analogue Output (GTAO) cards of RTDS are used to transmit simulated voltage and current signals from RTDS to relays. A GTAO card has a twelve, 16 bit output channels with output range of ± 10 V. A GTAO card has to be connected to an RTDS processor card (GPC or PB5) through a fibre cable or has to be daisy chained with other GTI/O cards where the first card of that chain is connected to an RTDS processor card. The main function of the RTDS processor card is to solve the equations representing the power system modeled in RTDS [35].

Four GTAO cards are used in this research to send simulated voltage and current values to all five relays. Figure 3-3 shows a GTAO card and the connections going out from it to relays and the Table 3-5 shows complete information of wiring connections from all four GTAO cards to relays.

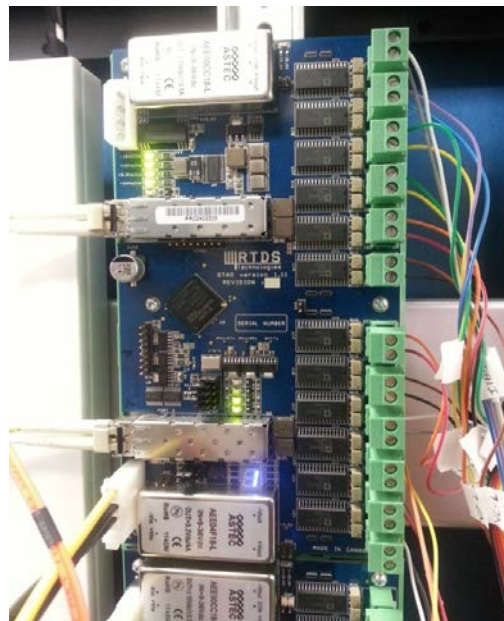


Figure 3-3: A GTAO card and its connection

Table 3-5: Connections from GTA0 cards to relays

GTA0 card number	Channel number	Relay	Signal name
1	1 to 3	TPRO 4000	HV side current
	4 to 6		HV side voltage
	7 to 9		LV side current
	10 to 12	SEL 487E	HV side voltage
2	1 to 3	LPRO 4000	Current
	4 to 6		Voltage
	7 to 9	SEL 487E	HV side current
	10 to 12		LV side current
3	1 to 12	BPRO 4000	Currents
4	1 to 3		Current
	4 to 6	Voltage	
	7 to 9	SEL 421	Current
	10 to 12		Voltage

3.3.4 Low Level Connection

The current and voltage inputs of the relays are usually designed to take secondary current and voltage signals from the high voltage instrument transformers. The standard nominal secondary currents of current transformers (CTs) are 1A or 5A and the nominal output of voltage transformers (VTs) are 67 V (phase to neutral). The nominal input current for SEL relays is 1 A and that for ERL Phase relays is 5 A. The nominal input voltage of both types of relays is 67 V. The instrument transformers inside the relays convert these currents and voltages signals to lower values which are suitable for their inner circuit boards that contain A/D converters. The traditional method of relay testing is to use current and voltage amplifiers to amplify the voltage and current signals from RTDS analog outputs to match with relay input range. However, use of many expensive and bulky amplifiers which can introduce slight delays and distortions can be avoided, if the output from RTDS GTA0 cards can be directly connected to the A/D converter boards inside relays. The low level interface of both types of relays can be accessed by opening

the relays and bypassing the instrument transformers. Furthermore, RTDS GTAO outputs are optically isolated making such connections very convenient. Therefore, in this experimental setup, analog outputs from RTDS are directly connected to low level interfaces of the relays using ribbon cables bypassing the internal instrument transformers in the relays. The Figure 3-4 shows the current and voltage inputs of SEL relay and Figure 3-5 shows the low level interface of the same relay. Similar arrangement can be seen in other relays as well.

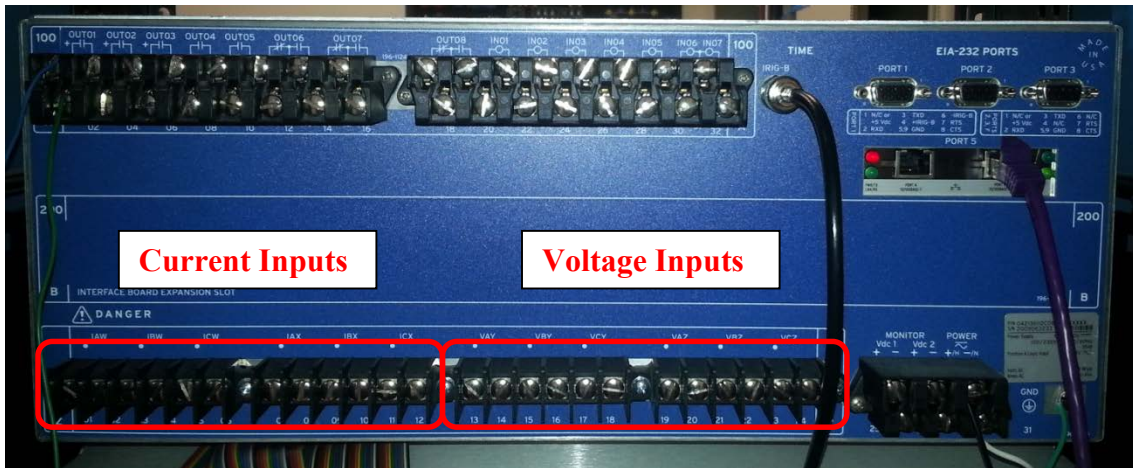


Figure 3-4: Normal Current and voltage inputs of SEL 421 relay



Figure 3-5: Low level interface of SEL 487E relay directly connected to RTDS with ribbon cables

Several intermediate terminal boards are used to distribute the ribbon cables coming from RTDS GTAO output to the low level interfaces of the respective relays. Figure 3-6 and Figure 3-7 show

some of the intermediate terminal boards used in the setup.



Figure 3-6: Intermediate boards of TPRO 4000 and BPRO 4000



Figure 3-7: Intermediate board of SEL 421 relay

The high voltages instrument transformers that step down primary voltages and currents are simulated in RTDS using the models of current and voltage transformers that accurately represent their magnetic and saturation characteristics. These secondary side values of the CTs and VTs are sent to GTA0 cards for producing analog outputs. These analog outputs need to be scaled to the range of voltages accepted at low level interfaces of the relays by entering the appropriate scale factors to the GTA0 configuration component in RSCAD software.

Table 3-6 shows the nominal secondary output and the low level interface input of each relay for voltage and current signals.

Table 3-6: Secondary outputs and low level interface input of relays

Relay	Voltage		Current	
	Nominal secondary output (Line-Neutral) (V)	Nominal low level input (V)	Nominal secondary output (A)	Nominal low level input (V)
LPRO 4000	67	0.7444	5	0.040
SEL 421	67	0.4460	1	0.066
TPRO 4000	67	0.6090	5	0.040
SEL 487E	67	0.4460	1	0.066
BPRO 4000	67	0.6090	5	0.033

In the relay setting files, it is necessary to set the CT and VT ratios as same as the ratios in RSCAD CT and VT models so that the relay can display correct primary side voltage and current values.

With the information of Table 3-6, the scaling factors for GTA0 configuration component are calculated using equation 3-1.

$$Scaling\ factor = \frac{5}{Nominal\ low\ level\ input} * Nominal\ secondary\ output \quad 3-1$$

Table 3-7 shows the scaling factors calculated using equation 3-1.

Table 3-7: Scaling factors for GTA0 configuration component

Relay	Scaling factor	
	Voltage	Current
LPRO 4000	450.00	625.00
SEL 421	751.12	75.075
TPRO 4000	550.00	625.00
SEL 487E	751.12	75.075
BPRO 4000	550.00	750.00

3.3.5 RTDS Inputs

The RTDS facilitates the application of a variety of faults. When a fault is applied, it is detected by a relay using simulated voltage and current signals, which are fed through analog outputs of the simulator. Once the fault is detected, a trip signal is sent by the relay to the relevant circuit breaker simulated in the RTDS. In this research, two different methods are used to send the trip signal from relays to RTDS.

The first method is through a GOOSE message. The GOOSE message from the relay is sent over the Ethernet LAN where it is received by the network interface (GTNET) card of the RTDS. Similar to the GTA0 card, the GTNET card is connected to a processor card (GPC or PB5) through fibre cable. Not only GTNET card supports IEC 61850 GOOSE protocol, it also supports protocols such as IEC 61850 SMV, IEEE C37.118.2 (Synchrophasor protocol), DNP3 (Distributed Network Protocol), and PLAYBACK. But one GTNET card can support only one protocol at a time [35]. Figure 3-8 shows the front view and the back view of a GTNET card.



Figure 3-8: Front and back view of two GTNET cards

The second method is through the traditional hardwired connection from relay output contact. The RTDS simulator is capable of receiving this signal through either digital or analog input cards. In this research, the digital input (GTDI) card is used to receive trip signals. The second method is mainly used to compare the performance of GOOSE with hardwired connection. The GTDI card includes 64 digital inputs. Similar to GTA0 card, a GTDI card has to be connected to an RTDS processor card (GPC or PB5) through a fibre cable or has to be daisy chained with other GTI/O cards where the first card of that chain is connected to an RTDS processor card [35]. Figure 3-9 shows the GTDI card and wiring connection of it whereas Figure 3-10 shows the hardwired output connection of the relay.



Figure 3-9: RTDS digital input card (GTDI)



Figure 3-10: Hardwired connection of TPRO 4000 relay

3.4 Relay Settings

3.4.1 LPRO 4000 Relay

LPRO 4000 is a line protection relay manufactured by ERL Phase Power Technologies. Its primary protection includes 5 zones of phase and ground distance functions with user defined Mho or Quadrilateral shapes. Also it is an IEC 61850 station bus compliant relay which means that it is capable of publishing and subscribing GOOSE messages [37]. In this research, LPRO 4000 relay's distance protection functionality is used to protect an overhead transmission line. A distance protection scheme with three zones is used to protect one of the 230 kV transmission lines. The basic parameters of the transmission line are given in Table 3-1, and the corresponding positive and zero sequence impedances are calculated and shown in Table 3-8.

Table 3-8: Positive and zero sequence impedance (primary)

	Magnitude (Ω)	Angle (degrees)
Positive sequence impedance	34.4	83.31
Zero sequence impedance	367.86	67.74

The CT and VT ratios used for this line are 240:1 and 2000:1 respectively. With that information, secondary values of the positive and zero sequence impedance are obtained and showed in Table 3-9.

Table 3-9: Positive and zero sequence impedance (secondary)

	Magnitude (Ω)	Angle (degrees)
Positive sequence impedance	4.13	83.31
Zero sequence impedance	44.14	67.74

L-PRO Offliner Settings and Relay Control Panel software developed by ERL Phase Power Technologies are used to enter and load the settings to LPRO 4000 relay, respectively. The important settings of LPRO 4000 relay are shown in Table 3-10. Detailed calculations corresponding to these settings are given in Appendix A.1.

Table 3-10: LPRO 4000 relay settings

Relay Identification	
Nominal CT secondary current	5 A
Nominal system frequency	60 Hz
System Parameters	
Main CT turns ratio	240:1
Main PT turns ratio	2000:1
Line Parameters	
Line length	200 km
Positive sequence impedance (secondary)	4.13 Ω
Positive sequence angle(secondary)	83.3 degrees
Zero sequence impedance (secondary)	44.14 Ω
Zero sequence angle(secondary)	67.2 degrees
K0 magnitude	3.24
K0 angle	-17.7 degrees
Protection functions	
21P – Phase Distance & 21N – Ground Distance	
Zone 1 enable	Yes
Zone 1 type	Mho
Zone 1 forward reach	3.30 Ω
Mho Char. Angle	83.3 degrees
Pick up delay	0 seconds
Zone 2 enable	Yes
Zone 2 type	Mho
Zone 2 forward reach	5.36 Ω
Mho Char. Angle	83.3 degrees
Pick up delay	0.33 seconds
Zone 3 enable	Yes
Zone 3 type	Mho
Zone 3 reverse reach	1.65 Ω
Mho Char. Angle	83.3 degrees
Pick up delay	1 second

As mentioned before, the trip signal is sent by two methods. To send the trip signal as a GOOSE

message, either “PDIS” (distance protection) logical node can be used or “PLGGIO1” (generic input/output logical node allocate for ProLogic outputs) logical node of LPRO 4000 relay can be used. In this research, “PDIS” logical node is used. Each zone’s phase and ground distance has its own PDIS logical node. Table 3-11 shows the logical node relevant to each distance element.

Table 3-11: Logical node relevant to distance element

Distance element	Logical node
Zone 1 Phase (21P1)	D21P1PDIS1
Zone 2 Phase (21P2)	D21P2PDIS2
Zone 3 Phase (21P3)	D21P3PDIS3
Zone 1 Ground (21N1)	D21N1PDIS7
Zone 2 Ground (21N2)	D21N2PDIS8
Zone 3 Ground (21N3)	D21N3PDIS9

If PLGGIO1 logical node is used, then the ProLogic outputs have to be set in such a way that when a fault is detected in any of the three zones, the relay should send a trip signal through a GOOSE message to the RTDS. Table 3-12 shows one way of doing it by publishing ProLogic 3 output as a GOOSE message.

Table 3-12: ProLogic output setting

	Logic Equation
ProLogic 1	21P1 trip OR 21P2 trip OR 21P3 trip
ProLogic 2	21N1 trip OR 21N2 trip OR 21N3 trip
ProLogic 3	ProLogic 1 OR ProLogic 2

To send the trip signal using hardwired connection through output contact 1, in the Output matrix, all the relevant trip signals (21P1 trip, 21P2 trip, 21P3 trip, 21N1 trip, 21N2 trip & 21N3 trip) have to be selected in L-PRO Offliner Settings software as shown in Figure 3-11.

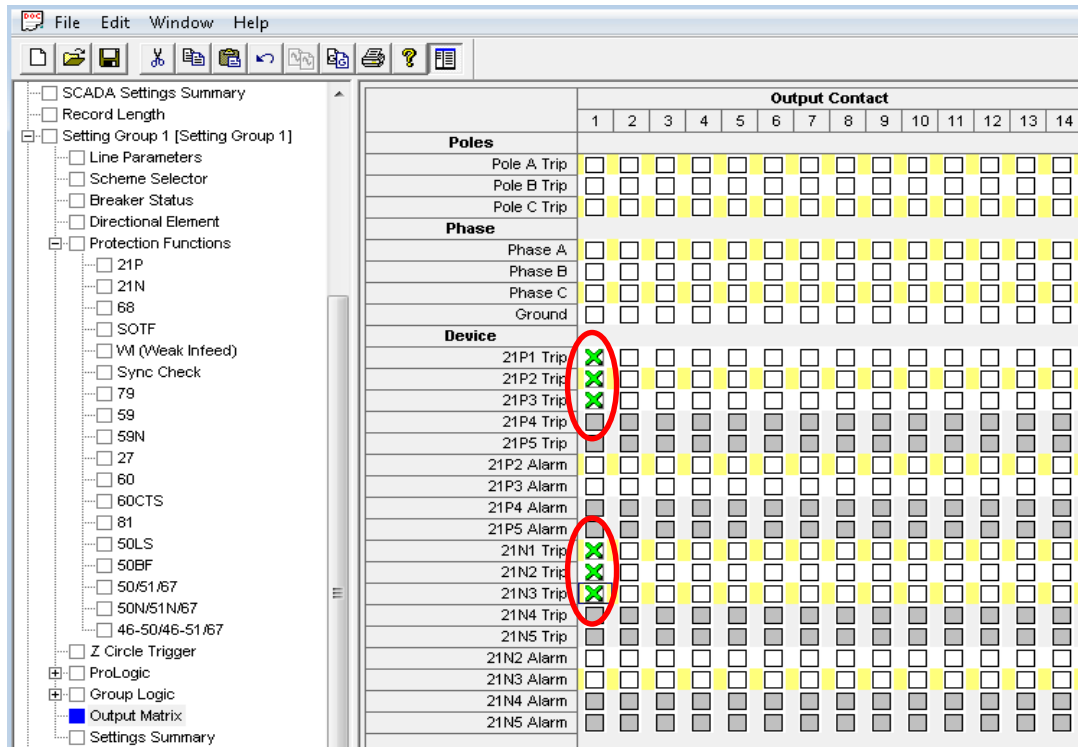


Figure 3-11: Assigning trip signals to output contact 1 of LPRO 4000 using L-PRO Offliner Settings

3.4.2 SEL 421 Relay

SEL 421 line protection relay is used to protect Line 2 shown in Figure 3-2 (parameters of this line is shown in Table 3-2). This relay is manufactured by Schweitzer Engineering Laboratories and features five zones of phase distance and ground distance elements and IEC 61850 protocol support [38]. Similar to Line 1, a distance protection scheme with three zones is used to protect Line 2 as well. A CT ratio of 240:1 and a VT ratio of 2000:1 are used for this line. Using the transmission line parameters in Table 3-2 and the instrument transformer information, the primary and secondary positive sequence and zero sequence impedances are calculated and the results are shown in Table 3-13.

Table 3-13: Positive and zero sequence impedance

	Primary		Secondary	
	Magnitude (Ω)	Angle (degrees)	Magnitude (Ω)	Angle (degrees)
Positive sequence impedance	29.66	83.45	3.56	83.45
Zero sequence impedance	75.94	76.66	9.11	76.66

AcSELerator QuickSet software developed by Schweitzer Engineering Laboratories is used to enter the settings for SEL 421. This software can be used for settings of all the SEL relays. The important settings of SEL 421 relay are shown in Table 3-14. Detailed calculations corresponding to these settings are given in Appendix A.1.

The trip signal is sent by two methods to compare the performance of GOOSE with hardwired connection. To send the trip signal as a GOOSE message, “CCOUTGGIO21” logical node of SEL 421 relay is used. The SEL 421 relay model and firmware version available in laboratory only allow CCOUT (communication card outputs) to be published as GOOSE messages. Therefore, by assigning 3PT (three pole tripping) to CCOUT1 and publishing CCOUT1 as a GOOSE message will send a trip signal to RTDS for any fault detected in any zone. Similarly, 3PT is assigned to OUT101 (output contact 1) to send the trip signal using hardwired connection. As GOOSE messages are sent through the Ethernet, it is important to set the communication setting of the SEL 421 relay. Communication Port 5 is used for GOOSE communication and the relevant settings are shown in Table 3-15.

Table 3-14: SEL 421 relay settings

General Global Settings	
Station Identifier	Station A
Relay Identifier	Relay 1 – SEL SN 2009063232
Nominal System Frequency	60
Breaker Monitor	
Breaker 1 trip type	3 pole
Breaker 1 contact input	CCIN001
Group Setting	
Group 1	
Set 1	
Line Configuration	
Current Transformer Ratio	240:1
Potential Transformer Ratio	2000:1
PT Nominal Voltage (L-L) (secondary)	115 V
Positive sequence line impedance magnitude (secondary)	3.56 Ω
Positive sequence line impedance angle (secondary)	83.45 degrees
Zero sequence line impedance magnitude (secondary)	9.11 Ω
Zero sequence line impedance angle (secondary)	76.66 degrees
Line length	200 km
Relay Configuration	
Phase Distance Elements & Ground Distance Elements	
Mho Distance zones	3
Zone 1 reach	2.85 Ω
Zone 2 reach	4.63 Ω
Zone 3 reach	1.42 Ω
Zero sequence compensation factor	
K0 Magnitude	0.523
K0 Angle (degrees)	-11.11
Distance Elements Common Time Delay	
Zone 1 time delay	0 cycles
Zone 2 time delay	20 cycles
Zone 3 time delay	60 cycles
Directional	
Zone 3 directional control	reverse
Directional control	auto

Table 3-15: SEL 421 communication settings of Port 5

Ethernet Settings	
IP address	192.168.100.85
Subnet mask	255.255.255.0
Default router	192.168.100.1
FTP Settings	
Enable FTP server	Yes
Enable IEC 61850 protocol	Yes
Enable anonymous FTP login	Yes
Associate anonymous user access right with user	2AC

3.4.3 TPRO 4000 Relay

TPRO 4000 is a transformer protection relay manufactured by ERL Phase Power Technologies. Its primary protection is percent restrained current differential function and complies with IEC 61850 station bus [39]. In this setup, TPRO 4000 relay’s current differential protection functionality is used to protect one of the transformers. The parameters of the transformer are given in Table 3-3. T-PRO Offliner Settings and Relay Control Panel software developed by ERL Phase Power Technologies are used to enter the settings and to load the settings to TPRO 4000 relay, respectively. The important settings of TPRO 4000 relay are given in Table 3-16.

Once again, the trip signal is sent by two methods. The first method uses GOOSE messages, and can be configured to use “PDIF” (differential protection) logical node or “PLGGIO3” (generic input/output logical node allocate for ProLogic outputs) logical node of TPRO 4000 relay. In the setup, “PDIF” logical node is used. Logical node that represents differential protection trip in TPRO 4000 relay is “D87TPDIF1”. If PLGGIO3 logical node is used, 87 trip (differential protection trip signal) has to be assigned to the ProLogic output 1 and use it as the trip signal.

Table 3-16: TPRO 4000 relay settings

Relay Identification	
Nominal CT secondary current	5 A
Nominal system frequency	60 Hz
Nameplate Data	
Transformer 3 phase capacity	93.7 MVA
Transformer windings	2
Winding/CT/PT Connections	
Transformer Nameplate	
HV voltage	230 kV
HV connection	Wye
LV voltage	65.1 kV
LV connection	Delta
LV phase (ref. A-phase)	-30 degrees
Voltage Input Connection	
PT turns ratio	2000:1
Location	HV
Current Input Connection	
Input 1 winding	HV
Input 1 CT Connection	Wye
Input 1 CT phase	0 degrees
Input 1 CT turns ratio	50:1
Input 2 winding	LV
Input 2 CT Connection	Wye
Input 2 CT phase	0 degrees
Input 2 CT turns ratio	180:1
Protection functions	
87 - Differential	
Enable	Yes
Minimum Pickup current (I _{Omin})	0.50 pu
Restraint current at slope change (I _{Rs})	5.00 pu
Slope-1 (S1)	30 %
Slope-2 (S2)	75 %
High current setting	10.00 pu
I ₂ cross-blocking	enable
I ₂ setting	0.20

To send the trip signal using hardwired connection through output contact 1, in the Output matrix, the 87 trip signal is assigned to output contact 1 using T-PRO Offliner Settings as shown

in Figure 3-12.

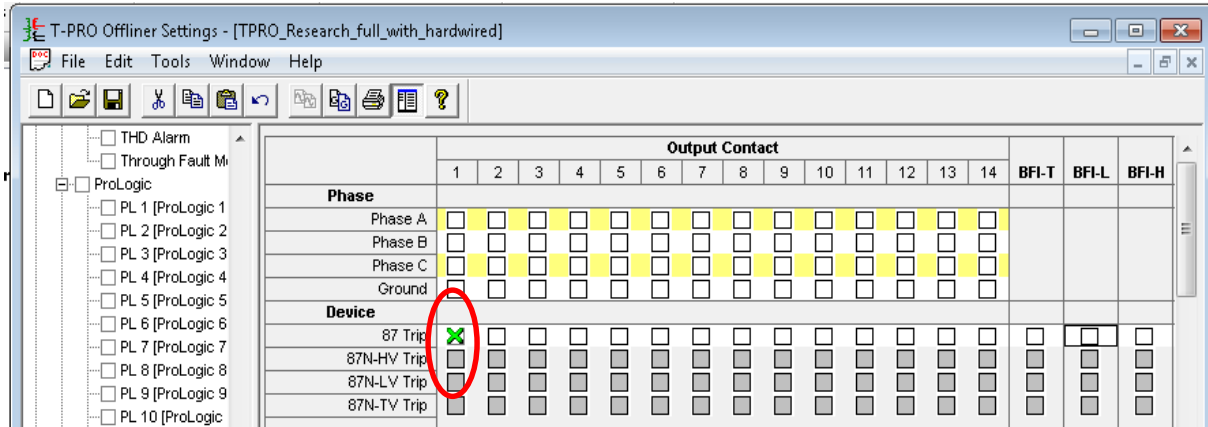


Figure 3-12: Assigning trip signal to output contact 1 of TPRO 4000

3.4.4 SEL 487E Relay

SEL 487E transformer protection relay is used to protect the other transformer for which the parameters are given in Table 3-3. This relay is manufactured by SEL and similar to TPRO 4000, SEL 487E primary protection is current differential protection and it supports IEC 61850 protocol [40].

AcSELERator QuickSet software is used to enter the settings for SEL 487E as it can be used to set settings for all the SEL relays. The important settings of SEL 487E relay are shown in Table 3-17.

Table 3-17: SEL 487E relay setting

General Global Settings	
Station Identifier	Station A
Relay Identifier	Relay 2
Nominal System Frequency	60
Monitor	
Enables	
Select the active breakers	S, T
Breaker Settings	

Breaker S Settings	
Breaker identifier	Breaker S
Breaker normally open (NO) contact input	VB001
Breaker T Settings	
Breaker identifier	Breaker T
Breaker normally open (NO) contact input	VB002
Group Setting	
Group 1	
Set 1	
Relay Configuration	
Enable the following current terminals	S, T
Enable the following voltage terminals	V
Include the following terminals in the differential element	S, T
Current Transformer Data	
Current transformer ratio for terminal S	250:1
Current transformer connection for terminal S	Wye
Current transformer ratio for terminal T	900:1
Current transformer connection for terminal T	Wye
Potential Transformer Data	
Potential transformer ratio for terminal V	2000:1
Potential transformer connection for terminal V	Wye
Potential transformer nominal line-to-line voltage for terminal V (secondary)	115 V
Differential Element Configuration and Data	
Include terminal S in the differential element for the following conditions	1
Include terminal T in the differential element for the following conditions	1
Internal CT connection matrix compensation enabled	Yes
Terminal S CT connection compensation	12
Terminal T CT connection compensation	1
Enter transformer maximum MVA rating	94 MVA
Terminal S line-to-line voltage	230 kV
Terminal T line-to-line voltage	65.1 kV
Differential element operating current pickup	0.50 pu
Slope 1 setting	30 %
Slope 2 setting	75 %
Unrestrained element current pickup	8.00 pu
Enable harmonic blocking differential element	Yes
Trip Logic	
Trip condition for transformer terminals	87R or 87U

The trip signal is sent by two methods and to send the trip signal as a GOOSE message, either

“PDIF” (differential protection) logical node or “OUT1GGIO17” (generic input/output logical node allocate for output contacts) logical node of SEL 487E relay can be used. In the setup developed in this research, “PDIF” logical node is used. Logical nodes that represent differential protection in SEL 487E relay are “D87RPDIF1” (restrained) and “D87UPDIF1” (unrestrained).

If OUT1GGIO17 logical node is used, TRPXFMR (differential protection trip signal) has to be assigned to the output contact 1 (OUT101) and use it as the trip signal. Also, the same output contact (OUT101) can be used to send the trip signal using hardwired connection.

Similarly to SEL 421 relay, communication setting of the SEL 487E relay is done by setting up Port 5 for GOOSE communication with the parameters shown in Table 3-18.

Table 3-18: SEL 487E communication settings of Port 5

IP Configuration	
Device IP address/prefix	192.168.100.86/24
Default router	192.168.100.1
FTP Configuration	
Enable FTP server	Yes
Enable anonymous FTP login	Yes
Anonymous user access level	2
IEC 61850 Configuration	
Enable IEC 61850 protocol	Yes

3.4.5 BPRO 4000 Relay

BPRO 4000 is a bus protection relay manufactured by ERL Phase Power Technologies. It provides primary protection using differential protection function and is capable of publishing and subscribing GOOSE messages [41]. Differential protection functionality of the BPRO 4000 relay is used to protect the 230 kV bus bar highlighted in Figure 3-2.

B-PRO Offliner Settings and Relay Control Panel software developed by ERL Phase Power Technologies are used to enter the settings and to load the settings to BPRO 4000 relay, respectively. The important settings of BPRO 4000 relay are shown in Table 3-19.

Table 3-19: BPRO 4000 relay setting

Relay Identification	
Nominal CT secondary current	5 A
Nominal system frequency	60 Hz
Connections	
System Parameters	
Bus voltage (primary)	230 kV
PT turns ratio	2000:1
Winding/CT Connections	
Differential Zones	
Bus1	Yes
Current Input Connection	
Input 1 connect to	Bus1
Input 1 CT turns ratio	240:1
Input 2 connect to	Bus1
Input 2 CT turns ratio	240:1
Input 3 connect to	Bus1
Input 3 CT turns ratio	50:1
Input 4 connect to	Bus1
Input 4 CT turns ratio	250:1
Input 5 connect to	Bus1
Input 5 CT turns ratio	100:1
Protection functions	
87B - 1 – Bus Differential	
Enable	Yes
Minimum Pickup current (I _{Omin})	0.25 pu
Restraint current at slope change (I _R s)	2.00 pu
Slope-1 (S1)	20 %
Slope-2 (S2)	40 %
High current setting	10.00 pu

Similar to all other relays, the trip signal is sent by using GOOSE and through hard wired connections. To send the trip signal as a GOOSE message, “PDIF” (differential protection)

logical node or “GGIO3” (generic input/output logical node allocate for ProLogic outputs) logical node of BPRO 4000 relay can be used. In this setup, “PDIF” logical node is used. Logical node that represents differential protection in BPRO 4000 relay is “PDIF1”.

If GGIO3 logical node is used, 87B-1 trip (Bus 1 differential protection trip signal) has to be assigned to the ProLogic outputs 1 and use it as the trip signal.

To send the trip signal using hardwired connection through output contact 1, in the Output matrix, the 87B-1 trip signal is assigned to output contact 1 using B-PRO Offliner Settings as shown in Figure 3-13.

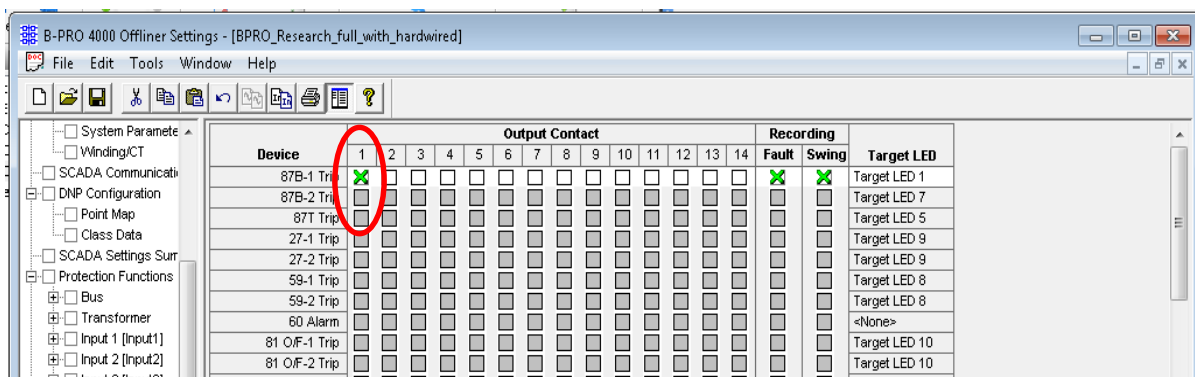


Figure 3-13: Assigning trip signal to output contact 1 of BPRO 4000

3.5 GOOSE Configuration

In the experimental setup developed in this thesis, the RTDS simulator (which simulate circuit breaker control IEDs) and all the relays (protection IEDs) are operated both as a GOOSE publisher and a GOOSE subscriber. When a fault is detected by a relay, it sends a trip signal to the corresponding breaker simulated in RTDS through a GOOSE message. In this case, the relay is the publisher IED whereas the RTDS simulator is the subscriber IED. Once the trip signal is received by the RTDS simulator, the circuit breaker IED simulated in RTDS opens the circuit

breaker in the simulated power system. Then, the updated circuit breaker status will be sent to the relay by the RTDS through a GOOSE message. This time, the RTDS acts as the publisher IED and the protection relay acts as the subscriber IED.

In IEC 61850 context, breaker IED is the IED that controls the breaker. It is located in the process level and connected to the other IEDs in the bay level through process bus. A breaker IED contains XCBR logical node that represents circuit breaker functionality. The breaker IED communicates with other IEDs through GOOSE messages. Usually, a breaker IED subscribes trip signals, recloser commands and breaker failure trip signals and publishes circuit breaker status to other IEDs [7].

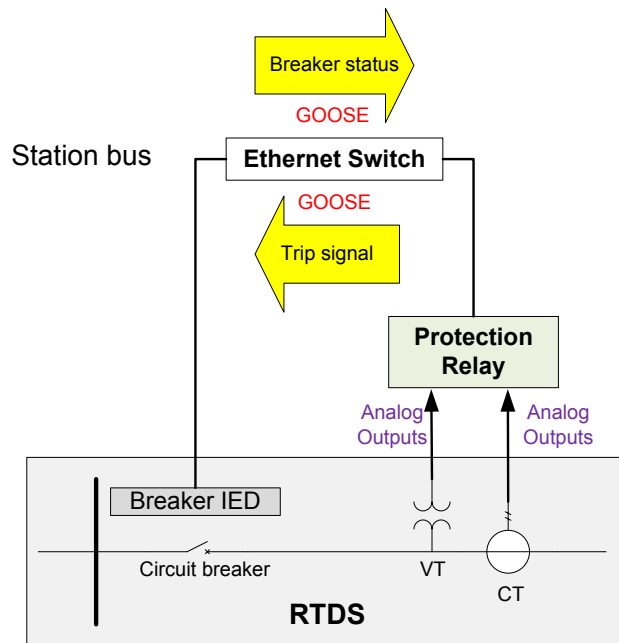


Figure 3-14: GOOSE messaging diagram [36]

There are several ways to configure both RTDS and all the relays as GOOSE publisher and subscriber. The preferred systematic approach shown in Figure 3-15 which has to be carried out using a system configuration tool and IED configuration tools, is explained in detail in the next section.

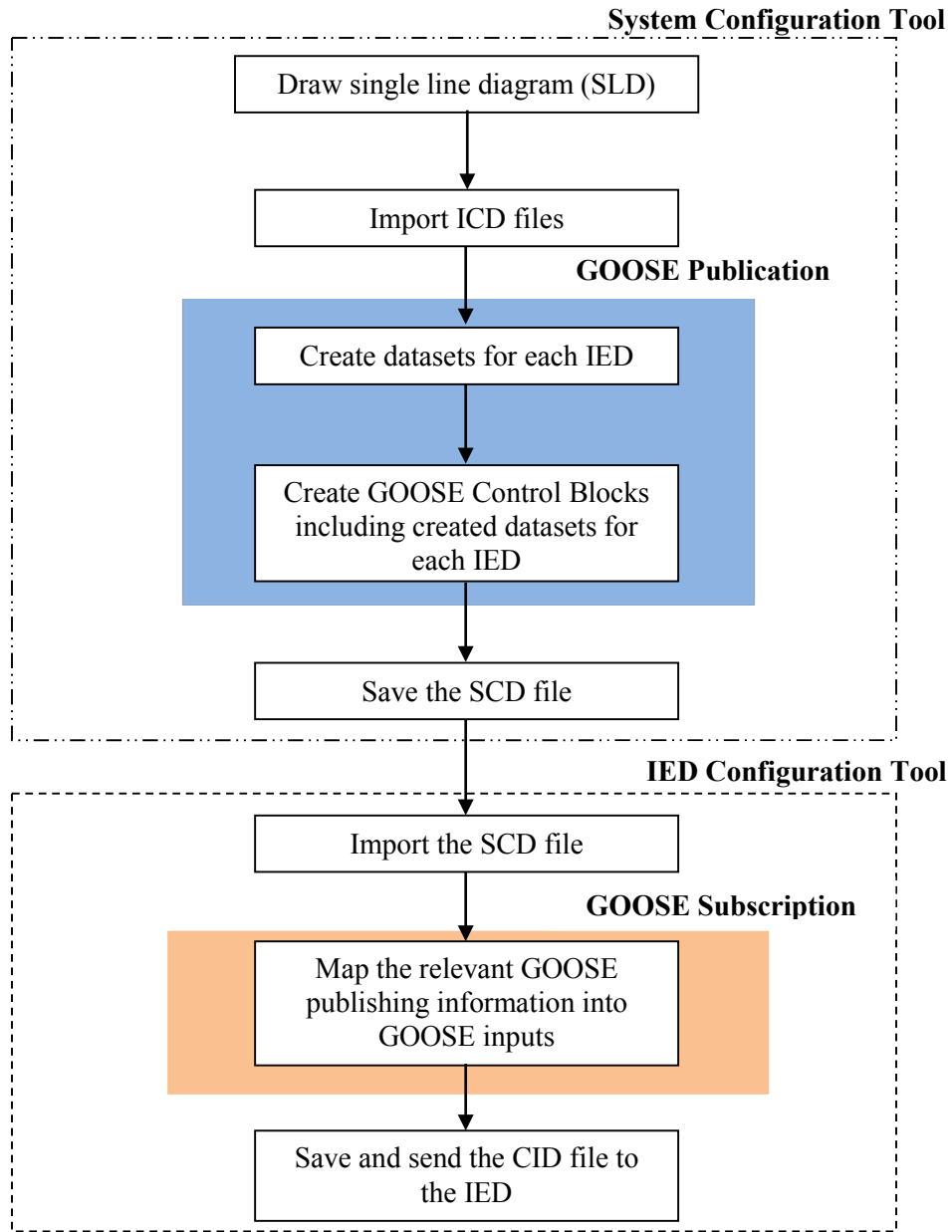


Figure 3-15: Overview of the GOOSE configuration process

In this research, three IED configuration tools and a system configuration tool are used to configure GOOSE communication. They are,

- SCD Editor software developed by RTDS Technologies (IED configuration tool of RTDS).

- ERL 61850 IED Configurator software developed by ERL Phase Power Technologies (IED configuration tool of ERL Phase relays).
- AcSELeRator Architect software developed by Schweitzer Engineering Laboratories (IED configuration tool of SEL relays).
- Kalkitech SCL Manager software developed by Kalkitech Pvt. Ltd (a system configuration tool).

3.5.1 GOOSE Publication Configuration using the System Configuration Tool

When using a system configuration tool, the IEC 61850 engineering process is started with drawing of the single line diagram (SLD) of the electrical substation. The system configuration tool used in this research, allows drawing the SLD of the system starting from scratch. The tool adopts an intuitive object oriented approach consistent with the IEC 61850. First, the substation level is drawn. The power system considered in this research (shown in Figure 3-2) consists of two voltage levels (230 kV and 65.1 kV). These voltage levels are then drawn inside the substation level. Then the bays are drawn inside each voltage levels and the equipment in each bay (CTs, VTs, circuit breakers, disconnectors, etc.) are drawn inside it. An XML code that describes the substation according to SCL syntax is automatically created with the development of the SLD and it can be saved and exported as SSD file. The Figure 3-16 shows the SLD of the substation developed using SCL Manager software.

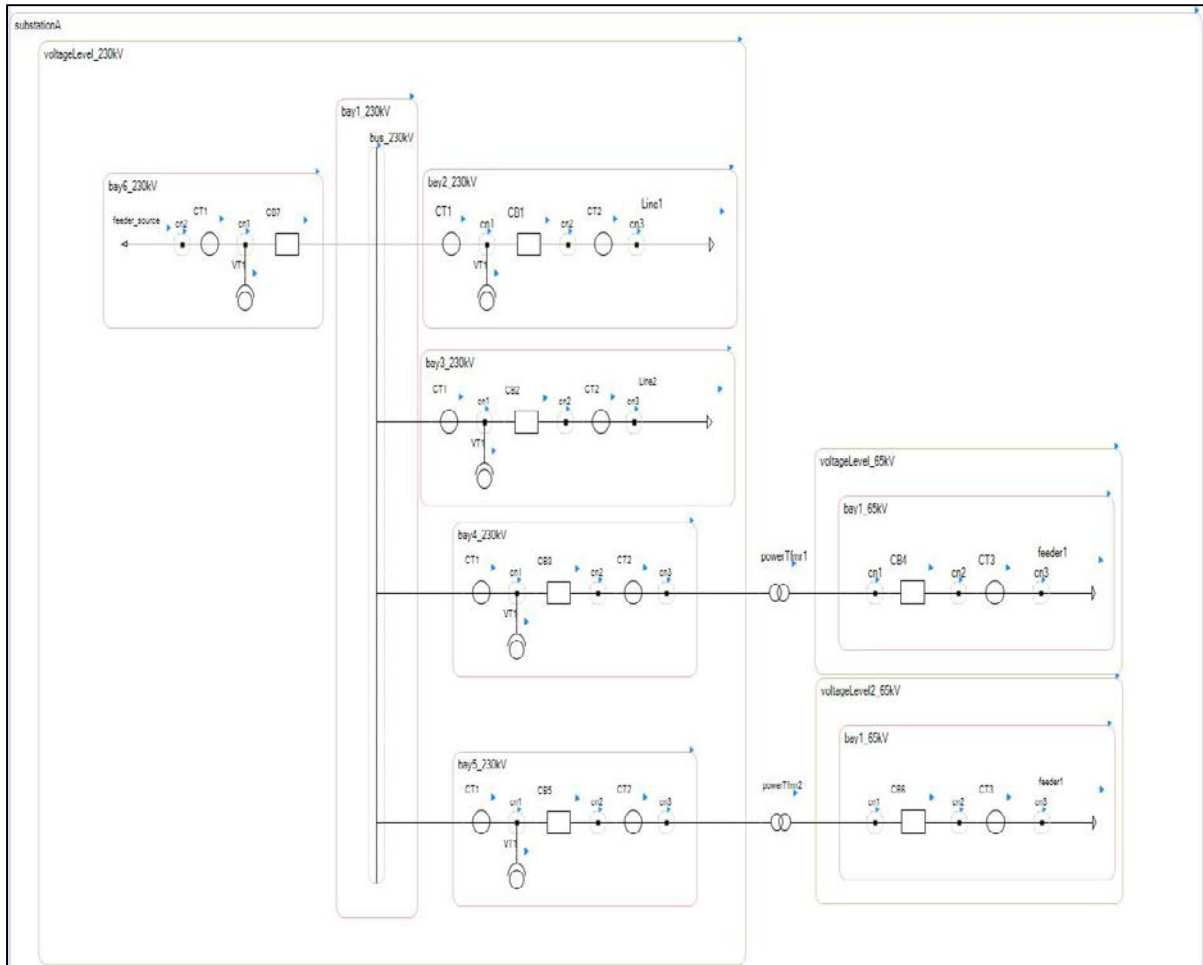


Figure 3-16: Single Line Diagram (SLD) of the substation developed using SCL Manager

Once the SLD is completed, the ICD (IED Capability Description) files of the existing IEDs are imported into the system configuration tool. The ICD files of the IEDs are obtained using three IED configuration tools. IED configuration tool of each vendor comes with a collection of ICD files for all IEC 61850 compliance IEDs manufactured by that vendor. Therefore, the relevant ICD files are imported from each IED configuration tool to the system configuration tool. The basic communication properties of the each IED are required to import the ICD files into the system configuration tool. The communication properties of each relay are shown in Table 3-20.

Table 3-20: Communication Properties of Each relay

	LPRO 4000	TPRO 4000	BPRO 4000	SEL 421	SEL 487E	RTDS
IED name	LPRO_1	TPRO_1	BPRO_1	SEL_421_1	SEL_487E_1	RTDS
IP address	192.168.100.13	192.168.100.12	192.168.100.14	192.168.100.85	192.168.100.86	192.168.100.15
IP - subnet	255.255.255.0					
IP - gateway	192.168.100.1					

Once all the ICD files are imported successfully, the GOOSE publication configuration process of each IED is started. Table 3-21 summarized the publishing information of each relay.

Table 3-21: GOOSE publishing information of each relay

Relay	Publishing information
LPRO 4000	Line 1 distance protection trip signal
TPRO 4000	Transformer 1 differential protection trip signal
BPRO 4000	Bus 1 differential protection trip signal
SEL 421	Line 2 distance protection trip signal
SEL 487E	Transformer 2 differential protection trip signal
RTDS	All breaker statuses (BRK 1 to 7)

The datasets and GOOSE control blocks of each relay are created as described in the following sections to publish the above information as GOOSE messages.

ERL Phase Relays

Initial step is to create datasets by including data objects that are needed to be published. In the simple setup designed in this research, the relay IEDs send only the trip signals to RTDS. As mentioned in the Relay Settings section, all ERL Phase relays can use either protection logical node (PDIS for LPRO 4000 or PDIF for TPRO 4000 and BPRO 4000) or GGIO logical node dedicated to ProLogic (ProLogic is a control statement of ERL Phase relays which can be used to

create Boolean logics [37], [39], [41]) to send GOOSE messages. The dataset information for both these options are shown in Table 3-22, Table 3-23 and Table 3-24 for TPRO 4000, LPRO 4000 and BPRO 4000, respectively. Only Dataset 1 is used in the implementation.

Table 3-22: TPRO 4000 dataset information

	Dataset 1	Dataset 2
Dataset name	dt	tt
Logical device	Protection	System
Dataset items	D87TPDIF1\$ST\$Op\$general	PLGGIO3\$ST\$Ind1\$stVal

Table 3-23: LPRO 4000 dataset information

	Dataset 1	Dataset 2
Dataset name	dl	tl
Logical device	Protection	System
Dataset items	D21P1PDIS1\$ST\$Op\$general	PLGGIO1\$ST\$Ind3\$stVal
	D21P2PDIS2\$ST\$Op\$general	
	D21P3PDIS3\$ST\$Op\$general	
	D21N1PDIS7\$ST\$Op\$general	
	D21N2PDIS8\$ST\$Op\$general	
	D21N3PDIS9\$ST\$Op\$general	

Table 3-24: BPRO 4000 dataset information

	Dataset 1	Dataset 2
Dataset name	db	tb
Logical device	Protection	System
Dataset items	PDIF1\$ST\$Op\$general	GGIO1\$ST\$Ind1\$stVal

The following are the information required to create GOOSE control blocks using the datasets defined in Table 3-22, Table 3-23 and Table 3-24.

Table 3-25: TPRO 4000 GOOSE control block information

	GOOSE control block for dt dataset	GOOSE control block for tt dataset
Control block name	ct	tc
Dataset	Protection.LLN0.dt	System.LLN0.tt
GOOSE ID	gt	tg
Config revision	1	1
Min time	2 ms	2 ms
Max time	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-B4	01-0C-CD-01-01-B4
App ID (0x)	0004	0001
VLAN ID (0x)	000	000
VLAN priority	4	4

Table 3-26: LPRO 4000 GOOSE control block information

	GOOSE control block for dl dataset	GOOSE control block for tl dataset
Control block name	cl	lc
Dataset	Protection.LLN0.dl	System.LLN0.tl
GOOSE ID	gl	lg
Config revision	1	1
Min time	2 ms	2 ms
Max time	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-B5	01-0C-CD-01-01-B5
App ID (0x)	0005	0001
VLAN ID (0x)	000	000
VLAN priority	4	4

Table 3-27: BPRO 4000 GOOSE control block information

	GOOSE control block for db dataset	GOOSE control block for tb dataset
Control block name	cb	tb
Dataset	Protection.LLN0.db	System.LLN0.tb
GOOSE ID	gb	tb
Config revision	1	1
Min time	2 ms	2 ms
Max time	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-A6	01-0C-CD-01-01-A6
App ID (0x)	0004	0001
VLAN ID (0x)	000	000
VLAN priority	4	4

SEL Relays

Again, datasets are created by including data objects that are needed to be published. As mentioned before, SEL 421 relay in the laboratory is an older version and it is only capable of publishing GGIO logical node dedicated to communication card outputs (CCOUT) as GOOSE. But SEL 487E relay is capable of publishing PDIF differential protection logical node as well as GGIO logical node dedicated to output contacts. Table 3-28 and Table 3-29 show the dataset information of SEL 421 and SEL 487E relays, respectively. Only Dataset 1 of SEL 487E relay is used in the implementation.

Table 3-28: SEL 421 dataset information

	Dataset 1
Dataset name	d2
Logical device	ANN
Dataset items	CCOUTGGIO21.ST.Ind01.stVal

Table 3-29: SEL 487E dataset information

	Dataset 1	Dataset 2
Dataset name	d8	o8
Logical device	PRO	ANN
Dataset items	D87RPDIF1.ST.Op.general D87UPDIF1.ST.Op.general	OUT1GGIO17.ST.Ind01.stVal

The following are the information required to create GOOSE control blocks for the datasets given in Table 3-28 and Table 3-29.

Table 3-30: SEL 421 GOOSE control block information

	GOOSE control block for d2 dataset
Control block name	c2
Dataset	CFG.LLN0.d2
GOOSE ID	g2
Config revision	1
Max time	2000 ms
Multicast MAC address	01-0C-CD-01-01-B1
App ID (0x)	0001
VLAN ID (0x)	000
VLAN priority	4

Table 3-31: SEL 487E GOOSE control block information

	GOOSE control block for d8 dataset	GOOSE control block for o8 dataset
Control block name	c8	m8
Dataset	CFG.LLN0.d8	CFG.LLN0.o8
GOOSE ID	g8	i8
Config revision	1	1
Max time	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-B2	01-0C-CD-01-01-B2
App ID	0x0002	0x0001
VLAN ID	0x000	0x000
VLAN priority	4	4

RTDS

The RTDS is only capable of publishing GGIO logical node dedicated to its outputs as GOOSE messages. Table 3-32 shows the dataset information and Table 3-33 shows the GOOSE control block information of the RTDS.

Once all the datasets and GOOSE control blocks are created, the complete file is saved and it is referred to as the SCD (Substation Configuration Description) file of the substation.

Table 3-32: RTDS dataset information

	Dataset 1
Dataset name	GOOSE_outputs_1
Logical device	CTRL
Dataset items	OUT_GGIO1\$ST\$Ind\$stVal
	OUT_GGIO2\$ST\$Ind\$stVal
	OUT_GGIO3\$ST\$Ind\$stVal
	OUT_GGIO4\$ST\$Ind\$stVal
	OUT_GGIO5\$ST\$Ind\$stVal
	OUT_GGIO6\$ST\$Ind\$stVal
	OUT_GGIO7\$ST\$Ind\$stVal

Table 3-33: RTDS GOOSE control block information

	GOOSE control block for GOOSE_outputs_1 dataset
Control block name	Gcb01
Dataset	GOOSE_outputs_1
GOOSE ID	1
Config revision	1
Max time	2000 ms
Multicast MAC address	01-0C-CD-01-01-B3
App ID (0x)	0001
VLAN ID (0x)	000
VLAN priority	4

3.5.2 GOOSE Subscription Configuration using the IED

Configuration Tools

ERL Phase Relays

ERL 61850 IED configurator software is used to configure GOOSE subscription of ERL Phase relays. Initially, the SCD file created by the system configuration tool is imported to the ERL 61850 IED configurator software. From the SCD file, the RTDS IED is added to the project editor along with LPRO 4000, TPRO 4000 and BPRO 4000 IEDs.

The ERL Phase relays only have one subscriber logical node which is a GGIO (Generic Input/Output). This logical node has 30 logical data objects which is capable of subscribing 30 binary GOOSE inputs [37], [39], [41]. These are called virtual inputs. GOOSE subscription mapping of each ERL phase relay relevant to this setup is shown in Table 3-34.

Table 3-34: GOOSE subscription mapping of ERL Phase relays

LPRO 4000	
Virtual Input 1 (VI01)	RTDS output 1
TPRO 4000	
Virtual Input 1 (VI01)	RTDS output 3
Virtual Input 2 (VI02)	RTDS output 4
BPRO 4000	
Virtual Input 1 (VI01)	RTDS output 1
Virtual Input 2 (VI02)	RTDS output 2
Virtual Input 3 (VI03)	RTDS output 3
Virtual Input 4 (VI04)	RTDS output 5
Virtual Input 5 (VI05)	RTDS output 7

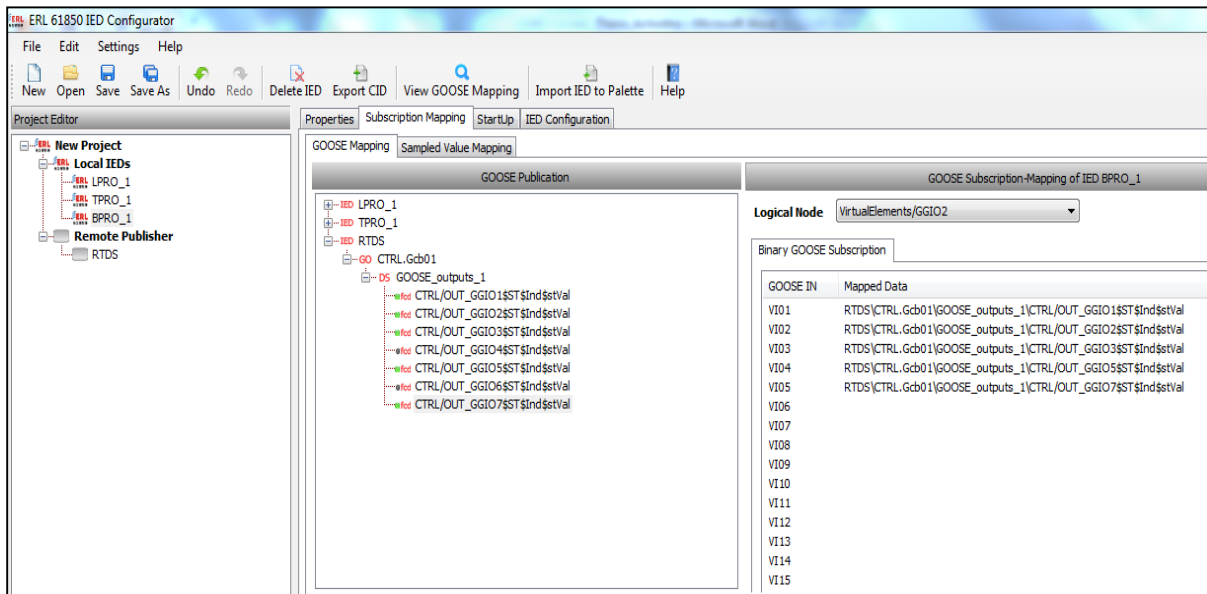
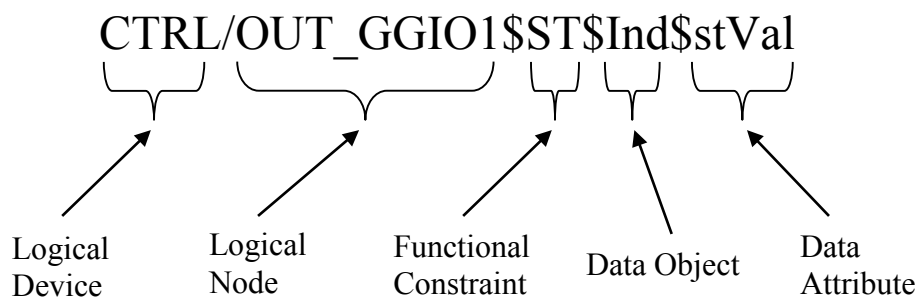


Figure 3-17: BPRO 4000 GOOSE subscription mapping using ERL 61850 IEC configuration tool

Figure 3-17 shows the GOOSE subscription mapping of BPRO 4000 relay. The GOOSE publication tab in the middle shows the GOOSE publishing IEDs available for BPRO 4000 to

subscribe. When an IED is expanded in the tree view in GOOSE publication tab, first it shows the GOOSE control blocks in that IED (ex: CTRL.Gcb01). The ‘CTRL’ is the logical device name and ‘Gcb01’ is the GOOSE control block name of the RTDS IED. Inside the GOOSE control block is the dataset that is included in the GOOSE control block (ex: GOOSE_outputs_1). Inside the dataset is the functionally constrained data attribute (FCDA) information included in that dataset. An FCDA contains following information.



In the GOOSE Subscription tab, ERL 61850 IED Configurator shows the subscribing logical node of the BPRO 4000. It also displays the complete information (i.e. IED name, GOOSE control block name, dataset name, logical device name, logical node, functional constraint, data object and data attribute) of the mapped data, in front of the GOOSE input.

SEL Relays

AcSELERator Architect software is used to configure GOOSE communication of SEL relays. As in the case of ERL Phase IED configurator tool, the SCD file is imported to the AcSELERator Architect and then, the RTDS, SEL 421 and SEL 487E IEDs are added to the project editor. SEL 421-3 relay has 128 binary inputs which can be used to map incoming binary GOOSE data [38]. SEL 487E-4 relay has 128 binary inputs and 256 analog inputs [40]. GOOSE subscription mapping of each SEL relay with RTDS is shown in Table 3-35.

Table 3-35: GOOSE subscription mapping of SEL relays

SEL 421	
Control Input 1 (CCIN001)	RTDS output 2
SEL 487E	
Control Input 1 (VB001)	RTDS output 5
Control Input 2 (VB002)	RTDS output 6

AcSElerator Architect software displays similar information as ERL 61850 IED Configurator about GOOSE publishing IEDs and mapped data.

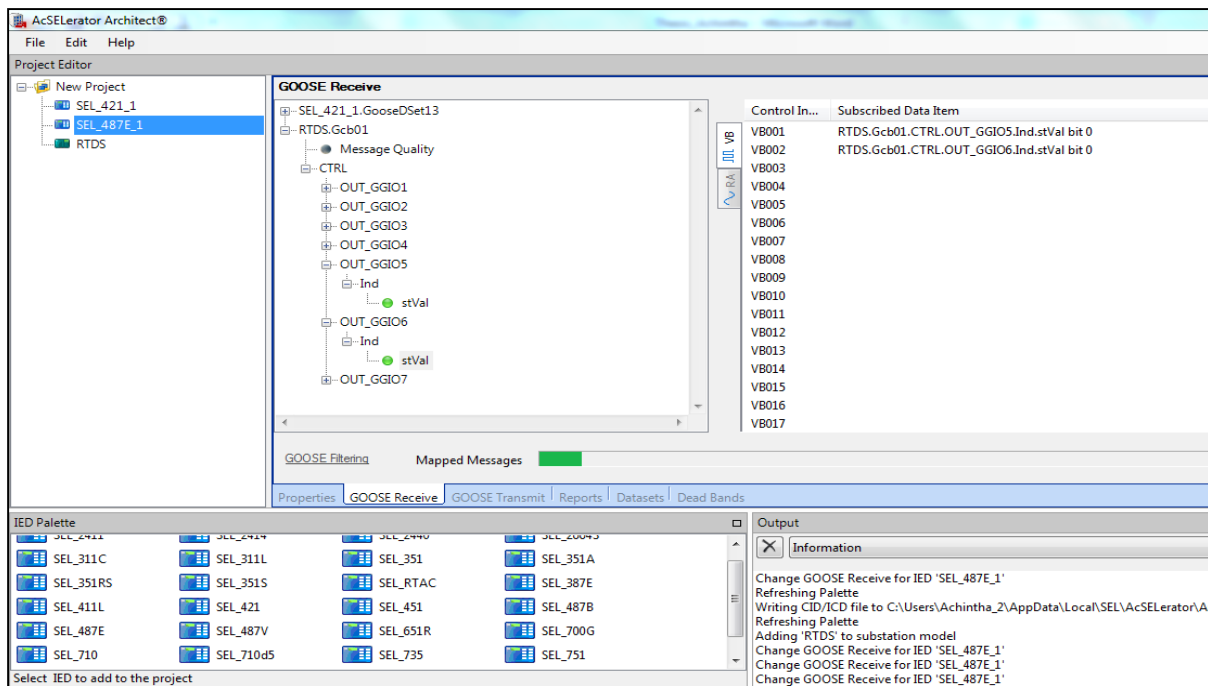


Figure 3-18: SEL 487E GOOSE subscription mapping

RTDS

The SCD file from the system configuration tool is imported to the RTDS SCD Editor. A GTNET-GSE component is capable of subscribing 32 GOOSE inputs plus associated quality bitmaps. Additional 32 binary GOOSE points can be received if the quality bitmap is not required [42].

GOOSE subscription mapping of RTDS relevant to this research is shown below. Table 3-36 shows subscription mapping of RTDS when relays’ protection logical nodes (PDIS or PDIF) are used as inputs whereas Table 3-37 shows subscription mapping of RTDS when relays’ GGIO logical nodes (ProLogic or communication card outputs) are used as inputs.

Table 3-36: GOOSE subscription mapping of RTDS when relays’ protection logical nodes are used as inputs

GOOSE Input	Mapped Data
Input 01 to GTNET	LPRO_1.Protection.D21P1PDIS1.Op.general
Input 02 to GTNET	LPRO_1.Protection.D21P2PDIS2.Op.general
Input 03 to GTNET	LPRO_1.Protection.D21P3PDIS3.Op.general
Input 04 to GTNET	LPRO_1.Protection.D21N1PDIS7.Op.general
Input 05 to GTNET	LPRO_1.Protection.D21N2PDIS8.Op.general
Input 06 to GTNET	LPRO_1.Protection.D21N3PDIS9.Op.general
Input 07 to GTNET	SEL_421_1.ANN.CCOUTGGIO21.Ind01.stVal
Input 08 to GTNET	TPRO_1.Protection.D87TPDIF1.Op.general
Input 09 to GTNET	SEL_487E_1.PRO.D87RPDIF1.Op.general
Input 10 to GTNET	SEL_487E_1.PRO.D87UPDIF1.Op.general
Input 11 to GTNET	BPRO_1.Protection.PDIF1.Op.general

Table 3-37: GOOSE subscription mapping of RTDS when relays’ GGIO logical nodes are used as inputs

GOOSE Input	Mapped Data
Input 01 to GTNET	LPRO_1.System.PLGGIO1.Ind3.stVal
Input 02 to GTNET	SEL_421_1.ANN.CCOUTGGIO21.Ind01.stVal
Input 03 to GTNET	TPRO_1.System.PLGGIO3.Ind1.stVal
Input 04 to GTNET	SEL_487E_1.ANN.OUT1GGIO17.Ind01.stVal
Input 05 to GTNET	BPRO_1.System.GGIO3.Ind1.stVal

Figure 3-19 shows the GOOSE subscription mapping of RTDS when relay’s protection logical nodes are used as inputs. The bottom left corner window shows RTDS IED and all the imported IEDs. When an IED is extracted, it shows the GOOSE control blocks in that IED. Inside a GOOSE control block is the dataset that is included in that GOOSE control block. Inside the dataset is the FCDA information includes in that dataset.

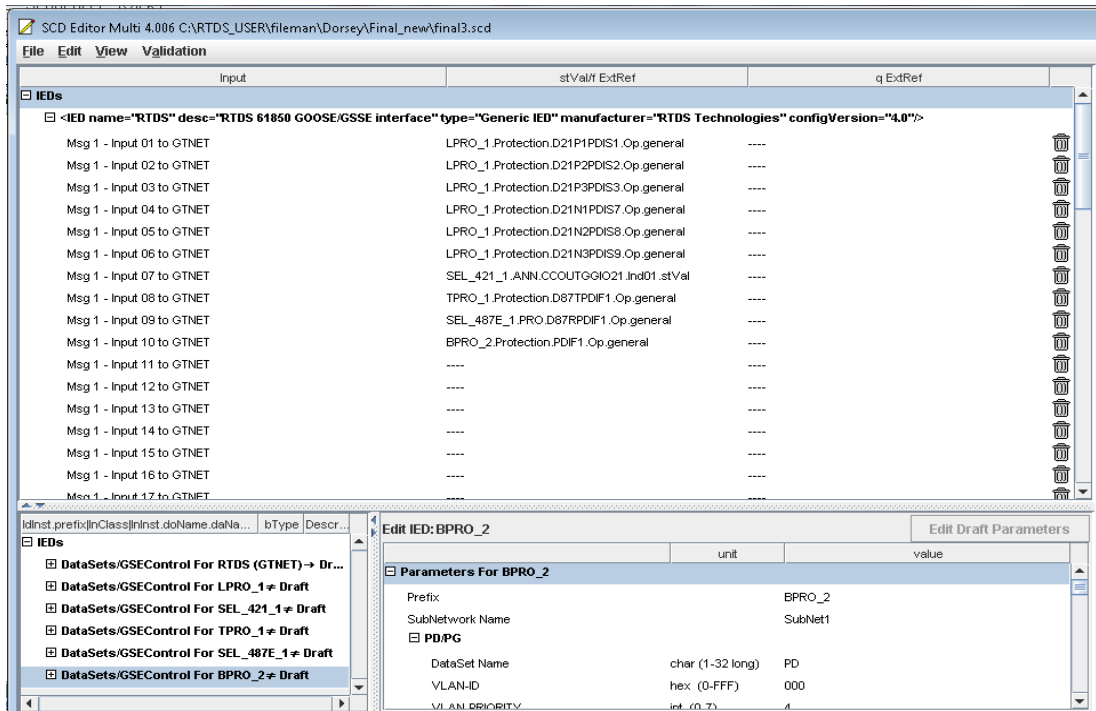


Figure 3-19: GOOSE subscription mapping of RTDS

When an IED is selected in the bottom left corner window, all the GOOSE control blocks' information of that selected IED are displayed in the bottom right window. The top window shows the RTDS subscription mapping information.

3.6 Performance Testing

3.6.1 Verification of GOOSE and Relay Configuration

This section discusses the test that performed to verify the GOOSE configuration of the complete laboratory setup. Wireshark software is used as a tool to conduct the test. Wireshark is a network protocol analyzer that is capable of inspect hundreds of protocols including GOOSE messages. Also, it is capable of reading live data from Ethernet [43]. This software is used to inspect GOOSE messages at steady state condition as well as at fault conditions.

Steady State Condition

The complete laboratory setup is connected as shown in Figure 3-1 and the power system is simulated in RTDS simulator. RSCAD (RTDS simulator software) running on a personal computer (PC) is used to setup the simulation, interact with the simulation during run-time, and to monitor the simulated system through waveform plots and meters. The Wireshark software is also installed in the PC and it is configured to capture GOOSE messages from the local area network (LAN). Figure 3-20 shows screen shot of the Wireshark software that captures the GOOSE messages of the network at steady state condition.

Time	Source	Destination	Protocol	Length	Info
1	0.00000000	Schweitz_06:4b:7f	Iec-Tc57_01:01:b2	GOOSE	116
2	0.00975500	RtdsTech_05:dc	Iec-Tc57_01:01:b3	GOOSE	146
3	0.05108200	Schweitz_00:f7:fa	Iec-Tc57_01:01:b1	GOOSE	116
4	0.14521700	Er1phase_01:0d:85	Iec-Tc57_01:01:b4	GOOSE	113
5	0.50651800	Schweitz_06:4b:7f	Iec-Tc57_01:01:b2	GOOSE	116
6	0.50976800	RtdsTech_05:dc	Iec-Tc57_01:01:b3	GOOSE	146
7	0.52861900	Er1phase_01:0d:87	Iec-Tc57_01:01:a6	GOOSE	446
8	0.52900300	Er1phase_01:0d:87	Iec-Tc57_01:00:01	GOOSE	789
9	0.66231700	Schweitz_00:f7:fa	Iec-Tc57_01:01:b1	GOOSE	114
10	0.67816600	Er1phase_01:0d:83	Iec-Tc57_01:01:b5	GOOSE	136
11	0.67817100	Er1phase_01:0d:83	Iec-Tc57_01:01:b5	GOOSE	121

Figure 3-20: GOOSE packets captured by Wireshark software at steady state condition

From the Figure 3-20, it can be seen that the Wireshark software had captured GOOSE packets from RTDS and all the relays in the setup. But this cannot verify the GOOSE configuration. It is important to verify the information inside those GOOSE packets to see whether it includes all the information. Wireshark software is also capable of displaying the information of a GOOSE packet. Figure 3-21 shows the information of a LPRO 4000 relay's GOOSE packet.

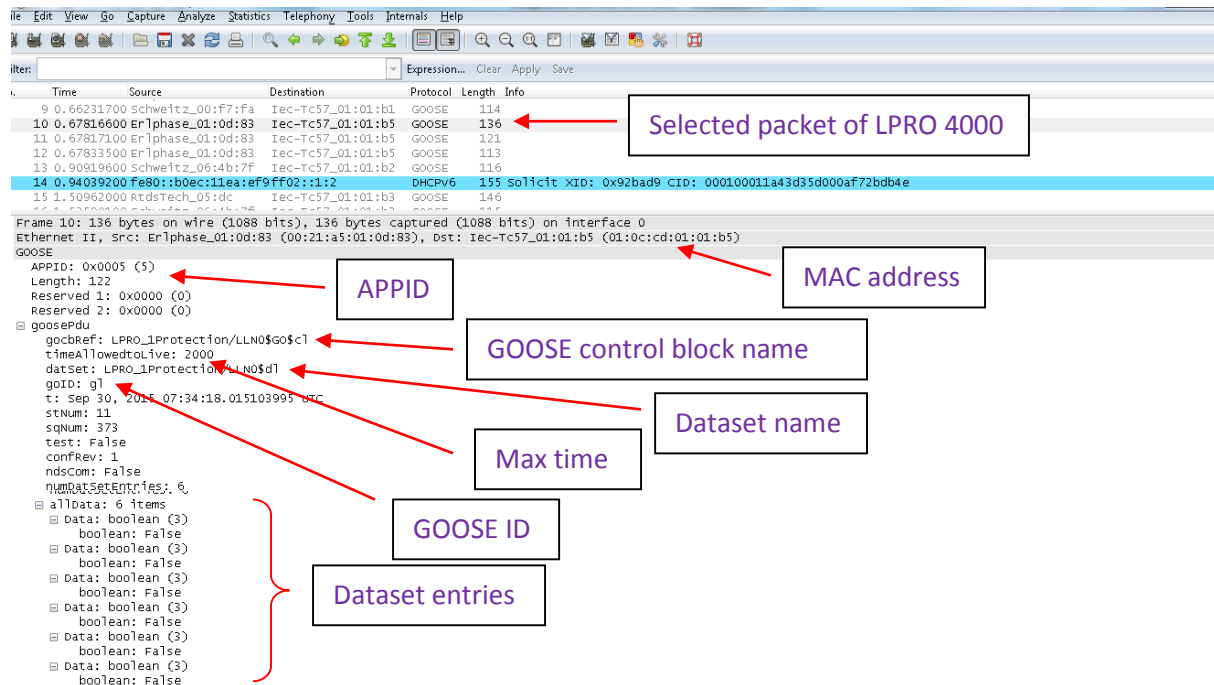


Figure 3-21: GOOSE packet information captured by Wireshark software

The information captured by the Wireshark software exactly matches with the information from Table 3-26. Dataset entries in this GOOSE packet represent the phase and ground trip signals of three zones. As it is in steady state condition and there is no fault in the system, their values are Boolean false. GOOSE packets of other relays were checked and all of them matched with their respective information. This verifies that the setup is properly configured and working accurately at steady state condition.

At a Fault condition

Figure 3-22 shows a screen shot of the Wireshark software that captures the GOOSE messages of the network when a zone 1 phase-to-phase fault (AB fault) is applied in line 1 (20 km away from bus bar).

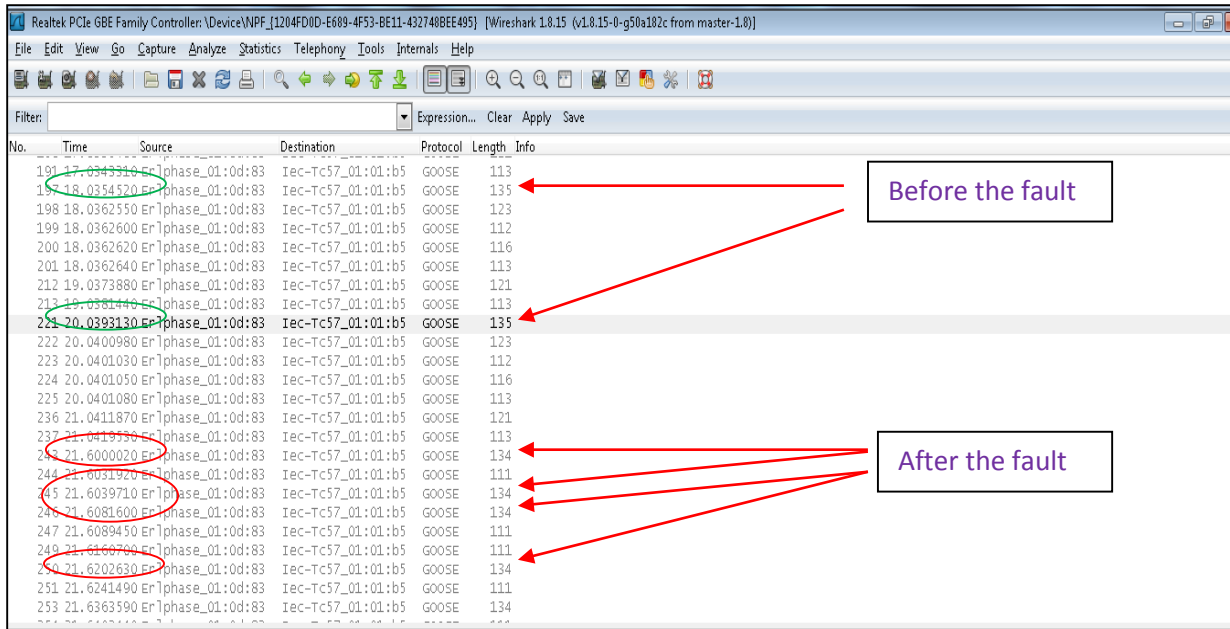


Figure 3-22: GOOSE packets captured by Wireshark software at a fault condition

In Figure 3-22, the arrows are pointed at a GOOSE control block that publishes same dataset of LPRO 4000 relay. It can be seen that before the fault, the GOOSE transmission process had come to stable transmission region where the transmission time between two GOOSE messages is its max time which is 2 seconds (green circles display the times). But after the fault, GOOSE retransmission process has become faster (red circles display the time). The time between two GOOSE messages increases until it reaches the maximum time. This proves the GOOSE transmission process mentioned in chapter 2 and that an event change has happened in the system. Also, because the event change has only changed the GOOSE transmission time of LPRO relay's GOOSE messages, event change can probably be a line fault in Line 1.

Figure 3-23 and Figure 3-24 show the information of two LPRO 4000 relay's GOOSE messages before and after a fault respectively.

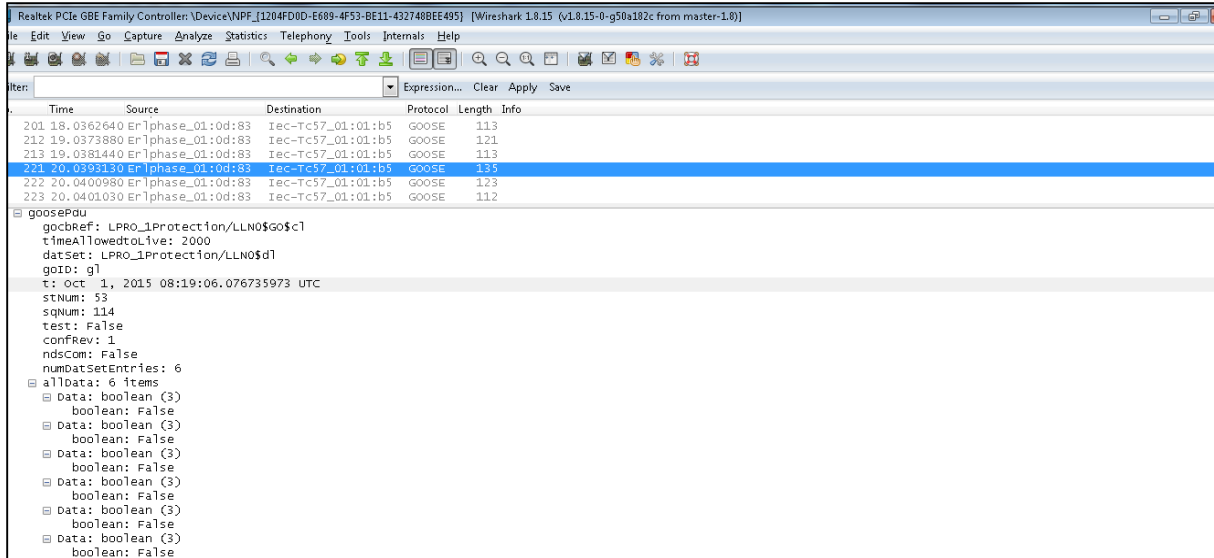


Figure 3-23: GOOSE packet information before the fault captured by Wireshark software

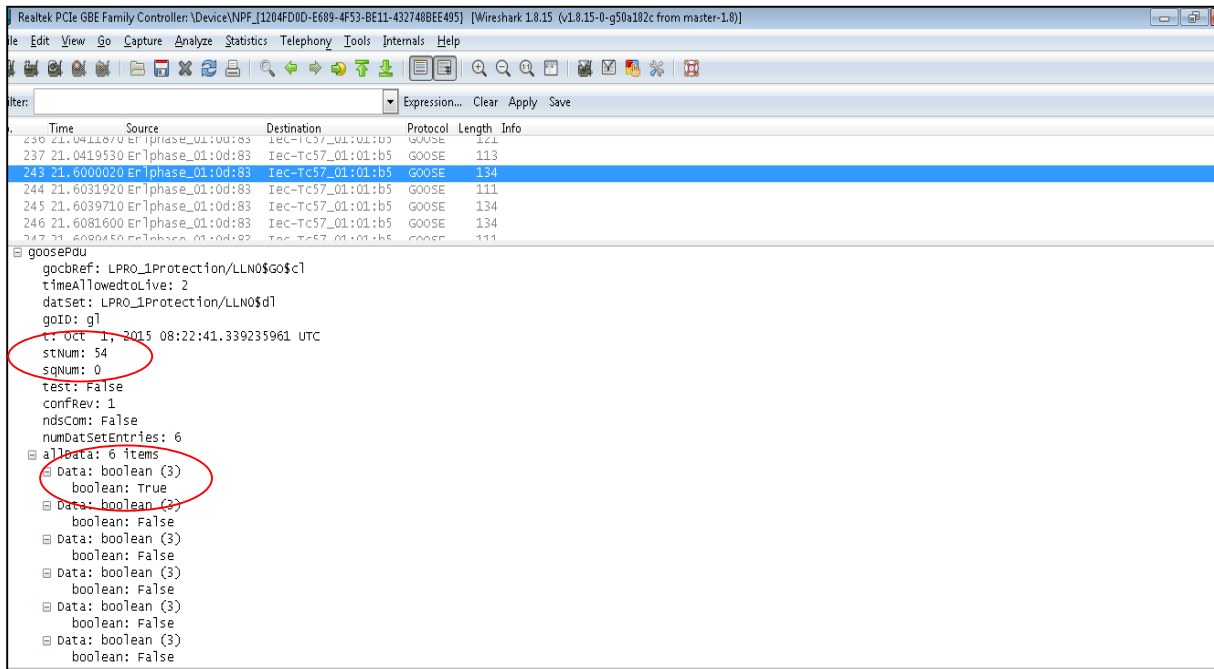


Figure 3-24: GOOSE packet information after the fault captured by Wireshark software

Compare with the Figure 3-23, it can be seen that in Figure 3-24, the “stNum” has increased by 1. This confirms an event change. Also, “sqNum” equals to zero means that this is the first GOOSE message after the fault related to “cl” GOOSE control block (“dl” dataset). Also, it can be seen from Figure 3-24 that first data entry has changed its value to true. According to Table 3-23, the first dataset entry of the “dl” dataset is “D21P1PDIS1\$ST\$Op” which represents the

phase element trip of zone 1. Therefore, from these information, it can be concluded that LPRO 4000 relay has detected a zone 1 fault in line 1 (phase-to-phase or three phase fault) and has issued a trip signal to RTDS. The LPRO 4000 relay event file confirmed that the relay has detected an AB fault and fault is located at 19.9 km away from the bus bar. Similarly, faults are applied to each transmission line, each of the transformers (internal fault) and the bus bar. Each relay detected the faults in its protected region and issued trip signals to RTDS. The information obtained using Wireshark software and relay event files are perfectly matched with the expected information. This verifies that the setup is properly configured (both relay settings and GOOSE configuration) and working accurately for all conditions.

3.6.2 Performance Comparison of GOOSE and Hardwired Communication

This section discusses results of the system conducted to test the speed of the GOOSE messages compared with the traditional hardwired connection. As mentioned earlier, all the relays in the setup are arranged to send the trip signal in two methods. One is to use the GOOSE messages and other is to use the hardwired connection. Timers are used in the RTDS simulator to measure the operating time of both methods. All together 10 timers are implemented in RTDS, two timer for each relay. When a fault is applied in RTDS, the two timers of the relay that is protecting the faulted area will be started and once the trip signal is received through GOOSE messages, one timer will be stopped and when the trip signal is received through hardwires connection, the other timer will be stopped. Table 3-38 shows the measured time of the LPRO 4000 relay for zone 1 faults.

Table 3-38: Comparison between GOOSE and hardwired trip signals of LPRO 4000 relay for zone 1 faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS (in ms)

Fault type	10% away from the 230 kV bus bar		30% away from the 230 kV bus bar		50% away from the 230 kV bus bar		70% away from the 230 kV bus bar	
	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired
AG	11.9	14.15	13.15	15.60	17.10	18.80	20.25	21.95
BG	9.10	11.60	12.45	14.20	17.15	19.55	18.55	20.15
CG	12.55	14.90	15.15	17.55	17.15	18.90	22.75	24.50
AB	16.75	19.00	19.50	21.75	21.90	24.10	24.80	26.95
BC	20.10	22.25	20.05	22.40	22.15	24.35	29.25	31.40
CA	18.85	21.10	21.20	23.45	24.75	27.00	27.40	29.55
ABC	17.15	19.40	19.50	21.75	23.25	25.10	25.55	27.70

It can be seen that for all the faults in zone 1, GOOSE trip signals were faster than the hardwired trip signals. Time increased with the distance of the fault from the bus bar because of the fault detection time of the relay changes with the location. Similar results are observed with the zone 2 and zone 3 (reverse) faults. The results are shown in Table 3-39. Note that to obtain the zone 3 results, the BPRO 4000 relay had to be removed from the system because the faults were applied in the 230 kV bus bar.

Table 3-39: Comparison between GOOSE and hardwired trip signals of LPRO 4000 relay for zone 2 and 3 faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS

Fault type	Zone 2 (in ms)				Zone 3 (reverse) (in seconds)	
	90% away from the 230 kV bus bar		95% away from the 230 kV bus bar			
	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired
AG	350.40	353.35	350.20	351.85	1.0203	1.0214
BG	347.25	349.30	346.90	349.05	1.0201	1.0212
CG	347.95	349.80	349.70	351.60	1.0202	1.0214
AB	350.80	351.50	352.25	353.20	1.0180	1.0190
BC	350.75	351.75	350.45	351.35	1.0204	1.0214
CA	353.05	354.00	354.75	355.70	1.0207	1.0216
ABC	351.15	352.05	350.80	351.75	1.0188	1.0197

Table 3-40 and Table 3-41 show the comparison between GOOSE and hardwired trip signals of

SEL 421 relay.

Table 3-40: Comparison between GOOSE and hardwired trip signals of SEL 421 relay for zone 1 faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS (in ms)

Fault type	10% away from the 230 kV bus bar		30% away from the 230 kV bus bar		50% away from the 230 kV bus bar		70% away from the 230 kV bus bar	
	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired
AG	10.30	11.40	12.05	13.20	12.05	13.20	23.30	24.45
BG	8.40	9.60	10.30	11.50	14.20	15.30	24.05	25.15
CG	13.00	14.20	12.75	13.80	14.50	15.75	26.20	27.35
AB	9.00	10.15	10.75	11.90	12.55	13.80	22.20	23.25
BC	13.85	15.05	13.60	14.55	15.15	16.35	26.50	27.70
CA	12.10	13.20	13.45	14.70	13.45	14.40	24.60	25.75
ABC	10.25	11.25	11.55	12.75	11.40	12.50	22.85	23.90

Table 3-41: Comparison between GOOSE and hardwired trip signals of SEL 421 relay for zone 2 and 3 faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS

Fault type	Zone 2 (in ms)				Zone 3 (reverse) (in seconds)	
	90% away from the 230 kV bus bar		95% away from the 230 kV bus bar			
	GOOSE	Hardwired	GOOSE	Hardwired	GOOSE	Hardwired
AG	345.40	346.50	346.20	347.35	1.0129	1.0141
BG	347.80	348.90	346.50	347.50	1.0136	1.0147
CG	347.90	349.00	346.45	347.60	1.0137	1.0149
AB	343.80	345.05	344.50	345.70	1.0118	1.0129
BC	348.00	349.15	346.75	347.90	1.0141	1.0152
CA	346.00	347.20	346.90	348.05	1.0142	1.0152
ABC	344.05	345.20	344.90	346.05	1.0122	1.0134

Similar as the LPRO 4000 and SEL 421 relays, the TPRO 4000, SEL 487E and BPRO 4000 relays' GOOSE trip signals were faster than the hardwired trip signals. Table 3-42, Table 3-43 and Table 3-44 show the comparison between GOOSE and hardwired trip signals of TPRO 4000, SEL 487E and BPRO 4000 relays respectively.

Table 3-42: Comparison between GOOSE and hardwired trip signals of TPRO 4000 relay for transformer internal faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS (in ms)

Fault type	GOOSE	Hardwired
AG	10.95	13.05
BG	11.30	13.95
CG	14.25	15.80
AB	9.60	11.85
BC	14.25	16.30
CA	12.25	15.00
ABC	9.45	11.50

Table 3-43: Comparison between GOOSE and hardwired trip signals of SEL 487E relay for transformer internal faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS (in ms)

Fault type	GOOSE	Hardwired
AG	16.05	17.65
BG	13.80	15.30
CG	13.30	14.90
AB	9.05	10.55
BC	12.80	14.35
CA	12.35	13.90
ABC	9.70	11.25

Table 3-44: Comparison between GOOSE and hardwired trip signals of BPRO 4000 relay for bus faults by measuring time elapsed from the application of the fault to the arrival of the trip signal in RTDS (in ms)

Fault type	GOOSE	Hardwired
AG	12.60	13.20
BG	9.90	10.15
CG	14.90	15.80
AB	13.95	15.05
BC	10.70	11.95
CA	12.45	13.45
ABC	11.75	12.90

3.6.3 GOOSE Round Trip Time

The GOOSE round trip time measured using the event files generated from each of the five relays. When a relay detects a fault in its protected area, it issues a trip signal. This trip signal is transmitted as a GOOSE message to RTDS. Once the RTDS receives the GOOSE message, it opens the circuit breaker. In simulation, a delay of three cycles (50 milliseconds) is used to open each breaker after the RTDS receives the relevant trip signal to represent the circuit breaker interrupting time. The updated circuit breaker status is sent to the relay through GOOSE messages. The time a relay issues a trip signal and the time it receives the circuit breaker status through GOOSE message can be discovered using that relay's event file. Taking the difference of the two time stamps and subtracting 50 milliseconds from it, gives the GOOSE round trip time. For example, an event file of the TPRO 4000 relay for CA fault is shown in Figure 3-25.

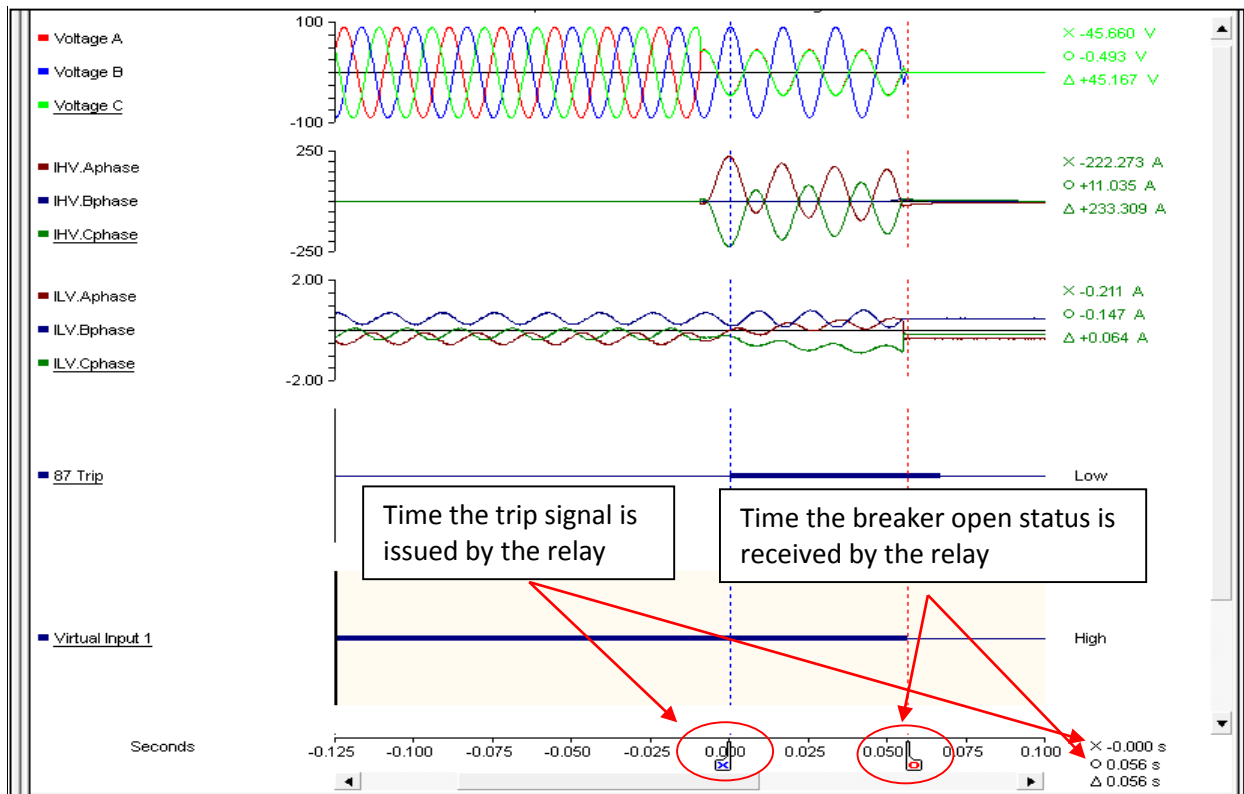


Figure 3-25: Event file of TPRO 4000 relay for CA fault

The blue vertical dotted line of Figure 3-25 represents the starting time of the 87 trip signal whereas the red dotted line shows the breaker status changing point from close to open. According to the TPRO 4000 event file above, it issued the 87 trip signal at 0.000 seconds and received the circuit breaker change signal at 0.056 seconds. If the 50 millisecond of circuit breaker interrupting time is subtracted from the difference of these two times, it can be concluded that the GOOSE round trip time is 6 milliseconds (also assuming the RTDS other application time is negligible). Similar tests were conducted using other relays and the summary of the results obtained using their event files are shown in Table 3-45.

Table 3-45: GOOSE round trip times of the system

	Time between the issue of trip signal and the circuit breaker change(ms)	GOOSE round trip time (ms)	GOOSE round trip time/2 (ms)
LPRO 4000	56.00	6.00	3.00
SEL 421	56.00	6.00	3.00
TPRO 4000	56.00	6.00	3.00
SEL 487E	56.00	6.00	3.00
BPRO 4000	58.00	8.00	4.00

These test results give GOOSE round trip time and dividing it by two, the GOOSE transfer time can be approximately estimated. Except for the case of BPRO 4000, estimated approximate GOOSE transfer time is 3 milliseconds, which meets the criteria in the first edition of the IEC 61850 standard. But the above values are obtained assuming that the other application times are negligible. But to measure the exact GOOSE transfer time, more tests were conducted and those are explained in the next section.

3.6.4 GOOSE Transfer Time

According to the IEC 61850 – 5, the GOOSE transfer time starts when the publisher IED starts the communication process of the data and the GOOSE transfer time finishes when the subscriber IED finishes the communication process of the data [7], [22], [44], [45]. GOOSE transfer time definition of the standard is shown in Figure 3-26 [7].

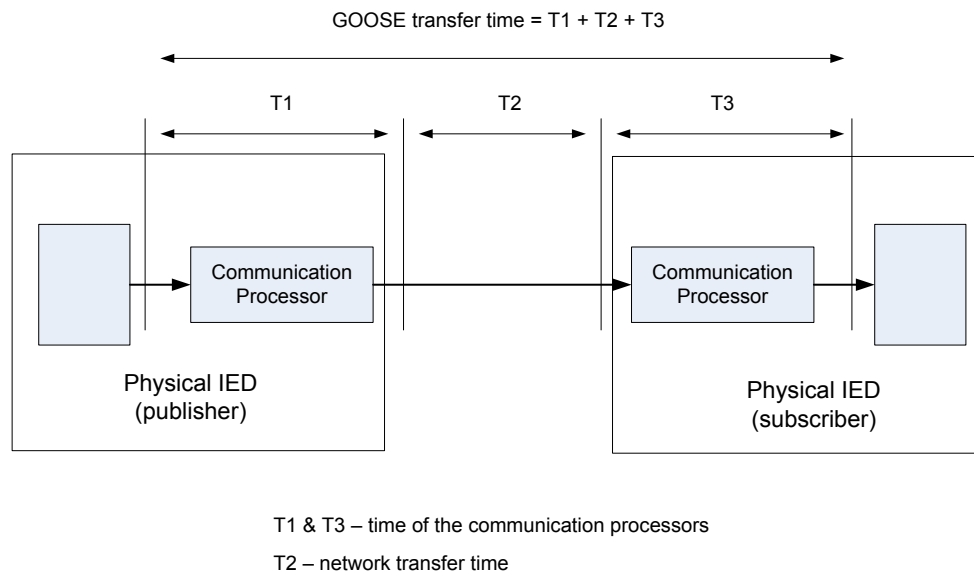


Figure 3-26: Definition of transfer time from IEC 61850-5 [7]

As mentioned before, all the devices in the setup are connected to a satellite synchronized clock. Therefore, all the devices are time synchronized. To measure the exact transfer time of the GOOSE messages, the following procedure is used.

First, from relay's event file, the time stamp of the trip signal issued is acquired. The trip signal issued time can be considered the time that relay starts its communication process of the GOOSE message. Then, in the RTDS, the time stamp when the GOOSE message changed the RTDS internal variable that is assigned to the trip signal is obtained. The time RTDS changes its internal variable relevant to GOOSE trip signal can be considered the time that RTDS finishes its

communication process of the GOOSE message. The time difference between two time stamps is the GOOSE transfer time from the relay to RTDS.

The histogram shown in Figure 3-27 shows the results obtained by applying 100 faults for the protected region of each relay.

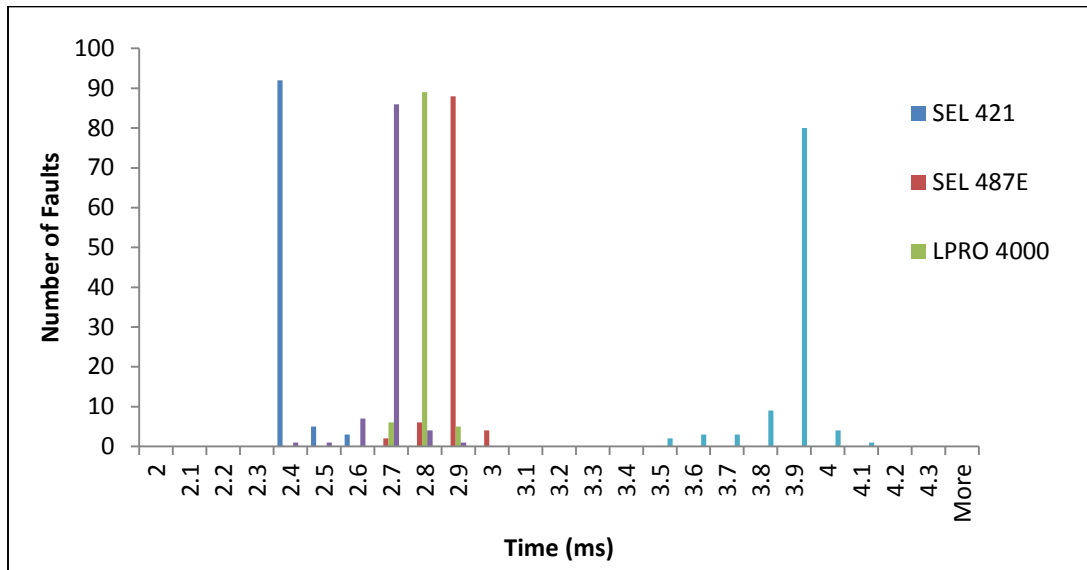


Figure 3-27: GOOSE transfer time from relays to RTDS

From Figure 3-27, it can be seen that all the GOOSE messages from SEL 421, SEL 487E, LPRO 4000 and TPRO 4000 relays are received by RTDS in less than 3 milliseconds which is the GOOSE message transfer time requirement for a Performance Class P2/3 trip signal. Performance class P2 is for transmission bay and Performance class P3 is for transmission bay with top performance synchronizing feature and breaker differential [7], [44]. The BPRO 4000 relay's GOOSE messages take around 3.9 milliseconds to reach RTDS.

Similarly, the time stamp of the breaker opening in RTDS and the time stamp when the GOOSE message changed the relevant relay's internal variable that is assigned to the breaker status are obtained. The time difference between two time stamps is the GOOSE transfer time from RTDS to the relay.

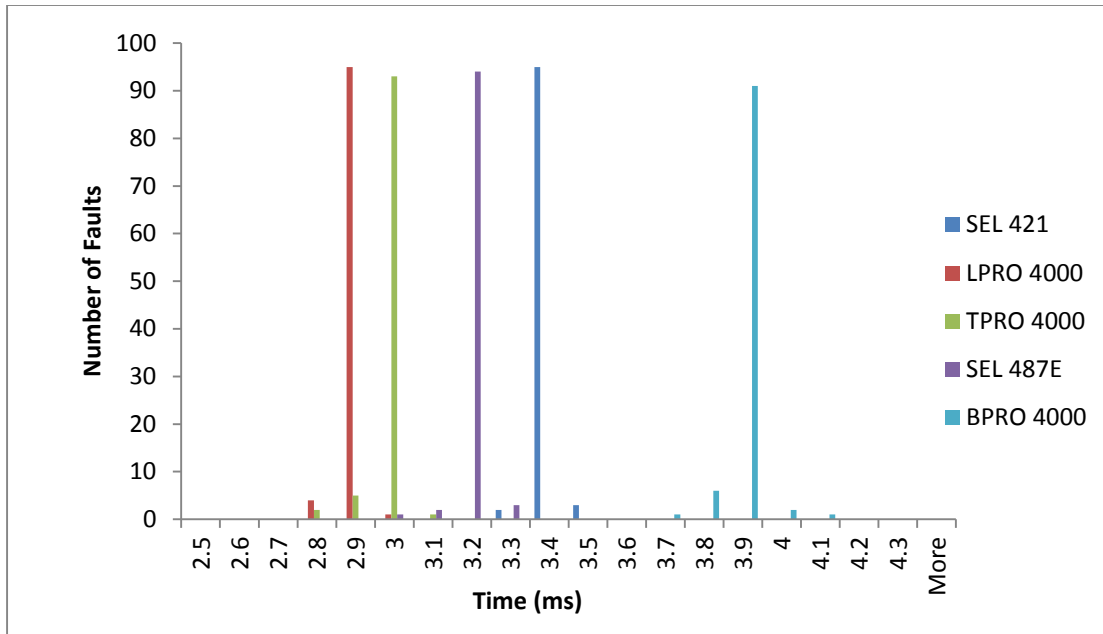


Figure 3-28: GOOSE transfer time from RTDS to relays

From Figure 3-28, it can be seen that the GOOSE transfer time from RTDS to all the relays are less than 4 milliseconds. The circuit breaker statuses are not required to be transferred as fast as trip signals.

3.7 Chapter Summary

A laboratory setup of an IEC 61850 station bus compliant substation was presented (objective 1). The structure of the experimental setup, implementation of the electrical substation in the RTDS and implementation of low level interface (objective 2) were explained. Relay settings of all the relays and a systematic approach to configure the RTDS and all the relays to publish and subscribe GOOSE messages were presented. The proper operation of the complete laboratory setup was validated. Tests were conducted to measure the speed of the GOOSE messages compared to traditional hardwired connection, the GOOSE round trip time and GOOSE transfer time, and the results obtained were presented (objective 3).

Chapter 4

Applications of GOOSE Messages for Implementation of Protection Schemes

4.1 Introduction

In this chapter, three applications of IEC 61850 station bus are presented (objective 4). The first application is a combination of two functionalities and implements reverse interlocking and breaker failure protection. A power system with a different configuration is implemented in RTDS for demonstrating this application and LPRO 4000 and SEL 421 relays are used to protect the system. Section 4.2 presents the implementation of the setup, settings of two relays, GOOSE configuration, and test results. The second application is a recloser scheme where GOOSE messages are used for implementing the standard recloser function. Section 4.3 discusses the implementation of the recloser function on the experimental setup developed in Chapter 3, relay setting, GOOSE configuration and test results. The third application is a backup bus protection scheme which is implemented using the laboratory setup discussed in Chapter 3. In this

application, a novel method is introduced to protect the 230 kV bus bar without using a dedicated bus protection relay. Section 4.4 includes a detailed explanation about the method, GOOSE configuration and the results of testing the application on the developed experimental setup.

4.2 Reverse Interlocking and Breaker Failure

Protection Applications

These applications are implemented to demonstrate the reverse interlocking and breaker failure functions using GOOSE messages. The LPRO 4000 and SEL 421 relays are used to implement these applications. A new simplified power system is implemented in RTDS to demonstrate these functions and the single line diagram of the system is shown in Figure 4-1.

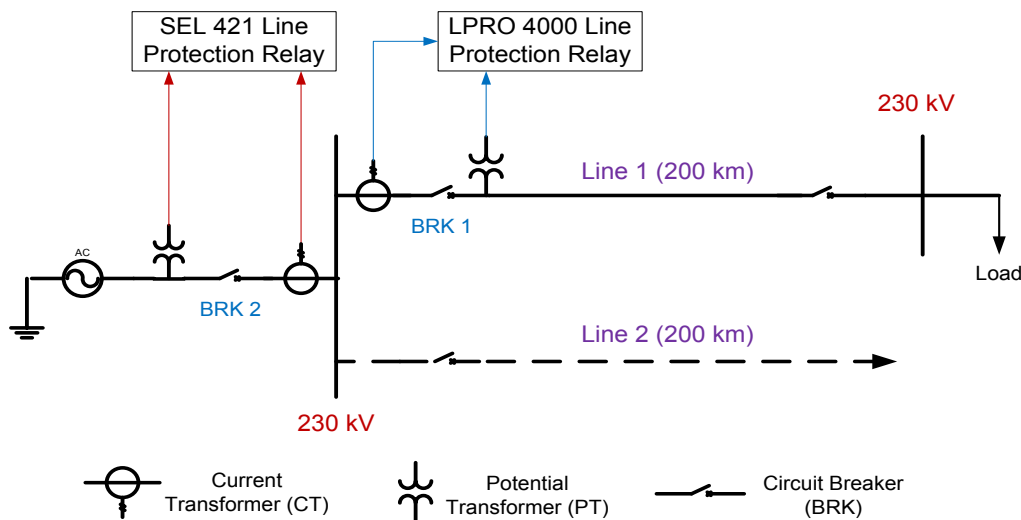


Figure 4-1: Single line diagram of the reverse interlocking and breaker failure application

This system is protected by an overcurrent protection scheme. Line 1 is protected by LPRO 4000 relay. An instantaneous and inverse time overcurrent protection functions are implemented in LPRO 4000 relay. Typically, instantaneous overcurrent protection of breaker 2 (BRK 2) is overridden and therefore, only has the inverse time overcurrent protection [46]. According to the

coordination, BRK 2 protection relay has longer fault clearance time compare to BRK 1 protection relay. This is an issue because when a bus fault occurs, BRK 2 protection relay takes a longer time to operate which may cause damages to the system. This problem can be overcome by using reverse interlocking application.

Reverse interlocking also known as fast bus tripping usually is used to protect radial distribution systems [47]. It is also a low cost bus protection with overcurrent protection scheme [48]. In this application, a definite time protection function is implemented in the SEL 421 relays. When a fault happens in Line 1, LPRO 4000 line protection relay detects the fault and issues a block signal to the SEL 421 line protection relay to block operating its definite time protection function. But for bus fault, definite time protection of the SEL 421 relay operates as there is no block signal from LPRO 4000 relay. This cause BRK 2 to operate faster for bus faults than traditional overcurrent protection schemes.

When a circuit breaker fails to operate after receiving a trip signal, the breaker failure protection function is expected to act quickly to minimize damages [46]. In this example, breaker failure protection of BRK 1 on line is demonstrated. When a fault occurs in Line 1, the LPRO 4000 relay detects it and sends a trip signal to the BRK 1 IED (simulated in RTDS) to open. When the relay sends the trip signal, it starts a timer and continues to monitor the fault current. If the fault current exists when the timer expires, the relay detects it as a breaker failure and issues a trip command to SEL 421, which is associated with BRK 2 located upstream, through a GOOSE message. When SEL 421 receives the breaker failure message, it immediately sends a trip signal to BRK 2 IED (simulated in RTDS) using GOOSE messages to open BRK 2 to clear the fault to avoid damages to the system.

4.2.1 Relay Setting

LPRO 4000 Relay

The important settings of LPRO 4000 relay relevant to reverse interlocking and breaker failure applications are shown in Table 4-1. Detailed calculations corresponding to these settings are given in Appendix A.2.

Table 4-1: LPRO 4000 relay settings for reverse interlocking and breaker failure applications

System Parameters	
Main CT turns ratio	40:1
Breaker Status	
52 – Breaker Status	
Main Breaker	VI 1 (Virtual Input 1)
Protection functions	
50BF – Breaker Failure	
Main enabled	Yes
Pickup Delay 1	0.1 seconds
50/51/67 – Phase overcurrent	
50 Enabled	Yes
Directional	forward
Pickup	32 A
Pickup delay	0.01 seconds
51 Enabled	Yes
Directional	forward
Pickup	5 A
Curve type	IEC std. inverse
TMS	0.05
TR	13.50
50/51/67 – Ground overcurrent	
50 Enabled	Yes
Directional	forward
Pickup	3.2 A
Pickup delay	0.01 seconds
51 Enabled	Yes
Directional	forward
Pickup	0.7 A
Curve type	IEC std. inverse
TMS	0.05
TR	13.50

Protection logical nodes are used to send the block signal and the breaker failure signal to SEL 421 relay, and the trip signal to RTDS. More information regarding this matter is explained in the GOOSE configuration section.

SEL 421 Relay

The important definite time overcurrent settings of SEL 421 relay are shown in Table 4-2. Detailed calculations corresponding to these settings are given in Appendix A.2.

Table 4-2: SEL 421 relay settings for reverse interlocking and breaker failure applications

Line Configuration Settings	
Main CT turns ratio	300:1
Breaker Monitor	
Breaker 1	
Breaker 1 contact input	CCIN001
Relay Configuration	
Phase Instantaneous overcurrent	
Phase inst./def.-time o/c elements	1
Level 1 pickup (A, sec)	1.3 A
Level 1 time delay	0.5 cycles
Residual Ground Instantaneous overcurrent	
Phase inst./def.-time o/c elements	1
Level 1 pickup (A, sec)	0.1 A
Level 1 time delay	0.5 cycles

To send the trip signal as a GOOSE message, “CCOUTGGIO21” logical node of SEL 421 relay is used. The following logic has been implemented in the relays to issue the trip signal.

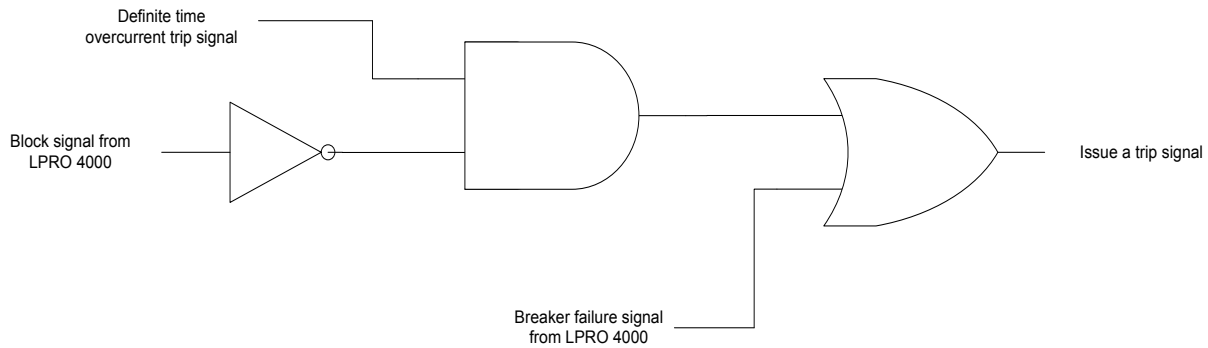


Figure 4-2: Logic diagram of the reverse interlocking and breaker failure schemes

The important factor of this scheme is that the time delay of the definite time overcurrent protection is set to have enough time for block signal GOOSE message from LPRO 4000 relay to arrive before SEL 421 issues a definite time overcurrent trip signal. Therefore, for a line fault, the block signal will stop this scheme from issuing a trip signal. But in a case of a breaker failure of the breaker controls by the LPRO 4000 relay, the breaker failure command of LPRO 4000 relay will override the block signal and force the SEL 421 relay to issue a trip signal.

4.2.2 GOOSE Configuration

LPRO 4000 Relay

The LPRO 4000 line protection relay requires to publish block signal and breaker failure command to SEL 421 relay. The data object “Str” (start) of “PTOC” time overcurrent logical node and the data object “Op” (operate) of “PIOC” instantaneous overcurrent logical node are used to send the block signal whereas the data object “OpEx” (breaker failure trip) of “RBRF” breaker failure logical node is used to send the breaker failure signal to SEL 421. The data object “Op” (operate) of “PTOC” and “PIOC” protection logical nodes are used to send the trip signal

to RTDS. There are separate “PTOC” and “PIOC” logical nodes for phase and ground elements. Datasets and GOOSE control block information relevant to publish this information are shown in Table 4-3 and Table 4-4, respectively.

Table 4-3: Dataset information of LPRO 4000 relay for reverse interlocking and breaker failure applications

For trip signal to RTDS	
Dataset name	oc
Logical device	Protection
Dataset items	D51PTOC1\$ST\$Op\$general
	D51NPTOC2\$ST\$Op\$general
	D50PIOC3\$ST\$Op\$general
	D50NPIOC4\$ST\$Op\$general
For block signal to SEL 421	
Dataset name	oa
Logical device	Protection
Dataset items	D51PTOC1\$ST\$Str\$general
	D51NPTOC2\$ST\$Str\$general
	D50PIOC3\$ST\$Op\$general
	D50NPIOC4\$ST\$Op\$general
For breaker failure command to SEL 421	
Dataset name	bf
Logical device	Protection
Dataset items	D50BF1RBRF1\$ST\$OpEx\$general

Table 4-4: GOOSE control block information of LPRO 4000 relay for reverse interlocking and breaker failure applications

	GOOSE control block for LPRO 4000 “oc” dataset	GOOSE control block for LPRO 4000 “oa” dataset	GOOSE control block for LPRO 4000 “bf” dataset
Control block name	co	ca	cb
Dataset	Protection.LLN0.oc	Protection.LLN0.oa	Protection.LLN0.bf
GOOSE ID	go	ga	gb
Config revision	1	1	1
Min time	2 ms	2 ms	2 ms
Max time	2000 ms	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-82	01-0C-CD-01-01-82	01-0C-CD-01-01-82
App ID (0x)	0001	0002	0003
VLAN ID (0x)	000	000	000
VLAN priority	4	4	4

In this application, LPRO 4000 relay only subscribes the circuit breaker status from RTDS and this subscription mapping is similar to what is described in Chapter 3.

Table 4-5: LPRO 4000 GOOSE subscription mapping for reverse interlocking and breaker failure applications

GOOSE Input	Mapped Data
Virtual Input 1	Circuit breaker status from RTDS (Output 1)

SEL 421 Relay

The SEL 421 line protection relay only publishes the trip signal to RTDS. The communication card output 1 (CCOUT01) is used to send the trip signal to RTDS. Datasets and GOOSE control block information to publish this information are shown in Table 4-6 and Table 4-7.

Table 4-6: Dataset information of SEL 421 relay for reverse interlocking and breaker failure applications

Dataset name	d2
Logical device	ANN
Dataset items	CCOUTGGIO21.Ind01.stVal

Table 4-7: GOOSE control block information of SEL 421 relay for reverse interlocking and breaker failure applications

	GOOSE control block for LPRO 4000 “d2” dataset
Control block name	m2
Dataset	CFG.LLN0.d2
GOOSE ID	g2
Config revision	1
Min time	2 ms
Max time	2000 ms
Multicast MAC address	01-0C-CD-01-01-83
App ID (0x)	0001
VLAN ID (0x)	000
VLAN priority	4

In this application, SEL 421 relay subscribes block signal and the breaker failure from LPRO

4000 relay as well as the circuit breaker status from RTDS. GOOSE subscription mapping of SEL 421 relay is shown Table 4-8.

Table 4-8: SEL 421 GOOSE subscription mapping for reverse interlocking and breaker failure applications

GOOSE Input	Mapped Data
CCIN001	Circuit breaker status from RTDS (output 1)
CCIN002 to CCIN005	Block signal from LRPO 4000 relay
CCIN006	Breaker failure signal from LRPO 4000 relay

RTDS

Table 4-9 shows the dataset information of the RTDS which publishes breaker statuses to relays.

Table 4-9: Dataset information of RTDS for reverse interlocking and breaker failure applications

	Dataset 1
Dataset name	GOOSE_outputs_1
Logical device	CTRL
Dataset items	OUT_GGIO1\$ST\$Ind\$stVal
	OUT_GGIO2\$ST\$Ind\$stVal

The following are the information required to create GOOSE control blocks of above dataset.

Table 4-10: GOOSE control block information of RTDS for reverse interlocking and breaker failure applications

	GOOSE control block for GOOSE_outputs_1 dataset
Control block name	Gcb01
Dataset	GOOSE_outputs_1
GOOSE ID	1
Config revision	1
Max time	2000 ms
Multicast MAC address	01-0C-CD-01-01-81
App ID (0x)	0001
VLAN ID (0x)	000
VLAN priority	4

GOOSE subscription mapping of RTDS relevant to this part is shown in Table 4-11.

Table 4-11: RTDS GOOSE subscription mapping for reverse interlocking and breaker failure applications

GOOSE Input	Mapped Data
Input 20 to GTNET	LPRO_1.Protection.D51PTOC1.Op.general
Input 21 to GTNET	LPRO_1.Protection.D51NPTOC2.Op.general
Input 22 to GTNET	LPRO_1.Protection.D50PIOC3.Op.general
Input 23 to GTNET	LPRO_1.Protection.D50NPIOC4.Op.general
Input 24 to GTNET	SEL_421_1.ANN.CCOUTGGIO21.Ind01.stVal

4.2.3 Test Results

Reverse Interlocking

The setup was tested for different line faults. Figure 4-3 shows the results obtained when a phase to phase fault is applied on line 1, 10% away from the bus bar.

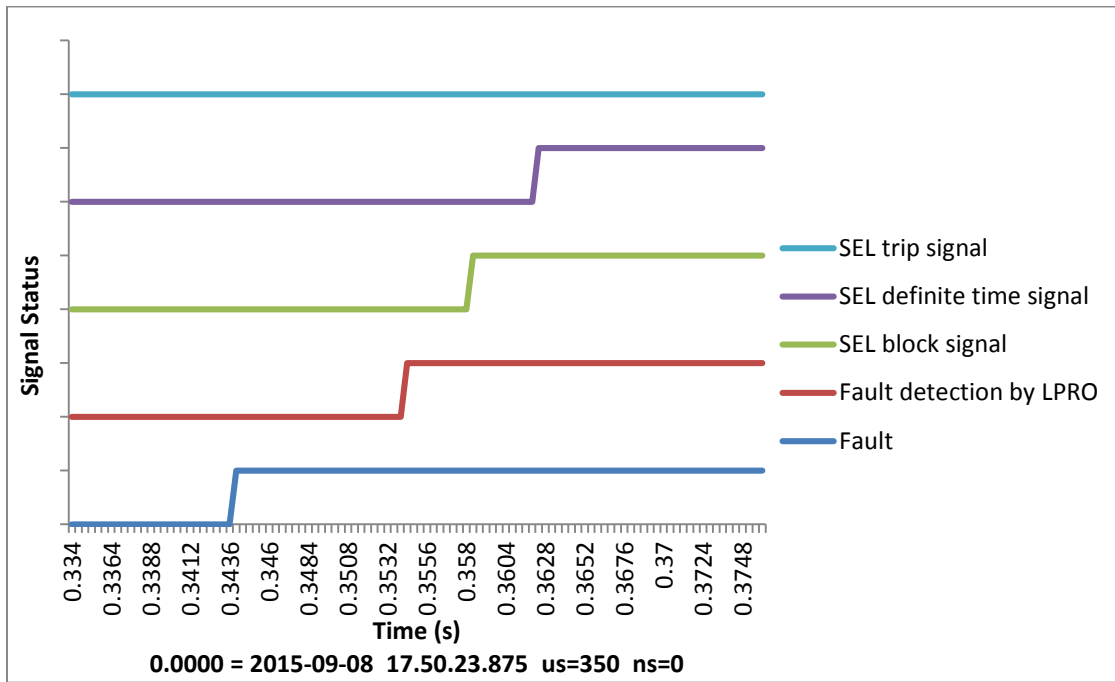


Figure 4-3: Results obtained from the reverse interlocking application

A phase to phase fault is applied to the line 344 milliseconds after the UTC time shown in Figure 4-3. The fault is detected by both line protection relays 10 milliseconds after it is being applied. The SEL 421 relay is set in such a way that it waits 8 milliseconds after the fault is detected,

before it issues a trip signal. Once the fault is detected by the LPRO 4000 relays, it issues a block signal to SEL 421 relay using GOOSE messages. This signal is shown by the “Fault detection by LPRO” graph of Figure 4-3. The block signal is received by the SEL 421 relay 4 milliseconds after it is being issued by the LPRO 4000 relay (“SEL block signal” graph). Even though the SEL definite time protection issue a trip signal 8 milliseconds after it detected the fault (“SEL definite time signal” graph), the trip signal is not sent to RTDS by the SEL relay (“SEL trip signal” graph) because it is inhibited by the block signal received from LPRO 4000 relay. In a bus fault situation, SEL 421 relay will not receive any block signal from LPRO 4000 relay because it will not detect the fault. Therefore, SEL 421 relay will issue a trip signal 8 milliseconds after it detects a bus fault.

Breaker Failure

The setup was tested for different line faults. Figure 4-4 shows the results obtained when a phase-to-ground fault is applied 20% away from the bus bar.

A phase-to-ground fault is applied on Line 1, 195 milliseconds after the UTC time shown in Figure 4-4. The fault is detected by both line protection relays 10 milliseconds after it is being applied. Reverse interlocking function is operated and blocked the SEL 421 trip signal. The LPRO 4000 overcurrent protection function is operated and issued a trip signal using GOOSE messages 15.8 milliseconds after it detected the fault (“LPRO trip” graph). At the same time, LPRO 4000 relay started the breaker failure initialization (“LPRO breaker failure initialize” graph). The trip GOOSE message is received by BRK 1 (Simulated in the RTDS) 2.95 milliseconds after it is issued by the relay (“RTDS BRK1 trip” graph). A breaker failure trip signal is issued by the LPRO 4000 relay to SEL 421 relay through GOOSE messages because the

fault is not cleared 100 milliseconds after it initialized the breaker failure function (“Breaker Failure trip” graph). A trip signal is issued by the SEL 421 relay to BRK 2 (simulated in RTDS) once it received the breaker failure trip signal from LPRO 4000 relay (“SEL trip” graph). When the trip signal GOOSE message is received by the RTDS, the circuit breaker BRK 2 is opened and the breaker status is sent to SEL 421 relay using GOOSE messages (“RTDS BRK2 trip” and “BRK2” graphs, respectively). The “SEL breaker status” shows the breaker status signal received from RTDS. The Table 4-12 shows the GOOSE transfer time measured between each relay.

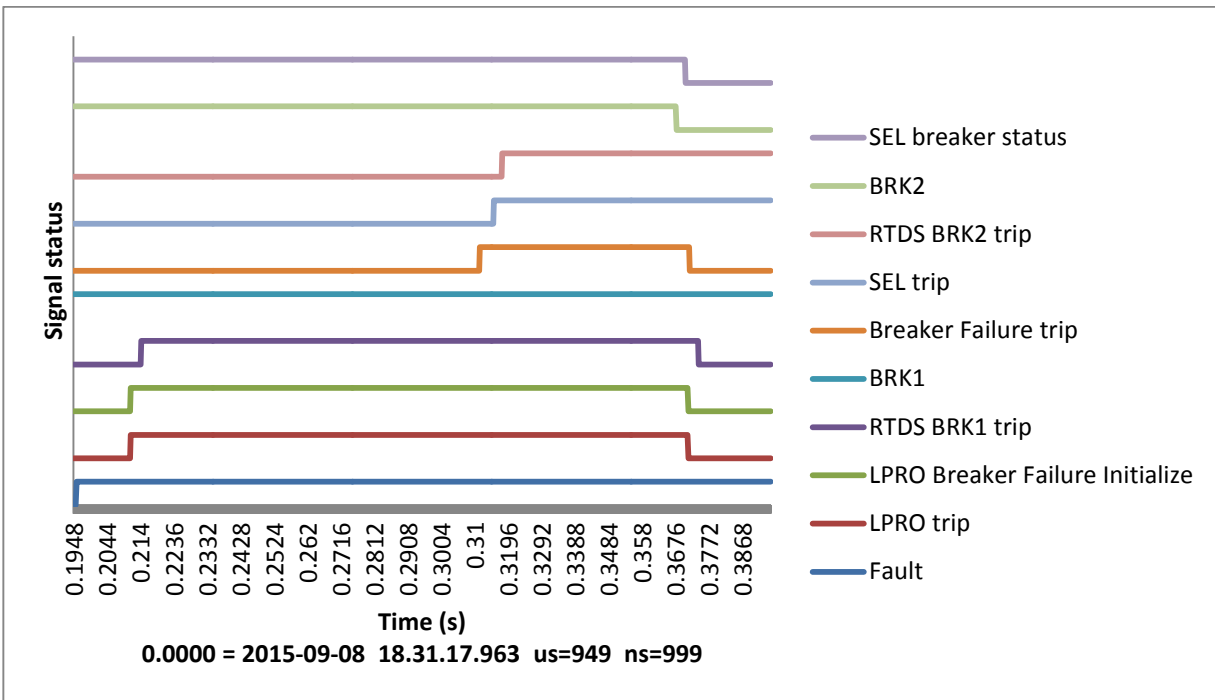


Figure 4-4: Results obtained from the breaker failure application testing

Table 4-12: GOOSE transfer time between each relay for reverse interlocking and breaker failure applications in milliseconds (ms)

Publisher IED	Subscriber IED		
	LPRO 4000	SEL 421	RTDS
LPRO 4000		4.00 ms	2.95 ms
SEL 421	3.00 ms		2.45 ms
RTDS	2.90 ms	3.35 ms	

4.3 Recloser Application

This application is implemented to demonstrate the recloser function using GOOSE messages. The LPRO 4000 relay, which is used to protect the Line 1 of the power system in Chapter 3 (Figure 3-2) is used to implement the recloser application.

When a zone 1 fault occurs in Line 1, the LPRO 4000 relay detects the fault and sends a trip signal through GOOSE messages to RTDS. Once the circuit breaker opens, the updated circuit breaker status is sent to LPRO 4000 relay by RTDS using GOOSE messages. Once the relay receives the circuit breaker status, it initiates the reclose function and waits for a user defined time to issue the first recloser shot. Once the time is up, the relay sends a reclose command to RTDS through a GOOSE message. Once the message is received by the RTDS, the RTDS closes the breaker and the new circuit breaker status is sent to relay using GOOSE message. If the fault is a temporary fault and is cleared before the first recloser command, the reclose operation is successful and the application ends. But if the fault is still there after the first recloser, the relay will detect a fault again and send a trip signal through a GOOSE message. The RTDS opens the breaker and sends the breaker status to the relay. Once breaker status is received by the relay, it waits for a user defined time to issue the second reclose command. This will continue up to four shots if the relay detects a fault after each recloser shot. If not, the application ends after the successful reclose operation. If the relay detects the fault after fourth shot, the relay concludes that fault is permanent and ends the application by issuing a trip signal and moving to a lockout state.

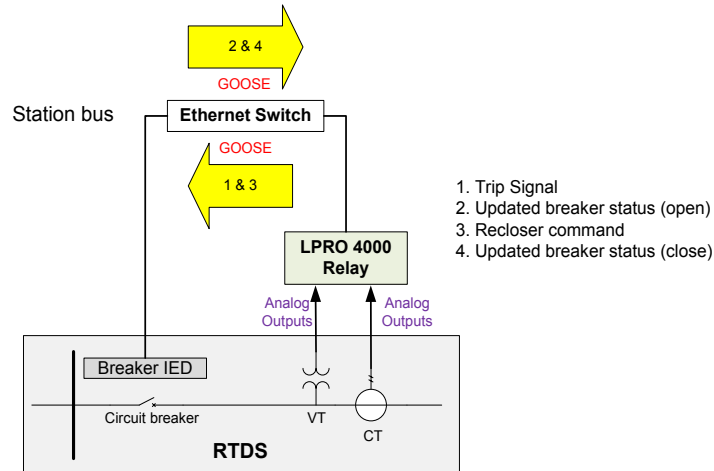


Figure 4-5: GOOSE communication of recloser application

4.3.1 LPRO 4000 Relay Setting

The recloser protection function of the LPRO 4000 relay can be enabled using L-PRO Offliner Settings software. The recloser settings of LPRO 4000 relay are shown in Table 4-13.

Table 4-13: LPRO 4000 relay recloser settings

Breaker Status	
52 – Breaker Status	
Main Breaker	VI 1 (Virtual Input 1)
Protection Functions	
79 – Recloser	
79 – 3Ph Recloser	
Enabled	Yes
Number of shots	4
First reclose (seconds)	1.0
Second reclose (seconds)	1.0
Third reclose (seconds)	1.0
Fourth reclose (seconds)	1.0
Close time (seconds)	0.1
Lockout reset (seconds)	25.0
Initiate reset (seconds)	0.1
Recloser Mode	Main only
Block reset (seconds)	0.5

Logical node that represents recloser protection function in LPRO 4000 relay is “D79ARREC1” and this logical node is used to send the recloser command to RTDS as a GOOSE message. More information regarding this matter is explained in section 4.3.2.

4.3.2 GOOSE Configuration

LPRO 4000 Relay

The LPRO 4000 line protection relay only requires publishing recloser command (in addition to the trip signal information published in Chapter 3) for this application. The data object “Op” (operate) of “RREC” recloser logical node is used to send the recloser command to RTDS. Dataset and GOOSE control block information relevant to this relay are shown in Table 4-14 and Table 4-15, respectively.

Table 4-14: Dataset information of LPRO 4000 relay for recloser application

Dataset name	rd
Logical device	Protection
Dataset items	D79MRREC1\$ST\$Op\$general

Table 4-15: GOOSE control block information of LPRO 4000 relay for recloser application

	GOOSE control block for LPRO 4000 “rd” dataset
Control block name	cr
Dataset	Protection.LLN0.rd
GOOSE ID	gr
Config revision	1
Min time	2 ms
Max time	2000 ms
Multicast MAC address	01-0C-CD-01-01-A5
App ID (0x)	0006
VLAN ID (0x)	000
VLAN priority	4

In this application, LPRO 4000 relay only subscribes the circuit breaker status from RTDS and

this subscription mapping is already done in Chapter 3.

RTDS

There is no new GOOSE publication from RTDS in addition to the breaker statuses publication explained in Chapter 3. GOOSE subscription mapping of RTDS relevant to this part is in Table 4-16.

Table 4-16: RTDS GOOSE subscription mapping for recloser application

GOOSE Input	Mapped Data
Input 18 to GTNET	LPRO_1.Protection.D79MRREC1.Op.general

4.3.3 Test Results

The setup was tested for different zone 1 faults with different fault durations. Figure 4-6 shows the results obtained when a three phase fault is applied 30% away from the bus bar. The time duration of the fault was assigned to 4.2 seconds so that the application successfully recloses in 4th shot.

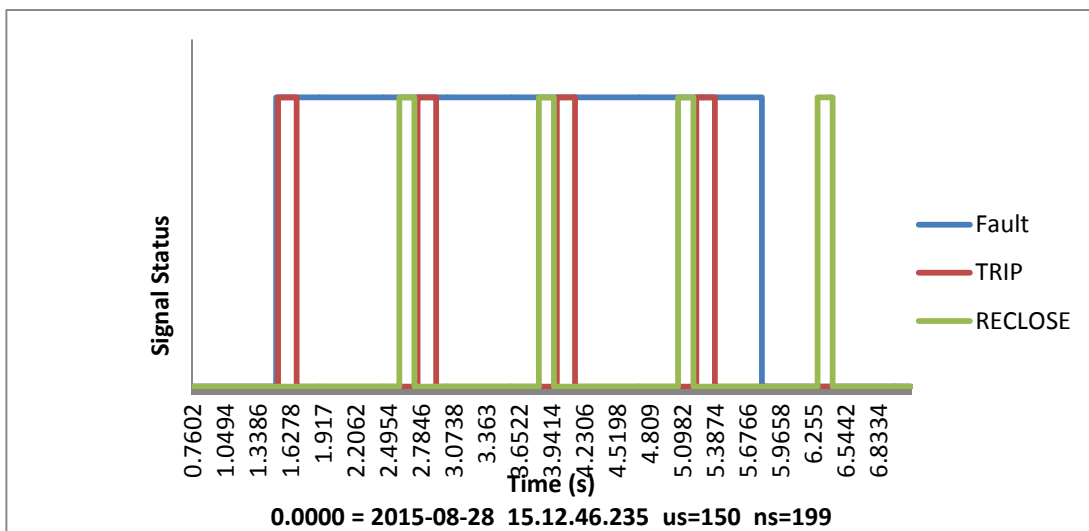


Figure 4-6: Results obtained from a successful recloser after 4th shot

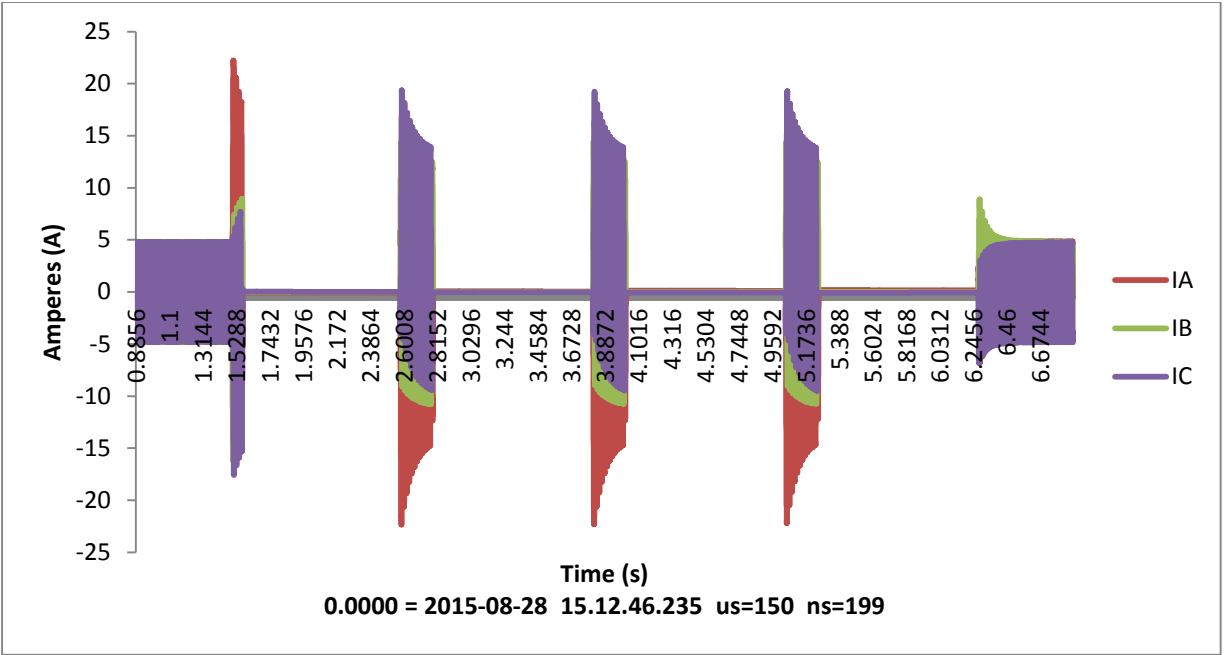


Figure 4-7: Secondary currents of the Line 1 current transformer

Table 4-17 shows the GOOSE transfer time measured for each trip signal, breaker status and recloser command.

Table 4-17: GOOSE transfer times for trip signal, breaker status and recloser command

	GOOSE transfer time for trip signal (ms)	GOOSE transfer time of breaker status after trip signal (ms)	GOOSE transfer time for recloser command (ms)	GOOSE transfer time of breaker status after recloser (ms)
1 st shot	2.85	2.95	2.95	2.90
2 nd shot	2.90	2.90	2.95	2.95
3 rd shot	2.90	2.95	2.90	2.95
4 th shot	2.90	2.95	2.95	2.90

The trip signal and the recloser command are in two different datasets and therefore in two different GOOSE control blocks. So in the above scenario, soon after the first three recloser shots, trip signals were issued due to fact that the fault was still there. When the trip GOOSE message was sent, the recloser GOOSE message retransmission process has not reached the stable condition and therefore, both messages were sent back to back. Despite this condition,

both GOOSE messages are still well within its performance requirement of 4 milliseconds.

4.4 Backup Bus Protection Scheme

Although rare, when occur, bus faults have immense impact on the equipment in a substation and the stability of the power system. At transmission level, reliable bus protection is provided for all important substations, usually with duplicate (A & B) schemes. In the event of failure in bus protection, the backup is provided by the protection schemes of the equipment connected to the bus or remote line protection relays. Generally, these backup protection schemes operate after a time delay. Bus differential protection schemes can get complicated and expensive because of the large number of current signals, different transformer ratios and changes in bus arrangements. Therefore, in many distribution substations, bus differential protection is not used and backup relays are used to clear the bus faults [49].

In this section, a novel method is proposed to implement a complementary, dedicated backup bus protection scheme using the protection devices of the equipment connected to the protected bus and IEC 61850 station bus communication. This complementary backup protection can be design to operate faster than the conventional methods of providing backup protection to bus bars.

In the proposed backup bus bar zone protection scheme, the bus bar is protected using the relays which are protecting the adjacent zones. In the 230 kV substation of the developed experimental setup, relays protecting the two transmission lines and the two transformers that are connected to the 230 kV bus bar are used. Information from protection functions which are already in operation of these relays are combined to determine whether the fault is a bus fault or not. In order to achieve this, it is essential to exchange information among the four relays, and GOOSE

messaging is used for fast and reliable exchange of information. Based on the information received, each relay independently decides and operates the circuit breaker connecting its primary protection zone (ex. line or transformer) and the bus bar. In the simple substation setup presented in Chapter 3, there is no relay protecting the zone that contains the 230 kV system equivalent source (intention is to add a generator protection relay in the future). Therefore in the existing setup, the circuit breaker that connects the system equivalent to the bus bar will operate only for bus faults, and the generator zone faults are not considered in testing. Once the generator protection relay is available, it can be easily configured and added into this scheme. The proposed bus protection scheme can be used as a backup for the primary bus protection relay. The scheme may be acceptable as a primary scheme at distribution level, if delayed fault clearance is acceptable.

It is important to have a backup bus protection scheme to the substation shown in Figure 3-2. Assume that generator protection relay is in use to protect the breaker 7 (BRK 7). If a bus fault occurs and BPRO 4000 relay (primary protection) fails to operate, then generator protection relay will open the breaker 7. But sources connected to Line 1 and 2 will continue to feed the fault. Breaker 1 and 2 will only open after one second because of the zone 3 time delay. But the breakers of the other end of Line 1 and 2 will open before that because they see the bus fault as zone 2 fault. Even that will take 20 cycles because of the zone 2 time delay. But if the proposed backup bus protection is in use, it will protect the systems from a bus fault well before three cycles.

Another advantage of the scheme is that in case of a relay malfunctioning, the other three relays will still be able to continue backup bus protection scheme and issue trip signals. In such a scenario, the breaker that is controlled by the malfunctioning relay will operate if and only if it

receives trip signals from all the other three relays. The detailed information about this method is explained in the next sub-section.

4.4.1 Method

Figure 4-8 shows the single line diagram of the power system used for demonstration. This is the same system shown in Chapter 3, with the 230 kV bus bar protection relay (BPRO 4000) removed for demonstration of the backup protection scheme.

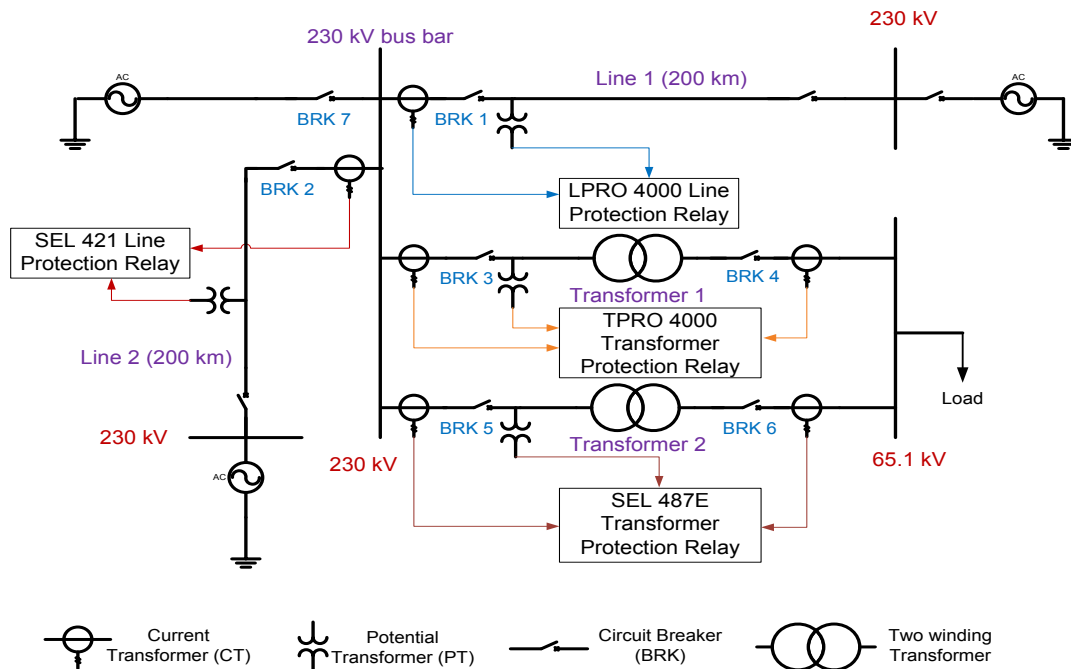


Figure 4-8: Single line diagram of the backup bus protection

When a bus fault occurs, both line protection relays will detect the fault as a reverse fault because zone 3 of both line protection relays is set to detect reverse faults. The pickup delay of the zone 3 is one second which means that each line protection relay will issue a trip command if the reverse fault is not cleared for one second. But both relays would detect a bus bar fault as soon as it happens, as a zone-3 fault and issue an alarm signal instantly. These two alarm signals can be sent through GOOSE messages to other relays to inform the occurrence of a potential bus

fault. However, simultaneous detection of reverse faults by two line protection relays cannot confirm the occurrence of a bus fault, because any internal fault that occurs in the transformers would appear as a reverse fault to both line protection relays. Similarly, if a line fault occurs close to the bus bar, the other line detects it as a reverse fault and issue an alarm signal. Therefore, in order to distinguish a bus fault from a transformer internal fault or from a close up line fault, it is necessary to wait to see whether any of the relays is issuing a trip signal based on its primary protection function. In this application, a two cycles waiting time is used before a decision is made. Two cycles is sufficient for detecting a transformer internal fault or a close up line fault, but can be extended based on the case at hand. After the waiting time, if there is no trip signal from any of the relays and either of the line protection relays still sees a reverse fault, it is decided as a bus fault and the backup bus protection function will issue a trip signal. This logic is set in each of the four relays connected to the bus and GOOSE messages are used to exchange information such as alarm signals and trip signals between each relay. The scheme should work even when some of the elements (a line or transformer) are removed for maintenance or due to trip. Figure 4-9 shows the flow chart of the decision logic implemented in each relay.

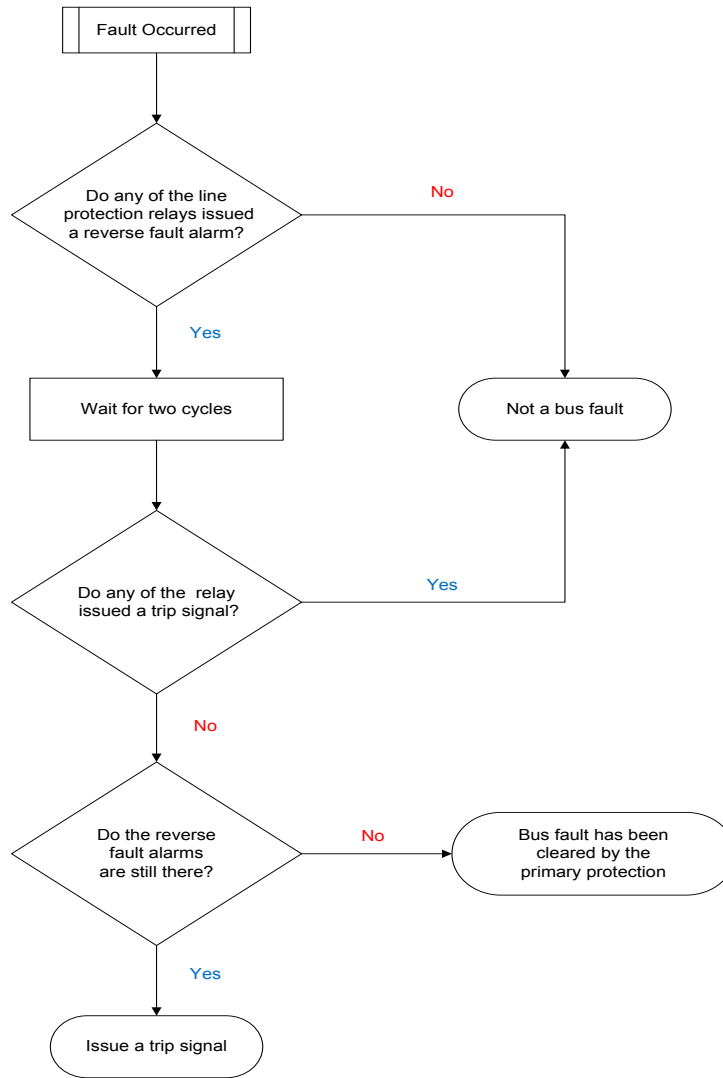


Figure 4-9: Flow chart of the logical diagram

4.4.2 GOOSE Configuration

ERL Phase Relays

As mentioned before, the only information that is published by the LPRO 4000 line protection relay (except the information that is published in Chapter 3) are the reverse fault (zone 3) alarm signal to other three relays (TPRO 4000, SEL 421 and SEL 487E) and the backup bus protection trip signal to the RTDS. LPRO 4000 relay has two protection logical nodes for phase and ground elements. So, “Str” (start) data object of both “PDIS” protection logical nodes are used to send

the alarm signal whereas ProLogic control output 15 is used to send the trip signal.

As the transformer differential protection trip signal is already configured to publish by the TPRO 4000 relay in the previous chapter, the backup bus protection trip signal is the only signal that TPRO 4000 relay has to publish. ProLogic output 16 is used to send the trip signal.

Datasets and GOOSE control blocks information relevant to both relays are shown in Table 4-18 and Table 4-19, respectively.

In this application, LPRO 4000 relay subscribes reverse fault (zone 3) alarm signal from SEL 421 and trip signals from SEL 421, TPRO 4000 and SEL 487E relays. GOOSE subscription mapping of LPRO 4000 relay is shown Table 4-20. On the other hand, TPRO 4000 relay subscribes reverse fault (zone 3) alarm signals from LPRO 4000 and SEL 421 relays as well as the trip signals from LPRO 4000, SEL 421 and SEL 487E relays. GOOSE subscription mapping of TPRO 4000 relay is shown Table 4-21.

Table 4-18: Dataset information of ERL Phase relays for backup bus protection

LPRO 4000	
Dataset name	bl
Logical device	System
Dataset items	PLGGIO1\$ST\$Ind15\$stVal
Dataset name	bd
Logical device	Protection
Dataset items	D21P3PDIS3\$ST\$Str\$general
	D21N3PDIS9\$ST\$Str\$general
TPRO 4000	
Dataset name	bt
Logical device	System
Dataset items	PLGGIO3\$ST\$Ind16\$stVal

Table 4-19: GOOSE control block information of ERL Phase relays for backup bus protection

	GOOSE control block for LPRO 4000 datasets		GOOSE control block for TPRO 4000 dataset
	bl dataset	bd dataset	
Control block name	nl	cb	nt
Dataset	System.LLN0.bl	Protection.LLN0.bd	System.LLN0.bt
GOOSE ID	il	gb	it
Config revision	1	1	1
Min time	2 ms	2 ms	2 ms
Max time	2000 ms	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-A5	01-0C-CD-01-01-A5	01-0C-CD-01-01-A4
App ID (0x)	0002	0007	0002
VLAN ID (0x)	000	000	000
VLAN priority	4	4	4

Table 4-20: LPRO 4000 GOOSE subscription mapping for backup bus protection

GOOSE Input	Mapped Data
Virtual Input 7	SEL 421 alarm signal (CCOUT02)
Virtual Input 8	TPRO 4000 trip signal
Virtual Input 9	SEL 487E trip signal
Virtual Input 13	SEL 421 trip signal (CCOUT01)

Table 4-21: TPRO 4000 GOOSE subscription mapping for backup bus protection

GOOSE Input	Mapped Data
Virtual Input 5 & 6	LPRO 4000 alarm signal
Virtual Input 7	SEL 421 alarm signal (CCOUT02)
Virtual Input 9	SEL 487E trip signal
Virtual Input 11 & 12	LPRO 4000 trip signal
Virtual Input 13	SEL 421 trip signal (CCOUT01)

SEL Relays

Similar to ERL Phase relays, in addition to the previously published variables, the SEL 421 line protection relay publishes the reverse fault (zone 3) alarm signal to other three relays (LPRO

4000, TPRO 4000 and SEL 487E) and the backup bus protection trip signal to the RTDS. CCOOUT02 (communication card output) is used to send the alarm signal whereas CCOOUT03 is used to send the trip signal. These outputs can be sent as GOOSE messages by publishing relevant GGIO logical node. In this application, both these outputs are included in to one dataset.

SEL 487E transformer protection relay only publishes transformer differential protection trip signal and the backup bus protection trip signal. As the dataset and the GOOSE control block are already created for differential protection trip signal in the previous chapter, only the backup bus protection trip signal has to be published. OUT107 (main output) is used to send this trip signal.

New datasets and GOOSE control blocks information relevant to both relays are shown in Table 4-22 and Table 4-23.

In this application, SEL 421 relay subscribes reverse fault (zone 3) alarm signal from LPRO 4000 and trip signals from LPRO 4000, TPRO 4000 and SEL 487E relays. GOOSE subscription mapping of SEL 421 relay is shown Table 4-24.

Table 4-22: Dataset information of SEL relays for backup bus protection

SEL 421	
Dataset name	b2
Logical device	ANN
Dataset items	CCOUTGGIO21.Ind02.stVal
	CCOUTGGIO21.Ind03.stVal
SEL 487E	
Dataset name	b8
Logical device	ANN
Dataset items	OUT1GGIO17.Ind07.stVal

Table 4-23: GOOSE control block information of SEL relays for backup bus protection

	GOOSE control block for SEL 421 dataset	GOOSE control block for SEL 487E dataset
Control block name	n2	n8
Dataset	CFG.LLN0.b2	CFG.LLN0.b8
GOOSE ID	d2	d8
Config revision	1	1
Max time	2000 ms	2000 ms
Multicast MAC address	01-0C-CD-01-01-A1	01-0C-CD-01-01-A2
App ID	0x0002	0x0003
VLAN ID	0x000	0x000
VLAN priority	4	4

Table 4-24: SEL 421 GOOSE subscription mapping for backup bus protection

GOOSE Input	Mapped Data
CCIN005 & CCIN006	LPRO 4000 alarm signal
CCIN008	TPRO 4000 trip signal
CCIN009	SEL 487E trip signal
CCIN011 & CCIN012	LPRO 4000 trip signal

On the other hand, SEL 487E relay subscribes reverse fault (zone 3) alarm signals from LPRO 4000 and SEL 421 relays as well as the trip signal from LPRO 4000, SEL 421 and TPRO 4000 relays. GOOSE subscription mapping of SEL 487E relay is shown Table 4-25.

Table 4-25: SEL 487E GOOSE subscription mapping for backup bus protection

GOOSE Input	Mapped Data
VB005 & VB006	LPRO 4000 alarm signal (ProLogic 4)
VB007	SEL 421 alarm signal (CCOUT02)
VB008	TPRO 4000 trip signal
VB011 & VB012	LPRO 4000 trip signal
VB013	SEL 421 trip signal (CCOUT01)

RTDS

There is no new GOOSE publication from RTDS relevant to this application in addition to the breaker statuses publication explained in Chapter 3. GOOSE subscription mapping of RTDS

relevant to this part is shown in Table 4-26.

Table 4-26: RTDS GOOSE subscription mapping for backup bus protection

GOOSE Input	Mapped Data
Input 13 to GTNET	LPRO_1.System.PLGGIO1.Ind15.stVal
Input 14 to GTNET	SEL_421_1.ANN.CCOUTGGIO21.Ind03.stVal
Input 15 to GTNET	TPRO_1.System.PLGGIO3.Ind16.stVal
Input 16 to GTNET	SEL_487E_1.ANN.OUT1GGIO17.Ind07.stVal

4.4.3 Relay Settings

The following logic has been implemented in all the four relays used for this application. In the ERL Phase relays, ProLogic control statements are used to implement the logic where as in the SEL relays, conditioning timers of protection logic settings are used to implement the logic.

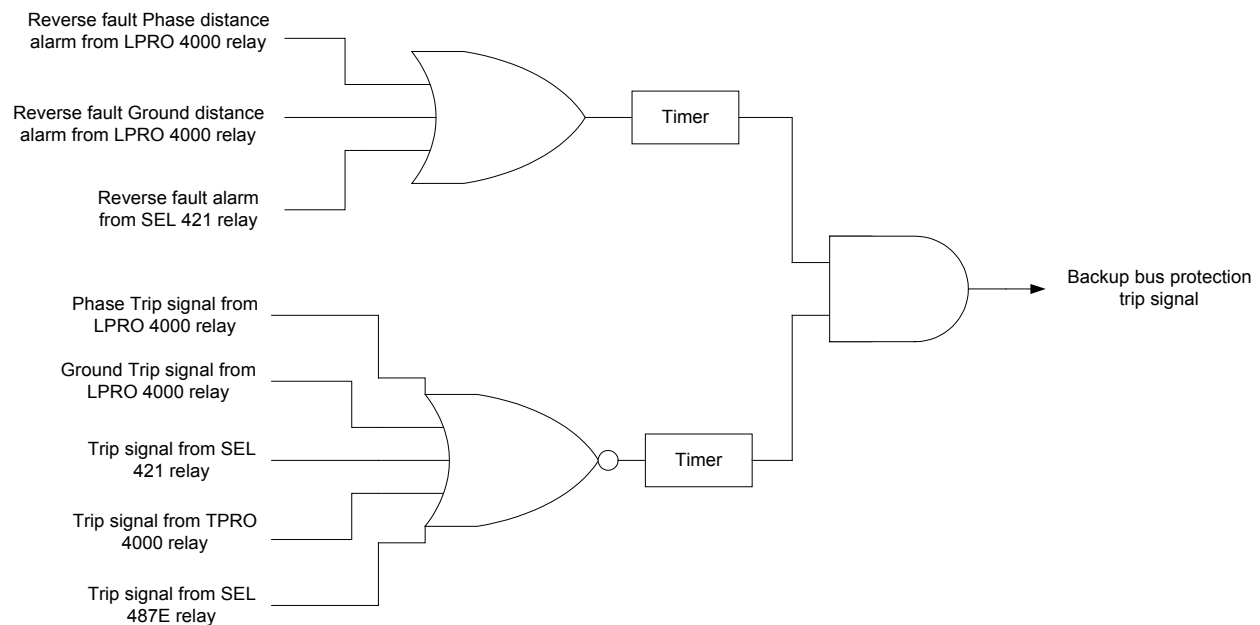


Figure 4-10: Logic diagram of the backup bus protection scheme

When a bus fault occurs, either the reverse fault phase distance alarm or ground distance alarm of LPRO 4000 relay or reverse fault alarm of SEL 421 relay will detect it. Therefore, the output of the OR gate will be “true”. In a case if one of the line protection relay malfunctions, still the

OR gate output will be “true”. Also, there will not be any trip signals from any of the relays and therefore, the output of the NOR gate will be “true”. Due to the fact that all the inputs of the AND gate are “true”, the output of the AND gate will be “true” as well. But the trip signal will be issued if and only if the inputs of the AND gate remain “true” for more than two cycles. The pickup delay of two cycles is used to overcome the following scenario.

As mentioned before, the two line protection relays see any fault close to the bus bar as a reverse fault. For any transformer internal fault, both relays detect the fault as a reverse fault whereas for a line fault near the bus bar, the relay that protects the healthy line detects it as a reverse fault. When an internal transformer fault or a line fault close to bus bar occurs, the relay that protects it takes some time to issue the trip signal (may be up to 1 and 1/2 cycles). The trip signal will also take the GOOSE transfer time to reach all the relays (around 4 milliseconds). Therefore, a trip signal can take around 2 cycles to reach other relays. But there is a possibility that one or both of the line protection relays may detect it as a reverse fault and send the alarm signal before receiving the trip signal from the primary protection function of transformer or line relay. In that case, all the input of the AND gate become “true” (because the trip signal is not being received by the relay yet). This can cause the backup bus protection scheme to issue unnecessary trip signals. But having a pickup delay of two cycles will force the application to wait two cycles to see whether the relay will receive a trip signal from a protection relay. If the relays receive a trip signal from any relay, the backup bus protection scheme will not issue trip signals. But if the relays do not receive a trip signal from a relay within the two cycles, the backup bus protection scheme will issue trip signals.

It should be noted that this scheme is proposed mainly as a backup to primary bus protection. Bus faults in major substation are very severe and should be cleared as fast as possible by the

primary bus protection without any intentional delay. If the primary bus protection fails, the proposed backup bus protection should operate after the two cycle delay.

4.4.4 Test Results

This section discusses the results of this application when all four relays are connected and when only three relays are connected.

Normal condition (when all four relays work properly)

The setup was tested for different bus faults. During the tests, the bus protection relay is not used (disabled), and therefore, there is no primary bus protection scheme. Therefore, when a bus fault is applied, the system is protected by the backup bus protection scheme. This section discusses the backup bus protection when all four relays (two line and two transformer protection relays) work properly.

Figure 4-11 shows the results obtained when a three phase bus fault is applied to the system. The fault is applied at 57.8 milliseconds ($t=0$ corresponds to the UTC time shown on the graph). The line protection relays detected the fault 10 milliseconds after the fault is applied. Then the two relays sent the alarm signals to rest of the relays and upon the completion of the backup bus protection scheme, each relay sent trip signal GOOSE messages to the RTDS. The RTDS received the trip signals from SEL 421 after 46.4 milliseconds, from LPRO 4000 after 47.0 milliseconds, from TPRO 4000 after 48.8 milliseconds, and from SEL 487 after 49.0 milliseconds after the fault. The detailed breakdown of the events leading the operation of the each relay is shown in Figure 4-12.

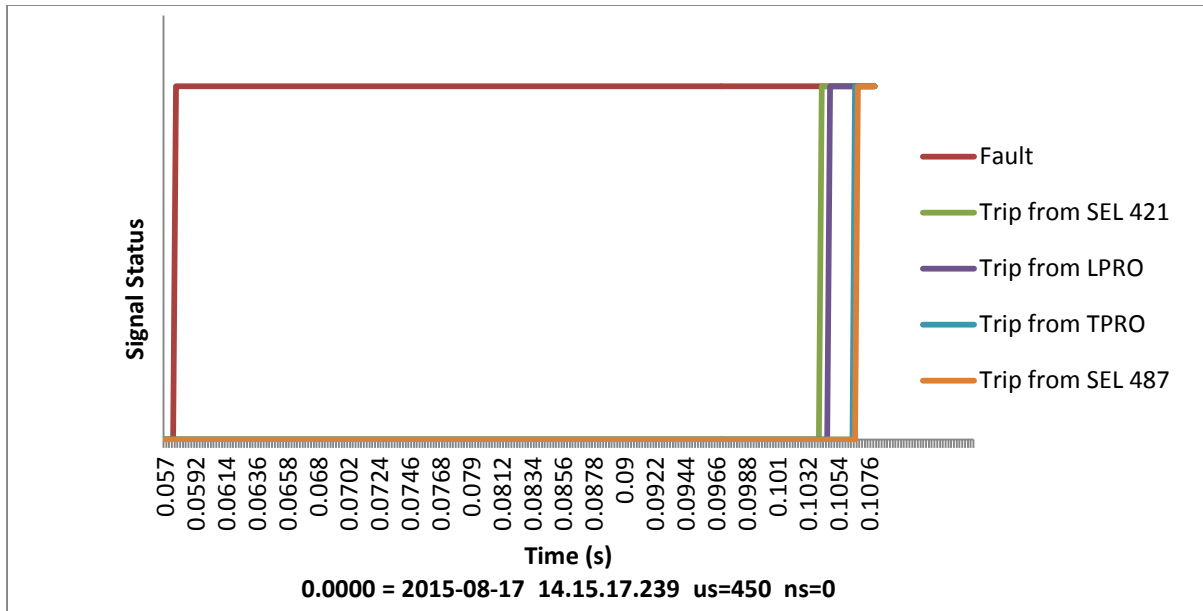


Figure 4-11: Operating times of the backup bus protection scheme when all relays work properly



Figure 4-12: Detailed breakdown of operating time

a → Fault applied in RTDS

b → Reverse fault detected by SEL 421 and LPRO 4000 relays. The alarm signal is sent to other relays using GOOSE messages. Also, both relays started the backup bus protection scheme.

c → LPRO 4000, TPRO 4000 and SEL 487E received the alarm signal from SEL 421 relay. TPRO 4000 and SEL 487E relays started the backup bus protection scheme.

d → SEL 421, TPRO 4000 and SEL 487E received the alarm signal from LPRO 4000 relay.

e → SEL 421 and LPRO 4000 relays issued the backup bus protection trip

signals.

f → TPRO 4000 and SEL 487E relays issued the backup bus protection trip signals.

g → RTDS received the SEL 421 relay's trip signal.

h → RTDS received the LPRO 4000 relay's trip signal.

i → RTDS received the TPRO 4000 relay's trip signal.

j → RTDS received the SEL 487E relay's trip signal.

Table 4-27 shows the GOOSE transfer times measured between each relay whereas Table 4-28 shows the trip signal and breaker status transfer time between RTDS and each relay. Note that the time stamps of all the relays event files are in milliseconds. Therefore, the GOOSE transfer time between relays are rounded up to closest millisecond.

Table 4-27: Measured GOOSE transfer time between each relay in milliseconds (ms)

Publisher IED	Subscriber IED			
	SEL 421	LPRO 4000	TPRO 4000	SEL 487E
SEL 421		2.0 ms	2.0 ms	2.0 ms
LPRO 4000	4.0 ms		4.0 ms	4.0 ms
TPRO 4000	4.0 ms	4.0 ms		4.0 ms
SEL 487E	4.0 ms	4.0 ms	4.0 ms	

Table 4-28: GOOSE transfer time of trip signals and breaker statuses

Relay	GOOSE transfer time from relay to RTDS (trip signal) (ms)	GOOSE transfer time from RTDS to relay (breaker status) (ms)
SEL 421	2.45	3.35
LPRO 4000	2.95	2.85
TPRO 4000	2.90	2.90
SEL 487E	2.80	3.10

Even though the number of GOOSE messages transferred through the network increased

significantly compared to the laboratory setup explained in the Chapter 3, the GOOSE messages were still able to reach its destination around 4 milliseconds. Also, all the trip signals arrived to RTDS from all the relays well before 3 milliseconds despite the high GOOSE message traffic in the network.

When one relay malfunctions

The setup was tested for different bus faults when one out of four relays is out of service. Bus faults were applied by disabling each of the four relays (one relay disabled at a time) from the system and the backup bus protection scheme worked as expected in the other relays. Figure 4-13 shows the results obtained when a BC (phase-to-phase) fault was applied on the bus and the LPRO 4000 relay was removed from the system.

The fault is applied 89.4 milliseconds after the UTC time shown in the Figure 4-13. SEL 421 line protection relay detected a zone-3 fault 10 milliseconds after the fault is applied. Then the relay sent the alarm signals to rest of the relays. Once the backup bus protection scheme is completed, each relay (except LPRO 4000) sent trip signal GOOSE messages to the RTDS. The RTDS received the trip signals from SEL 421, TPRO 4000 and SEL 487 relays, respectively.

Each breaker IED (simulated in RTDS) subscribes backup bus protection trip signals from all the relays. Each breaker IED will open its breaker if and only if it receives the backup bus protection trip signal from its relevant protection relay or if it receives the backup bus protection trip signals from all other three protection relays. Therefore, in this scenario, breaker IED of LPRO relay operates when it receives all other backup bus protection trip signals.

RTDS opened the circuit breakers 50 milliseconds (interrupting time of the breaker) after it

received the relevant trip signals. BRK2 opened first followed by BRK3, BRK5 and BRK1.

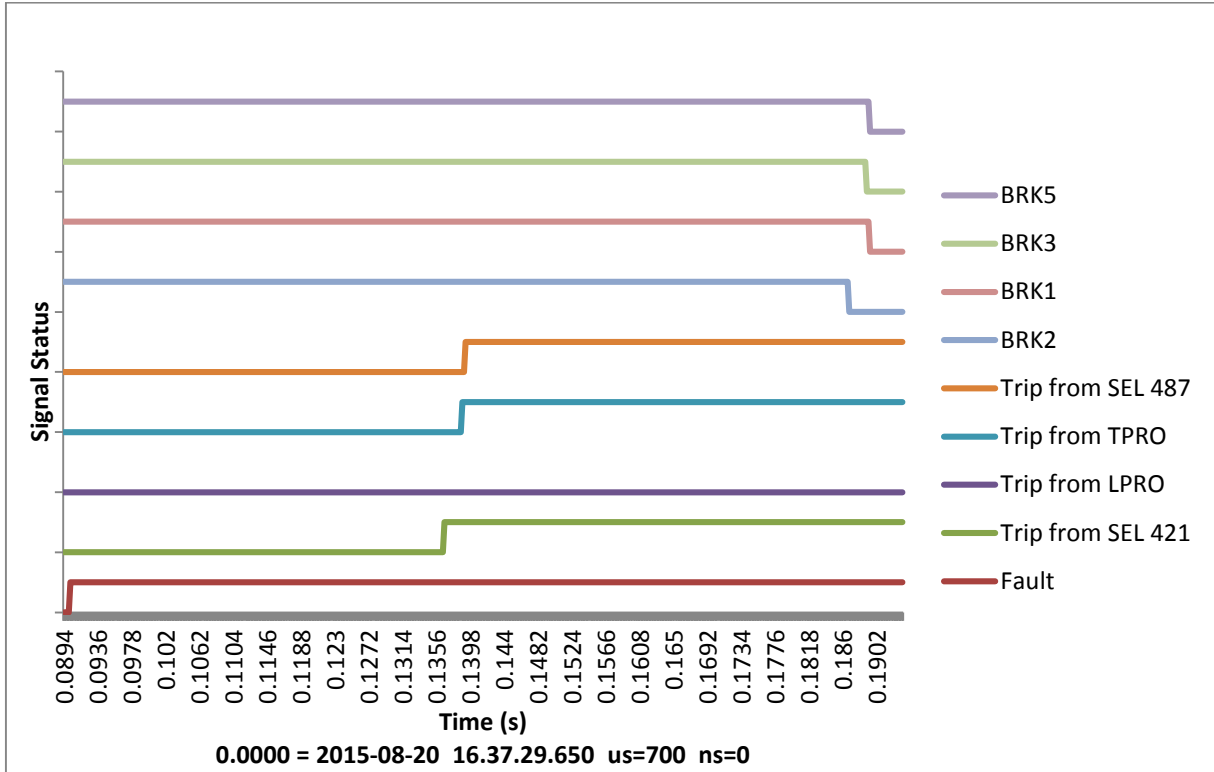


Figure 4-13: Backup bus protection results when LPRO 4000 relay is not in service

For an external fault

The setup was tested for different external faults. Figure 4-14 shows the results obtained when a phase to phase fault is applied on Line 1, 10% away from the bus bar.

The fault is applied 73.4 milliseconds after the UTC time shown in Figure 4-14. SEL 421 line protection relay detected a zone-3 fault 10 milliseconds after the fault is applied. SEL 421 relay sent this alarm to rest of the relays through GOOSE messages and initiated its backup bus protection scheme. Soon after (around 12 milliseconds after the fault is applied), the LPRO 4000 relay detected the zone-1 fault and issued a trip signal. At the same time LPRO 4000, TPRO 4000 and SEL 487E relays received the reverse fault alarm signal from SEL 421 relay. Both TPRO 4000 and SEL 487E relays initiated their backup bus protection scheme with the reception

of reverse fault alarm signal from SEL 421 relay. But LPRO 4000 did not start the backup bus protection due to the fact that it detected the fault as a zone-1 fault. The rest of the three relays (SEL 421, TPRO 4000 and SEL 487E) stopped their backup bus protection schemes soon after they received the trip signal GOOSE message from LPRO 4000 relay.

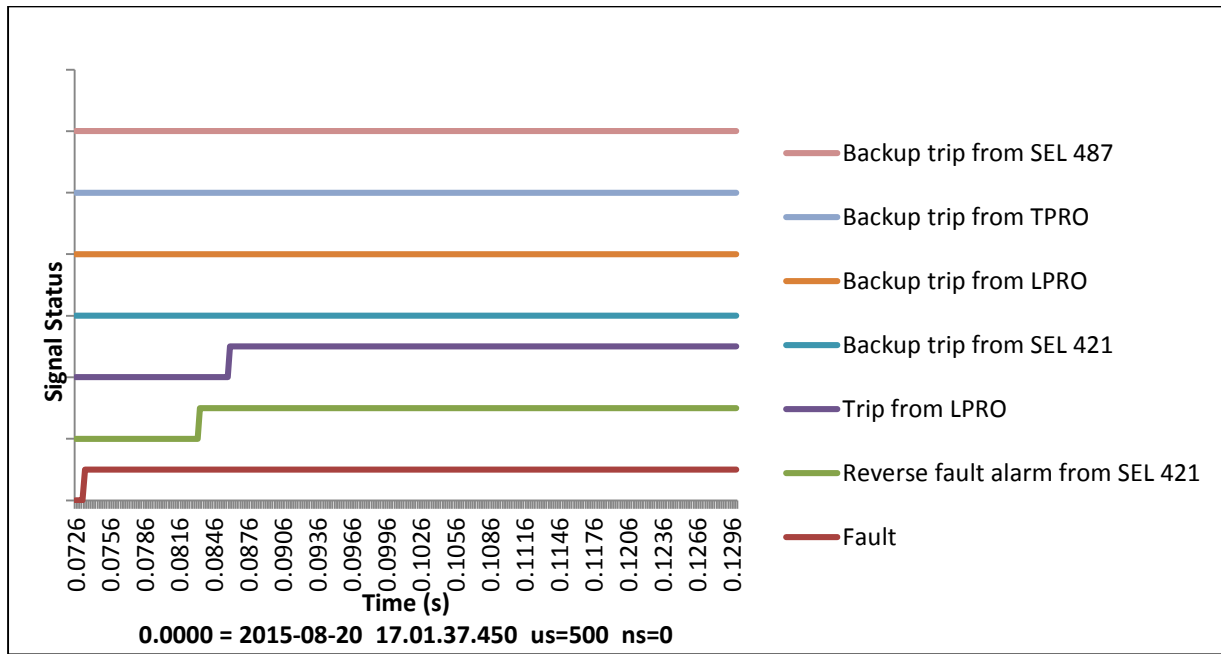


Figure 4-14: Backup bus protection results for a Line 1 fault

4.5 Chapter Summary

In this chapter, three inter IED communication based protection and automation applications including a novel backup bus protection scheme were presented. All three applications utilized GOOSE messages for communication of time critical information. Implementation, relay settings and GOOSE configuration of each application were explained. Several tests were conducted and the GOOSE performance results obtained from those tests were presented. These applications demonstrated the use of GOOSE messages in real world applications and emphasized the importance of GOOSE messages in time critical substation automation applications (objective 4).

Chapter 5

Laboratory Experiments to Familiarize with IEC 61850 Station Bus Functionality

5.1 Introduction

This chapter presents three laboratory experiments which will help to familiarize with IEC 61850 station bus functionality (objective 5) before using the laboratory setup with all five relays. The first experiment is an interoperability experiment and it mainly focuses on GOOSE mapping between IEDs of different vendors. The second experiment uses the substation discussed in Chapter 3, but only focuses on the two overhead transmission lines. This experiment is intended to provide understanding on use of GOOSE messages in protection schemes as well as on configuration of modern relays. The third experiment presents the intended engineering process of IEC 61850. This experiment allows students to familiarize with a system configuration tool

and its capabilities.

5.2 Interoperability Experiment

5.2.1 Overview of the Experiment

The main objective of this experiment is to understand the concept of multi-vendor interoperability with respect to the IEC 61850 standard. In addition, some of other objectives of the experiment are listed in section 5.2.2. The concepts are introduced by setting-up inter IED GOOSE communication among IEDs of three vendors on the station bus as shown in Figure 5-1.

IED configuration tools of each vendor are used to configure the GOOSE publication and subscription process of each IED. IED configuration tool is different from usual relay setting software of the vendor. ICD (IED Configuration Description) file of each IED is required for GOOSE configuration. Usually, IED configuration tool consists of all the ICD files of its own IEDs. If not, IED configuration tool is capable of importing them from IED database.

GOOSE publication configuration consists of two steps. First step is to create a dataset by including the required functionally constrained data attributes (FCDA) and next step is to create a GOOSE control block by including the created dataset (Please refer Section 2.5.2 for more information).

GOOSE subscription configuration process requires CID (Configured IED Description) files of all the publishers. IED configuration tool is capable of importing CID files from different vendors and extracting publisher information from them. GOOSE subscription can be done by mapping the required data attributes from the GOOSE publishes into the suitable GOOSE inputs

of the subscriber (Please refer Section 2.5.2 for more information).

5.2.2 Learning Objectives

- To familiarize with GOOSE mapping.
- To learn the process of configuring GOOSE messages.
- To familiarize with IED configuration tools of three vendors (RTDS, ERL Phase Power Technologies and SEL).
- To learn about GOOSE datasets and GOOSE control blocks.

5.2.3 Procedure

The experimental setup is shown in Figure 5-1.

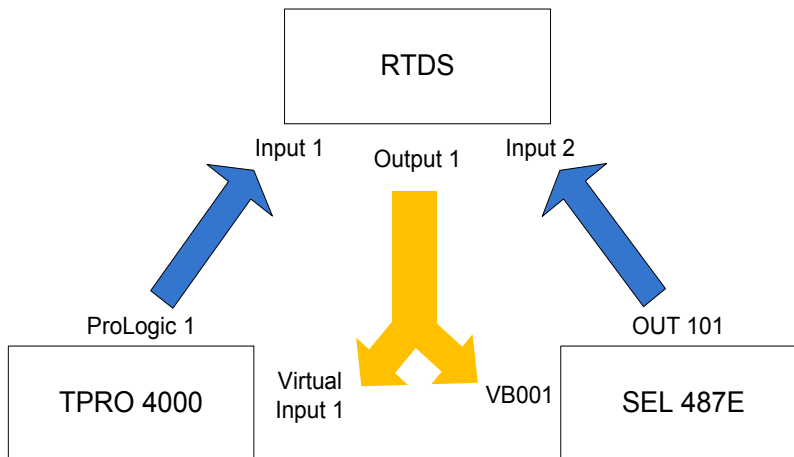


Figure 5-1: Interoperability experimental setup

Output of a binary switch is assigned to Output 1 of the RTDS. When the binary switch changes, the Output 1 of RTDS publishes GOOSE messages to the network. The output 1 of the RTDS is subscribed by the Virtual Input 1 of the TPRO 4000 relay and the VB001 of the SEL 487E relay.

In TPRO 4000 relay, virtual input 1 is assigned to ProLogic 1 whereas in SEL 487E relay, VB001 is assigned to OUT 101. Both the ProLogic 1 and the OUT 101 are published as GOOSE messages by each relay and the RTDS subscribes both those outputs (ProLogic 1 and OUT 101).

Table 5-1: Publisher-subscriber variables of relays for laboratory experiment 1

	Publish	Subscribe
TPRO 4000	ProLogic 1 (to RTDS)	Virtual Input 1 (from RTDS)
SEL 487E	Out 101 (to RTDS)	VB001 (from RTDS)
RTDS	Output 1 (to SEL 487E & TPRO 4000)	Input 1 (from SEL 487E) Input 2 (from TPRO 4000)

The main objective of this experiment is to be familiarized with GOOSE mapping. Therefore, the relay setting files and the RSCAD draft file are provided. The following steps explain the basic procedure to complete the GOOSE mapping of the system shown in Figure 5-1.

- Open the RSCAD draft file and be familiarized with the case. The GTNET-GSE block is the component that enables GOOSE communication in RTDS.

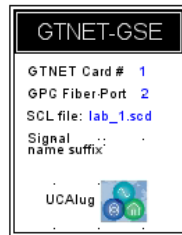


Figure 5-2: GTNET-GSE component

- Right click on GTNET-GSE block to open the SCD editor. The SCD editor is the IED configuration tool of the RTDS.

Configuring RTDS as a GOOSE publisher

- In the SCD editor, go to Edit → Outputs/Dataset → RTDS → GOOSE_Output_1/Gcb01.

Dataset Entries window will be opened.

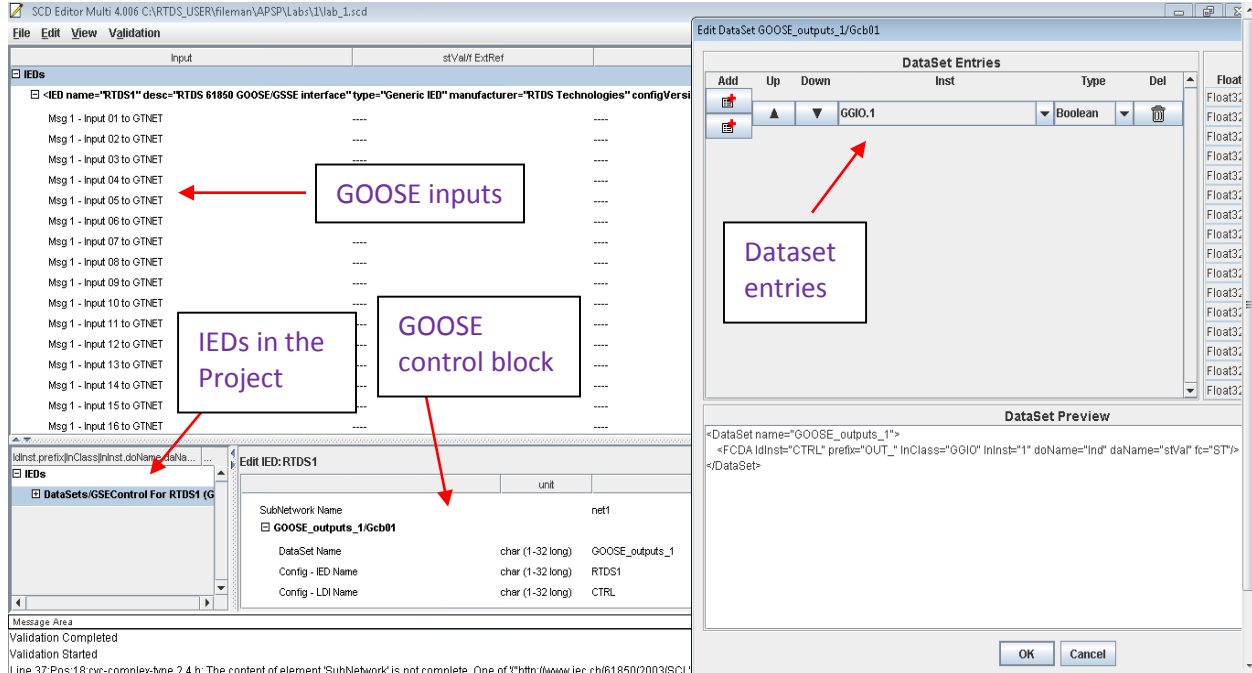


Figure 5-3: SCD editor and dataset entries windows

- As the experiment requires only one output to publish from RTDS, only one dataset entry is required and the type of it should be Boolean. This dataset will be automatically included in the GOOSE control block. Use the GOOSE control block box shown in Figure 5-3 to edit information such as dataset name (GOOSE_output_1), IED name (RTDS), VLAN ID (000), VLAN priority (4), MAC address (01-0C-CD-01-01-11), App ID (0001).
- Save the publisher information as a CID file.

Configuring TPRO 4000 as a GOOSE subscriber

- Open ERL 61850 IED Configurator which is the IED configuration tool of ERL Phase relays.

- Import the saved CID file of the RTDS into the IED palette. Then add the TPRO 4000 ICD file and imported RTDS CID file from IED palette into project editor.
- In the subscription mapping tab, map the output 1 of the RTDS into virtual input 1 (VI 1) of the TPRO 4000.

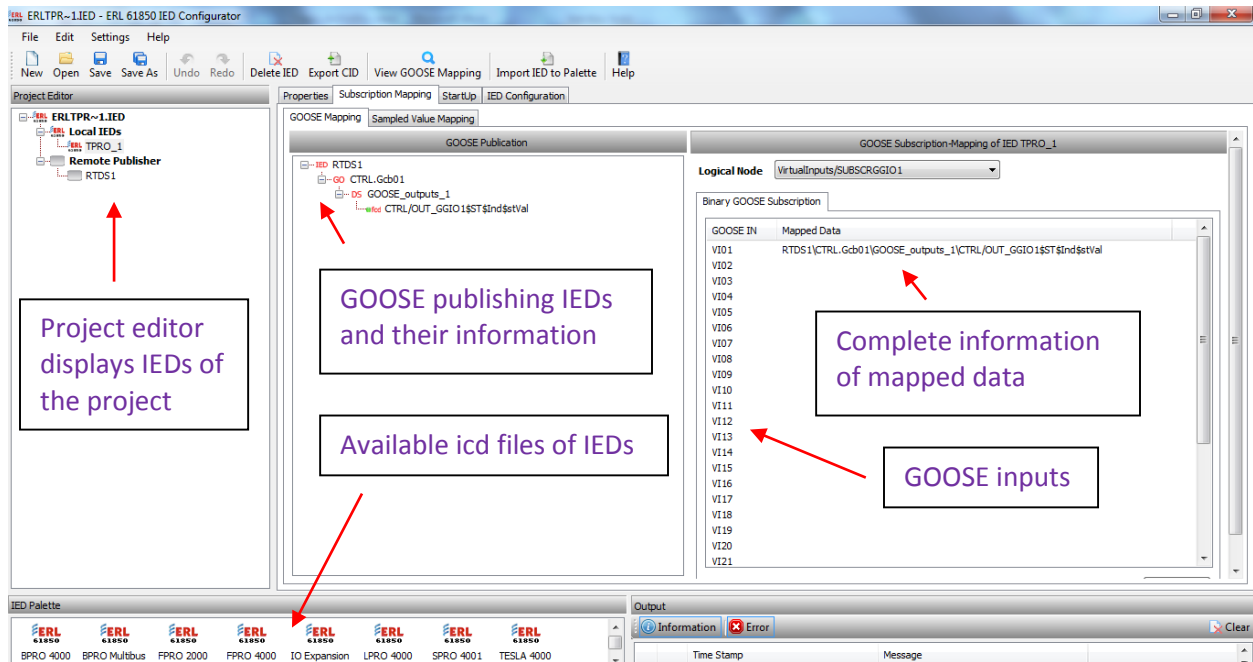


Figure 5-4: GOOSE subscription mapping of ERL Phase configuration tool

Configuring TPRO 4000 as a GOOSE publisher

- Go to the tab IED configuration → Datasets, and create a dataset with a “system” logical device. Select System (logical device) → PLGGIO3 (logical node) → ST (functional constraint) → Ind1 (data object) → stVal (data attribute) and assign it as a dataset item (please refer Figure 5-5).
- Create a GOOSE control block for the dataset created to publish the information as shown in Figure 5-6.
- Save the TPRO 4000 CID file and send the file to the relay.

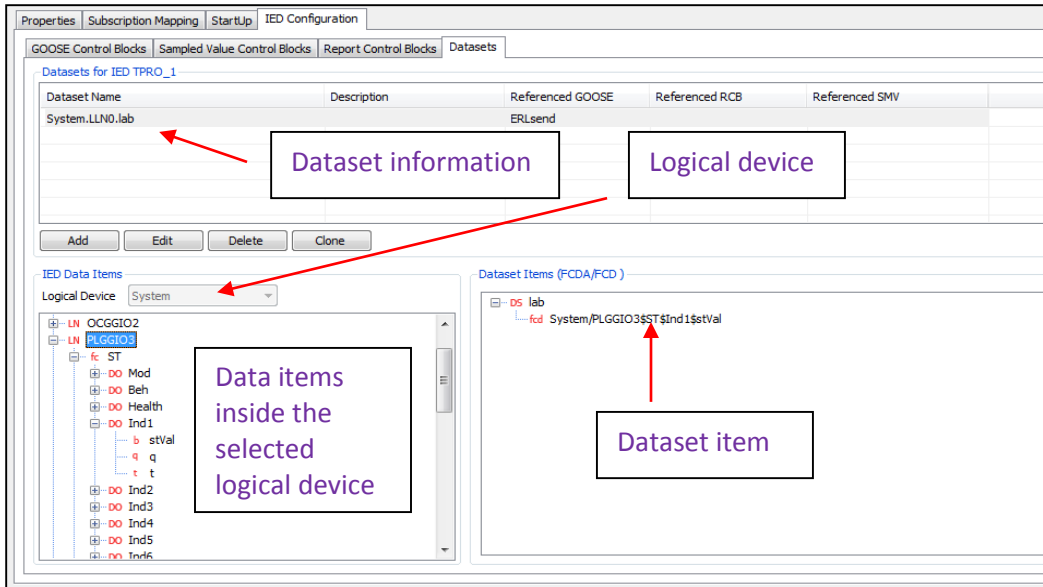


Figure 5-5: Datasets information of ERL Phase configuration tool

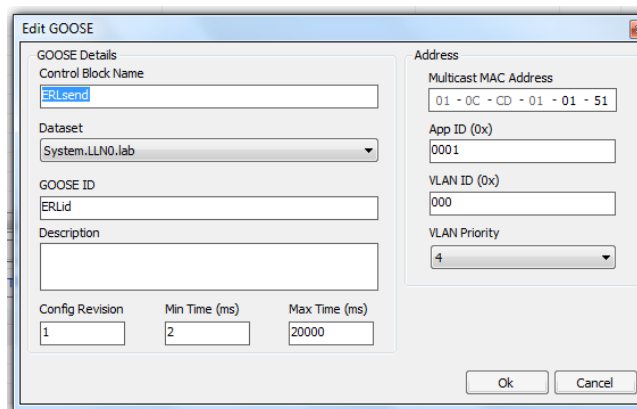


Figure 5-6: GOOSE control block information of ERL Phase configuration tool

Configuring SEL 487E as a GOOSE subscriber

- Open AcSELerator Architect which is the IED configuration tool of SEL relays.
- Import the saved CID file of the RTDS into the IED palette. Then add the SEL 487E ICD file and the imported RTDS CID file from IED palette into project editor.
- In the GOOSE receive tab, map the output 1 of the RTDS into VB001 of the SEL 487E.

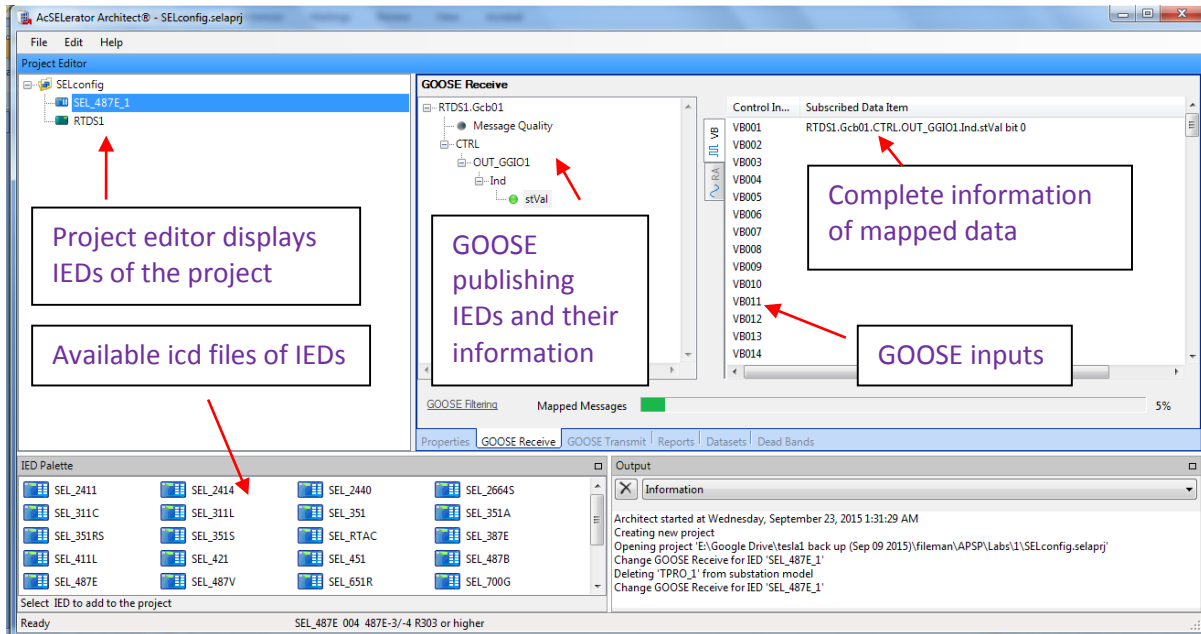


Figure 5-7: GOOSE subscription mapping of SEL configuration tool

Configuring SEL 487E as a GOOSE publisher

- Go to the Datasets tab, and create a dataset. Select ST (functional constraint) → ANN (logical device) → OUT1GGIO17 (logical node) → Ind01 (data object) → stVal (data attribute) and assign it to the dataset.

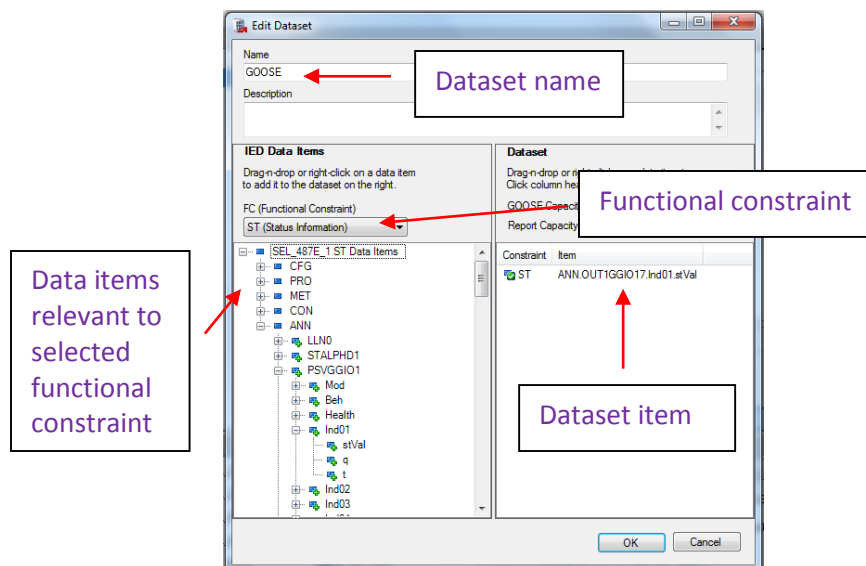


Figure 5-8: Datasets information of SEL configuration tool

- Create a GOOSE control block for the dataset created to publish the information.

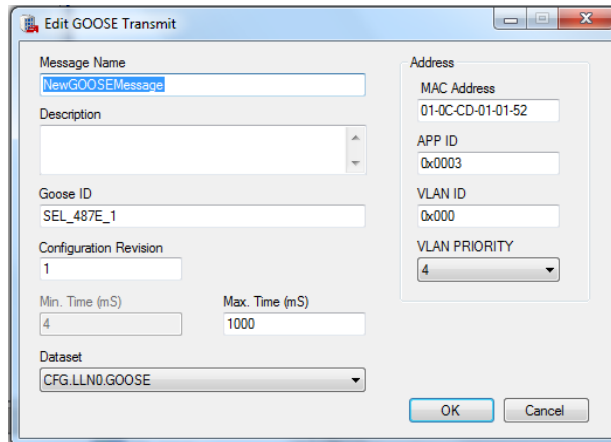


Figure 5-9: GOOSE control block information of SEL configuration tool

- Save the SEL 487E CID file and send the file to the relay.

Configuring RTDS as a GOOSE subscriber

- Go back to the RSCAD draft file and open the SCD editor.
- Import the saved CID files of two relays into the SCD editor.
- Map the ProLogic 1 of the TPRO 4000 into input 1 of RTDS and the OUT 101 of the SEL 487E into input 2 of RTDS as shown in Figure 5-10.
- Now the GOOSE mappings are complete. Compile the case and open the runtime window of the case.
- In the runtime window, there is a switch that control output 1, two lights to display input 1 and input 2, and two timers to measure the round trip times of GOOSE messages between RTDS and each relay.
- When the switch turns on, two lights should turn on and two timers should display the round trip times. Once the switch turns off, two lights should turn off.

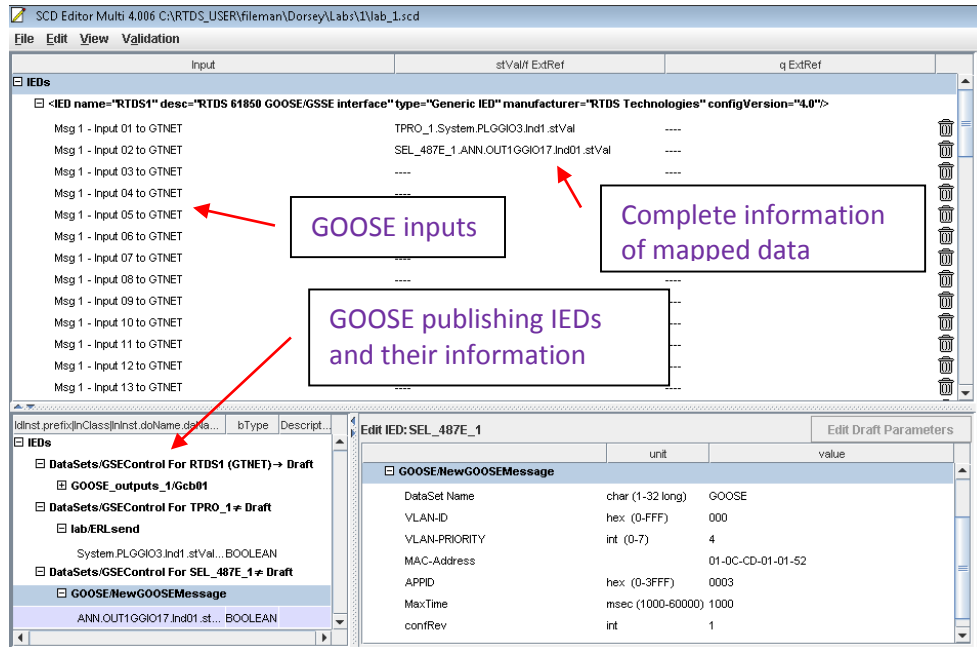


Figure 5-10: GOOSE subscription mapping of RTDS configuration tool

Wireshark software can be used to capture and analyse the GOOSE packets from all three devices. Also, the changes made to an ICD file due to this process can be observed by comparing the ICD file with its final CID file.

5.3 Implementation of Distance Protection using GOOSE Messages

5.3.1 Overview of the Experiment

The main objective of this experiment is to use GOOSE communication to send trip signals and breaker status information in a simple line protection scheme. By completing this experiment, students will be able to gain knowledge of various logical nodes and configuring and setting modern digital relays to perform line protection.

Distance protection schemes with Mho characteristics with reach setting of 80%, 130% and 40% (reverse) are used for the zones one, two and three, respectively to protect the Line 1 and 2 in the system shown in Figure 5-11.

Reach impedances and zero sequence compensation factors are to be calculated as a pre-lab exercise using the provided impedance and CT/VT data. Line protection relays from ERL Phase Power Technologies and SEL are used to protect the Line 1 and 2 respectively, while breaker IEDs are implemented in RTDS simulator. Figure 5-12 shows the GOOSE message exchanges between the line protection IED and the RTDS. For trip signal, line protection relay acts as the GOOSE publisher and the RTDS acts as the GOOSE subscriber whereas for breaker status, it is vice versa.

5.3.2 Learning Objectives

- To learn the use of GOOSE messages in a line protection scheme.
- To learn the functionality of the IEC 61850 station bus.
- To learn the process of configuring modern relays for protection functions.
- To learn the speed and reliability features of GOOSE messages.

5.3.3 Procedure

The single line diagram of the experimental setup is shown in Figure 5-11.

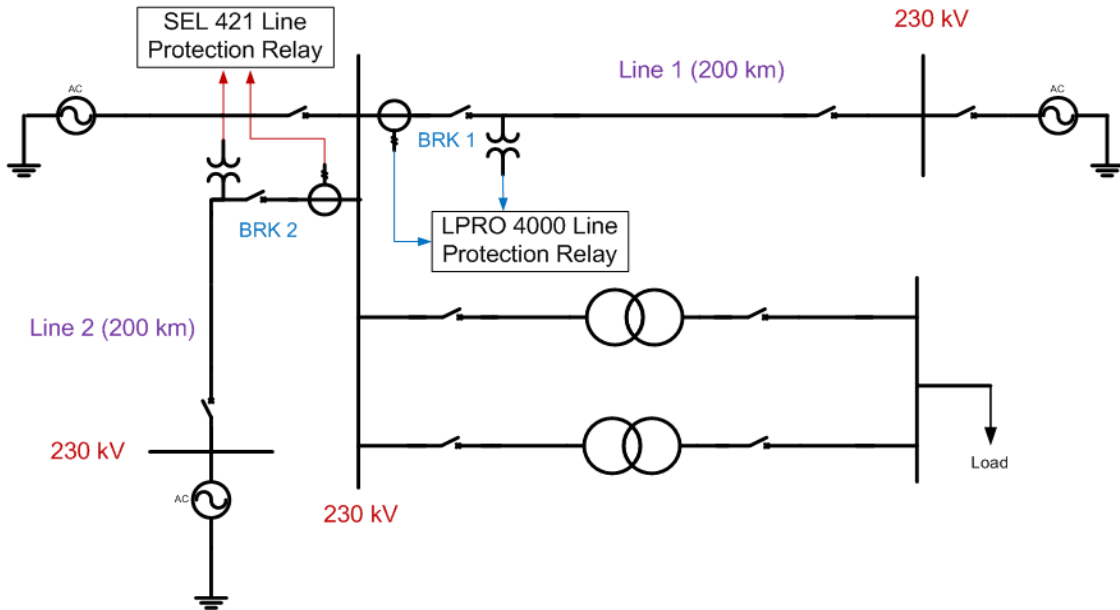


Figure 5-11: Single line diagram of the system

The LPRO 4000 relay protects Line 1 whereas the SEL 421 relay protects Line 2 of the system. A distance protection scheme is implemented in each of the relay. The power system is simulated in RTDS, and the relevant voltage and current signals are fed to relays through analog outputs of RTDS. When a fault is applied to a line, the relay protecting the faulted line detects the fault and sends a trip signal through GOOSE messages to the corresponding circuit breaker simulated in RTDS. Once RTDS receives the GOOSE message and open the circuit breaker, it sends the updated circuit breaker status to the relay via GOOSE messages.

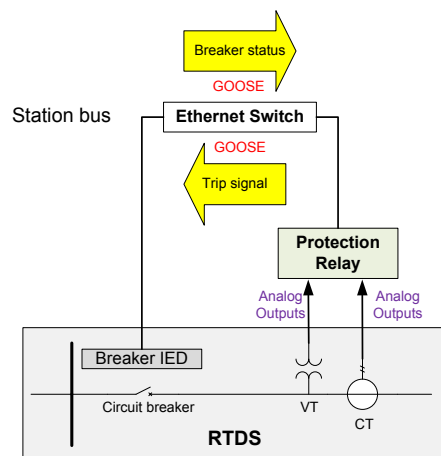


Figure 5-12: GOOSE message exchange between a relay and RTDS in an event of a fault [36]

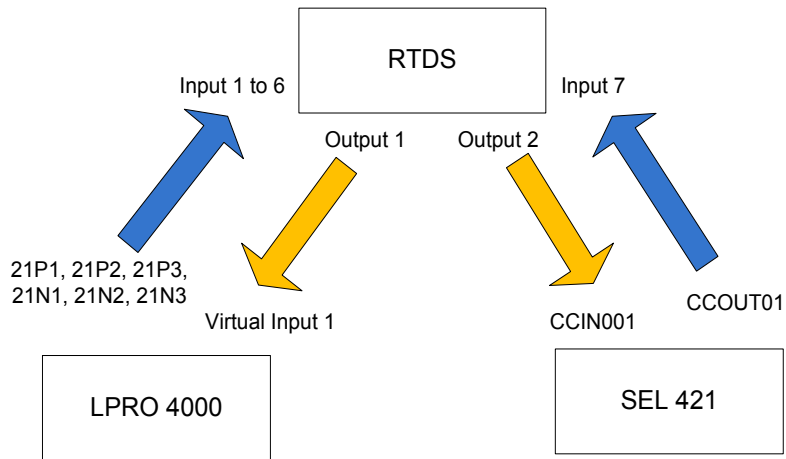


Figure 5-13: experimental setup

Table 5-2: Publisher-subscriber variables of relays for laboratory experiment 2

	Publish	Subscribe
RTDS	Output 1 (to LPRO 4000) Output 2 (to SEL 421)	Input 1 to 6 (from LPRO 4000) Input 7 (from SEL 421)
LPRO 400	21P1 (to RTDS) 21P2 (to RTDS) 21P3 (to RTDS) 21N1 (to RTDS) 21N2 (to RTDS) 21N3 (to RTDS)	Virtual Input 1 (from RTDS)
SEL 421	CCOUT01 (to RTDS)	CCIN001 (from RTDS)

The following steps explain the basic procedure of the laboratory experiment

- Follow the GOOSE mapping procedure described in the interoperability experiment (section 5.2.3). But there are some differences which are described below.
- In this experiment, the RTDS publishes two variables (two circuit breaker statuses). Therefore, the RTDS dataset should include two Boolean dataset entries.
- In the LPRO 4000 relay, protection logical node “PDIS” is used to send the trip signal to RTDS. The distance protection scheme implemented in LPRO 4000 relay consists of

three zones. There is a phase element (21P) and ground element (21N) for each zone. Each of these elements is represented by a different “PDIS” protection logical node. Therefore, all these six data items should be included in the LPRO 4000 dataset and all these six should be subscribed by the RTDS (Input 1 to 6).

Table 5-3: Functionally constrained data attribute of each element

	Functionally Constrained Data Attribute (FCDA)
Zone 1 phase element trip (21P1)	Protection/D21P1PDIS1\$ST\$Op\$general
Zone 2 phase element trip (21P2)	Protection/D21P2PDIS2\$ST\$Op\$general
Zone 3 phase element trip (21P3)	Protection/D21P3PDIS3\$ST\$Op\$general
Zone 1 ground element trip (21N1)	Protection/D21N1PDIS7\$ST\$Op\$general
Zone 2 ground element trip (21N2)	Protection/D21N2PDIS8\$ST\$Op\$general
Zone 3 ground element trip (21N3)	Protection/D21N3PDIS9\$ST\$Op\$general

- The SEL 421 relay in the lab only allows publishing communication card output as GOOSE messages. So the CCOUT01 is set to send a GOOSE message for any trip signal in any of the three zones. So in the SEL configuration tool (AcSELERator Architect), go to dataset tab and select ST (functional constraint) → ANN (logical device) → CCOUTGGIO21 (logical node) → Ind01 (data object) → stVal (data attribute) to assign CCOUT01 to the dataset.
- Before implementing distance protection schemes in the two relays, it is required to calculate positive sequence impedance and zero sequence impedance values in secondary and the zero sequence compensation factor. Table 5-4 shows the information needed to calculate these requirements.

Table 5-4: Information to calculate positive and zero sequence impedances of two transmission lines

	Line 1	Line 2
Positive sequence line impedance (Ω)	4.00 + j34.16	3.38 + j29.46
Zero sequence line impedance (Ω)	142.30 + j339.22	17.52 + j73.90
CT ratio	240:1	
VT ratio	230 kV : 115 V	

- Positive and zero sequence impedances in secondary can be calculated using equations 5-1 and 5-2.

$$Z_{1(\text{secondary})} = Z_{1(\text{primary})} * \frac{CT \text{ ratio}}{VT \text{ ratio}} \quad 5-1$$

$$Z_{0(\text{secondary})} = Z_{0(\text{primary})} * \frac{CT \text{ ratio}}{VT \text{ ratio}} \quad 5-2$$

- Zero sequence compensation factor can be calculated using equation 5-3.

$$K_0 = \frac{Z_{0(\text{secondary})} - Z_{1(\text{secondary})}}{3 * Z_{1(\text{secondary})}} \quad 5-3$$

- Calculate Zone 1, 2 and 3 reach settings based on the specifications provided in Table 5-5.

Table 5-5: Reach settings

Zone	Characteristic	Direction	Reach setting (% Distance)	Time delay (cycles)
Zone 1	Mho	Forward	80	0
Zone 2	Mho	Forward	130	20
Zone 3	Mho	Reverse	40	60

Creating LPRO 4000 setting file

- Open LPRO Offliner Settings software. Go to System Parameters and set the CT and PT ratios accordingly.

- Go to Line Parameters and set the calculated secondary positive and zero sequence impedances.
- Go to Protection Functions and set 21P – Phase Distance and 21N – Ground Distance using calculated reach setting values.

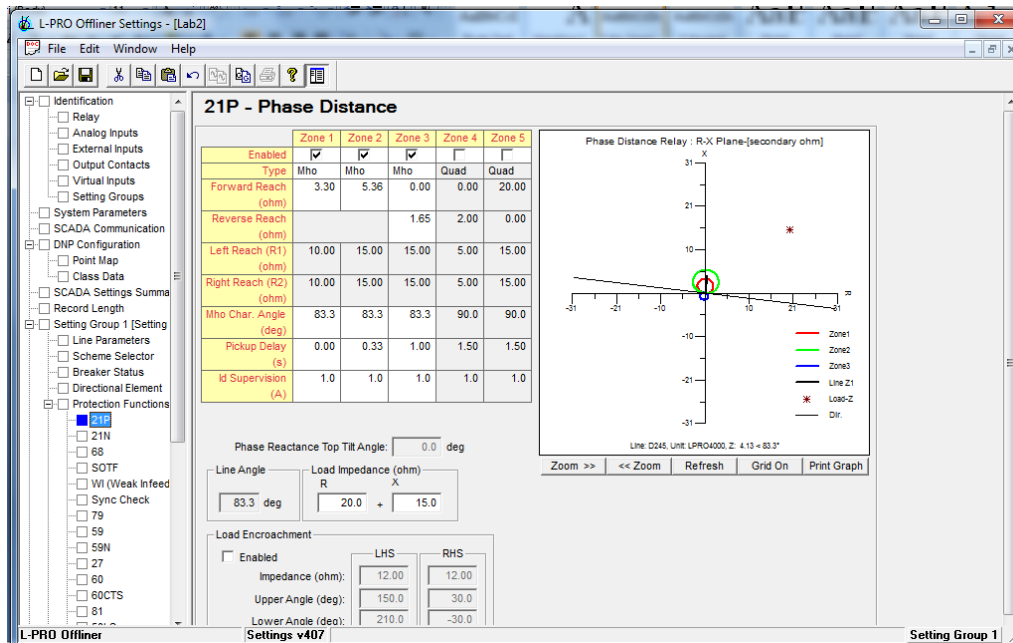


Figure 5-14: Distance protection setting of LPRO 4000 relay settings software

- Save and send the settings to the relay.

Creating SEL 421 setting file

- Open AcSElerator Quickset software. Go to Line Configuration to set the CT, VT ratios and the calculated secondary positive and zero sequence impedances.
- Go to Relay Configuration and set Phase Distance Elements and Ground Distance Elements using calculated reach settings values.
- Go to Distance Elements Common Time Delay to set the time delays of each zone.

Line Configuration

Line Configuration Settings

CTRW Current Transformer Ratio - Input W
240 Range = 1 to 50000

CTRX Current Transformer Ratio - Input X
240 Range = 1 to 50000

PTRY Potential Transformer Ratio - Input Y
2000 Range = 1 to 10000

VNOMY PT Nominal Voltage (L-L) - Input Y (volts, sec)
115 Range = 60 to 300

PTRZ Potential Transformer Ratio - Input Z
2000 Range = 1 to 10000

VNOMZ PT Nominal Voltage (L-L) - Input Z (volts, sec)
115 Range = 60 to 300

Z1MAG Pos.-Seq. Line Impedance Magnitude (ohms, sec)
3.56 Range = 0.25 to 1275.00

Z1ANG Pos.-Seq. Line Impedance Angle (degrees)
83.45 Range = 5.00 to 90.00

Z0MAG Zero-Seq. Line Impedance Magnitude (ohms, sec)
9.11 Range = 0.25 to 1275.00

Z0ANG Zero-Seq. Line Impedance Angle (degrees)
76.66 Range = 5.00 to 90.00

Phase Distance Elements

E21P Mho Phase Distance Zones
3 Select: N, 1-5

Mho Phase Distance Element Reach

Z1P Zone 1 Reach (ohms, sec)
2.85 Range = 0.25 to 320.00, OFF

Z2P Zone 2 Reach (ohms, sec)
4.63 Range = 0.25 to 320.00, OFF

Z3P Zone 3 Reach (ohms, sec)
1.42 Range = 0.25 to 320.00, OFF

Z4P Zone 4 Reach (ohms, sec)
OFF Range = 0.25 to 320.00, OFF

Z5P Zone 5 Reach (ohms, sec)
OFF Range = 0.25 to 320.00, OFF

Distance Elements Common Time Delay

ECDTD Distance Element Common TD
Y Select: Y, N

Distance Elements Common Time Delay

Z1D Zone 1 Time Delay (cycles)
0.000 Range = 0.000 to 16000.000, OFF

Z2D Zone 2 Time Delay (cycles)
20.000 Range = 0.000 to 16000.000, OFF

Z3D Zone 3 Time Delay (cycles)
60.000 Range = 0.000 to 16000.000, OFF

Z4D Zone 4 Time Delay (cycles)
OFF Range = 0.000 to 16000.000, OFF

Z5D Zone 5 Time Delay (cycles)
OFF Range = 0.000 to 16000.000, OFF

Figure 5-15: Distance protection setting of SEL 421 relay settings software

- Save and send the settings to the relay.
- Now go back to RSCAD draft file, compile the case and open the runtime window of the case.
- In the runtime window, apply different types of faults to different locations of the lines and complete Table 5-6 and Table 5-7 for each relay (LPRO 4000 and SEL 421).

Table 5-6: Forward faults

Fault type	Location	Fault Impedance	Relay response				
			Fault type	Location (km)	Operating times (s)	Zone	Comments
AG	10%	0.01 Ω					
BC							
ABC							
AG	90%						
BC							
ABC							

Table 5-7: Reverse fault (bus fault)

Fault type	Location	Fault Impedance	Relay response				
			Fault type	Location (km)	Operating times (s)	Zone	Comments
AG	0% (bus fault)	0.01 Ω					
BC							
ABC							

Events file can be downloaded from the relay to get time stamps of the GOOSE messages (time the trip signal left the relay and time the circuit breaker status received by the relay). Also, using Wireshark software or RTDS run time graphs, time the trip signal is received by the RTDS and the breaker status left the RTDS can be obtained. The time difference between RTDS and the relay is the transmission time of the GOOSE messages.

5.4 Intended Engineering Process of IEC 61850

5.4.1 Overview of the Experiment

The main objective of this laboratory exercise is to understand and familiarize with the engineering process involved in the design of substation automation (SA) systems as envisioned in the standard IEC 61850. A system configuration tool is used to draw a single line diagram (SLD), allocation of logical nodes and creation datasets, control blocks, external mapping and various SCL files as part of this exercise.

A system configuration tool named KalkiTech SCL Manager designed by KalkiTech Technologies is used for this laboratory exercise. The engineering process starts with the drawing of the single line diagram (SLD) of the given substation section. The software is capable

of translating the XML code from the single line diagram. This can be saved or exported as a SSD (System Specification Description) file.

Secondly, some of the ICD files are imported into the system configuration tool and the rest of required numbers of IED instances with necessary configurations are created. After all the IED instances are created, allocation of LNs is carried out to ensure that all equipment in primary plant is represented by corresponding LNs inside IEDs. GOOSE and Sampled Values (SV) datasets and control blocks are created to publish the required information. Moreover, signal mapping between IED is carried out to define the information exchange among them. Finally, a file with all the above information (including SLD, IED configurations and communication network) is created and saved. This file is referred to as the SCD (Substation Configuration Description) file.

5.4.2 Learning Objectives

- To familiarize with the engineering process envisaged in the IEC 61850 standard.
- To familiarize with system configuration tool.
- To learn about the logical node allocation.
- To learn the process of creating GOOSE and SV datasets and control blocks.

5.4.3 Procedure

- Open “KalkiTech SCL Manager”. (The perceived system configuration tool here)
- Click on “New project” under getting started, a new project window will be opened.

- Give an appropriate project name, select project type as substation (select version 2).

Drawing the SLD

- Following the descriptive instructions given in section 4 of the SCL Manager user manual, Substation Specification and create the single line diagram (SLD) of the substation section given below in Figure 5-16. An image of the completed SLD on KalkiTech SCL Manager is given in Figure 5-17.

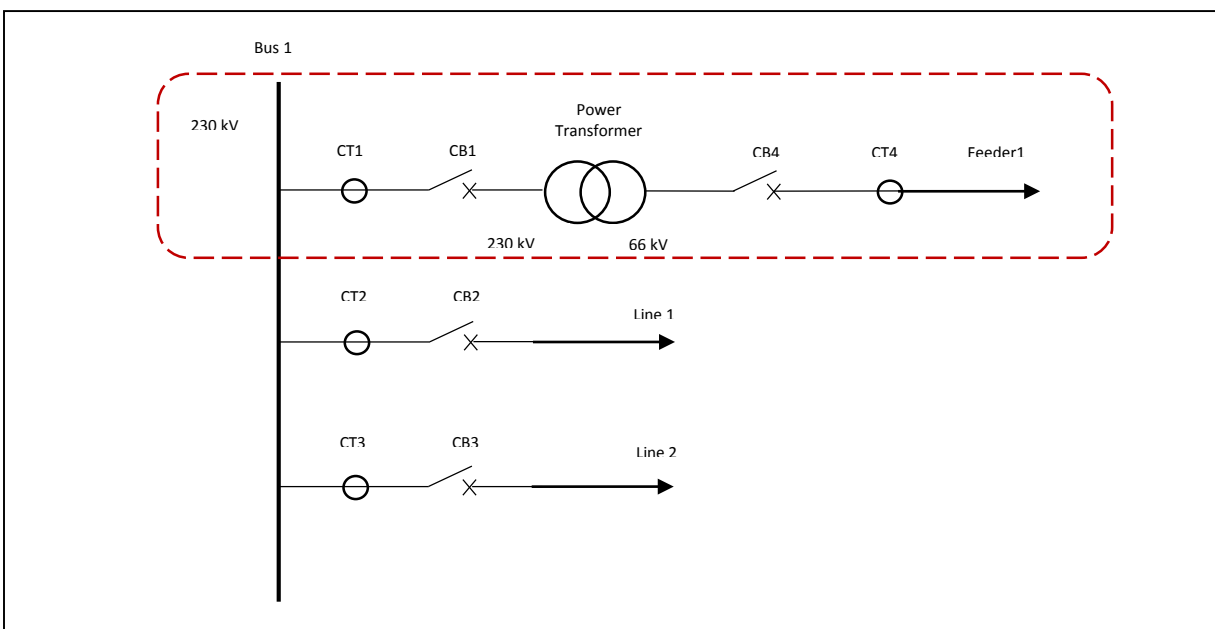


Figure 5-16: Substation section

While drawing the SLD, observe how the SCD file is being updated as you add different elements. After completing the diagram, compare the information in the SCD file and the SLD.

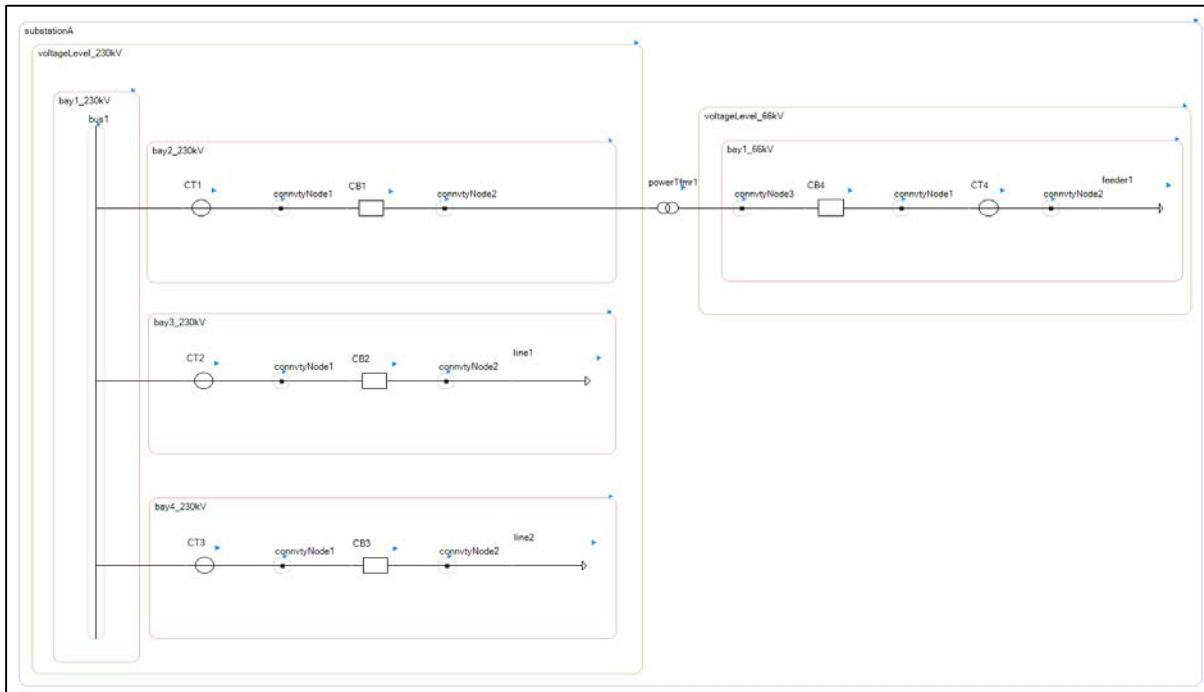


Figure 5-17: Completed SLD on KalkiTech SCL Manager

Create a new IED

To perform the configurations, ICD file of all the IEDs (physical devices) are required to be imported into the system configuration tool. In an actual IEC 61850 compliant substation automation system all the primary equipment is controlled by IEDs with ICD files of their own. Since such a system is unavailable, we can use KalkiTech SCL Manager to create ICD files for imaginary IEDs governing the primary equipment. Further, ICD file for one protection IED is created as well.

- Go to Project explorer → IED → Add → IED → Create New. Give “Bay2_230kV_IED” as IED name. Give the following information to the address fields.

IP address : 192.168.100.90

Subnet Mask : 255.255.255.0

Gateway : 192.168.100.1

- Choose number of Logical Devices (LD) as 2. Name them as “BIED” and “CT”.
- Select the created IED from the IED section in the project explorer and then go to the tree view at top right hand corner. From the tree view, select the LD BIED, right click on it and go to Add → Logical Nodes → Switchgear → XCBR (circuit breaker).
- Similarly, add **three** instances of “TCTR-Current Transformer” (for three phases) logical node to the LD CT. (Use “Create New TCTR” option and go to DO: Amp → DA; instMag and tick both boxes “i” and “f”.)
- Repeat above four steps and create IEDs with following specifications,
 - An identical IED to Bay2_230kV_IED named “Bay1_66kV_IED” (IP address: 192.168.100.91).
 - A transformer IED named “Transformer_IED” with a single instance of “YPTR-Power transformer” logical node using default option (IP address: 192.168.100.92).
 - A protection IED named “Protection_IED_1” with a single instance of “PDIF-Differential Protection” logical node and 12 instances of “GGIO-Generic Process I/O” logical node. Use “Create New GGIO” option and go to DO: AnIn → DA; instMag and tick both boxes “i” and “f”, similarly, tick DO: Ind. (IP address: 192.168.100.93).

Importing an ICD file

- Go to Project explorer → IED → Add → IED → Import from file system. Browse the

SEL 421 ICD. Assign “sel421” as the IED name, fill in the following,

IP address : 192.168.100.85 (use the above given Subnet Mask and Gateway)

Allocation of Logical Nodes

Allocation of logical nodes aids to ensure that all the primary equipment (in the SLD) and its functions (logical nodes: LNs) are represented in the system configuration tool. There is no connection between the LNs in the SLD and those in an .icd file other than the said representation.

- Refer section 4.7 in the user manual and link the LNs of the two circuit breakers and two CTs in bays 2 and 5, to the LNs created in the IED in the above steps. Before doing the allocation make sure that you add two additional TCTR logical nodes to the CT elements in the SLD to represent the three phases. (First, right click on the CT element and go to Add → LNode → Txxx: Transducers and instrument transformers → TCTR: Current Transformer)
- Go to SCD file, observe and compare its details with the SLD diagram.

Creating datasets and control blocks

A differential protection scheme is to be implemented for the power transformer, where three line currents at each end of the transformer is fed as sampled valued to the protection relay and the trip signal is send to the two circuit breakers via GOOSE messaging (A schematic is given in Figure 5-18). To implement the IEC 61850 related communication part of this scheme, a similar procedure is taken as in previous labs, wherein datasets (with necessary data attributes to be

published) and control blocks are created as required.

- Select Bay2_230kV_IED from the IED section in the project explorer, go to (in tree view) the LD CT and right click on LNInstance: LLNO → Add → DataSet.
- In the appearing window, put a suitable dataset name, choose CT as LD and pick TCTR1 from the list of logical nodes.
- Select “TCTR1\$MX\$Amp\$instMag\$i” from the Data Tags and click the arrow button to add it to the FCDA tags. Repeat the step with TCTR2 and TCTR3.
- Go to LNInstance: LLNO → Add → SMV control block. Name the control block appropriately and select the dataset created in above from the drop-down-list. Set the MAC address as 01-0C-CD-04-00-01.
- Follow the same procedure for Bay1_66kV_IED and create a dataset and a SMV control block (Set the MAC address as 01-0C-CD-04-00-02 for the SMV control block).
- Follow the same procedure for Protection_IED_1 and create a dataset. But in this IED, instead of a SMV control block, create GSE control block (LDevice: IDevice1, LNode: PDIF1, Data Tag: “PDIF1\$ST\$Op\$general”, and here, create a GSE control clock with the MAC address as 01-0C-CD-01-00-01).

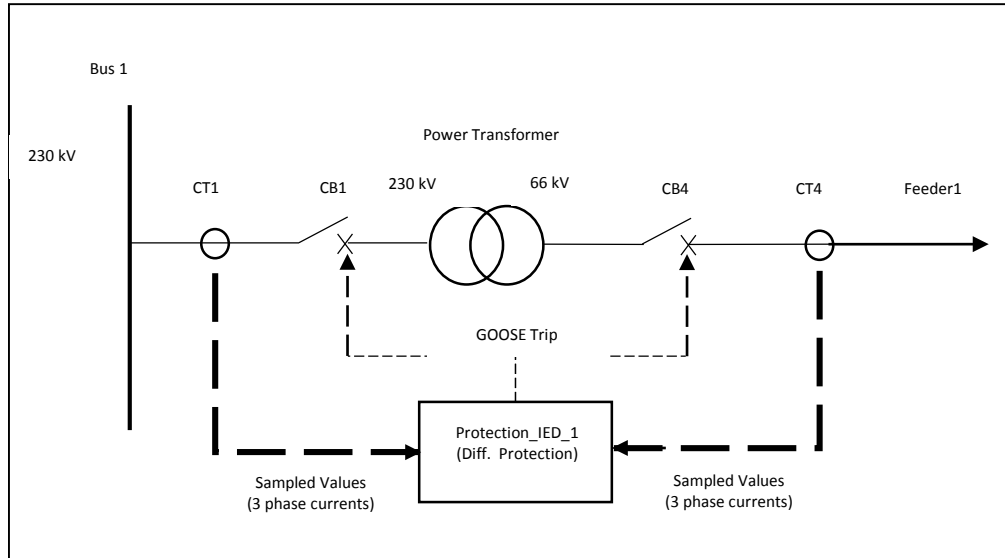


Figure 5-18: Differential protection scheme implemented

External Signal Mapping

- Right click on the “Project” in the project explorer and go to “Map External Signals”. A new window will be opened.
- Under Source, select “Bay2_230kV_IED” as IED, “CT” as LD, “All” from radio button options, “TCTR1” as LN and “TCTR1\$MX\$Amp\$instMag\$i” from Data Tags. Then click the button MAP.
- In the newly popped up window, select “Protection_IED_1” as IED, “IDevice1” as LD, “GGIO1” as LN and “GGIO1\$MX\$AnIn\$instMag\$i” from Data Tags and click ok. Notice the mapped source and destination data tags appear in a table in the Map External Signals window.
- Repeat the above two steps and map the entire following data signal as shown in Table 5-8.

Table 5-8: Signal Mapping

Source		Destination	
Bay2_230k V_IED	TCTR2\$MX\$Amp\$instMag\$i	Protection_ IED_1	GGIO2\$MX\$AnIn\$instMag\$i
	TCTR3\$MX\$Amp\$instMag\$i		GGIO3\$MX\$AnIn\$instMag\$i
Bay1_66k V_IED	TCTR1\$MX\$Amp\$instMag\$i		GGIO4\$MX\$AnIn\$instMag\$i
	TCTR2\$MX\$Amp\$instMag\$i		GGIO5\$MX\$AnIn\$instMag\$i
	TCTR3\$MX\$Amp\$instMag\$i		GGIO6\$MX\$AnIn\$instMag\$i
Protection_ IED_1	PDIF1\$ST\$Op\$general		Bay2_230k V_IED
		Bay1_66k V_IED	XCBR1\$ST\$Pos\$stVal

- Right click on SCD file in Project Explore → Export. Save the file and give a suitable name.

This SCD file consists of all the substation configurations. This file can be also imported into an IED configuration tool. The IED configuration tool will recognize all the IEDs in the system and all the created datasets and control blocks. But the external mapping will not be recognized by the IED configuration tool as it is a local issue.

5.5 Chapter Summary

In this chapter, three laboratory experiments were discussed. First experiment was a simple setup developed to demonstrate the interoperability feature of the IEC 61850 standard. The second experiment used the laboratory setup developed in Chapter 3 to illustrate the IEC 61850 station bus functionality. The third experiment was the intended engineering process of IEC 61850. This chapter presented learning objectives and detailed procedures of the three experiments. These experiments are intended to educate and to provide hands on training for students (objective 5).

Chapter 6

Conclusion and Recommendations

6.1 Summary of Work and Conclusions

The main goal of the research is to demonstrate the IEC 61850 station bus concept for education, training and research purposes. The objectives that are essential for this goal are to develop a laboratory setup of an IEC 61850 station bus compliant substation, implementation of low level interface between the real-time simulator and various protection IEDs, and to evaluate the performance of the laboratory setup. Also, to implement test cases and applications to illustrate interoperability between IEDs of different vendors and the effectiveness of GOOSE messages, as well as to develop laboratory exercises and instruction sheets based on the developed laboratory setup to provide hands on training for students.

The laboratory setup was implemented in the Intelligent Power Grid Laboratory (IPGL) of the Stanley Pauley Centre of the University of Manitoba using the hardware available in the laboratory. RTDS is used to implement and simulate a 230 kV electric substation. The laboratory is equipped with three IEC 61850 station bus compliant relays from ERL Phase Power

Technologies and two IEC 61850 station bus compliant relays from Schweitzer Engineering Laboratories. The electrical network configuration was chosen so that the protection can be provided with the available protection relays. Simulated voltage and current signals taken through the analog outputs of the RTDS are fed to internal low level interfaces of the protection relays. This low level interfacing methodology adopted in this thesis resulted in significant cost saving and a less complex, energy efficient test setup. All the relays and the RTDS were connected to a Ruggedcom Ethernet switch which was used to implement the station bus communication. The SEL 2407 satellite clock was connected to all the devices for time synchronization. IED configuration tool of each vendor and a system configuration tool were used to implement the GOOSE configuration so that trip signals and circuit breaker statuses were sent through GOOSE messages. A number of tests were conducted to verify the correct operation of the protection system. The GOOSE transfer time of trip signals and breaker status signals were measured and the performance of GOOSE messages was compared with the traditional hardwired connection. Based on the tests conducted, it can be concluded that

- All protection and control schemes work as intended in the design.
- The GOOSE transfer time results were well within the specifications mentioned in the standard.
- The trip signals transferred via GOOSE messages were faster than those sent through hardwired connections.
- Step by step information on how to implement, configure, and test the laboratory setup, documented in Chapter 3, is a very useful reference for future developments and research.

Three applications were developed in Chapter 4 to demonstrate the use of GOOSE messages in protection functions. The first application was an interlocking and breaker failure application. A new radial setup was implemented for this application and an overcurrent protection scheme was used. In the interlocking application, a feeder relay sends a block signal through a GOOSE message to an upstream relay during feeder faults to prevent inadvertent operation of the upstream relay's definite time overcurrent protection function. For the breaker failure application, if the feeder side breaker fails to open for a feeder fault, the relay that controls the feeder side breaker sends a breaker failure trip signal to the upstream relay via GOOSE messages. The second example was a recloser application implemented in the line protection relay that protects one of the transmission lines. In this application, GOOSE messages were used to send the reclose commands in addition to trip signal and circuit breaker statuses. Results of the tests verified the correct operation of the above applications.

The third application is a novel idea to implement a backup bus bar protection without using additional IEDs. This example application used GOOSE messages from the two line protection relays and two transformer protection relays to protect a 230 kV bus from bus faults. Each relay subscribed GOOSE messages from rest of the relays, and the protection logic was implemented in all the relays so that each relay works independently. The application is designed in such a way that even when one of the relays malfunctions, the other three relays are still able to detect the bus fault and issue trip signals. The tests involving both internal and external faults confirmed that the proposed backup bus protection scheme is dependable and secure.

All trip signals used in the example applications reached the respective breaker IEDs simulated in RTDS before 3 milliseconds and rest of the GOOSE messages carrying status signals reached their destination IEDs within 4 milliseconds despite the high GOOSE message traffic in the

network. These results confirm that the GOOSE messages are fast, reliable and well suited for time critical protection applications.

Instruction sheets for three laboratory experiments were developed in Chapter 5. One was a simple setup used to demonstrate the interoperability feature and the GOOSE mapping process. The second experiment used the substation developed in Chapter 3, but only utilized the two line protection relays to illustrate the IEC 61850 station bus functionality. Third experiment used a system configuration tool to demonstrate the engineering process of IEC 61850. The developed laboratory instruction sets were used in a course on advanced power system protection to provide hands on training for students. The developed laboratory instructions are expected to be used for education and research in this emerging area.

6.2 Recommendations for Future Research

The developed laboratory setup is protected by relays of only two vendors due to the fact that Intelligent Power Grid Laboratory is only equipped with relays of two vendors. But the system can be easily expanded by adding more relays of different vendors. For example, the existing setup can be augmented with a generator protection relay from a different vendor to protect the source directly connected to the 230 kV bus bar. This will help further demonstration and testing of the interoperability feature. More relays in the system means more GOOSE messages are communicating through the system. This can also allow testing the transmission time of the GOOSE messages when there is high density of GOOSE messages transmitting through the network.

Currently, all the relays in the laboratory require analog inputs to receive voltage and current

signals. RTDS requires GTA0 cards to supply these analog signals to relays. Four GTA0 cards are used for the current laboratory setup. Increased number of relays may cause issues due to the limitation of GTA0 cards and the space to attach the GTA0 cards. This can be easily overcome by expanding this system with relays which are capable of IEC 61850 Sampled Values (SV). Not only it will reduce complexity of the connections between RTDS and relays, also it will open up more research opportunities in the IEC 61850 process bus area as well. Moreover, having both process bus and station bus compliant relays can make this laboratory setup a fully IEC 61850 compliant test setup.

Another aspect of the station bus is to communicate with the Human Machine Interface (HMI) which can be done through MMS messages. Also, a good user interface is needed to control and monitor the complete system. This can be helpful when this system is expanded for future research.

Appendix

A.1. Distance Protection Calculations

Line 1

Positive sequence impedance

- Positive sequence resistance = $0.0200491 \text{ } \Omega/\text{km} * 200 \text{ km} = 4.00982 \text{ } \Omega$
- Positive sequence reactance = $0.17084055 \text{ } \Omega/\text{km} * 200 \text{ km} = 34.16811 \text{ } \Omega$

Therefore, positive sequence impedance in primary is,

$$Z_{1(primary)} = 4.00982 + j34.16811 = 34.40/_{-83.3^\circ} \text{ } \Omega$$

- CT ratio = 240:1
- VT ratio = 230000:115

Therefore, positive sequence impedance in secondary can be calculated as follows,

$$Z_{1(secondary)} = Z_{1(primary)} * \frac{CT \text{ ratio}}{VT \text{ ratio}} \quad \text{A.1 - 1}$$

$$Z_{1(secondary)} = \mathbf{4.13/_{-83.3^\circ} \text{ } \Omega}$$

Zero sequence impedance

- Zero sequence resistance = $0.71147855 \text{ } \Omega/\text{km} * 200 \text{ km} = 142.29571 \text{ } \Omega$

- Zero sequence reactance = $1.6960798 \text{ } \Omega/\text{km} * 200 \text{ km} = 339.21596 \text{ } \Omega$

Therefore, zero sequence impedance in primary is,

$$Z_{0(\text{primary})} = 142.29571 + j339.21596 = 367.85/_{-67.2^\circ} \text{ } \Omega$$

- CT ratio = 240:1
- VT ratio = 230000:115

Therefore, zero sequence impedance in secondary can be calculated as follows,

$$Z_{0(\text{secondary})} = Z_{0(\text{primary})} * \frac{\text{CT ratio}}{\text{VT ratio}} \quad \text{A.1 - 2}$$

$$Z_{0(\text{secondary})} = \mathbf{44.14/_{-67.2^\circ} \text{ } \Omega}$$

Zero sequence compensation factor

$$K_0 = \frac{Z_{0(\text{secondary})} - Z_{1(\text{secondary})}}{3 * Z_{1(\text{secondary})}} \quad \text{A.1 - 3}$$

$$K_0 = \mathbf{3.24/_{-17.7^\circ} \text{ } \Omega}$$

Reach settings

- $\text{Zone 1} = Z_{1(\text{secondary})} * 0.8 = 4.13/_{-83.3^\circ} * 0.8 = \mathbf{3.30/_{-83.3^\circ}}$
- $\text{Zone 2} = Z_{1(\text{secondary})} * 1.3 = 4.13/_{-83.3^\circ} * 1.3 = \mathbf{5.36/_{-83.3^\circ}}$
- $\text{Zone 3} = Z_{1(\text{secondary})} * 0.4 = 4.13/_{-83.3^\circ} * 0.4 = \mathbf{1.65/_{-83.3^\circ}}$

Table A- 1: Reach settings of transmission line 1

Zone	Characteristics	Direction	Reach Settings		Time delays (cycle)
			% distance	Ohms	
Zone 1	Mho	Forward	80	3.30/_83.3°	0
Zone 2	Mho	Forward	130	5.36/_83.3°	20
Zone 3	Mho	Reverse	40	1.65/_83.3°	60

Line 2

Positive sequence impedance

- Positive sequence resistance = $0.016928 \Omega/\text{km} * 200 \text{ km} = 3.3856 \Omega$
- Positive sequence reactance = $0.1473265 \Omega/\text{km} * 200 \text{ km} = 29.4653 \Omega$

Therefore, positive sequence impedance in primary is,

$$Z_{1(primary)} = 3.3856 + j29.4653 = 29.66/_83.45^\circ \Omega$$

- CT ratio = 240:1
- VT ratio = 230000:115

Therefore, positive sequence impedance in secondary can be calculated using equation A.1-1,

$$Z_{1(secondary)} = 3.56/_83.45^\circ \Omega$$

Zero sequence impedance

- Zero sequence resistance = $0.0876024 \Omega/\text{km} * 200 \text{ km} = 17.52048 \Omega$

- Zero sequence reactance = $0.3695065 \text{ } \Omega/\text{km} * 200 \text{ km} = 73.9013 \text{ } \Omega$

Therefore, zero sequence impedance in primary is,

$$Z_{0(\text{primary})} = 17.52048 + j73.9013 = 75.95/_-76.66^\circ \text{ } \Omega$$

- CT ratio = 240:1
- VT ratio = 230000:115

Therefore, zero sequence impedance in secondary can be calculated using equation A.1-2,

$$Z_{0(\text{secondary})} = 9.11/_-76.66^\circ \text{ } \Omega$$

Zero sequence compensation factor

Using equation A.1-3,

$$K_0 = 0.523/_-11.11^\circ \text{ } \Omega$$

Reach settings

- $Zone\ 1 = Z_{1(\text{secondary})} * 0.8 = 3.56/_-83.45^\circ * 0.8 = 2.85/_-83.45^\circ$
- $Zone\ 2 = Z_{1(\text{secondary})} * 1.3 = 3.56/_-83.45^\circ * 1.3 = 4.63/_-83.45^\circ$
- $Zone\ 3 = Z_{1(\text{secondary})} * 0.4 = 3.56/_-83.45^\circ * 0.4 = 1.42/_-83.45^\circ$

Table A- 2: Reach settings of transmission line 2

Zone	Characteristics	Direction	Reach Settings		Time delays (cycle)
			% distance	Ohms	
Zone 1	Mho	Forward	80	2.85/_83.45°	0
Zone 2	Mho	Forward	130	4.63/_83.45°	20
Zone 3	Mho	Reverse	40	1.42/_83.45°	60

A.2. Calculations of Overcurrent Relay

Settings

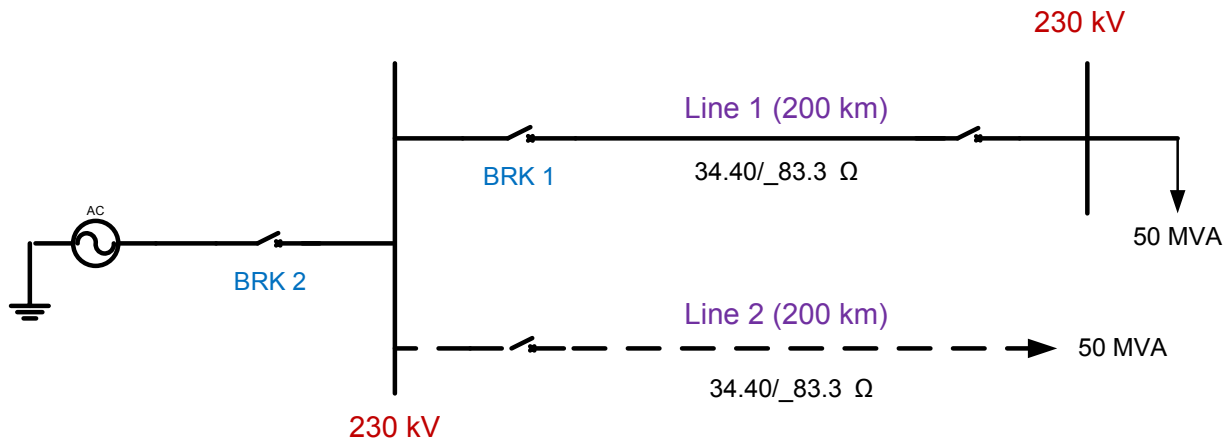


Figure A- 1: Single line diagram of the system

Fault currents

$$I_{f(BRK2)} = I_{f(BRK1)} = \frac{\left(\frac{230}{\sqrt{3}}\right) * 10^3}{34.40} = 3.862 \text{ kA}$$

Nominal currents

$$I_{nominal (BRK1)} = \frac{50 * 10^6}{\sqrt{3} * 230 * 10^3} = 125.51 A$$

$$I_{nominal (BRK2)} = 2 * 125.51 = 251.02 A$$

Assuming that the CT for breaker 1 (BRK 1) is of C-100 type with 5A secondary rating and have 1 Ω burden.

$$I_{P_rated(BRK1)} = I_{f(BRK1)} * \frac{5 A}{100 V} * 1 \Omega = 193.1 A$$

Assuming that the CT for breaker 2 (BRK 2) is of C-100 type with 1A secondary rating and have 2 Ω burden.

$$I_{P_rated(BRK1)} = I_{f(BRK1)} * \frac{1 A}{100 V} * 2 \Omega = 77.24 A$$

Table A- 3: Suitable CT ratios for two breakers

	$I_{nominal}$ (A)	I_{p_rated} (A)	Suitable CT ratio
BRK 1	125.51	193.1	200:5
BRK 2	251.02	77.24	300:1

Pickup currents for phase overcurrent

$$I_{pickup (BRK 1)} = 125.51 * 1.5 * \frac{5}{200} = 4.70 A \rightarrow \mathbf{5 A}$$

$$I_{pickup (BRK 2)} = 251.02 * 1.5 * \frac{1}{300} = 1.26 A \rightarrow \mathbf{1.3 A}$$

Pickup currents for ground overcurrent

$$I_{pickup (BRK 1)} = 125.51 * 0.2 * \frac{5}{200} = 0.62 A \rightarrow \mathbf{0.7 A}$$

$$I_{pickup (BRK 2)} = 251.02 * 0.2 * \frac{1}{300} = 0.16 A \rightarrow \mathbf{0.2 A}$$

Instantaneous for phase overcurrent

$$I_{Instantaneous (BRK 1)} = 10 * 125.51 * \frac{5}{200} = 31.37 A \rightarrow \mathbf{32 A}$$

$$I_{Instantaneous (BRK 2)} = 10 * 251.02 * \frac{1}{300} = 8.37 A \rightarrow \mathbf{8.5 A}$$

Instantaneous for ground overcurrent

$$I_{Instantaneous (BRK 1)} = 125.51 * \frac{5}{200} = 3.13 A \rightarrow \mathbf{3.2 A}$$

$$I_{Instantaneous (BRK 2)} = 251.02 * \frac{1}{300} = 0.83 A \rightarrow \mathbf{1.0 A}$$

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