MONITORING, PROTECTION, AND VOLTAGE CONTROL OF PARALLEL POWER TRANSFORMERS BASED ON IEC 61850-9-2 PROCESS BUS

by

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DECLARATION

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

Signed   Date

ABSTRACT

The purpose of an electrical power system is to supply electrical energy to the customers. Power transformers are required to transform the system voltage from generation to transmission and distribution levels. Protection and control systems must ensure that power system high voltage equipment such as transformers operate and deliver save, reliable and secure electricity supply.

The aim of the project research work is to develop and implement a strategy, methods and algorithms for monitoring, protection and voltage control of parallel power transformers based on IEC 61850-9-2 process bus standard.

NamPower is a power utility in Namibia. The IEC 61850 protocol for electrical substation automation system is used for the protection and control of 5 power transformers operated in parallel in an existing substation system.

The IEC 61850-9-2 process bus standard is however not used in regards of Sampled Values (SV). Protection and control devices are connected to a substation communication network, routers and switches using fibre optic linked Ethernet. Inductive Current Transformers (CTs) and Voltage Transformers (VTs) secondary circuits are hardwired to Intelligent Electronic Devices (IEDs) and fibre optic links are not used for this purpose at process level communication.

The research focuses on the implementation of the IEC 61850 standard with Merging Units (MUs) and sampled values to improve the existing implemented protection and control system at NamPower. This includes substation communication networks and MUs used for transformer protection, voltage regulator control and cooling fan control.

At the present the CTs located at the transformer bushings and switchgear and the VTs located at the switchgear are hardwired to the inputs on protection and control IEDs. The research focuses on issues with the copper wires for voltage and currents signals and how these issues can be eliminated by using the MUs and the SV protocol.

The MUs which are considered in this Thesis is to improve the voltage regulator control and the control of the cooling fan motors. The voltage regulator control IED is situated at the tap change motor drive of the On-Load Tap Changer (OLTC). The IED of each transformer is required to regulate the voltage level of the secondary side bus bar it is connected to. All the regulating IEDs are required to communicate with each other and collectively to control the bus bar voltage depending on the switching configuration of the parallel transformers.

The control circuit for controlling the cooling fan motors is hardwired. Temperature analogue signal input into a programmable automation controller IED can be used for controlling the transformer cooling fans.

A strategy, methods and algorithms for transformer protection, voltage regulator control and cooling fan motor control of parallel power transformers need to be developed and implemented based on IEC 61850-9-2 process bus.

Power utilities and distributors can benefit from interpretation of the IEC 61850-9-2 standard and implementing MUs and SV in substations. MUs can be included in the power transformer protection, automation and control systems. A cost reduction in high voltage equipment, substation installation and commissioning costs and better performance of protection and control system are anticipated.

Key Words:
Transformer differential protection, IEC 61850-9-2, Sampled Values, Merging Units, Transformer voltage control, Tap Changer Control, Process bus, Substation automation system, Transformer cooling fan control.

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DEDICATION

This Thesis is dedicated to my wife Hanlie, my daughter Johanè, and my son Wihan. Thank you for your support.

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GLOSSARY

Terms	Explanation
Abstract communication service interface -	Virtual interface to an IED providing abstract information modelling methods for logical devices, logical nodes, data, and data attributes, and communication services.
A/D Conversion-	The process of converting an analogue signal into an equivalent digital one, involving the use of an analogue to digital converter.
Back up protection-	A protection system intended to supplement the main protection in case the latter should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection.
Biased relay-	A relay in which the actuating quantity characteristics are modified by the introduction of some other quantity which is usually in opposition to the actuating quantity.
Broadcast-	Message placed onto a communication network intended to be read and acted on, as appropriate, by any IED.
Bus-	Communication system connection between IEDs with communication facilities
Data link layer-	Layer 2 of the OSI reference model for Open Systems Interconnection, responsible for the transmission of data over a physical medium. Layer 2 performs data rate control, error detection, contention/collision detection, quality of service monitoring and error recovery

Data object-	Part of a logical node object representing specific information for example status or part measurement. From an object-oriented point of view, a data object is an instance of a data class
Dependability-	A measure of a protection scheme's ability to operate correctly when it is called upon.
Digital signal processor-	A microprocessor optimised in both hardware architecture and software instruction set for the processing of analogue signals digitally, through use of the DFT and similar techniques.
Digital signal processing-	A technique for the processing of digital signals by various filter algorithms to obtain some desired characteristics in the output. The input signal to the processing algorithm is usually the digital representation of an analogue signal, obtained by A/D conversion.
Earth fault protection system-	A protection system which is designed to respond only to faults to earth.
Earthing transformer-	A three-phase transformer intended essentially to provide a neutral point to a power system for earthing.
Gateway-	The Gateway is a computer which provides interfaces between the local computer system and one or several SCADA or RCC systems
Generic Object Oriented Substation Event-	On the occurrence of any change of state, an IED will multicast a high speed, binary object, Generic Object Oriented Substation Event (GOOSE) report.
Global Positioning System-	A system used for locating objects on Earth precisely, using a system of satellites in

geostationary orbit in Space. Used by some numerical relays to obtain accurate UTC time information.

Intelligent Electronic Device- A device incorporating one or more processors, with the capability to receive or send data/control, from, or to, an external source, for example electronic multi-function digital relays.

Local area network- Communications network which covers the area within the substation.

Logical Node- Standardised IEC61850 data model describing the logical attributes of a protection or control function.

Main Protection- The main protection system which is normally expected to operate in
response to a fault in the protected zone

Merging unit- Interface unit that accepts multiple analogue CT/VT and binary inputs and produces time synchronised digital outputs.

Network- Layer 3 of the OSI reference model for Open Systems Interconnection, provides functional and
procedural means of transmission, also independence from routing and communications relaying considerations, enabling the transparent transfer of data between transport entities.

On load tap changer- A tap changer that can be operated while the transformer is supplying load.

Protection system- A combination of protection equipment designed to secure, the under predetermined conditions, usually abnormal, disconnection of an element of a power system, or to give an alarm signal, or both.

Physical layer- Layer 1 of the OSI reference model for Open Systems Interconnection provides the mechanical, electrical, functional and procedural means to activate, maintain and de-activate physical connections for bit transmission between data-link entities. Physical layer entities are interconnected by means of a physical medium.

Redundancy- Existence of more than one means for performing a required function

Selectivity- When a fault occurs, the protection scheme is required to trip only those circuit breakers whose operation is required to isolate the fault.

Security- A measure of a protection scheme's ability to restrain and prevent spurious operation, when no operation is required.

Sensitivity- A term frequently used when referring to minimum operating level of relays or complete protection schemes.

Speed- The function of protection systems is to isolate faults on the power system as rapidly as possible, to prevent widespread loss of synchronism and consequent collapse of the power system.

Stability- refers to the ability of the protection system to remain unaffected by conditions external to the protected zone, for example through-load current and faults external to the protected zone.

Substation automation system-	Provides automation within a substation and includes the IEDs and communication network infrastructure.
Switch-	Active network component. Switches connect two or more sub networks. Switches establish the borders for so called collision domains. Collisions cannot take place between networks divided by switches, data packets destined to a specific sub network do not appear on the other sub networks.
Tap changer-	A mechanism, fitted to the winding of a transformer, to alter the turns ratio of the transformer by small discrete amounts over a defined range.
Unit protection-	A protection system that is designed to operate only for abnormal conditions within a clearly defined zone of the power system.
Universal Time Coordinated.	The precise internationally recognised time reference, equivalent to GMT.

ABBREVIATIONS AND ACRONYM

CAN -	Controller Area Network
CT -	Current Transformer
CSAEMS -	Centre for Substation Automation and Energy Management Systems
CPUT -	Cape Peninsula University of Technology
DANH -	Doubly Attached Node running HSR
DANP -	Doubly Attached Node running PRP
ESI -	Electricity Supply Industry
FO -	Fibre Optic
GIS -	Gas Insulated Switchgear
GOOSE -	Generic Object Oriented Substation Event
GPS -	Global Positioning System
HSR -	High-availability Seamless Redundancy
IED -	Intelligent Electronic Device
IEC -	International Electrotechnical Commission
IT -	Instrument transformers
LAN -	Local Area network
LCC -	Local Control Cubicles

LN-	Logical Nodes
LVC -	Low Voltage Cubicle
MMS -	Manufacturing Message Specification
MR -	Maschinenfabrik Reinhausen
MSTP -	Multiple Spanning Tree Protocol
MTBF -	Mean Time Between Failure
MU -	Merging Unit
NCIT -	Non-Conventional Instrument Transformer
NEC -	Neutral Electromagnetic Coupler
NER -	Neutral-Earthing Resistor
NTP -	Network Time Protocol
OLTC -	On Load Tap Changer
PRP -	Parallel Redundancy Protocol
PTP -	Precision Time Synchronization Protocol
PTPv2 -	Precision Time Protocol version 2
REF -	Restricted Earth Fault
RSTP -	Rapid Spanning Tree Protocol
RTDS -	Real-Time Digital Simulator
SAS -	Substation Automation System

SCSM -	Specific Communication Service Mapping
SEL -	Schweitzer Engineering Laboratories
SMV -	Sampled Measured Values
SV -	Sampled Values
VLAN -	Virtual Local Area Network
VT-	Voltage transformer

1 CHAPTER ONE
INTRODUCTION

1.1 Introduction

Power utilities and distributors as part of the Power Supply Industry (PSI) play an important part of development in a country by supplying uninterrupted electricity at a cost-effective price to the customer.

Generated electricity is transmitted and distributed through power transformers used in electrical substations to transform the system voltage to the different voltage levels.

Substation equipment such as power transformers are monitored, protected, and automatically controlled by Substation Automation Systems (SASs) using Intelligent Electronic Devices (IEDs) connected using high-speed communications network.

The traditional way of connecting the IEDs in the control room at a station level to High Voltage (HV) equipment such as instrument transformers and control devices in the yard at the process level requires a lot of copper cables and wiring. The engineering, installation, commissioning time and cost can be reduced, if the copper cables are replaced with a fibre optic communication network.

The replacement of copper wires also reduces wires and terminal connection blocks in the protection and control panels. This results in a reduction of the panel size, manufacturing time and cost. The size of the panels influences the size and cost of the control room.

This document describes research done on an existing substation automation system by developing an algorithm that can apply the IEC61850-9-2 standard to improve transformer protection, voltage regulator control and cooling fan motor control.

This chapter explains the components that are found in a SAS and transformer protection, automation and control schemes.

This chapter also covers the Awareness of the problem, Description of the substation under study, Problem statement, Sub problems, Proposed problem solution, Research aim and objectives, Hypothesis, Delimitation of research, Assumptions, Research design and methodology, Literature review, Research investigation of transformer protection design and Evaluation.

1.2 Awareness of the problem

Initially a SAS in NamPower was vendor specific. It was difficult to integrate IEDs from different vendors into a SAS. It was also tough to extend existing substations by adding new IEDs from different vendors. An international standard was important to provide interoperability between different vendors of IEDs and SAS.

The International Electrotechnical Commission (IEC) developed the IEC 61850 standard that consist out of ten parts (Adamiak et al., 2009).The standard allowed interoperability between different vendor IEDs when they comply to the standard (Chen et al., 2014: 1). The standard is also independent of communication technologies and made the upgrade and implementation of new communication technologies easier. The IEC 61850 standard can be implemented in a SAS into three distinct levels, namely a Substation Level, a Bay Level and a Process Level.

NamPower implemented the IEC 61850 standard for electrical substation automation systems in many substations mainly at a station and bay level. High ambient temperatures and a conservative approach to protection systems design were the main reasons for not installing IEDs in the high voltage yard and implementing the standard at a process level.

In the most recent SAS, the implementation of the IEC 61850 standard was extended to the process level. The power transformers and switchgear are installed inside a substation building and the IEDs installed at the process level were not exposed to a harsh environment.

The following are typical example of benefits with applications of a process bus at utility substations (Seco & Cardenas, 2016; Mackiewicz, 2006: 7).

- Time reduction: Standardization results in time reduction in substation design and drawings, reduces installation time and reduces commissioning time.
- Cost reduction: Less cable trenches, less man hours, instrument transformer savings, less protection and control panel space, less control room space.
- Testing and IED configuration time may take initially longer but it also decreases with experience.

1.3 Description of the substation under study

The 132/11kV substation consists out of 5 x 40 MVA YNd1 connected power transformers, Double 132kV bus bar, 2 x 132kV Feeders, Single 11kV bus bar with 4 x Bus Sections, 3 x 11kV Feeders connected to loads and 3 x 11kV Feeders connected to two power stations. The simplified substation diagram is shown in Figure 1.1.

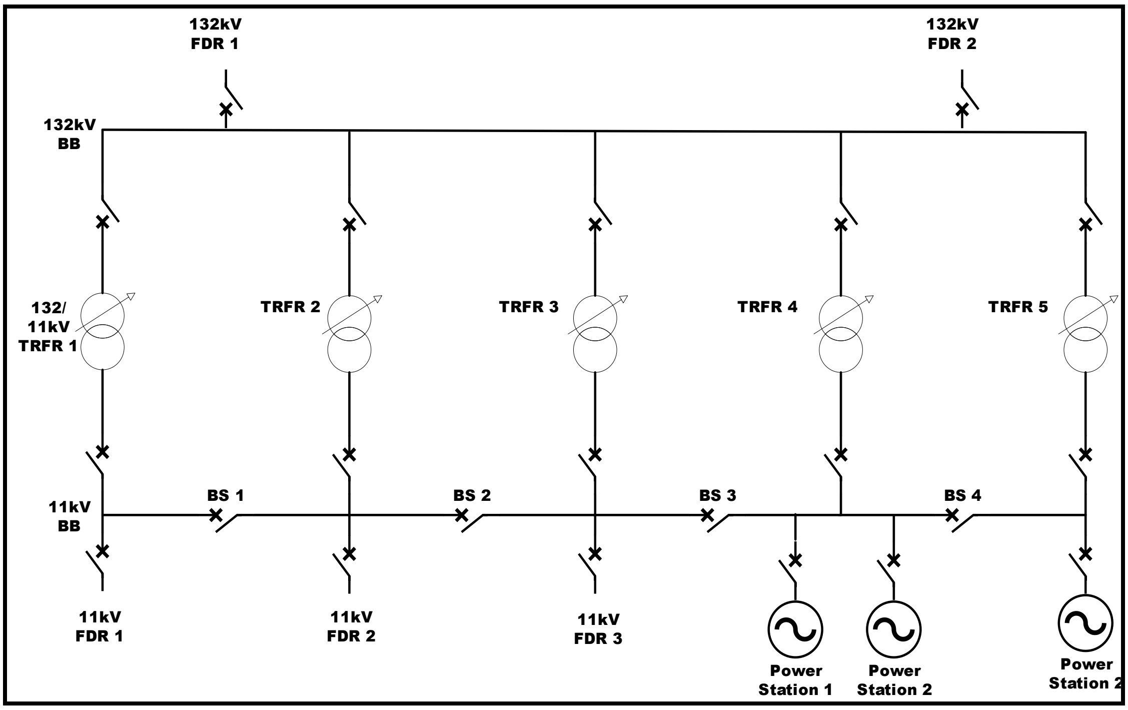


Figure 1.1: Substation Case Study

The 132kV switchgear is SF6 GIS and 11kV switchgear is metal enclosed. Schweitzer Engineering Laboratories, Inc. (SEL) Protection Automation and Control (PAC) Intelligent Electronic Devices (IEDs) were used. SEL Merging Units (MUs) were not available at the time when the Substation Automation System (SAS) was designed and built. The IEC 61850 standard was implemented but 61850-9-2 process bus is not currently implemented.

Data models defined in IEC 61850 are mapped to only MMS and GOOSE protocols and the SMV protocol is not used.

Protection and Control IEDs are connected to a substation LAN, RUGGEDCOM RX 1500 routers and switches using fibre optic linked Ethernet.

SEL IEDs are used for protection automation and control of the power transformers. The detailed configuration of each transformer unit within network communication is described in this section.

The dedicated transformer differential protection SEL 487E IEDs, Bay controllers using SEL 451-5 and SEL 751 IEDs are given in Figure 1.2.

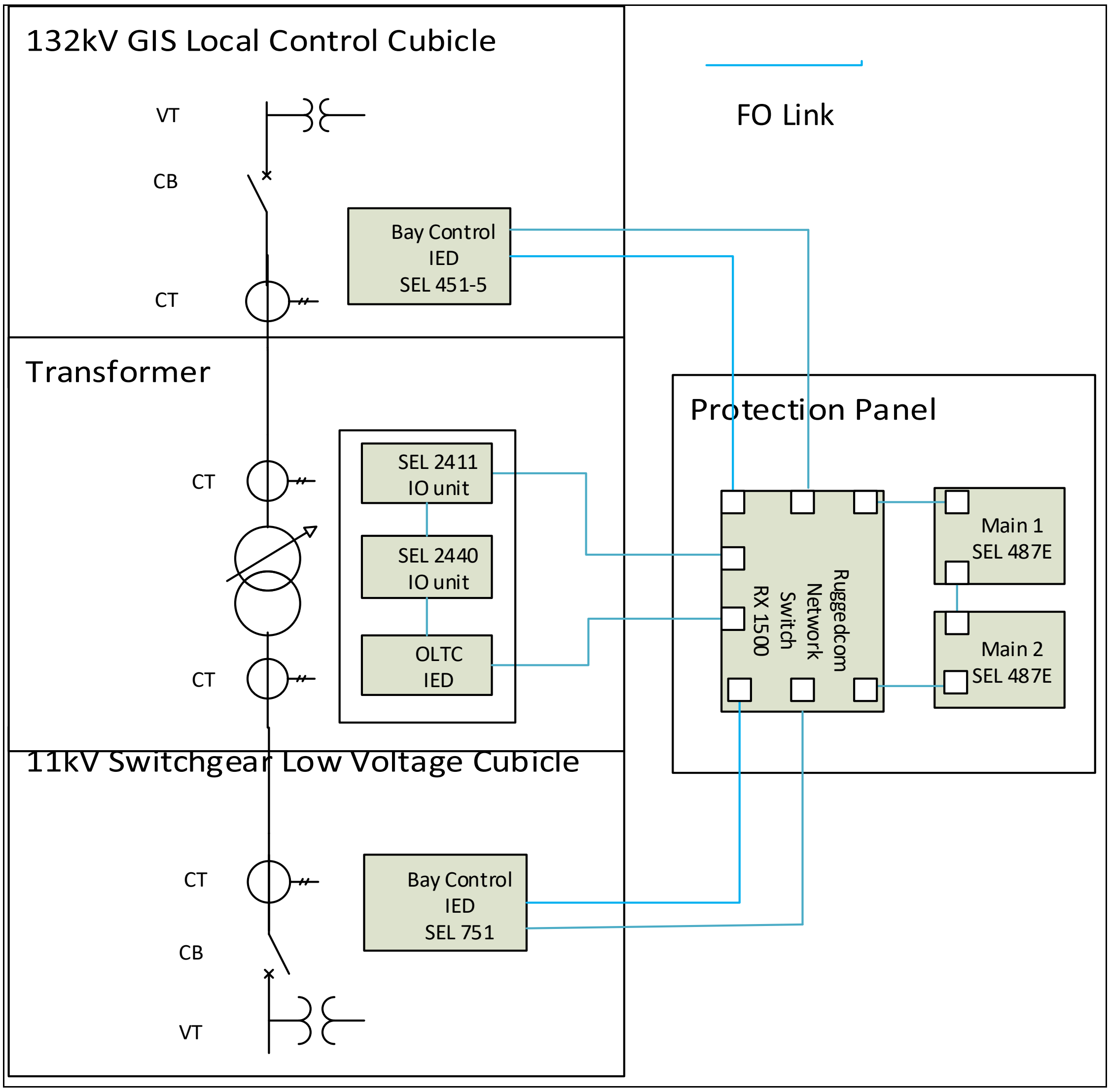


Figure 1.2: Protection Communication network

Protection panels in the control room contain the main transformer protection IEDs and a network switch. Redundancy is obtained with two identical SEL 487E IEDs connected in a ring configuration to a RX 1500 network switch.

Bay control units are installed at the switchgear, a single unit for each bay and voltage level. The SEL 451-5 bay control unit is located at the 132kV switchgear in the Local Control Cubicle (LCC).

The SEL 751 as bay control unit is located at the 11kV switchgear Low Voltage Cubicle (LVC). These SEL 451-5 and SEL 751 units are connected to the RX 1500 network switch in the transformer protection panel.

SEL 2440 and 2411 Programmable Automation Controllers (PAC) are used as input /output units (IO) and are in the Transformer Marshalling Interface Box (MIB) (Schweitzer Engineering Laboratories, 2016b). Transformer alarms and trip signals are hardwired to the IO units. These units are connected in a ring configuration with the TAPCON OLTC IED to a RX 1500 network switch in the transformer protection panel.

The protection IEDs, bay control IEDs and IO units related to a transformer bay are connected using fibre optic to a RX 1500 network switch in the transformer protection and control panel. The fibre optic replaced a lot of copper wires from the HV equipment to the protection panel and reduced the size of the PAC panels in the control room.

The 132kV and 11kV bus bars are protected with bus zone protection by using SEL 487B IEDs. A single line diagram showing the 132kV bus zone protection is shown in Figure 1.3. Three IED devices are used, one IED for the red, white and blue phases each. The bay CT is hardwired to the IED and the isolator status and bus zone trip is done with GOOSE messages. A similar system is used on the 11kV Bus Bar.

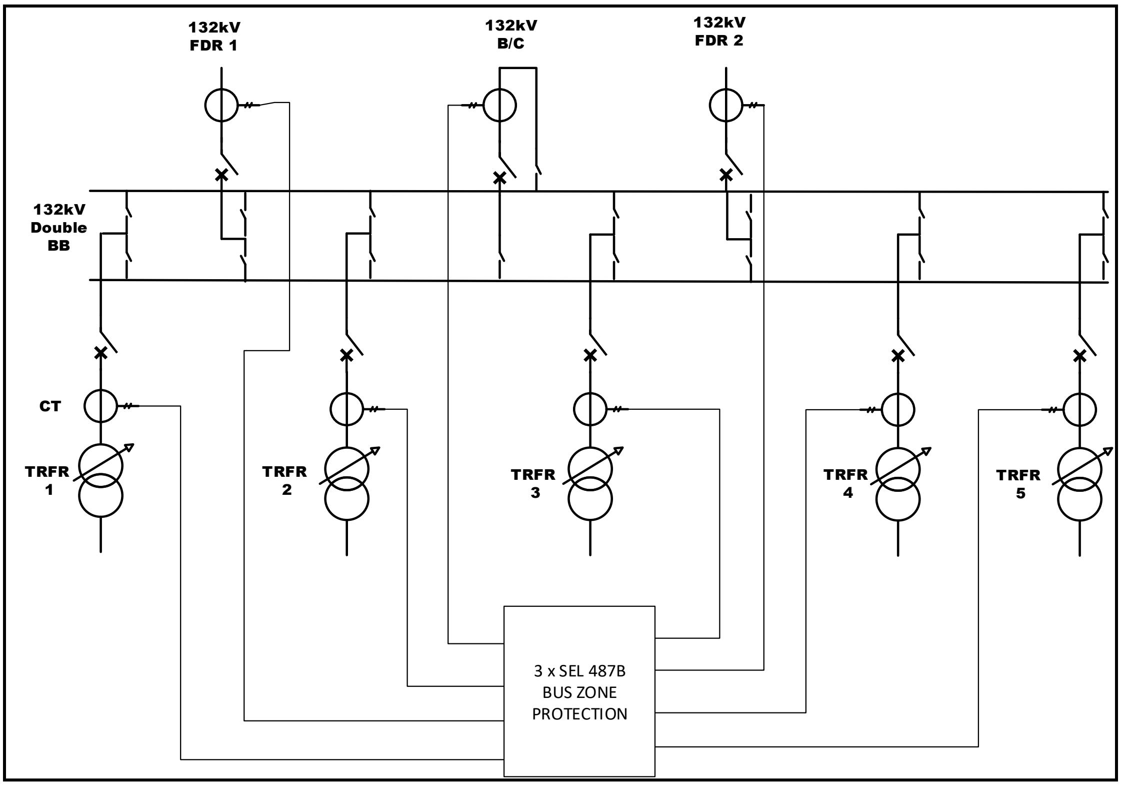


Figure 1.3: 132kV Bus Zone Protection

132 and 11kV inductive VTs are located at the switchgear. CTs are located at the switchgear and internal to the power transformer and the specifications for these CTs are not the same. This has an impact on the transformer protection scheme.
The secondary sides of instrument transformers are copper hardwired to IEDs and fibre optic links are not used for these signals. The analogue signals from the secondary side of the CTs (1 Aac) and VTs (110 Vac) are to be converted to digital Sampled Value (SV) signals using Merging Units (MUs) at the process level.

1.4 Problem statement

The IEC 61850 standard for electrical Substation Automation Systems (SAS) has 10 parts. Parts 8 and 9 describe Specific Communication Service Mapping (SCSM). Data can be transmitted from the source, i.e. High Voltage (HV) equipment to where it is used, i.e. IEDs. Logical nodes can be mapped to various protocols, MMS in part 8 and SMV in part 9 (Hogan, 2014:30). The MMS protocol is regularly used by power utilities for the IEC 61850 implemented SAS compared to part 9-2 and the SMV protocol. The slower implementation of the SMV protocol may partly be due to the slow implementation of Non-Conventional Instrument Transformers (NCIT) and compatibility issues between MUs and IEDs of different suppliers.

The main research problem is to investigate the IEC 61850-9-2 standard related to SCSM in the SAS. The IEC 61850-9-2 process bus is not currently implemented using merging units and sampled values.

1.5 Sub Problems

This research work proposes to develop a complete monitoring, protection, and voltage control system for parallel power transformers based on IEC 61850-9-2 process bus. To complete this, the following sub-problems have been identified:

1.5.1 Voltage control

The Maschinenfabrik Reinhausen TAPCON voltage regulator control IED is situated at the tap change motor drive of the transformer On Load Tap Changer (OLTC). CTs and VTs are hardwired from the switchgear panels to inputs on the voltage regulator control IED. MUs and the SMV protocol are not used.

The IED of each transformer is required to regulate the voltage level of the secondary side bus bar it is connected to. All the regulating IEDs is required to communicate with each other and collectively control the bus bar voltage depending on the switching configuration of the parallel transformers. The Tap Change Control IEDs use Controller Area Network (CAN) bus communication over copper wire. This was converted from analogue to digital communication to be able to use the existing FO network.

A strategy, methods and algorithms for voltage regulator control of parallel power transformers need to be developed and implemented based on IEC 61850-9-2 process bus.

1.5.2 Transformer protection

The transformer protection is done with two SEL 487E IEDs as Main 1 & 2 protection to cover the two different protection zones. One differential IED is using internal transformer bushing CTs covering only for internal faults. The other differential IED uses the CTs at the 11 and 132kV switchgear covering the cable and transformer bushings.

The transformer with vector group YNd1 requires an earthing transformer on the 11kV delta connected side. This is achieved with a Neutral Electromagnetic Coupler (NEC) / Neutral-Earthing Resistor (NER) transformer. The neutral on the NEC/NER transformers is switchable for transformer units no 4 and 5, they can be disconnected when the power transformers are connected to generators. This is shown in Figure 1.4. Transformer units no 1 to 3 have auxiliary transformers added to the NEC/NER transformers for station auxiliary supply.

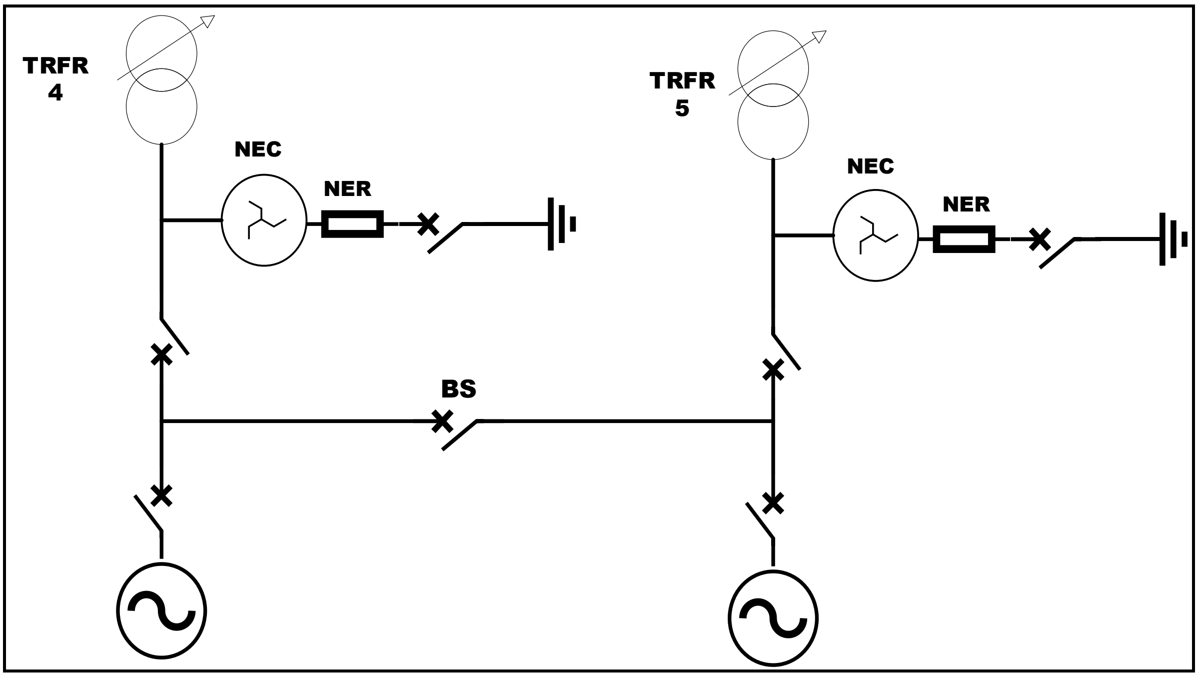


Figure 1.4: Transformers with NEC/NER units

Issues of using copper wires for voltage and currents can be eliminated by applying MUs and the SMV protocol. Time Synchronised SV streams is used for MUs. Unsynchronized SV streams cannot be used to accomplish for example differential protection.

A strategy, methods and algorithms for transformer protection need to be developed and implemented based on IEC 61850-9-2 process bus.

1.5.3 Cooling fan control

The control circuit for controlling the cooling fan motors is hardwired. A temperature analogue signal input into a programmable automation controller IED can be used for controlling the transformer cooling fans. The protection can switch of the fans during a fault in case a transformer fault develops into a fire. A strategy, methods and algorithms for transformer cooling fan motor control need to be developed and implemented based on IEC 61850-9-2 process bus.

1.5.4 Communication network

The currently implemented communication network connecting IEDs to network switches in the SAS needs to be evaluated to determine if is suitable for addition of MUs to the process bus. The process and station bus can physically or virtually be separated.
A strategy, methods and algorithms for a communication network need to be developed and implemented based on IEC 61850-9-2 process bus.

1.5.5 Time synchronisation

The time synchronisation for IEDs is done with an IRIG-B signal over a separate network. Evaluation of the network is needed to determine if this is adequate when a process bus network for sampled values is added. A strategy, methods and algorithms for time synchronisation need to be developed and implemented based on IEC 61850-9-2 process bus.

1.6 Proposed problem solution

Communication between protection IEDs at a bay level and control IEDs at a process level is a combination of an Ethernet-Based Local Area Network (LAN) and conventional copper wires. Data models defined in IEC 61850 are mapped to only Manufacturing Message Specification (MMS) and Generic Object Oriented Substation Event (GOOSE) protocols, the Sampled Measured Values (SMV) protocol as part of IEC 61850-9-2 process bus is not currently implemented. A process bus using GOOSE and MMS is shown in Figure 1.5. The instrument transformers secondary sides are copper hardwired to inputs on the transformer protection, control and voltage regulator control IEDs.

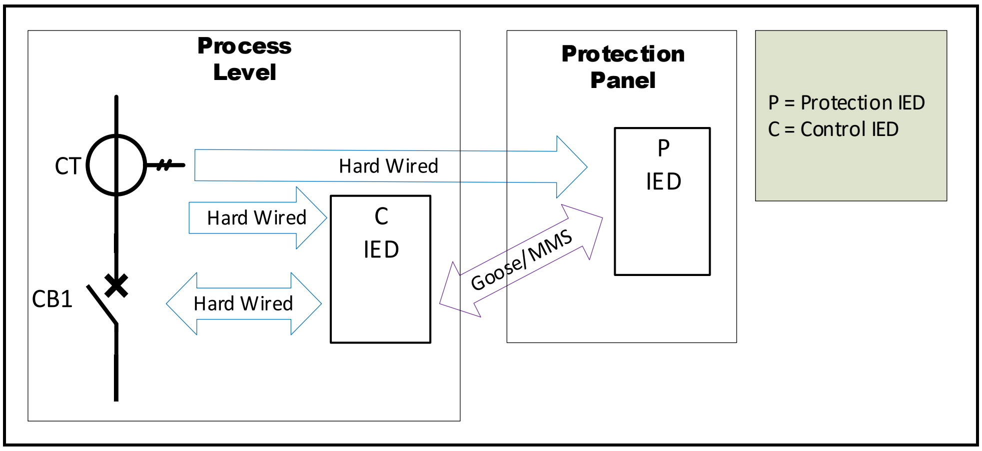


Figure 1.5 Process level communication using GOOSE and MMS

The area of implementing IEC61850-9-2 is the focus of this research work and the author focuses on how to develop an existing implementation of IEC 61850 to include SVs in a NamPower SAS. This is shown in Figure 1.6.

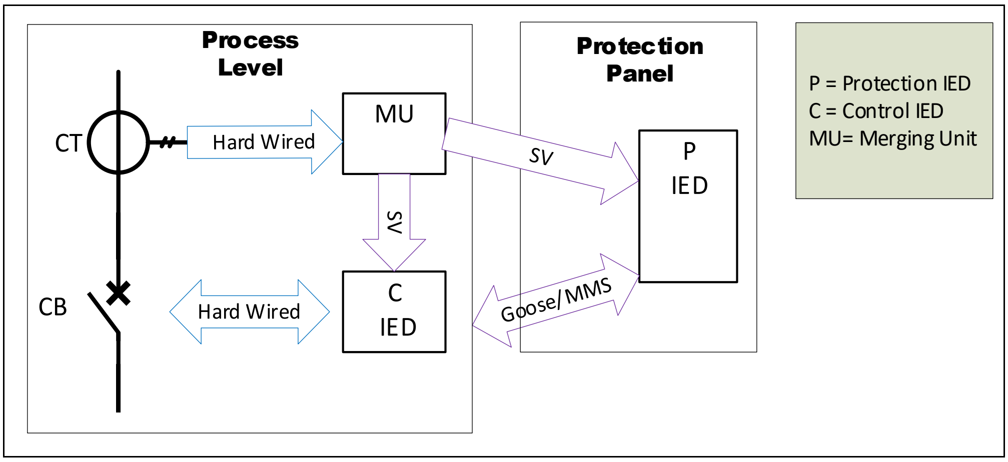


Figure 1.6 Process level communication using a Merging Unit & SV

1.7 Research aims and objectives

The aim of the research project is to develop and implement a strategy, methods and algorithms for monitoring, protection and voltage control of parallel power transformers based on IEC 61850-9-2 process bus.

To provide solutions to the problems listed above the following objectives are proposed:

1.7.1 Theoretical Background

To provide theoretical background of power transformers, transformer tap change control, instrument transformers, merging units, substation communication, substation automation, protection, and control.

1.7.2 Literature Review

To provide a literature review on IEC 61850-9-2, transformer protection, tap changer controls, merging units, instrument transformers, time synchronisation, SAS communication networks.

1.7.3 Real-Time RSCAD application

To develop a Real-Time RSCAD simulation of the parallel power transformer system.

1.7.4 Protection and control strategy

Development of a strategy for monitoring, protection and voltage control of power transformers.

1.7.5 Power Transformer Protection

To design and implement the protection schemes for power transformers based on IEC 61850-9-2 process bus.

1.7.6 Tap Changer Voltage control

To design and implement the IEC 61850 standard-based voltage regulating IEDs to control on load tap changers of the parallel connected power transformers.

1.7.7 Integration of the protection and voltage control schemes

To develop a method to integrate the protection and voltage control schemes for the automation of the parallel power transformer system.

1.7.8 Test-Bench

Development of a test-bench for real-time implementation and testing of the developed system using hardware-in-the-loop tests with a Real-Time Digital Simulator, Merging Units and transformer protection and control IEDs. Physical Merging Unit devices can be used, or they can be simulated in the RTDS.

1.7.9 Experiments

Experiments with the test-bench to be conducted for various scenarios using the RTDS simulated Merging Units and conventional instrument transformers signals. The IEDs performance to be evaluated using the RTDS simulated current and voltage as inputs to the IEDs. Different communication networks for a process bus to be considered and tested.

1.7.10 Analysis of the results, recommendations, and conclusions.

The experiment results to be analysed to make recommendations and conclusions on the proposed system for protection and control of the parallel power transformers according to the IEC 61850 standard.

1.8 Hypothesis

- The MUs connected to IEDs with a fibre optic network can successfully replace hardwired connections from the instrument transformers in the yard to the IEDs in the control room.
- The MU and sampled value implementation at the process level will improve a protection and control system for power transformers, by solving issues related to copper wired instrument transformers, reduce the cost of high voltage equipment, increase flexibility of the design and reduces the installation cost.

- The research work will contribute to the knowledge base and develop scares skills at universities and the Electricity Supply Industry in Southern Africa.

1.9 Delimitation of research

- Only 5 x 40 MVA, 132/11kV parallel power transformers are considered in the implementation of IEC 61850-9-2 standard at the process level of a Substation Automation System.
- The tap changers of the transformers have 17 taps each. The voltage range referred to the primary 132kV side is from +5 % to – 15%
- The five paralleled power transformers are connected to a 132kV and 11kV bus bar system.
- The battery voltage of the SAS is 110 Vdc.
- The protection and control of the 11kV and 132kV bus bars, feeders, bus couplers and bus sections will not be covered in the research work.
- Non-Conventional Instrument Transformers (NCITs), such as optical current transformers will not be covered in the research work. The focus will be to use the conventional CTs and VTs connected to the MUs.

1.10 Assumptions

- All software and hardware equipment required for the completion of this research work is available at the Cape Peninsula University of Technology laboratory at the Centre for Substation Automation and Energy Management Systems.
- The process bus application area for the transformer protection and control is based on an existing NamPower implementations of SAS communication network in a substation.
- Differential and restricted earth fault protection are considered for the transformer protection and discussed in this document.
- The transformer on load tap changer control function can be included in the transformer protection and control IED or in a separate IED. Tap changer IEDs can be installed at the transformer marshalling box or in the control panel.
- The proposed station and process bus communication topologies can be implemented.

1.11 Research design and methodology

The research aim is to develop a strategy, methods and algorithms to improve the transformer protection and control scheme by the implementation of Merging Units and sampled values without sacrificing on the reliability of the complete scheme. The above objective can be met by making use of the IEC61850-9-2 process bus standard. The research methods that will be used in achieving the thesis aim are:

1.12 Literature review

- The literature provides transformer protection and control functions from different vendor's IEDs. IEDs using conventional analogue signal inputs from instrument transformers need to be compared with the IEDs using sampled value inputs.
- Different protection and control functions are included in the IEDs. The transformer on load tap changer control function is included in some vendor transformer protection IEDs. A separate tap changer control IED is required if this function is not included in the transformer protection IED.
- Time synchronisation of IEDs and Merging Units is vital for using sampled values. Different methods for time synchronisation are available.
- The different substation communication networks need to be reviewed to determine the best possible solutions that can be used for the sampled value implementation.

1.13 Research investigation of transformer protection design

Transformer protection uses conventional Instrument Transformers (IT) in the HV yard which are copper hardwired to the IED inputs. Modern protection using IEC 61850-9-2 considers ITs connected to Merging Units where the analogue current and voltage signals are converted to digital sampled values and sent to the IEDs using optical fibre connections. Figure 1.7 is shown to compare the two systems.

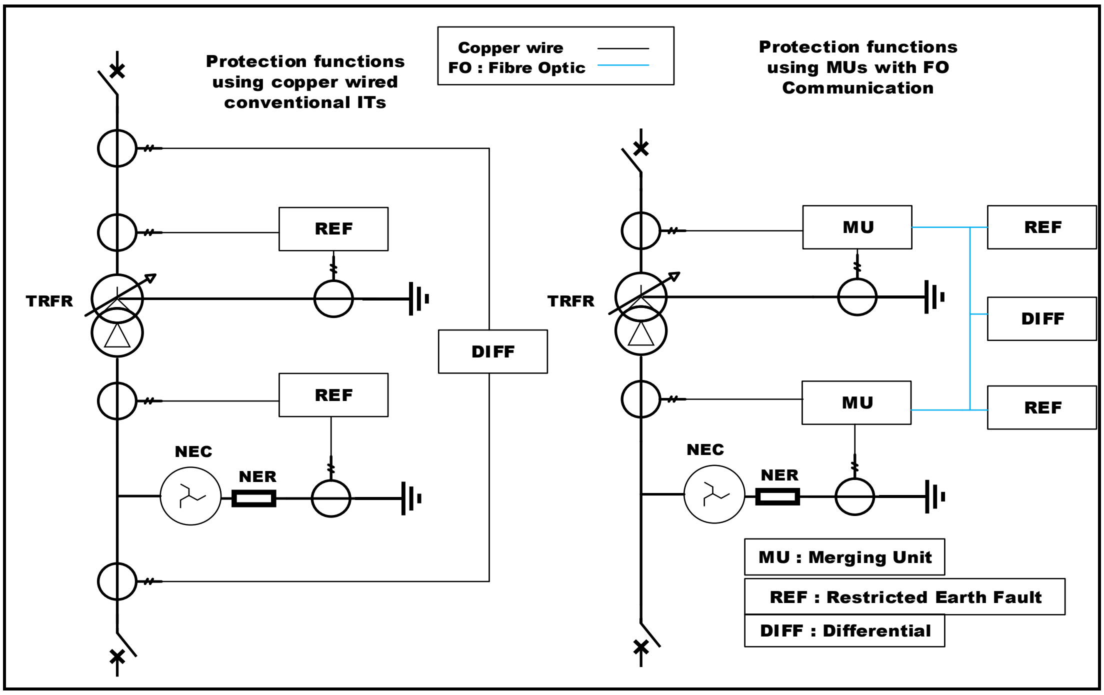


Figure 1.7 Protection with ITs using copper wires & MUs with Fibre Optic communication

1.14 Research investigation of transformer OLTC control

The substation bus bar voltage is regulated by an IED with a voltage regulating function to control a transformer on load tap changer. This function can be included in a transformer protection IED or in a separate control IED. CT and VT signals are used for controlling the transformer tap changer. The best location for this function needs to be determined for implementing the Merging Units and sampled values. A transformer protection function can block the tap changer operation during faults conditions, because a high current flowing through the tap switch can damage it. Figure 1.8 shows how an OLTC IED can be connected to a protection IED and a MU using a fibre optic network. GOOSE and SV messages can be sent over this network.

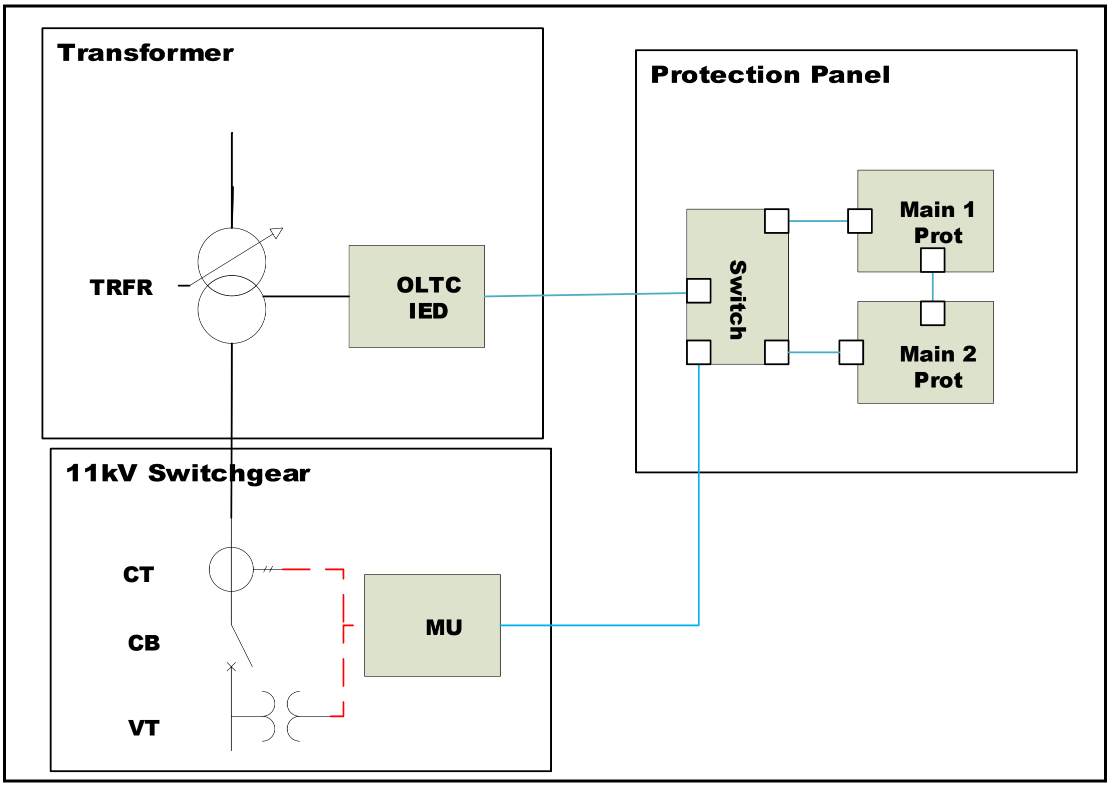


Figure 1.8 Tap Changer Control

1.15 Research investigation of time synchronisation

Time synchronisation of merging units and IEDs will be established using several methods. The best method needs to be investigated that is suitable for implementing a process bus and sampled values.

1.16 Research investigation of substation communication network

The availability and reliability of the communication network need to be considered for the process bus implementation using MU sampled values.

1.17 Research investigation using a Test-Bench

A power system Real-Time Digital Simulator (RTDS) is required to simulate a part of the power system that is used to test the transformer protection and control scheme. The simulator from the RTDS technologies is also used to simulate the power system, MUs, VT and CT signals.

IEC 61850-9-2 sampled value messaging or analogue outputs from instrument transformers can be simulated using the RTDS. The trip signals for both digital hardwired copper communication and GOOSE messages using optical fibre communication will be considered and tested.

The analogue CT and VT output signals from the RTDS need to be amplified to typically power system values and connected to the protection IEDs shown in Figure 1.9. The RTDS sends equipment status, for example the Circuit Breaker (CB) position to the IED and the IEDs send CB trip and close signals to the simulator to simulate CB operation.

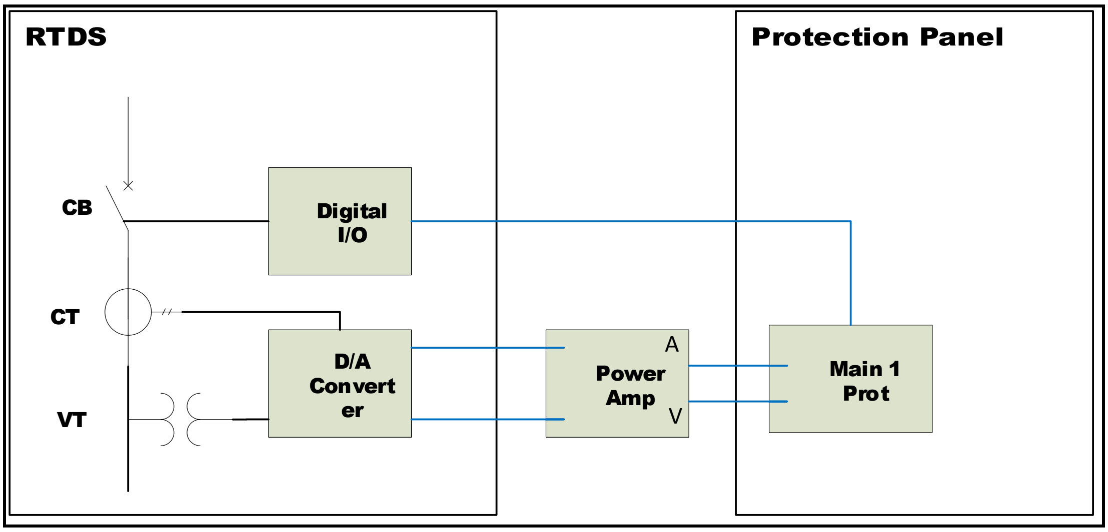


Figure 1.9 RTDS with analogue VT & CT Outputs & Digital Inputs/Outputs

The test-bench setup using process bus options needs to be considered and implemented. The process bus communication network includes the use of network switches. The instrument transformer digital signals need to be communicated to the protection and control IEDs in an application where the IEDs use sampled value messages.

Sampled values and GOOSE messages can be produced inside the RTDS, see Figure 1.10. Equipment status and operation messages are sent with GOOSE messages between the IED and the RTDS.

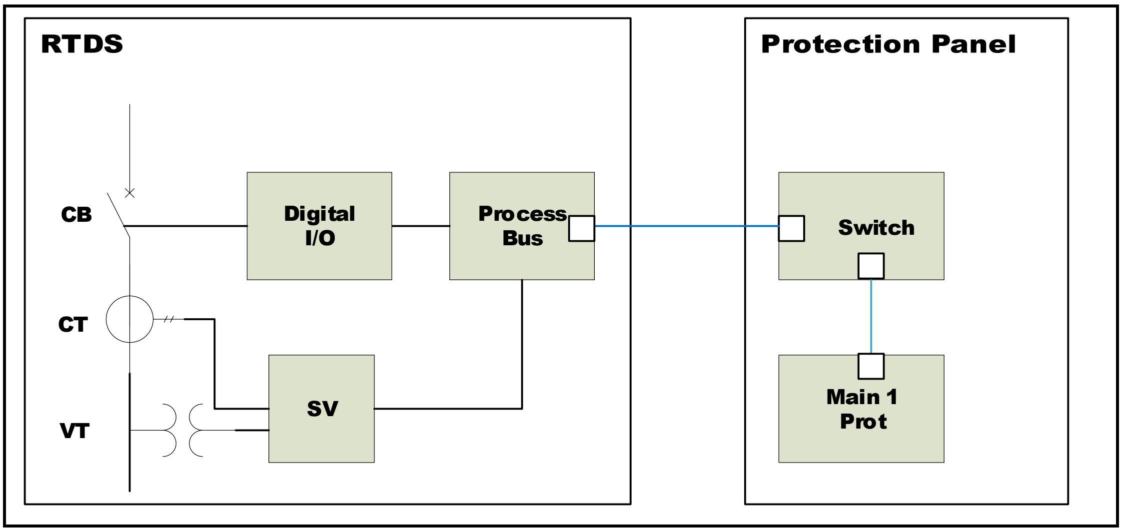


Figure 1.10 RTDS with SV & GOOSE messages

The RTDS can produce power system simulated analogue CT and VT values which can be amplified. External Merging Units can be used to digitise it to sampled value messages. GOOSE messages can be used for control and status indication of the simulated high voltage equipment. This is shown in Figure 1.11.

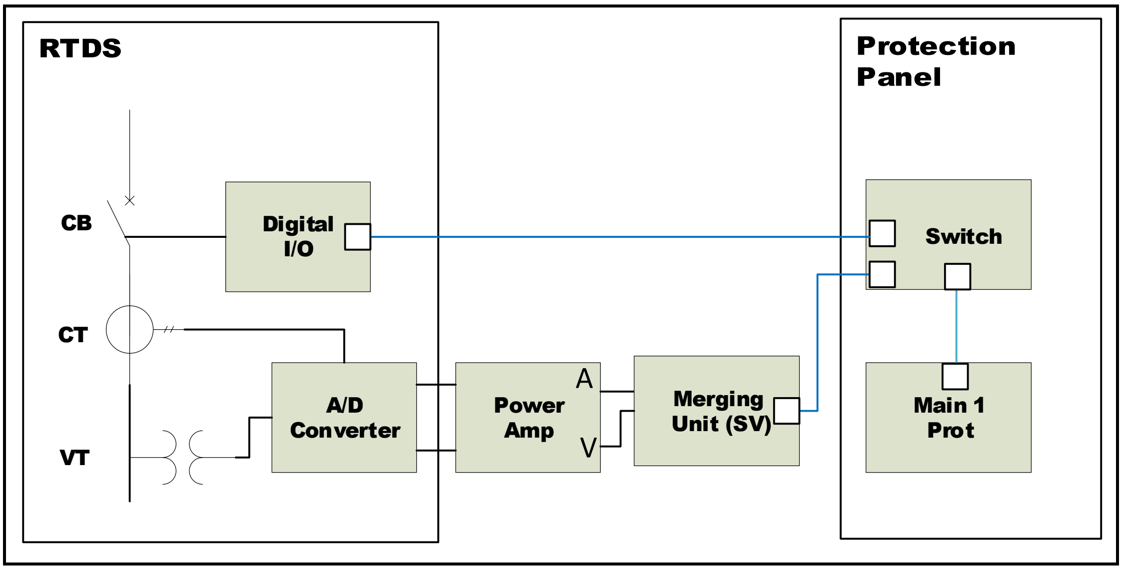


Figure 1.11 RTDS with analogue & GOOSE outputs, External MU

1.18 Evaluation

The performance of transformer protection and control when replacing copper wired connections for analogue CT & VT signals with digital converted SV messages over Fibre Optic (FO) networks need to be evaluated.

1.19 Thesis chapters

The documentation of the research investigations is divided into 8 chapters and 9 appendixes as follows:

1.19.1 Chapter One

This chapter covers the Awareness of the problem, Description of the substation under study, Problem statement, Sub problems, Proposed problem solution, Research aim and objectives, Hypothesis, Delimitation of research, Assumptions, Research design and methodology, Literature review, Research investigation of transformer protection design and Evaluation are described.

1.19.2 Chapter Two

This chapter covers the literature review of different types of primary equipment components in protection and control of power transformers, substation control systems and communication networks. The importance of using merging units connected to conventional instrument transformers is described and compared with systems where conventional instrument transformers are copper hard wired to IEDs.

1.19.3 Chapter Three

This chapter covers the IEC 61850 standard and digital substation Ethernet technology. The IEC 61850 standard is discussed under the following point:

- A standard name space of logical nodes, data objects and attributes,
- A System Configuration Description Language (SCL) and,
- Abstract Communication Service Interface (ACSI) services that can be mapped to specific protocols to exchange this information

The communication network architecture, communication protocols, physical layer, data link layer and time synchronization of substation communication networks in an IEC 61850 standard digital substation is discussed.

1.19.4 Chapter Four

In this chapter, the system of five 40MVA 132/11kV YNd1 power transformers connected in parallel is modelled and simulated in the Real-Time Digital Simulator (RTDS).

The system configuration is changed by controlling different circuit breakers.

The quantity of power transformers connected in parallel can be controlled in this way.

Faults are applied at different points in the system and for different system configurations. The fault currents are measured and analysed.

The configuration of the RTDS / RSCAD software models, power source, power transformer, power system load and instrument transformers models are shown.

The simulation results are discussed.

1.19.5 Chapter Five

In this chapter, the protection system for two 40MVA 132/11kV YNd1 paralleled power transformers is modelled, simulated and tested in the Real-Time Digital Simulator (RTDS).

The configuration of the RTDS RSCAD differential protection function, overcurrent protection function and IEC 61850 -9-2 LE sampled values are shown.

The protection system simulation results are discussed. It is shown that power transformer protection settings can be adapted when the system configuration for parallel power transformers is changed.

1.19.6 Chapter Six

In this chapter, the controller design of tap changers for a system of two 40MVA 132/11kV YNd1 paralleled power transformers is modelled, simulated and tested in the Real-Time Digital Simulator (RTDS).

The configuration of the RTDS RSCAD tap changer model is shown.

The tap changer controller simulation results have shown that the power transformer tap changer controller can be adapted to the system configuration for parallel power transformers.

1.19.7 Chapter Seven

Conclusion on the application the IEC 61850 standard for communication networks and systems used to implement IEC 61850-9-2 sampled values for a typical substation system with parallel power transformers is described.

In this chapter, different Test-Benches are setup and discussed. The configurations of Merging Units (MUs), transformer protection and control Intelligent Electronic Devices (IEDs) and Ethernet equipment are shown.

The Real-Time Digital Simulator (RTDS) is used to run the real-time power system model and do simulations. IEC 61850-9-2 Sampled Values (SV) streams are published from the RTDS as well as using stand-alone MUs.

A Micom P645 transformer differential protection IED and a differential protection function configured in the RTDS RSCAD are used for experimentation.

It is shown that Analogue Merging Units (AMUs) publish successfully IEC 61850-9-2 Sampled Value (SV) streams on the Ethernet network.

The RTDS GTNET_SV9−2 component publishes IEC 61850−9−2 Sampled Value (SV) streams successfully on the Ethernet network.

The MiCOM P645 IED subscribes to the SV streams and measures the analogue signal correctly.

The RTDS RSCAD developed transformer protection component is tested successfully. The RTDS IEC 61850-9-2 SV streams are used to show that the burden on the Instrument Transformers is less when using MU and SV streams compared to copper wired instrument transformers

1.20 Conclusion

The Awareness of the problem, Description of the substation under study, Problem statement with Sub problems, Proposed problem solution, Research aim and objectives, Hypothesis, Delimitation of research, Assumptions, Research design and methodology, Literature review, Research investigation of transformer protection design and Evaluation are described and explained.

The topics covered in the different chapters are explained.

In the next chapter the literature in protection and control of power transformers is described and different types of papers and articles based on primary and secondary equipment related to the protection and control of power transformers are reviewed and analysed.

2 CHAPTER TWO
LITERATURE REVIEW

2.1 Introduction

Power transformers are required to transform the system voltage from generation to transmission and distribution levels.

Protection and control devices must ensure that power system high voltage equipment such as transformers operate correctly to deliver safe, reliable and secure supply. This is achieved using protection and control schemes. Different standards were developed over the years that are related to protection, automation and control of power systems and are used by power utilities (Kanabar et al., 2012). Real-time simulations is important to test these new technologies (Dufour & Belanger, 2014).

The IEC 61850 standard series defines the communication between Intelligent Electronic Devices (IEDs) in the substation and the related system requirements (IEC, 2002b). The standard also allows interoperability among automation devices of different vendors and is needed for digital substation application. Utilities implement the digital substation technology in substations to proof the concept, learn and understand the different components of a digital substation (Vardhan et al., 2018)

Methods to synchronizing different devices clocks over the network like IRIG-B and IEEE 1588 standard are discussed (Bhardwaj et al., 2014).

Reliability, selectivity, stability, speed, sensitivity are fundamentals that need to be considered when a protection system is designed (Alstom, 2002: 11–12).

Protection, automation, and control of power transformers is reviewed in this chapter for the following cases:

- Protection relays using copper hardwired instrument transformers.
- Protection relays using merging units connected to conventional instrument transformers.

Primary and secondary substation equipment at station and process levels are involved in a protection and control system. The following equipment need to be considered when a protection and control system is designed:

- Secondary equipment reviewed in section 2.2 : substation automation and control system, time synchronization source, communication network, Merging Units, power transformer protection and control,
- Primary equipment reviewed in section 2.3: instrument transformers and earthing transformers.

Real-time digital simulation is discussed in section 2.4.

2.2 Secondary substation equipment

The protection and control IEDs, network equipment and Merging Units are regarded as secondary equipment in the substation. Secondary equipment are reviewed with the focus on how these fit into a digital substation. A review of different topics regarding digital substations are done. A total of 61 conference proceedings and journal articles are reviewed on substation control systems, communication networks, network redundancy protocols and Ethernet equipment. Most of the papers were published between 2006 and 2019,Figure 2.1.

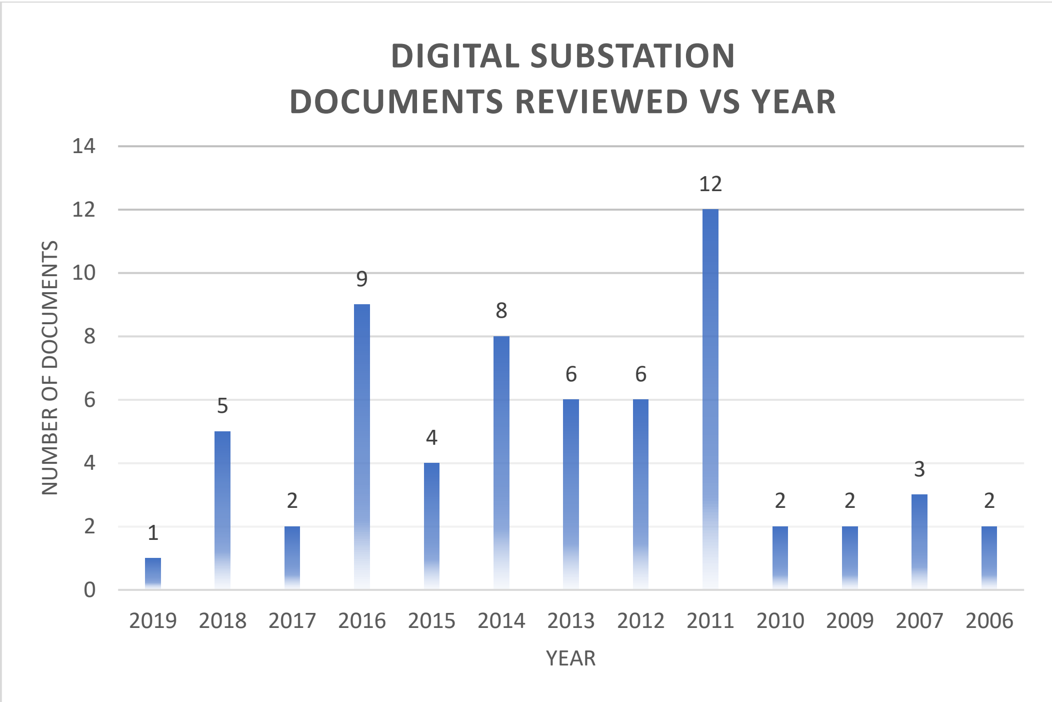


Figure 2.1 Digital substation documents reviewed per year

2.2.1 Substation control system

Different communication protocols and standards are used in a modern substation, The two most used standards are IEC 61850 and IEC 60870 (Bhardwaj et al., 2014). (Skendzic et al., 2007: 1) divide a substation protection and control system using the IEC 61850 standard into three distinct levels, namely a Substation Level, a Bay Level and a Process Level.

The protection and control Intelligent Electronic Devices (IEDs) related to a specific transformer bay can be connected to each other in a communication network at a bay level, and to other bays or the substation SCADA network at a station level.

The status collection and the control of high voltage equipment such as breakers and disconnectors can be done at a process level (IEC, 2015). A Protection, automation and control scheme for power transformers is discussed where high voltage equipment and switchgears are connected to IEDs in the yard at substation process level making Ethernet networks in the substation a requirement (Ali Raza, Khalil Ullah, Saleem Ahmed, 2009; Stark et al., 2013; Stefanka et al., 2013). The IEDs in the yard are connected via a fibre optic network to IEDs in the control room. The transformer marshalling interface box and the switchgear such as circuit breakers and isolator / disconnectors are hard wired to IEDs in the high voltage yard. The IED can be situated at the device or in a yard junction box close to the equipment. Equipment status and control at process level is then possible when this IED is connected to the substation communication network. A control room environment were protection and control IEDs are located, can be air conditioned. The ambient temperature needs to be considered when IEDs are in yard enclosures.

Analogue data, in addition to binary data, can also be gathered at the process level. Conventional Instrument Transformers (IT) wired to Merging Units (MUs) can gather the analogue data and digitise them per the standard to sampled values. Replacing the copper wires with fibre optic from the yard to the control room can reduce some hazardous voltages and currents and therefore increase the safety of substation control rooms (Ingram et al., 2013a: 5941). The interface where Merging Units are used at process level and connected to the protection and control devices at the Bay Level is described (Apostolov & Vandiver, 2010: 2). The performance of a process bus based protection scheme must be comparable to a conventional hardwired scheme (Crossley et al., 2011).

The research will focus on how to improve the SAS by using sampled values in the process level communication. Investigations on the performance of the Process Bus and different protection functions have been of interest to researchers (Adewole & Tzoneva, 2014; Chen et al., 2014; Ingram et al., 2013b)

IED vendors can apply the IEC 61850 standard differently when they offer IEDs capable to receive sampled value and interface with the MUs. The IEC 61850-9-2 LE is an Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9- 2, issued to get a uniformed standard implementation (Bhardwaj et al., 2014: 2).

The instrument transformers connected hardwired from the yard to the control room are compared to instrument transformers connected to Merging Units in the yard which are connected via a fibre optic network to IEDs in the control room.

The substation automation system uses IEC 61850 messaging not only for control related functions like blocking and interlocking schemes but for protection as well.

Message types can be subdivided into performance classes: (a) control and protection and (b) metering and power quality applications (Hasan Ali et al., 2014).

The engineering and the process of designing an IEC 61850 protection and control scheme are not the same in comparison with the hardwired scheme. The IEC61850 functional specification and a testing system for the automation system is required (Ryono et al., 2019; Huang, 2018a). The documentation is another issue that is different. The DC key diagrams that contains conventional hardwires for tripping and indication signals are different to when GOOSE messages are used, this can no longer be indicated in the conventional way. New ways need to be considered in fault finding and other operational tasks where normal printed DC key diagrams are used in the field (Chang et al., 2014: 19).

2.2.2 Substation communication network

Protection and control IEDs perform critical functions in the electrical substations. One of the major advantages of implementing process bus GOOSE-based control and protection tripping is that it replaced a lot of copper hardwired networks to transfer information between the equipment in the yard and the protection and control IEDs in the control building. The copper is now replaced with fibre optic networks. In an IEC 61850 based protection and control systems the IEDs depend on a reliable Substation Communication Network (SCN) architecture that meets redundancy requirements when failures do occur. Networks must be capable of reconfiguring and self-healing in case of communication device or link failures (Goraj & Harada, 2012: 1).

The ring and star architectures are the most used in communication networks. The ring architecture has an advantage over a star where switches connected in a ring have no single point of failure compared to a network where a central switch is a single point of failure (Liu et al., 2014: 2).

The data flow in substations is divided in three proposed kinds of mathematical models, cyclic data, stochastic data, and burst data. Network performance and data flow were analysed for a typical sub-station while taking network topologies, Virtual Local Area Network (VLAN) and impacts of system faults into account (Zhang et al., 2015). The cost of duplicating the complete communication network needs to be compared with the requirement for redundancy. Other network designs can be considered to have some redundancy at a lower cost. The star and ring topologies have each there own advantages and disadvantages (Rahat et al., 2019). A combination of star and ring topologies is considered for this network design. The SEL IEDs have two Ethernet ports connected to an internal switch with failover technology. This enables a redundant design where devices can be connected in a ring topology, each IED connected with two ports.

All the transformer bay protection and control devices are connected in ring networks to one bay level layer 2 switch. The switch can be considered as a single point of failure. The risk, probability and consequences of the switch failure need to be considered against the cost of duplicating the switches. The RUGGEDCOM RX1500 series switches considered in this design have two redundant load sharing power modules to provide a secure/redundant power supply (Siemens Industry, 2015). The different bay level layer 2 switches are connected in a ring network to a layer 3 station level router. The station router can be duplicated for redundancy.

The communication network requirements for a process bus may not be the same for GOOSE and MMS messages compared to SV messages. The traffic produced by SV messages is much more than that of GOOSE messages (Konka et al., 2011). GOOSE messages containing the same information are sent and resent at defined intervals after the original message was sent. SV messages are, in comparison, a continuous stream of digitised current and voltage measurements. The information lost will therefore not be the same for the different types of messages during communication failures. To prevent SV data lost, networks must be capable of fast reconfiguring and self-healing in case of communications device or link failures (Goraj & Harada, 2012: 1).

The use of time critical sampled value and GOOSE messages increases the overall performance requirements of the IEC 61850 communication system. The system performance must be tested, assessed and certified (Meier et al., 2016; Lopes et al., 2015; Rinaldi, Ferrari, Flammini, et al., 2016; Sidhu et al., 2011).

The reliability and availability of the communication network have an impact on the operation of the protection IEDs and a protection system when MUs with digital information replace the hardwired analogue CT and VTs information. It is shown how the Reliability Block Diagram and state space approaches can be combined to analyse the reliability and availability of all the components in a substation communication network (Younis, 2016).

The ring architecture where all bay IEDs are connected to one bay network switch applied to a network without MUs may not be appropriate when MUs are added. The bay network switch will be a single point of failure. Different mechanisms and protocols must be implemented in these networks to obtain better redundancy and shorter outage time. Rapid Spanning Tree Protocol (RSTP) uses two communication links or loops from the source to destination. The MU will need two communication ports with RSTP to connect to the process buss network. IEDs connected to a process bus as well as a station bus will need two ports to connect to each network.

MSTP that allows Multiple instances of Spanning Tree Protocol on Virtual LANs may be a suitable solution. In a single physical network, there can be multiple VLANs, each with their own instance of Spanning Tree Protocol. An example could be where GOOSE applications and SV streams are logically segregated by various VLANs

Merging units will require two Ethernet ports or Doubly Attached Nodes (DAN) if Parallel Redundancy Protocol (PRP) is used to provide redundancy. It will be possible for merging units running PRP to connect to two separated and independent networks.

A Redundancy Box (Redbox) is needed for Merging Units with Singly Attached Nodes (SAN) to connect to PRP or High Availability Seamless Redundancy (HSR) networks.

The HSR nodes require more processing power because every node needs to process a frame twice. This also has an impact on the bandwidth used due to every frame sent twice over the same network. This is important when a network is used for multicast SV sent from MUs (Goraj & Harada, 2012: 4).

2.2.3 Network protocols

Different mechanisms and protocols can be implemented in networks to obtain redundancy and to have the outage time as short as possible. The outage time that can be tolerated can depend on the type of substation, how critical it is for the power system and the importance and supply contract of the customer.

A Rapid Spanning Tree Protocol (RSTP) is one of the network redundancy protocols (Cisco Systems, 2004). RSTP is an improved and faster version of STP. A Spanning tree topology such as RSTP consist out of a Root Bridge, Designated Switches and End Nodes connected in a LAN in such a way that all equipment is connected and there are no loops.

Any switch in a network can be a Root Bridge but only one Root Bridge can exist at a specific time. The priority part and MAC address of a switch or bridge ID can be selected. The switch with the lowest value priority is the Root Bridge. The lowest MAC address is used to select a Root Bridge if two switches have the same priority. The Designated switch is responsible to forward information from the Root bridge to the End Node (Wojdak, 2003).

RSTP uses two communication links or loops from the source to the destination. The redundant links are temporary disabled until a failure in the primary link occurs. (Goraj & Harada, 2012) reason that one of the disadvantages of RSTP, is that Ethernet root switch failures can be non-deterministic in highly meshed networks and is recommended to be avoided using RSTP in highly meshed networks for substation automation.

Another spanning tree protocol, MSTP, allows multiple instances of Spanning Tree Protocol on Virtual LANs. In a single physical network, there can be multiple VLANs, each with their own instance of Spanning Tree Protocol. An example could be where GOOSE applications are logically segregated to a separate VLANs.

Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are bus redundancy architectures proposed by the IEC 62439-3 standard (Igarashi et al., 2015: 3; Kumar et al., 2015a). PRP is tested by (Darby et al., 2014) in a case study for new substations and considered to be multi-vendor interoperable. HSR topologies are compatible with the Ethernet standard IEEE802.3 and considered to offer zero recovery time (Araujo et al., 2012). Network redundancy can be managed within the network or in the end nodes.

2.2.4 Time synchronization source

A review of types of time synchronization sources is done. A total of 29 conference proceedings and journal articles were reviewed, Figure 2.2. Only one was published before 2010 and most were published in the last decade. Precision Time Synchronization Protocol (PTP) and Simple Network Time Protocol (SNTP) are reviewed for use in process bus networks.

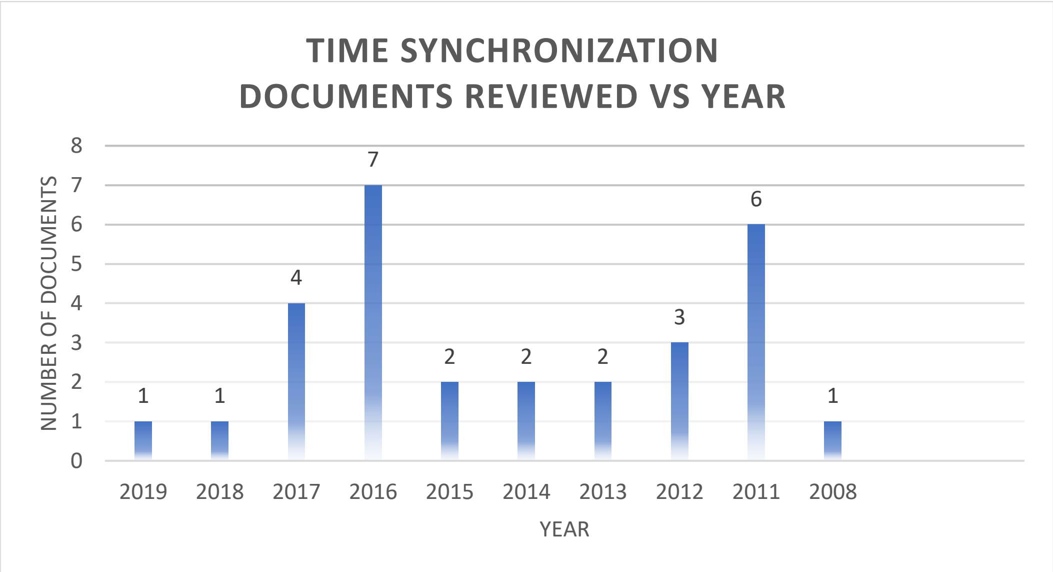


Figure 2.2 Time synchronization documents reviewed per year

The equipment status collected at the process level by protection and control devices need to be time stamped and published in a frame format on the substation communication network. All the devices therefore need internal clocks that are synchronized with a substation GPS clock. Bhardwaj et al.,(, 2014: 4) showed that these synchronised device clocks can in addition to time stamping, also be used to calculate delays in the communication network. The synchronization is performed through IRIG-B, or indirectly over a network using one of several standards.

The IEC 61850 standard recommends the Network Time Protocol (NTP) as a synchronization method (Rinaldi, Della Giustina, et al., 2016). The NTP time accuracy

(0.1 to 1 ms) can be considered enough for data acquisition and control applications. The IEEE came up with IEEE 1588 standard (De Dominicis et al., 2011; Guo & Crossley, 2017) to synchronize multiple devices over a network where their clock is in master/slave mode (Bhardwaj et al., 2014: 4). A single network implementation can be accomplished using IEEE 1588 Precision Time Synchronization Protocol (PTP) (Skendzic et al., 2007: 5). Part 9-3 of IEC 61850 specifies a PTP profile of IEC 61588:2009. The IEEE Std 1588-2008 applicable to power utility automation allows compliance with the highest synchronization classes of IEC 61850-5 and IEC 61869-9 (IEC, 2016a). IRIG and PTP can be considered as alternatives to NTP.

The timing class is defined in IEC 61850-5 standard (IEC, 2013b).

The substation under discussion for the research project uses a GPS receiver for time synchronization by distributing IRIG-B encoded time signals to protection and control IEDs. IRIG-B is a time code format, which provides date and time in a coded form. The accuracy of 1 µs can be achieved by 1 pulse per second (PPS) input (Bhardwaj et al., 2014). The SEL-2440 Discrete Programmable Automation Controller (DPAC) is considered as an input/output (I/O) unit for control and collecting equipment status in the yard (Schweitzer Engineering Laboratories, 2016a). The DPAC can use IRIG-B or SNTP for time synchronization. The 1 µs IRIG-B accuracy offered is better than ±5ms SNTP accuracy for this device. The IRIG-B network requires additional cabling compared to SNTP that can use the communication network to all the devices to be synchronised.

A time synchronization source is required for the MUs to time stamp the sampled analogue signals and convert these into digital information. Skendzic et al. (, 2007: 5) explain that the SV streams must be synchronized to a common time reference. This is of importance when this information is used for power system protection and especially differential protection where data are sampled at different locations, sent over a communication network, and compared in a protection IED.

Network Time Protocol (NTP) as synchronization method is previously discussed. The NTP time accuracy (0.1 to 1 ms) can be considered insufficient for SV applications which require <1 µs accuracy.

Time synchronization by distributing IRIG-B encoded time signals to the MUs in the high voltage yard can provide better accuracy but additional cabling is required to the MUs.

A single network implementation can be accomplished using PTP on the communications network (De Dominicis et al., 2011). PTP is recommended and used for the synchronization of SV messages in process bus implementations (Ingram et al., 2013a: 5935). The data traffic can affect the synchronisation accuracy (Liu et al., 2016). The coexistence of SNTP and PTP by using Time Gateways to translate the time from a time domain to the other are analysed (Ferrari, Flammini, Rinaldi & Prytz, 2011; Ferrari, Flammini, Rinaldi, Prytz, et al., 2011).

Attacks on time synchronisation and other vulnerabilities can affect the functionality and security of the power network (IEEE, 2019; Fodero et al., 2017).

The paper (Ingram, Schaub, et al., 2012: 1179) demonstrates that PTPV2 is a viable method of providing time synchronization for an SV process. The paper also notes “transparent clocks” and how this impacts the PTPV2 timing system where “sampling errors increase as transparent clocks are added to the system”.

2.2.5 Equipment

PRP uses IEDs with two Ethernet ports or Doubly Attached Nodes (DAN) to provide redundancy. The IED with two Ethernet ports, DAN running PRP (DANP), makes it possible to connect the IEDs to two separated and independent networks. Duplicated Ethernet packets are sent simultaneously through these two networks. The destination IED can still receive the data from one network if one data frame fails to reach the IED from the other network. A Redundancy Box (Redbox) is needed for IEDs with Singly Attached Nodes (SAN) to connect to PRP networks (Liu et al., 2014: 2).

HSR also uses IEDs with DAN but running HSR (DANH) it is not connected to separate networks as with PRP. A frame is duplicated when a multicast frame is sent from the DAN on the same network. Each duplicate frame is tagged with the destination MAC address and a different sequence number. The first of the two duplicated frames received is passed on at the destination, and the other frame is discarded. A Redbox is needed for SAN to connect to HSR networks in the same way as with PRP networks (Alstom, 2002: 440).

The HSR nodes require more processing power because every node will need to process a frame twice. This also has an impact on the bandwidth used due to every frame sent twice over the same network. This is important when a network is used for multicast SV sent from MUs (Goraj & Harada, 2012: 4).

Managed network switches allow configuration on how it functions for different IEC 61850 messages e.g. GOOSE and SV. VLANs and Quality of Service (QoS), which is defined in IEEE 802.1Q. can be configured (Oliveira et al., 2016: 3).

2.2.6 Merging Unit (MU)

A review of Merging Units is done. A total of 51 conference proceedings and journal articles are reviewed. Only a few were published before 2010 and most were published in the last decade, Figure 2.3.

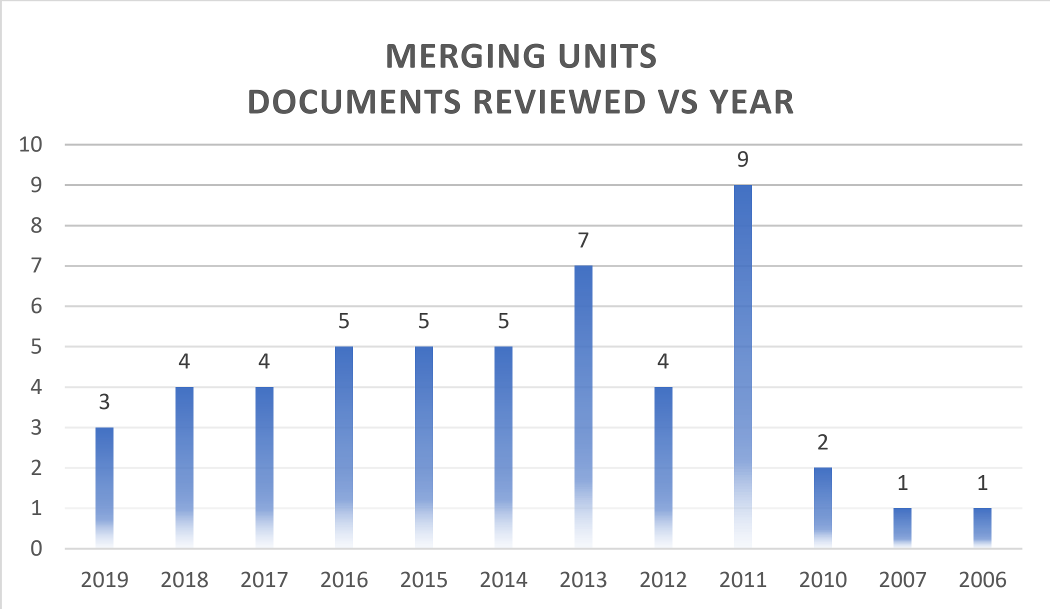


Figure 2.3 Merging Units documents reviewed per year.

The first papers described Merging Units (MUs) and Sampled Values (SV), their benefits, and application. The substation total cost of ownership can be reduced, compact substations can be build and the availability of real-time operational and maintenance data are believed to be some of the benefits (Buhagiar et al., 2016; Wuthayavanich et al., 2019). That is followed by discussions on the reliability and performance of the related process bus Ethernet network used for publishing SV. Calibration and testing of merging units and devices producing sampled values is also discussed.

The use of Sampled measured Values (SV) is described in IEC 61850-9-2 and IEC 61869 to replace analogue current and voltage measurement. IEC 61869-9 provides a product standard for instrument transformers with a digital interface according to the IEC 61850 series (IEC, 2016b; Brunner et al., 2004). The copper cabling is replaced with a digital communication network. A Merging Unit is the equipment that can digitize the analogue signals. Results show the good comparison of measurements between Merging Units and conventional systems (Dutra et al., 2014).

Merging Units can have a point to point connection to the IEDs as described in IEC61850-9-1 (IEC, 2003a) or can be connected to a LAN as a process bus. Research is required to determine if a point to point connection will be more secure compare to a design where the MU is connected to a process bus and the protection and control IEDs are connected to the same process bus. Communications conditions, such as bandwidth limitations, latency, and packet loss are presented for sampled value based line protection (Chase et al., 2019) and this can be eliminated by using point to point connections.

It is important to understand that there is a difference in sampling process of data in IEDs and MUs. The first differences between the data sampling in an IED and the MU is the control of the sampling rate. The IED generally uses frequency tracking and the MU uses a fixed number of samples per cycle at the nominal frequency. Another difference is that the A/D conversion is done in the MU before the data is multicast to all the IED subscribers. In the absence of MUs, the IED will do the A/D conversion (Apostolov & Vandiver, 2010: 2).

Sampled values can be sent from the MU in two modes per IEC 61850-9-2, depending on the application. 80 samples per cycle is used for protection application where one Ethernet frame has one set of samples. 256 samples per cycle is used for waveform recording where 8 sets of samples in an Ethernet frame is sent 32 times in a cycle (Apostolov & Vandiver, 2010: 3).

The reliability of a new SAS design is important. The analogue to digital conversion is moved to a new devise, (the MU) and this device is relying on a dc supply and a time synchronization source (for multiple SV streams) the same as what the protection IED requires. In the paper of (Skendzic et al., 2007: 2–3) it is discussed how the addition of devices can influence the Mean Time Between Failure (MTBF) of the system and how combining different functions in devices can improve the system MTBF This is relevant for the power transformer as it has multiple instrument transformers that are located at different locations. The system MBTF can negatively be influenced when several MUs are added to produce SVs.

The SV messages need to be time stamped and a time synchronization system is required for a SV process bus. The type of time synchronization system is not specified in IEC 61850-9-2. The IEEE Std 1588-2008 Precision Time Protocol version 2 (PTPV2) for precision timing is discussed and evaluated by (Ingram, Schaub, et al., 2012; Moore & Goraj, 2011; Puhm et al., 2016). PTPV2 is recommended to be use for time synchronization mandatory for a SV process bus.

MUs is proposed to have additional functionality to include substation equipment health condition monitoring functions as well (Gaouda et al., 2016; Balan & Mathew, 2018).

An approach for the real-time compression of SV data based on the IEC 61869-9 recommendations is demonstrated by typically compressing data to less than half of the original size (Blair et al., 2016). The author reason that this can be done to reduce MU encoding time and IED decoding time. The reduced data frame size can reduce the transmission times and bandwidth requirements where many sampled value massages are sent from MUs over a network.

Calibration and testing of merging units and devices producing sampled values is needed and can be achieved using real-time simulations (Ingram et al., 2011). Different calibration setups are proposed (Agustoni & Mortara, 2017a; Lehtonen & Hällström, 2016; Carvalheira & Coronel, 2015). It is presented that commercial test sets can generate analogue outputs simultaneously with their IEC 61850-9-2 LE SV messages that can be used as calibrators for Merging Units (Djokic & Parks, 2018). Researchers use different tools to analyse sampled values (Bajanek & Sumec, 2016b). Merging units can be used to produce sampled values or test set like the OMICRON CMC 353 can be used to play back a record of a sampled value message (Wannous et al., 2019). A simple over-current protection relay model is described which is programmed in LabVIEW and used to process the sampled values. The Sampled Value Analyzer software and other software are used for verification and visualization of sampled values (Bajanek, 2014; Sumec, 2014). Other protection models such as a negative sequence protection relay can be programmed and tested in a similar way (Bajanek & Sumec, 2016a). Total Vector Error (TVE) is an important concept that is applicable to phasor measurements. Merging Units and Sampled Measured Values (SMV) measure phasors and TVE is therefore also related. This allowable TVE compares the vectoral difference of the estimated Phasor to the theoretical Phasor in percentages (Abdolkhalig & Zivanovic, 2015). Cyber treads, digital signatures and the detection of spoofed sampled values is discussed (El Hariri et al., 2019; Farooq et al., 2019).

The implementation of an SV estimation algorithm with a buffer is proposed in a protection IED as a corrective measure for loss or delay of SV messages. Busbar differential and line impedance protection functions were evaluated for an IEC 61850-9-2 system in a laboratory environment using simulated protection IEDs and a MU (Kanabar et al., 2011).

An IED functional test platform using software MU (sMU) is proposed by researchers. This concept has been proved by performing accuracy and operate-time tests with transformer differential protection (Wu et al., 2015; Honeth et al., 2013).

2.2.7 Power Transformer Protection

A review of different topics regarding substation protection are done. A total of 52 conference proceedings and journal articles are reviewed, Figure 2.4.

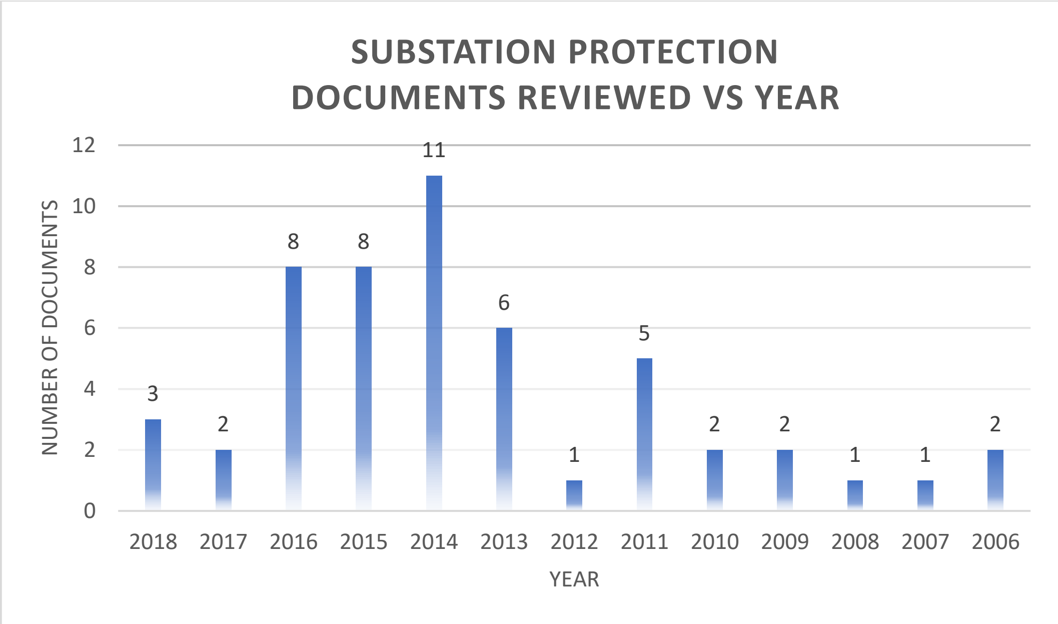


Figure 2.4 Substation protection documents review per year.

Transformer faults can be caused by abnormal system conditions or external faults. Transformer faults are categorized into two classes: external faults and internal faults (Lin et al., 2015: 17). Transformer protection can be achieved using protection IEDs to detect faults e.g. winding, core and tap changer faults.

Fault currents in the transformer can be due to phase to phase faults or phase to earth faults and the magnitude will depend on the transformer impedance, winding connections, positions of the fault on the winding, fault voltage and on the type of earthing for star connected windings (Alstom, 2002: 272). Faults need to be cleared as fast as possible to limit the damage to the transformer.

Temperature measuring devices installed on the power transformers can detect abnormal temperature and produce alarm or trip signals for the protection scheme and controlling the cooling fans of the power transformer.

Instrument transformers at the high voltage yard measuring power system currents and voltages are used by the protection IEDs to determine abnormal system conditions.

Current transformers can be installed external to the power transformer or internally in the bushings of the power transformer. CTs can also be situated on the neutral of a star connected winding or earthing transformer. The conventional instrument transformers can be copper hardwired to the protection IEDs in the control room or Merging Units in the HV yard.

Protection function e.g. Restricted Earth Fault (REF), Differential, Over Current (O/C) and Earth Fault (E/F) can be included into the same modern IED. Each IED would be wired to a separate CT protection core where possible. Different IEDs wired to the same protection core would increase the burden on the CT. The distance between the CT and the IED and the cross section of the copper wires also influence the burden on the CT.

Adaptive protection is when the protection characteristic is changed by an outside variable (Moxley & Becker, 2018). Adaptive protection is becoming a regular topic due to the changes in power systems as a result of increasing renewable energy sources or Distributed Energy Resource (DER). Adaptive protection is using a combination of algorithms, communications and shared information and can be used in a digital substation. Modern protection relays can have multiple setting groups. This can be activated/selected by substation configuration information as the information is changing in real-time.

Time synchronization is reviewed separately under its own section. Time synchronization is important when sampled values are used but also when GOOSE messages are used for protection application. It is noteworthy that using SNTP is enough for GOOSE messages, however the time discrepancy of 10ms can be considered too long during system event analysis. IRIG-B or Precision Time Protocol (PTP) has better accuracy within 1ms and a better choices for captured events and records (Theron et al., 2018).

Protection functions such as Over Current (O/C), Earth Fault (E/F), Restricted Earth Fault (REF) and Differential are described separately in the following sections.

2.2.7.1 Over current protection

Over current protection can be used to protect against over loading and faults on the primary winding. A high-set instantaneous overcurrent relay element is often used to trip for primary side short circuits. It is not effective for faults on the secondary winding due to the low magnitude of fault current transferred to the primary side. Timed delayed overcurrent protection chosen to discriminate with protection on the secondary side of the transformer increases the trip time to disconnect the faulted equipment from the power system. The O/C protection can be supplemented with an earth fault element. The E/F element can be connected in the residual circuit of the three phase CTs or on the neutral conductor of a star connected winding. A P protection class CT can be used for O/C protection.

Unit protection is used to have a shorted tripping time as it can be set more sensitive compared to O/C protection and it does not have to grade with other protections external to the transformer zone of protection. Examples of transformer unit protection is restricted earth fault and differential protection (Alstom, 2002).

A resistor in a secondary winding neutral point of a Delta /Wye connected power transformers is used to limit ground fault currents. The neutral resistor will negatively impact the sensitivity of a Differential and REF protection. A Bridge-Type Fault Current limiter (BFCL) in transformer neutral point is proposed to rectify the problem (Ghafourifard et al., 2016).

2.2.7.2 Restricted earth fault protection

Restricted Earth Fault (REF) protection is typically applied to one winding of a power transformer and act as a unit protection differential scheme. It can be of a high or low impedance type protection. The residual current of the three phase CTs are balanced out with the neutral CT. The REF protection system will operate only for faults in the zone between the phase CTs and neutral CT on a star connected winding and will not operate for external faults. The effectiveness of REF protection is related to issues with mismatched CTs, CT saturation and varying copper lead resistance. The shorter distance from the MU to the instrument transformer decreases the influence of these factors on the biased low impedance type REF protection (Alstom, 2002: 16–7).

2.2.7.3 Differential protection

The differential protection IED compares the primary and secondary currents flowing in and out of a power transformer. The currents flowing into and out of a power transformer is nearly equal and no or a small differential current is present in normal operating conditions (Alencar et al., 2014: 78–79)

A differential current is however present and measured by the differential protection for a transformer internal fault in the differential zone. The fault current in the protected zone is equivalent to the differential current or the difference between the primary and secondary currents.

The following factors can influence the differential current measured by the protection IED during normal load conditions: winding phase shift and earthing, filtering of zero sequence currents, CT ratio miss match and different taps for voltage control. Magnetising inrush during initial energisation and occurrence of over fluxing can also influence the differential current (Alstom, 2002: 277; Blackburn & Domin, 2006: 322).

Differential protection IEDs must be highly sensitive for internal faults and at the same time stable and reliable for external fault conditions. An adaptive differential relay is proposed that can self-adjust its protection characteristics according to the differential current measured (Dhinesh kumar et al., 2016). Internal fault has a high differential current compared to external faults that has low differential current. The adaptive relay can similarly be done with different characteristic curves according to different operation conditions (Huang et al., 2016).

Phase shift correction is required where there is a 30-degree phase shift between the primary and secondary side currents of a transformer with star-delta connected windings and YNd1 vector group. Star connected windings can pass zero sequence currents to faults external to the differential zone, this can operate the differential IED for faults out of the protected zone. Zero sequence current filters are required for star connected windings. The phase shift correction, zero sequence current filtering and CT ratio mismatch correction is done in the software of the digital differential protection IEDs.

A transformer protection algorithm is proposed in a research publication where the negative sequence differential current, the phase difference between the primary and secondary currents and the fundamental frequency for the primary and secondary currents are used. The proposed protection technique offers a reliable, secure and dependable solution compared to false operation of the conventional differential protection that has problems such as vector group, CT mismatch and saturation problems (Htita et al., 2016).

An adaptive protection criterion is proposed, which can change the percentage differential relay parameters according to the transformer operating conditions. Test results show that the proposed scheme can give high sensitivity on internal faults as well as high security on external faults (Zhang et al., 2013).

The sensitivity of Differential protection is related to issues with mismatched CTs, CT saturation, lead resistance and tap settings. An adaptive differential protection algorithm can be investigated by including the transformer winding tap-position information available at a process level, into the protection IED algorithm.

The shorter distance from the MU to the instrument transformer decreases the influence of the sum of factors such as mismatched CTs, CT saturation, and lead resistance on the biased low impedance percentage differential protection.

The process bus implementation where the main protection uses MUs and the backup protection uses copper wires is an interesting application of IE 61850 process bus where they wanted to get familiar and confident with the process bus technology (Bonfiglio et al., 2016). The loss of time synchronisation can have an effect on the performance of sampled-value-based differential protection (Igarashi & Santos, 2014b).

2.2.7.4 Magnetising inrush current

Magnetic flux needs to be formed in the power transformer core when it is energised. The core can have some or no remnant or residual flux after it was previously energised. A power transformer is designed to operate magnetically close to saturation. Consider a power transformer that is energised with no residual flux. The additional energising current to produce the flux when the power transformer is energised causes saturation. This draw additional high current. This phenomenon is called magnetising inrush current. The time constant of this transient condition can be from cycles up to a second depending to the size of the power transformer (Alstom, 2002: 274; Blackburn & Domin, 2006: 322; Horowitz & Phadke, 2008: 210). Magnetising inrush can be separated in to three types: initial, recovery, and sympathetic.

Recovery inrush can occur after a voltage dip during a fault or momentary dip in system voltage. The worst case will be when the voltage is reduced to zero and increase to normal again. This magnetizing inrush has not the same magnitude as the initial inrush because the transformer was already energized. A sympathetic magnetizing inrush can occur with parallel transformers, in an energized transformer when paralleled transformer is energized. This is caused by a DC component of the inrush current (Blackburn & Domin, 2006: 324).

Magnetising inrush is a transient condition that causes a differential current, but the protection should be stable and not operate for this condition.

Different methods are used to detect magnetising inrush currents and distinguishing it with internal faults current (Naseri et al., 2017; Cano-González et al., 2015; Hosny & Sood, 2014). A method is proposed to identify sympathetic magnetizing inrush that can occur with parallel transformers to prevent differential protection mal-operation (Wang et al., 2015).

Differential protection is proposed using negative sequence current and negative sequence voltage to improve sensitivity during energization and detect turn-to-turn faults (Zacharias, 2013). Transformer differential protection combined with a core saturation detection-based blocking scheme is offered as an alternative to harmonic blocking schemes. This proposed saturation detection scheme also successfully discriminates CT saturation from the power transformer saturation (Lee et al., 2014). Transformer protection based on comparisons of sequence components of the current from both sides of a transformer is proposed to discriminate internal fault with external faults, a magnetizing inrush condition and CT saturation (Patel et al., 2015).

2.2.7.5 Automatic voltage control

Power transformers are equipped with manual or automatic On-Load Tap-Changers (OLTC). The load that the power transformer supplies can change and that causes a change in the secondary voltage level. The secondary voltage level can be adjusted by changing the voltage ratio on the transformer with an OLTC. The voltage regulator measures and compares the setpoint voltage with a measured voltage and controls the on load tap changer by lowering or raising the tap position.

Power transformers can be connected in parallel. The main methods of controlling parallel transformers are Master-Follower control, Circulating Current control and Reactance control (Constantin et al., 2014).

The regulator can regulate the voltage at the receiving end substation by measuring the local load current to compensate for the voltage drop over the line. This function is called line drop compensation.

2.3 Primary substation equipment

The high voltage equipment such as the power transformers, circuit breakers and instrument transformers are regarded as primary substation equipment.

The monitoring of transformers and circuit breakers is not reviewed in this document but is important in a substation protection and control system. Online monitoring of power transformers is not novel. Circuit breaker monitoring has advantages (Costa et al., 2018) and is more feasible as equipment status information like circuit breaker SF6 gas level, contact wear, the stored energy system and the status of the control circuit, becomes further available in a digital substation.

2.3.1 Instrument Transformers

Current and voltage transformers are generally called Instrument Transformers (ITs). The function of IT is to transform high power system currents and voltages to lower magnitudes suitable for measuring devices in the substation (Ganesan, 2006). They are designed to operate in normal and abnormal system conditions. Protection current transformers are designed to withstand fault currents for a few seconds, while voltage transformers are required to withstand power system dynamic over voltages (Horowitz & Phadke, 2008: 61)

The primary windings of current and voltage transformers are connected differently to the power system and respond differently to conditions in the power system. Current transformer primary windings are connected in series with the circuit and voltage transformers are connected in parallel to the power circuit (Alstom, 2002: 88). According to Alstom (2002:87), protection systems are required to operate during the transient disturbance in the power system following a system fault by reacting to the output of the measuring transformers. Errors in the measuring transformer output may delay the operation of the protection or cause unnecessary operations.

The lead resistance from the Instrument Transformers (ITs) in the yard to the IEDs in the control room as well as the IED input impedance have an influence on the IT burden. The distances from different bay equipment in the HV yard to the control room are different. The burden on each IT will be different depending on the installed position due to the varying lead resistance when copper wires are used. The manufacturing cost is influenced by the IT specification, for example the burden. The lead resistance does not have such a large effect on the VT burden compared with CTs where high currents occur during fault conditions.

The interface between the instrument transformer with digital or analogue outputs and the substation is managed by IEC 61869 and IEC 60044-8 standards (Bhardwaj et al., 2014: 3; IEC, 2002a). A typical power system CT or VT can have several protection and metering cores. A typical 132kV CT can have 6 different cores. A power system VT or CT connected to a MU does not have the need for several protection and metering cores. The MU distributes the sampled values to the different protection and control IEDs. This can also reduce the cost of an instrument transformer.

2.3.1.1 Current transformers

The IEC standard provides for different protection and metering accuracy classes. The metering accuracy classes are related to currents in the normal operating range of the power system for metering application. The protection accuracy classes are applicable when currents several times higher than the rated current are measured for protection during system fault conditions.

Modern protective IED may demand a different current transformer performance compared to the old electro-mechanical relays (Ganesan, 2006). The IEC protection accuracy classes P and PX are considered for protection applications. Class PX is typically used for unit protection such as TRFR differential protection. The knee-point voltage and exciting current are important specifications for a class PX CT.

Two types of CT saturation can occur. The first type is with a symmetrical AC primary input current and occurs because a high secondary burden. The second type occurs because of a DC offset of the AC primary current (Blackburn & Domin, 2006: 183; Hargrave et al., 2018). The saturation can also be due to a combination of the DC offset and the burden.

The core saturation voltage or knee-point voltage of a current transformer is the point at which the output current ceases to linearly follow the input current. At this point on the excitation curve, a further increase of 10% of secondary e.m.f. would require an increase of the exciting current of 50% (Alstom, 2002: 95).

The CT knee-point voltage requirement is a function of the total circuit resistance.

VK = f (RCT, RL, RRP) (2-1)

Where:

VK = Required CT knee-point voltage (volts)

RCT = Resistance of the current transformer secondary winding (ohms)

RL = Resistance of a single lead from relay to current transformer (ohms)

RRP = Impedance of a relay phase current input (Apostolov & Vandiver, 2010: 5).

The total CT burden when connected with short leads to a MU is much less compared to when long copper leads are used from the CT in the yard to the IED in the control room. The lead resistance from the CT to the MU can be reduced and the MU input impedance is also typically very small.

The Differential protection compares the current values of CTs at different locations in the high voltage yard. The burden on CTs is significantly different depending on the location of CTs due to the varying lead resistance of the wires from the CT to the protection relay. The burden on CTs is similar when MUs are used and not depending on location of the CT, as fibre optic is used from the MU to the control room.

The cost of manufacturing the CT can be reduced if the knee-point voltage requirement is less when the MU is installed close to the CT.

2.3.1.2 Voltage transformers

Power systems are operated at voltage close to the rated system voltage. Over voltages during unbalanced faults depend on systems earthing. It also can occur due to switching or low load conditions on long power lines. The voltage factor of a VT is a quantity expressed in per unit of the rated voltage and the upper limit of operating voltage (Alstom, 2002: 89). In the IEC standard, the maximum voltage factor is 1.2 for a continuous operation and 1.9 for a short duration.

A fault in the power system may reduce the system voltage to a low value. The accuracy of voltage measurement for protection purposes have to be maintained during these low voltage levels (Alstom, 2002: 89).

Saturation is not a problem in VTs because power systems should not be operated above normal voltage, and faults result in a collapse or reduction in voltage (Blackburn & Domin, 2006:188).

The VT can be connected to a VT junction box from where separate supplies are distributed to the different protection and control IEDs. A second design can be implemented where a VT bus is created, for example a bus bar VT, between the different protection and control bays. The lead resistance and burden on the VT need to be considered for these different applications. Typical VT connections to IEDs are shown in Figure 2.5.

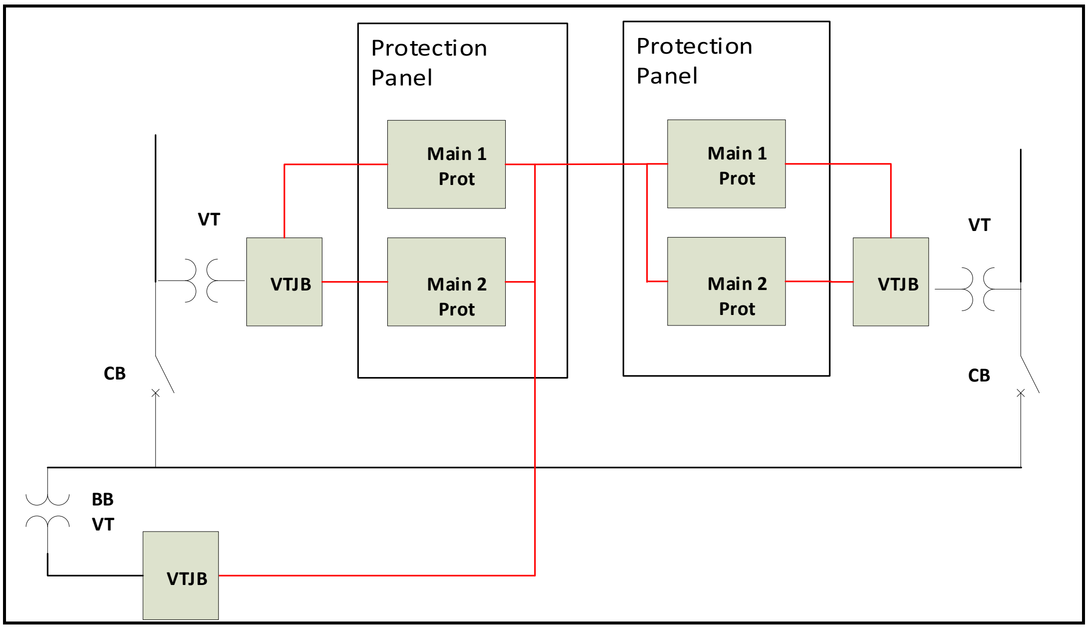


Figure 2.5 VT Connections

The lead resistance from the VT to the MU can be reduced for an application where the MU is close to the VT. The total VT burden when connected with short leads to a MU is much less compared to when long copper leads is used from the VTJB in the yard to the IED in the control room. The cost of manufacturing the VT can be reduced if the burden requirement is less.

2.3.2 Earthing Transformer

An auxiliary (AUX) transformer is combined with a Neutral Electromagnetic Coupler (NEC) and Neutral-Earthing Resistor (NER). The NEC is to provide a neutral point in the delta connected system and a (NER) connected to the neutral point to limit earth fault current. The NEC/NER AUX transformer is connected on each of three power transformers in the substation under study. The auxiliary transformers supply the substation auxiliary loads with 400VAC.

Two of the five transformers have NEC/NER transformers without auxiliary windings. Power stations are connected to these transformers via the 11kV bus bar. The NER limit the fault current to 360A. The 11kV Generators connected are not capable to handle this magnitude of currents flowing in their neutrals. The NER is switched and disconnected when one or more generators are running.

2.4 Real-time digital simulation

The use of a Real-Time Digital Simulator (RTDS) for testing of a differential relay and discrimination among magnetizing inrush and internal fault currents for a power transformer is described (Moravej & Bagheri, 2015).

A power system model can be executed in real-time with a digital simulator. Protection IEDs can be connected as Hardware-In-the-Loop (HIL) to the simulator to evaluate their performance. This is called hardware-in-the-loop testing (Almas & Vanfretti, 2013). The RTDS can simulate the actual behaviour of the power transformer in a power system. The RTDS exports signals to an external hardware/ IED and receives inputs from the hardware. The RTDS software i.e., RSCAD is used to create a power system model for simulation of a power transformer.

A project to develop a methodology and facility for protection and control coordination studies implementing real-time simulation and HIL testing of the protective relays and new technologies using RTDS is described (Kong et al., 2015).

A RTDS was also used in research work where system tests incorporate hardware-in-the-loop transformer differential relay test included merging units, PTP time synchronization, network traffic tests (Ingram et al., 2014).

2.5 Analysis of the findings of the literature review

In an IEC 61850 based protection and control systems the IEDs depend on a reliable Substation Communication Network (SCN) architecture that meets redundancy requirements when failures do occur.

A SCN requires a time synchronisation network. The different types are reviewed.

2.5.1 Network architecture and redundancy protocols

Research is done to determine the reliability of different network topologies and how effective different redundancy protocols are. These papers are summarised in Table 2-1 below.

The most common architectures used are star and ring but cascaded and mesh structures are used as well (Sun et al., 2011).

Rapid Spanning Tree Protocol (RSTP), Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are mostly used to obtain redundancy in the communication network.

The reliability studies results depend on the Mean Time to Failure (MTTF) of individual components. The outcome of the research will therefore depend on the MTTF value that the researcher uses for the different components in the study. A specific component, like a switch or an IED will have different MTTF values for different suppliers.

The network design must be cost effective. The network design engineer must choose the architecture for the communication network to be reliable and cost effective.

A star connected network has a switch as a single point of failure. The star architecture can be combined with a PRP based SCN architectures to provide a solution to fulfil the availability and performance requirements in SAS for strategic important substations.

Practical implementation depends on the components used in the SCN. An example is for the case where an existing station bus network is implemented in a substation and the process bus is required to be added. An IED will require 4 communication ports if the station bus and the process bus are two separate networks and PRP is considered for each network. It may not be economical to replace all the IEDs to implement the process bus.

The IED must support the selected redundancy protocol. The IED of a specific manufacturer may support SNTP and not PRP as an example.

The reliability requirement for a SCN that is used to send GOOSE messages at a station bus level is different than a network that is used to send Sampled Value (SV) messages at a process bus level. The mechanism for sending GOOSE messages allows for messages to be resend. SV messages are sent only once. All the messages are significant for the correct operation of bus zone and differential protection schemes that compares station wide SV messages. A delayed or lost message can cause incorrect protection operation.

Table 2-1 Network Architectures and redundancy protocols

Paper	Aim of the paper	Network Architecture	Protocol	Result
Araujo et al.,2012	A prototype of a HSR node has been developed and proved over some virtual machines connected in a ring network as the standard states and achieved the target of seamless availability.	Ring	PRP and HSR.	The comparison of PRP and HSR experiments shows solutions to get high availability of the communication with zero time recovery.
Bhardwaj et al,2014	This paper discusses standards IEC 61850 and IEC 61869 used in the communication profile with data availability standard IEC 62439		PRP and HSR	Standards IEC 61850, IEC 61869, and IEC 62439 were discussed with methods IRIG-B and IEEE 1588 to synchronize
Buhagiar et al,2016	The paper describes a French smart substation project, as part of the French government's plan for smart sub stations.		HSR	Extra IED (MPx), connected to the substation buses, to replace the functions inside another IED in the case of failure
Darby et al,2014	The paper discusses the principle of operation of PRP, and the benefits for use in an IEC 61850-based SAS.		PRP	Interoperability is proven by extensive multi-vendor interoperability testing and by utility in-service use
Ferrari et al,2103	This paper discusses synchronization systems applied to redundant network infrastructures for substation automation. infrastructures for substation automation: in these systems the reconfiguration of the network after a		PRP & RSTP	PRP performs better as RSTP and guarantees seamless synchronization performance in case of a single fault.

Goraj et al,2012	This paper provides an overview of high availability networks and redundancy protocols for seamless failover critical substation automation applications.	Ring and Star	PRP and HSR	PRP and HSR is discussed and compared for substation, station and process bus applications
Kanabar et al,2011	This paper presents the hardware implementation of a process bus communication network and investigate the proposed corrective measure for Sampled Value (SV) loss/delay.	Cascaded		the SV estimation algorithm as a corrective measure for SV loss/delay can enhance the reliability and security of digital protection functions using an IEC 61850-9-2-based process bus
Kanabar et al,2012	This paper review available standards for Power system protection, control and monitoring and discusses their applications and current developments.		PRP and HSR	Available standards for Power system PCM are discussed
Kumar et al.,2015	This paper presents simulation results with respect to the delay in GOOSE and SV packets transfer in an Ethernet environment related to a digital protection scheme.	Ring		It was observed that the increase in the SV frequencies caused higher packet losses for GOOSE messages
Liu et al,2014	This paper proposes a methodology to evaluate the reliability of a Substation Communications Network (SCN) considering different architectures.	Star and Ring	RSTP and PRP	The ring architecture station bus is proved to be reliable and cost effective. PRP based SCN architectures is an economical and solution to fulfil the availability and performance requirements in SAS
Meier et al.,2016	Example substations are used to verify the standardized performance figures		HSR	The paper discussed the validity of fault clearance timings for digital substation

	defined in IEC 61850, IEC 60044 and IEC 61869 standards.			architectures with reference to timing and performance requirements.
Rahat et al.,2019	A mathematical approach is used to analyse the reliability and availability. A suitable design for efficient operation is proposed.	Ring and Star		Advantages and disadvantages of different network topologies are discussed. Simulation results are discussed
Raza et al.,2009	This paper presents analysis and the crucial need for the deployment of Gigabit Ethernet in the substation.			Gigabit Ethernet in the substation is optimized for the current IEC61850 constraints but can also support future considerations smoothly
Stark et al.,2013	This document describes the utilization of the nonconventional measurements and advanced features of IEC 61850 standard for substation automation systems.		PRP and HSR	Non-conventional instrument transformers together with IEC 61850 provide cost-efficient solutions with higher availability compared to traditional instrument transformers
Sun et al.,2011	This paper describes the different Ethernet based process bus architectures, analysis of the mean time to failure and availability	Cascaded, Star and Ring		The star architecture provides the highest MTTF and availability. The ring and cascade architecture have the same MTTF and availability.
Younis,2016	The objective of this paper is to evaluate the reliability and availability of different substation communication architectures by using the Reliability Block Diagram (RDB) method.	Cascaded, Star and Ring		Reliability of the specific IEC 61850 SAS has been significant approved when adding redundancy components to the system
Wester and Adamiak,2011	This paper is a tutorial in Ethernet communications and architectures.	Star, Mesh and Ring		The paper address Ethernet fundamentals and cover the most common elements of an Ethernet architecture

2.5.2 Network time synchronisation methods

Research is done to determine the accuracy of different time synchronisation methods and the effect they have on the performance of an IEC 61850 digital substation. A summary of papers is shown in Table 2-2.

The same physical fibre optic network for the process bus communication can be used for time synchronisation. Precision Time Synchronization Protocol (PTP) and Simple Network Time Protocol (SNTP) are reviewed for use in process bus networks. The SNTP time accuracy (0.1 to 1 ms) is adequate when only GOOSE messages are used but is not adequate for SV applications which require <1 µs accuracy (Crossley et al., 2016).

The papers demonstrate that PTPV2 is a viable method of providing time synchronization for an SV process bus network.

PRP as redundancy protocol, performs better than RSTP with regards to SNTP seamless synchronization performance in case of a single network fault (Ferrari et al., 2013).

Different papers also discuss protection schemes where the time synchronisation time stamp of the measure values is critical. Differential protection compares two measurement values which must be compared at the identical time values (Aichhorn et al., 2016).

It is a practical consideration that not all IEDs supports PTPv2 as it is a newer time synchronisation protocol then SNTP. It may not be economical to replace all the IEDs and network switches in the SCN to have a PTPv2 solution.

Table 2-2 Time synchronization

Paper	Aim of the paper	Synchronisation	Result
Agustoni and Mortara, 2016	The working principle and the architecture of a calibration system for devices operating with the IEC 61850-9-2 standard are described.	PTP	The setup described in this document allows performing calibrations for IEC 61850-9-2 devices such as merging units (MU)
Agustoni and Mortara, 2017	The Calibration system for commercial test sets, operating with IEC 61850-9-2 standard, is described	PTP	Preliminary results show that the setup described allows performing the required measurements for calibrating IEC 61850-9-2 test sets.
Bhardwaj et al,2014	This paper discusses the methods to synchronize different devices clocks over the network like IRIG-B and IEEE 1588.	PTPv2	
Hogan,2014	The report details the literature review, design, construction, and performance evaluation on the IEC 61850 substation automation designs with the use of a test facility.	SNTP	The successful development and evaluation of an IEC 61850 SAS with multiple vendor devices.
IEEE,2019	A modelling and analytical technique is proposed based on queueing theory. The model behaviour is studied for IEC 61850 standard for deliberately limited and weak adversaries regarding time accuracy de-synchronisation attacks.	SNTP & PTP	De-synchronisation attacks was demonstrated against IEC 61850 time synchronisation systems with minimal strength adversaries based on a novel queueing model.
Igarashi et al,2014	The paper presents a summary of challenges implementing a process bus according to IEC61850-9 Standard.	SNTP & PTP	IEC61850-9 variations, process bus reliability, time synchronization between devices, cyber security and measurement accuracy was discussed

Igarashi et al,2015	Our aim is to show the results from a mathematical simulation of the behaviour of a differential protection algorithm for power transformers compared with the loss of the time synchronization signal in the process bus according to IEC 61850-9-2.	PTP	An algorithm is adapted for power transformer differential protection relays, used in a process bus network, when sampled values synchronisation is lost. The algorithm shows satisfactory results.
Igarashi et al,2015	Presents a summary of the most significant factors for implementing a process bus according to IEC61850-9 Standard.		Important standards were highlighted for the successful implementation of the process bus according to IEC61850-9 Standard
Ingram et al,2012	This document presents a technique to assess the overall network performance of sampled value process buses based on IEC 61850-9-2 using measurements from a single location in the network.	PTPv2	Time synchronisation to a time source is required for this method of measuring the network performance of an IEC 61850-9-2 sampled value process bus network.
Ingram et al,2012	The suitability of PTPv2 to synchronize sampling in a digital process bus is evaluated,	PTPv2	The results presented demonstrate that PTPV2 is a viable. method of providing time synchronization for a SV process bus using IEC 61850-9-2.
JV et al,2008	SNTP Time synchronization system in digital substation is applied	SNTP	It is concluded that time synchronization system based on SNTP has a bright future in digital substations
Kanabar et al,2011	This paper presents the performance evaluation of the IEC 61850-9-2 process bus for a typical 345 kV/230 kV substation.		A sampled value estimation algorithm is presented and tested in this paper.

Kumar et al,2015	This paper presents simulation results with respect to the delay in packets transfer in an Ethernet environment.		The results shows that the lost of data packets can have a significant effect on the reliability of a protection system.
Moore and Goraj, 2011	This paper describes the experience from a design and implementation of a digital high voltage substation, based on fibre optic switchyard with IEEE 1588 v 2 time synchronization.	SNTP & PTP	NCIT, Merging Units IEC 61850-9-2, multiple vendors IEDs had been used. Sampled Values, GOOSE and IEEE 1588 v.2 used in the same Ethernet network
Rinaldi et al,2016	In this paper a new distributed measurement system for the estimation of IEC61850 Transfer Time over Smart Grid communication infrastructure is introduced.	SNTP	Test case has been realized to show the effectiveness of the proposed instrument in highlighting the performance of real IEC61850 devices.
Ussoli & Prytz,2013	To investigate the kind of accuracy level with the use of SNTP in modern switched networks.	SNTP & PTP	It is possible to reach the milliseconds level accuracy with SNTP when sufficient timestamping accuracy is implemented
Yamada et al,2012	A high-accuracy error measurement system for calibration of digital-output equipped electronic current transformers (ECTs) is described.		
Yung et al.,2017	The aim is to measure the time delay of SV packets transmission in a network switch,		The test result shows that the SV transmission time delay measurement value can be measured.is basically same as the set value.

2.5.3 Merging Units

Research is done on the testing and calibrating of Merging Units (MUs). Different test systems are required to do the calibration tests on the MUs (Agustoni & Mortara, 2017b; Song et al., 2017). Merging Units have analogue signals as inputs that must be compared to digitals signals as outputs. Suppliers must ensure that the MUs can be calibrated and that the MUs perform as required. However, is can benefit the Utility as end user to perform acceptance tests on the MUs before it is put into service (Sheng-zong & Tie-zhu, 2017).

The main function of Merging Units is to produce SV messages from analogue voltage and currents. Process interface of high voltage equipment such as circuit breakers and power transformers, digital inputs and outputs, can be added to the MU. With this additional information available, it is realised that additional functionality can be included in the MU. Protection algorithms and control functionality can be added.

A case is presented that compares the tripping times of transformer differential protection when using hardwired current transformer connections is compared with sampled values and process bus application. The result is that the tripping times are the same. This is expected due to the following. The same protection algorithm is used for the differential protection. The difference is that the Digital to Analogue (D/A) conversion is performed in the IED located in the control room with a hardwired protection scheme. The D/A conversion is performed in the Merging Unit located in the yard when sampled values is used.

Sampled value packet delay or lost is important factors that will influence the correct operation of differential protection schemes that compares different sampled value messages with each other (Kanabar & Sidhu, 2011). Direct point to point connection from the Merging Unit to the protection IED without using a network and network switches can be a solution to prevent packet loss or delays due to the Ethernet network(Qin et al., 2014).

Cybersecurity is an important component that must be considered for a digital substation communication network (Ishchenko & Nuqui, 2018).

Table 2-3 Merging Units

Paper	Aim of the paper	Key word	Result	Comment
Abdolkhalig and Zivanovic,2013	This paper evaluates the performance of proposed phasor estimator using IEC 61850-9-2 Sampled Value (SV) measurement for Phasor measurement.	Merging Units (MU), Sampled Values, Total Vector error,	The Kalman Filter is employed for computing the Phasor based on IEC 61850-9-2 Sampled Measured Values. The Total Vector Error is analysed for the effects of the IEC 61850-9-2 samples loss.	The data traffic, frame size and number of ASDUs influences the TVE.
Agustoni and Mortara, 2016	The working principle and the architecture of a calibration system for devices operating with the IEC 61850-9-2 standard are described.	Merging Unit, calibrating	The setup described in this document allows performing calibrations for IEC 61850-9-2 devices such as Merging Units (MU)	Merging Units cannot be calibrated with traditional systems
Agustoni and Mortara, 2017	The Calibration system for commercial test sets, operating with IEC 61850-9-2 standard, is described	IEC 61850-9-2, calibration test	Preliminary results show that the setup described allows performing the required measurements for calibrating IEC 61850-9-2 test sets.	Will allow performing calibrations for a MU.
Almas and Vanfretti, 2013	In this paper a power system is modelled in SimPowerSystems and is executed in real-time using Opal-RT's eMEGAsim real-time simulator	Process bus, Hardware-in-the-loop, Differential protection	Hardware-in-the-Loop testing of process bus performance for differential protection is presented. The results are that the tripping time is very similar to hard wired protection scheme.	The Digital to analogue conversion is moved from the IED in the control room to the yard. The process bus has other advantages on a protection scheme.
Apostolov and Vandiver, 2010	Distance protection and IEC 61850 Process Bus - Principles, Applications and Benefits are discussed	Distance protection, merging units	Substation protection applications based on Sampled Values are described in the paper and demonstrates the	

			advantages and Improvements in functionality.	
Bajanek,2014	This document deals with usage of Sampled Values for over current protection functions.	Sampled Values, Protection	Overcurrent protection relay was tested. Functions of the algorithm was tested successfully with sampled values.	
Bajanek and Sumec, 2016	This paper is focused on software developed to use Sampled Values in LabView development environment.	Sampled values, testing	Software tools is presented that can be used for generating Sampled Values, visualize them and SVRLIB library in LabView	Can be used to test protection algorithms.
Bajanek and Sumec, 2016	This paper focuses on development of negative sequence relay model that is processing IEC 61850-9-2 Sampled Values.	Sampled Values, negative sequence current, protection	The developed negative sequence protection relay was tested compared to a conventional relay with comparable results.	LabView can be used to develop other protection relay algorithms.
Balan et al,2018	This paper discusses the details of a novel concept for Merging Units. The MU has additional functions to serves as a control unit with the capabilities of real- time decision making as well.	Merging Units	A Merging Units was tested that has analogue input module to produce SV. Additional Digital Input / Output (DI/DO) modules are included in the MU	The process bus is not only related to SV messages Other process interface must be included for the substation high voltage equipment.
Chase et al, 2019	This paper discusses communications conditions, such as bandwidth limitations, latency, and packet loss, and analyses them with respect to SV-based protection.	Merging Units, Sampled Values, Protection	A SV-based line protection schemes using SV messages from multiple MUs was tested. The scheme is impacted by communications conditions in several ways. It is recommended to monitor the SV channel status and appropriately make	The same issues related to line current differential protection schemes may be applicable to transformer differential protection schemes.

			protection blocking or alarming decisions.	
Crossley et al, 2011	The design and performance evaluation for a protection system utilising IEC 61850-9-2 process bus is discussed. The paper describes an overview of the concepts and benefits of the process bus, and how it affects the design a protection scheme.	Process bus, Merging Unit, protection	The presented results show the performance of a process bus based protection scheme is comparable to a conventional hardwired scheme.	The process bus architecture and the ethernet switches influence the system performance
Djokic et al,2018	A synchronized current-comparator-based power bridge for calibrating analogue merging units at power frequencies is described	Merging Unit, calibrating	A current-comparator-based system for the calibration of analogue merging units at power frequencies of 60 Hz and 50 Hz is devolved.	Commercial test sets is required that generate analogue outputs simultaneously with IEC 61850-9-2 LE SVs that is used as calibrators for merging units.
Dutra et al, 2014	The performance of a process bus based protection scheme is compared to a conventional hardwired scheme	Merging Units, sampled values	The presented results show process bus based protection scheme performs the same a conventional hardwired scheme	Analogue to Digital conversion the same for conventional relays and merging units
Farooq et al,2019	This paper describes a developed software framework, S-GoSV (Secure GOOSE and SV), that generates custom GOOSE and Sample Value messages.	Sampled Values, cyber security	MAC based digital signature algorithm HMAC-SHA256 is implemented for GOOSE messages to solve security issues.	Digital signature algorithm for SV messages is not implemented
Gaouda et al,2018	This paper proposes the functionality of a smart IEC 61850 Merging Unit that supports self-healing and asset management functions of future power grids.	Merging Unit	The proposed IEC 61850 MU as a smart tool that can monitor, control, protect, and initiate corrective actions	MU can be equipped with protection algorithms to act as protection IEDs in the high voltage yard

Hariri et al,2019	This paper investigates the feasibility of using neural network forecasters to detect spoofed sampled values and proposes an algorithm to detect the accumulation of the forecasting error.	Merging units, Sampled values	An algorithm is presented, to enhance the reliability of the neural network forecaster in terms of detecting spoofed SMV packets.	Each IED will be able to verify the integrity of the SMV packets coming into it.
Honeth et al, 2013	The paper presents the development of an IEC 61850-9-2 software Merging Unit (sMU)	Merging Unit, process bus protection	The results show that the sMU platform provides a useful tool for testing protection and SAS experimentation.	
Igarashi et al,2014	The paper presents a summary of challenges implementing a process bus according to IEC61850-9 Standard.	IEC 61850-9	IEC61850-9 variations, process bus reliability, time synchronization between devices, cyber security and measurement accuracy was discussed	
Igarashi et al,2015	This article presents a prototype development of a digital optical Instrument Transformer with IEC 61850-9-2 interface.	IEC 61850-9-2, instrument transformers	A prototype of a digital optical IT for high voltage metering with IEC 61850-9-2 interface was presented with satisfactory results.	A digital optical IT has advantages over a system with a conventional IT and MU
Igarashi et al,2015	A summary is presented of the most significant factors for implementing a process bus according to IEC61850-9 Standard	IEC 61850-9	Important standards were highlighted for the successful implementation of the process bus according to IEC61850-9 Standard	
Ingram et al,2012	This document presents a technique to assess the overall network performance of sampled value process buses based on IEC 61850-9-	IEC 61850-9-2, network latency.	The latency introduced by Ethernet switches is measured to determine the Network latency.	That is the reason why sampled value messages is time stamped.

	2 using measurements from a single location in the network.			
Ingram et al,2013	This paper analyses the performance of a process bus network including the impact on network switches when using high sampled values traffic.	Ethernet networks, Merging Units, network performance	Process bus networks have been shown to be reliable at very high network loads.	This developed test methodology can identify when network capacity is reached, and this can be used to assess the safe limits of operation for a network.
Ingram et al,2014	This paper presents an investigation of process bus transformer differential protection performance	IEC 61850, Transformer differential protection	Test results showed that the protection relay operated correctly with process bus network traffic at full capacity.	
Kaibo et al,2015	This paper proposed a scheme of high sampling rate data in Merging Unit for relay protection.	High sampling rate, low pass filter, Merging Unit	The conclusion of the study showed that low pass filtering and interpolation synchronization scheme is simple and efficient for high rate sampling.	
Kanabar et al,2010	This paper presents the performance evaluation of the IEC 61850-9-2 process bus for a typical 345 kV/230 kV substation	Sampled values, delayed and lost packets	The delay and packet loss for the sampled value packets is analysed by considering various communication parameters, the sampled value estimation algorithm is tested as corrective measure to address the issues	
Kanabar et al,2011	This paper presents the hardware implementation of a typical IEC 61850-9-2-based process bus communication	Sampled values, delayed and lost packets, differential	The SV estimation algorithm is implemented as a part of bus differential and transmission-line distance protection IEDs. it is tested	

	network for digital protection systems		for various SV loss/delay scenarios.	
Konka et al,2011	a traffic generation system has been developed for IEC 61850 Sampled Values	Sampled Values, testing, performance	an accurate and realistic model of a IEC 61850 Sampled Values traffic generator was shown.	The process bus communication network can be tested with realistic sampled value traffic. The interoperability of devices can be tested.
Kumar et al,2015	This paper presents simulation results with respect to the delay in packets transfer in an IEC 61850-9-2 Ethernet environment.	Packet delay, Sampled Values	Packet delays and losses was increasing as SV messages was increased.	The GOOSE packet losses were monitored. GOOSE packets are resent frequently. SV packet losses are more important to consider.
Lehtonen and Hällström, 2016	This paper describes a reference Merging Unit for producing a stream of sampled values over Ethernet. A measurement setup for calibrating other equipment is built around the Merging Unit.	Merging Unit, calibration	A calibration setup with a reference Merging Unit to calibrate other devices is shown.	
Moore and Goraj, 2011	This paper describes the experience from a digital high voltage substation, based IEC 61850-9-2 sampled values with IEEE 1588 v 2 time synchronization.	Merging Units, process bus, time synchronization	A communication network uses sampled values data and time synchronization IEEE 1588 version 2 signals over the same fibre optic network.	No test results were provided in the paper.
Sheng-zong and Tie-zhu, 2017	Accelerated life test was studied on Merging Units used in intelligent substation to reveal reasons and potential defects for units with a high field failure rate.	Merging Units, Test	The tests were carried out successfully on the Merging Units to expose the potential defects An acceptance evaluation method was developed	Performance testing to evaluate MUs before they are put into service

Skendzic et al,2007	This paper analyses the Sampled Value Process Bus according to the IEC 61850-9-2 standard	Sampled Values, Process Bus, IEC 61850-9-2	Protection reliability, Ethernet network traffic, time synchronisation issues are shown and discussed	These issues are solved by new technologies.
Song et al,2017	This paper proposes a passive interoperability test method for IEC 61850-9-2 based Merging Units.	Merging Units, interoperability	The interoperability of two commercial MUs from different vendors has been tested based on IEC 61850-9-2 LE. The MUs passed the interoperability test as defined.	IEC 61850-9-2 LE assist with the implementation of the standard by different vendors
Stark et al,2013	This document describes the utilization of sampled values according IEC 61850 part 9-2 can be used to improve the reliability and functionality of the system	Sampled values	Calculated results indicate improvements on availability, performance and reliability of the system.	
Stefanka,2013	The paper discusses how the application of IEC 61850-9-2 can improve the measurement system in MV switchgear using sensors.	MV switchgear, sensors, IEC 61850-9-2	The paper has described the advantages of an arrangement where IEC 61850-9-2 is used together with sensors in MV Switchgear,	Sensors have advantages over conventional instrument transformers and merging units.
Sumec,2014	Paper introduces a tool designed for verification of sampled values generated by various devices using the IEC 61850-9-2 protocol.	Sampled values, Ethernet network	Diagnostic tool for verification and visualization data from a merging unit was introduced in this paper	
Sun et al,2011	This paper describes these different types of process bus, their implementations and their relative advantages and disadvantages.	Reliability, architecture	A methodology used to calculate the reliability and availability of the communication networks based on component failure modes was shown	The mean time to failure (MTTF) values used for the calculations will not be the same for different equipment and different manufacturers

Wu et al,2015	This paper proposes a novel IED functional test platform using software MU (sMU), with less limitation on the number of MUs and higher flexibility in MU modification.	IEC 61850-9-2, Merging Unit, functional testing	This paper presents an IED function testing platform using software Merging Units. The sMU has design flexibility, cost savings, no limitation on the number of required MUs and time saving benefits.	This test sMU platform does not require expensive amplifiers to test IEDs.
Yamada et al,2012	A high-accuracy error measurement system for calibration of digital-output equipped such as electronic current transformers (ECTs) is described.	IEC 61850-9-2, Merging Unit	A high-accuracy error measurement system for calibrating digital-output equipment, according to IEC 61850-9-2, has been presented.	The Measurement system is used for electronic current transformers but is required for Merging Units as well.
Yang et al,2017	The aim is to measure the time delay of SV packets transmission in a network switch,	Process bus, network switches	The test result shows that the SV transmission time delay measurement value can be measured.	This method can enhance the reliability and security of digital protection functions of an IEC 61850-9-2 process bus network
Yaojia et al,2015	This paper analyses the quantization error produced in the data transmission process of the electronic the electronic transformer merging unit.	Quantization, signal processing, Merging Units	Matlab is used to do the simulation and verification., This paper drew a conclusion through analysis and calculation that the quantization error is so small that it can be ignored.	

2.6 Conclusion

The literature on the different types of primary equipment components in protection and control of power transformers, substation control systems and communication networks is reviewed.

The importance of using Merging Units connected to conventional instrument transformers is described and compared with systems where conventional instrument transformers are copper hard wired to IEDs. Network redundancy and time synchronisation are critical in an IEC 61850-9-2 network and affects the protection system performance.

In the next chapter the network architecture, communication protocols and devices of substation communication networks in an IEC 61850 standard digital substation are covered.

3 CHAPTER THREE

THE IEC 61850 STANDARD AND DIGITAL SUBSTATION ETHERNET TECHNOLOGY

3.1 Introduction

IEC 61850 is a standard used for communication networks and systems for Power Utility Automation (PUA). The functions of a PUA system are protection, monitoring and control of the primary equipment in substations and of the grid.

The first edition of the IEC61850 standard was as a standard for communication networks and systems in substations. Its scope was expanded in edition 2 to include the modelling of other parts of the power system. The modelling of hydropower plants (see IEC 61850-7-410) distributed energy resources (see IEC 61850-7-420) are also covered by the IEC 61850 series. The standard has also been extended to substation to substation communication (see IEC 61850-90-1). The application scope of IEC 61850 is shown below in Figure 3.1.

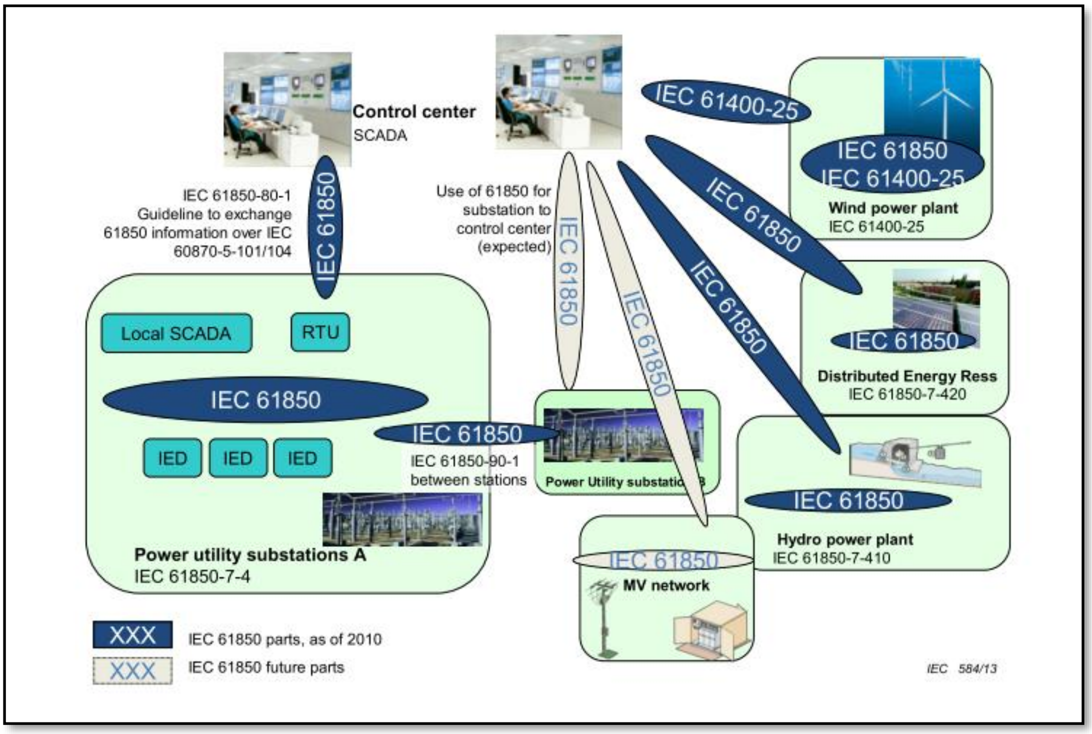


Figure 3.1: Scope of application of IEC 61850, IEC/TR 61850-1 (IEC, 2013a: 14)

The architecture of an IEC 61850 substation consists out of a station level, a bay level and a process level. Digital technologies and the implementation of these technologies in substations were first done at station and bay levels and now also at the process level.

The IEC 61850 standard series defines the communication between the intelligent electronic devices (IEDs) in the substation and the related system requirements. The standard also allows interoperability among automation devices of different vendors for digital substation application. (Bhardwaj et al., 2014).

Part 2 of the IEC 61850 series contains the glossary of specific terminology and definitions used in the context of Substation Automation Systems (IEC, 2003b).

The chapter covers the three levels of IEC 61850, standard namespace of logical nodes, system configuration description language and abstract communication service interface in section 3.2.

The functions and communication interfaces are discussed in section 3.3, data modelling in section 3.4, the SCL language in section 3.5, the SCL file types in section 3.6 and the communication services in section 3.7.

Digital substation Ethernet technology is discussed at the end of the chapter in section 3.8. Communication network architecture, network redundancy protocols and Open Systems Interconnection (OSI) model physical and data link layers are covered in sub sections 3.8.1 to 3.8.4.

Time synchronisation is discussed in the last section 3.9.

3.2 The levels of definition of the IEC61850 standard

The IEC 61850 standard provides three main levels of definition:

- A standard name space of logical nodes, data objects and attributes (IEC 61850 part 7-3 and 7-4),
- a System Configuration description Language (SCL) covered in IEC 61850 part 6 and,
- Abstract Communication Service Interface (ACSI) services (part 7) that can be mapped to specific protocols: MMS (part 8) and Sampled values (part 9) to exchange this information. The Mapping is done by using Specific Communication Service Mapping (SCSM)

The original name space focused on electrical data for protection, monitoring and control purpose mainly. New name spaces were added for hydro power plants and distributed energy resources recently.

SCL is based on the XML meta language. It can describe IED capabilities, how IED are configured and can also describe a power system.

The IEC 61850 standard defines transmission protocols used to handle specific types of data transfer. The abstract data models defined in IEC 61850 can be mapped to a few protocols, including MMS (Manufacturing Message Specification), GOOSE (Generic Object Oriented Substation Events), and SMV (Sampled Measured Values). The IEC

61850 part 9-2 determines the specific communication service mappings for the communication between the bay and process levels (IEC, 2011c). These protocols can run over high speed TCP/IP networks to ensure the fast response time (< 4 ms) needed for protective relays.

3.3 Functions and communication interfaces

IEC 61850 part 5 specifies the communication requirements of the functions being performed and the device models in systems for power utility automation. All known functions and their communication requirements are identified. Transfer time classes are also specified in part 5 (Rinaldi, Ferrari & Loda, 2016).

The devices of a power utility automation system may be physically installed on different functional levels (station, bay, and process). Bay level devices consist of secondary control, protection or monitoring units. Process level devices are typically remote input /output units (I/Os), Merging Units, intelligent sensors and actuators at the primary equipment such as breakers and instrument transformers.

The functions of a Substation Automation System (SAS) or Power Utility Automation System (PUAS) refer to tasks which must be performed in utility substations. These are control, monitoring and protection functions and are allocated to the devices. The allocation can depend on availability requirements, performance requirements, cost constraints, technology, utilities' philosophies etc.(IEC, 2013a) The standard is not restrictive and allows a free allocation of functions to IEDs

The IEC 61850 standard supports the following communication at the process level: sampled value exchange for CTs and VTs, fast exchange of I/O data for protection and control, control signals and trip signals.

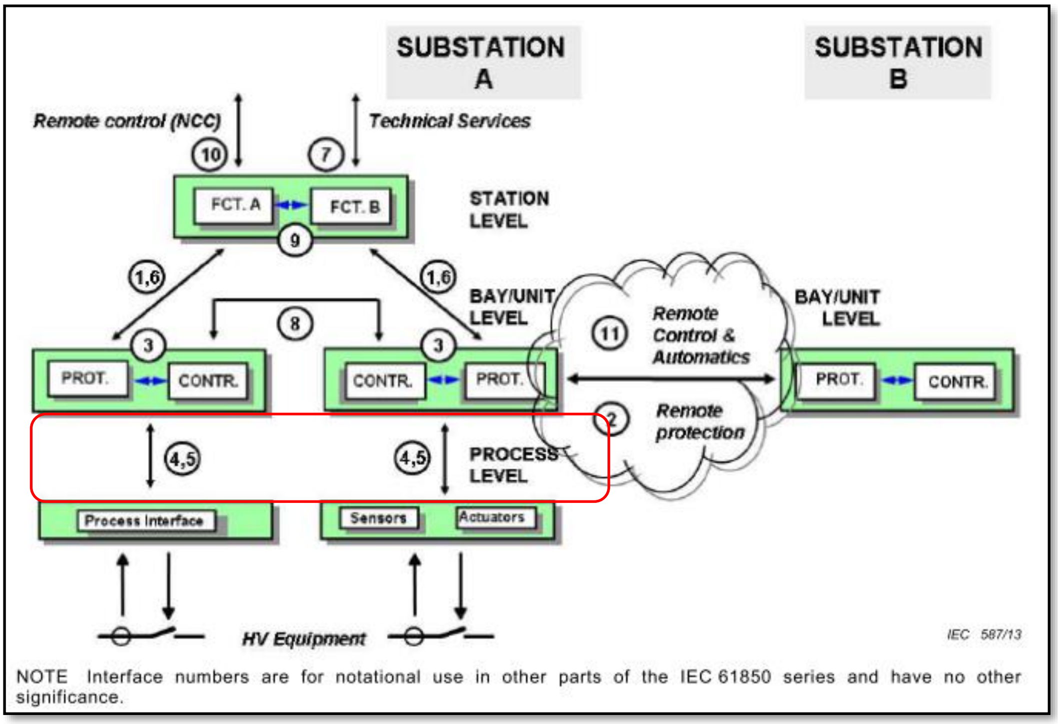


Figure 3.2 Interface model within substation and between substations, IEC61850-5 (IEC, 2013b: 19)

The logical communication interfaces (IF) within substation and between substations are presented in IEC 61850. The different interfaces are shown in Figure 3.2 (IEC, 2013b: 19).

Two interfaces, namely IF4 and IF5 are between the bay and process levels. IF 4 is related to the CT and VT instantaneous data exchange, and IF 5 control-data exchanges between the process and bay levels.

3.4 IEC 61850 data modelling

The modelling concept virtualises real physical power system primary and secondary devices. These devices contain information that can be exchanged with other devices and the IEC 61850 standard provides interoperability of the devices to exchange this information to be used in the protection and automation system(Huang, 2018b; Vandiver & Rietmann, 2018).

The Abstract Communication Service Interface (ACSI) models provide information models and information exchange services models (Liang & Campbell, 2007). This is covered in part 7-2 of the IEC 61850 standard.

The different protection and control functions in the substation are modelled into standard logical nodes which can be grouped under different logical devices. The IEC 61850 data model is based on two main levels shown in Figure 3.3 below:

- The breakdown of a physical device into logical devices,
- and the breakdown of a logical device into logical nodes, data objects and attributes.

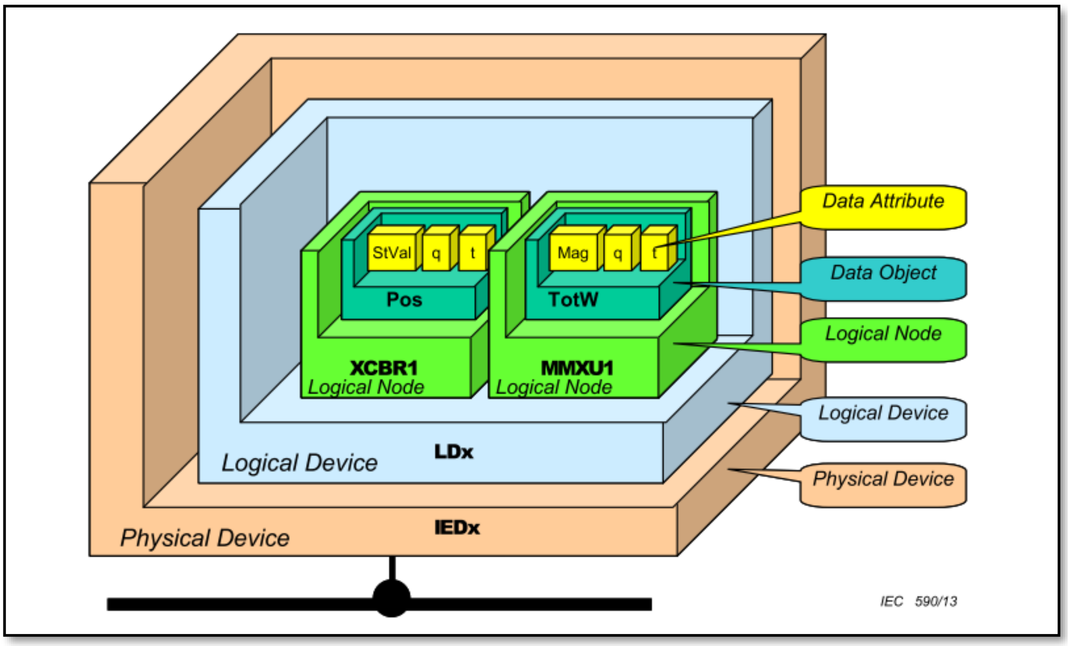


Figure 3.3 IEC 61850 Data modelling, IEC/TR 61850-1 (IEC, 2013a: 24)

The generic models or meta models for logical nodes and data classes including their services, are defined in Clause 5.3 of part 7.2 and are applied in parts 7-3 and 7-4 of IEC 61850 standard.

3.4.1 Logical Device and Logical Nodes

A Physical Device (PHD), i.e. multifunction IED can be modelled with this IEC 61850 modelling concept and can be broken down into Logical Devices (LDs). A LD usually represents a group of typical automation or protection functions. Common functions in a power utility automation system have been identified and split into Logical Nodes (LN). One LD cannot be part of more than one physical device.

The modelling concept can also be used to specify the IEDs of a power utility automation system.

The LNs may reside in different devices and at different levels. Examples are shown below in Figure 3.4 (IEC, 2013a: 31). In the example below it is shown that two functions, each having a logical node for distance and over current protection can be allocated to one device. PHD number three has distance protection unit with integrated overcurrent function. The other devices in the figure are: PHD 1 Station computer, PHD 2 Synchronised switching device, PHD 3 Distance protection unit with integrated overcurrent function, PHD 4: Bay control unit, PHD 5 Current instrument transformers and PHD 6 & 7: Voltage instrument transformers.

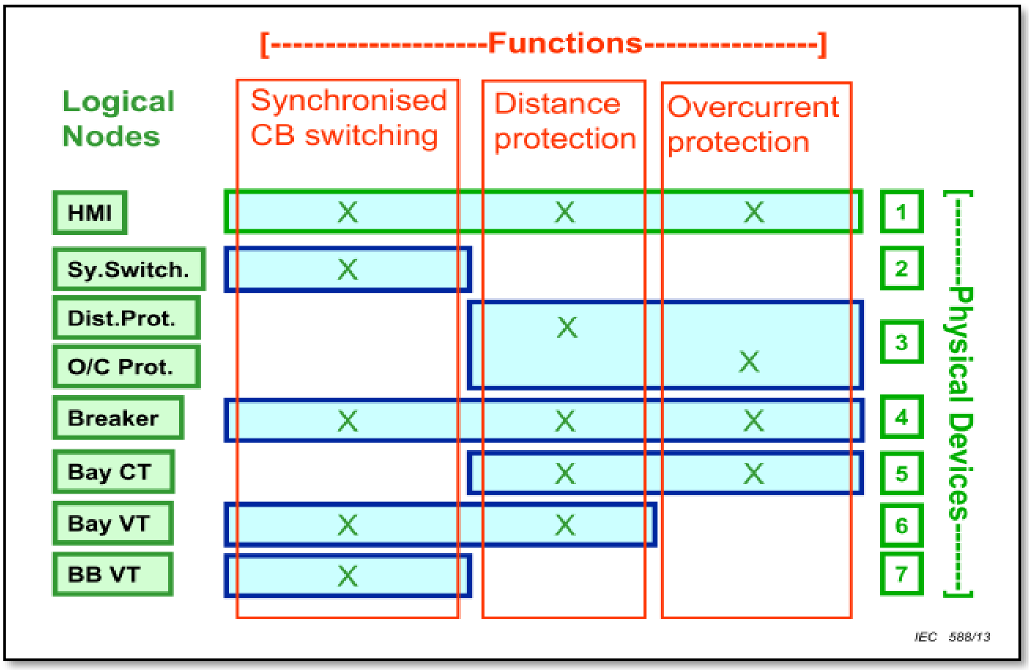


Figure 3.4 Relationship between functions, logical nodes, and physical devices IEC61850-5 (IEC, 2013a: 31)

A LD hosts a communication access point of the physical device and provides nameplate and health information about the physical device.

A LD is built up by Logical nodes (LN). LN are the smallest entities of application functions which are used to exchange information.

Each LN in a logical device may have a working mode, e.g. the LN may be in a test mode. This working mode of the LN may be different to the Logical Device that it belongs to.

3.4.2 Standard name space

The standard name space of the IEC 61850 series, defined in part 7, contains standard logical nodes, data object and data attributes classes.

The relationship between the LN data and data attributes is shown in Figure 3.5 (IEC, 2013a)

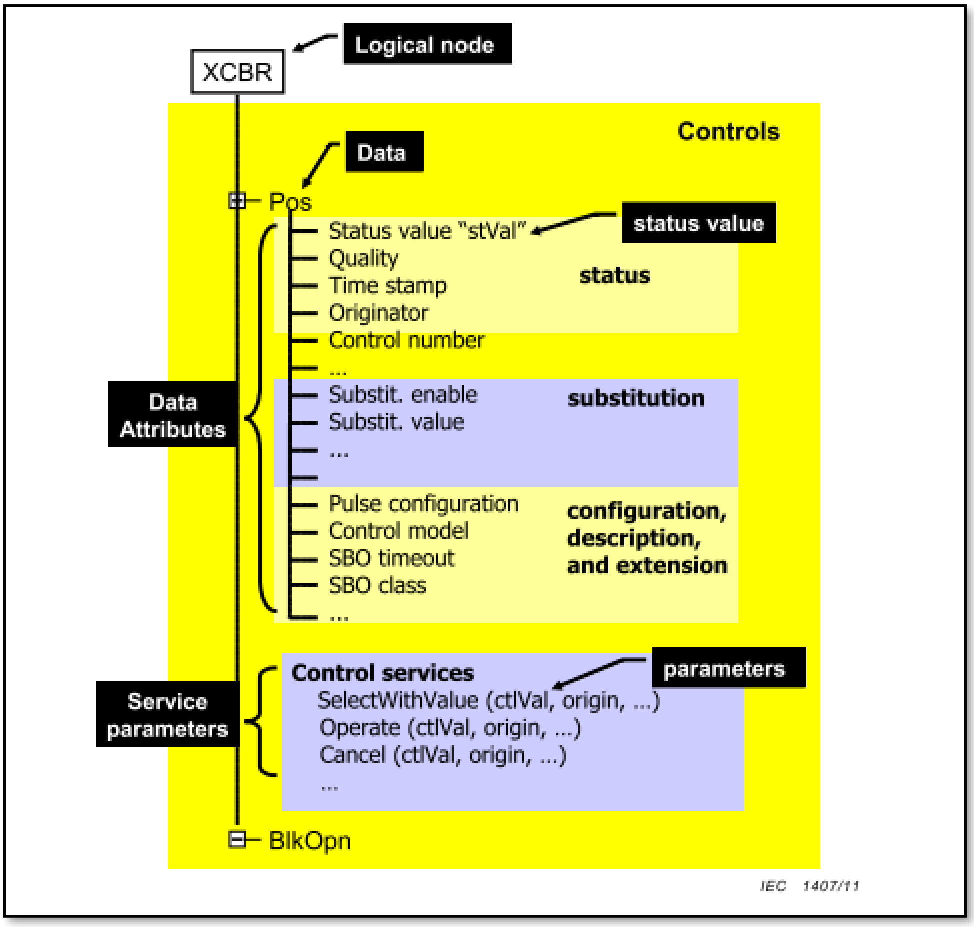


Figure 3.5 Relationship between logical nodes, data and data attributes (IEC, 2011a: 21)(IEC, 2013a)

IEC 61850-7-4 defines more than a hundred Logical Nodes divided into Logical Groups. The first letter of the Logical Node name identifies the group. See Table 3-1 of the Logical Node Groups below.

Table 3-1 Logical Node Groups IEC 61850-7-1 (IEC, 2011a: 18)

Group indicator	Logical node groups
A	Automatic control
C	Supervisory control
D	DER (Distributed Energy Resources)
F	Functional blocks
G	Generic function references
H	Hydro power
I	Interfacing and archiving
K	Mechanical and non-electrical primary equipment
L	System logical nodes
M	Metering and measurement
P	Protection functions
Q	Power quality events detection related
R	Protection related functions
S	Supervision and monitoring
T	Instrument transformer and sensors
W	Wind power
X	Switchgear
Y	Power transformer and related functions
Z	Further (power system) equipment

3.4.2.1 Logical nodes (LN)

The LN instance name shall be composed of the class name, the LN-Prefix and LN-Instance-ID according to IEC 61850-7-2, Clause 22.

The LN for a circuit breaker function, XCBR belongs to the switchgear group X. Another example is the PDIF LN for the differential protection function that belongs to the protection group P.

Several logical nodes build a logical device. An IED with the differential protection functions can have the LN differential protection function, PDIF and differential measurements, RXMU. The RXMU LN provides current values for PDIF and can use the current samples sent from the local TCTR current sensors

A transformer protection IED can have the following LN:

PDIF- A function that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electrical quantities,

PTDF Special for transformers are inrush currents with dedicated harmonics which request the use of the harmonic restraint function (PHAR),

PHAR This LN represents the harmonic restraint data object especially for the transformer differential protection. There may be multiple instantiations with different settings, especially with different data object HaRst, ATCC is the LN name for automatic tap changer controller. CCGR is the LN name for cooling group.

3.4.2.2 Data objects

Specific Data Objects (DO) are provided by each logical node as defined in IEC 61850-7-4. Each of the data contains several data attributes.

Data object names are listed alphabetically in part 7-4, Clause 6 (IEC, 2010c). The data objects in the logical node classes are grouped into status, measured and meter values, controls, and settings categories:

- Status information contains DO, which show either the status of the process or of the function allocated to the LN class. This information is produced locally and cannot be changed via communication for operational reasons unless substitution is applicable. Data objects such as “start” or “trip” are examples listed in this category. Most of these data objects are mandatory.
- Measured values are analogue data objects measured from the process or calculated in the functions such as currents, voltages, power, etc. Metered values are analogue data objects representing quantities measured over time, for example energy. This information is produced locally and cannot be changed remotely unless substitution is applicable.
- Controls contain data objects which are changed by commands such as switchgear state (ON/OFF), tap changer position or resettable counters. They are typically changed remotely and are changed during operation much more often than the settings.
- Settings are data objects which configure the function for its operation. Since many settings are dependent on the implementation of the function, only a commonly agreed minimum is standardised. They may be changed remotely, but normally not very often.

Descriptions are data objects, which give information about the LN itself or an allocated device. This information consists of identification information and general properties like configuration revision, hard and software revisions, etc.

A Data object can be mandatory (M), optional (O) or conditional (C).

A circuit breaker is defined in the logical node XCBR. The data name for the position of a circuit breaker is named Pos and is part of Controls category. The data Pos can be controlled via a control service.

3.4.2.3 Data attributes

Each of the data has data attributes. A whole set of all the data attributes defined for i.e. the position data (Pos) is called a common data class (CDC). The common data classes are defined in Clause 7 in part 7-3 of the IEC 61850 standard. Common Data Classes (CDC) are specified and categorised as follows: for status information, measurand information, controls, status settings, analogue settings, configuration and description information.

Examples of CDC for status information are Single Point Status (SPS), Double Point Status (DPS) and Integer Status (INS). Each of them has mandatory data attributes i.e status value of the data (stVal), quality (q) and timestamp (t).

Examples of CDC for measurand information are measured value (MV), complex measured value (CMV) and sampled value (SAV). In addition to quality and time stamp data attributes they have other mandatory data attributes. The sampled value CDC has a magnitude of the instantaneous value of a measured value (instMag) data attribute.

Examples of CDC for control information are controllable single point (SPC), controllable double point (DPC) and controllable analogue process value (APC).

Examples of CDC for settings are single point setting (SPG), integer status setting (ING) and time setting group (TSG) with the data attribute, value of a status setting (setVal).

Every specification for a CDC has defined services according to part 7-2 of the IEC 61850 standard. These services may include services such as GetDataSetValues or SetDataSetValues according to the Data set model; SendGOOSEMessage and SendMSVMessage according to the GSE and Sampled value models.

Data attributes are defined primarily by an attribute name and an attribute type. Other information is of functional constraint, trigger condition, value or value range and the indication of the attribute. See the type of information in Table 3-2 (IEC, 2011a: 22)

Table 3-2 Data Attribute information IEC 61850-7-1 (IEC, 2011a: 22)

Attribute name	Attribute type	FC	TrgOp	Value/value range	M/O/C
stVal	CODED ENUM	ST	dchg	intermediate-state | off | on | bad-state	M
ctlModel	CtlModels	CF	dchg	status-only | direct-with-normal-security | sbo-with-normal-security | directwith-enhanced-security | sbo-with-enhanced-security	M

The data attribute names are standardised names that have a specific semantic as defined in clause 8, Table 64 in part 7-3 of the IEC 61850 standard.

Other information that specify the date attributes are:

- the services allowed or Functional Constraint (FC),
- the trigger conditions that cause a report to be sent (TrgOp),
- the value or value range,
- the indication if the attribute is Optional (O), Mandatory (M) or Conditional (C).

The Functional Constraint data attribute (FC) shall be as specified in Table 20 of IEC 61850-7-2 under clause 12.3.3.2 of the standard. Only some of the FC values are shown below in Table 3-3 (IEC, 2010a: 54).

Table 3-3 Functional Constraint Values IEC 61850-7-2 (IEC, 2010a: 54)

FunctionalConstraint values			
FC	**Semantic**	**Services allowed**	**Initial values/storage/ explanation**
ST	Status information	**DataAttribute** shall represent status information whose value may be read, substituted, reported, and logged but shall not be writeable.	Initial value of the **DataAttribute** shall be taken from the process.
MX	Measurands (analogue values)	**DataAttribute** shall represent measurand information whose value may be read, substituted, reported, and logged but shall not be writeable.	Initial value of the **DataAttribute** shall be taken from the process.
SP	Setting (outside setting group)	**DataAttribute** shall represent setting parameter information whose value is read and may be written. Changes of values shall become effective immediately, and may be reported.	Initial value of the **DataAttribute** shall be as configured; value shall be non-volatile.
SV	Substitution	**DataAttribute** shall represent substitution information whose value may be written to substitute the value attribute and read.	If the value of the **DataAttribute** is volatile then the initial value shall be FALSE, else the value should be as set or configured.

The status information data attribute (ST) can be used in the circuit breaker logical node XCBR to represent the status information. This information value may be read, substituted, reported, and logged, but is not writeable. The measurand data attribute can be used in a current sensor (TCTR) logical node. This information may be shared to the logical nodes RXMU as part of a merging unit logical device LD, and logical nodes for Automatic Tap Changer Controller (ATCC) and differential protection function (PDIF) in logical devices for a multifunction protection IED.

A data attribute may have a sub data attribute. The sub data attribute of a data object having a specific Functional Constraint (FC) value shall be called Functional Constrained Data Attribute (FCDA) according to the standard.

The trigger condition (TrgOp) information specifies the condition that may cause a report to be sent or a log entry to be stored into a log. The services associated with the TrgOp shall be as specified in Table 21 of IEC 61850-7-2 under clause 12.3.3.3 of the standard. The services allowed for data change, quality change or data value update conditions are shown in Table 3-4 ((IEC, 2010a: 56) below.

Table 3-4 Trigger Condition services allowed IEC 61850-7-2 (IEC, 2010a: 56)

TrgOp	**Semantic**	**Services allowed**
dchg	data-change	A report or a log entry shall be generated due to a change of the value of the associated data attribute
qchg	quality-change	A report or a log entry shall be generated due to a change of the value of the associated quality data attribute **q**
dupd	data value update	A report or a log entry shall be generated due to updating the value of a data attribute. An updated value may have the same value as the old value. An example is freezing the value of a freezable data attribute updating the value of another data attribute, which could lead to the same value it already has.

The status information of a circuit breaker is represented by the status data attribute (stVal) for the position data (Pos) of the circuit breaker logical node (XCBR) shown in Figure 3.5 on page 3-6. (IEC, 2011a: 21)(IEC, 2013a). The attribute stVal can be represented in four states: intermediate, off, on, bad.

3.5 IEC 61850 SCL language

Part 6 of IEC 61850 specifies a file format, of the System Configuration description Language (SCL) for describing IED, substation automation and communication system configurations. SCL is also used to describe the substation equipment and power system functions through logical nodes. The SCL is used to exchange IED capability descriptions, and substation automation system descriptions using IED and system engineering tools. This data exchange shall be interoperable between an IED configuration tool and a system configuration tool from different manufacturers. The configuration language is based on the Extensible Markup Language (XML).

The SCL object model has three basic parts, a substation structure part, a product or IED structure part and a communication structure part. These parts are discussed in more detail in Appendix A. The substation part and the product part form hierarchies. The overview of the SCL object model is shown in Figure 3.6 (IEC, 2009: 20) by using UML notation.

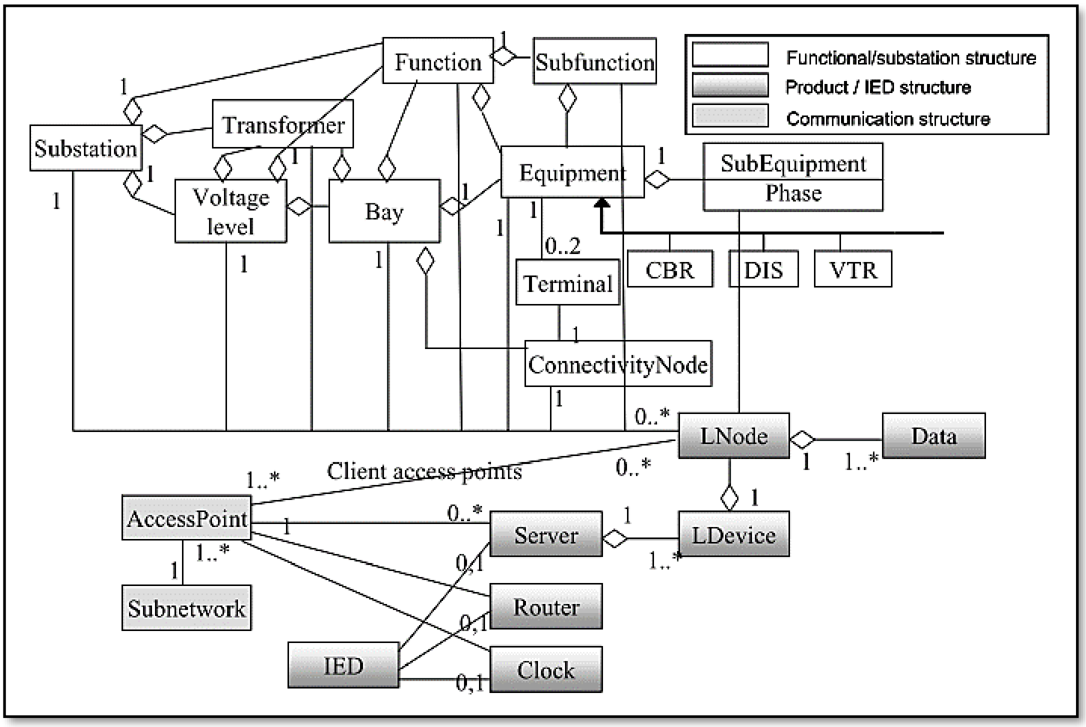


Figure 3.6 SCL object model IEC 61850-6 (IEC, 2009: 20)

3.6 SCL file types

There are different purposes for SCL data exchange and Part 6 of the standard defines six types of SCL files each having a different file extension (Peng et al., 2017). The data exchange using these files between a system configuration tool and an IED configuration tool is also defined.

A sender creates or produces a SCL instance for processing or to be used by a receiver. The file types: a System Specification Description (SSD) file, an IED Capability Description (ICD) file, a Substation Configuration Description (SCD) file, a System Exchange Description (SED) file, an Instantiated IED Description (IID) file and a Configured IED Description (CID) file are discussed in Appendix A.

3.7 IEC 61850 communication services

Part 7-2 of IEC 61850 applies to the Abstract Communication Service Interfaces (ACSI) communication for utility automation. The ACSI provides abstract interface:

- describing communications between a client and a server,
- for event distribution between a publisher and subscriber,
- for transmission of sampled measured values from a publisher to a subscriber.

The ACSI is defined in terms of a hierarchical class model of all information and the associated services that can be accessed via a communication network.

ACSI and the meta model for IEC 61850 is discussed in more detail in Appendix B.

3.7.1 Abstract communication service interface (ACSI)

The Object Management Group (OMG) meta model hierarchy is used for the ACSI model in the conceptual model of IEC 61850. The top level meta-meta model definitions is a list of base types and rules how to build the meta model and hierarchical structures. The meta model defines generic model classes for logical nodes, data objects and common data classes including their services. The ACSI model also provides domain type models at level M1 and instance models at level M0 in part 7-2 of the IEC 61850 standard(IEC, 2010a)

3.7.1.1 The meta model

The meta model comprises classes for the description of data models and information exchange models.

a) Information modelling classes

The following overall classes are defined: Server, Logical device, Logical node and data objects.

All other ACSI models are part of the server. A server communicates with a client and sends information to peer devices.

Each of these models is defined as a class and the classes comprise attributes and services.

b) Information exchange modelling classes

The ACSI includes the following models for data objects and data attributes services: Data set, Substitution, Setting group control, Report control and logging, Control blocks for generic substation events, Control blocks for transmission of sampled values, Time and time synchronization, File system and Tracking.

3.7.2 ACSI mappings to Manufacturing Message Specification (MMS)

Specific communication service mapping (SCSM) is a standardised procedure which provides the mapping of ACSI services and objects onto a particular protocol stack or communication profile. (IEC, 2003b: 22). Part 8-1 of the IEC 61850 standard specifies the SCSM of the objects and services of the ACSI, IEC 61850-7-2) to Manufacturing Message Specification (MMS), ISO 9506 and ISO/IEC 8802-3 frames.

The SCSM uses the 7-layer OSI reference model (ISO/IEC 7498-1) where layering of communication functions is defined. The layers are grouped in an application profile (A-Profile) and transport profile (T-Profile)

The upper three layers of the ISO A-Profile consist out of application, presentation, and session layers. The lower 4 layers of the ISO T-Profile consist out of the transport, network, datalink and physical layers. The combination of A and T-profiles is specified for each SCSM.

Each SCSM consists of:

- the mapping of the abstract specifications of IEC 61850-7 series on the real elements of the stack being used, and
- the implementation specification of functionality, which is not covered by the stack being used.

The Server, Logical device and Logical node objects models of 61850 as well as the generic substation event model (GSE) can be mapped to MMS (IEC, 2011b). These models are discussed in detail in Appendix B as part of the Communication services.

3.7.3 ACSI mappings to Sampled Values (SV)

The ACSI mapping of sampled values can be done for two types of services:

- The first is client/server services bases on MMS and,
- The second is SV publisher/subscriber mechanism with services based on the data link layer.

Two methods to exchange SV are specified:

- The first is between a publisher and one or more subscribers, a multicast-application-association.
- The other method uses unicast or two-party-application- association.

Different combinations of A-Profiles and T-Profiles are defined to support the transmission of SV.

3.7.3.1 Client/server services and communication profiles

This communication profile is used if the client requires access to the sampled value control blocks. (e.g. GetMSVCBValues and SetMSVCBValues for the multicast sampled value control block). Similar control blocks are specified for unicast sampled values. The services and protocols are specified for each of the layers in the A and T-profiles in clause 5.2 of IEC 61850 part 9-2. Services for each of the ISO layers are specified to be mandatory, optional or recommended. Parallel redundancy protocol and high availability seamless ring are specified but are optional. Fibre optic transmission system 100Base-FX is specified but to make provision for future technologies, it is recommended for the physical ISO Layer.

3.7.3.2 SV service and communication profile

Multicast SV message and Unicast SV message services are supported. Services and protocols of the A-Profile and T-Profiles are specified for SV.

Ethernet addresses in the link layer of the T-profile are specified. The destination ISO/IEC 8802-3 multicast/unicast address must be configured for sampled values. A 6-octet string multicast addresses are recommended to have the following structure: The first three octets are assigned with 01-0C-CD. The fourth octet will be 01 for GOOSE, 02 for GSSE, and 04 for multicast sampled values. The last two octets will be used as individual addresses. (e.g. 01-0C-CD-04-00-00 for an SV string).

Priority tagging and virtual LAN configurations are also important at the link layer. Priority tagging according to IEEE 802.1Q is used to separate time critical high priority SV messages. Tag Protocol Identifier (TPID) field indicates the Ethernet type and the value shall be 0x8100. The Tag Control Information (TCI) fields consist out of the priority, CFI (Canonical Format Indicator) and VLAN identifier (VID). The value 1 is used for the priority of untagged frames. Higher priority frames shall have a value from 4-7. The default priority of an SV is 4. This standard specifies the single bit flag value of the CFI to be = 0. Virtual LAN support is optional and if it is not used the VID shall be set=0.

3.7.3.3 Mapping of the sampled value buffer

Clause 19 of IEC61850 part 7-2 defines a buffer structure for the transmission of sampled values. The SV information exchange.is based on a publisher/subscriber mechanism.

The publisher samples the inputs with the specified sample rate and is responsible to write the values in a local buffer at the sending side (Kaibo et al., 2015). The subscriber read the values from a local buffer at the receiving side. The information is time stamped for the subscriber. The communication system shall be responsible to update the local buffers of the subscribers. The publisher uses a Sampled Value Control Block (SVCB) to control the communication

The Application layer has the functionality where the mapping can be done such as to concatenate more than one Application Service Data Unit (ASDU) into one Application Protocol Data Unit (APDU) before the APDU is posted into the transmission buffer. The number of ASDUs is indicated in the Application Protocol Control Information (APCI).

3.8 Digital Substation Ethernet Technology

There was an evolution of substation secondary equipment from electro-mechanical devices to digital devices in the Power Utility Automation Systems (PUAS). PUAS use Intelligent Electronic Devices (IEDs) to perform protection, monitoring and control functions. There was a need for an efficient communication network between the IEDs and a standard protocol to use. The IEC 61850 standard was developed as a communication standard that meets functional and performance requirements as well as supports future technological developments.

The Technical Report TR 61850-90-4 provides definitions, guidelines and specifications for the network engineering of IEC 61850-based substation automation (SABS, 2014).

This section covers the communication network architecture, communication protocols, physical layer and data link layer of substation communication networks in an IEC 61850 standard digital substation.

3.8.1 Communication Network Architecture

Different architectures can be implemented in a digital substation communication network. The same substation may have different network architectures implemented for the station and process bus networks. The architecture depends on the budget available as well as the reliability and availability requirements. The most common used architectures are cascaded, star, ring and a combination of them. The communication network architectures are discussed in Appendix C.

3.8.2 Network redundancy protocols

Redundant network connections are essential when designing high availability communication networks. Different mechanisms and protocols can be implemented in substation communication networks to obtain redundancy and to have high availability by keeping the outage time as short as possible. The outage time that can be tolerated can depend on the type of the substation, how critical it is for the power system and the importance and supply contract of the customer. IEC 62439-1:2010 is applicable to high-availability automation networks based on the ISO/IEC 8802-3 (IEEE 802.3) Ethernet technology. Rapid Spanning Tree Protocol (RSTP) and MSTP are network spanning tree redundancy protocols. Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are bus redundancy architecture proposed by the IEC 62439-3 standard (Igarashi et al., 2015: 3; Kumar et al., 2015b). RSTP, PRP and HSR is discussed in Appendix B

3.8.3 Physical layer

The physical layer defines specifications of the data physical transmission medium. The IEC 61850 caters for future development and therefore is not specific on the communication medium and required speed. It usually considers networks with copper and fibre physical layers and 100 Mbit/s and 1 Gbit/s rates.

Fibre has the advantage of galvanic isolation over copper. Each medium has a specific price, bandwidth and distance that it can cover. The distance that can be covered decreases with increasing data rate

IEC 61850 assumes that communication is full-duplex and auto-negotiated. The peer ports are configured to recognize automatically the polarity, the duplex setting and highest common speed.100Mbit/s copper, 100Mbit/s and 1Gbit/s optical fibre as physical layers is discussed in Appendix E.

3.8.4 Data Link layer

The data link layer or layer 2 is the second layer of the seven-layer Open Systems Interconnection (OSI) model. It defines the protocol for the transmission of data frames and establishes and terminates a connection between two physically connected devices. The data link layer has two sublayers: logical link control (LLC) and media access control (MAC).

A media access control address (MAC address) is a 48-bit address space and a unique identifier assigned to network interface controllers (NIC) for communications at the data link layer. The Data link layer, Unicast and multicast filtering, Virtual LAN traffic control and quality of service are discussed in more detail in Appendix F.

3.8.4.1 Unicast and multicast MAC addresses

Each data frame carries a source and destination address.

A frame sent to one receiver is called unicast. In IEC 61850, the MMS traffic use unicast addresses.

A frame sent to a group of destinations is a multicast one. The IEC61850, GOOSE and SV traffic use multicast addresses. Packets sent to a multicast addresses are received by all devices on a LAN that have been configured to receive it.

Data frame enters the bridge on ingress ports and leave the bridge on egress ports. When a frame enters an ingress port it will use the MAC address to determine on which egress ports the frames are to be forwarded to.

MAC address filtering is traffic control mechanism that reduces the traffic. The bridge sends only the relevant part of the traffic to the end device. In IEC 61850, the MAC address filtering only reduces the MMS traffic, since the GOOSE and SV traffic is multicast. A bridge does not apply MAC address filtering to multicast traffic, since the multicast frames are forwarded on all egress ports. The network is flooded by multicast messages if not filtered. This results in excessive bandwidth consumption and unnecessary processing of unwanted traffic by IEDs or end devices.

Multicast filtering can reduce the traffic to end devices by letting through only those multicast addresses the end device is interested in. A bridge port uses a configurable multicast filtering table to know which multicast addresses may egress from that port.

3.8.4.2 Virtual LANs (VLAN) traffic control

VLANs is a method to separate different types of traffic that share the same bandwidth on physical medium at the data link layer (OSI layer 2). The protocol most commonly used to configure VLANs is IEEE 802.1Q. The IEEE 802.3 frames carry a header, called the VLAN tag, 32-bit field between the source MAC address and the Ether Type fields of the original frame.

The header consists out of a 16-bit field Tag Protocol Identifier (TPID) and a 16-bit field Tag Control Information (TCI).

The TPID field is set to a value of 0x8100 to identify the frame as an IEEE 802.1Q-tagged frame. This field is located at the same position as the EtherType field in untagged frames and is used to distinguish the frame from untagged frames.

The VID with hexadecimal reserved value 0x000 indicates that the frame does not carry a VLAN ID and is called a priority tag.

3.8.4.3 Quality of Service (QoS)

Priority tagging (IEEE 802.1p) and VLANs are specified in the same standard IEEE 802.1Q and share the same tag, but they are separate concepts.

The QoS technique, class of service (CoS) is the 3-bit field PCP and specifies a priority value that can be used by QoS to priorities the traffic. Priority means that a bridge that receives several frames simultaneously will forward the highest priority frames and queue the other lower priority frames. IEC 61850 prescribes that GOOSE and SV frames are priority-tagged. The value 1 is the lowest priority mark and priority 7 is the highest. Default priority is 4 for GOOSE and SV message given in IEC61850-9-2 but different priority can be assigned for GOOSE and SV messages.

3.8.4.4 Bridge port filtering

The bridge needs to be VLAN-aware to recognise the frames with the IEEE 802.1Q tag. The bridge ports need to be configured or set to allow the frames to enter. This can be done by a Port VLAN member set (PVMS) or VLAN ID table. Frames will not be allowed to ingress when a frame does not have a VLAN ID that is a member in the PVMS of that port. According to IEEE 802.1Q-2011, A bridge port can be set to admit the following frames:

• only VLAN-tagged frames;

• only untagged and priority-tagged frames;

• all frames (not VLAN-aware).

The option to admit all frames or VLAN un-aware, must be used when an IED connected to a port, sends tagged (GOOSE, SV) and untagged (MMS) messages.

The egress from a port of a bridge is also controlled by the Port VLAN Member Set (PVMS). This port will forward the frames tagged or untagged.

An egress port sends the frame only if the frame VID belongs to the port membership set PVMS.

The port sends the frame without a change if it is configured to forward tagged frames. The port removes the VLAN tag including the PCP if it is configured to forward untagged frames.

3.8.4.5 Static and Dynamic VLAN configuration

Static VLAN configuration is done by using a network management and configuration tool to assign the priority PPCP and PVIDs to all device ports.

Dynamic VLAN configuration can be done by using protocols such as Generic VLAN Registration Protocol (GVRP) or Multiple VLAN Registration Protocol (MVRP)

It is recommended by TR 61850-90-4 Technical report that substation automation should avoid dynamic VLAN assignment.

3.9 Time Synchronization

The equipment status collected at process level by protection and control devices needs to be time stamped and published in a frame format on the substation communication network. All the devices therefore need an internal clock that is synchronized with a substation GPS clock. The synchronization is performed through IRIG-B, or indirectly over a communications network using one of several standards.

Timing classes are defined in IEC 61850-5 standard (International Electrotechnical Commission, 2013: 68). The IEEE came up with IEEE 1588 standard (De Dominicis et al., 2011) to synchronize multiple devices over a network where their clock is in master/slave mode (Bhardwaj et al., 2014: 4). A single network implementation can be accomplished by using IEEE 1588 Precision Time Synchronization Protocol (PTP) (Skendzic et al., 2007: 5). IRIG and PTP can be considered as better alternatives to Simple Network Time Protocol (SNTP) for process bus applications.

IRIG time codes, Simple Network Time Protocol (SNTP), Precision Time Protocol (PTP) and Time gateways are discussed in Appendix G.

3.10 Conclusion

In this chapter the IEC 61850 standard was discussed under the following parts:

- A standard name space of logical nodes, data objects and attributes (IEC 61850 part 7-3 and 7-4),
- a System Configuration description Language (SCL) covered in IEC 61850 part 6 and,
- Abstract Communication Service Interface (ACSI) services (part 7) that can be mapped to specific protocols (part 8 and 9) to exchange this information.

The communication network architecture, communication protocols, physical layer and data link layer of substation communication networks in an IEC 61850 standard digital substation were reviewed. The Technical Report TR 61850-90-4 provides definitions, guidelines and specifications for the network engineering of IEC 61850-based substation automation

The most common used architectures are cascaded, star, ring and a combination of them were discussed. The architecture will depend on the budget available as well as the reliability and availability requirements.

Redundant network connections are essential when designing high availability communication networks. Network redundancy protocols such as Spanning Tree Protocol (STP), Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are reviewed.

The physical layer defines the data physical transmission medium. The IEC 61850 caters for future development and therefore is not specific on the communication medium and required speed. Copper and fibre physical layers and 100 Mbit/s and 1 Gbit/s bit rates are reviewed.

The data link layer or layer 2 is the second layer of the seven-layer Open Systems Interconnection (OSI) model. It defines the protocol for the transmission of data frames.

MAC address and multicast filtering, VLANs, IEEE 802.1Q and Quality of Service are described.

Time synchronisation of time stamped information on the process bus network of a substation communication network was considered as a requirement for the proper performance of the substation automation system. Time synchronization can be performed through IRIG-B over a dedicated system, or indirectly over a communication network. The number of devices to be synchronized and the distances between devices affect the IRIG-B system architecture. The NTP time accuracy was considered as not enough for the process bus using Sampled Values. IEEE 1588 Precision Time Synchronization Protocol (PTP) version 2 can be used to synchronize multiple devices over a network where the clocks are in master/slave mode. PTP has less cabling infrastructure requirements as IRIG-B due to not needing a dedicated network for time synchronization. The Thesis test-bench set up used a combination of 1 PPS time signals and an IRIG-B signal. A 1 PPS time synchronisation source from the RTDS, was used for time signals via fibre optic for the synchronization of the MUs. The P645 IED has an IRIG-B input with BNC connector for time synchronization. The IRIG-B signal is supplied from a network switch.

The modelling and simulation of the system of parallel power transformers is discussed in the next chapter.

4 CHAPTER FOUR

MODELING AND SIMULATION OF THE SYSTEM OF PARALLEL TRANSFORMERS

4.1 Introduction

The modelling and simulations of the system of parallel power transformers is discussed in this chapter. A system of parallel transformers is modelled in the Real-Time Digital Simulator (RTDS) for simulation, faults are applied to the system and the fault currents are measured and analysed. The system configuration is changed, and the fault currents are analysed for the different system configurations.

A system of five 40MVA 132/11kV YNd1 power transformers connected in parallel is modelled and simulated in the Real-Time Digital Simulator (RTDS) for the simulation Case 1,Figure 4.1.

The system has a source connected to the 132kV bus bar. The 11kV bus bar has 4 x Bus Sections, 3 x 11kV loads and 2 x 11kV sources connected to the 11kV bus bar sections. Primary substation equipment such as instrument transformers and circuit breakers are modelled.

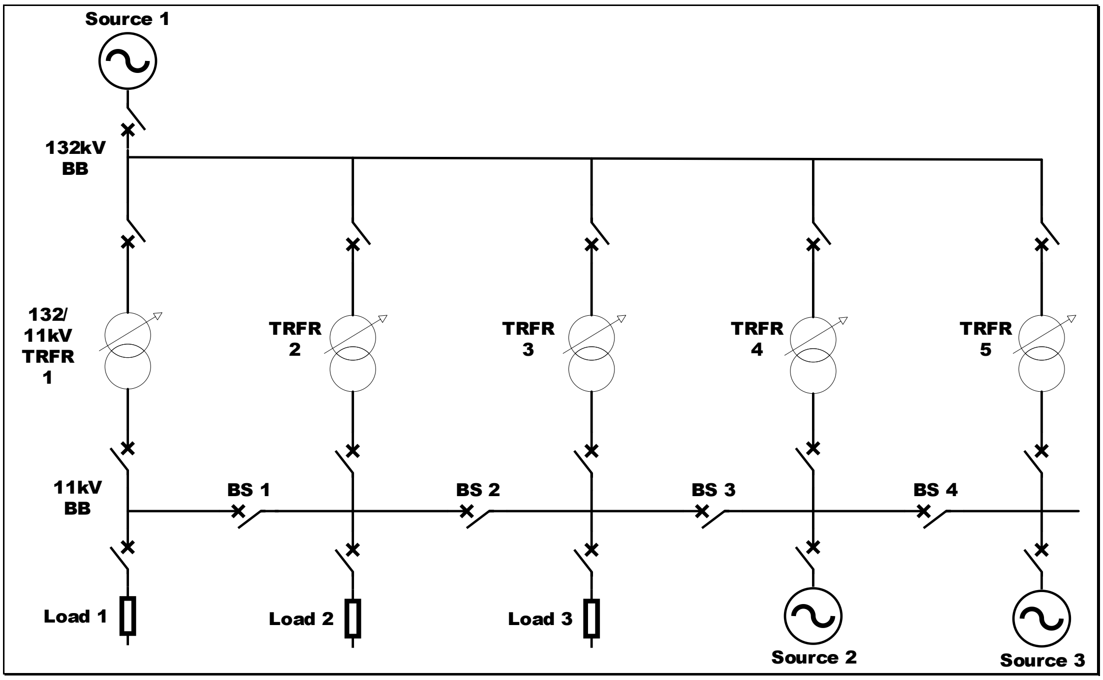


Figure 4.1 A System of five parallel power transformers

Faults are applied to the 132kV high voltage side and 11kV medium voltage side of the system of power transformers and the fault currents are measured and analysed.

The different bus section circuit breakers are opened to change the system configuration and the fault currents are analysed for the different system configurations.

The RTDS hardware and software are discussed in section 4.2. The configuration of the power system models is described in sub sections for the power source, the transformer model and the load model in section 4.3. The configuration of current and voltage instrument transformer models is discussed in section 4.4.

RSCAD/RunTime is used to interact with and control the Draft simulation case being performed on the RTDS hardware. Set point adjustment, fault application and breaker operation are performed through the RunTime Operator's Console. This is described in section 4.5.

The simulation results for different cases are shown in section 4.6 and discussed in section 4.7 of this chapter.

4.2 Real-Time Digital Simulator (RTDS)

The RTDS Simulator is used to run the real-time power system model of the system of parallel power transformers. Current transformers (CTs) are modelled in the RTDS software to provide analogue signals that are proportional to the real-time secondary current signals. The CT model used in simulation software must represent the saturation and remanence characteristics of CT core accurately (Kanokbannakorn & Penthong, 2019).

4.2.1 Hardware

RTDS processor cards are mounted in racks which together with input/output cards are housed in cubicles. Each RTDS rack includes a GTWIF card which provides communication between the RTDS rack and the computer workstation running the RSCAD software.

The processor cards are used to solve the equations representing the power system components modelled within the RTDS. Two types of processor cards are used, Giga processor card (GPC) and PB5 cards. An RTDS rack typically contains between 2 and 6 processor cards.

4.2.2 Software

RSCAD is a software package providing a graphical interface to the RTDS. RSCAD includes several modules that allow real-time simulations to be created, executed, controlled and analysed. The RSCAD/FileManager (Fileman) module is the home page and is used for project and case management. All other RSCAD programs are launched from the Fileman module.

RSCAD/Draft is used for circuit assembly and parameter entry of components. The Draft screen is divided into the library section and the circuit assembly section. Individual component icons are selected from the library and placed in the circuit assembly section.

Power System and Protection and Automation models from the library are interconnected to build a simulation circuitry.

RSCAD/RunTime is used to control the simulation case being performed on the RTDS hardware. Simulation can be controlled (start / stop commands) as well as other controls e.g. set point adjustment, fault application and breaker operation can be performed through the RunTime Operator's Console. Online metering and recording functions are available in RunTime.

RSCAD/MultiPlot is used for post processing and analysis of results captured and stored during a simulation study. Report can be generated by MultiPlot.

4.3 Development of a power system model in RTDS

RSCAD is a software package providing a graphical interface to the RTDS.

The following steps are required to prepare and run a new simulation case

- Start the RSCAD Software
- Create a new Project and Case directory in the FileManager module
- Start the RSCAD/Draft software module
- Create a new circuit diagram for simulation
- Compile the new circuit
- Start the simulation case from RSCAD/RunTime

RSCAD/Draft is used for circuit assembly and parameter entry of components. The Draft screen is divided into the library section and the circuit assembly section. Individual component icons are selected from the library and placed in the circuit assembly section. The method of modelling of the power system in the RTDS/ RSCAD Draft software is shown in Figure 4.2.

Firstly, a Single Line Diagram (SLD) of the system to be modelled is to be determined. The power system circuits are drawn using circuit components from the RSCAD library. Components for power systems, protection, automation and control are used. The component's parameters must be edited.

The project must be compiled after it is completed.

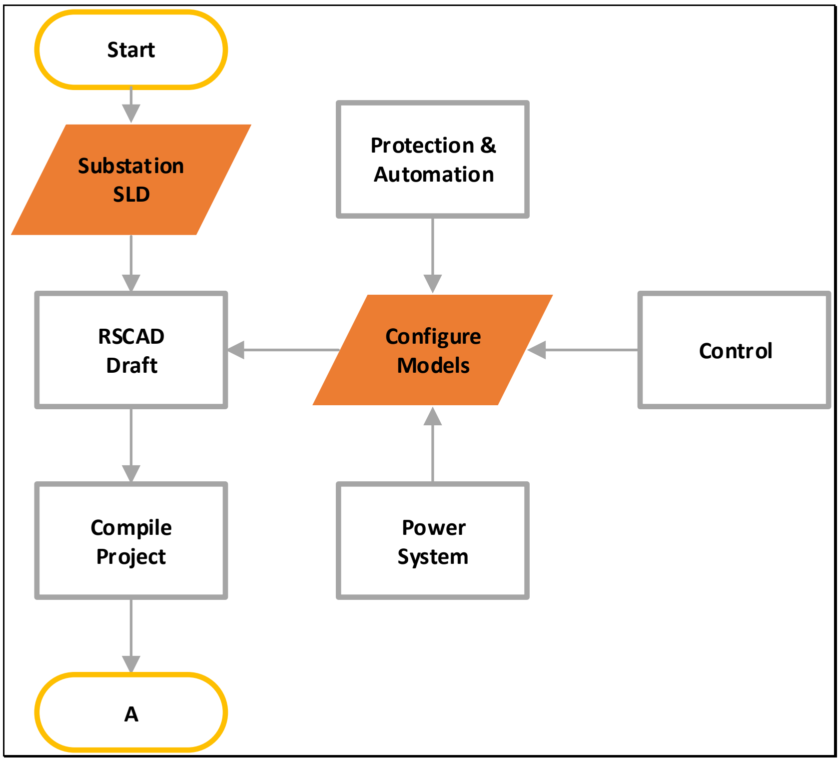
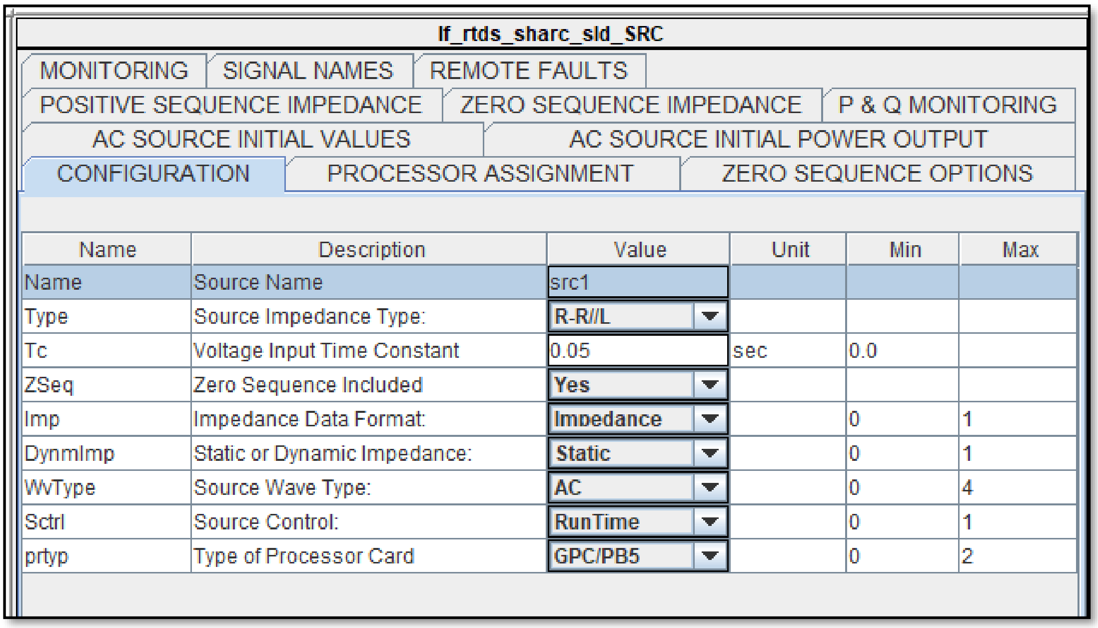


Figure 4.2 RSCAD/Draft modelling flow chart

4.3.1 Power Source

A three phase source model with a balanced sinusoidal 132kV three phase ac infinite bus voltage without harmonics is selected as a main source for the system of power transformers. Two smaller sources are connected to two 11kV bus bar sections to simulate two power stations. The Source model is configured by choosing an impedance type of connections of resistive branches and inductive branches. The connection can be series (R-L) or parallel (R//L). A combination of R-R//L is selected for the sources of simulation case 1. R−R//L source's positive sequence impedance is specified in absolute terms by entering the actual R series, R parallel and L parallel parameters. The zero sequence circuit consists of a resistive branch and an inductive branch connected in parallel. The source positive sequence impedance is specified by entering the source impedance magnitude of 55ohms and 80° angle. The source negative sequence impedance is specified by entering the source impedance magnitude of 45ohms and 80° angle. The configuration window is shown in Figure 4.3 below.



Name	Description	Value	Unit	Min	Max
Name	Source Name	src1			
Type	Source Impedance Type:	R-R//L			
Tc	Voltage Input Time Constant	0.05	sec	0.0	
ZSeq	Zero Sequence Included	Yes			
Imp	Impedance Data Format:	Impedance		0	1
DynmImp	Static or Dynamic Impedance:	Static		0	1
WvType	Source Wave Type:	AC		0	4
Sctrl	Source Control:	RunTime		0	1
prtyp	Type of Processor Card	GPC/PB5		0	2

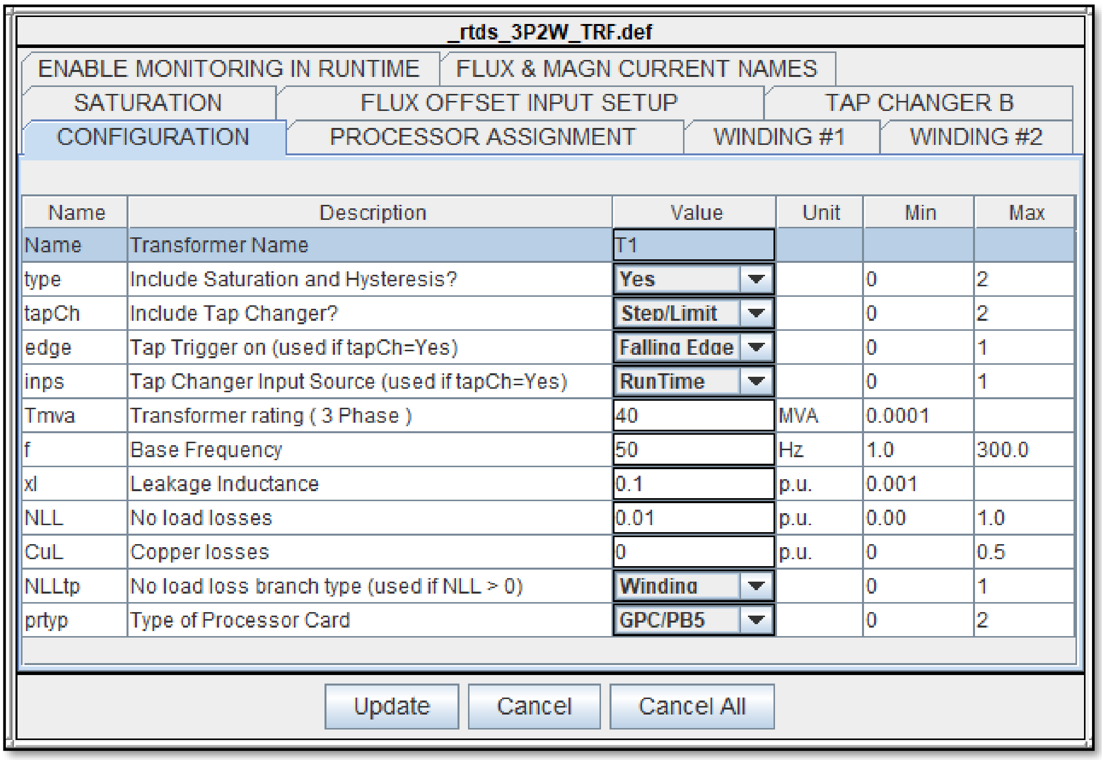
Figure 4.3 RSCAD Power source model configuration

4.3.2 Power transformer model

Different types of basic power transformers for various applications can be represented on the RTDS. Two, three winding or auto transformer configurations on a single 2 limb core with each winding connected in either wye−grounded, wye−ungrounded or delta can be configured. Online tap changers are available to be configured with the three phase two winding transformer model.

Five transformers are configured, each being a three phase 50Hz 40MVA 132/11kV two winding transformer with YNd1 connected windings and on-line tap changer, for the power system circuit.

The transformer can be configured to be Ideal or Non-ideal type. An ideal transformer will have no magnetizing inductance and will be represented by the specified leakage reactance only. Non−ideal transformers will involve a reactance magnetizing branch with the specified leakage reactance value. The core saturation and hysteresis can be modelled in the three phase two winding transformer model. The configuration window is shown in Figure 4.4 below.



_rtds_3P2W_TRF.def

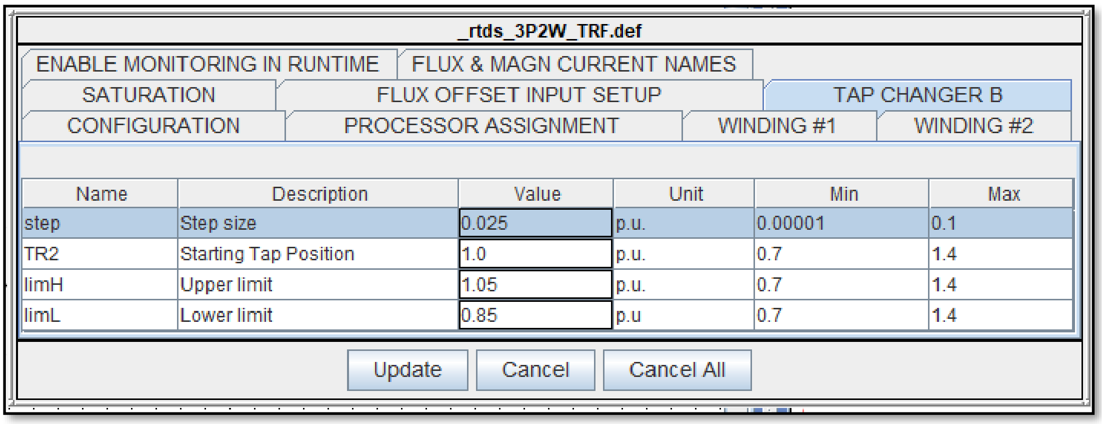
ENABLE MONITORING IN RUNTIME | FLUX & MAGN CURRENT NAMES
SATURATION | FLUX OFFSET INPUT SETUP | TAP CHANGER B
CONFIGURATION | PROCESSOR ASSIGNMENT | WINDING #1 | WINDING #2

Name	Description	Value	Unit	Min	Max
Name	Transformer Name	T1			
type	Include Saturation and Hysteresis?	Yes		0	2
tapCh	Include Tap Changer?	Step/Limit		0	2
edge	Tap Trigger on (used if tapCh=Yes)	Falling Edge		0	1
inps	Tap Changer Input Source (used if tapCh=Yes)	RunTime		0	1
Tmva	Transformer rating (3 Phase)	40	MVA	0.0001	
f	Base Frequency	50	Hz	1.0	300.0
xl	Leakage Inductance	0.1	p.u.	0.001	
NLL	No load losses	0.01	p.u.	0.00	1.0
CuL	Copper losses	0	p.u.	0	0.5
NLLtp	No load loss branch type (used if NLL > 0)	Winding		0	1
prtyp	Type of Processor Card	GPC/PB5		0	2

Update | Cancel | Cancel All

Figure 4.4 RSCAD Transformer 1 model configuration

Two selections are available for setting the tap positions for the on-line tap changer. A position Table “POS Table” or a step Table “Step/Limit”. The position Table requires all tap positions to be entered whereas the Step/Limit Table requires an initial position, an increment and an upper limit. The Step/Limit Table is used for the system of power transformers and is shown in Figure 4.5 below.



_rtds_3P2W_TRF.def

ENABLE MONITORING IN RUNTIME | FLUX & MAGN CURRENT NAMES
SATURATION | FLUX OFFSET INPUT SETUP | TAP CHANGER B
CONFIGURATION | PROCESSOR ASSIGNMENT | WINDING #1 | WINDING #2

Name	Description	Value	Unit	Min	Max
step	Step size	0.025	p.u.	0.00001	0.1
TR2	Starting Tap Position	1.0	p.u.	0.7	1.4
limH	Upper limit	1.05	p.u.	0.7	1.4
limL	Lower limit	0.85	p.u	0.7	1.4

Update | Cancel | Cancel All

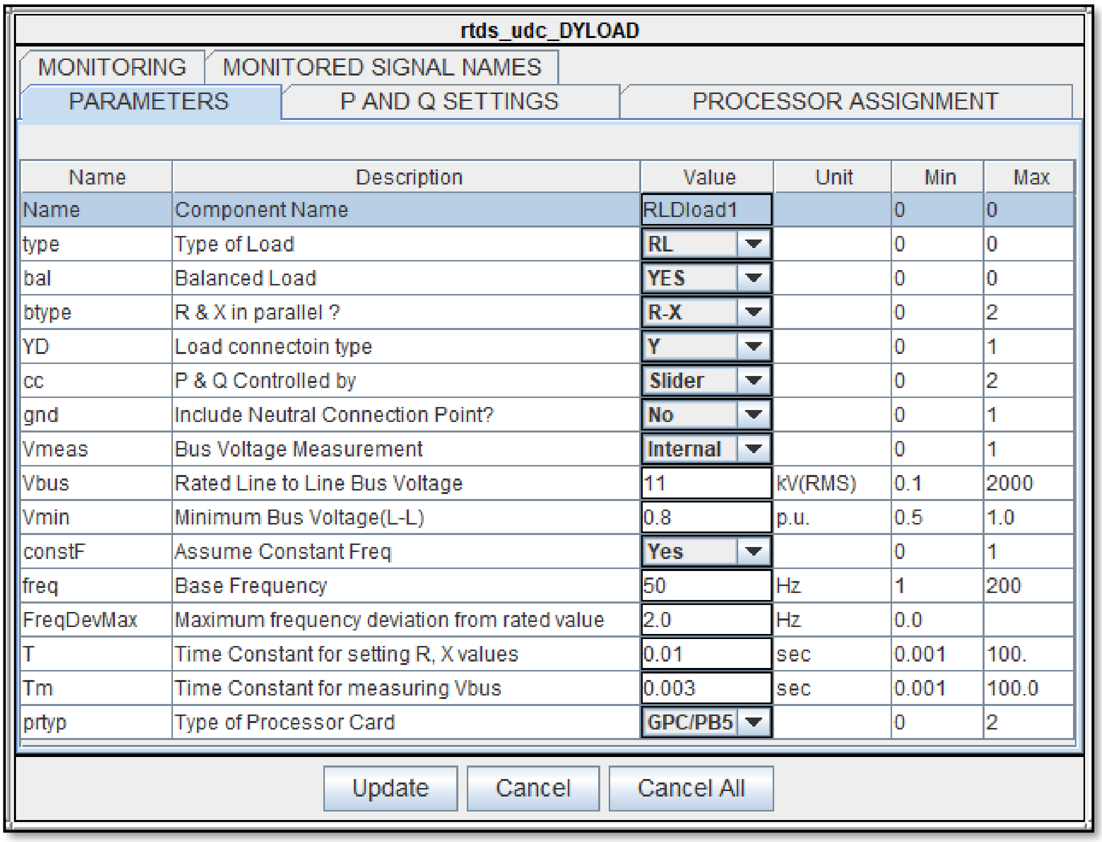
Figure 4.5 RSCAD Transformer 1 Tap Changer configuration

All winding currents, magnetizing current and flux computed of the power transformer during the simulation can be monitored on the RunTime Operator’s Console

4.3.3 Power system load

The load of the power system circuit can be modelled with the RSCAD load model. The load model can be used to dynamically adjust the load to maintain the Real Power (P) & Reactive Power (Q) set points. RL, RC or RX type loads can be modelled. RX is selected for the power system simulation circuit. The load type will change to RC type if Q is negative, if Q is positive, the load is modelled as an RL type load.

The load can be modelled as parallel (R//X) or series (R−X). The Real and Reactive power is set in the P and Q menu. Real and reactive power as well as phase currents can be monitored. The load model parameter configuration is shown in Figure 4.6 below



Name	Description	Value	Unit	Min	Max
Name	Component Name	RLDload1		0	0
type	Type of Load	RL		0	0
bal	Balanced Load	YES		0	0
btype	R & X in parallel ?	R-X		0	2
YD	Load connectoin type	Y		0	1
cc	P & Q Controlled by	Slider		0	2
gnd	Include Neutral Connection Point?	No		0	1
Vmeas	Bus Voltage Measurement	Internal		0	1
Vbus	Rated Line to Line Bus Voltage	11	kV(RMS)	0.1	2000
Vmin	Minimum Bus Voltage(L-L)	0.8	p.u.	0.5	1.0
constF	Assume Constant Freq	Yes		0	1
freq	Base Frequency	50	Hz	1	200
FreqDevMax	Maximum frequency deviation from rated value	2.0	Hz	0.0	
T	Time Constant for setting R, X values	0.01	sec	0.001	100.
Tm	Time Constant for measuring Vbus	0.003	sec	0.001	100.0
prtyp	Type of Processor Card	GPC/PB5		0	2

Figure 4.6 RSCAD Load Model parameters

4.4 Instrument transformers

Current and Voltage or Potential transformers are modelled and used in the power system circuit. CTs and VTs are used to transform system current and voltage quantities to lower values that can be used by protection and control IEDs.

4.4.1 Current transformers (CTs)

The primary system current in the power transformer may be several hundreds or thousands of amperes. The CT is required to scale or transduce the primary current of thousands of amps down to several amperes. Two sets of CTs are modelled for the power system circuit. One set is on the 132kV side of the power transformer with a turns ratio of 200/1 and the other set on the 11kV side has a turns ratio of 2000/1.

The CT secondary current (I sec) is equal to the primary current (I prim) divided by the turns ratio (N). Therefore, I sec = I prim / N. The accurate transducing of the primary side current to the secondary side circuit occurs within the linear operating region of the CT flux−current plane. In this region between the ankle and knee points the core loss and magnetizing losses or magnetising branch do not significantly affect the accuracy of the CT. When the CT operates close to the knee point, the magnetising branch draws more current and an error is introduced. The CT will operate under abnormal operating conditions when a fault occurs on the power system and may exceed the saturation knee point.

The model developed for the RTDS is based on a CT equivalent circuit that includes both saturation and core loss effects. CT Core characteristic data can be entered as B−H characteristic, or V rms−I rms characteristic, or as physical core data. The V rms−I rms characteristic is used for the simulation model of current transformers. The configuration window is shown below in Figure 4.7.

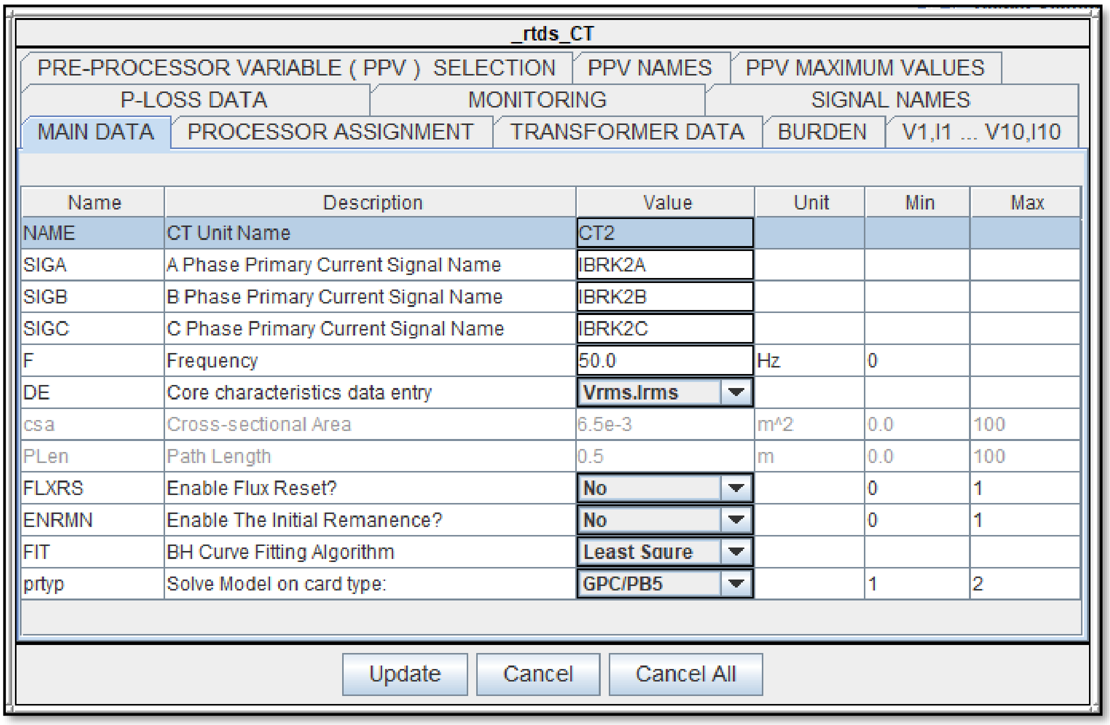
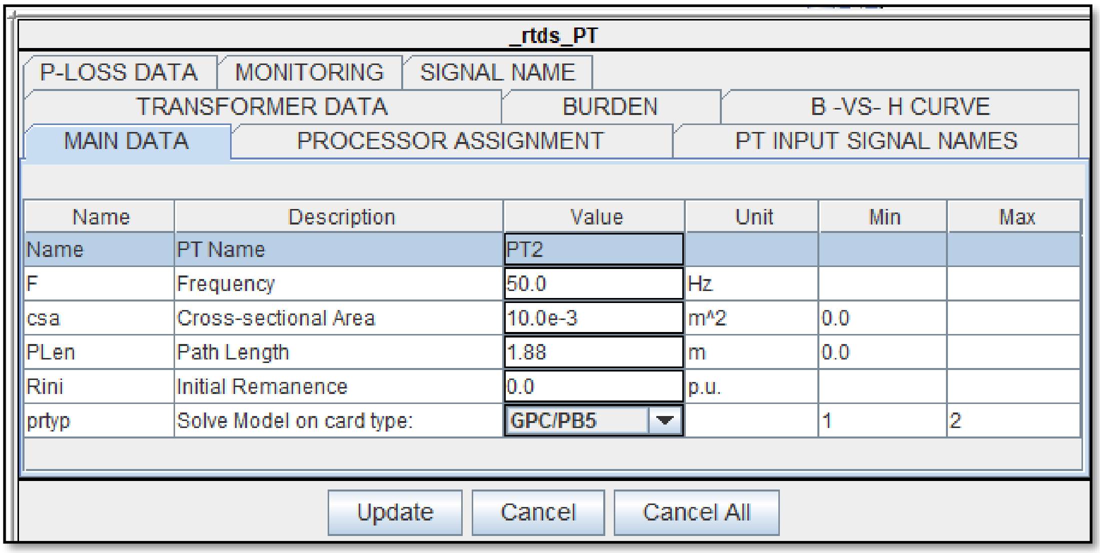


Figure 4.7 RSCAD Current Transformer main data

It is possible to enable the reset of the flux during simulation or set the CT at an initial remanence condition. The CT secondary side resistance, inductance and turns ratio can be entered under the transformer data tab. The Burden series resistance and inductance is entered under the Burden tab.

4.4.2 Voltage transformers (VTs)

Potential transformers (PTs) or VTs are modelled in the power system Test-Bench circuit on the 11kV bus bar to give an output of 110V that can be used by protection and control IEDs. The configuration window for the VT is shown in Figure 4.8 below.



Name	Description	Value	Unit	Min	Max
Name	PT Name	PT2			
F	Frequency	50.0	Hz		
csa	Cross-sectional Area	10.0e-3	m^2	0.0	
PLen	Path Length	1.88	m	0.0	
Rini	Initial Remanence	0.0	p.u.		
prtyp	Solve Model on card type:	GPC/PB5		1	2

Figure 4.8 RSCAD Voltage Transformer main data

The primary and secondary side resistance, inductance and turns ratio can be entered under the transformer data tab. The Burden series resistance and inductance and parallel resistance is entered under the Burden tab.

4.5 Running the Simulation in RSCAD Runtime

RSCAD/RunTime is used to interact with and control the Draft simulation case being performed on the RTDS hardware. Set point adjustment, fault application and breaker operation are performed through the RunTime Operator's Console. Online metering and recording functions are done in RunTime.

The method of running the simulation in RSCAD Runtime is shown in Figure 4.9 flow chart. The flow chart continues from modelling of the power system in the RSCAD Draft software shown in Figure 4.2. Runtime components such as sliders, dials, push buttons and meters are used to build the Runtime page.

The load is changed using active and reactive power sliders. The system configuration is changed by controlling circuit breakers to connect the power transformers in parallel.

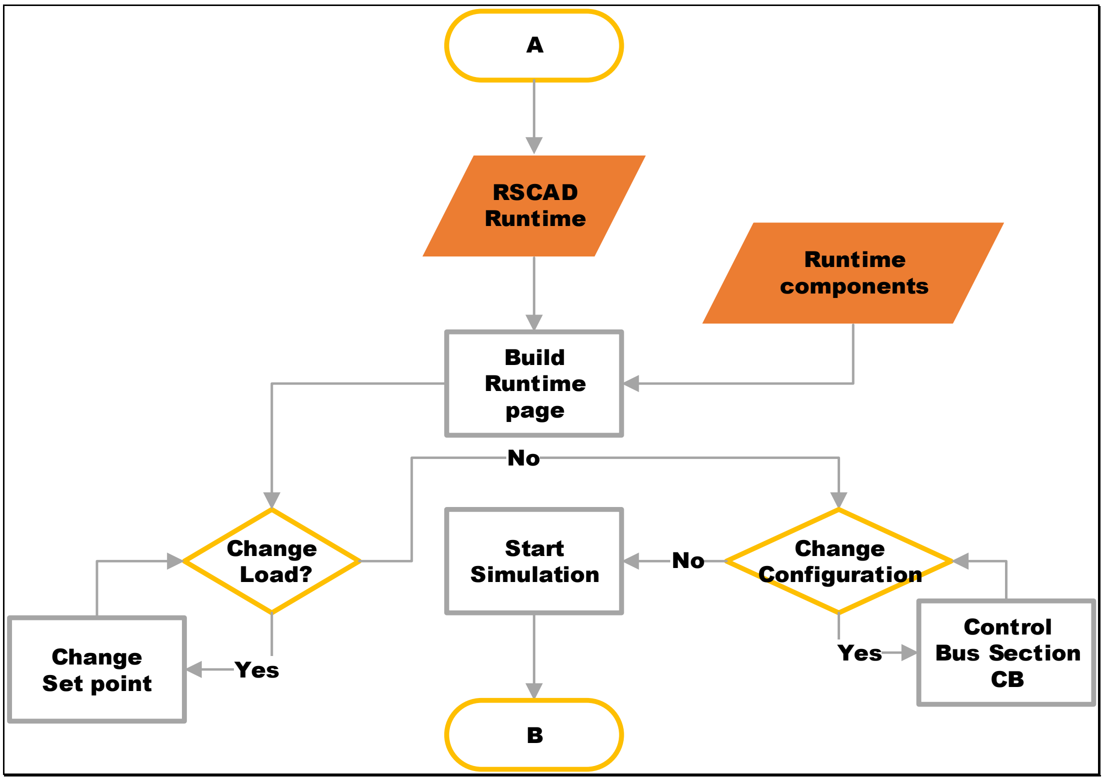


Figure 4.9 RSCAD/Runtime flow diagram

The RunTime Operator Console window of the simulation Case 1 is shown in Figure 4.10.

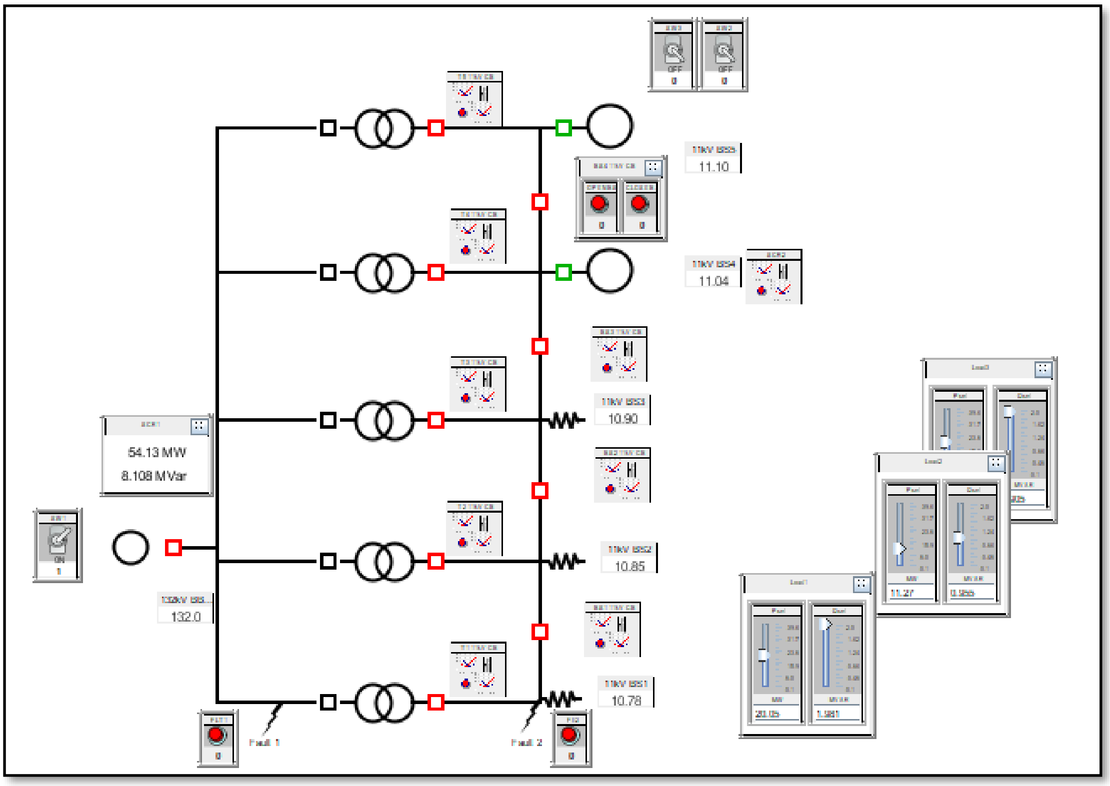


Figure 4.10 Runtime circuit of system of parallel power transformers Case 1

A part of the system of 5 parallel power transformers, Single Line Diagram (SLD) for RunTime Case 1 is shown in Figure 4.11 below. A Circuit Breaker (CB) is indicated in the RSCAD/RunTime SLD with a square symbol. The CB symbols are configured to be interactive with the status of the CB status. A green square indicates a CB with an open status. A red square indicates a CB with a close status. The CB is operated by open and close push buttons.

A fault is applied with a push button. Two positions are simulated, Fault 1 on the 132kV side of Transformer 1, and Fault 2 on the 11kV side. The type of fault e.g. phase A to ground (Ia-g), can be selected with a dial switch.

Meters for Megawatt (MVA), Megavar (MVAr) and kilovolt (kV) are monitoring the measurement values for the simulation case 1.

Sliders are used to change the resistive and inductive values of the load.

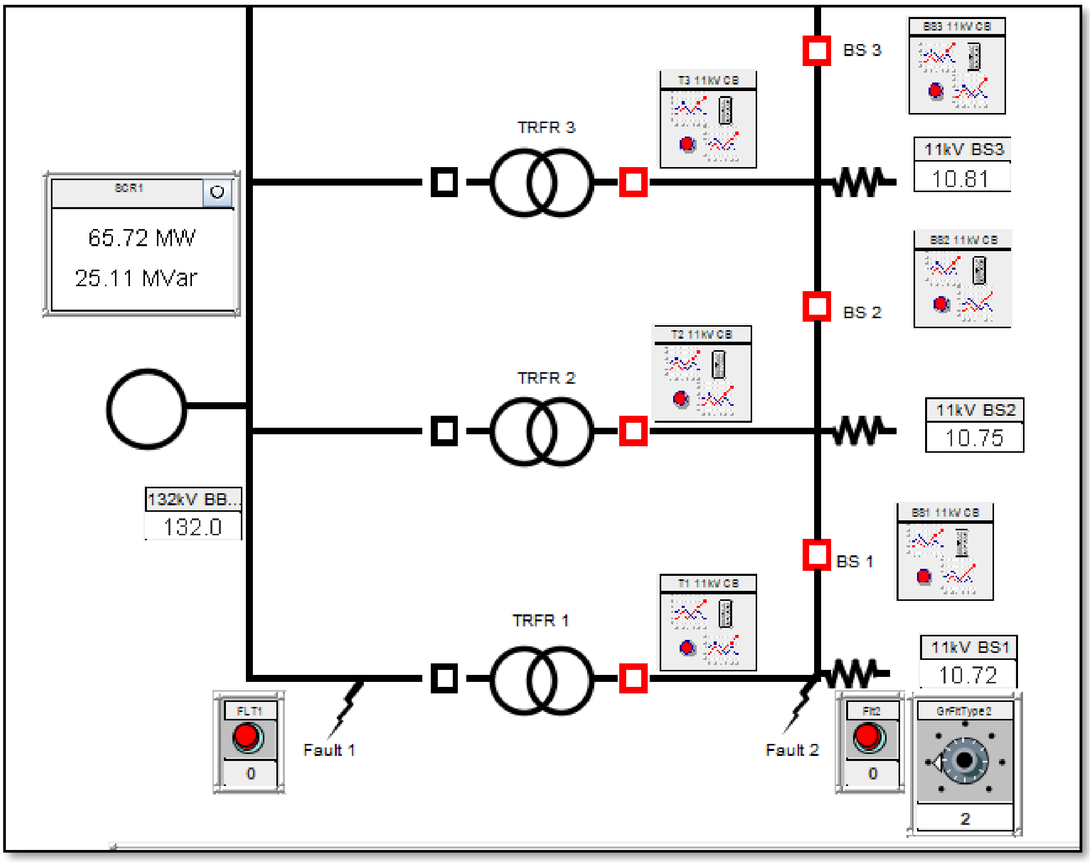


Figure 4.11 RunTime Case 1

4.6 Simulation results

A Simulation is done to determine how the fault level and fault current will be influenced by having power transformers connected in parallel compared to individual connected transformers. It is suspected that the fault level will change on the secondary side of the transformers as more transformers are connected in parallel.

The method of applying faults to the system during the simulation in RSCAD Runtime is shown in Figure 4.12 flow chart. The flow chart continues from Figure 4.9 above. Two faults are possible according to the fault position. Fault 1 on the 132kV side of Transformer 1, and Fault 2 on the 11kV side of the simulated transformer. The type of fault e.g. phase A to ground (Ia-g), can be selected with a dial switch for each position. Circuit breakers are opened or closed to connect the transformers in parallel.

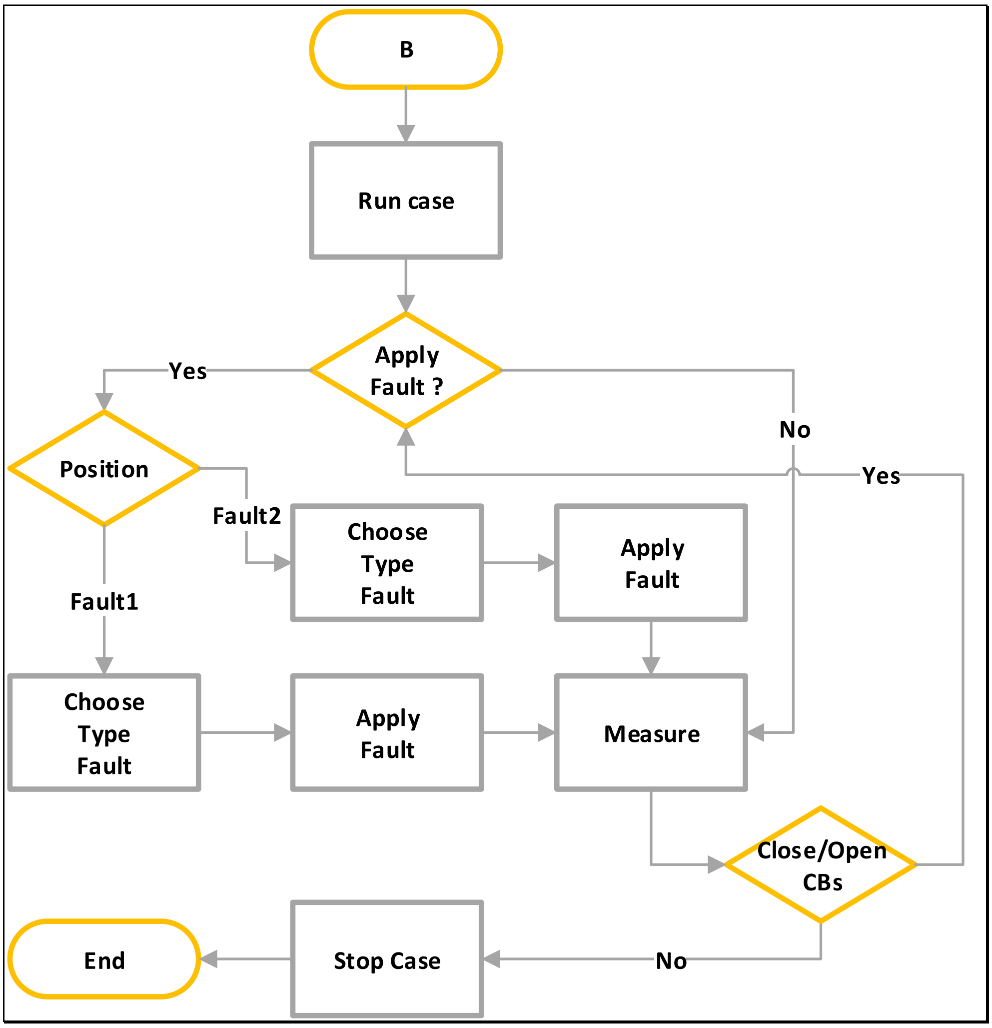


Figure 4.12 RSCAD/Runtime Faults

RSCAD/MultiPlot is used for post processing and analysis of results captured and stored during a simulation study. Report can be generated by MultiPlot.

4.6.1 Transformer 1 MV Fault Case 1A

The magnitude of the fault current is measured flowing through Transformer 1 when fault is applied at position 2 (Fault 2). A single phase fault on the B-phase, phase to ground, is applied on the MV 11kV side of the transformer.

The magnitude of 7,5kA for IBRK2ABC currents flowing, on the 11kV side of the transformer, is shown in Figure 4.13 when a Fault 2 is applied. The bus section 1 circuit breaker is close therefore the other parallel transformers are also sharing the fault current.

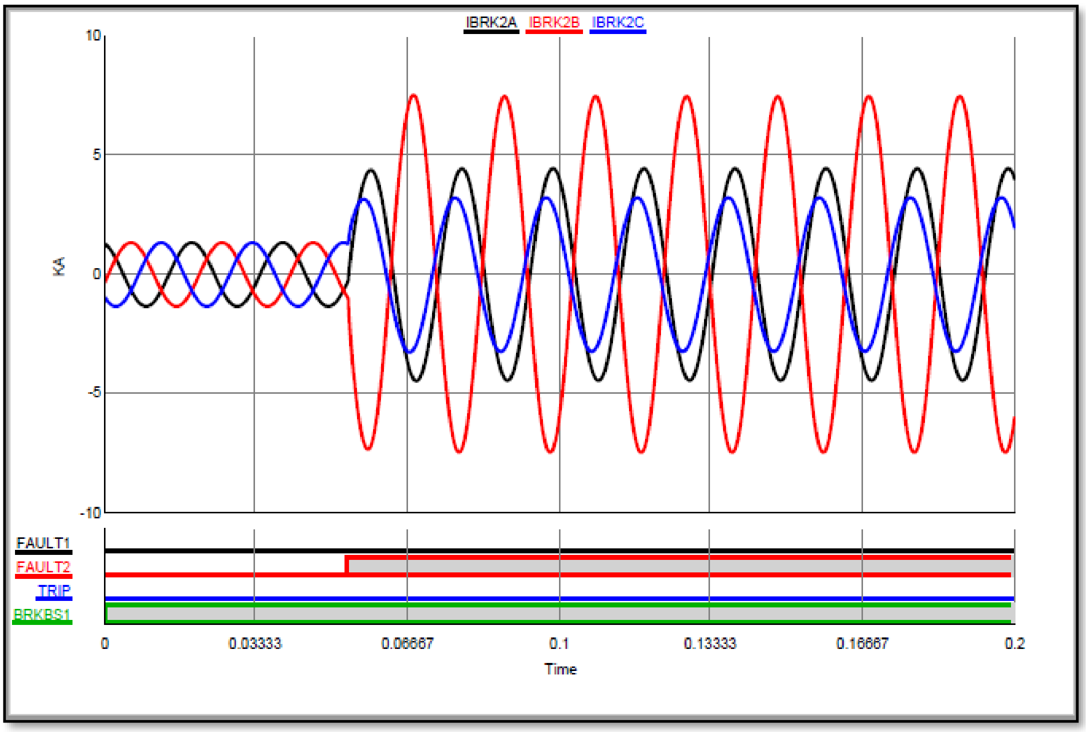


Figure 4.13 TRFR 1 MV Fault Case 1A

4.6.2 Transformer 1 MV Fault Case 1B

The magnitude of the fault current is measured flowing through Transformer 1 when fault is applied at position 2 (Fault 2). A single phase fault on the B-phase, phase to ground, is applied on the MV 11kV side of the transformer. The Bus Section 1 circuit breaker is open in this case shown Figure 4.15 below.

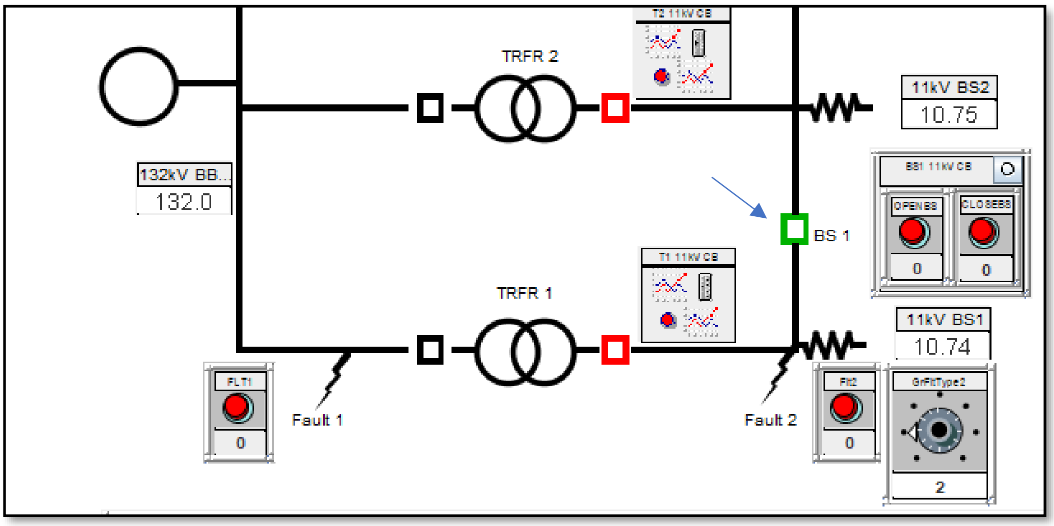


Figure 4.14 RunTime Case 1B with BS1 CB open

The magnitude of 2,3kA for IBRK2ABC currents flowing, on the 11kV side of the transformer, is shown in Figure 4.17 when a Fault 2 is applied. The Bus Section 1 circuit breaker is open therefore the other parallel transformers are not sharing the fault current.

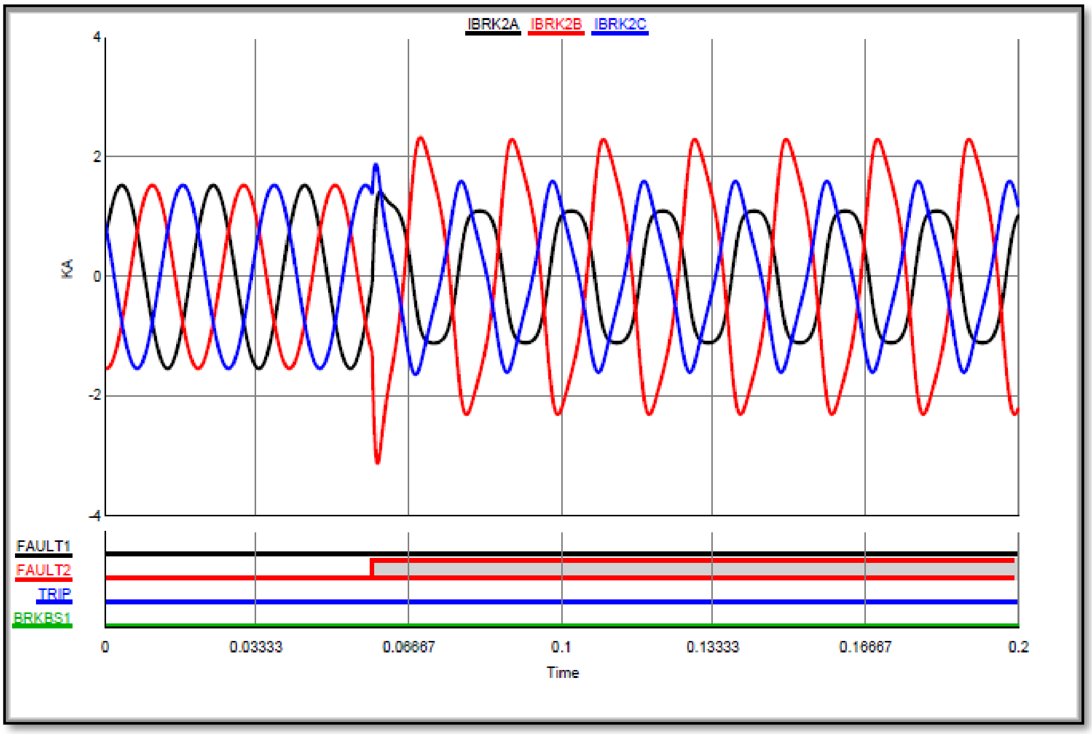


Figure 4.15 TRFR1 MV Fault Bus Section1 open

4.6.3 Transformer 1 HV Fault Case 1C

The magnitudes of the fault currents on the 132kV High Voltage (HV) side of the power transformer is measured using a current transformer with a ratio of 200/1.

A single phase fault on the A-phase, phase to ground, is applied on the HV side of the transformer shown in Figure 4.16 .

IBUR1ABC are Current Transformer (CT) secondary currents measured on the HV side. The fault current calculates to 4kA with a secondary CT current of 20A.

A DC offset can be seen on the AC fault current. This results in CT saturation and the CT cannot reproduce the secondary current to be in relation with the primary current. This can influence the performance of the protection system.

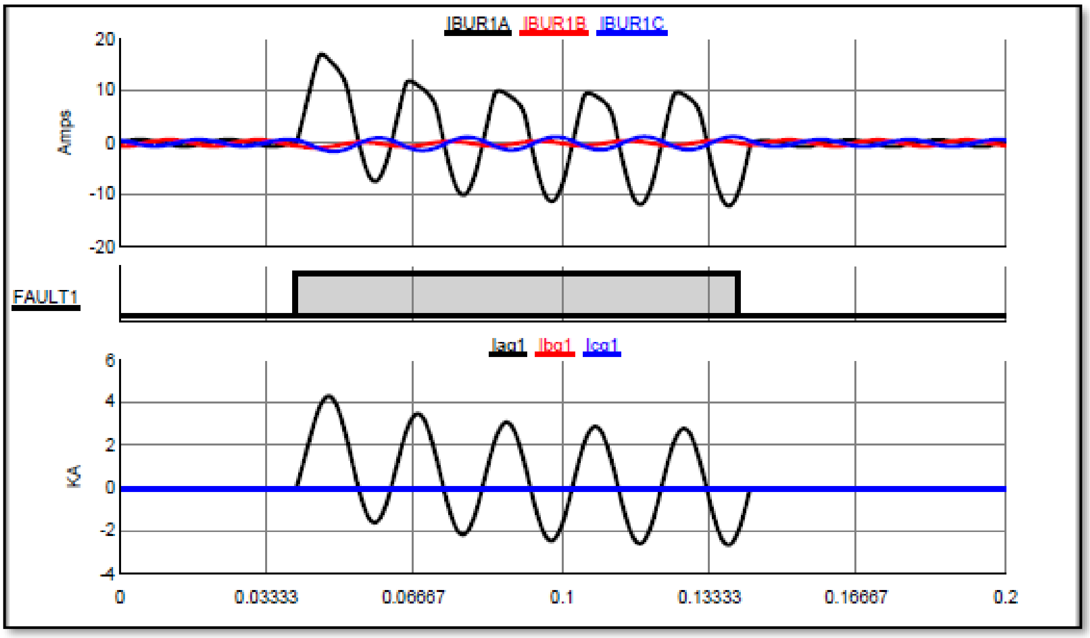


Figure 4.16 Transformer 1 HV CT saturation

4.6.4 Transformer 1 vector group Case 1D

The magnitudes of the fault currents on the 132kV High Voltage (HV) and 11kV Medium Voltage (MV) side of the power transformer with a YNd1 vector group is measured to determine the effect that the transformer vector group will have on the fault currents when a fault is applied on the 11kV bus bar. The Current Transformers (CT) secondary currents are measured.

A single phase fault on the B-phase, phase to ground, is applied on the MV side of the transformer. It can be seen in Figure 4.17 that a phase to ground fault on the Transformer MV side appears as a phase to phase fault on the HV side.

IBUR1ABC are CT secondary currents measured on the HV side. The current transformer has a ratio of 200/1. The fault current for phase A calculates to 540A with a secondary CT current of 2.7A on for phase B to 460A with a secondary CT current of 2.3A.

IBUR2ABC are CT secondary currents measured on the MV side. Ibg2 is the B-phase, phase to ground fault, of Fault 2. The current transformer has a ratio of 2000/1. The fault current for Phase B calculates to 7,2kA with a secondary CT current of 3,6A, Phase A calculates to 4kA with a secondary CT current of 2A. Phase B calculates to 3kA with a secondary CT current of 1,5.

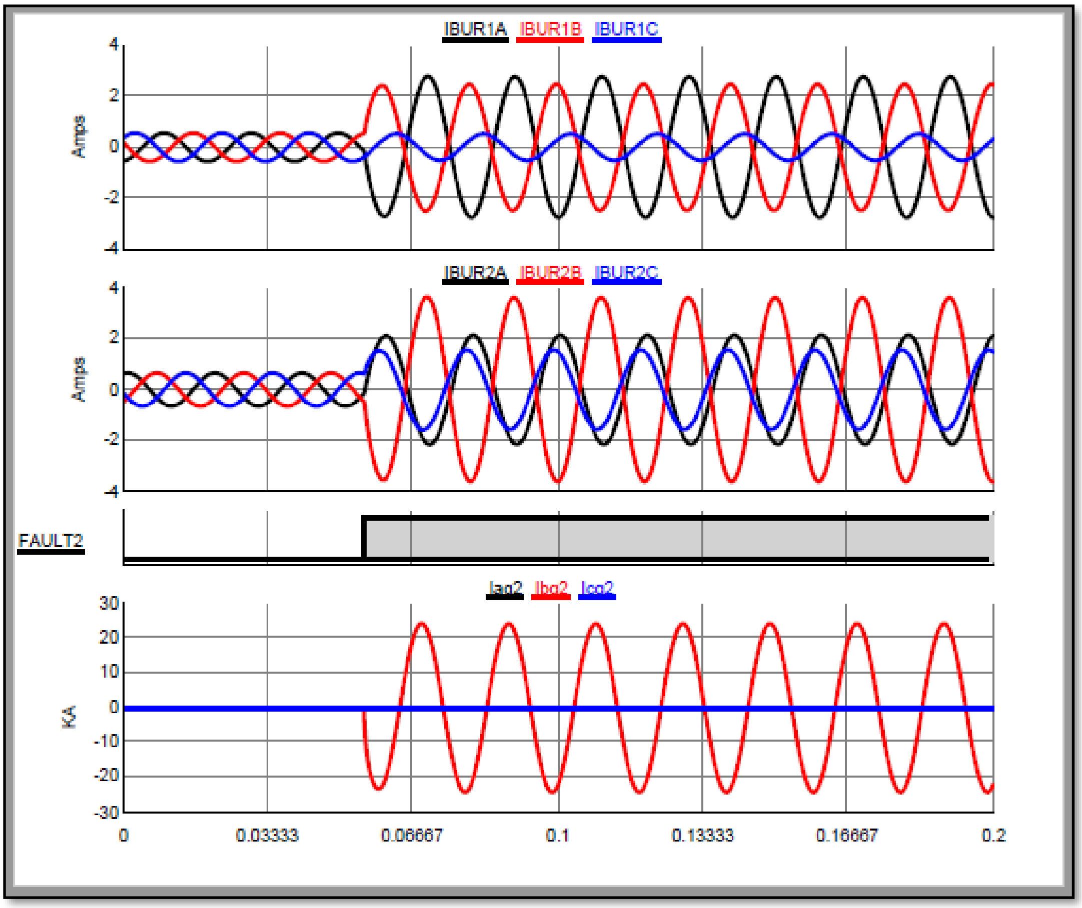


Figure 4.17 TRFR1 Fault 2

4.6.5 Transformer 1 Switch on Case 1E

The magnitudes of the currents on the 132kV High Voltage (HV) of the power transformer is measured to determine the effect of energisation of the transformer. The phenomenon of magnetising inrush is a transient condition that occurs primarily when a transformer is energised. The Current Transformers (CT) secondary currents are measured.

IBUR1ABC are the CT secondary currents measured on the HV side. The current transformer has a ratio of 200/1. The energisation current for phase A calculates to 154A with a secondary CT current of 0,76. This is less than the full load current of 175A. The energisation current is a high non-sinusoidal magnetising current waveform shown in Figure 4.18 and is dependent on the core saturation, the point of the wave where the switch on occurs as well as the remanent flux.

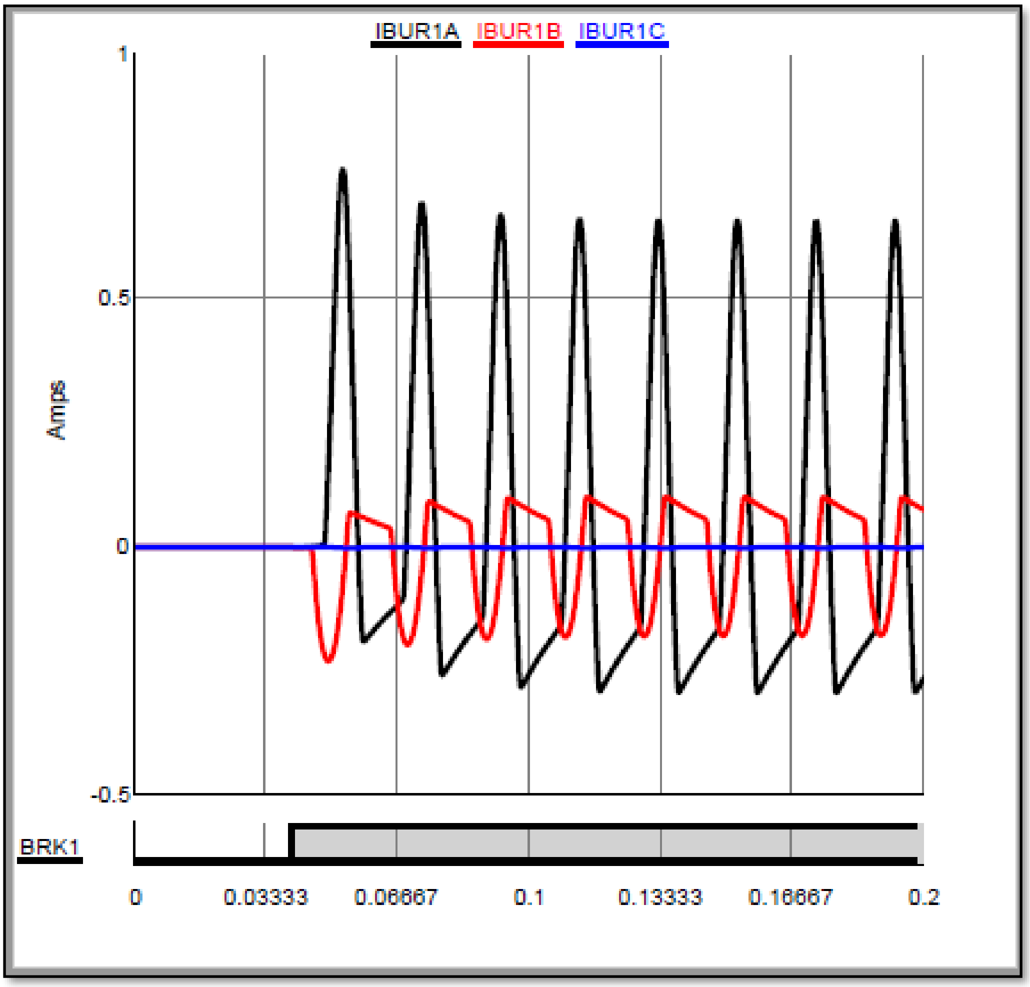


Figure 4.18 Transformer 1 magnetising inrush

4.7 Discussion.

A system of five 40MVA 132/11kV YNd1 power transformers connected in parallel is modelled and simulated in the Real-Time Digital Simulator (RTDS) for the simulation Case 1.

Faults are applied at two positions in the developed system of parallel power transformers, to the 132kV High Voltage (HV) side and 11kV Medium Voltage (MV) side. The fault currents are measured and analysed.

The status of bus sections circuit breakers is altered to change the system configuration. The fault currents are analysed for the different system configurations in Case 1A and 1B. The magnitude of the fault current measured changed for the same type of fault that was applied at the same position in the modelled system. This has an influence on the protection settings that are applied to the transformer protection and needs to be considered when a protection system is designed for a power transformer.

A fault is applied to the modelled system In Case 1 C on the 132kV High Voltage (HV) side of the power transformer. The magnitude of the fault current and the secondary Current Transformer (CT) currents are measured. CT saturation is shown, and this can influence the performance of the protection system. The use of merging units can eradicate this problem.

A single phase fault on the B-phase, phase to ground, is applied on the MV side of the transformer in Case 1D. It is shown that a phase to ground fault on the Transformer MV side appears as a phase to phase fault on the HV side. Current distribution of fault currents on the HV and MV side of the transformer is influenced by the transformer vector group. This need to be understood when a protection system is designed for a power transformer.

The transient condition of magnetising inrush that occurs primarily when a transformer is energised is shown in Case 1E. This need to be considered when the transformer protection system is designed for parallel power transformers.

4.8 Conclusion

In this chapter, the system of five 40MVA 132/11kV YNd1 power transformers connected in parallel is modelled and simulated in the Real-Time Digital Simulator (RTDS).

The system configuration is changed by controlling different circuit breakers. The amount of power transformers connected in parallel can be controlled in this way.

Faults are applied at different points in the system and for different system configurations. The fault currents are measured and analysed.

The configuration of the RTDS power source, power transformer, power system load and instrument transformers models are shown.

The simulation results are discussed.

The protection design for the system of parallel power transformers is discussed in the next chapter.

5 CHAPTER FIVE
PROTECTION DESIGN FOR THE SYSTEM OF PARALLEL POWER TRANSFORMERS

5.1 Introduction

A Protection scheme for a system of parallel power transformers is designed and discussed in the chapter.

A system of two parallel 40MVA 132/11kV YNd1 power transformers is designed, modelled and simulated in the Real-Time Digital Simulator (RTDS)/RSCAD software for the simulation Case 2.

The system has a source connected to the 132kV bus bar. The 11kV bus bar has one Bus Section, one 11kV load and one 11kV source is connected to the 11kV bus bar section. The RTDS model of simulation Case 2, the system of parallel power transformers is shown in Figure 5.1. in a Single Line Diagram (SLD).

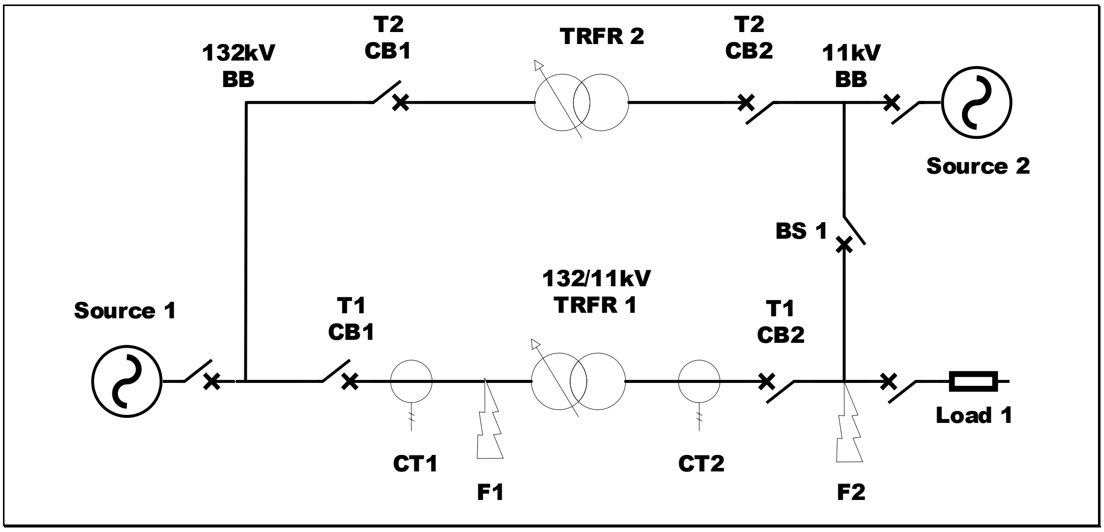


Figure 5.1 Single line diagram system of two parallel transformers Case 2

RSCAD/RunTime software is used to control the simulation case being performed on the RTDS hardware. Set point adjustment, fault application, breaker operation is performed through the RunTime Operator's Console.

The simulations in this chapter includes the following case studies:

- Faults are applied at different locations of the system of two parallel power transformers and fault currents are measured.
- Differential and Overcurrent Protection of Transformer 1 is tested for correct operation.

- Different setting groups for over current protection for Transformer 1 are use depending on how the power transformers are connected in the system.
- Sampled Value streams are simulated and measured.

Faults are applied to the 132kV high voltage side (F1) and 11kV medium voltage side F2) of the system of power transformers and the fault currents are measured and analysed. The faults applied at a position F1 is in the protection zone of the transformer. The faults applied at a position F2 are out of the protection zone of the transformer.
Two different setting groups are automatically selected depending on the status of the Bus Section (BS) and Transformer circuit breakers. The operation of the transformer protection is tested for different system configurations.
The IEC 61850 9.2LE implementation is used in the RTDS/ Draft simulation circuit to transmit SV data streams for 4 current and 4 voltage channels, sampled at a rate of 80 samples/cycle.

Transformer protection design with Differential and Overcurrent protection is discussed in Section 5.2. Differential protection as main protection and Instantaneous Overcurrent as backup protection is selected for the transformer protection scheme simulated in Case 2.
The configuration of the RTDS Differential and Overcurrent protection relays is discussed in section 5.3. The GTNET_SV9−2 component of the RSCAD software provides IEC 61850−9−2 Sampled Values communications to transmit or receive SV data streams. The configuration is also discussed in this section.
Running the simulations using the RSCAD/RunTime is discussed in section 5.4.
The results of the simulations are shown in section 5.5 and discussed in section 5.6.
The conclusions are made in section 5.7. It is shown that power transformer protection operates correctly, and settings can be adapted when the system configuration for parallel power transformers is changed.

5.2 Transformer protection design

The size and the importance of a power transformer is considered when the transformer protection is described. Protection schemes must have the following properties: selectivity, speed and stability (Alstom, 2002: 2–6).

- Selectivity is obtained by the protection scheme by tripping only those circuit breakers to isolate the fault. A unit protection scheme can be selective to trip circuit breakers for a fault in the protective zone, for example in the transformer, to isolate the transformer from the rest of the system.

- The speed or the fault clearing time is important. A short fault clearing time can reduce the effects of thermal stress and electromechanical forces, in a transformer, due to a fault.
- Stability can also be obtained with unit protection schemes. The scheme remains stable and do not trip for faults external to the protected zone. The transformer unit protection must not trip for faults outside the protective zone.

The main objectives of transformer protection to provide selectivity, speed and stability can be realised by using transformer differential protection (Blackburn & Domin, 2006: 319).

The following are categories of transformer faults according to (Alstom, 2002: 16–1):

- winding and terminal faults
- core faults
- tank and transformer accessory faults
- on–load tap changer faults
- abnormal operating conditions
- sustained or uncleared external faults

Transformer Differential protection can protect the transformers against most of the winding and core fault mentioned above.

Over current protection can effective protect the transformer primary winding against phase to phase and phase to earth faults.

The following types of protection are selected for the Transformer 1 protection scheme:

- Differential protection is selected for the main protection.
- Over current protection is selected for the back-up protection.

5.2.1 Main Protection

The differential protection function compares the primary and secondary currents flowing in and out of a power transformer.

The basic operation of the Differential protection function is as follows. The vector sum of the phase currents flowing into the transformer (I_{CT1}) is equal to the vector sum of the phase currents flowing out of the transformer (I_{CT2}). The protective zone is between CT1 and CT2 shown below in Figure 5.2.

Under normal operation the magnitude of I_{CT1} equals I_{CT2}.

$$\mathbf{I_{CT1} = I_{CT2}} \tag{5-1}$$

A small differential current will be present in normal operating conditions or for a fault out of the protective zone, at position (F2). It is described by Equation (5-2).

$$\mathbf{I_{DIFF} = I_{CT1} - I_{CT2}} \tag{5-2}$$

A larger differential current will however be present for a transformer internal fault, in the protective or differential zone, at position (F1).

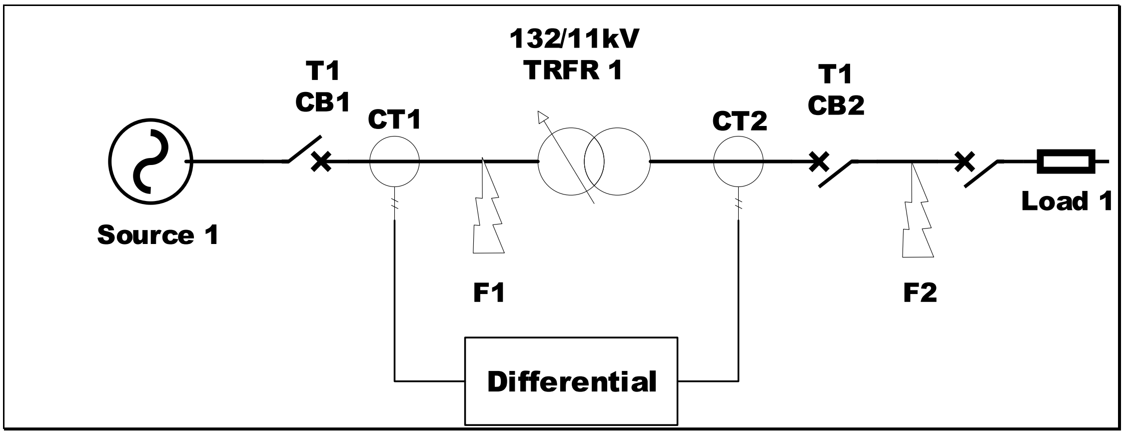


Figure 5.2 Transformer Differential protection

Some factors can influence the differential current measured during normal load conditions: different taps for voltage control, Magnetising inrush during initial energisation and occurrence of over fluxing(Alstom, 2002: 16–7).

Phase shift correction is required where there is a 30-degree phase shift between the primary and secondary side currents of a transformer with star-delta connected windings and YNd1 vector group. Star connected windings can pass zero sequence currents to faults external to the differential zone, this can operate the differential protection for faults out of the protected zone. Zero sequence current filters are required for star connected windings. The phase shift correction, zero sequence current filtering and CT ratio mismatch correction is done in the software of the digital differential protection IEDs.

An adaptive protection criterion is proposed in research, which can change the percentage differential relay parameters according to the transformer operating conditions. The use of negative and zero sequence currents is proposed as a criterion (Zhang et al., 2013: 61).

The sensitivity of Differential protection is related to issues with mismatched CTs, CT saturation, lead resistance and tap settings. An adaptive differential protection algorithm can be investigated by including the transformer winding tap-position information available at process level, into the protection IED algorithm.

The shorter distance from the MU to the instrument transformer decrease the influence of the sum of factors such as mismatched CTs, CT saturation, lead resistance on the biased low impedance percentage differential protection.

5.2.2 Back-up protection

Over Current (O/C) protection can be used to protect against overloading, high trough faults, primary side bushing faults and faults on the primary winding.

A high-set instantaneous overcurrent relay element is selected as backup protection and used to trip for primary side short circuits. This can be measured with the CT1 shown in Figure 5.3.

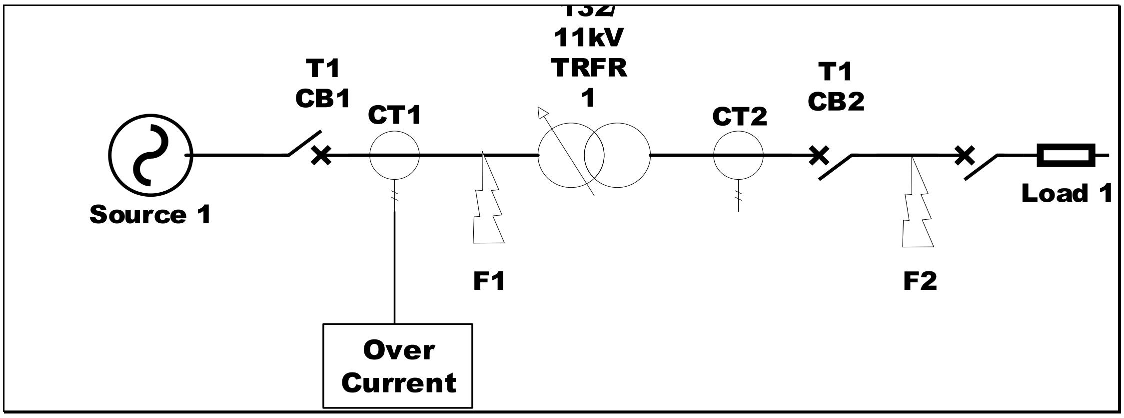


Figure 5.3 Transformer Over Current protection

An O/C protection function on the primary side (CT1) of a transformer is not effective for faults on the secondary winding due to the low magnitude of fault current transferred to the primary side.

Timed delayed overcurrent protection chosen to discriminate with protection on the secondary side of the transformer will increase the trip time to disconnect the faulted equipment from the power system and therefore not selected as backup protection.

The O/C protection can be supplemented with an Earth Fault (E/F) element. The E/F element can be connected in the residual circuit of the three phase CTs or on the neutral conductor of a star connected winding.

5.2.3 System parameters

The system of parallel power transformers and the parameters used for building the RTDS power system simulation circuit are discussed in this section.

The network of the system in Figure 5.1 has a source (Source 1) connected to the 132kV bus bar, representing the rest of the power system that the substation is connected to. The source connected to the 11kV busbar (Source 2) represents the total 11kV generation. The load (Load 1) represents the total load connected to the 11kV busbar.

The power transformer parameters considered for Transformer 1 in the system model are shown in Table 5-1 below.

Table 5-1 Transformer parameters

Transformer power rating	40 MVA
Rated Primary voltage rating	132kV
Rated Secondary voltage rating	11kV
Vector group	YNd1
Impedance	10%

The current transformer ratios are selected by considering the rated power of the transformer.

The following formula is used.

$$\mathbf{I_{rms} = S/(\sqrt{3}\ x V_{rms})} \qquad (5\text{-}3)$$

Where:

I_{rms} = the root-mean-square current (A)

S = Apparent power (VA)

V_{rms} = the root-mean-square voltage (V)

The calculated full load rated current at the 132kV and 11kV sides of the transformer is shown in Table 5-2.

Table 5-2 Current calculated for a 40MVA transformer

kV	kA
132	0,175
11	2,099

A current transformer ratio of 200/1 is selected on the primary 132kV side and 2000/1 on the secondary 11kV side of the power transformer.

5.2.3.1 Circuit impedance values

The short circuit capacity and the fault level on the High Voltage (HV) 132kV busbar is depended on the source short circuit impedance. The fault level on the Medium Voltage (MV) 11kV busbar is determined by the short circuit impedance on the HV side of the transformer added to the transformer impedance.

When a source is connected to the 11kV busbar, the source short circuit impedance contributes to the fault level. The real and reactive power of a load also has an influence on the fault levels.

Different units related to the system impedance are used for building the power system model. This is shown in Table 5-3 below.

Table 5-3 Power system model parameters

Power system model	Input Parameters related to impedance
Source	Positive and Zero sequence impedance
Power transformer	Per unit leakage inductance
Load	Real and Reactive power

The following formula is used to calculate impedance from apparent power and voltage values.

$$\mathbf{Z = V^2 / S} \qquad (5\text{-}4)$$

Where:

Z = Impedance in ohm (Ω)

S = Apparent power (VA)

V = Nominal voltage (V)

The current can be calculated by:

$$\mathbf{I = V / (1.732 * Z)} \qquad (5\text{-}5)$$

or

$$\mathbf{I = S / (1.732 * V)} \qquad (5\text{-}6)$$

Equation 5-4 can also be used to calculate the short circuit impedance (Z_{SC}) from the short circuit fault level (S_{SC}) and nominal busbar voltage (V).

A fault level of 300MVA is used for Source 1 at the 132kV busbar:

$$\mathbf{Z_{SC} = 132^2 / 300}$$

$= 58$ ohm

A fault level of 200MVA for Source 2 at the 11kV busbar will have a fault impedance of:

$$\mathbf{Z_{SC} = 11^2 / 200}$$

$= 0{,}605$ ohm

The impedance values and fault current values in kA is compared for Source 1 and 2 in Table 5-4 below.

Table 5-4 Source fault impedance and current

	MVA	kV	Impedance (ohm)	kA
Source 1	300	132	58	1,312
Source 2	200	11	0,605	10,497

Equation 5-4 can also be used to calculate the transformer impedance (Z) from the transformer rated power (S) and nominal busbar voltage (V).

A 40MVA transformer at a 132kV base voltage with a 10% impedance:

$Z = 132^2 / 40*10/100$

$= 43,56$ ohm

A 40MVA transformer at a 11kV base voltage with a 10% impedance:

$Z = 11^2 / 40*10/100$

$= 0,3025$ ohm

The transformer impedance values for the 132kV primary and 11kV secondary sides are shown in Table 5-5.

Table 5-5 Transformer impedances

40MVA 132/11kV Transformer	
kV	Impedance (ohm)
132	43,56
11	0,3025

The most important types of faults are:

- single-phase to earth
- phase to phase
- phase-phase-earth
- three-phase (with or without earth)

The magnitude of the fault current is limited by the Thévenin equivalent impedance of the network. The number of transformers connected in parallel, the load and the sources connected to the network will therefore have an impact on the fault current values.

5.3 Configuration of RTDS protection relay models

Transformer Protection models are added to the RTDS power system simulation circuit. The Differential (DIFF) and Over Current (O/C) protection models are shown in Figure 5.4. The Circuit Breaker and fault controls are included in the circuit for the simulation and testing of the transformer DIFF and O/C protection functions when applying faults in and out of the protective zone.

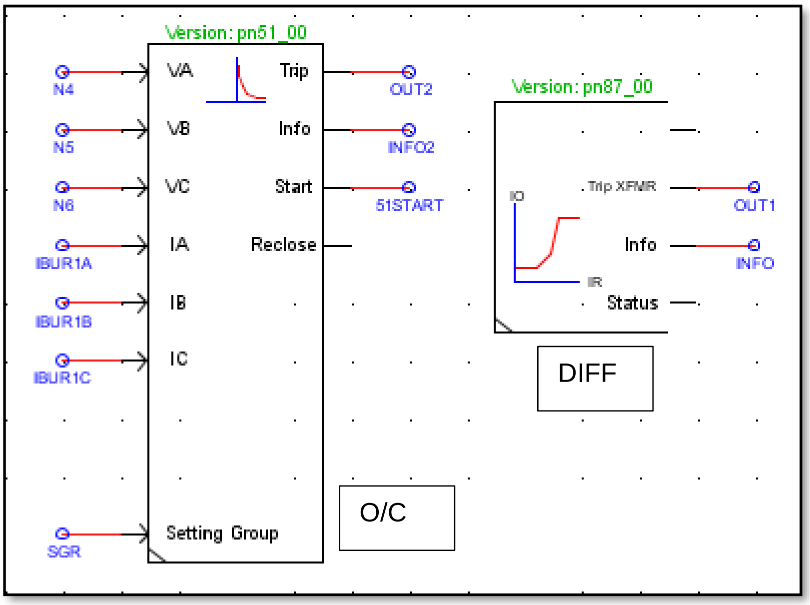


Figure 5.4 RTDS Differential and Over Current protection relay models

5.3.1 Differential protection relay

The fundamental phase currents are fed into the inputs of the differential (87) function. It is possible to compensate for ratio mismatch and phase shifts in the 87 function. The operating quantity and restraining quantity are calculated for each phase and applied to the 2-slope differential current characteristic shown in Figure 5.5. The operating current quantity must be above the restraint current and the minimum operating value (IO-min) setting for the relay to operate and issue a trip output.

The basic operation of the RTDS Differential protection function is as follows (Proctor, 2016). The operating quantity is the vector sum of the phase currents.

$$\mathbf{I_{OP} = I_{CT1} - I_{CT2}} \qquad (5\text{-}7)$$

The operating current Iop is the vector sum of CT1 on the primary side of the transformer and CT2 on the secondary side of the transformer. Under normal operation the magnitude of I_{CT1} equals I_{CT2}, but the phases are 180 degrees apart.

The restraint quantity is calculated using the summation of current magnitudes of every connected CT divided by 2.

$$\mathbf{I_{RS} = (I_{CT1} + I_{CT2})/2} \qquad (5\text{-}8)$$

The amount of restraint current determines the amount of operating current required to operate. The operating quantity must be above the minimum operating value setting or the relay will not operate.

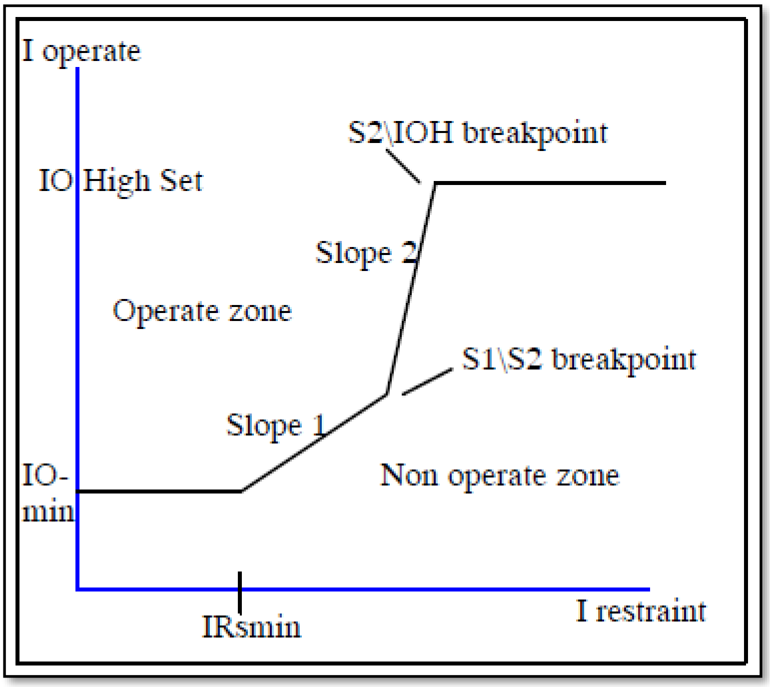


Figure 5.5 RTDS Two slope percentage transformer differential algorithm

The operating current required to operate when it is above the restraint current (IRSMIN) will increase using slope 1 (IRSMIN = IOMIN * 1.0 ⁄ Slope1).
When the restraint current increases above the slope1\slope2 breakpoint (IRs), the restraint current (IORS) will be calculated using slope 2. (IORS = IRS * 1.0 ⁄ Slope2). The operating current necessary to operate the relay does not increase above the restraint current high set breakpoint setting (HiSet).
The transformer protection element uses an additional measurement of 2nd harmonic over fundamental to prevent mis operation during transformer energization.

5.3.1.1 Differential function considered for changing loads

The operate and restrain currents calculated for different MVA values are shown in Table 5-6 below. Current transformer ratios of 200/1 are used on the HV (132kV) side and 2000/1 on the MV (11kV) side.

Where for Transformer 1:

I_{HV} = the primary HV current.

I_{CT1} = the secondary HV CT1 current

I_{MV} = the primary MV current.

I_{CT2} = the secondary MV CT2 current

I_{OP} = Differential operating current

I_{RS} = Differential restraining current

It is shown below that the operating as well as the restrain current increases as the load current is increased. The restrain current stays above the operate current and therefore the differential relay will not issue a trip signal.

Table 5-6 Differential function Operate & Restrain current for load conditions

MVA Load	I_{HV}	I_{CT1}	I_{MV}	I_{CT2}	I_{OP}	I_{RS}
10	43.74	0.2186997	524.88	0.26243964	0.0437	0.241
20	87.48	0.4373994	1049.76	0.52487928	0.0875	0.481
40	174.96	0.8747988	2099.52	1.04975856	0.175	0.962

5.3.1.2 Differential function considered for transformer tap changers

An on−load tap changer function is available in the RTDS/RSCAD transformer models. A voltage regulating function controls the tap changer. The number of turns for a winding is changed with different tap positions. This changes the turns ratio between the transformer primary and secondary windings and results in a variance in load current. This influences on the differential current measured.

The following three cases shown in Table 5-7 are considered where the ratio between the primary and secondary windings changes. The operating as well as the restrain current increases as the tap positions is changed. The restrain current stays above the operate current and therefore the differential relay will not issue a trip signal.

Table 5-7 Differential Operate & Restrain current for different tap positions

Case	MVA Load	$I\ H_V$	I_{CT1}	I_{MV}	I_{CT2}	I_{OP}	I_{RS}	Tap ratio
1	40	174.96	0.875	2210.02	1.105	0.2302	0.990	0.95
2	40	174.96	0.875	2099.52	1.050	0.175	0.962	1
3	40	174.96	0.875	1999.54	1.000	0.125	0.937	1.05

5.3.1.3 Differential function considered for different fault currents

The operate and restrain currents calculated for different fault values are shown in Table 5-8 below. Fault 1 is for a case where no source is on the MV side and the fault current is from the HV side only. Fault 2 is for a case where a source is connected to the MV side and the fault current is flowing from both the HV and MV side.

It is shown below that the operating increases well above the restrain current for both faults. The differential relay will issue a trip signal if the operating current is above the minimum operating setting.

Fault 3 is for a case where CT1 saturates and the secondary output does not correspond to the primary current. The relay calculates an operating current above the restrain current and will issue a trip.

Table 5-8 Differential function Operate & Restrain current for fault conditions

Fault	$I\ H_V$	I_{CT1}	I_{MV}	I_{CT2}	I_{OP}	I_{RS}
1	1000.00	5	0.00	0	5	2.500
2	1000.00	5	-2000.00	-0.952	5.952	2.024
3	875.00	0.5	10000.00	4.761	4.262	2.631

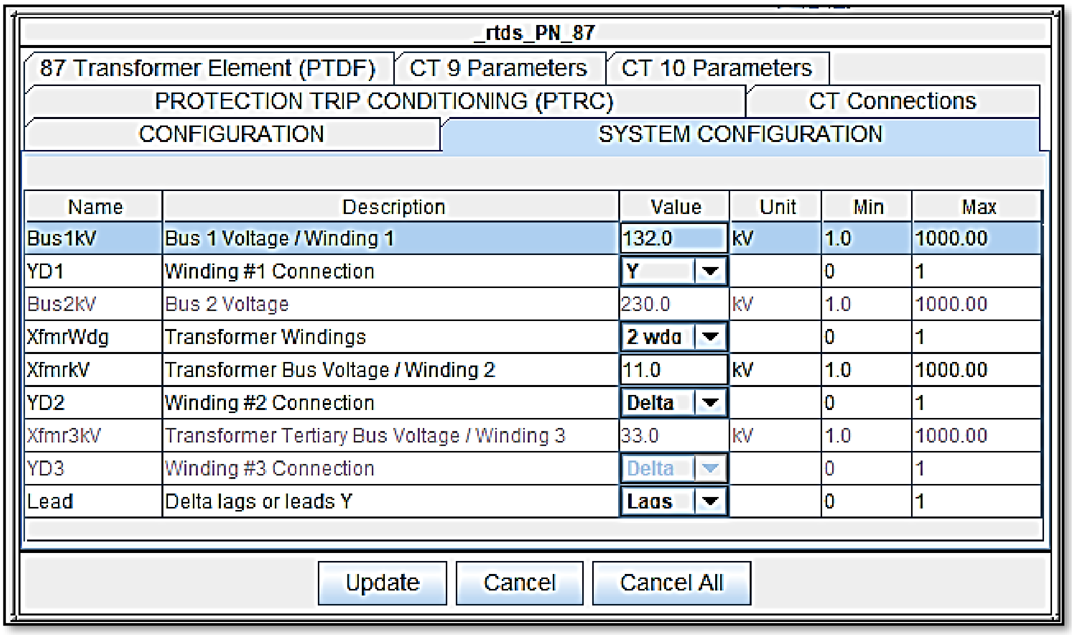
The differential relay is required to be stable for a through fault condition and not issue a trip signal. This is for a case where the fault is out of the protection zone on the 11kV side of the transformer. This fault can be at the load or at the busbar. The following Table 5-9 shows the operating as well as the restrain current increases as the fault level (MVA_{SC}) is increased. The restrain current stays above the operate current and therefore the differential relay will not issue a trip signal.

Table 5-9 Differential function Operate & Restrain current for fault levels

MVA SC	$I\ H_V$	I_{CT1}	I_{MV}	I_{CT2}	I_{OP}	I_{RS}
50	218.70	1.093	2624.40	1.3122	0.219	1.203
100	437.40	2.187	5248.79	2.6244	0.437	2.406
200	874.80	4.374	10497.59	5.2488	0.875	4.811

5.3.1.4 Differential relay configuration

The transformer winding voltage and connection are configured in the system configuration tab of the RTDS/RSCAD 87 protection function. A two winding 132/11kV YD transformer with the delta winding lagging the star winding is configured in Figure 5.6



Name	Description	Value	Unit	Min	Max
Bus1kV	Bus 1 Voltage / Winding 1	132.0	kV	1.0	1000.00
YD1	Winding #1 Connection	Y		0	1
Bus2kV	Bus 2 Voltage	230.0	kV	1.0	1000.00
XfmrWdg	Transformer Windings	2 wdg		0	1
XfmrkV	Transformer Bus Voltage / Winding 2	11.0	kV	1.0	1000.00
YD2	Winding #2 Connection	Delta		0	1
Xfmr3kV	Transformer Tertiary Bus Voltage / Winding 3	33.0	kV	1.0	1000.00
YD3	Winding #3 Connection	Delta		0	1
Lead	Delta lags or leads Y	Lags		0	1

Figure 5.6 RTDS Transformer differential protection relay configuration

The CT turns ratios is entered in the tabs for CT parameters. A ratio of 200/1 is used on the 132kV winding 1 and 2000/1 is used for the 11kV winding 2.

- **The minimum operating current setting.**

A low setting makes the differential relay sensitive for low fault currents. It should be high enough for the relay not to operate for normal conditions.

It was calculated previously that the value of the operating current was 0.175 Amp for a 40MVA load through the transformer. The minimum operating current is needed therefore to be above 0.175 for the differential relay not to trip under load conditions. A setting of 0.2 can be used to allow for a 10% overload on the transformer. Provision also needs to be made for current transformer measuring errors.

It was calculated that the operating current will increase to 0.23 amp for the condition where the maximum current is reached for a tap position where the transformer turns ratio is the lowest. The minimum operating current setting can be increased to make provision for this condition.

The relay lowest setting for minimum operating current is 0.25.

- **The Slope 1 setting**

The slope 1 setting can be used for the case where the currents flowing through the transformer are higher than the normal operating conditions, but the differential relay should not operate. The operating current required, for the differential relay to operate, when it is above the restraint current will increase using slope 1. The restrain current is therefore increased by the relay against the slope setting, as the current through the transformer is increasing. This slope 1 setting can be used to prevent a trip for the condition described in 5.3.1.2 to make provision for tap changers. The slope 1 setting is also used to for a condition described in 5.3.1.3 for through fault conditions where the fault is outside the protection zone. The setting range for slope 1 is between 5 and 50%. This principle is shown in Figure 5.7 below. When the retrain current is larger than 1 amp the operating current to operate the relay increases from the 0,3 A against the slope setting.

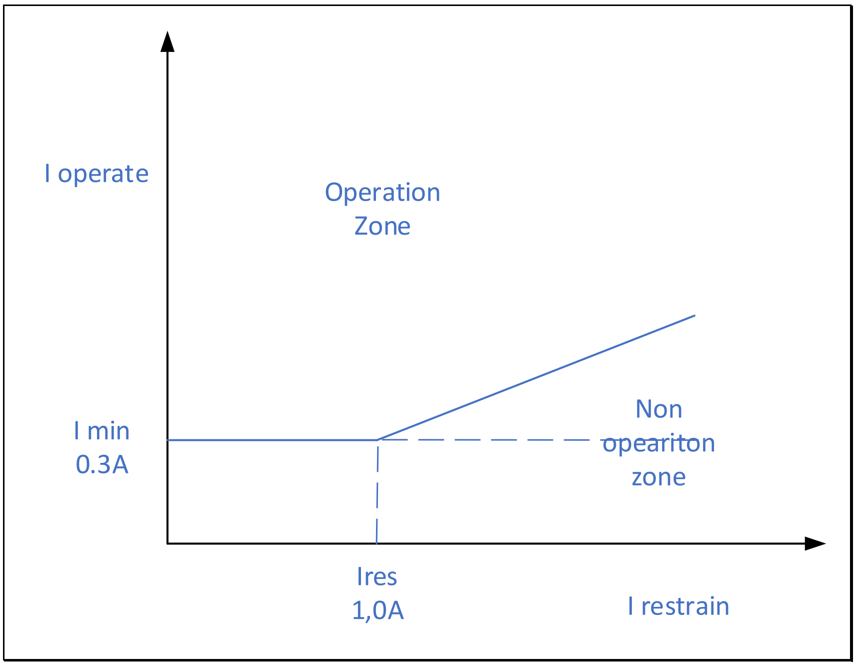
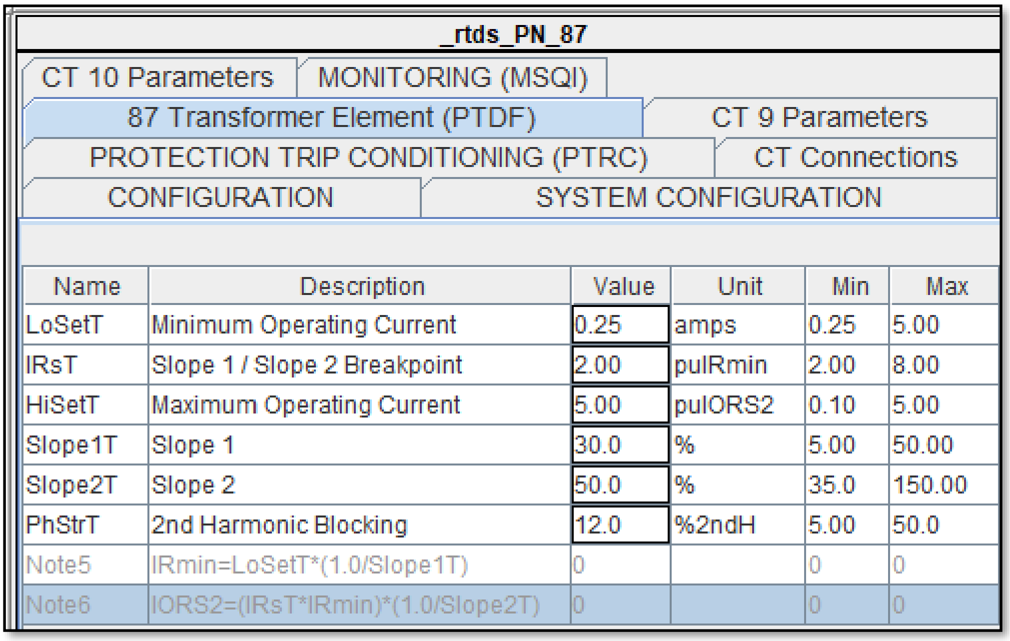


Figure 5.7 Differential function Slope 1algoritim

- **The Slope 2 setting**

Slope 2 is available as part of the differential algorithm to increase the restrain current even further. The operating current required for the relay to operate when it is above the restraint current will increase using slope 2 shown above in Figure 5.5. The slope 2 setting can be used for the case where the currents flowing through the transformer is much higher than the normal operating conditions, but the differential relay should not operate. Current transformers may saturate when high through faults flow through the transformers, but the fault is out of the protection zone. The operating current calculated may be above the restrain current calculated, but the relay should not operate for this condition. The restrain current can be further increased by slope 2 for higher restrain currents.

The settings for the 2-slope percentage differential protection function are entered in the 87 Transformer element tab shown in Figure 5.8.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CT 10 Parameters | MONITORING (MSQI) | 87 Transformer Element (PTDF) | CT 9 Parameters | PROTECTION TRIP CONDITIONING (PTRC) | CT Connections | CONFIGURATION | SYSTEM CONFIGURATION

Name	Description	Value	Unit	Min	Max
LoSetT	Minimum Operating Current	0.25	amps	0.25	5.00
IRsT	Slope 1 / Slope 2 Breakpoint	2.00	pulRmin	2.00	8.00
HiSetT	Maximum Operating Current	5.00	pulORS2	0.10	5.00
Slope1T	Slope 1	30.0	%	5.00	50.00
Slope2T	Slope 2	50.0	%	35.0	150.00
PhStrT	2nd Harmonic Blocking	12.0	%2ndH	5.00	50.0
Note5	IRmin=LoSetT*(1.0/Slope1T)	0		0	0
Note6	IORS2=(IRsT*IRmin)*(1.0/Slope2T)	0		0	0

Figure 5.8 RTDS Transformer differential (87) protection element settings

5.3.2 Over current protection function

The RTDS Over Current (O/C) protection function includes instantaneous phase (50P), instantaneous neutral (50N), time delayed phase (51P) and time delay neutral (51N) elements. The time delayed protection that operates against a curve where the tripping time depends on the magnitude of the fault current is not used as part of the design. It is slower because it is required to use time grading with other over current protection downstream.

Only the instantaneous 50P elements are configured to provide back-up protection. The operation starts as soon as the pickup current is reached. The definite current characteristic is shown in Figure 5.9. This is very fast protection to limit the damage in the transformer during short circuit currents. The grading with other downstream over current protection is done by using the different fault level as a result of different impedance values in the system.

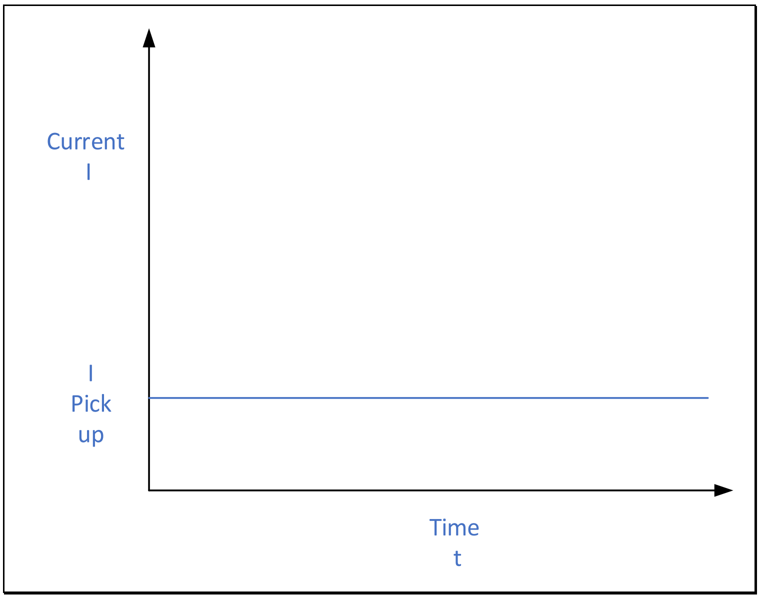
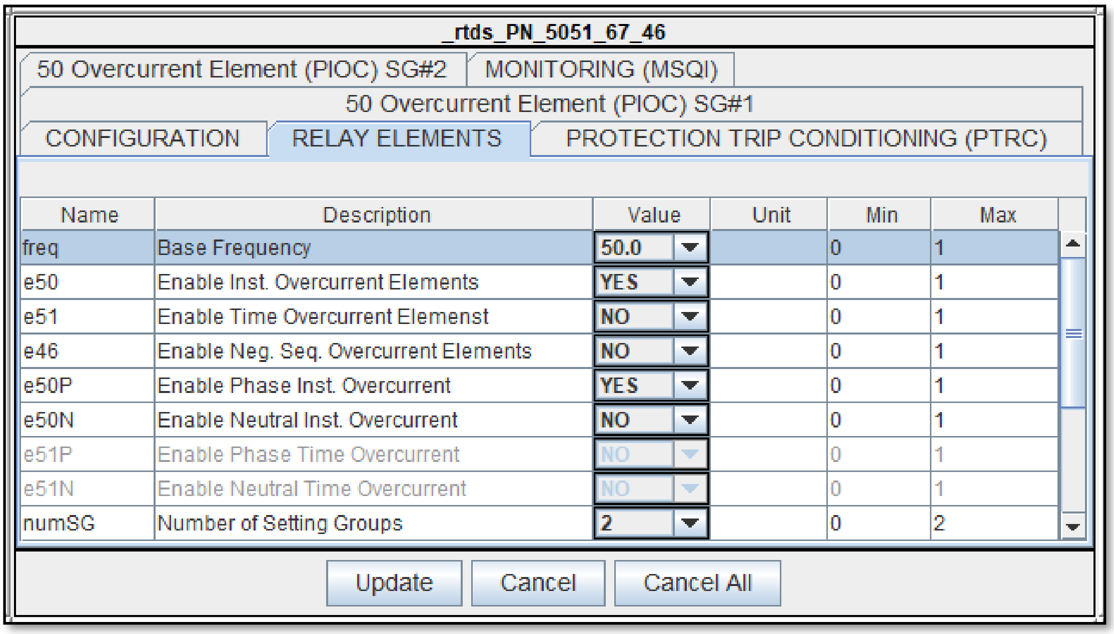


Figure 5.9 Definite -current characteristic of overcurrent relays

The over current is measured on the 132kV side of the transformer in Figure 5.3. The fault level at Fault 1 will be higher compared to this for Fault 2 due to the transformer impedance that is added to the source impedance. The relay can be set to only operate for faults at Fault 1 position. The configuration of the over current elements is shown in Figure 5.10.



Name	Description	Value	Unit	Min	Max
freq	Base Frequency	50.0		0	1
e50	Enable Inst. Overcurrent Elements	YES		0	1
e51	Enable Time Overcurrent Elemenst	NO		0	1
e46	Enable Neg. Seq. Overcurrent Elements	NO		0	1
e50P	Enable Phase Inst. Overcurrent	YES		0	1
e50N	Enable Neutral Inst. Overcurrent	NO		0	1
e51P	Enable Phase Time Overcurrent	NO		0	1
e51N	Enable Neutral Time Overcurrent	NO		0	1
numSG	Number of Setting Groups	2		0	2

Figure 5.10 RTDS instantaneous phase elements configuration

The magnitudes of the fault currents measured on the 132kV High Voltage (HV) of the power transformer with a YNd1 vector group is for a fault applied on the MV (11kV) side. The Current Transformers (CT) with a ratio of 200/1 is used and secondary currents are measured.

A single phase fault on the B-phase, phase to ground, is applied on the MV busbar. It can be seen in Figure 5.11 that a phase to ground fault on the Transformer MV side appears as a phase to phase fault on the HV side.

IBUR1ABC are A, B and C phase CT secondary currents measured on the HV side. The fault current for phase B is measured.

The fault is applied for the two cases where the Bus section circuit breaker is close, Figure 5.11 and open Figure 5.12.

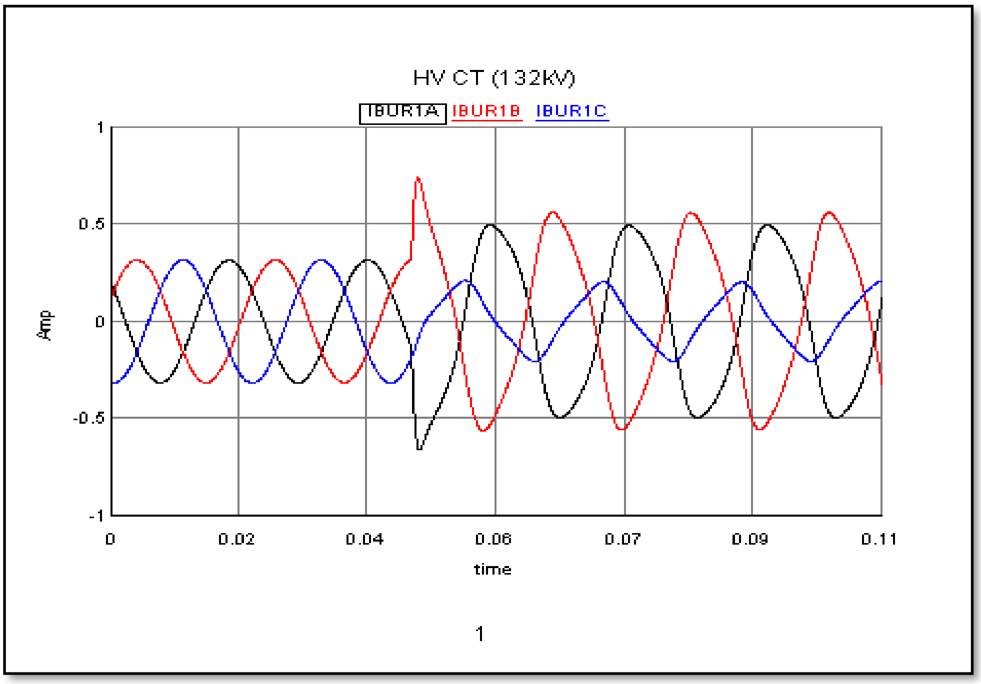


Figure 5.11 MV Fault case with Bus Section closed

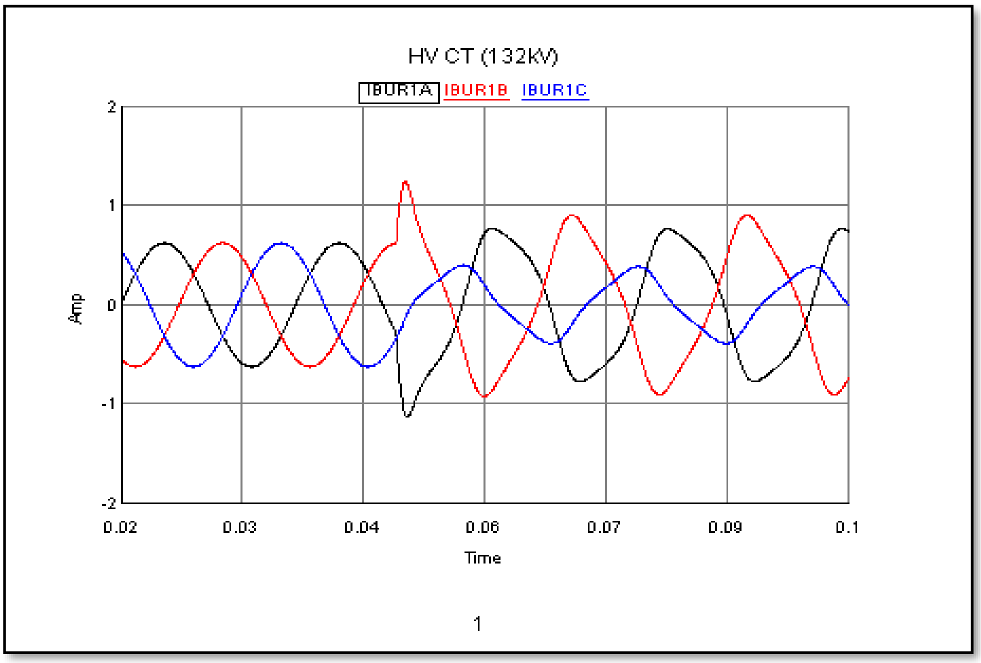


Figure 5.12 MV Fault case with Bus Section open

The over current instantaneous element must not issue a trip for these fault currents because the fault location is on the MV busbar.

The values for the fault and load currents changed for the two conditions where the Bus Section circuit breaker is in the closed and open positions. This is shown in Table 5-10.

Table 5-10 Currents for two cases of bus section open and closed

Fault current (A)	Load current (A)	Bus Section CB status
0,55	0,3	Closed
0,9	0,6	Open

Provision is made in the configuration for 2 setting groups for the overcurrent elements, which allows the function to switch to a new setting group via a control component.
The start value pickup setting (StrVal50P1) was set to 1,0 Amp for setting group 1. The StrVal50P2 was set to 0,7 Amp for setting group 2. The pickup setting for the instantaneous overcurrent element of setting group 2 is shown below in Figure 5.13

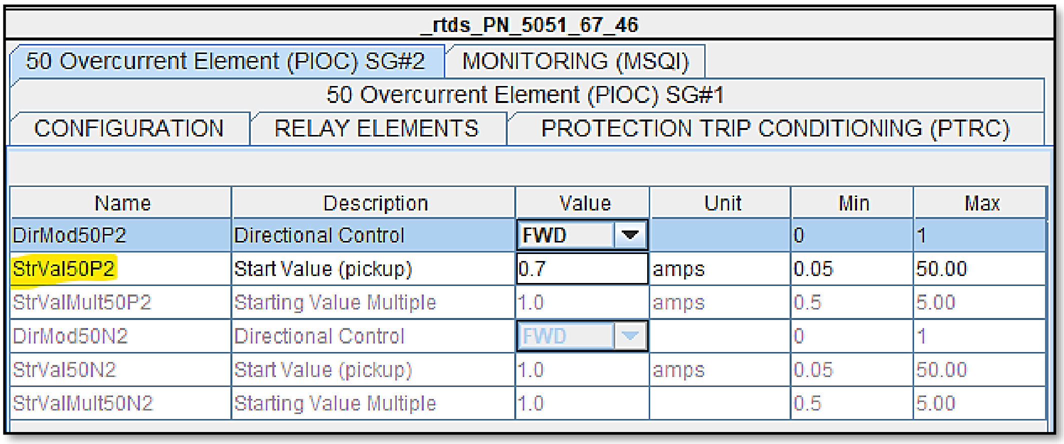


Figure 5.13 Setting group 2, start value pickup setting for the 50P element

5.3.3 Setting group selection

Power transformers will share the load when two transformers are connected in parallel. Considerer the Single Line Diagram of two parallel transformers in Figure 5.1. for the following two conditions as described in Table 5-11:

Table 5-11 System configuration changed for parallel transformers

Condition	Initial status	Changed status
Condition 1	TRFR1 & 2 in parallel	TRFR 2 taken out of operation
Condition 2	TRFR1 & 2 in parallel	TRFR1 & 2 not in parallel, BS1 breaker opened

Condition 1, the load current through Transformer 1 (TRFR1) will double when the circuit breakers of Transformer 2 (TRFR2), T2 CB1 & CB2 is opened or tripped. The protection of Transformer 1 (TRFR1) should be stable and not operate for this condition.

Condition 2, when the Bus Section 1 circuit breaker (BS1) is opened the fault level will change because the equivalent system impedance will change. This change is due to the impedances connected in parallel and series will be connected in a different way. Settings of protection relays is done using fault level values.

The settings of the protection for the transformer can be done using the worst case scenario or by having different setting groups. The advantage of different setting groups is that the protection settings can be set more sensitive.

The system configuration changes when the Bus Section 1 (BS1) circuit breaker or the Transformer 2 (TRFR2) circuit breaker is opened. The Setting group for the protection function is controlled with a logic diagram. Setting Group 1 is used if any of the TRFR2 11kV MV circuit breaker and the BS1 circuit breaker is opened. Setting Group 2 is used if both the TRFR2 11kV MV circuit breaker and the BS1 circuit breaker are closed. The setting group logic is shown below in Figure 5.14. BRKBS1 is the closed status of the bus section circuit breaker, BRK2 is the close status of the Transformer 2 11kV circuit breaker. SGR is a word bit control component input into the relay which allows the relay to switch to a new setting group. An integer value of 1 on the input will activate setting group 1, an integer value of 2 will activate setting group 2.

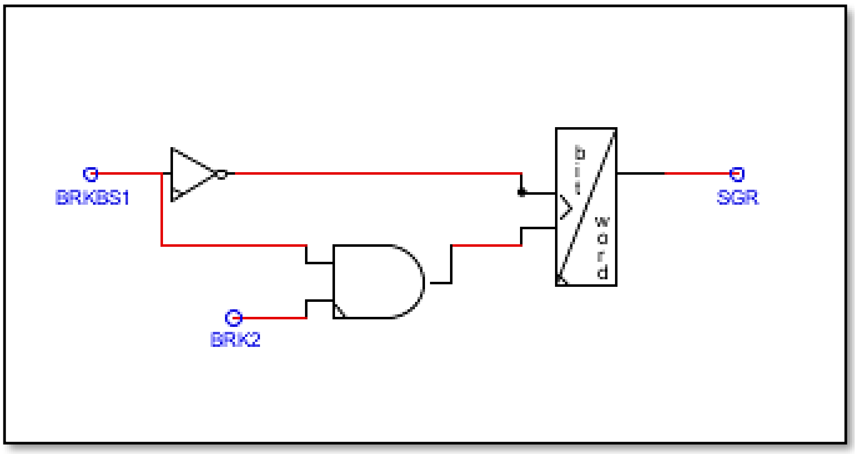


Figure 5.14 Setting group selection logic diagram

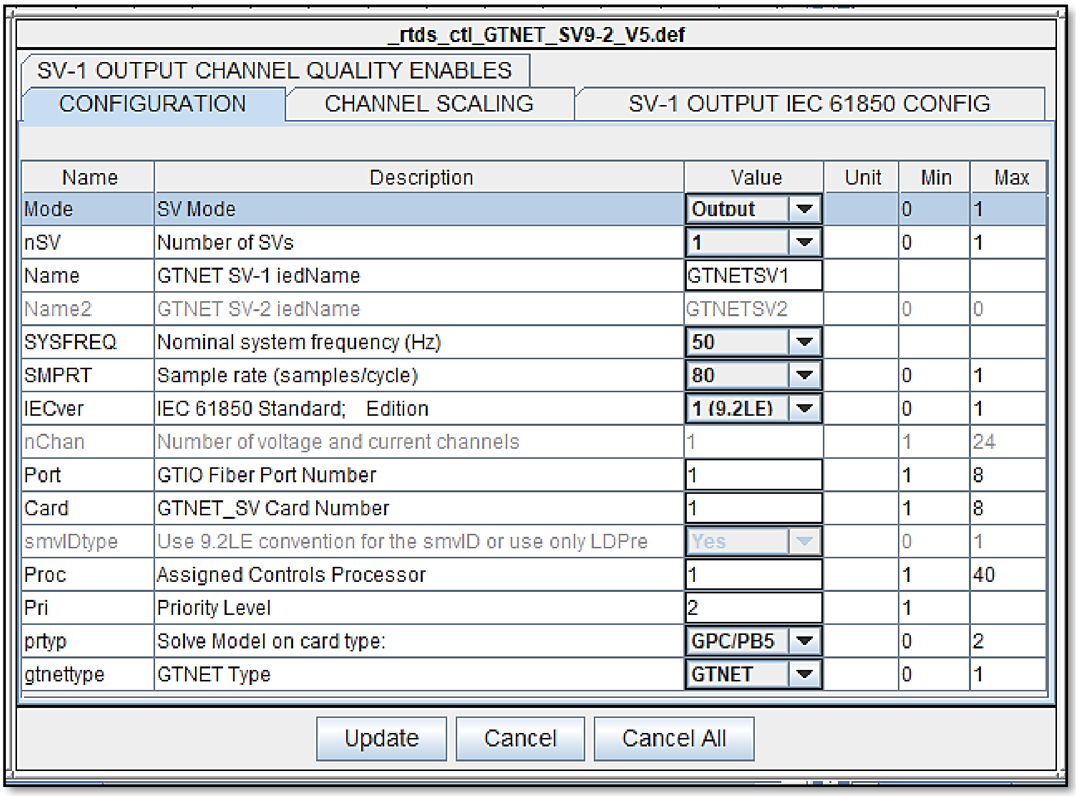
5.3.4 Sampled Values

The GTNET_SV9−2 component of the RSCAD software provides IEC 61850−9−2 Sampled Values communications to transmit or receive SV data streams. The GTNET_SV9−2 component has 2 configurations, the first is the 9.2LE implementation and the other is based on IEC 61869−9 Standard for SV merging units. The configuration window is shown below in Figure 5.15.

With the 9.2LE configuration up to two SV data streams for 4 current and 4 voltage channels at a rate of 80 samples/cycle, or one stream at 256 samples/cycle can be transmitted.

The GTNET_SV9−2 component can be configured to receive SV data from one Merging Unit for 4 currents and 4 voltages at either 80 or 256 samples/cycle. The voltage and current inputs to the GTNET−SV9−2_v5 component cannot be individually enabled or disabled. When a channel is not required, the input should be set to a value of “0” by using a constant.

The GTNET_SV9−2 component requires a synchronised time source to synchronize the SV timestamps to an external 1PPS (pulse−per−second) signal. The time signal is provided by the RTDS GTSYNC synchronization card.



_rtds_ctl_GTNET_SV9-2_V5.def

SV-1 OUTPUT CHANNEL QUALITY ENABLES | CONFIGURATION | CHANNEL SCALING | SV-1 OUTPUT IEC 61850 CONFIG

Name	Description	Value	Unit	Min	Max
Mode	SV Mode	Output		0	1
nSV	Number of SVs	1		0	1
Name	GTNET SV-1 iedName	GTNETSV1			
Name2	GTNET SV-2 iedName	GTNETSV2		0	0
SYSFREQ	Nominal system frequency (Hz)	50			
SMPRT	Sample rate (samples/cycle)	80		0	1
IECver	IEC 61850 Standard; Edition	1 (9.2LE)		0	1
nChan	Number of voltage and current channels	1		1	24
Port	GTIO Fiber Port Number	1		1	8
Card	GTNET_SV Card Number	1		1	8
smvIDtype	Use 9.2LE convention for the smvID or use only LDPre	Yes		0	1
Proc	Assigned Controls Processor	1		1	40
Pri	Priority Level	2		1	
prtyp	Solve Model on card type:	GPC/PB5		0	2
gtnettype	GTNET Type	GTNET		0	1

Update | Cancel | Cancel All

Figure 5.15 RTDS GTNET SV9-2 Configuration

The 9.2LE implementation used in the Draft simulation circuit to transmit and receive SV data streams is shown below in Figure 5.16. GTNET-SV1 is transmitting SV data and GTNET-SV is receiving SV data.

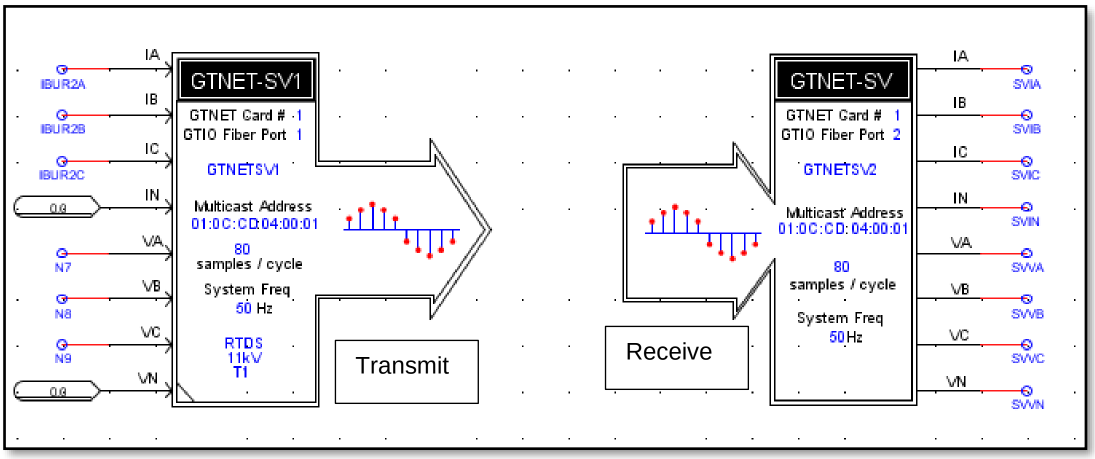
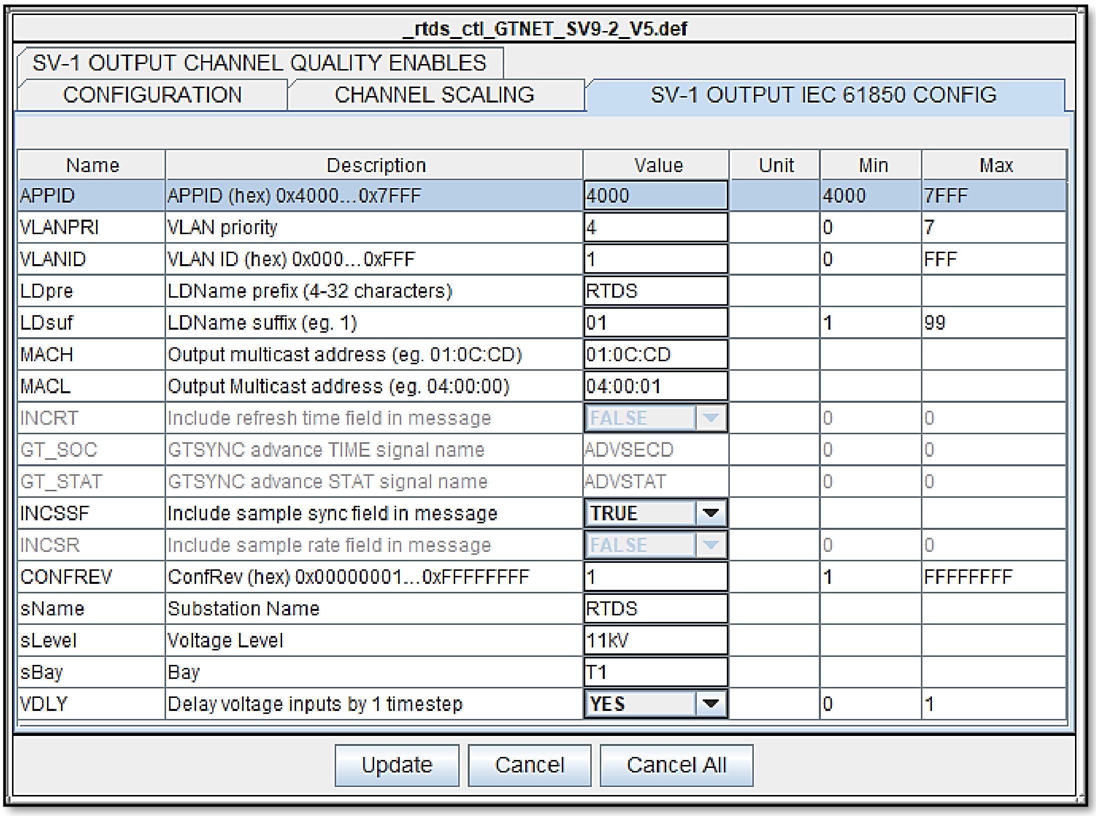


Figure 5.16 GTNET-SV Components

The sampled value output configuration for configuring the SV data to be transmitted on the Ethernet network is shown in Figure 5.17. The configuration is used to create the attribute Logical Device name (LDName). The VLAN priority and VLANID, multicast address can be configured.



_rtds_ctl_GTNET_SV9-2_V5.def

SV-1 OUTPUT CHANNEL QUALITY ENABLES

CONFIGURATION | CHANNEL SCALING | SV-1 OUTPUT IEC 61850 CONFIG

Name	Description	Value	Unit	Min	Max
APPID	APPID (hex) 0x4000...0x7FFF	4000		4000	7FFF
VLANPRI	VLAN priority	4		0	7
VLANID	VLAN ID (hex) 0x000...0xFFF	1		0	FFF
LDpre	LDName prefix (4-32 characters)	RTDS			
LDsuf	LDName suffix (eg. 1)	01		1	99
MACH	Output multicast address (eg. 01:0C:CD)	01:0C:CD			
MACL	Output Multicast address (eg. 04:00:00)	04:00:01			
INCRT	Include refresh time field in message	FALSE		0	0
GT_SOC	GTSYNC advance TIME signal name	ADVSECD		0	0
GT_STAT	GTSYNC advance STAT signal name	ADVSTAT		0	0
INCSSF	Include sample sync field in message	TRUE			
INCSR	Include sample rate field in message	FALSE		0	0
CONFREV	ConfRev (hex) 0x00000001...0xFFFFFFFF	1		1	FFFFFFFF
sName	Substation Name	RTDS			
sLevel	Voltage Level	11kV			
sBay	Bay	T1			
VDLY	Delay voltage inputs by 1 timestep	YES		0	1

Update | Cancel | Cancel All

Figure 5.17 GTNET SV9-2 OUTPUT Configuration

The LDName is configured by adding a user configurable prefix and suffix to the string "ppppMUss01" where "pppp" is the parameter "LDpre" and "ss" the parameter "LDsuf". RTDS was set for the LDName. Two SV streams can be configured. Prefix. 01 was set for parameter "LDsuf" for the first stream and 02 for the second stream. The string MU and 01/02 are fixed and cannot be changed by the user. The value 01 is used for 80 samples/cycle and 02 is used for 256 samples/cycle. The complete LNName configured is RTDSMU0101 for the first SV data stream and RTDSMU0201 for the second stream. The sample sync field is configured to be included in the message.

The output scaling needs to be configured as well. A scaling factor for the voltage and current channels is configured for kV and kA unit.

5.4 Running the Simulation in RSCAD Runtime

A system of two parallel power transformers, Single Line Diagram (SLD) for RunTime Case 2 is shown in Figure 5.18 below. A Circuit Breaker (CB) is indicated in the RSCAD/RunTime SLD with an interactive square symbol. A green square indicates a CB with an open status. A red square indicates a CB with a close status. The CB is operated by open and close push buttons.

A fault is applied with a push button. Two positions are simulated, Fault 1 on the 132kV side of Transformer 1(TRFR1), and Fault 2 on the 11kV side. The type of fault e.g. phase A to ground (Ia-g), can be selected with a dial switch.

Meters for megawatt (MVA) and kiloamp (kA) are monitoring the measurement values for the simulation Case 2.

Sliders are used to change the resistive and inductive values of the load.

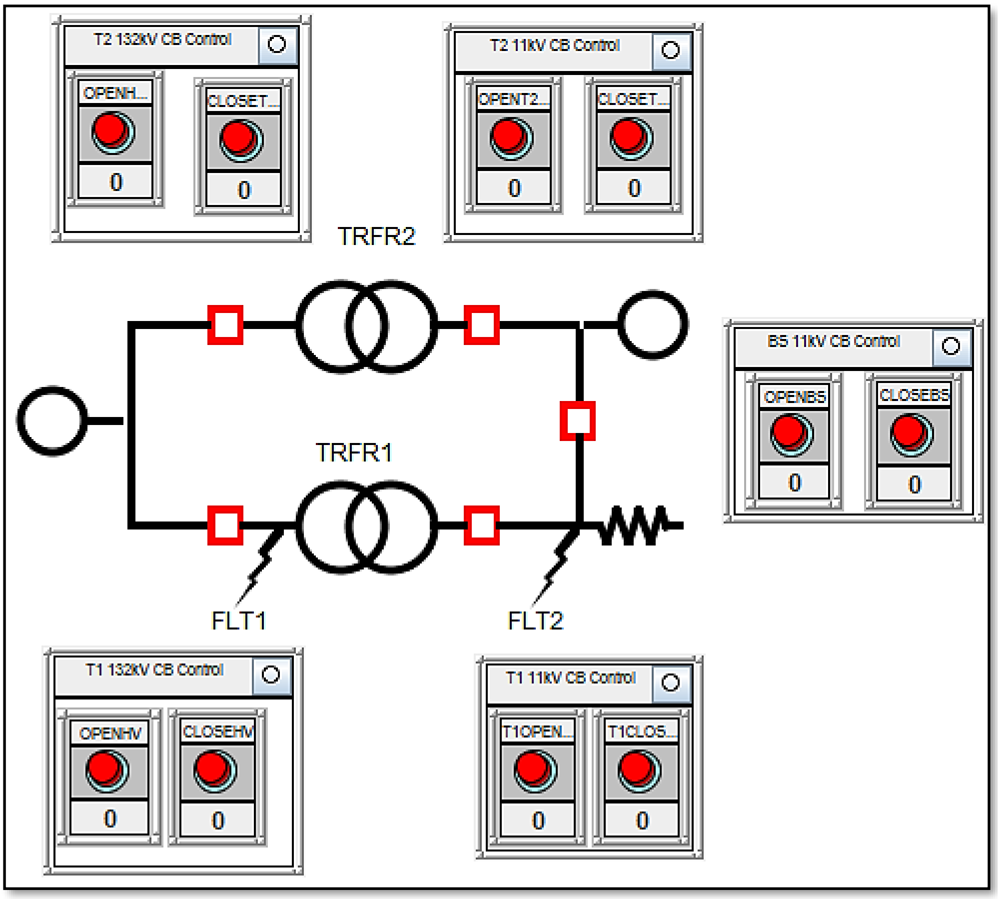


Figure 5.18 RTDS/RunTime SLD window for Case 2

The RTDS/RunTime current measurements for Transformer 1 is with a load of 21,11 MW connected to the system is shown in Figure 5.19. Only Transformer 1 is connected to supply the load.

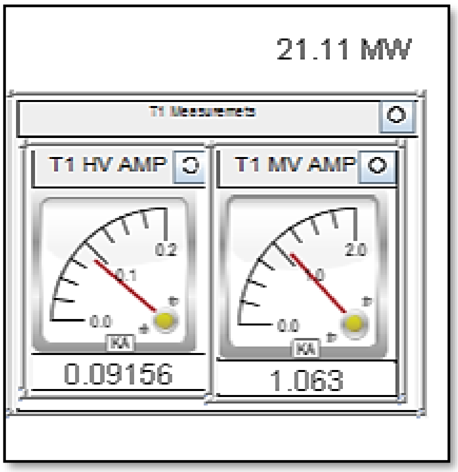


Figure 5.19 RTDS/RunTime Transformer 1 Measurements for Case 2

5.5 Simulation results

A Simulation is done to determine if the designed protection scheme operates correctly. Protection settings are adapted for different system configurations.

The following simulations are done:

- The RTDS/RSCAD software differential protection (87) function is tested,
- The RTDS/RSCAD software differential protection (87) and instantaneous phase over current (50P) functions are tested together,
- The analogue secondary output current produced by a Current Transformer (CT) is compared with the digital Sampled Value (SV) produced by the RTDS.

The following simulations will be done for Simulation Case 2, Table 5-12:

Table 5-12 Simulation Case 2

Case 2A	
Aim	Test Differential protection (87) relay
Method	1) Apply faults at positions in the protection zone (FLT1) and out of the protection zone (FLT2). 2) Disconnect TRFR 2 from the parallel system.
Expected result	1) The 87 Protection relay issues trip for faults in the protective zone, stays stable for faults out of the protective zone. 2) The load current through TRFR 1 increases, 87 protection stays stable and does not issue trip when TRFR 2 is disconnected from the system.
Case 2B	
Aim	Test Differential protection (87) relay and Instantaneous Over Current (50P) relay together

Method	1) Apply faults (FLT2) out of the protection zone with Bus Section closed 2) Apply faults (FLT2) out of the protection zone with Bus Section opened 3) Apply faults (FLT1) in the differential and over current protection zone.
Expected Result	Show that: 1) Different protection settings can be used for different system configurations. 2) Scheme with 87 and 50P protection operates correctly for fault in the protection zone.
Case 2C	
Aim	Test the IEC 61850−9−2 Sampled Values (SV) produced by the GTNET_SV9−2 component of the RSCAD software
Method	1) The analogue secondary output current produced by a Current Transformer (CT) is measured. 2) The digital Sampled Value (SV) message produced by the RTDS is measured. 3) The magnitude of the fault current is measured flowing through Transformer 1 (TRFR 1) when a fault is applied at the position 2 (Fault 2).
Expected Result	The analogue secondary output current produced by a Current Transformer (CT) compares with the digital Sampled Value (SV) produced by the RTDS.

The flow chart of testing the 87 function is shown in Figure 5.20. The position of Fault 1 (FLT1) is inside the protective zone. The protection must issue a trip signal for a fault at position 1 (FLT 1) on the 132kV HV side of TRFR1.

The position of Fault 2 (FLT2) is outside the protective zone. The protection must not issue a trip signal for a fault at position 2 (FLT 2) on the 11kV MV side of TRFR1.

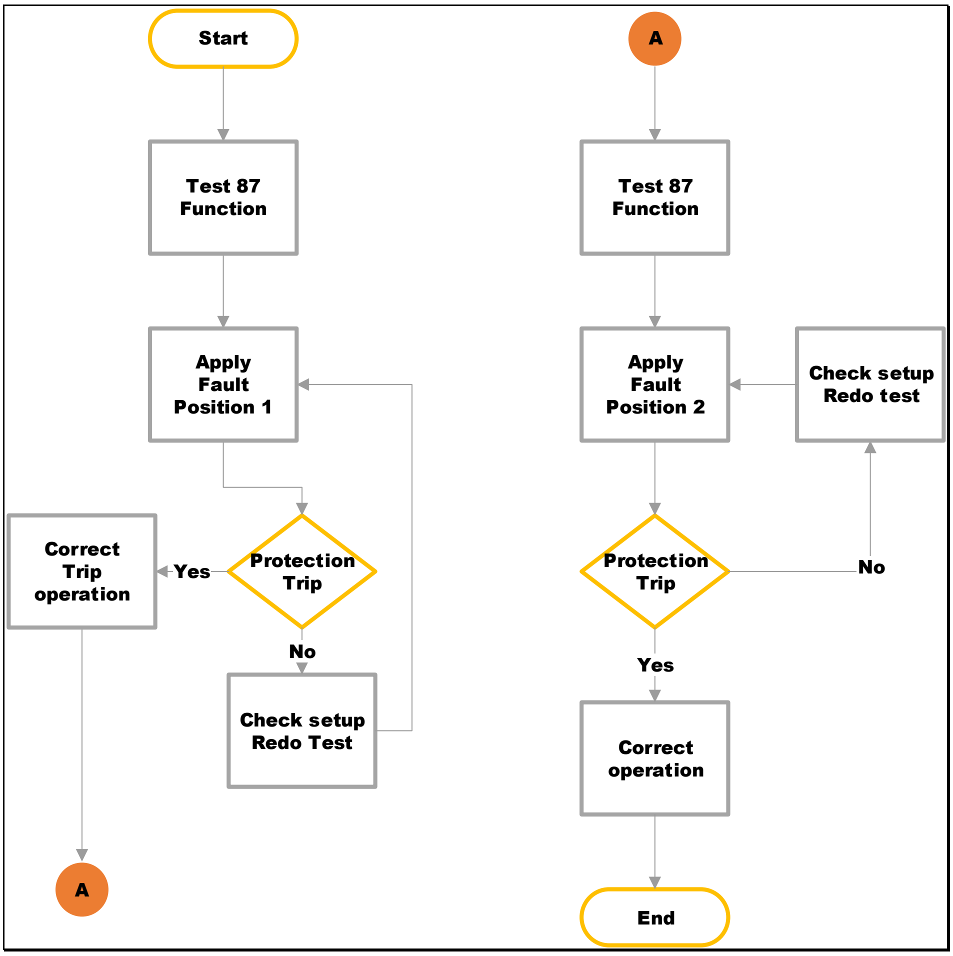


Figure 5.20 Testing flow chart of RTDS 87 function

5.5.1 Transformer 1 Differential Protection Case 2A

The RTDS differential protection (87) function of the simulated Case 2 is tested in Case 2A. The RTDS/RunTime single line diagram (SLD) is shown in Figure 5.21 below. The Transformer 1, HV and MV currents, are measured by the Differential (87) function when faults are applied at different positions.

Three simulations are done for the following cases:

- The first simulation is for a case where a fault (FLT1) is applied in the protective zone of Transformer 1
- The second simulation is for the case where a fault (FLT2) is applied out of the protective zone of Transformer 1
- The third simulation is for a case when initially the two transformers are in parallel connected and Transformer 2 is disconnected from the system.

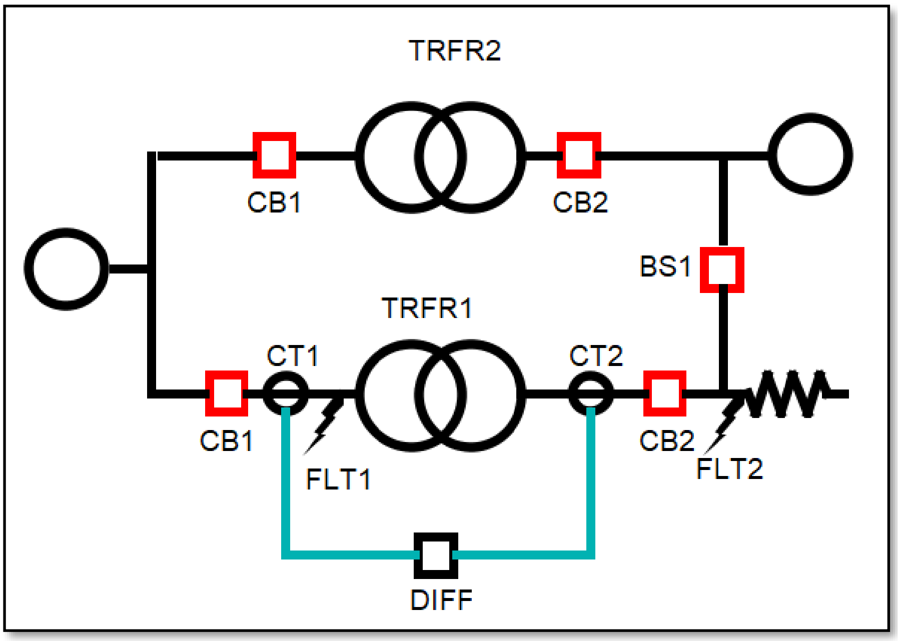


Figure 5.21 RTDS/Runtime SLD for Case 2A

5.5.1.1 Simulation case for a fault in the protective zone

A fault is applied at position 1 (FLT1) in the protection zone of the Differential protection. The following A-Phase currents are indicated on the plot for the 87 function shown in Figure 5.22 :.

- Transformer 1 A Phase Operating (T1AOP),
- Transformer 1 A Phase Restrain (T1ARS),
- Transformer 1 Minimum Operating current (IOMINT).

The closed status of the circuit breakers for the parallel transformers is also shown. BRK1 is the HV circuit breaker for Transformer 1, T2BKR1 is the HV circuit breaker for Transformer 2. This indicates the two transformers are connected in parallel.

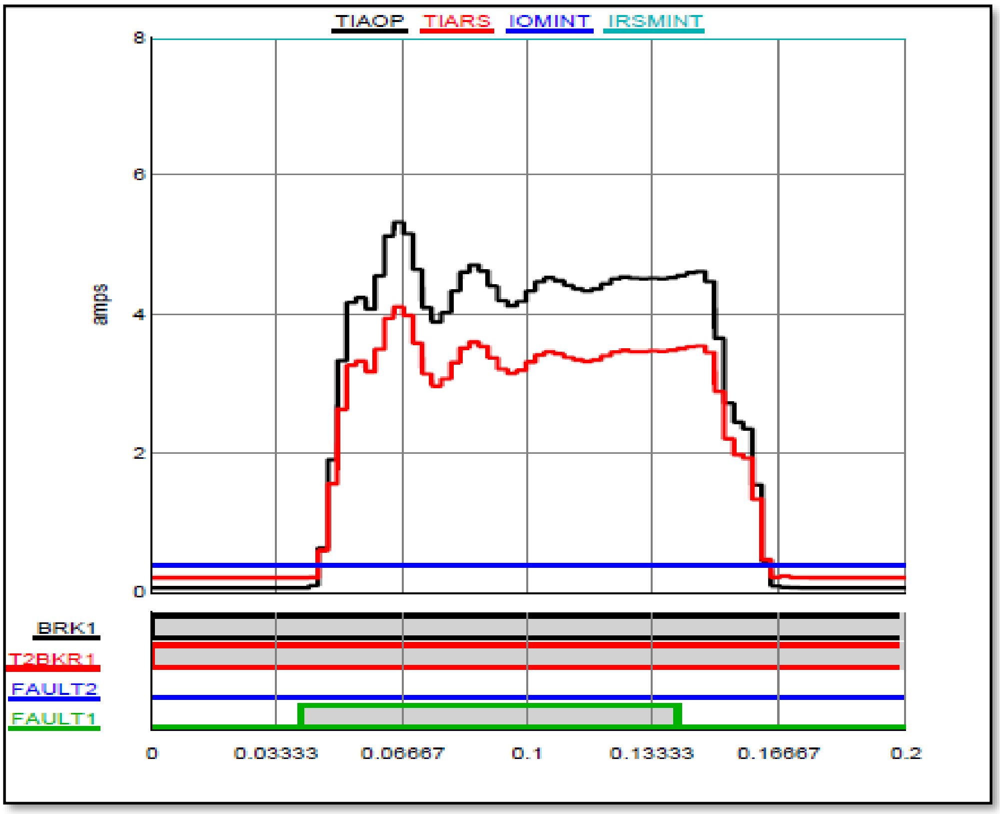


Figure 5.22 TRFR1 87 Fault 1 Case 2A

The operating quantity must be above the restraint current and minimum operating value (IOMIN) setting for the 87 protection function to operate and issue a trip signal.

The Fault position is in the protection zone and the current flowing into the differential zone is more than the current flowing out. It is shown in this simulation case that operating quantity is more than the restrain quantity for a fault in the protection zone.

5.5.1.2 Simulation case for a fault out of the protective zone

In Figure 5.23 below, the Fault 2 is applied outside the protective zone. The fault currents flowing into and out of the protective zone are the same and the restrain quantity increases as the fault current increases. The operating current is above the minimum operating setting but below the restraining quantity and the 87 Function will not issue a trip signal.

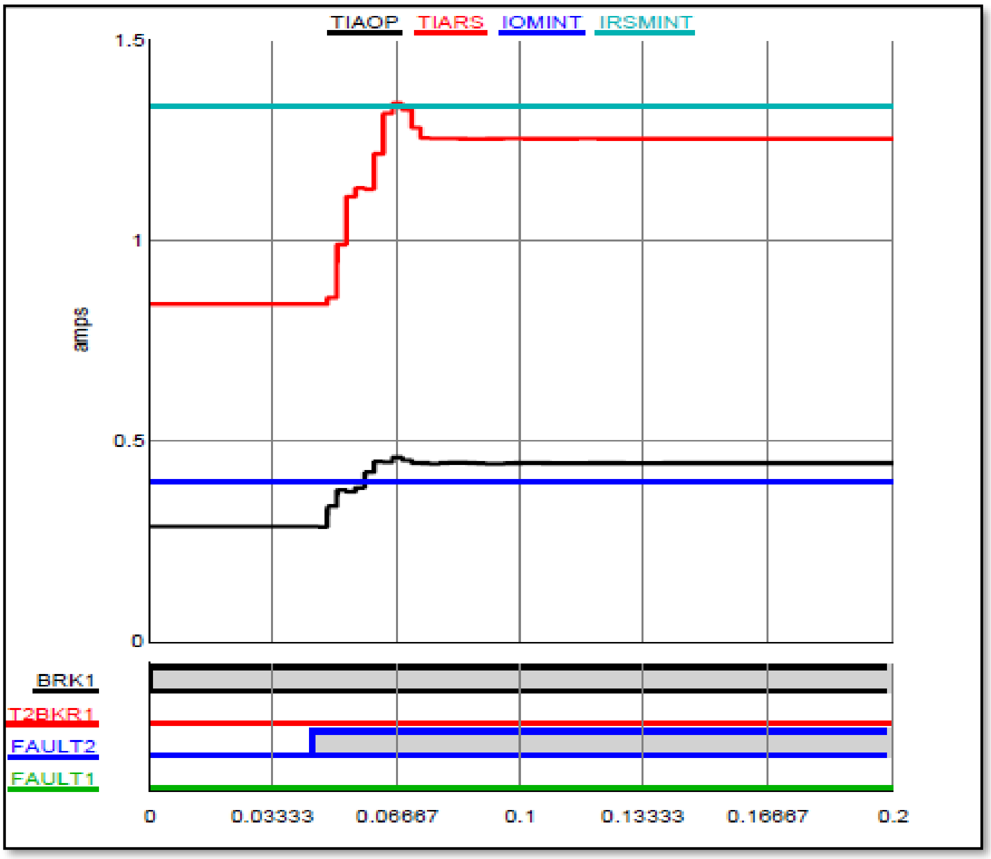


Figure 5.23 TRFR1 87 Fault 2 Case 2A

5.5.1.3 Simulation case for a change in load current

Transformer 1 and 2 are connected in parallel for the next simulation. The HV Breaker for Transformer 2 is opened. The load current will increase through Transformer 1 from sharing half of the load to supply the full load. The 87 protection function must not operate for this condition.

The simulation result is shown in Figure 5.24 below. The load currents flowing into and out of the protective zone are the same and the restrain quantity increases as the load current increases. The operating current is below the minimum operating setting and below the restraining quantity and the 87 function will not issue a trip signal.

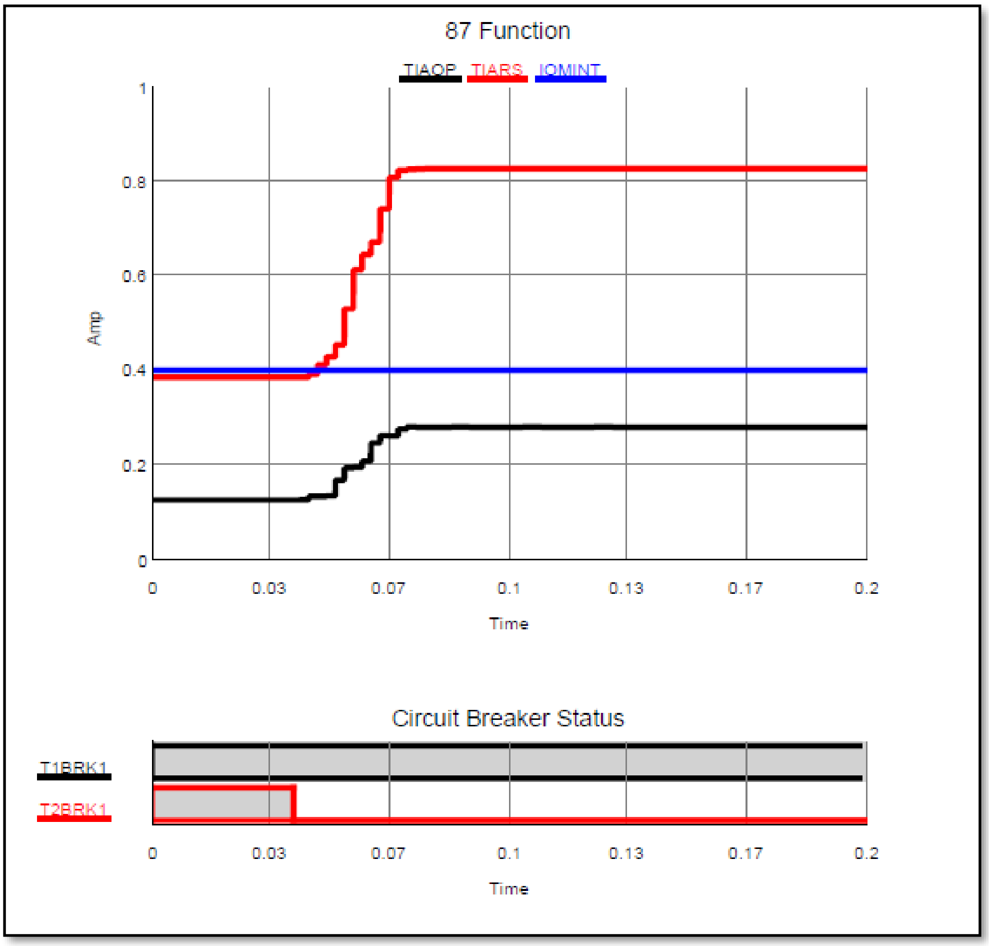


Figure 5.24 TRFR1 & 2 Parallel

5.5.2 Transformer 1 Differential and Over Current Protection Case 2B

The RTDS differential protection (87) and instantaneous phase over current (50P) functions of the simulated Case 2 is tested in Case 2B. The RTDS/RunTime single line diagram (SLD) is shown in Figure 5.25 below. The Transformer 1, HV and MV fault currents, are measured by the 87 and 50P functions.

Simulations are done for the following cases:

- Position 1 (Fault 1) is on the 132kV HV side of TRFR1 inside the protective zone.
- Position 2 (Fault 2) is on the 11kV MV side of TRFR1 outside the protective zone.
- Transformer 1 and 2 are connected in parallel. The system configuration is changed when the Bus Section 1 circuit breaker is opened and closed.

The magnitudes of the fault currents on the 132kV High Voltage (HV) side of the power transformer is measured using a current transformer with a ratio of 200/1.

Output 1 is a trip signal issued by the 87 protection function. Output 2 is a trip signal issued by the 50P function.

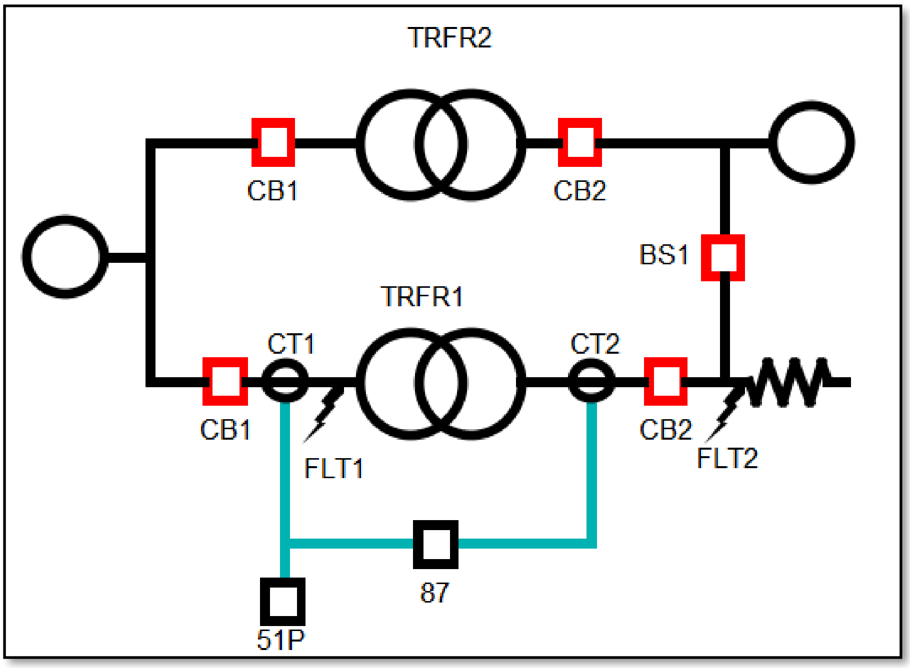


Figure 5.25 RTDS/Runtime SLD for Case 2B

5.5.2.1 Protection on-off logic

A Protection on-off logic is built in the RTDS/Draft and is shown below in Figure 5.26. This is to enable the measurement of the fault currents for a longer period. The protection is switched off and will not issue a trip to open the breaker that interrupts the fault.

The protection can be switched on (SWPROTON) to enable the issue of a trip signal. The trip signal will be blocked if the switch is off. OUT1 is a trip signal issued by the differential protection relay. OUT2 is a trip signal issued by the over current protection relay. TRIP is the output that trips the transformer circuit breakers. The TRIP can be reset by a push button.

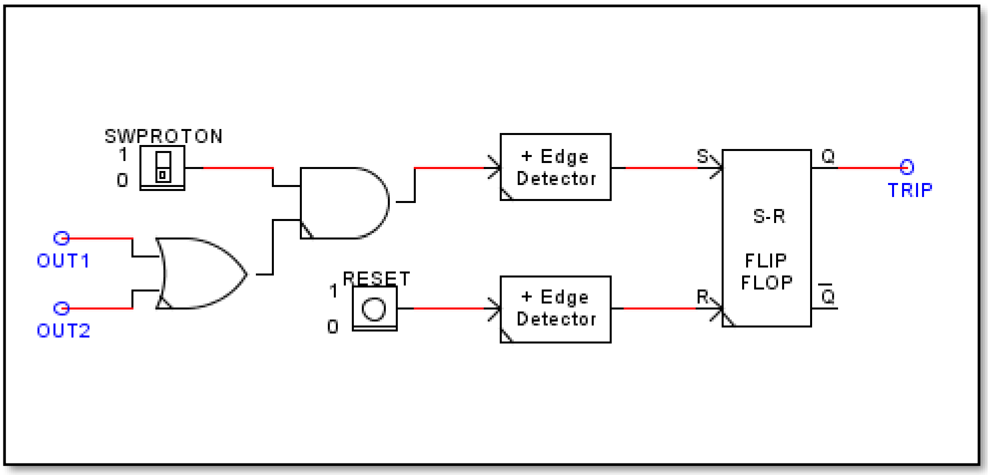


Figure 5.26 Protection switch logic to block protection functions issuing a trip

5.5.2.2 Simulation case for a fault out the protection zone, Bus Section Closed

A single phase fault on the A-phase, phase to ground fault, is applied at fault position 2 (ApplyGrFlt2) with Transformers 1 and 2 connected in parallel and the Bus Section 1 closed. The resulted fault current is shown below in Figure 5.27. IBUR1A, B and C are Current Transformer (CT) secondary currents measured on the Transformer 1 HV side. None of the 87 and 50P protection relays issue a trip signal because the fault is out of the protective zone. The protection is switched off (SWPROTON) to deactivate the issue of a trip signal.

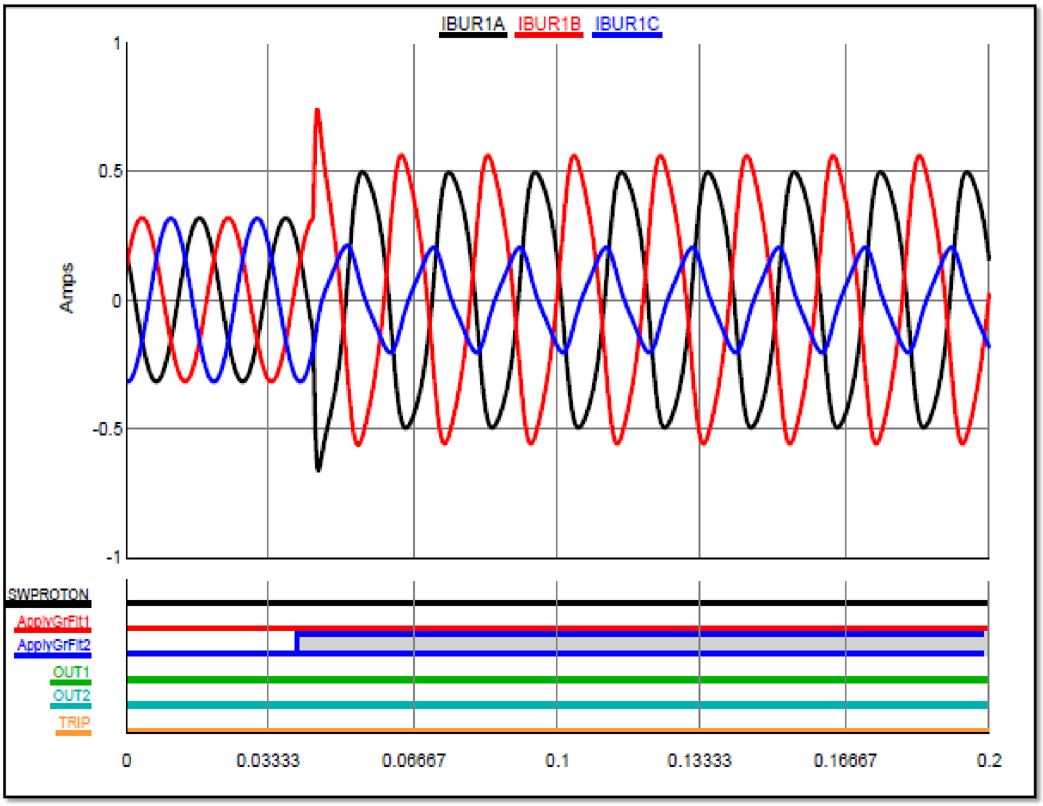


Figure 5.27 Fault currents for the case of TRFR1, BS1 Closed, Fault2

5.5.2.3 Simulation case for a fault out the protective zone, Bus Section open

A single phase fault on the A-phase, phase to ground fault, is applied at fault position 2 (ApplyGrFlt2) with Transformers 1 and 2 connected in parallel and the Bus Section 1 open. The resulted fault current is shown below in Figure 5.28. IBUR1ABC are Current Transformer (CT) secondary currents measured on the Transformer 1 HV side.

The magnitude of the fault currents is different for the different system configurations when the bus section circuit breaker is opened and closed with the same fault applied. Different settings are applied for the protection function when the system configuration changes.

None of the 87 and 50P protection relays issue a trip signal because the fault is out of the protective zone.

The protection is switched off (SWPROTON) to deactivate the issue of a trip signal.

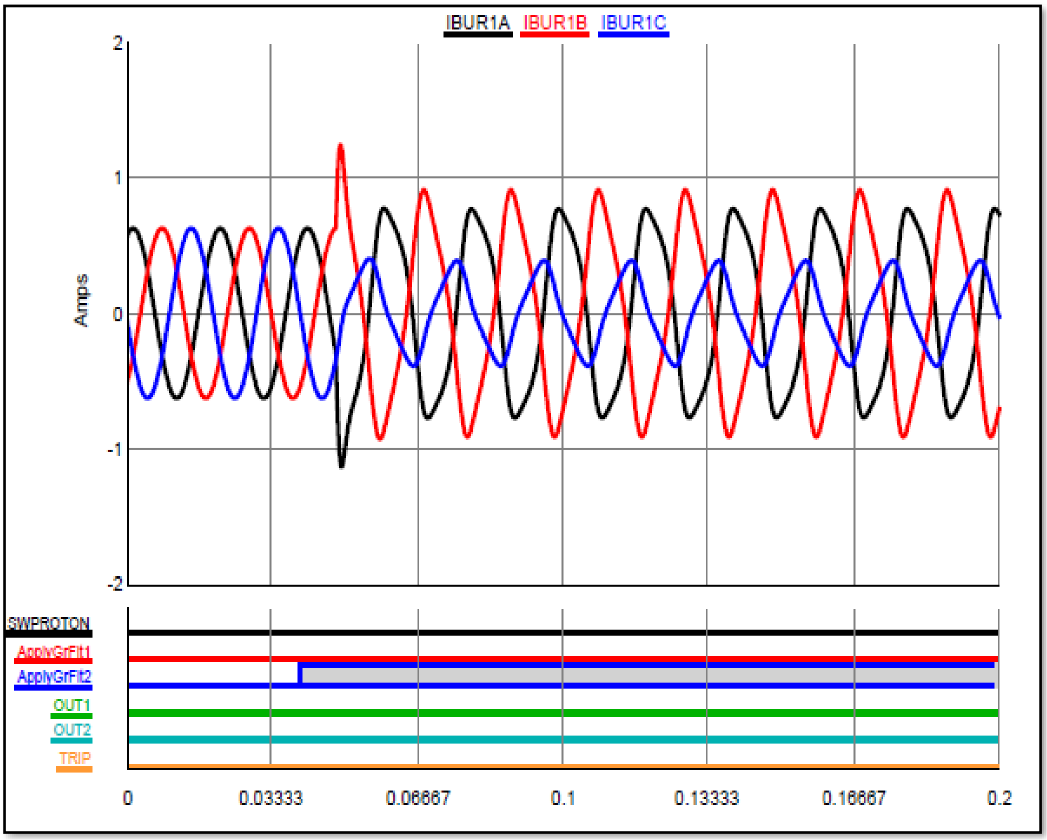


Figure 5.28 Fault currents for the case TRFR1, BS1 Opened, Fault2

5.5.2.4 Simulation case for a fault in the Differential & Over Current protective zone

A single phase fault on the A-phase, phase to ground, is applied at fault position 1 (ApplyGrFlt1) on the HV side of the transformer shown in Figure 5.29.

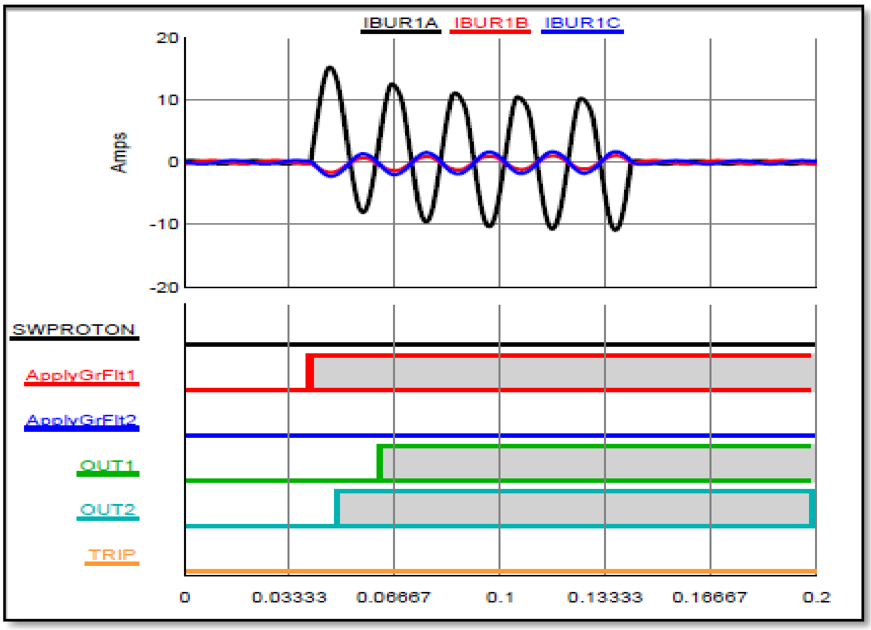


Figure 5.29 Fault current for the case TRFR1 with 87 & 50P functions, Fault 1

IBUR1A, B and C are Current Transformer (CT) secondary currents measured on the HV side. The protection is not switched on and the trip output is blocked to operate the Transformer 1 HV & MV circuit breakers. It is shown that the 50P function trip (OUT2) is faster than the 87 function trip (OUT1).

5.5.2.5 Simulation case for a fault in the Differential & Over Current protective zone with protection switched on

A single phase fault on the A-phase, phase to ground, is applied on the HV side of the transformer with the Protection switched on (SWPROTON) in Figure 5.30. The 50P function issue a trip before the 87 function for an in zone fault at fault postion1 (ApplyGrFlt1). The trip output from the protection scheme operates the Transformer 1 circuit breakers to clear the fault.

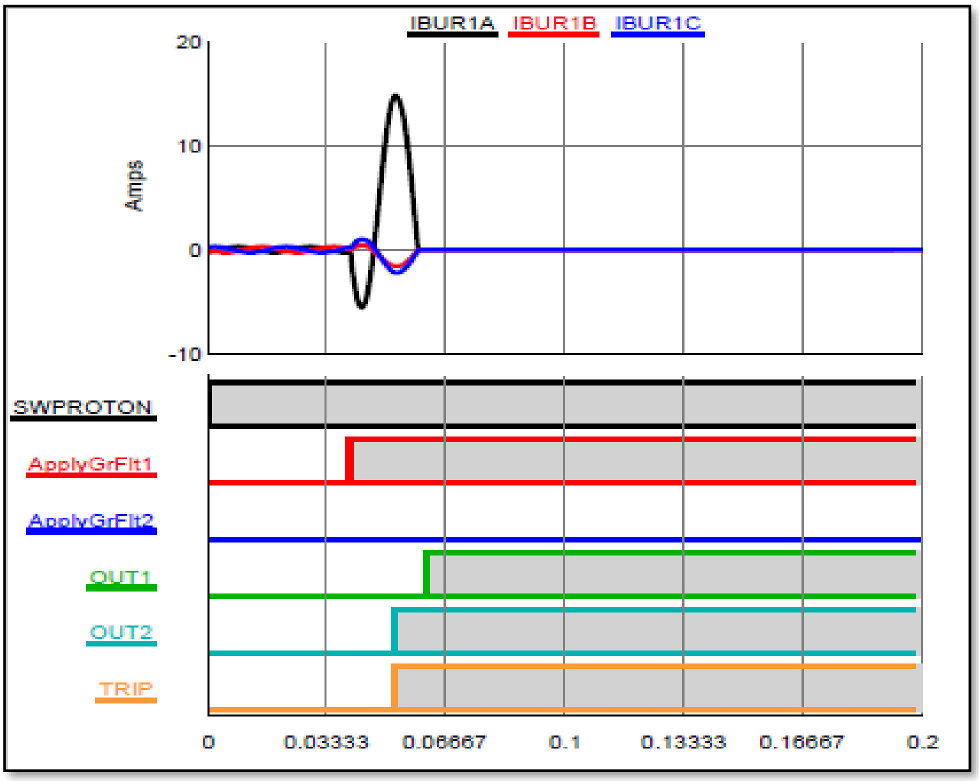


Figure 5.30 Fault currents for the case of TRFR1 with 87 & 50P functions, Fault 1, Protection on

5.5.3 Transformer 1 Sampled Value and Current Transformer Case 2C

The analogue secondary output current produced by a Current Transformer (CT) is compared with the digital Sampled Value (SV) produced by the RTDS in Case 2.

The SV current is sampled at 80 sampled per cycle according to IEC 61850-9-2 standard. The magnitude of the fault current is measured flowing through Transformer 1 (TRFR 1) when fault is applied at position 2 (Fault 2). A single phase fault on the A-phase, phase to ground, is applied on the MV 11kV side of the transformer.

The current IBUR2A is the A-Phase secondary side output current from the MV Side TRFR1 current transformer. SVIA is the A-Phase digitised Sampled Value (SV) current value for current for the MV side TRFR1 current. The MV side currents of the transformer 1, is shown in Figure 5.31 when a Fault 2 is applied, the analogue CT current is compared to the digitised SV current.

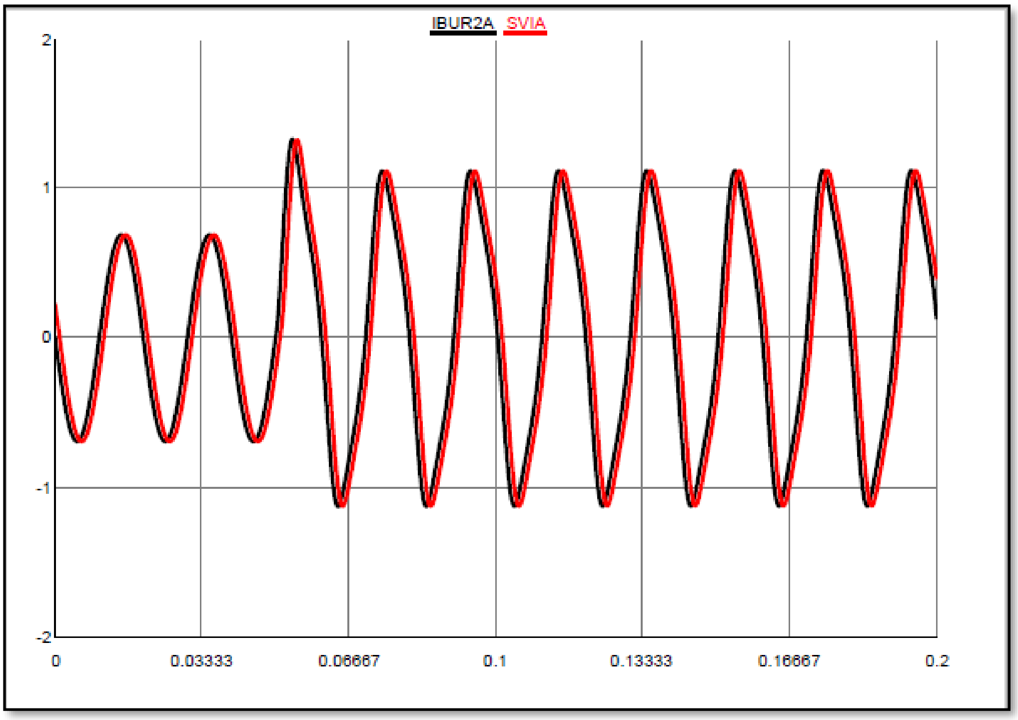


Figure 5.31 TRFR 1 Fault, CT compared with SV

5.6 Discussion

A Protection scheme for a system of parallel 40MVA 132/11kV YNd1 power transformers is designed, modelled and simulated in the Real-Time Digital Simulator (RTDS) for the simulation Case 2.

Differential protection as main protection and instantaneous overcurrent as backup protection is used for the transformer protection scheme.

The following results are obtained and shown in Table 5-13.

Table 5-13 Results for Simulation Case 2

Case 2A	
Aim	Test Differential protection (87) relay
Method	1) Apply faults for cases of fault positions in the protection zone (FLT1), and out of the protection zone (FLT2), 2) Disconnect TRFR 2 from parallel system.
Results	1) The 87 Protection relay issues a trip correctly for faults in the protective zone, stays stable for faults out of the protective zone.

	2) The 87 protection stays stable and does not issue trip when TRFR 2 is disconnected from the system.
Case 2B	
Aim	Test Differential protection (87) relay and Instantaneous Over Current (50P) relay together
Results	Show that: 1) Different protection settings are used for different system configurations. The protection scheme operates correctly. 2) Scheme with 87 and 50P protection operates correctly for fault in the protection zone.
Case 2C	
Aim	Test the IEC 61850−9−2 Sampled Values (SV) produced by the GTNET_SV9−2 component of the RSCAD software
Result	The analogue secondary output current produced by a Current Transformer (CT) is the same as the digital Sampled Value (SV) produced by the RTDS.

Faults are applied to the 132kV high voltage side and 11kV medium voltage side of the system of power transformers. The differential and instantaneous over current protection functions operate correctly for faults in the protection zone.

The 11kV bus bar has one Bus Section that is opened and closed to simulate a system configuration change. Two different setting groups are automatically selected depending on the status of the Bus Section (BS) and Transformer circuit breakers. The protection functions correctly operate and does not operate for the case where the Transformer 2 is disconnected from the system of parallel power transformers.

The analogue secondary output current produced by a Current Transformer (CT) is the same as the digital Sampled Value (SV) produced by the RTDS.

5.7 Conclusion

In this chapter, the power system for two 40MVA 132/11kV YNd1 paralleled power transformers is modelled, simulated and tested in the Real-Time Digital Simulator (RTDS).

The configuration of the RTDS RSCAD software differential protection function, overcurrent protection function and IEC 61850 -9-2 LE sampled values are shown.

The protection system simulation results show that:

- The designed protection scheme operates correctly as required.

- The power transformer protection settings can successfully be adapted when the system configuration for parallel power transformers is changed.
- Digital Sampled Value (SV) were successfully produced by the RTDS.

The tap change controller design for the system of parallel power transformers is discussed in the next chapter.

6 CHAPTER SIX

CONTROLER DESIGN OF THE TAP CHANGERS FOR THE SYSTEM OF PARALLEL POWER TRANSFORMERS

6.1 Introduction

An automatic tap changer controller for a system of parallel power transformers is designed, simulated, tested and discussed in the chapter.

A Master-Follower scheme for parallel tap changer controllers is designed and built with a logic circuit in the RTDS/RSCAD software. The one tap changer controller is the Master and the other tap changer controller will follow the master's operations when two transformers are parallelly connected. Each controller will control its own tap changer when the transformers are not connected in parallel.

A system of two parallel 40MVA 132/11kV YNd1 power transformers is designed, modelled and simulated in the Real-Time Digital Simulator (RTDS) for the simulation Case 3. The system has a source connected to the 132kV bus bar. The 11kV bus bar has one Bus Section and two 11kV loads connected to the 11kV bus bar sections. The RTDS/RunTime model of the simulation Case 3, the system of parallel power transformers is shown in Figure 6.1 in a Single Line Diagram (SLD).

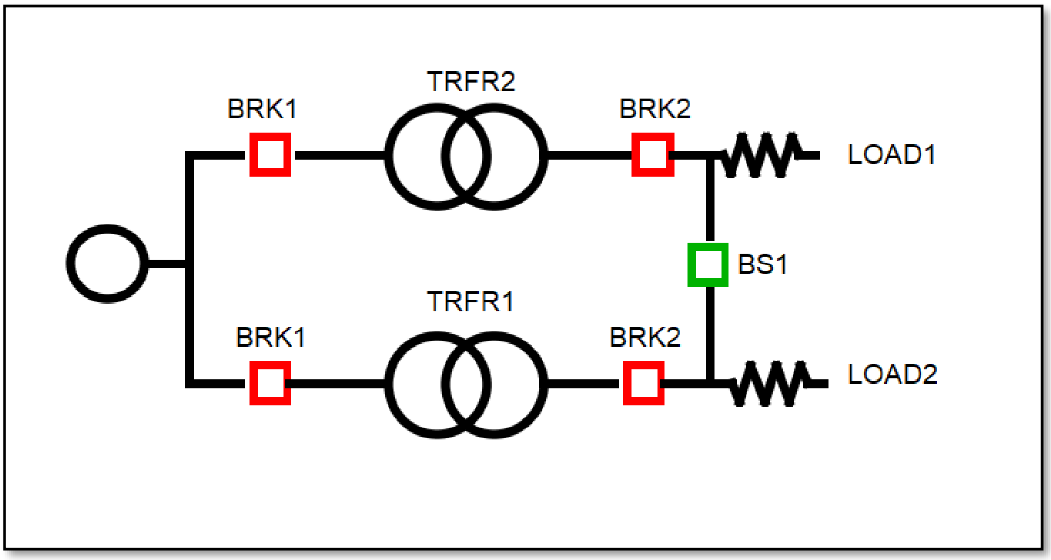


Figure 6.1 RTDS/Runtime Tap Changer Control Case 3

The RTDS/RSCAD tap changer model is used to control the transformer on load tap changer. The model can be selected to operate in a manual or automatic mode. The controller changes the transformer tap positions to regulate the bus bar voltage. The algorithm of the tap changer model is explained in 6.2.1. The configuration of the RTDS tap changer control is discussed in section 6.3.

The Master-Follower tap changer controller scheme design and logic circuit is considered in section 6.2.2. The scheme is automatic and depends on the status of the Bus Section (BS) and Transformer MV circuit breakers.

RSCAD/RunTime is used to control the simulation case being performed on the RTDS hardware. The Simulations are discussed in section 6.4. Circuit breaker operation and the tap changer control for the power circuit are performed through the RunTime Operator's Console. The simulation results are shown in section 6.5 and discussed in section 6.6.

6.2 Transformer tap changer controller design

An automatic tap changer controller for a system of parallel power transformers is designed. The controller can operate in the following modes:

- Manual or Automatic
- Master or Follower

The controller is designed and modelled in the RTDS/RSCAD software.

6.2.1 RTDS/RSCAD Transformer tap changer controller

The RTDS/RSCAD tap changer control model is shown in Figure 6.2.

The tap changer controller regulates the measured voltage and automatically adjusts the tap position of the transformer On Load Tap Changer (OLTC) to keep the measured voltage at the specified setpoint. The measured voltage (Va) as input is compared to the voltage setpoint parameter. The controller operates the OLTC when the voltage deviation between the measured and setpoint is greater than the deviation parameter. The tap changer controller raises the measured voltage with output (up) and lowers the voltage with output (dn) by selecting the different taps in the transformer model. The tap changer controller uses tap position indication input (pos) from the transformer model.

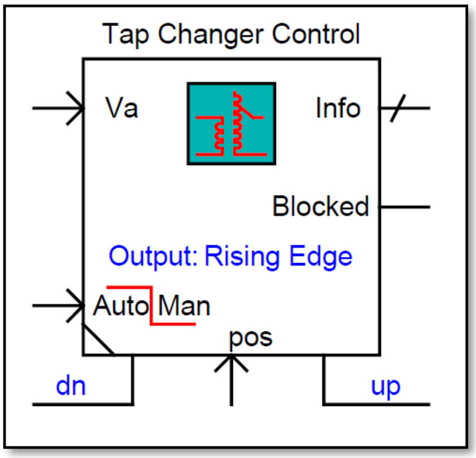


Figure 6.2 RTDS/RSCAD Tap Changer control model

Automatic or Manual mode selection is done with an input to the controller. The controller operates the OLTC when an automatic mode selected considering the measured voltage and the set point parameter. Push buttons inputs are used to control the OLTC when manual mode is selected. The flow chart to describe the algorithm is shown in Figure 6.3.

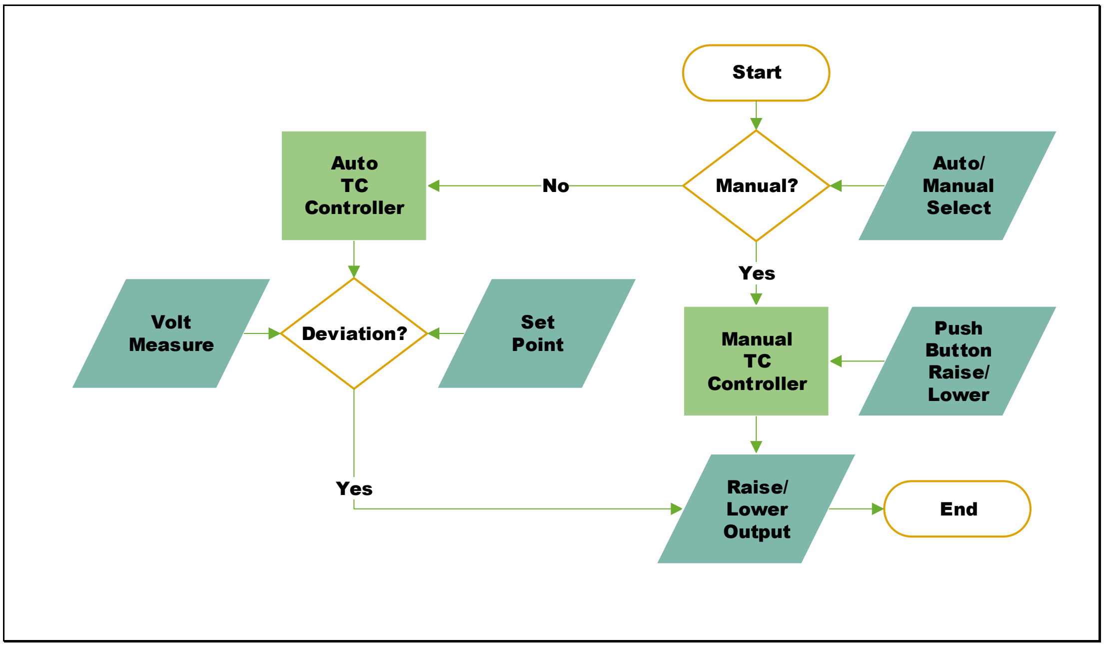


Figure 6.3 Auto/Manual Tap changer controller flow chart

6.2.2 RTDS/RSCAD Transformer tap changer controller for parallel transformers

A tap changer controller scheme is required for transformers operating parallelly. The RTDS/RSCAD scheme discussed in section 6.2.1 is modified to make provision for two transformers operating parallelly. A flow chart is shown in Figure 6.4 for the designed parallel transformer tap changer controller.

Each transformer Tap Change (TC) controller can be selected to operate in a manual or an automatic mode.

The Transformer 1 (T1) tap changer control is the Master and the Transformer 2 (T2) tap changer control will follow the master's operations when two transformers are parallel connected.

Each controller will control its own tap changer when the transformers are individually connected and in automatic mode.

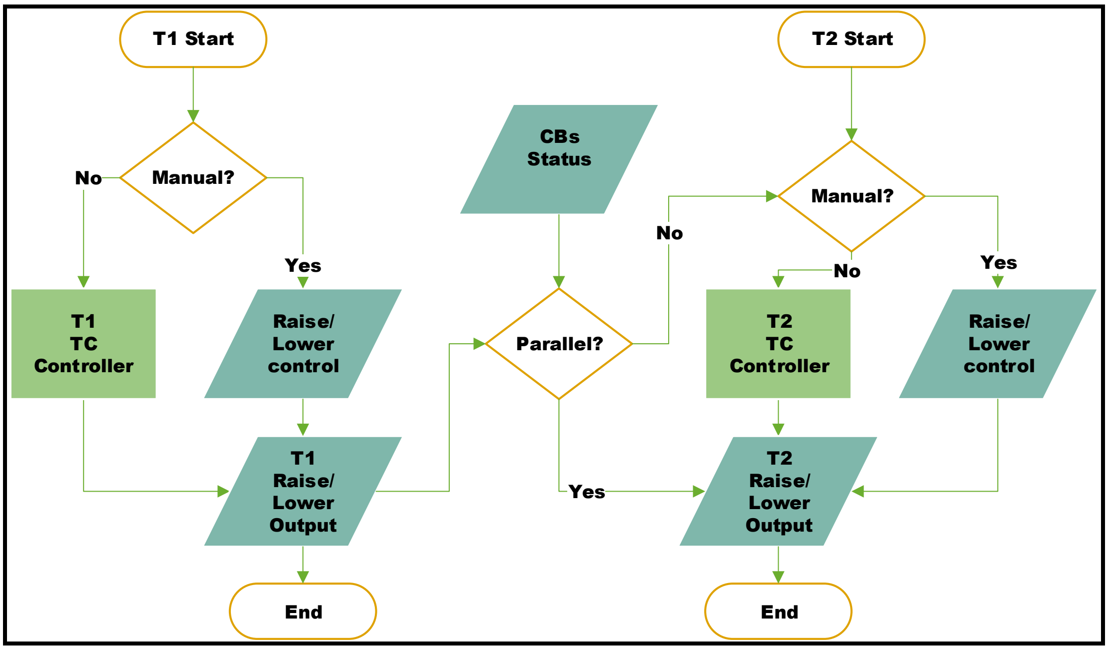


Figure 6.4 Master-Follower Tap changer controller flow chart

6.3 Configuration of RTDS control models

The RTDS/RSCAD simulation circuit that includes the Tap Changer control model is shown in Figure 6.5. The standard model is discussed above in section 6.2.1. The tap changer controller raises the busbar voltage with output (T2TCUP) and lowers the voltage with output (T2TCDN) by selecting the different taps in the transformer model. The tap changer controller uses tap position indications input from the transformer model and voltage value input from the 11 kV bus (N14).

The transformer OLTC raise action is realised with an Up input (T2UP) and the lower action with a Down input (T2DN).

The block (i) T2 TC CONTROL in the figure contains the logic circuit for the Master-Follower tap changer controller scheme that determine if the transformers are connected parallely or individually by monitoring the status of circuit breakers. This is discussed in 6.3.2.

The control blocks (ii and iii) T2_BREAKER_HV and T2_BREAKER_MV in the figure contains the logic circuits to control the High Voltage (HV) and Medium Voltage (MV) circuit breakers of Transformer 2 (T2).

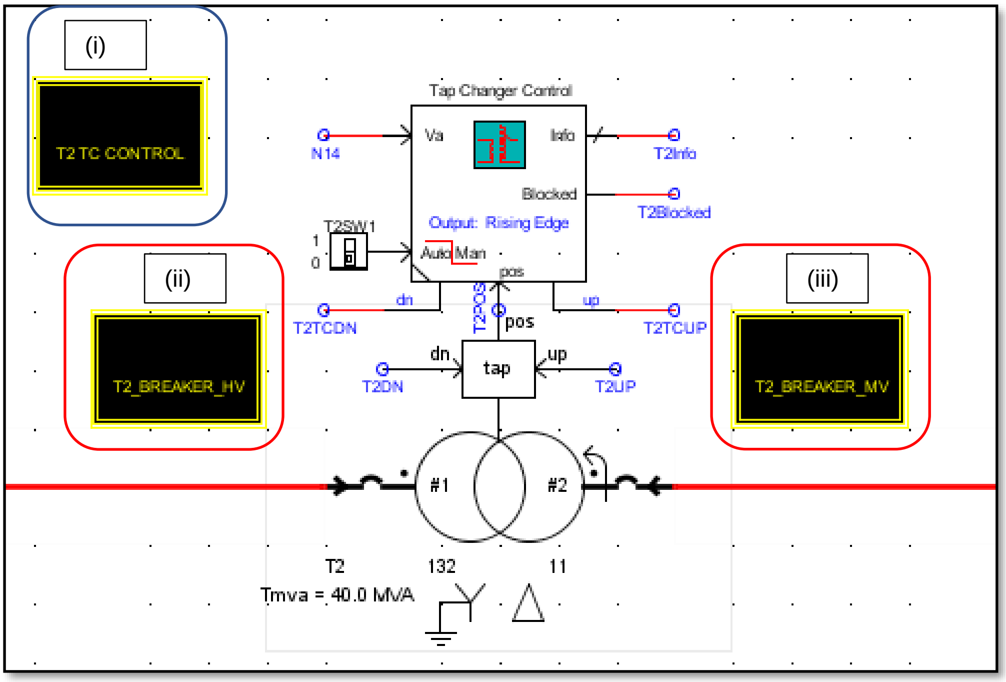


Figure 6.5 RTDS Tap Changer Controller for Transformer 2

The logic circuit of T2_BREAKER_MV is shown in Figure 6.6 . Control push buttons are used to open and close the breaker T2BKR2 which is the MV circuit breaker of Transformer 2.

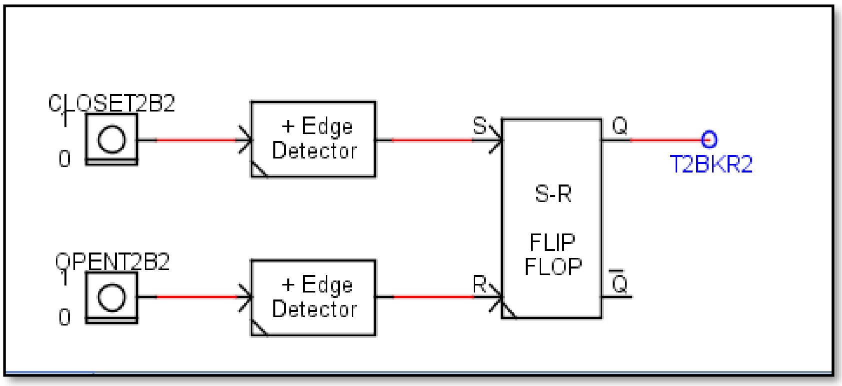


Figure 6.6 Circuit breaker control logic for T2_BREAKER_MV.

6.3.1 Tap change controller

The RTDS/RSCAD software tap changer controller provides control of the 40MVA power transformer with On Load Tap Changers (OLTC).

Load current compensation is configurable. A compensation voltage is added to the voltage setpoint before the voltage deviation is calculated. The compensation voltage is calculated by multiplying a compensated constant with the per unit load current.

Under and over voltage, and over current blocking functions are available but not used in this simulation. The tap change controller model configuration is shown in Figure 6.7.

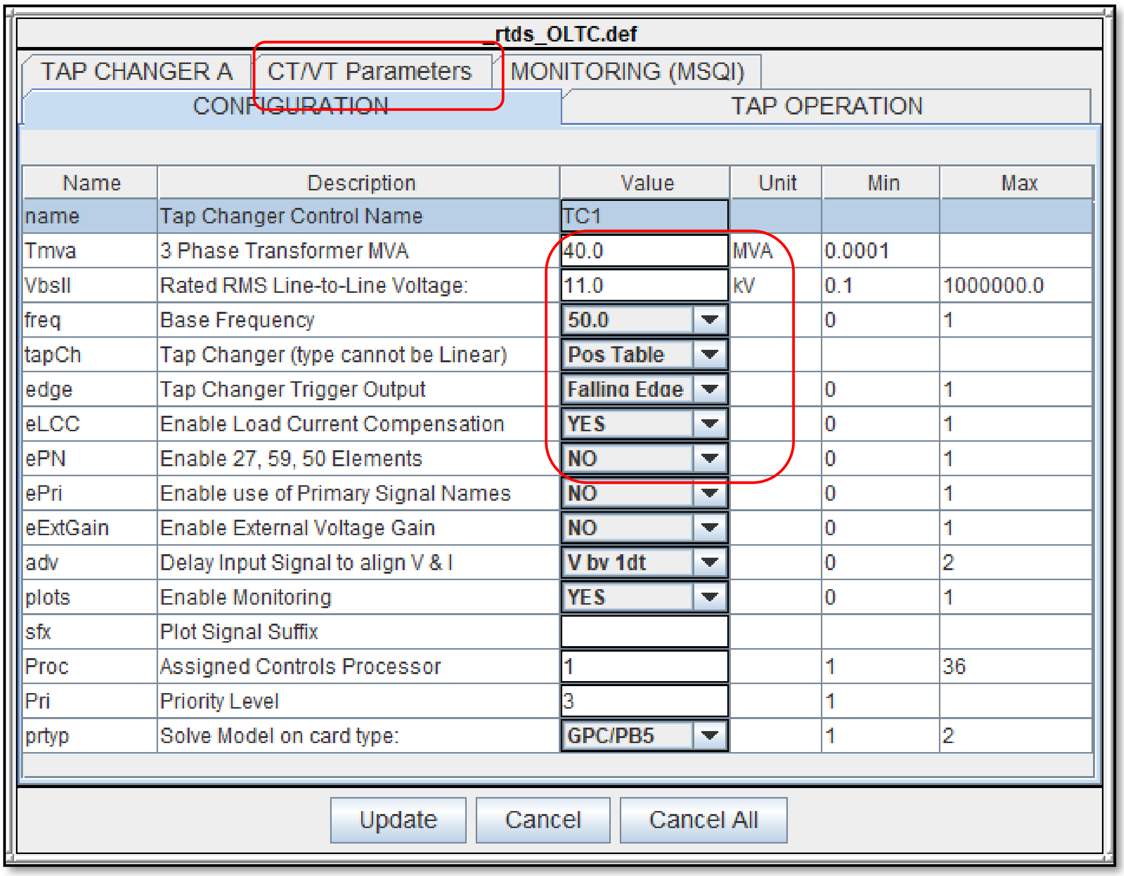


Figure 6.7 RTDS/RSCAD Tap Changer controller configuration

The Current Transformer (CT) ratio is configured to be 2000/1 for the 11kV CT and the Voltage Transformer (VT) ratio was configured to be 100/1 for the 11kV VT in the CT/VT configuration Tab.

17 tap positions, upper limit, lower limits and starting position parameters are configured in the tap changer controller model setting tabs, Figure 6.8.

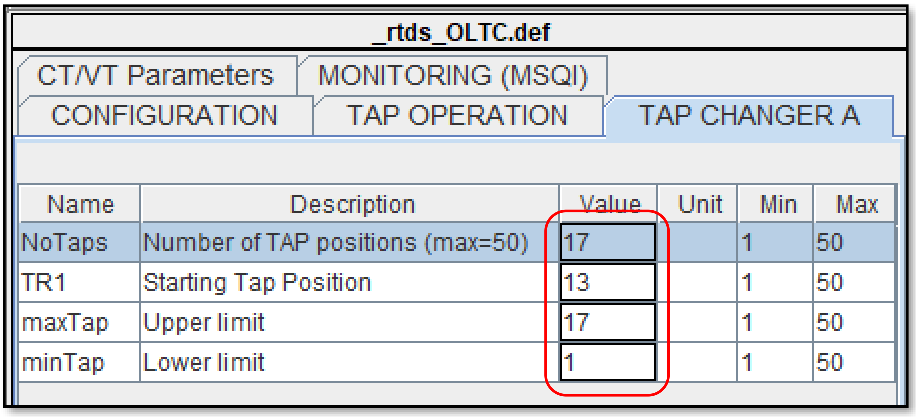


Figure 6.8 RTDS/RSCAD On Load Tap Changer settings

6.3.2 RTDS Tap Changer Controller Logic

Logic functions are used to build a logic control circuit to adapt the tap changer controller to the system configuration. The logic circuit contains two parts.

The first part of the circuit is explained first. The status of the Transformer 1 11kV side circuit breaker (T1BRK2), Transformer 2 11kV side circuit breaker (T2BRK2) and the 11kV Bus Section circuit breaker (BRKBS1) are used to determine if the transformers are connected in parallel in the logic diagram shown below in Figure 6.9.

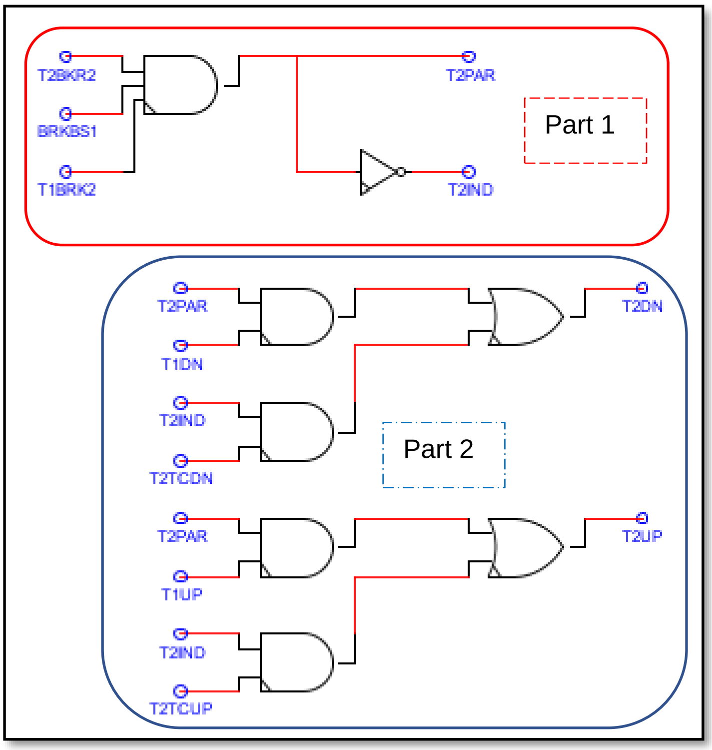


Figure 6.9 RTDS Transformer 2 Tap Changer Control Logic

The transformers are connected in parallel if the status of all monitored circuit breakers is closed. The transformers are operating in individual mode if the status of any of the circuit breakers is open this is explained in the matrix shown in Table 6-1.

Table 6-1 Matrix to determine if the transformers are in Parallel or Individually connected.

T1BRK2	T2BRK2	BRKBS1	Individual	Parallel
Close	**Close**	**Close**	No	**Yes**
Open	Close	Close	**Yes**	No
Close	**Open**	Close	**Yes**	No
Close	Close	**Open**	**Yes**	No

The part 2 of the logic circuit controls the On Load Tap Changer (OLTC) of Transformer 2 in Figure 6.9 is discussed next.

The tap changer controller of Transformer 2 (TRFR2) will follow the tap changer operation of Transformer 1 (TRFR1), who will act as the Master, when the transformers are connected in parallel. The status of input T2PAR will be high if TRFR2 is parallelly connected to TRFR1. The status of input T2IND will be high if TRFR2 is individually connected. The tap changer controller of TRFR2 will individually control the tap changer of Transformer 2 with T2TCDN and T2TCUP when the transformers are individually connected.

6.4 Running the Simulation in RSCAD Runtime

The system of two parallel power transformers, Single Line Diagram (SLD) for RunTime Case 3 is shown in Figure 6.1 RTDS/Runtime Tap Changer Control Case 3 above.

A Circuit Breaker (CB) is indicated in the RSCAD/RunTime SLD with an interactive square symbol. A green square indicates a CB with an open status. A red square indicates a CB with a closed status. The CB is operated by open and close push buttons.

The RTDS/Runtime tap changer operator console for Transformer 2 is shown in Figure 6.10 below. The controller is selected with a switch (T2SW1) to be in on (Automatic) or off (Manual) operation mode.

Push buttons (UP & DOWN) in the figure are used to operate the tap changer to move tap positions up or down, when the controller is in Manual mode operation.

The controller does the tap changer up and down operations, according to the voltage set point, when in Automatic mode. Lights indicated these operations with (T2TCDN & T2TCUP)

Counters indicates the tap operations count (T2opCnt) and tap position value (T2posVal). Lights indicate the status for parallel (T2PAR) and individual (T2IND) operation. A light Block indicates if the tap changer is in a blocked mode. The blocked mode is resettable with a push button (RESET).

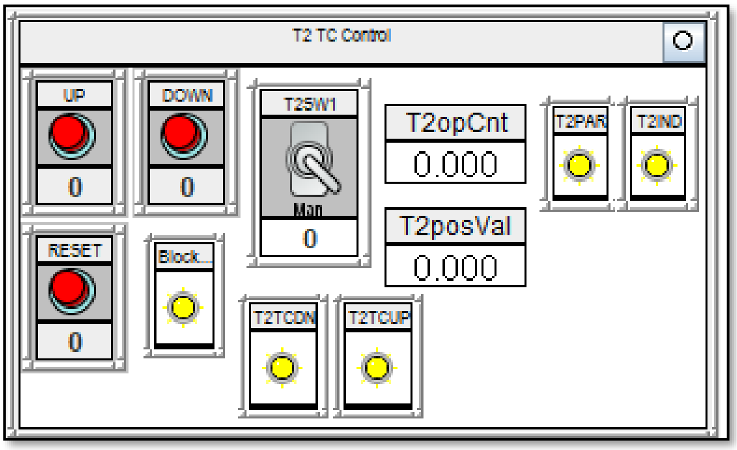


Figure 6.10 RTDS/Runtime Transformer 2 Tap Changer Controller operating console

A Simulation is done with the RTDS to determine if the tap changer controller operates correctly for different system configurations. Two system configurations are simulated: when the transformers are connected in parallel and when they are operating individually.

The following simulations are done:

Case 3A:

The bus section and transformer circuit breakers are used to connect Transformer 1 (TRFR1) and Transformer 2 (TRFR2) in parallel,

Case 3B:

- Transformer 2 is parallel connected to Transformer 1,
- Transformer 2 is operating in individual and automatic modes,
- Transformer 2 is operating in individual and manual modes.

The summary of simulation for Case 3 are shown in the Table 6-2 below.:

Table 6-2 Summary of Simulations for Case 3

Case 3A	
Aim	Test the Parallel / Individual mode selection
Method	1) Open and Close Transformer 1 (TRFR1) & Transformer 2 (TRFR 2) and Bus Section (BS) circuit breakers. 2) Use the logic to determine if the transformers are connected in parallel or individual mode. Asses if the logic is working correctly.
Expected result	The logic circuit uses the status of the circuit breakers and correctly determine if the transformers are operated in parallel or individual mode.
Case 3B	

Aim	Test Master-Follower scheme for the tap changer controllers.
Method	1) Connect TRFR 1 and 2 in parallel by closing the circuit breakers. 2) Disconnect TRFR 2 from TRFR 1 by opening circuit breakers. 3) For the case when TRFR 2 is parallelly connected to TRFR 1. TRFR 1 is the Master and TRFR 2 is the Follower. Assess that TRFR 2 is following the tap changer operations of TRFR 1. 4) For the case when the Transformers operates in an individual mode. Switch TRFR 2 in Automatic mode and accesses if the controller of TRFR 2 is controlling its own tap changer correctly. 5) When TRFR 2 is operating in an individual mode, switch TRFR 2 to manual mode. Operates the TRFR 2 tap changer manually with push buttons.
Expected Result	Show that: 1) TRFR 2 follows the controller operations of TRFR1 when they are connected in parallel. 2) TRFR 2 is individually controlled by its own controller when it is in automatic mode. 3) TRFR 2 is individually controlled by push buttons when it is in manual mode.

6.5 Simulation results

The simulations are done to determine if the designed controller of the automatic tap changers for a system of parallel power transformers is operating correctly.

6.5.1 Parallel tap changer controller mode

The automated determination of parallel or individual status, of the two transformers, using a logic control circuit, is simulated in the simulation Case 3A.

The statuses of the Transformer 1 11kV side circuit breaker (T1BRK2), Transformer 2 11kV side circuit breaker (T2BRK2) and the 11kV Bus Section circuit breaker (BRKBS1) are used to determine if the transformers are connected in parallel, Figure 6.11.

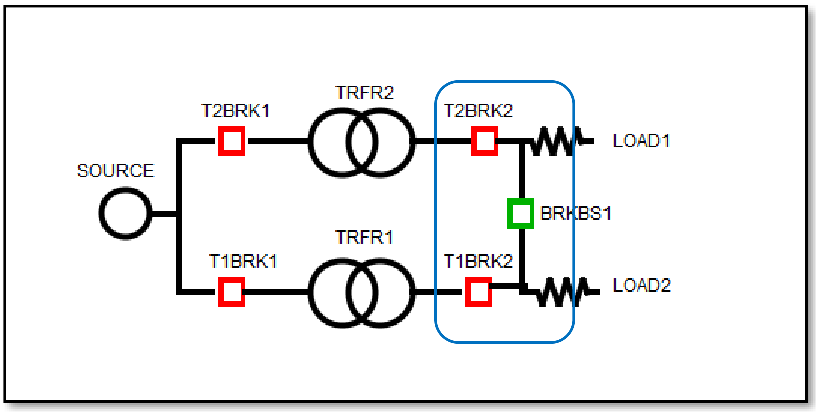


Figure 6.11 RTDS/Runtime Tap Changer Control Case 3A

The correct operation of the logic circuit is tested by controlling the circuit breakers and monitoring if parallel or individual status is correctly determined.

The case is shown for operating the Transformer 2 circuit breaker (T2BRK2) in the captured RDTS/Runtime plot, Figure 6.12. The initial status of the three circuit breakers T1BRK2, T2BRK2 and BRKBS1 is closed, shown with the inputs high. Transformer 2 is connected in parallel with the Transformer 1 and this is shown with the input (T2PAR) high. The status of the Transformer 2 changes to an individual mode (T2IND), when Transformer 2 11kV side circuit breaker (T2BRK2) is opened.

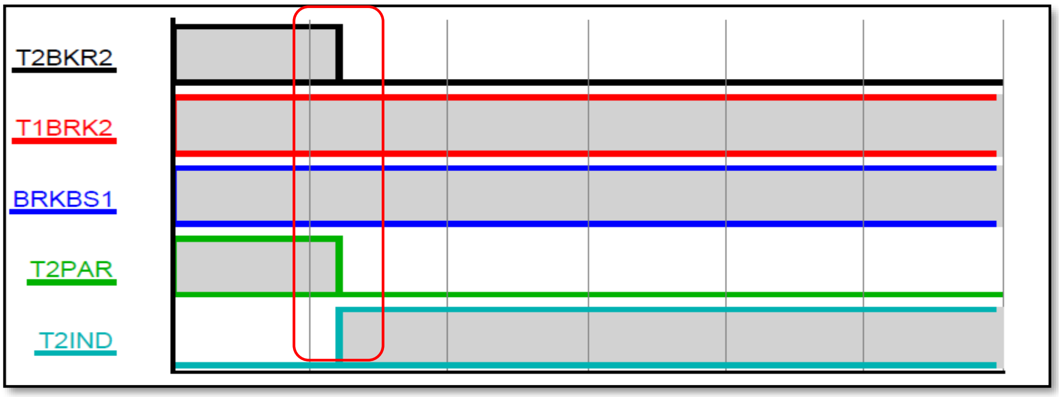


Figure 6.12 Transformer 2 tap change controller, Parallel / Individual

The Bus Section circuit breaker is controlled for the next simulation case, shown in the captured plot in Figure 6.13 below. The status for Transformer 2 changes from parallel (T2PAR) to individual mode (T2IND), when Bus Section 1 11kV circuit breaker (BRKBS1) is opened. Both Transformers 1 and 2 11kV side circuit breakers are closed.

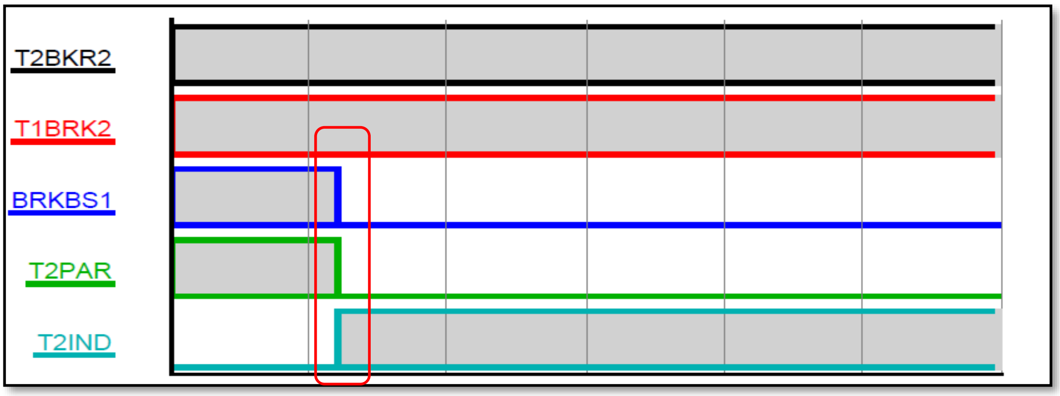


Figure 6.13 Transformer 2 tap change controller, Bus Section open

The logic circuit is correctly determining that the Transformer 2 is not connected in parallel when any of the three circuit breakers is opened.

6.5.2 Master-Follower tap changer controller mode

The Master–Follower operation of parallelly connected transformers is simulated in simulation Case 3B.

The following interpretation is used for Case 3B in the plots below.

T1SW1 and T2SW1 are switches to change the operations between Manual and Automatic mode for Transformer 1 and 2 respectively. When the input SW1 is high the switch is in Automatic mode. Up or Down commands can be issued to the tap change controller with push buttons when Manual is selected. The tap change controller controls the transformer tap changer to regulate the measured voltage when Automatic is selected. The controller change tap positions to get the measured voltage to the voltage set point.

The input (T2PAR) is high when TRFR 2 is parallelly connected and low when individually connected.

Transformer (TRFR) 1 and 2 are in parallel connected for the case below in Figure 6.14. When TRFR 2 is parallelly connected to TRFR 1, TRFR 1 will act as the Master and TRFR 2 will follow the controller operation of TRFR 1.

The TRFR 1 controller is switched with T1SW1 in manual operation. The tap changer is controlled with bush buttons to manually change the transformer tap positions.

TRFR 1 controller issues a “T1UP” output command to advance the tap position upwards and TRFR2 follows with a “T2UP” output command.

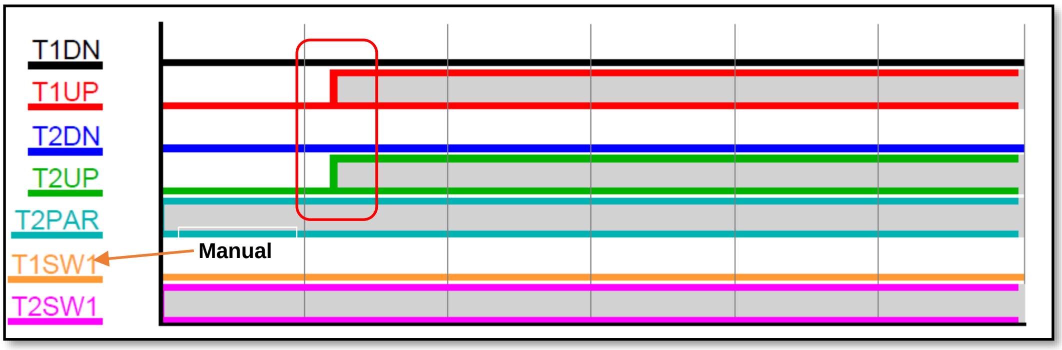


Figure 6.14 Transformer 1 Master, Transformer 2 Follower

The plot below shows in Figure 6.15, when the TRFR 2 is not parallel (T2PAR) connected to TRFR 1, TRFR 2 controller will individually control its tap changer. The TRFR 2 controller in a manual mode and a DOWN push button is operated, the controller issues a “T2DN” command to advance the tap position downwards.

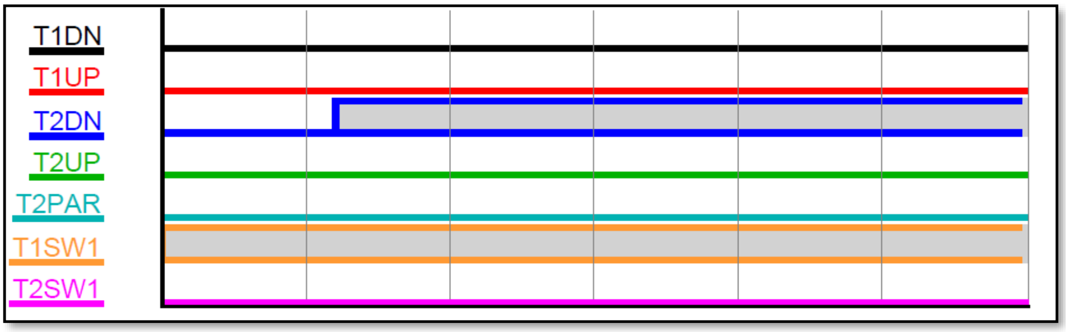


Figure 6.15 Transformer 2, Individual, Manual mode

The plot below shows in Figure 6.16, that when the TRFR 2 is Individually connected, and in Automatic mode, TRFR 2 controller will individually control its tap changer. The measured voltage deviates with the set point voltages and the TRFR 2 controller issue a “T2UP” command to advance the tap position upwards to raise the bus bar voltage.

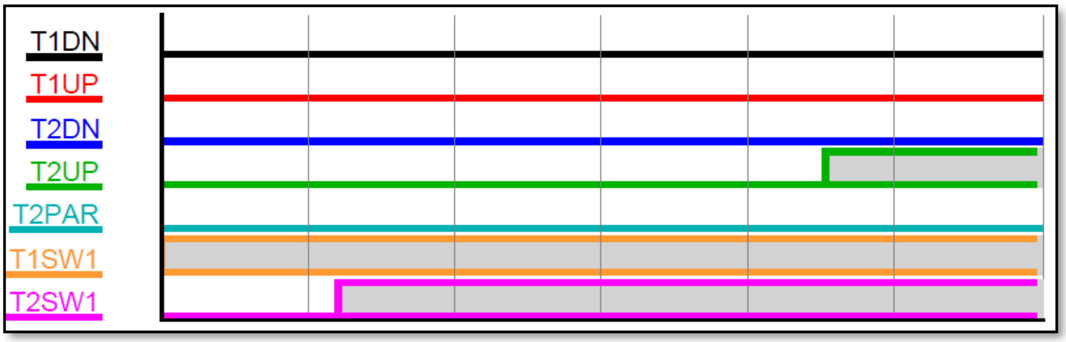


Figure 6.16 Transformer 2, Individual, Automatic mode.

6.6 Discussion

A Master-Follower scheme was designed in RTDS.

A system of two parallel 40MVA 132/11kV YNd1 power transformers is designed, modelled and simulated in the Real-Time Digital Simulator (RTDS) for the simulation Case 3

A tap changer controller for a system of parallel power transformers is designed, simulated and tested.

The 11kV bus bar has one Bus Section with a circuit breaker that is opened and closed to simulate a system configuration change. The status of the transformers circuit breakers and the bus section circuit breaker are used as inputs to a logic control circuit to determine if the transformers are parallelly connected.

The following results are obtained and shown in Table 6-3 .

Table 6-3 Results for simulation Case 3

Case 3A	
Aim	Test the logic circuit for Parallel / Individual selection
Result	The logic circuit uses the status of the circuit breakers and correctly determines if the transformers are operated in a parallel or an individual mode.
Case 3B	
Aim	Test Master-Follower scheme for the tap changer controllers.
Result	It is shown that: 1) Transformer 2 follows the controller operations of Transformer 1 when they are connected in parallel. 2) Transformer 2 is individually controlled by its own controller when it is in an automatic mode. 3) Transformer 2 is individually controlled by push buttons when it is in a manual mode.

The results show that:

- The logic circuit built in the RSCAD software uses the status of the monitored circuit breakers and correctly determines if the two transformers are operated in a parallel or in an individual mode.
- Transformer 2 follows the controller operations of the Transformer 1 when they are connected in parallel. Transformer 1 acts as the Master and Transformer 2 is the Follower.
- Transformer 2 is individually controlled by its own controller when it is in an automatic mode and not connected in parallel to the Transformer 1.

- Transformer 2 is individually controlled by push buttons when it is in a manual mode and it is not parallelly connected to the Transformer 1.

6.7 Conclusion

In this chapter, the tap changers controller for a system of two 40MVA 132/11kV YNd1 paralleled power transformers is designed, modelled, simulated and tested in the Real-Time Digital Simulator (RTDS).

The configuration of the RTDS RSCAD tap changer controller model is shown.

The tap changer controller simulation results are discussed. It is shown that the power transformer tap changer controller operates successfully as was expected.

- The developed logic circuit is correctly determining when the transformers is connected in parallel according to the open/close status of the circuit breakers.
- The Master-Follower mode operates correctly when the transformers are connected in parallel.
- The separate Manual and Automatic modes operate correctly.

The implementation of the developed protection scheme and tap change controller in the RTDS hardware in the loop real-time simulation is discussed in the next chapter.

7 CHAPTER SEVEN

IMPLEMENTATION OF THE DEVELOPED PROTECTION SCHEME IN A RTDS HARDWARE IN THE LOOP REAL-TIME SIMULATION

7.1 Introduction

The IEC 61850 standard for communication networks and systems for Power Utility Automation is used to implement IEC 61850-9-2 sampled values for a typical substation system with parallel power transformers.

Power-system protection is required to protect the electrical power system by removing a faulted part as fast as possible from the rest of the electrical network to keep the power system stable and to limit the damage to equipment such as transformers. Power transformer protection can be achieved by using protection Intelligent Electronic Devices (IEDs) to detect faults e.g. winding, core and tap changer faults.

Fault currents in the transformer can be due to three phases, phase to phase or phase to earth faults. The magnitude will depend on the transformer impedance, winding connections, positions of the fault on the winding and on the type of earthing for star connected windings (Alstom, 2002: 272).

Instrument transformers at the high voltage yard measure power system currents and voltages which are used by the protection IEDs to determine abnormal system conditions. The conventional instrument transformers can be copper hardwired to the protection IEDs in the control room or Merging Units (MUs) in the HV yard. The distance between the Current Transformers (CTs) and the IED and the cross section of the copper wires influence the burden on the CT.

Current Transformers and Voltage Transformers (VTs) are modelled in the Real-Time Digital Simulator (RTDS) RSCAD software to provide analogue signals that are proportional to the real-time system currents and voltages. IEC 61850-9-2 Sampled Values (SV) streams are converted from the instrument transformer AC currents and voltages. The produced SV streams are measured and analysed in this chapter. SV streams are produced in the RTDS or by using standalone MUs external to the RTDS

It is shown in previous Chapter Five that power transformer protection settings can be adapted when the system configuration for the parallel power transformers is changed.

In Chapter Six it was shown that the power transformer tap changer controller can be adapted to the system configuration of the parallel power transformers.

In this chapter, test-benches are developed for experimentation in section 7.2.

The test-bench components are described in section 7.3. The real-time implementation and testing of the developed protection scheme are by means of a RTDS, MUs, transformer protection and control IEDs and Ethernet equipment.

The configuration of the MU is shown in section 7.4 , protection and control IED in section 7.5 and network switches in section 7.6.

The arrangement of time synchronization equipment is shown in section 7.7.

The experimental results are shown in section 7.8 for different cases using different test-benches.

The conclusion is made in section 7.9

7.2 Development of a laboratory test-bench

Different test-benches are required to do practical experiments and test the developed system to determine in what way the IEC 61850-9-2 sampled values can be implemented for protection, monitoring and control of the power transformers.

7.2.1 Test-bench A

The first test-bench is used where the power system with the power transformers is simulated in the RTDS. The test-bench is shown in Figure 7.1. The RTDS simulated instrument transformers analogue signals are sent to an Omicron CMS 156 amplifier outside the RTDS. These analogue signals, proportional to the real-time secondary voltage and current signals are sent to an Analogue Merging Units (AMU). The AMU converts the CT and VT signals to one IEC 61850-9-2 Sampled Value (SV) stream and publishes it on the Process Bus Ethernet network. Two Omicron amplifiers and two AMUs are used, one set for the CT and VT analogue signals on the High Voltage (HV) 132kV side of the power transformer and the second is used for the Medium Voltage (MV) 11kV side.

The AMUs are connected to a network switch which is connected to the fibre optic LAN. Another switch is connected to the LAN and the protection IED. The MiCOM P645 IED subscribes to both SV streams. A laptop computer connected to the Ethernet network is used to configure the RTDS, the IED and the network switches. The AMUs cannot be configured over the network, the laptop is connected directly to an AMU to configuration it.

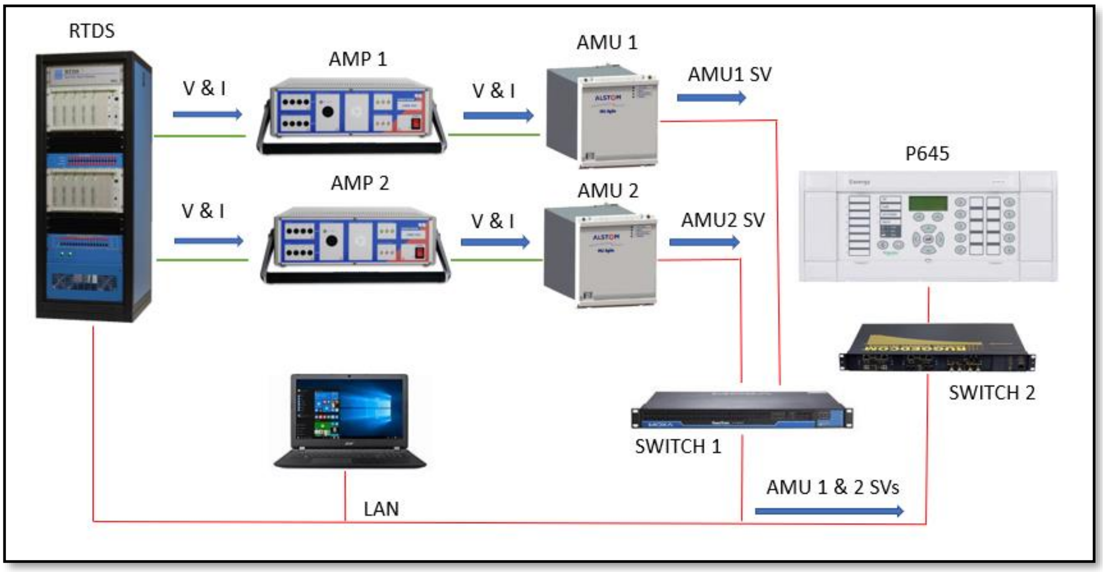


Figure 7.1 Test-bench A

The following configuration is done on this test-bench:

- Configuring the RTDS to produce analogue VT & CT signals out of the RTDS.
- Configurate the AMUs to receive analogue VT & CT signals and produce SV streams.
- Configure the network switches.
- Configure the P645 IED

The following investigations are done on this test-bench:

- Measure SV streams on the Ethernet network using software tools and the computer.
- Measure SV streams with the IED.
- Determine if SV values are consistent with the power system current and voltage values.

7.2.2 Test-bench B

In the second test-bench shown in Figure 7.2, the RTDS GTNET_SV-9−2 component is replacing the Merging Unit of the first test-bench. The GTNET SV-9-2 component produces IEC 61850−9−2 Sampled Values which are sent to the Ethernet network. The developed power system is simulated in the RTDS. The RTDS simulated instrument transformers analogue signals are converted to IEC 61850-9-2 Sampled Value (SV) streams. One GTNET_SV9-2 component can produce 2 SV streams at 80 samples/cycle.

The Sampled value streams are measured and captured to analyse. The MiCOM P645 IED subscribes to the SV streams. Different current transformer burdens can be simulated to compare the use conventional current transformers, analogue signals and copper wiring with AMU, SV and Fibre Optic (FO) networks.

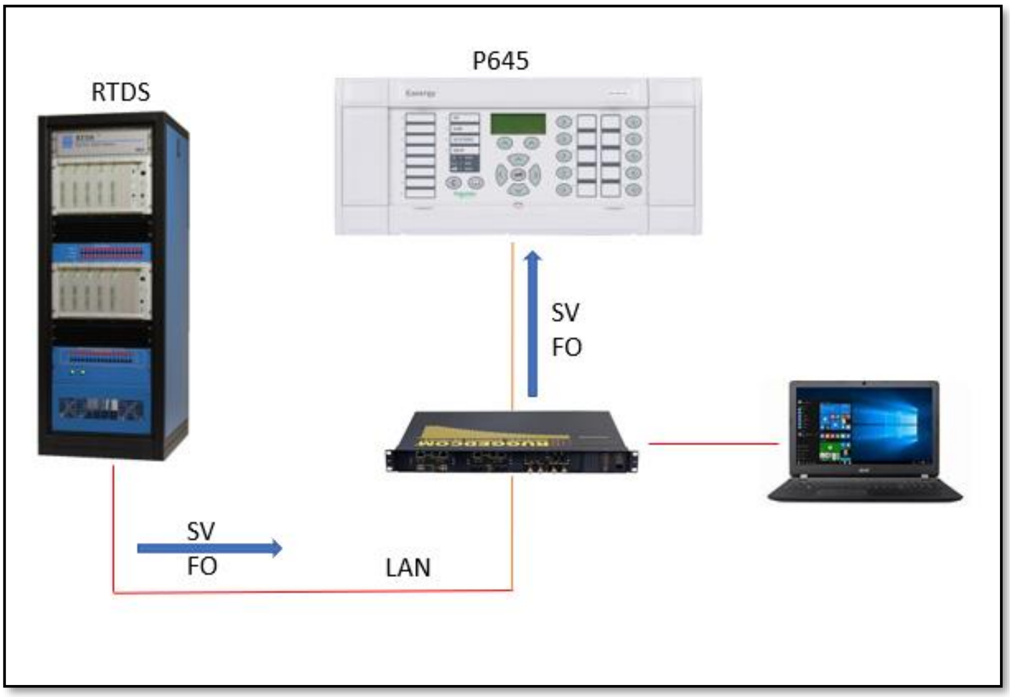


Figure 7.2 Test-bench B

The following configuration is done on this test-bench:

- Configuring the RTDS to produce analogue VT & CT signals internal to the RTDS.
- Configurate the RTDS SV9-2 component to receive analogue VT & CT signals and produce SV streams.
- Configure the network switch.
- Configure the P645 IED

The following investigations is done on this test-bench:

- Measure SV streams on the Ethernet network using software tools and the computer.
- Measure SV streams with the IED.
- Determine if SV values are consistent with the power system current and voltage values.

7.2.3 Test-bench C

The third test-bench has the structure shown in Figure 7.3. The RTDS developed system in Test-bench B is expanded to include transformer differential and over current protection relay components. The RTDS/RUNTIME case is shown in Figure 7.40. The

RTDS simulated instrument transformers analogue signals are converted to IEC 61850-9-2 sampled value (SV) streams.

The following configurations are done on this test-bench:

- Configure the RTDS RSCAD transformer differential and over current protection components,
- Configure the RTDS RSCAD SV9-2 component to produce SV streams.

The following investigations are done on this test-bench:

- Measure SV streams on the Ethernet network using software tools and the computer.
- Apply different type of faults at different positions in the system with parallel power transformers and measure the fault currents.
- Test the RTDS RSCAD software transformer protection components.

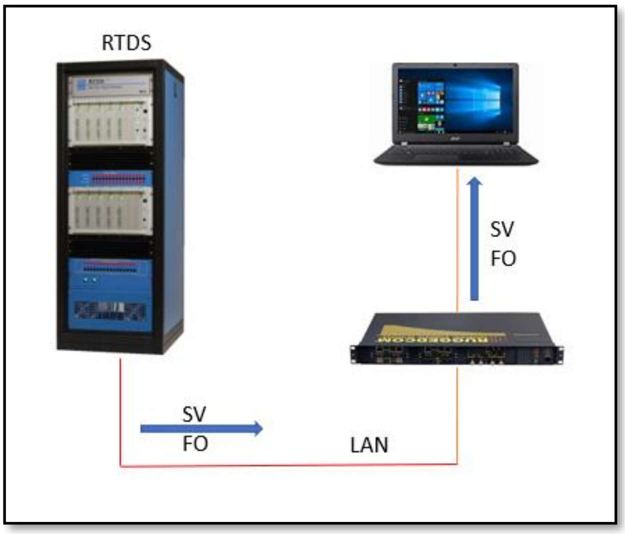


Figure 7.3 Test-Bench C

The RTDS and computer are connected using Fibre Optic (FO) cables to the network switch.

7.2.4 Test-bench D

The fourth test-bench shown in Figure 7.4 is the same as Test-bench C but the modelling inside the RTDS is different. The power system is simulated in the RTDS. The RTDS developed system includes transformer differential and over current protection relay components. The RTDS simulated instrument transformers analogue signals are converted to IEC 61850-9-2 sampled value (SV) streams. The SV streams are used inside the RTDS/RSCAD software for experimentation.

The LAN is used to connect the computer to the RTDS hardware with the RSCAD software to configuration, execution, and analysis the real-time simulations

This test-bench compares a system using SV streams to a system that only uses conventional instrument transformers. Copper wires are modelled and are used in both cases, but the length of copper wires is different. The copper wires from the instrument transformers (IT) to the IED, in the control room, measuring analogue signals are much longer compared to the wires from the IT to the merging units in the yard.

The burden on the IT is much less when using MU. The burden effect on the IT when using merging units was simulated in the RTDS. The IT burden when merging units are used is discussed in 2.3.1.1 Current transformers.

The following configuration is done on this test-bench:

- Configure the RTDS RSCAD transformer differential and over current protection components,
- Configure the RTDS RSCAD current transformer component
- Configure the RTDS RSCAD SV9-2 component to produce SV streams.

The following investigations are done on this test-bench:

- Measure SV streams in the RTDS/RSCAD software.
- Compare the burden on current transformers when a system using AMUs is compared to a system not using AMUs.

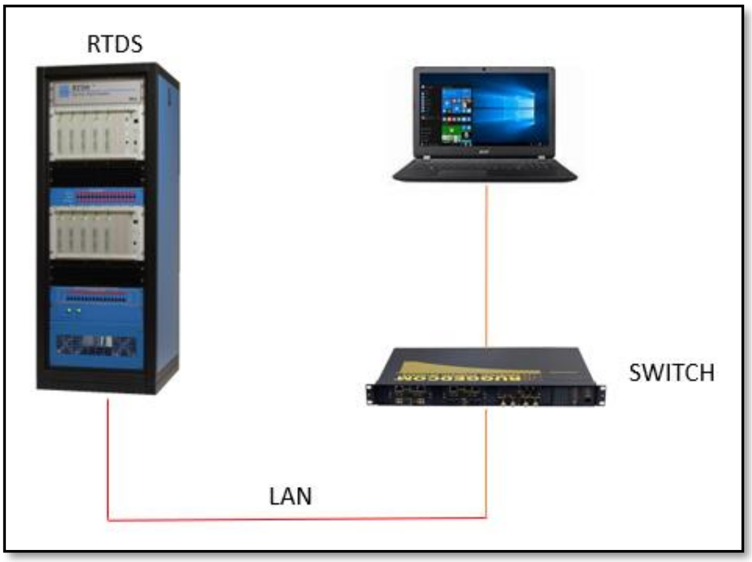


Figure 7.4 Test-bench D

7.3 Test-bench components

The Laboratory test-benches consists of the following components:

- Real-Time Digital Simulator (RTDS)
- Two Alstom IEC61850 Agile AMUs (Analogue Merging Unit),
- Moxa PowerTrans PT-7728-PTP Ethernet switch,
- Ruggedcom RSG2288 Ethernet switch,

- Schneider Electric Easergy MiCOM P645 Power Transformer IED,
- Acer Aspire ES 15 personal laptop computer.

The following software were used on the laptop computer:

- RSCAD Power system simulation software by RTDS Technologies,
- MiCOM S1 Agile IED Engineering suite of tools by GE Grid solutions
- MU Agile configurator
- Schneider Electric Easergy Studio V7.1.0
- Wireshark network protocol analyser
- Omicron SVScout
- Telnet console
- Hyperterminal

7.3.1 Real-Time Digital Simulator (RTDS)

The RTDS Simulator is used to run the developed real-time power system model. This offers a means to test protection systems by connecting the RTDS to physical protection equipment in a closed-loop with the power system model.

Instrument transformers (CTs and VTs) are modelled in the RTDS/RSCAD software to provide analogue signals. These analogue signals are proportional to the real-time secondary voltage and current signals making it possible to evaluate their effect on the performance of the protection system.

7.3.1.1 Hardware

RTDS processor cards are mounted in racks which together with input/output cards are housed in cubicles. Each RTDS rack includes a GTWIF card which provides communication between the RTDS rack and the computer workstation running the RSCAD software.

The processor cards are used to solve the equations representing the power system components modelled within the RTDS. Two types of processor cards are used, Giga processor card (GPC) and PB5 cards. An RTDS rack typically contains between 2 and 6 processor cards.

The I/O cards permit the RTDS hardware to be interfaced with external equipment such as a protective IEDs. The Gigabit Transceiver Analogue Output Card (GTAO) and the Gigabit Transceiver Analogue Input Card (GTAI) are used to interface analogue signals to and from an external device and the RTDS. The Gigabit Transceiver Digital Input Card (GTDI) is used to interface digital signals from an external device to the RTDS.

The GTFPI card forms the interface between the processor card, the digital I/O panel and the High Voltage interface panel on the front of the rack. The digital I/O panel is used to interface up to 16 digital input and 16 digital output signals between the RTDS and the external equipment. i.e. to interface trip and close signals from a protective relay to the RTDS. The HV panel may be used to provide digital status signals of up to 250 volts and includes solid state switches which are able to switch an external supply's voltage.

The GTNET network interface card is used to interface the RTDS to external equipment over a LAN connection using various standard network protocols. IEC−61850 GOOSE and IEC−61850−9−2 (sampled values) are supported and used for the test-bench building.

The GTSYNC card is used to ensure that the RTDS clock remains locked to the time−reference signal provided as input to the GTSYNC. The GTSYNC uses either IEEE 1588 PTP, 1 PPS, or IRIG−B unmodulated signals as synchronization source. The GTSYNC is used to synchronize IEC 61850−9−2 Sampled Values output with a GPS time source via a 1 PPS signal.

7.3.1.2 Software

RSCAD is a software package providing a graphical interface to the RTDS. RSCAD includes several modules that allow real-time simulations to be created, executed, controlled and analysed. The RSCAD/FileManager (Fileman) module is the home page and is used for project and case management. All other RSCAD programs are launched from the Fileman module.

RSCAD/Draft is used for circuit assembly and parameter entry of components. The Draft screen is divided into the library section and the circuit assembly section. Individual component icons are selected from the library and placed in the circuit assembly section. Power System and Protection and Automation models from the library are interconnected to build a simulation circuitry.

RSCAD/RunTime is used to control the simulation case being performed on the RTDS hardware. Simulation can be controlled (start / stop commands) as well as other controls e.g. set point adjustment, fault application, breaker operation are performed through the RunTime Operator's Console. On-line metering and recording functions are available in RunTime.

RSCAD/MultiPlot is used for post processing and analysis of results captured and stored during a simulation study. Report can be generated by MultiPlot.

7.3.2 Merging Unit

The Alstom Merging Unit, type: MU Agile AMU takes analogue inputs from current transformers (CTs) and voltage transformers (VTs) and outputs time-stamped digital sampled values streams according to IEC 61850-9-2LE process bus. This provides safer and more economical communication using fibre optics and allows the primary and secondary plant to be decoupled.

7.3.2.1 Hardware

The rear panel consists of:

- Terminal blocks for 4 x CT connections, 4 x VT connections, watch dog outputs and power supply unit connection,
- 1 PPS time synchronisation fibre optic ST connector,
- Ethernet fibre optic 100BaseFX LC connector for connecting to the Ethernet network and transmitting the Sampled Value message streams,
- The front panel provides a USB port and four LEDs. The USB port is used to communicate with a locally connected PC to transfer settings, upload firmware updates and extract events.
- The LEDs show the Time Sync, Alarm, Out of service and Healthy conditions.

7.3.2.2 The MU Agile Configurator

The MU Agile Configurator is a software tool used to configure MU Agile AMU IEDs.

AMU Configuration Language and IEC 61850 Substation Configuration Language (SCL) are used.

The AMU is a proprietary language file which contains configuration information and is used for transferring data to or from the IED.

The XML-based standard SCL file is used to configure the AMU by using the IED Capability Description (ICD) Template file.

The Editor allows general configuration, configuration of the communication Subnetwork, Sampled Values configuration, client/server SNTP time synchronisation configuration,1 PPS configuration, network frequency configuration, CT and VT Configuration, setting of simulated magnitudes and angles of phase currents and voltages and to set password restrictions.

7.3.3 Moxa PowerTrans PT-7728-PTP Ethernet switch

The PowerTrans PT-7728 series Ethernet switch is designed and IEC 61850-3 certified to be used in substation automation systems. The PT-7728 has a modular design where 4 slots support modules with different port configurations are used to cater for 1 slot Gigabit and 3 slots Fast Ethernet. The switch has dual isolated redundant power supply units to increase the communications reliability.

Module and system status LED indicators are provided on the front panel.

The configuration settings can be accessed using the serial console, Telnet console, and web console.

The switch provides two levels of configuration access, admin and user accounts. The admin account has read/write access and the user account has read access only.

Simple Network Management Protocol (SNMP) is supported by this switch. SNMP is used for configuring network devices such as switches and routers on an Internet Protocol (IP) network.

It supports Rapid Spanning Tree Protocol (IEEE-802.1w), Turbo Ring and Turbo Ring V2 protocols for communication network redundancy. Turbo Ring and Turbo Ring V2 are Moxa proprietary protocols for managed switches.

The PT-7728 has Virtual LAN (VLAN) and traffic prioritization capability to recognise 802.1Q VLAN packets which are used to carry VLAN identification as well as IEEE 802.1p priority information. VLAN configuration is achieved by using trunk or access ports settings.

Multicast filtering is achieved by using Internet Group Management Protocol (IGMP) Snooping, GARP Multicast Registration Protocol (GMRP), and adding a static multicast MAC manually.

7.3.4 Ruggedcom RSG2288 Ethernet switch

The RUGGEDCOM is a fully managed, modular Ethernet switch designed to operate reliably in electrically harsh utility substation environments. The RSG2288 includes the IEEE 1588 v2 protocol with hardware time stamping, allowing high precision time synchronization over the Ethernet network with accuracies of 1 μs or better and support GPS and IRIG-B time synchronization as well.

The switch is embedded with the Rugged Operating System (ROS). A workstation can be connected directly to the RS232 console port to access the device. The configuration is done by using a web interface.

The RSG2288's modular flexibility offers 5 slots with 1000BaseX multi-mode optic fiber LC and RJ45 1000BaseTX copper port combinations. Each communication port is equipped with an LED that indicates the link/activity state of the port

IEEE 802.1D-2004 Rapid Spanning Tree Protocol (RSTP) is supported.

Tagged frames with 802.1Q (VLAN) tags that specify a valid VLAN identifier (VID), Untagged frames without tags, or frames that carry 802.1p priority-tagged frames are supported.

Each communication port can be configured to be an Edge or Trunk type. Classes of service (CoS) and multicast filtering can be configured on the RSG2288.

7.3.5 MiCOM P645 Power Transformer protection IED

The Easergy MiCOM P645 from Schneider Electric is a power transformer protection and control IED. The Easergy MiCOM P645 incorporates differential, Restricted Earth

Fault, thermal, overfluxing, overcurrent and earth fault protection. The P645 Model variant covers two or three winding and autotransformers with up to 5 sets of three-phase CT inputs.

7.3.5.1 Hardware

The P645 has a front port Serial PC interface EIA(RS)-232 DCE, 9 pin D-type female connector with Courier protocol for interface to Easergy Studio software. The front panel also has a 16-character by 3-line alphanumeric Liquid Crystal Display (LCD). There is a 19-key keypad with 4 arrow keys, an enter key, a clear key, a read key, 2 hot keys and 10 programmable function keys. 22 LEDs, 4 fixed function LEDs, 8 tri-colour programmable function LEDs and 10 tri-colour programmable function LEDs associated with the function keys are available on the front panel.

The rear has different slots for communication modules and general Input/Output (IO) terminals for power supply, opto inputs and output contacts.

IEC 61850 is implemented in the P645 IED by use of a separate Ethernet card with a RJ45 copper connector and two ST optical fibre connectors. The P645 can be configured from a configuration file using an IEC61850 IED Configurator tool. The preconfigured IEC 61850 SCD or CID configuration files can be transferred to the IED. The configuration files for the P645 can also be created manually based on their original IED Capability Description (ICD) file. Time synchronization is supported using SNTP (Simple Network Time Protocol) over the Ethernet link. An IRIG-B input with BNC connector is also available on the IED.

The P645 has an additional 9-2 Ethernet board that allows an alternative path with IEC61850-9.2LE Ethernet link. The board has an RJ45 connector and two 1300 nm multi-mode 100BaseFx ST optical fibre connectors.

A Ports Redundant Ethernet Board is optional but not installed on the P645. The redundant Ethernet board allows an alternative communication path by using Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) protocols.

7.3.5.2 Easergy Studio software

The Software includes features to:

- Send settings to a device and extracting settings from a device
- Extract event and fault records from the device
- Real-time measurement visualisation
- Edit the Programmable Scheme Logic (PSL) with a PSL Editor
- Configure the device with an IEC61850 configuration tool.

- Create a system to mimic a real-world system. Systems can be sub-divided using substations, voltage levels and bays.

7.3.6 Wireshark network protocol analyser

Wireshark is a network packet analyser that can be used to capture Ethernet network packets and display the detailed packet data. It supports IEC61850 Sampled Values protocol. The live packets can be captured and be saved to a file. Offline analysis can be done on the packets.

7.3.7 Omicron SVScout

SVScout is a tool for visualizing Sampled Values (SV) according to IEC 61850-9-2LE sampled at 80 or 256 samples per cycle. It subscribes to the SV streams from multiple merging units and displays the waveforms of the primary voltages and currents in an oscilloscope view. A report can be generated to summarise the SV measurement information. SVScout supports IEEE 1588 (PTP).

7.4 Configuration of Alstom Agile Merging unit

The MU Agile Configurator software tool is used to configure the Alstom MU Agile AMU IED.

The MiCOM S1 Agile software Version V1.3.1 by Alstom Grid has different tools to manage the MiCOM devices. The tools are grouped in folders on the start page shown in Figure 7.5 below. The folder "Smart Grid" contains the MU Agile Configurator.

Figure 7.5 MiCOM S1 Agile Start page

The MU Agile configurator allows the user to create and edit IED configurations. Configuration files can be sent to an IED or retrieved from and IED. The configuration can be done offline or online. The IED configuration file is a proprietary language file which contains an Analog Merging Unit (AMU)'s IEC 61850 configuration information and has an .amu file extension.

A new MiCOM configuration can be created when in an offline mode from a template or an IED Capability Description (ICD) file. The IED model number is used to choose the ICD file. The selecting of the ICD file is shown below in Figure 7.6.

The ICD file is selected and opened in the Configuration tool. The main area is shown on the left side window. The detail of the selected category will show on the right-hand side.

The IED configuration can also be extracted from the IED online. A password is required to manage the IED. The default password is “AAAA”.

The edited configuration file must be validated before it is sent to the device. The right-hand lower pane shows lists of Errors, Warnings and Messages.

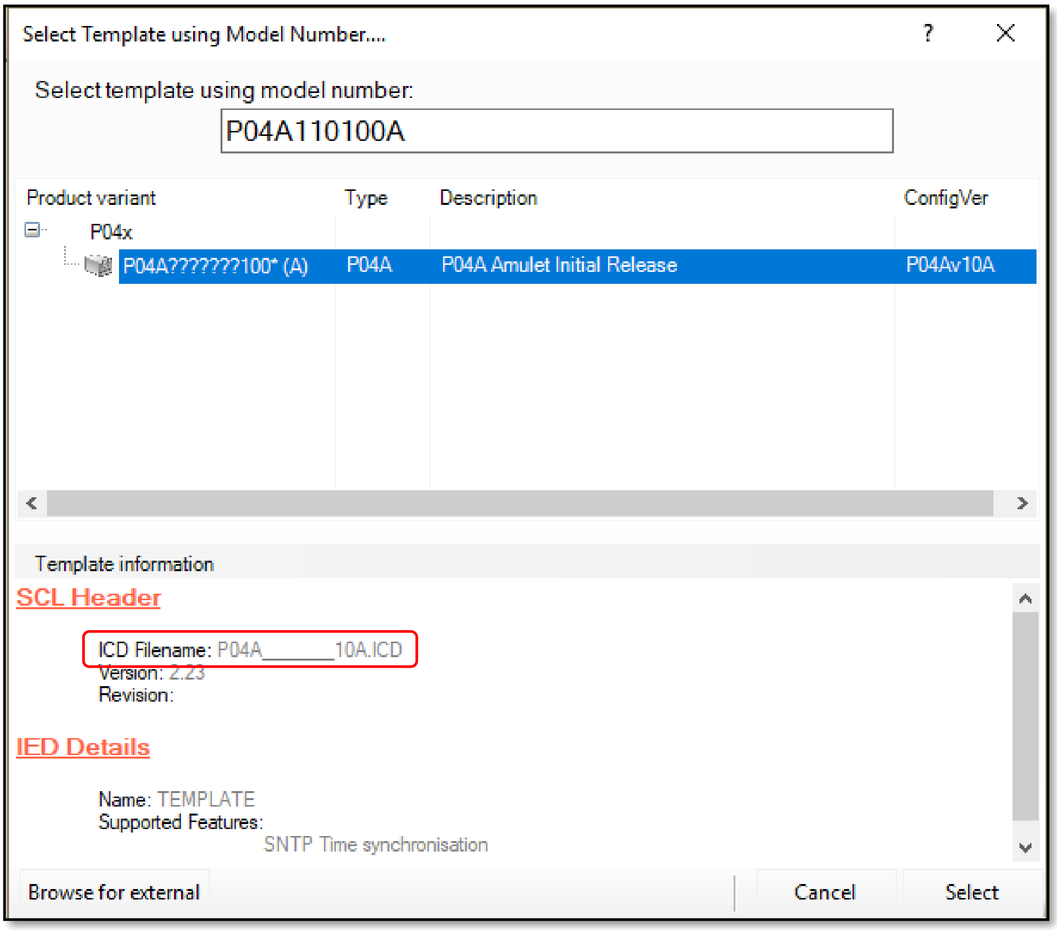


Figure 7.6 AMU configuration from .ICD file

The configurable items are categorised into groups in the Editor window. The Groups are IED details, communications, sampled values, SNTP, 1 PPS, Acquisition, CT and VT Configuration, Simulation and Cybersecurity. The groups are shown in the left window of Figure 7.7

7.4.1 IED Details

The first group is IED Details. Most of the data is not user configurable and is factory set. General configuration and data about the IED and the selected ICD template file are displayed on the right side of Figure 7.7.

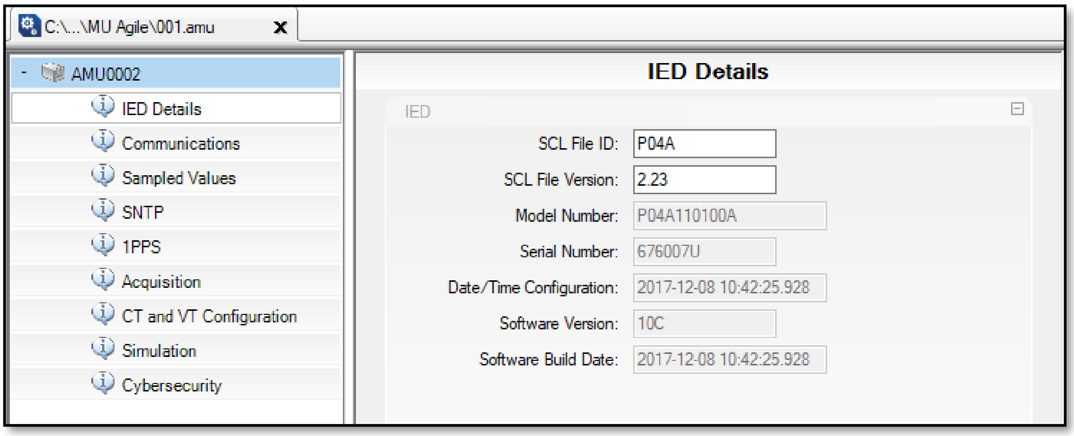


Figure 7.7 AMU IED Details

7.4.2 Communications

Configuration of the communications Subnetwork is shown in Figure 7.8. The IED name, IP address and Subnet Mask can be configured. The IED MAC Address is factory pre-set.

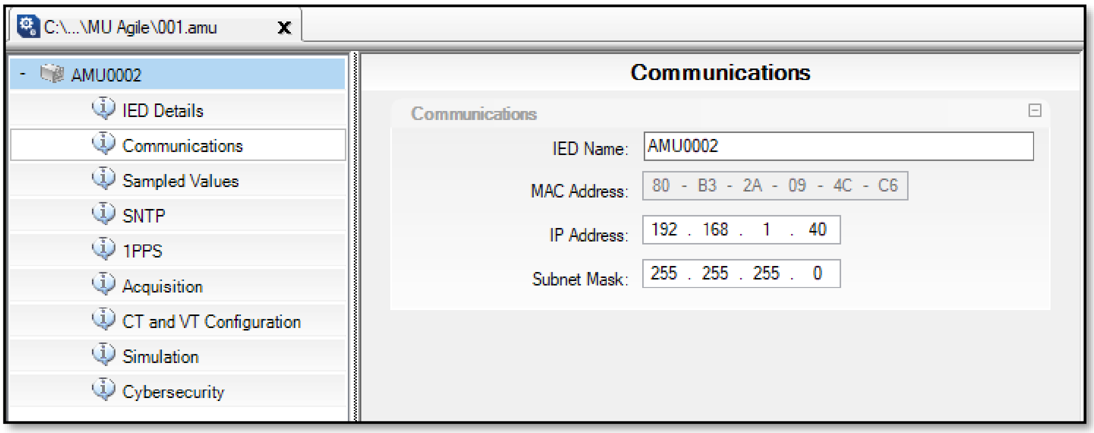


Figure 7.8 AMU Communications configuration

Two Analog Merging Units (AMU) were set up for the test-bench. The IED name of the first AMU is AMU0001 with IP Address 192.168.1.39 and the second AMU name is AMU0002 with IP Address 192.168.1.40.

7.4.3 Sampled Values

In the Sampled Values (SV) group shown in Figure 7.9, the details are set for the AMU IED to transmit IEC 61850-9-2LE sampled values. These samples are taken at a resolution of 80 times per cycle, which is 4000 samples/sec at 50 Hz

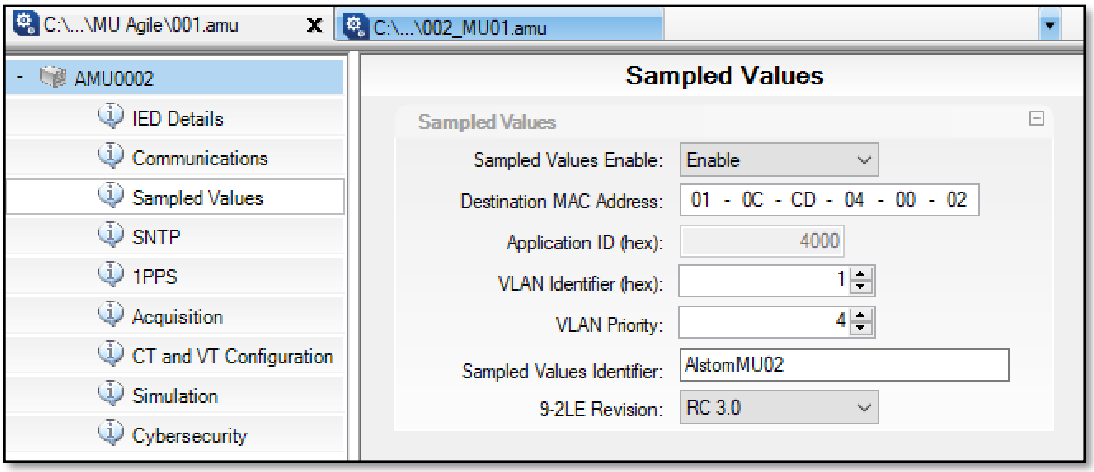


Figure 7.9 AMU Sampled Values configuration

A multicast destination MAC Address is set for subscribing IED to identify SV data streams.

Table 7-1 MAC Addresses for AMUs

IED	MAC Address
AMU 1	01-0C-CD-04-00-02
AMU 2	01-0C-CD-04-00-03

The Application ID is not set able.
VLAN ID and priority can be set. The priority of sampled value data frames can be set from 1-7. Lowest priority = 0, highest priority = 7.
The VLAN ID was set to 1 and the priority to 4 for both AMUs.

7.4.4 SNTP

The SNTP group allows the configuration of SNTP time synchronisation. SNTP can be used to synchronise the internal clock of the IED using IEC 61850 over internet with the clock of the SNTP server. The IP address of the main SNTP server and a second IP address for the backup server. The Poll rate is set to define how often the IED attempts to contact the SNTP server.

7.4.5 1PPS

1 PPS setting allows to set the delay caused by the length of the 1 PPS fibre optic cable from the source to the IED input. The following equation is used to calculate the delay. Fibre optic delay (µsec) = Fibre cabling length (meters) / 300 according to the AMU configurator help file.

7.4.6 Acquisition

Acquisition allows to set the network frequency to 50 Hz.

7.4.7 CT and VT Configuration

CT and VT Configuration allows to set the CT and VT parameters. The phase and neutral CTs can be configured. The phase CT parameters are shown below in Figure 7.10.

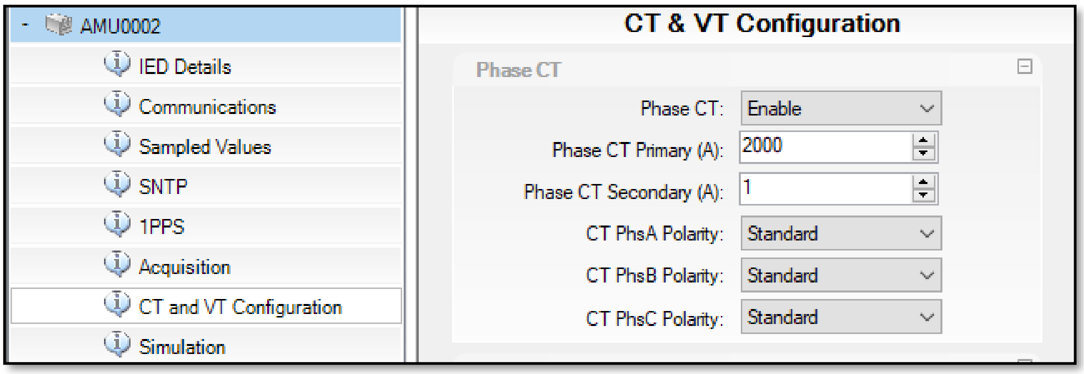


Figure 7.10 AMU SV CT configuration

The primary and secondary currents of the CT can be set. The CT polarity can be set between standard and inverted. Two merging units were set for the test-bench. AMU 1 is set with a primary current of 200A to be used on the 132kV side and AMU 2 is set with a primary current of 2000A to be used on the 11kV side of the power transformer.
The neutral CT parameters are shown below in Figure 7.11.

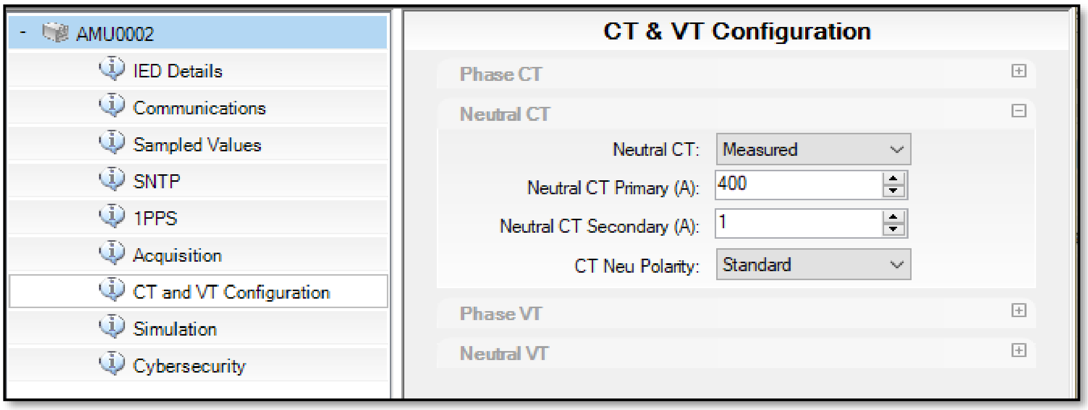


Figure 7.11 AMU SV Neutral CT configuration

The neutral CT can be set to Derived / Measured / Disabled. The Neutral CT sampled values are measured from the AMU Neutral CT input when it is set to Measured. The Neutral CT sampled values are not measured but calculated from the phase CT values when it is set to Derived. The primary current and the polarity can be set for the neutral CT.

The phase and neutral VT parameters are set similar like for the CTs and are shown in Figure 7.12. The AMU 2 set on the 11kV side of the power transformer is shown. The neutral VT primary and secondary voltage can be set. The neutral VT can be set to Derived / Measured / Disabled like for the neutral CT.

AMU 1 set for the 132kV side is done in a similar way but with a primary voltage set to 132kV.

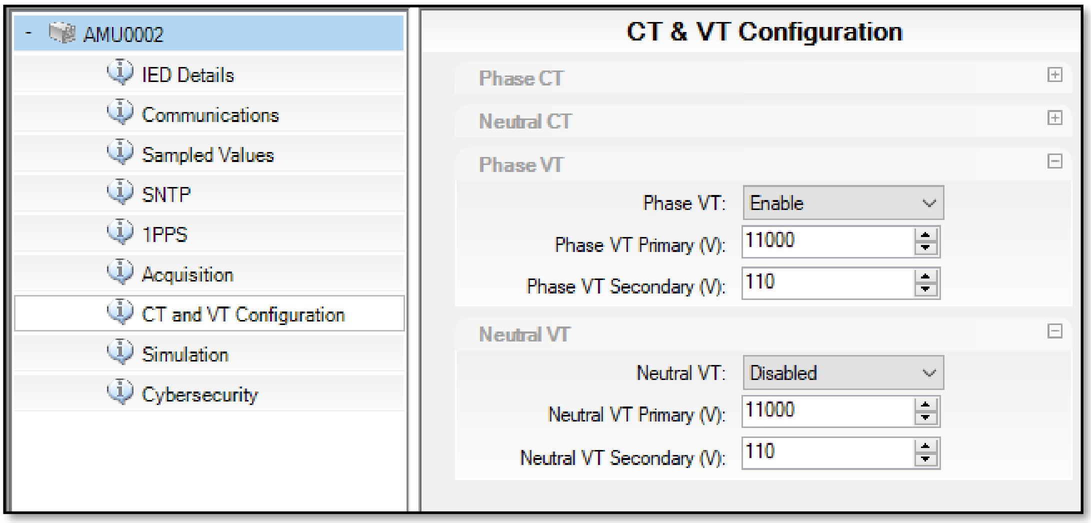


Figure 7.12 AMU SV VT configuration

7.4.8 Simulation

The AMU can simulate sampled values with simulated magnitudes and angles of phase currents and voltages. This can be configured at the Simulation tab. The simulation values of the currents are shown below in Figure 7.13. The VT simulation is set in the similar way as for the CT simulation.

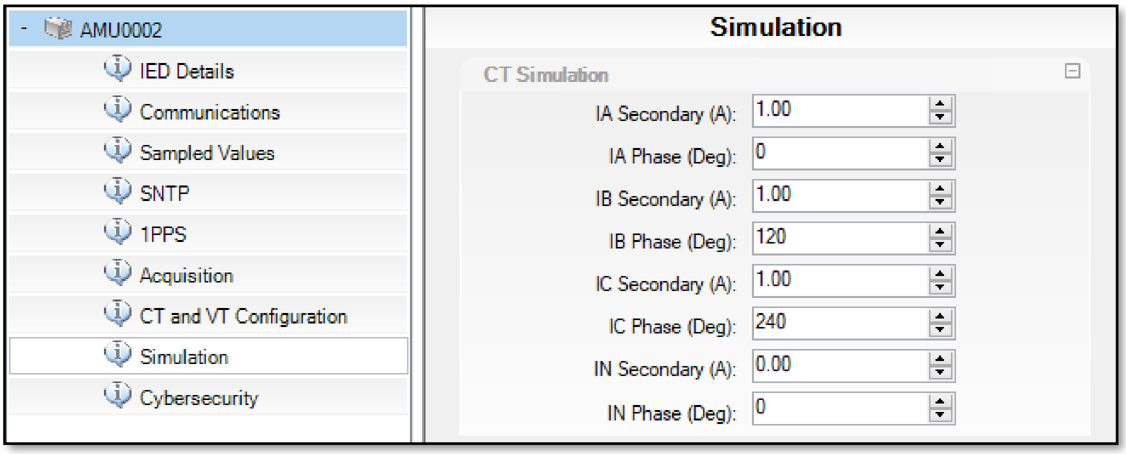


Figure 7.13 AMU SV CT Simulation

7.4.9 Cybersecurity

Cybersecurity settings allow to set password parameters. The “Attempts limit” parameter set the number of attempts allowed to enter a valid password. The time limit to enter a valid password can be set with the Attempts timer parameter (in minutes). The “blocking timer” parameter set the time the password is barred.

7.5 Configuration of Transformer protection and control IED

The power transformer protection and control Easergy MiCOM P645 IED from Schneider Electric is used as a component in the test-bench setup. The P645 IED is set up for a two winding power transformer.

Easergy Studio software provides support for MiCOM IEDs from Schneider Electric. The software lets the user manage the MiCOM IED. Easergy Studio has different tools available to send settings to an IED, extract settings from an IED, manage event and fault records, IEC 61850 configuration and edit Programmable Scheme Logic (PSL).

In MiCOM S1 Studio, a system can be created in the Studio Explorer. Substations, bays, voltage levels and devices is added to the system.

7.5.1 System in Easergy Studio

A new system, Test-bench 1, is created and shown in Figure 7.14.

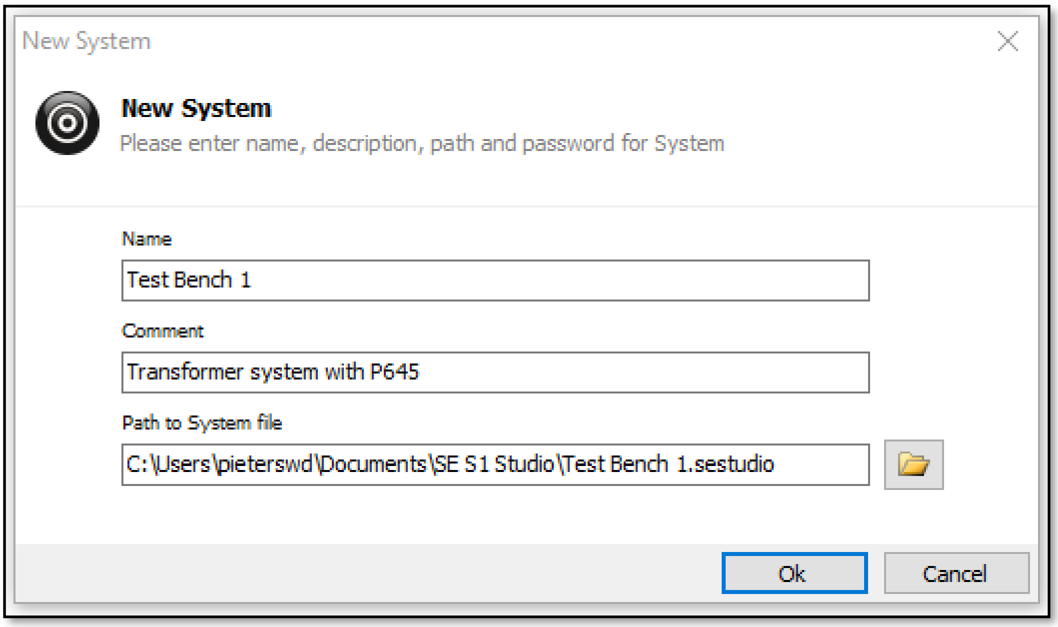


Figure 7.14 Easergy Studio-new system

An example is shown where a substation, Substation 1, is created with a 11kV and 132kV voltage level. A Feeder bay is added to the 11kV Voltage level and a Transformer bay is added to the 132kV voltage level, shown in Figure 7.15.

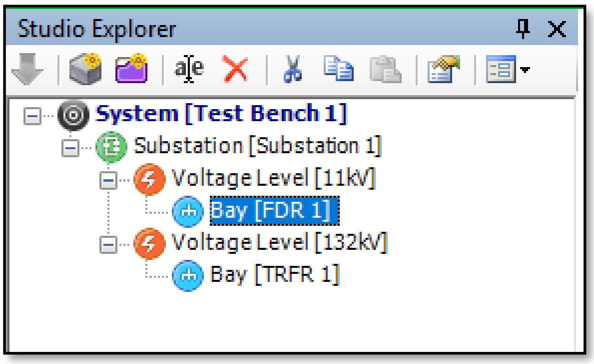


Figure 7.15 S1 Studio Explorer

One of the Tools of Easergy Studio is a data model manager that can be used to download the data models for the devices that can be added to the system. The device type and full model number must be selected when a new device is added to the system. A P645 device is added to the TRFR1 bay, shown below in Figure 7.16.

Different folders for settings, PSL, 61850 configurations, measurements, events and disturbance recordings are available for the device.

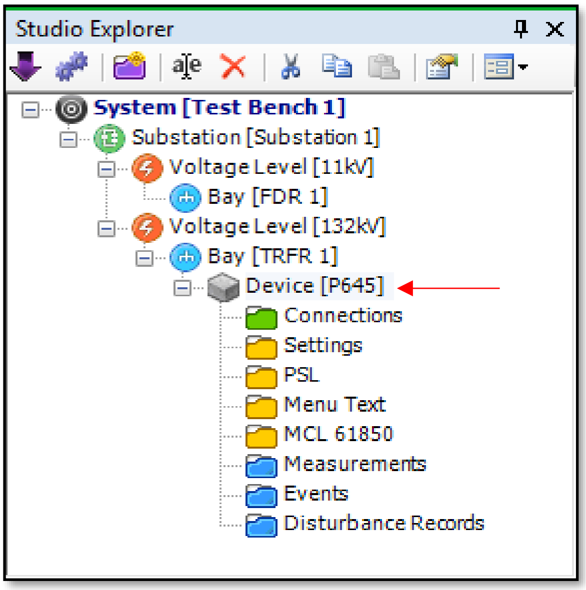


Figure 7.16 Easergy Studio Explorer - device

A connection to the device must be configured before file transfer to and from the device can happen. A connection can be configured to either the front serial port of the device or a rear Ethernet port. The Device IP address is required for an Ethernet connection. The device used for the test-bench setup has an IP address of 192.168.1.17.

7.5.2 Settings

A new settings file can be created from the data model or an existing settings file can be extracted from the device. The settings file can be changed and sent to the device. All the folders are shown in a default settings file that was created for the P645 device in Figure 7.17.

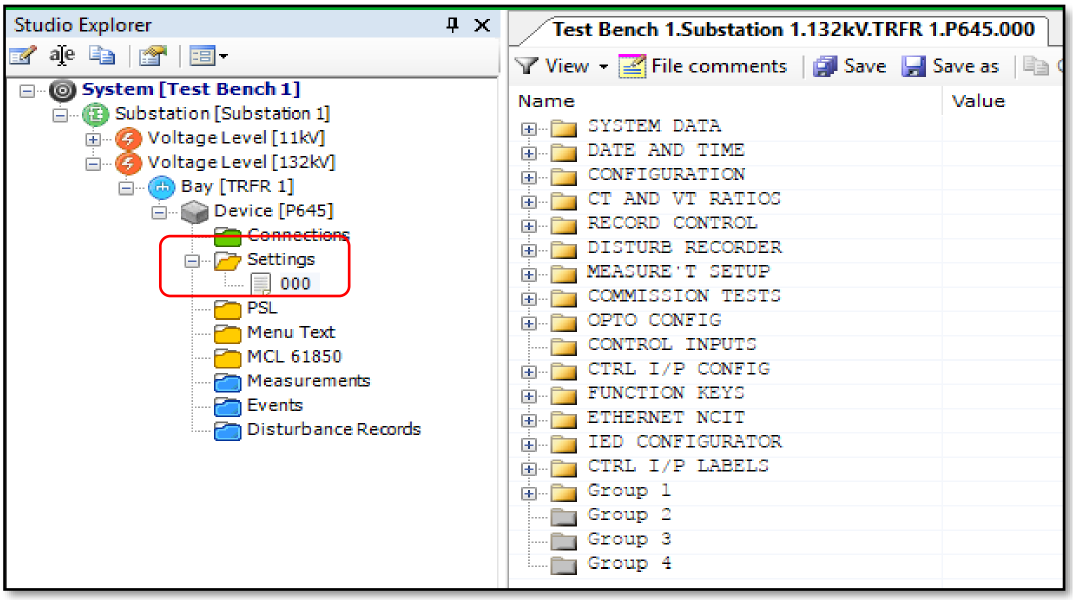


Figure 7.17 P645 Settings file

7.5.3 Configuration

The P645 can have 4 different setting groups. Each of the groups can be enabled or disabled. The active settings group must be set. The active settings group can be switched by using the setting menu on the IED front display or programmable scheme logic (PSL), E.g. the settings group can be changed when an input to the device is received. Different protection functions can be enabled or disabled. This is shown in Figure 7.18.

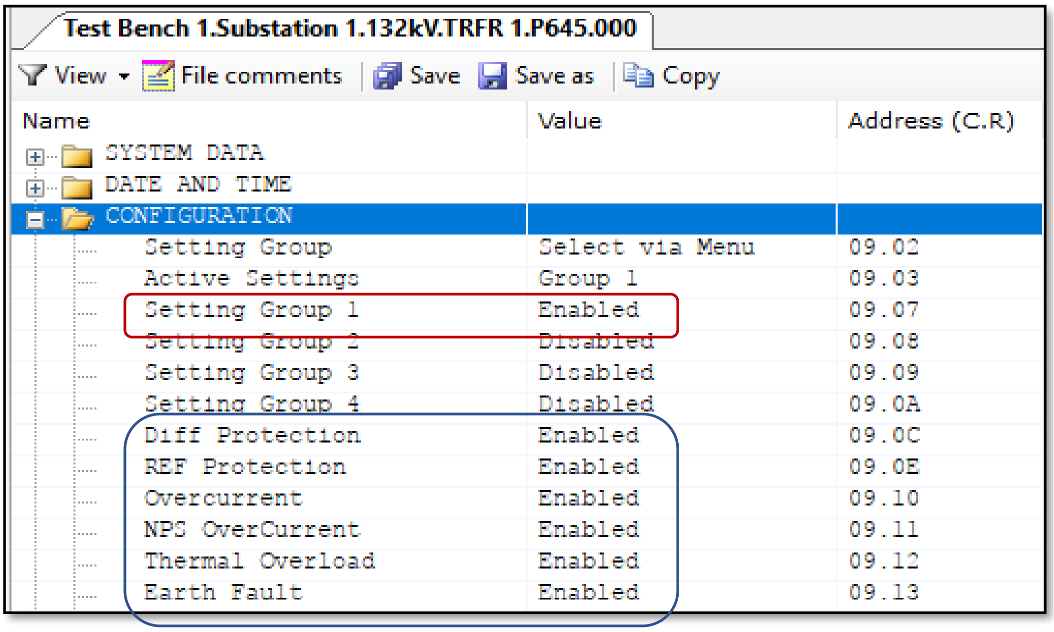


Figure 7.18 Settings file configuration

7.5.4 Group System configuration

Each off the four settings groups has individual settings. Each group comprises out of setting folders for the system configuration and different protection functions (e.g. Differential, REF and over current). Group 1 Settings as shown in Figure 7.19.

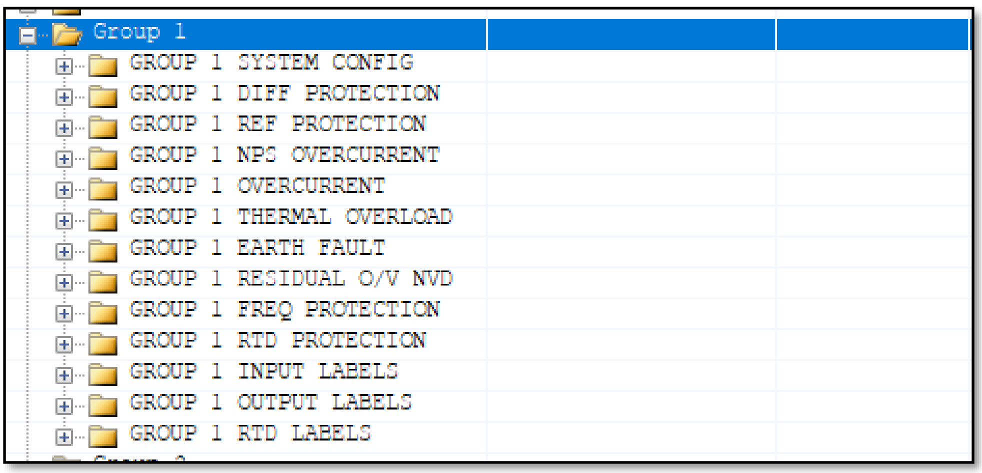
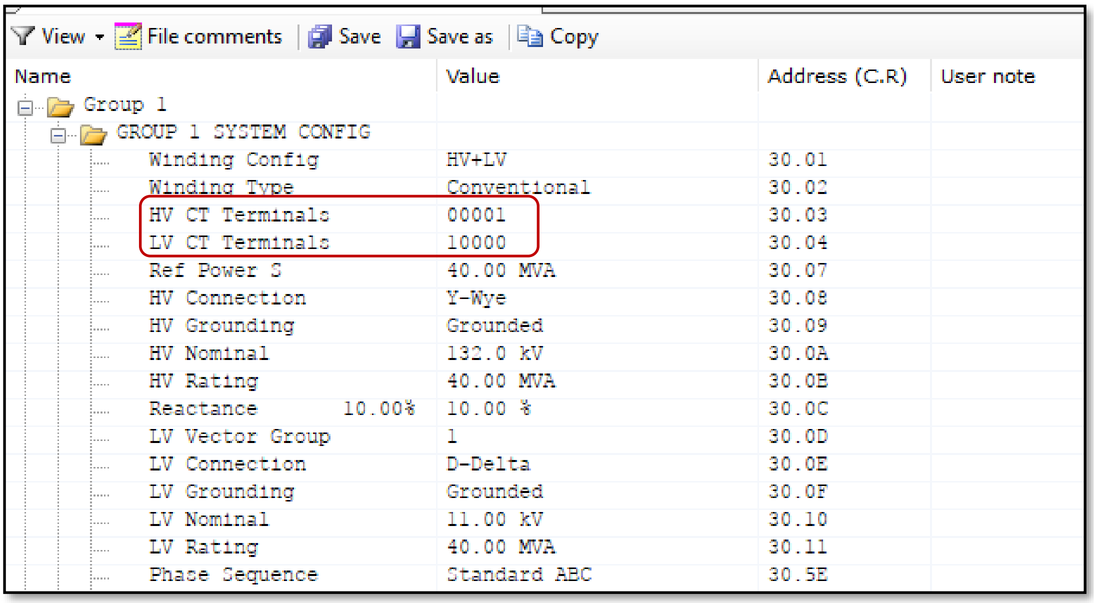


Figure 7.19 Group 1 Settings

The transformer parameters are set in the system configuration settings folder for each settings group. The system configuration for Group 1 settings is shown below in Figure 7.20. The configuration can be set for a two or three winding power transformer. The nominal voltage, winding connection, winding type and MVA rating can be set for each winding. The group 1 configuration was set for a two winding, 40MVA, 132/11kV, YNd1 power transformer. A winding can be set to be grounded or ungrounded.


View ▾ | File comments | Save | Save as | Copy

Name	Value	Address (C.R)	User note
Group 1			
GROUP 1 SYSTEM CONFIG			
Winding Config	HV+LV	30.01	
Winding Type	Conventional	30.02	
HV CT Terminals	00001	30.03	
LV CT Terminals	10000	30.04	
Ref Power S	40.00 MVA	30.07	
HV Connection	Y-Wye	30.08	
HV Grounding	Grounded	30.09	
HV Nominal	132.0 kV	30.0A	
HV Rating	40.00 MVA	30.0B	
Reactance 10.00%	10.00 %	30.0C	
LV Vector Group	1	30.0D	
LV Connection	D-Delta	30.0E	
LV Grounding	Grounded	30.0F	
LV Nominal	11.00 kV	30.10	
LV Rating	40.00 MVA	30.11	
Phase Sequence	Standard ABC	30.5E	

Figure 7.20 Group 1 system configuration

One or two CT terminals for each winding can be set. One CT terminal is set for each of the HV and LV windings

7.5.5 Current and Voltage transformer ratios

The polarity, primary and secondary current values for each of the 5 terminals for phase CTs, HV and LV E/F CT terminals for neutral CTs are set. The location of E/F CTs can be set to Starpoint, residual or none.

Primary and secondary voltage setting are set for a VT.

7.5.6 IEC 61850 9-2 SV

The configuration of sampled values is set under sub menu “Ethernet NCIT” shown below in Figure 7.21.

The physical link for the proses bus Ethernet communication is set to either copper or Fibre optic (FO). It is recommended by the manufacturer to set the physical link to FO for a permanent connection and use the copper link only during testing and commissioning.

The communication link connected to the RJ45 connector is used when copper is selected. The fibre optic links connected to the RX / TX connectors is used for a FO selection.

The Anti-Aliasing filter prevents high frequency noise from being sampled by the 9-2 Ethernet board. It is recommended by the manufacturer to enable the Anti-Alias filter except where high-speed processing is needed.

Merging unit delay setting is used when Sampled Values (SV) from several Merging Units (MU) is not received at the same time due to transmission delays. The transmission delay from the MU to the IED depends on the topology of the Ethernet network as well as the network traffic. The IED will wait for the merging unit delay time setting and delay the signal processing of the different SV from the different MUs.

The logical node names are set to match each MU Logical Node name that is broadcast. Synchronised SV from more than one MU is needed for differential protection. SVs are synchronized to a local or global 1 PPS signal.

A GPS signal is used when “Global 1PPS” is selected for synchronization.

ETHERNET NCIT		
Physical Link	Copper	18.01
AntiAlias Filter	Disabled	18.02
Merge Unit Delay	0 s	18.03
LN Arrangement	5VILabc, VxHV	18.04
Logical Node 1	MiCOM Logical Node 1 ...	18.20
Logical Node 5	MiCOM Logical Node 5 ...	18.24
Logical Node 6	MiCOM Logical Node 6 ...	18.25
Logical Node 7	MiCOM Logical Node 7 ...	18.26
Logical Node 8	MiCOM Logical Node 8 ...	18.27
Synchro Alarm	No SYNC CLK	18.30

Figure 7.21 Ethernet NCIT Settings

7.6 Configuration of Network equipment

Different Ethernet switches are used to set up the substation automation test-bench and connect the different components to the process bus network. This network is shown in Figure 7.22.

A MOXA PowerTrans PT-7728 series Ethernet switch is used to connect the Alstom Agile Merging Units (AMU) to the process bus.

A RUGGEDCOM RSG2288 managed Ethernet switch is used to connect the MiCOM P645 Transformer protection and control devices to the process bus. The PT-7728 and RSG2288 are connected to each other. The Acer Aspire ES 15 personal laptop computer is connected to the RSG2288 but can be connected to the PT-7728 as well.

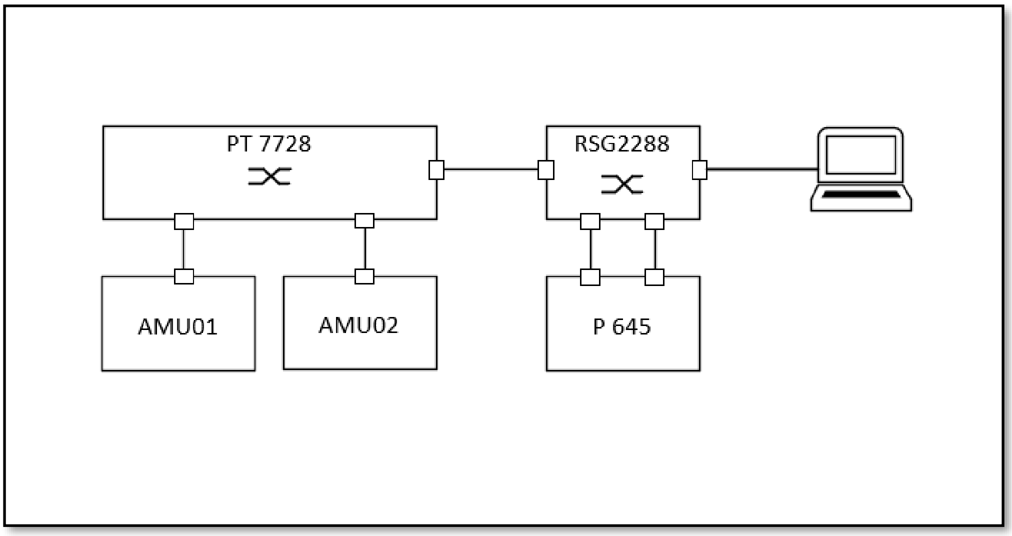


Figure 7.22 Test-bench Network Diagram

The configuration of the network switches is described in APPENDIX I.

7.7 Arrangement of Time synchronisation equipment.

The devices connected in a process bus network need an internal clock that are synchronized with a substation GPS clock. The synchronization is performed through IRIG-B or indirectly over a network using SNTP or IEEE 1588 PTP. PTP has better accuracy and is more suitable for Process Bus application.

PTP use the same Ethernet medium as the data communications for the time synchronization information communication. PTP reduces the cabling infrastructure requirements as there is no need of dedicated network for time synchronization information when compared to IRIG-B.

A SEL2407 Satellite-Synchronized Clock is used for the test-bench setup. This is shown in Figure 7.23. The synchronization is done with ±100 ns average timing accuracy. The SEL 2407 use one modulated and six demodulated IRIG-B outputs to synchronize Intelligent Electronic Devices (IEDs). Three of the six demodulated outputs can be set to 1 PPS. The SEL2407 provided time synchronization signals for the RTDS and RSG2288 network switch.

The RTDS GTSYNC card uses either IEEE 1588 PTP, 1 PPS, or IRIG−B unmodulated signals as the synchronization source. The GTSYNC is used to synchronize IEC 61850−9−2 Sampled Values output with a GPS time source via a 1 PPS signal. A 1 PPS or IRIG−B Copper BNC Output Port as well as 4 times 1 PPS or IRIG−B Fibre Output Ports.

The Merging Units allowed for SNTP as well is 1 PPS time synchronization. A 1 PPS time synchronisation source from the RTDS was used via fibre for the synchronization of the MUs.

The P645 IED has an IRIG-B input with BNC connector available for time synchronization. The IRIG-B signal is supplied from the network switch.
The RSG2288 network switch supports 1 PPS or IRIG-B copper BNC input and output ports. It has a GPS antenna input port. It also supports PTP and SNTP over the network.
The PT-7728 network switch supports PTP and SNTP over the network

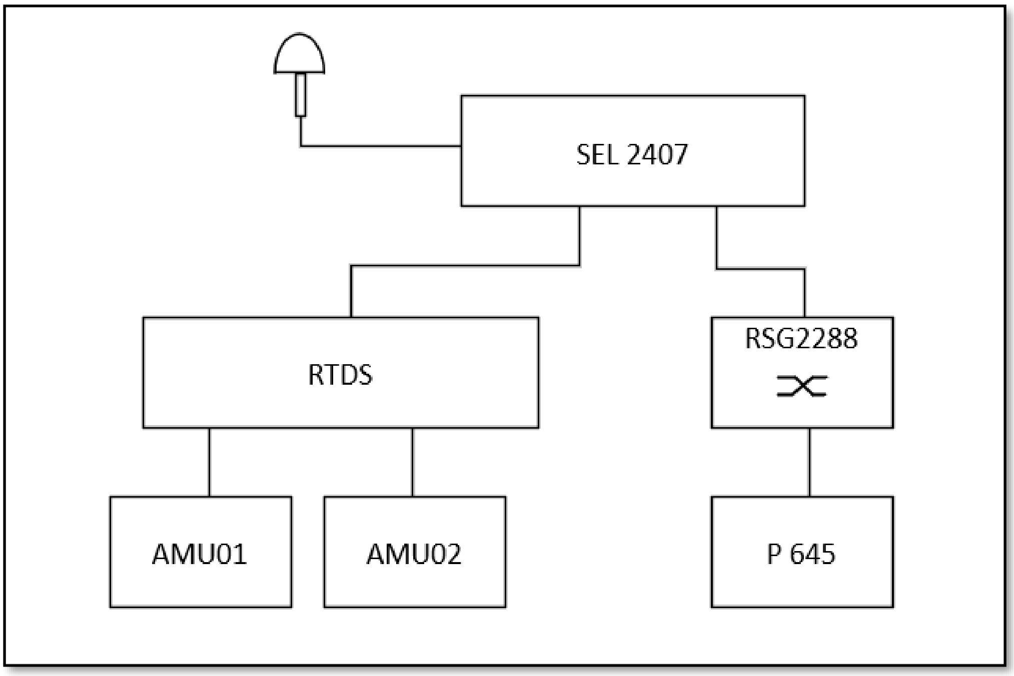


Figure 7.23 Time synchronisation network

7.8 Practical experiment results

Three test-benches are used to do different experiments. The following table show the aim and expected results for these practical experiments.

Table 7-2 Summary of test-bench aims and expected results

Test-bench A	
Aim	Publish Sampled Value (SV) streams on the Ethernet network and measure it.
Method	1) Use the RTDS and Omicron amplifier to produce power system Current Transformer (CT) and Voltage transformer (VT) analogue signals. 2) Use the Analogue Merging Units (AMUs) to convert the analogue CT and VT signals to IEC 61850-9-2 Sampled Value (SV) streams.

	3) Measure the SV streams using software tools. (Wireshark and SVScout). 4) Measure the SV streams with a MiCOM P645 protection IED
Expected result	1) The SV streams are successfully measured on the Ethernet network. 2) The SV data values are consistent and compare well with the analogue CT and VT signals.
Test-bench B	
Aim	Publish and test the IEC 61850−9−2 Sampled Values (SV) produced by the GTNET_SV9−2 component of the RTDS/ RSCAD software
Method	1) Use the RTDS to convert the power system analogue CT and VT signals to IEC 61850-9-2 Sampled Value (SV) streams. 2) Measure the SV streams using software tools. (Wireshark and SVScout). 3) Measure the SV streams with a MiCOM P645 protection IED.
Expected Result	1) The SV streams are successfully measured on the Ethernet network. 2) The SV data values are consistent and compare well with the analogue CT and VT signals.
Test-bench C	
Aim	1) Use IEC 61850−9−2 Sampled Values (SV) produced by the GTNET_SV9−2 component of the RTDS/ RSCAD software. 2) Measure the magnitude of fault currents for different system configurations. 3) Test the developed transformer protection scheme using the RTDS/ RSCAD software.
Method	1) Apply different types of faults and analyse the fault currents. 2) Apply faults (FLT2) out of the protection zone with Bus Section closed, 3) Apply faults (FLT2) out of the protection zone with Bus Section opened, 4) Apply faults (FLT1) in the protection zone and test the differential and over current protection.
Expected Result	Show that: 1) Different types of faults have different fault current values.

	2) Different protection settings can be used for different system configurations. 3) The scheme with differential and over current protection does not operate for faults out of the protection zone. 4) The scheme with differential and over current protection operates correctly for fault in the protection zone.
Test-bench D	
Aim	1) Compare a system that uses AMUs with a system that does not use AMUs
Method	1) Apply different types of faults and analyse the current transformer burden. 2) Apply faults (FLT2) out of the protection zone. 3) Apply faults (FLT1) in the protection zone 4) Compare the burden on the CTs for a system that uses AMUs with a system that does not use AMUs.
Expected Result	Show that: 1) The burden on current transformers is reduced when AMUs is used.

7.8.1 Test-bench A

The setup for Test-bench A is shown in Figure 7.1. A power system with source, power transformer and load models were developed and simulated in the RTDS. The RTDS simulated current and voltage instrument transformers were configured. The instrument transformers produce analogue signals. These analogue signals are sent out of the RTDS using the RTDS Gigabit Transceiver Analogue Output Card (GTAO) to interface analogue signals from the RTDS to the external devices. The GTAO card has analogue output channels with an output range of +/− 10 volts. The analogue signals from the RTDS GTAO cards are amplified using an Omicron CMS 156, 3 Phase Voltage and Current Amplifier. These analogue signals, proportional to the real-time secondary voltage and current signals, are sent to Analogue Merging Units (AMUs). The AMU converts the signals to IEC 61850-9-2 sampled value (SV) streams and publishes them on the network. Two AMUs are used, one for the CT and VT analogue signals on the primary 132kV side of the power transformer and the second is used for the 11kV side. The AMUs are connected to a network switch.

The MiCOM P645 subscribes to the SV streams. The 5 terminal Transformer differential IED requires 5 SV streams to be configured in the IED. Only two SV streams were available, the absence of the other SV streams caused a logical node (LN) and non-conventional instrument transformer (NCIT) alarm resulting in the IED not functioning correctly. It was therefore not possible to determine if the IED will measure the current and voltage values correctly.

The SV streams are captured using the Wireshark network protocol analyser and Omicron SVScout software to verify that the SV streams are published on the process bus network. The tools can be used to determine if network is correctly configured and the SV streams are transmitted through a switch port, blocked or filtered by a network switch.

7.8.1.1 Wireshark network protocol analyser

The live packets were captured and saved to a file. Offline analysis is done on the packets. The frame information of an AMU SV 122-bit packet is shown in Figure 7.24.

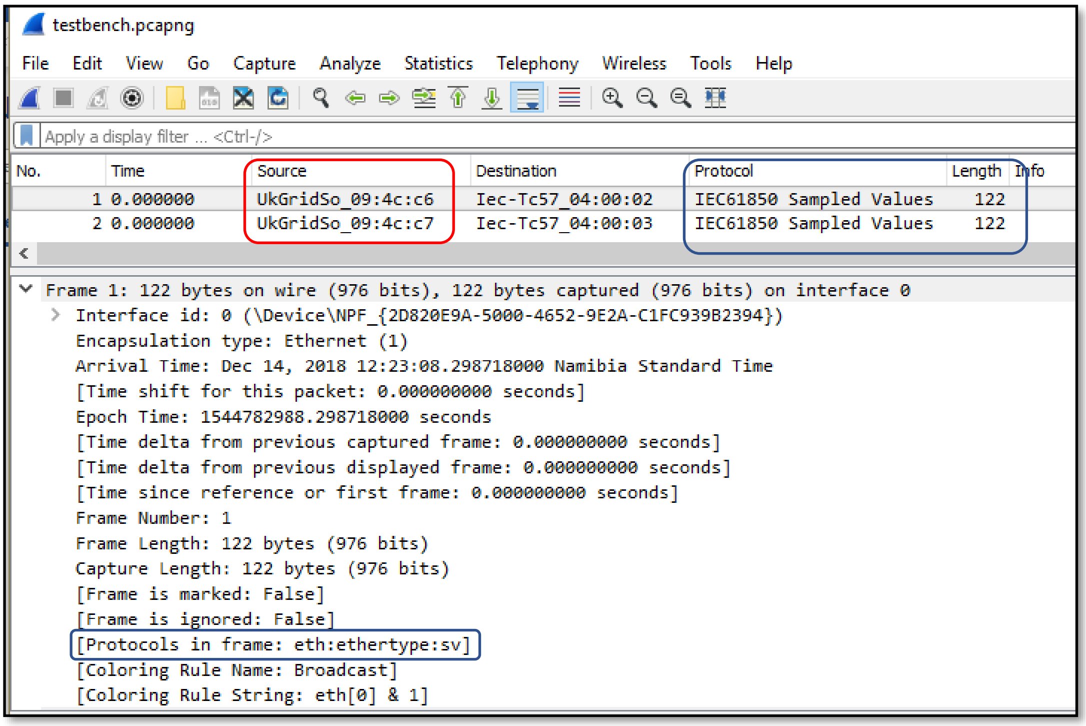


Figure 7.24 Wireshark AMU SV packet

SV packet format is shown in Figure 7.25. The name and values of each field are shown. The Header MAC address at the start of the frame shows the destination and source addresses. The field Application Protocol Data Unit (APDU) can be expanded to show the Application Service Data Unit (ASDU). The svID AlstomMU02 indicates the LNName of the SV multi cast message sent from the AMU. The measured values are saved in the data set field at the end of the ASDU in SV Ethernet frame.

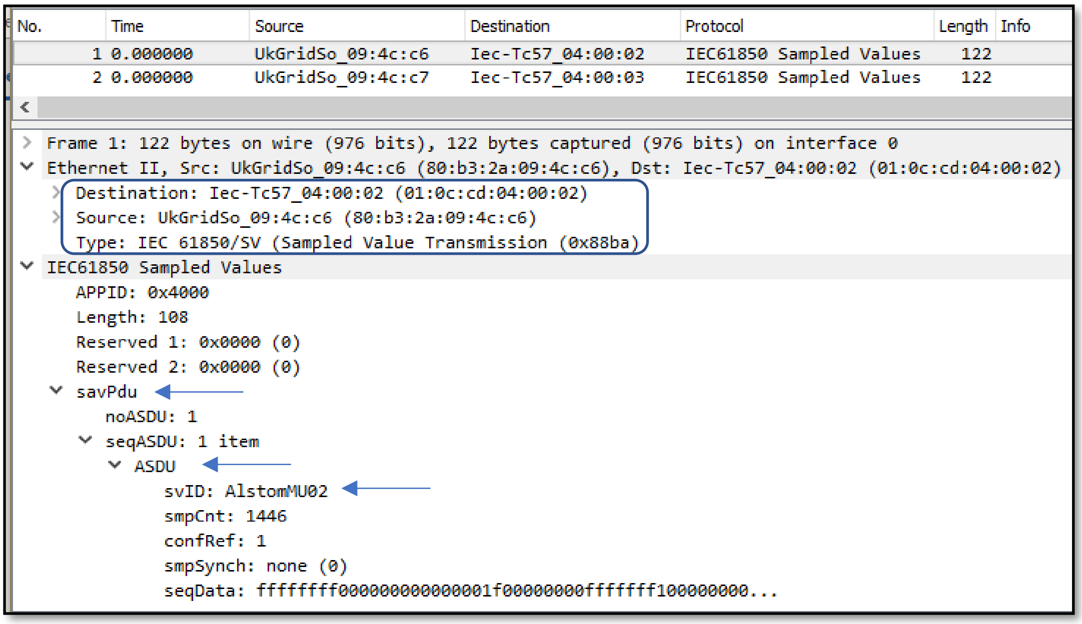


Figure 7.25 Wireshark AMU SV Ethernet frame

7.8.1.2 SVScout

SVScout was used as a tool for visualizing Sampled Values (SV) according to IEC 61850-9-2LE sampled at 80 samples per cycle and 4000Hz. It subscribes to the SV streams from multiple merging units and displays the waveforms of the primary voltages and currents in an oscilloscope view. A report can be generated to summarise the SV measurement information.

A part of the test report is shown in Figure 7.26. The information included the sampling frequency, SV Stream ID, Source and destination MAC addresses.

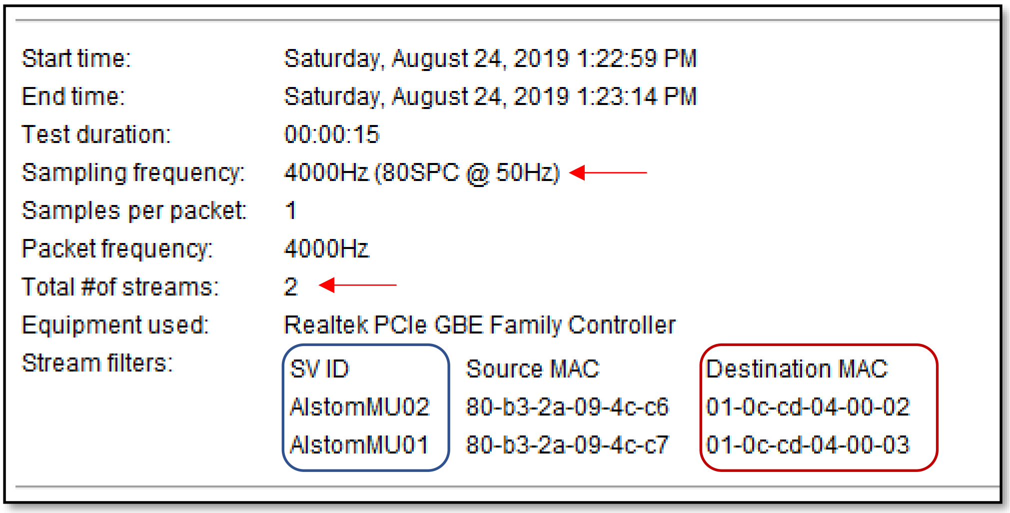
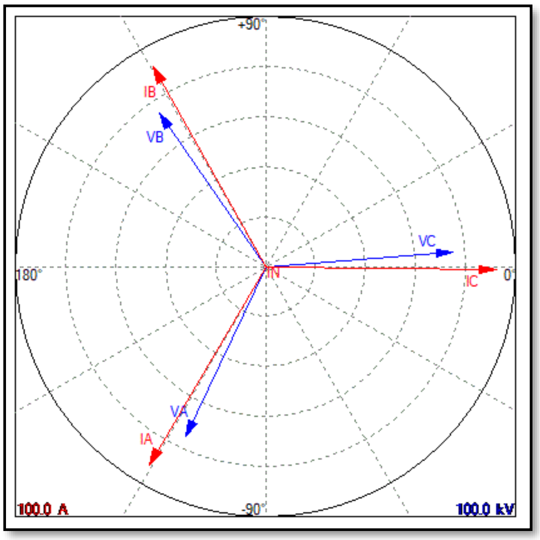


Figure 7.26 SVScout AMU report SV information

The Test report also shows the current and voltage values and phasors of the SV Streams shown in Figure 7.27.

Phasors

Channel	RMS	Phase
IA	92.235 A	-120.49 °
IB	92.159 A	119.24 °
IC	92.169 A	-0.77 °
IN	1.379 A	65.59 °
VA	75.210 kV	-115.39 °
VB	75.214 kV	124.61 °
VC	75.193 kV	4.61 °
VN	0.000 kV	0.00 °



Phasors

Channel	RMS	Phase
IA	1.078 kA	-90.11 °
IB	1.077 kA	149.93 °
IC	1.077 kA	29.94 °
IN	0.001 kA	120.00 °
VA	6.056 kV	-90.99 °
VB	6.055 kV	149.02 °
VC	6.055 kV	29.02 °
VN	0.002 kV	110.17 °

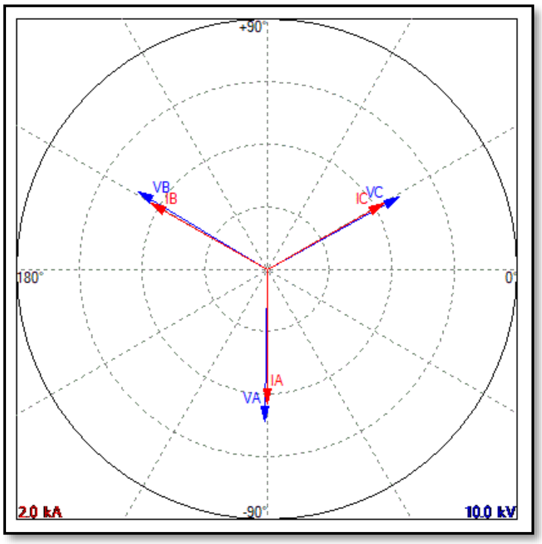


Figure 7.27 SVScout AMU Test Report SV Phasor values

With this tool it is possible to subscribe to the SV message and measure it on the process bus network. It is also possible to produce a report on the current and voltage values of the phasors.

The Sampled Value measured current and voltages values are consistent with the system current and voltage values measured in the RTDS. The RTDS measurements on the HV 132kV side is shown below in Figure 7.28 and the MV 11kV side is shown in Figure 7.29.

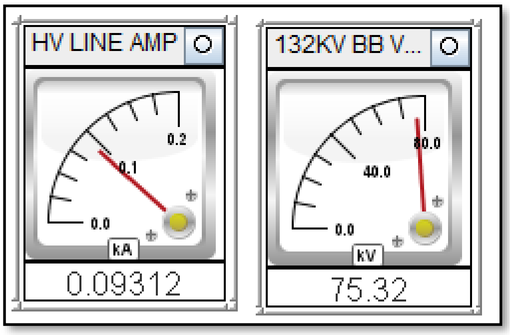


Figure 7.28 RTDS Runtime HV current and voltage measurements

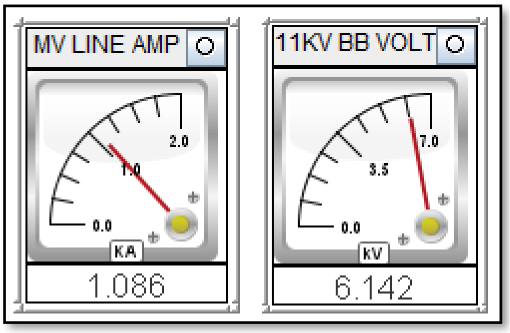


Figure 7.29 RTDS Runtime MV current and voltage measurements

7.8.2 Test-bench B

The setup for Test-bench B shown in Figure 7.2 is used. A power system model with a source, power transformer and load were developed and simulated in the RTDS. The RTDS simulated current and voltage instrument transformers were configured.

The instrument transformers produced analogue signals proportional to the real-time secondary voltage and current signals. These signals are taken to a RTDS GTNET_SV9−2_v5 component that provides IEC 61850−9−2 Sampled Values messages using the GTNET hardware. The GTNET_SV9−2_v5 component has a 9.2LE configuration to convert 4 current and 4 voltage signals to one IEC 61850-9-2 sampled value (SV) stream and publish it on the communication network. Two SV streams are used, one for the CT and VT analogue signals on the primary 132kV side of the power transformer and the second is used for the 11kV side. The RTDS is connected to a network switch. The MiCOM P645 subscribes to the SV streams and measures the power system currents and voltages.

The SV streams were captured using the Wireshark network protocol analyser and Omicron SVScout software to verify that the SV streams are published on the process bus network.

The tools can be used to determine if network is correctly configured and the SV streams are transmitted through a switch port, blocked or filtered by a network switch.

7.8.2.1 Wireshark network protocol analyser

The live packets were captured and saved to a file. Offline analysis is done on the packets. The Ethernet frame information of an RTDS SV 122-bit packet is shown in Figure 7.30.

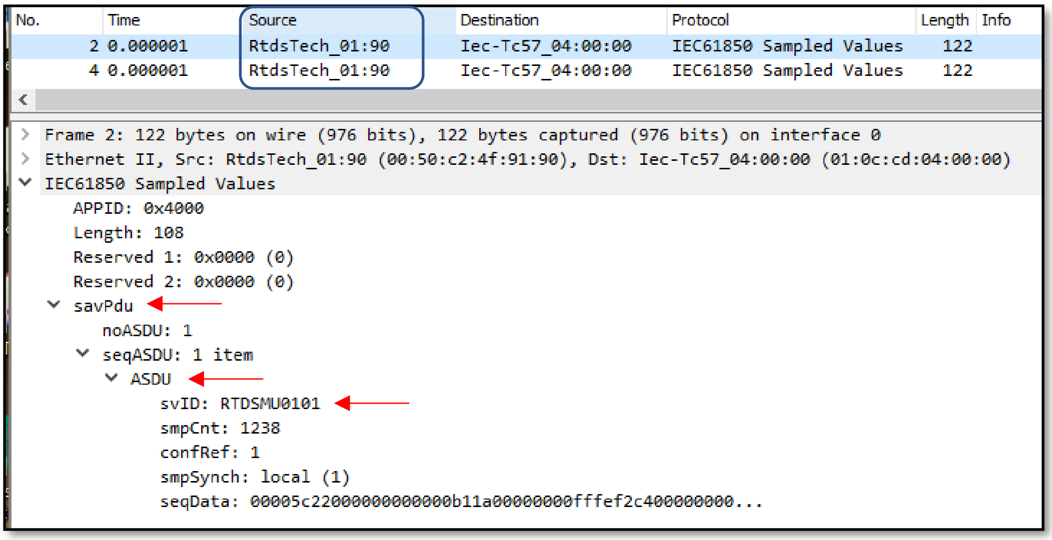


Figure 7.30 Wireshark RTDS SV Ethernet frame

The name and values of each field are shown. The Header MAC address at the start of the frame shows the destination and source addresses. The field Application Protocol Data Unit (APDU) can be expanded to show the Application Service Data Unit (ASDU). The svID RTDSMU0101 indicates the LNName of the SV multi cast message sent from the RTDS. The measured values are saved in the data set field at the end of the frame.

7.8.2.2 SVScout

The SVScout software tool was used to visualize the Sampled Values (SV) according to IEC 61850-9-2LE sampled at 80 samples per cycle and 4000Hz. SVScout subscribes to the SV streams from the RTDS and displays the waveforms of the primary voltages and currents in an oscilloscope view. A report was generated to summarise the SV measurement information.

A part of the test report is shown in Figure 7.31. The information includes the sampling frequency, SV Stream ID, Source and destination MAC addresses of both SV streams.

Start time:	Wednesday, January 31, 2018 10:43:42 AM
End time:	Wednesday, January 31, 2018 10:43:49 AM
Test duration:	00:00:07
Sampling frequency:	4000Hz (80SPC @ 50Hz)
Samples per packet:	1
Packet frequency:	4000Hz
Total #of streams:	2
Equipment used:	Realtek PCIe GBE Family Controller

Stream filters:

SV ID	Source MAC	Destination MAC
RTDSMU0101	00-50-c2-4f-91-90	01-0c-cd-04-00-04
RTDSMU0201	00-50-c2-4f-91-90	01-0c-cd-04-00-05

Figure 7.31 SVScout RTDS MU report SV information

The phasors and oscilloscope view of the two SV streams sent from the RTDS are shown below in Figure 7.32 and Figure 7.33. The one is of current and voltage values on the 132kV Side of the power transformer and the second is on the 11kV side.

Phasors

a) Stream 1

Channel	RMS	Phase
IA	89.474 A	-10.26 °
IB	89.485 A	-130.26 °
IC	89.468 A	109.73 °
IN	0.000 A	0.00 °
VA	75.377 kV	-3.60 °
VB	75.376 kV	-123.60 °
VC	75.376 kV	116.40 °
VN	0.000 kV	0.00 °

Phasors

b) Stream 2

Channel	RMS	Phase
IA	1.043 kA	20.56 °
IB	1.043 kA	-99.44 °
IC	1.043 kA	140.56 °
IN	0.000 kA	0.00 °
VA	6.257 kV	23.49 °
VB	6.257 kV	-96.51 °
VC	6.257 kV	143.49 °
VN	0.000 kV	0.00 °

Figure 7.32 SVScout RTDS MU Report- Phasors

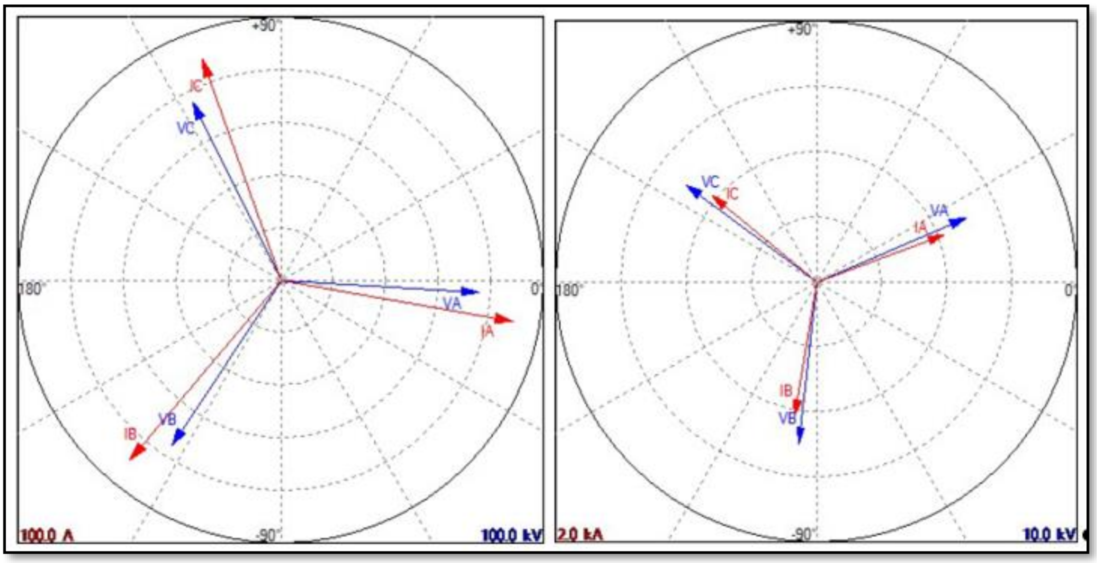


Figure 7.33 SVScout RTDS MU Report oscilloscope

The Sampled Value measured current and voltages values are the same as the system current and voltage values measured in the RTDS Runtime software. The RTDS measurements on the HV 132kV side is shown below in

Figure 7.34 and the MV 11kV side is shown in

Figure 7.35.

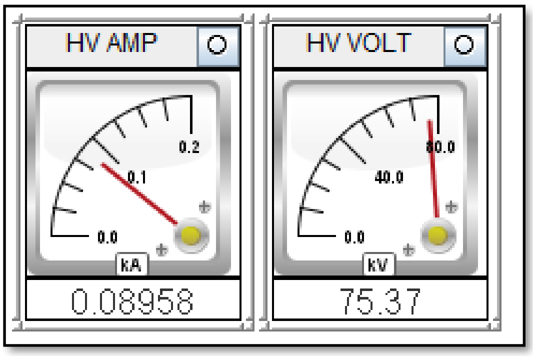


Figure 7.34 RTDS Runtime HV current and voltage measurements

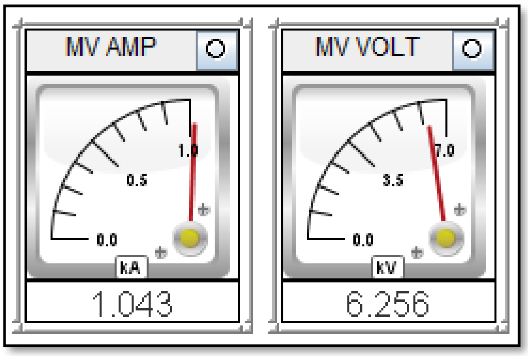


Figure 7.35 RTDS Runtime MV current and voltage measurements

7.8.2.3 P645 IED

The MiCOM P645 Five terminal Transformer differential IED requires five Logical Nodes for the SV streams to be configured in the IED. Only two AMUs were available to produce SV streams.

Three SV streams produced by the RTDS GTNET_SV9−2_v5 component and sent to the Ethernet network from the RTDS and the two SV produced from the AMU were used for the test-bench setup to test the Micom P645 IED. This is shown in Figure 7.36 below. RTDS 1,2 & 3 represent the three SV streams from the RTDS. AMU1 and AMU2 SV represents the SV streams from the two analogue Merging Units. The IED requires to measure all five SV streams. The absence of an SV stream caused a logical node (LN) and non-conventional instrument transformer (NCIT) alarm on the IED resulting in the IED not functioning correctly.

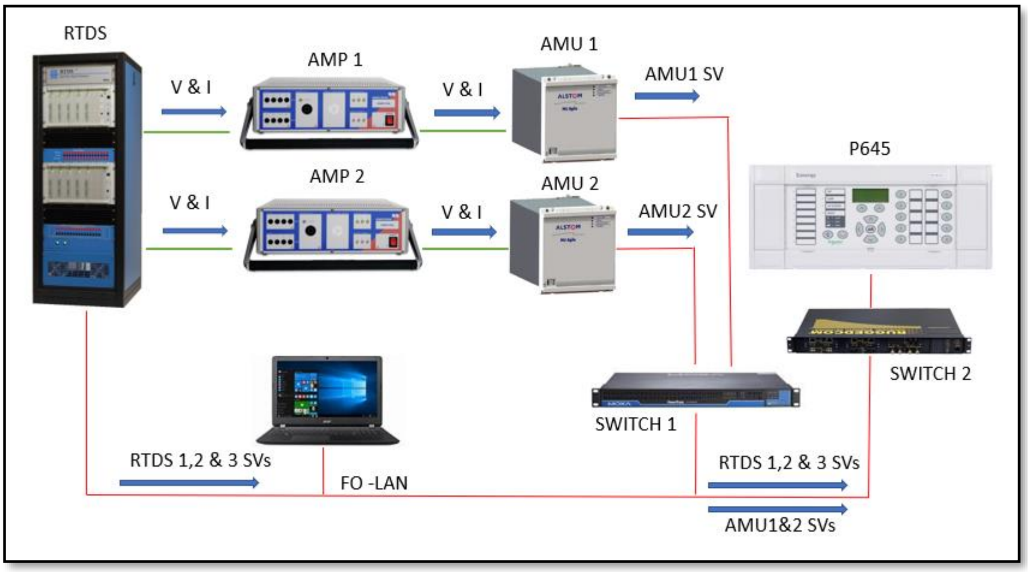


Figure 7.36 Setup for 5 SV streams sent to the P645 IED

The following terminals were configured to subscribe to the Sampled Value streams (SV) streams:

Terminal 1 was configured to use the SV stream from RTDSMU0101,

Terminal 2 SV from AlstomMU02,

Terminal 3 SV from AlstomMU01,

Terminal 4 SV from RTDSMU0301,

Terminal 5 SV from RTDSMU0201.

The 5 SV streams is measured on the Ethernet network using SVScout. This is shown below in Figure 7.37.

Start time:	Thursday, September 27, 2018 3:58:22 PM		
End time:	Thursday, September 27, 2018 3:58:30 PM		
Test duration:	00:00:08		
Sampling frequency:	4000Hz (80SPC @ 50Hz)		
Samples per packet:	1		
Packet frequency:	4000Hz		
Total #of streams:	4		
Equipment used:	Realtek PCIe GBE Family Controller		
Stream filters:	SV ID	Source MAC	Destination MAC
	AlstomMU01	80-b3-2a-09-4c-c7	01-0c-cd-04-00-03
	AlstomMU02	80-b3-2a-09-4c-c6	01-0c-cd-04-00-02
	RTDSMU0101	00-50-c2-4f-91-90	01-0c-cd-04-00-01
	RTDSMU0301	00-50-c2-4f-95-9e	01-0c-cd-04-00-04
	RTDSMU0201	00-50-c2-4f-95-9e	01-0c-cd-04-00-05

Figure 7.37 The 5 Sampled values measured by SVScout

RTDSMU0101 produced SV streams for the HV 132kV Side of the transformer and RTDSMU0201 for the MV 11kV side. The currents and voltages measured on the IED are shown in Table 7-3. It is shown that the A Phase voltage (Phase to neutral) is the reference voltage. The other two (B and C Phases) voltage vectors have a 120 ° phase angle difference to the A Phase voltage.

A 30° angle difference is shown for the current vectors between the 132kV and 11kV sides of the transformer due to the vector group connection of YNd1.

Table 7-3 IED P645 Measured current & voltage values

HV Side (132kV)	**A rms**	**Angle**	**MV Side (11kV)**	**kA rms**	**Angle**
IA-1	177,7	-154°	IA-5	2,002	3,583
IB-1	177,6	85,95	IB-5	2,002	-123,8
IC-1	177,7	-34,03	IC-5	2,002	116,1

MV Side (11kV)	kV rms	Angle	MV Side (11kV)	kV rms	Angle
VAN	6,622	0	VAB	11,47	30
VBN	6,622	-120	VBC	11,47	-90
VCN	6,622	120	VCA	11,47	150

The three phase currents (IBUR1 ABC) measured by the current transformer on the 132kV side are shown below in Figure 7.38. It is a balanced three phase system.

The peak value for the measured current is 1.25 amp and changed to a RMS value. The RMS value is 1.25 x 0.707 = 0.884 Amp. A ratio of 200/1 is used for the current transformer resulting in a primary line current of 200 x 0.884 = 176,8 Amp. This is the same as the currents (IABC-1) measured by the IED.

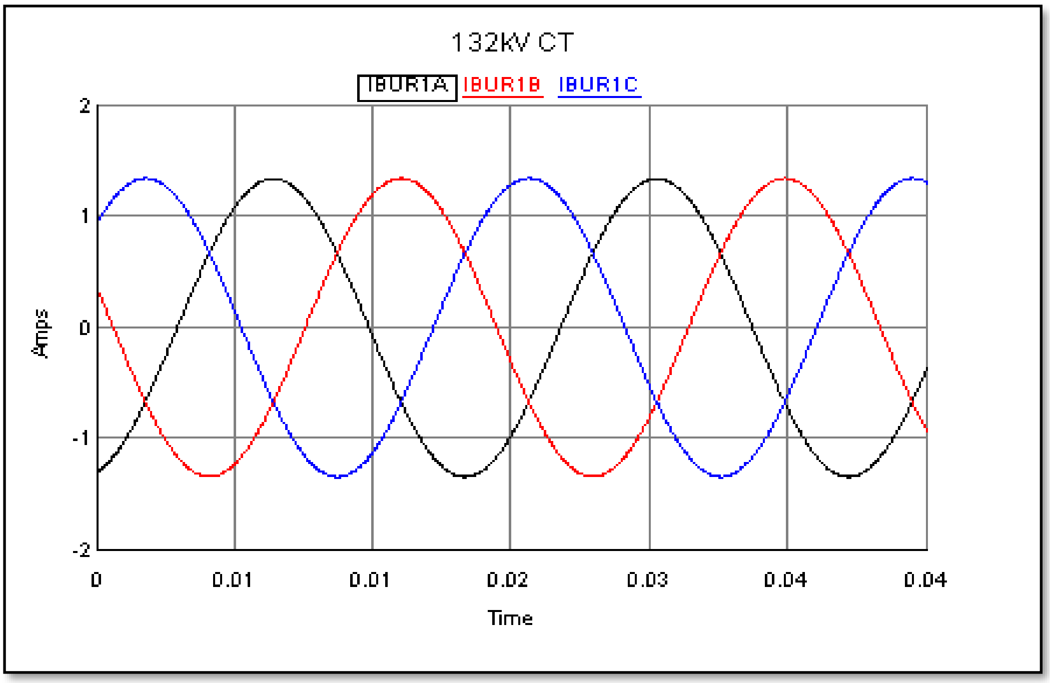


Figure 7.38 3-Phase currents measure by the 132kV CT

The three phase currents (IBUR2 ABC) measured by the current transformer on the 11kV side are shown below in Figure 7.39.

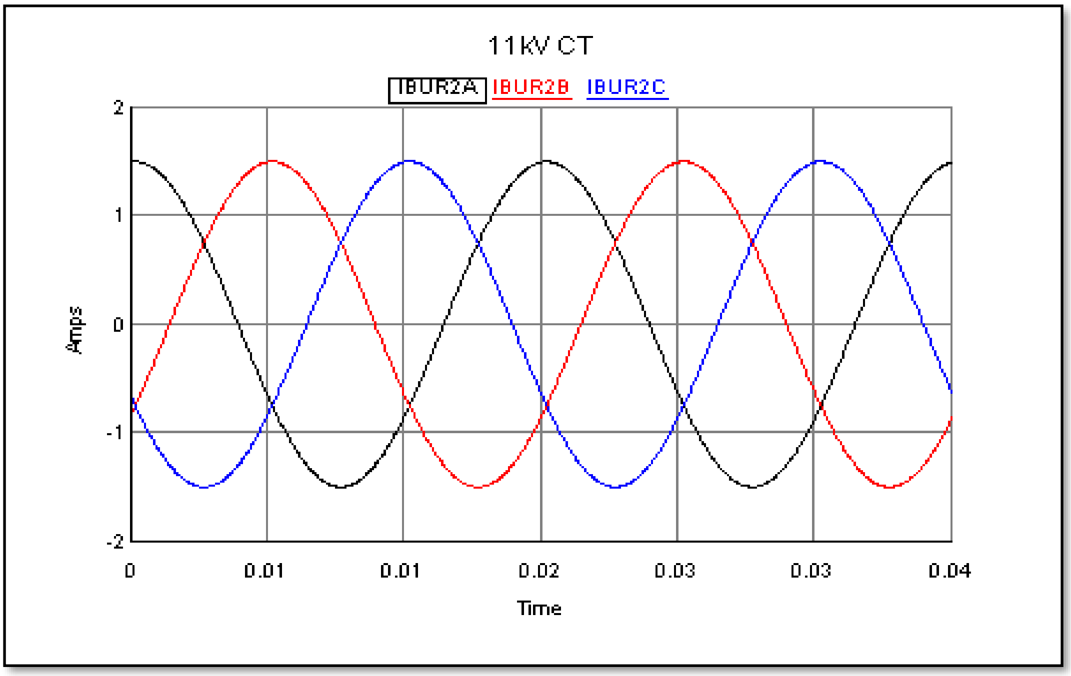


Figure 7.39 3-Phase currents measure by the 11kV CT

The peak value for the measured current is 1.4 amp and converted to RMS it is 1.41 x 0.707 = 0.997 Amp. A ratio of 2000/1 is used for the current transformer resulting in a primary line current of 2000 x 0.997 = 1994 Amp. This is the same as the currents (IABC-5) measured by the IED.

The P645 measured values are the same as the line currents and voltages measured in the RTDS runtime for the power system model.

7.8.3 Test-bench C

A system of two 40MVA 132/11kV YNd1 power transformers connected in parallel is modelled and simulated in the Real-Time Digital Simulator (RTDS) for the Test-bench C setup.

The system has a source connected to the 132kV (SRC1) bus bar. The 11kV bus bar has 2 x Bus Sections, 1 x 11kV load and 1 x 11kV Source (SRC2) are connected to the 11kV bus bar sections. A Bus Section circuit breaker (BS1) connects the two bus sections.

The RTDS RSCAD Runtime model of the simulation Case C, the system of parallel power transformers using SV, is shown in Figure 7.40 below.

Primary substation equipment such as instrument transformers and circuit breakers are modelled. Differential and Over Current protection relays are modelled in the RSCAD Draft software.

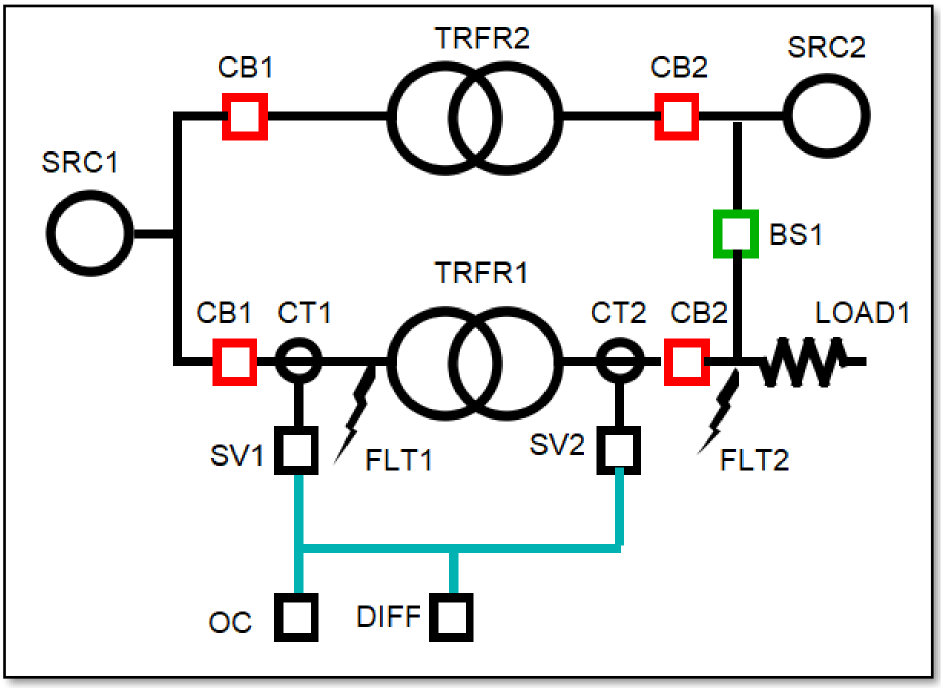


Figure 7.40 RTDS RUNTIME Case C for Test-bench C with TRFR 1 & 2 with SV

The instrument transformers produce analogue signals proportional to the real-time primary system voltage and current signals. These signals represented by the SV1 and SV2 in the figure above are taken to a RTDS GTNET_SV9−2_v5 component. The GTNET SV components provide IEC 61850−9−2 Sampled Values messages using the GTNET hardware. The GTNET_SV9−2_v5 component has a 9.2LE configuration to convert 4 current and 4 voltage signals to one IEC 61850-9-2 Sampled Value (SV) stream and to publish it on the communication network. Two SV streams are used, one for the CT and VT analogue signals on the primary 132kV side of the power transformer and the second is used for the 11kV side. The RTDS is connected to a network switch. A Laptop computer is connected to the Ethernet network and software is used to measure the sampled value messages.

The Over Current and Differential protection relays in the RTDS/RSCAD software do not use the Sampled Values directly. The Sampled Values streams are again taken to a GTNET_SV9-2_v5 component that produces analogue CT an VT signals for the protection relays to use. This is shown in Figure 7.41 below. The GTNET-SV1 component on the left converts the CT currents (IBUR2A, B & C) to Sampled Values. The GTNET_SV component on the right converts the SV stream to analogue currents (SVA, B and C).

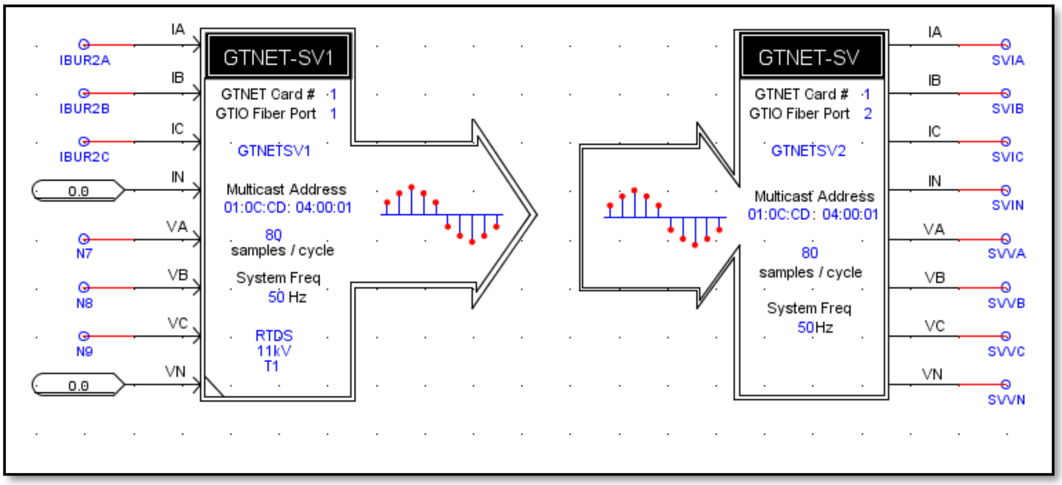


Figure 7.41 RTDS GTNET Sampled Values

7.8.3.1 Test-bench C setup

Different type of faults at different positions are applied in the system with parallel power transformers. The results were monitored in RTDS Runtime.

The following type of faults are applied:

- Single phase to ground faults
- Phase to Phase faults
- Three phase faults

It is expected that the results will show that different types of faults will result in different magnitudes of fault currents.

The system is configured in different ways by operating different circuit breakers as follows:

- All circuit breakers are closed with the transformers 1 and 2 connected in parallel and the Source 2 connected. The two parallel transformers and Source 2 are sharing the load. Source 2 is contributing to increasing the system fault level.
- The circuit breaker CB2 of Transformer 2 is opened. Transformer 1 is connected to the Source 2.
- The circuit breaker BS1 of the Bus Section is opened. Transformer 1 is supplying the full load.

It is expected that the results will show that the current flowing through Transformer 1 will change as the system configuration is changed. One power transformer in a system of parallel transformers is therefore impacted by the system configuration.

Faults are applied at the following positions:

- Fault 1 is applied in the transformer differential protection zone for which the protection should operate.

- Fault 2 is applied out of the transformer differential protection zone for which the protection should not operate and must remain stable.

The results are expected to show that the protection system for the tested power transformer is operating correctly in a system of parallel power transformers.

7.8.3.2 The behaviour of the system during different conditions.

The output currents produced by Current Transformers (CTs) are measured and analysed during normal load conditions and when different types of faults are applied to the 11kV busbar. The A-Phase current of the Transformer 1 CT on the 132kV side is measured.

7.8.3.2.1 The behaviour of the system during normal loading conditions.

The system supplies a load of 40MVA. The system configuration is changed while keeping the load constant. The following three system configurations are considered for the experiment:

- Transformer 1, Transformer 2 and Source 2 are connected in the system to supply the load together. Source1 supplies 28.6MVA of the total load through the two parallel transformers with Source 2 supplying the rest of the load.
- Transformer 1 and Source 2 are connected. Source1 supplies 26.1MVA through Transformer 1 with Source 2 supplying the rest of the load.
- Source1 supplies 40MVA through Transformer 1 for the case when only Transformer 1 is connected.

The A-Phase secondary output peak currents for Transformer 1, 132kV Current Transformer (CT) are measured for the three different system configurations. This is shown in Figure 7.42.

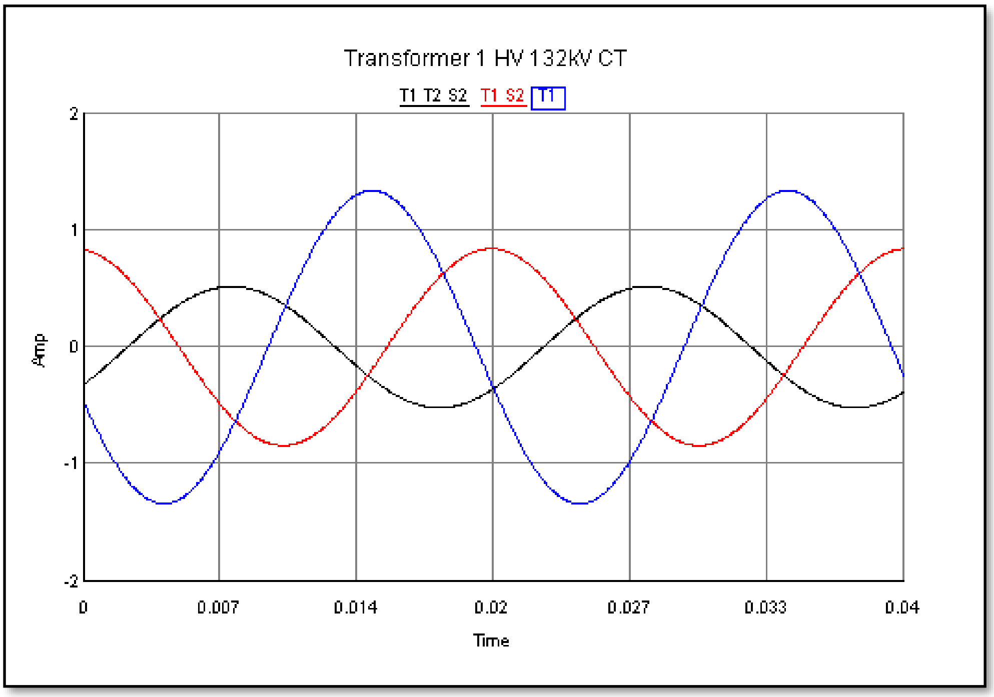


Figure 7.42 Transformer 1, 132kV CT A-Phase currents for different system configurations

A summary is shown in Table 7-4 below of how the current flowing through Transformer 1 is changing as the system configuration is changed. The Source MVA and CT 1 measurements are presented.

Table 7-4 Summary of system behaviour for different system configurations

Connected in system	Source 1 MVA	T1 CT1
Transformer 1, 2 and Source 2	28.6	0,52
Transformer 1 and Source 2	26.1	0.84
Transformer 1	40	1.34

It is shown with the results of this experiment that:

- The parallelly connected transformers share the load.
- Sources connected influence the currents flowing through the system of parallel power transformer
- The load current flowing through Transformer 1 is changing for the same load condition and for different system configurations.

7.8.3.2.2 The behaviour of the system during a single phase to ground fault

The single phase to ground fault level depends on the system zero sequence impedance. The zero sequence impedance does not influence balanced faults like a three phase fault. The single phase to ground faults can be of a lower value compared to three phase faults and phase to phase faults.

A single phase to ground type of fault is applied to the A-Phase in the system with parallel power transformers. The Fault is applied to the 11kV bus bar in the system.

The system configuration is changed by opening different circuit breakers.

The following three configurations are considered for the experiment:

- Transformer 1, Transformer 2 and Source 2 are connected in the system,
- Transformer 1 and Source 2 are connected,
- Transformer 1 is connected.

The results are monitored in RTDS Runtime.

The A-Phase secondary output peak currents for Transformer 1, 132kV CT are measured for the three different system configurations. This is shown in Figure 7.43. The three measurements are not time synchronised.

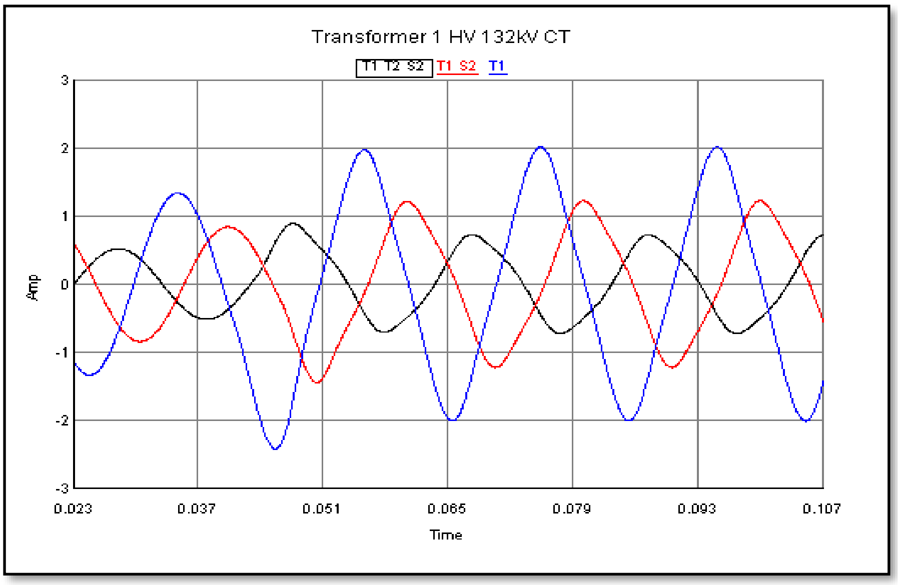


Figure 7.43 Transformer 1, 132kV CT A-Phase current for Phase to Ground faults and different system configurations.

A summary is shown in Table 7-5 below. Fault currents flowing through Transformer 1 are different as the system configuration is changed.

Table 7-5 Summary of system behaviour for a phase to ground fault and different system configurations

Connected in system	T1 CT1 A-Phase
Transformer 1, 2 and Source 2	0,72
Transformer 1 and Source 2	1,2
Transformer 1	2

It is shown with the results of this experiment that:

- The parallelly connected transformers influence the fault levels and current magnitude.
- Power Sources connected influence the fault levels and the current magnitude.
- The fault current flowing through Transformer 1 is changing for the same phase to ground fault in the cases for different system configurations.

7.8.3.2.3 The behaviour of the system during a phase to phase fault

A phase to phase type of fault is applied between the A and B-Phases in the system with parallel power transformers. The Fault is applied to the 11kV bus bar in the system. The system configuration is that only Transformer 1 is connected.

The results are monitored in RTDS Runtime.

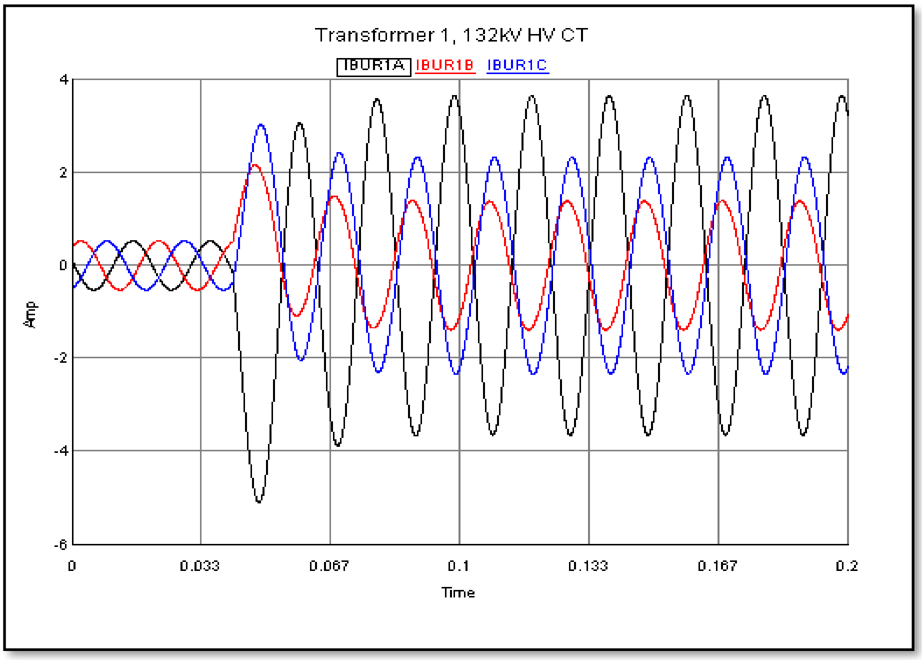


Figure 7.44 Transformer 1, 132kV CT for Phase to Phase fault.

The A, B and C-Phases (IBUR1A, B and C) are secondary output peak currents for Transformer 1, High Voltage 132kV current transformer. The currents are measured for the case where only Transformer 1 is connected. This is shown in Figure 7.44.

The A-Phase current measures over 5 amp for the first cycle and the rest of the cycles have a lower value of 3,64 Amp. This is much higher compared to the Phase to Ground fault current measurement of 2 Amp in the previous section.

7.8.3.2.4 The behaviour of the system during a three phase fault

A three phase type of fault is applied between the A, B and C-Phases in the system with parallel power transformers. The Fault is applied to the 11kV bus bar in the system. The system configuration is changed by opening different circuit breakers.

The following three configurations are considered for the experiment:

- Transformer 1, Transformer 2 and Source 2 are connected in the system,
- Transformer 1 and Source 2 are connected,
- Transformer 1 is connected.

The results are monitored in RTDS Runtime.

The A-Phase secondary output peak currents for Transformer 1, (132kV current transformer) are measured for the three different system configurations. This is shown in Figure 7.45. The current measurements are not time synchronised.

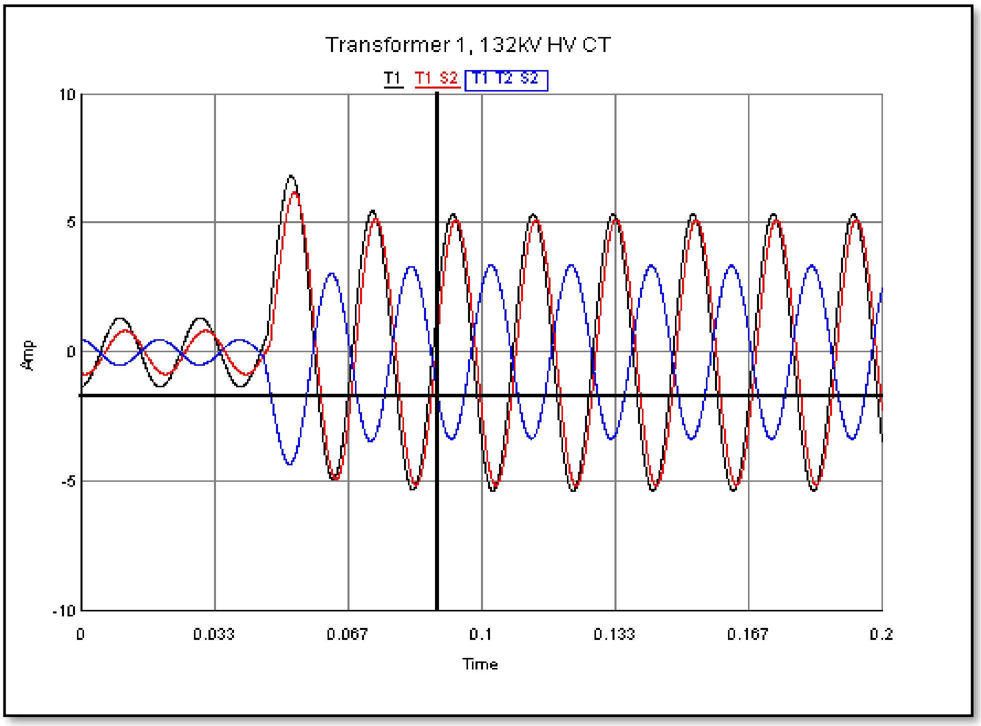


Figure 7.45 Transformer 1, 132kV CT A-Phase currents for a Three Phase fault and different system conditions

A summary is shown in Table 7-6 below. The fault currents flowing through Transformer 1 are different as the system configuration is changed. The 132kV CT A-Phase output currents for Transformer 1 are shown.

Table 7-6 Summary of system behaviour for a 3-phase fault and different system configurations.

Connected in system	T1 CT1 A-Phase
Transformer 1, 2 and Source 2	3,3
Transformer 1 and Source 2	5,1
Transformer 1	5,4

The highest fault current is measured when transformer 1 is connected. The three phase and phase-to-phase faults produce the highest fault currents. The results also show that the highest current will flow through Transformer 1 when it is not parallelly connected. The fault currents for the different types of faults will be lower for the case where Transformer 1 is parallelly connected.

7.8.3.3 Differential protection relay

The RTDS/RSCAD Differential protection relay model used in this simulation case, is discussed in Chapter 5 under section 5.3.1.

The system phase currents are fed into the inputs of the differential (87) function.

Ratio mismatch and phase shifts in the 87 function are compensated for in the model. The operating quantity and restraining quantity are calculated for each phase and applied to the 2-slope differential current characteristic.

A Two winding 132/11kV YD transformer is configured in RTDS Draft. A ratio of 200/1 is used on the transformer 132kV winding 1 and 2000/1 is used for the 11kV winding 2.

The Current transformer output currents are monitored and compared for a protection system using Merging Units and a protection system without Merging Units. The Merging Units are simulated by using the RTDS/RSCAD GTNET_SV9−2_v5 component to produce IEC 61850-9-2 Sampled Value (SV) streams.

The basic operation of the RTDS Differential protection function is as follows. The operating quantity is the vector sum of the phase currents.

$$\mathbf{I_{OP} = I_{CT1} - I_{CT2}} \qquad (7\text{-}1)$$

The operating current **Iop** is the vector sum of the currents of CT1 on the primary side of the transformer and CT2 on the secondary side of the transformer. Under normal operation the magnitude of $\mathbf{I_{CT1}}$ equals $\mathbf{I_{CT2}}$, but the phases are 180 degrees apart.

The restraint quantity is calculated using the summation of current magnitudes of every connected CT divided by 2.

$$I_{RS} = (I_{CT1} + I_{CT2})/2 \qquad (7\text{-}2)$$

The amount of restraint current determines the amount of operating current required to operate. The operating quantity must be above the minimum operating value setting or the relay will not operate.

7.8.3.4 The behaviour of the Differential relay during normal conditions.

The system supplies a load of 40MVA. For the experiment the system configuration is changed while keeping the load constant. The following three system configurations are considered:

- Transformer 1, Transformer 2 and Source 2 are connected in the system to supply the load together.
- Transformer 1 and Source 2 are connected.
- Transformer 1 is connected.

RTDS Runtime results measured are shown in Table 7-7. The Differential protection function stays stable when the load current increases with I operate is increasing but stay lower as the restrain current.

Table 7-7 Differential operating / restrain currents

Connected in system	I operate	I restrain
Transformers 1, 2 and Source 2	0,12	0,3543
Transformer 1 and Source 2	0,1964	0,5784
Transformer 1	0,314	0,9218

The amount of restraint current determines the amount of operating current required to operate.

- **The minimum operating current setting.**

A low setting makes the differential relay sensitive for low fault currents. It should be high enough for the relay not to operate for normal conditions.

It was measured above that the highest value of the operating current is 0,314 Amp for a 40MVA load through the transformer. The minimum operating current need therefore to be above 0,314 Amp for the differential relay not to trip under load conditions.

The operating quantity must be above the minimum operating value setting or the relay will not operate. The minimum operating current setting of 0,4 is selected for the Differential relay.

7.8.3.5 The behaviour of the Differential relay during faults applied outside the protection zone.

Different types of faults are applied to the system at the 11kV Busbar. The faults are applied outside the protection zone (FLT2) shown in the Figure 7.40 above, for the Case C. The following type of faults are applied:

- Single phase to ground faults
- Phase to Phase faults
- Three phase faults

The secondary output current of the 11kV current transformers (CT2) is measured for three phases (A, B and C).

It is expected that the results for this section will show that the Differential protection operating and restrain currents will change for different types of faults. The protection should stay stable during the faults and will not issue trips during the different types of faults due to the fault being outside the protection zone.

The worst case for which the protection should not operate can be determined by measuring the different fault currents for different types of faults. The protection settings for the protection relays are optimised using these results.

7.8.3.5.1 The behaviour of the Differential relay during a single phase to ground fault applied out of the protection zone

A fault is applied to the A-Phase in the system with parallel power transformers to the 11kV bus bar in the system (position Fault 2). It is shown above in section 7.8.3.2.2 that the highest fault current occurs when a single phase to ground type of fault is applied when only Transformer 1 is connected.

The result of the experiment is monitored in RTDS Runtime where the operating and restrain currents are shown.

The graphs of the Differential (87) function, operating and restrain currents are shown in Figure 7.46. The three different operating currents, for each of the three phases are measured for Transformer 1 with A-Phase Operating current (T1AOP), B-Phase Operating current (T1BOP) and C- Phase Operating current (T1COP). Transformer Minimum Restrain current (IRSMINT) and Transformer Minimum Operating current (IOMINT) are also shown, Figure 7.46.

The operating current for the A-Phase increases correctly above the minimum operating current during the fault on the A-Phase. The operating currents for the other two non-faulted B and C phases decreased slightly.

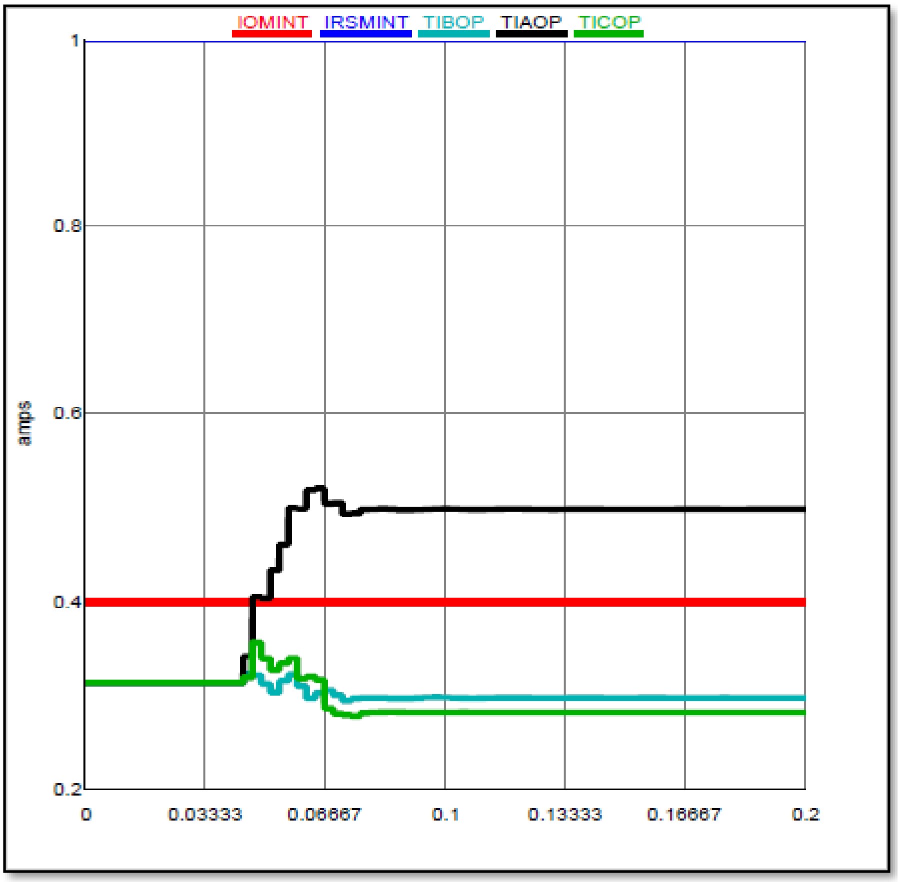


Figure 7.46 TRFR1 87 Differential currents for Fault 2

The next graphs of the Differential (87) function, operating and restrain currents are shown in Figure 7.47 where only the Transformer 1 A Phase Operating current (T1AOP), A Phase restrain current (T1ARS), Transformer Min Restrain current (IRSMINT) and Transformer Minimum Operating current (IOMINT) are shown.

The operating current as well as the restrain currents for the A-Phase increas correctly above the minimum operating current during the fault on the A-Phase. The restrain current is larger than the operating current. It is also shown that the fault current is not cleared by the protection.

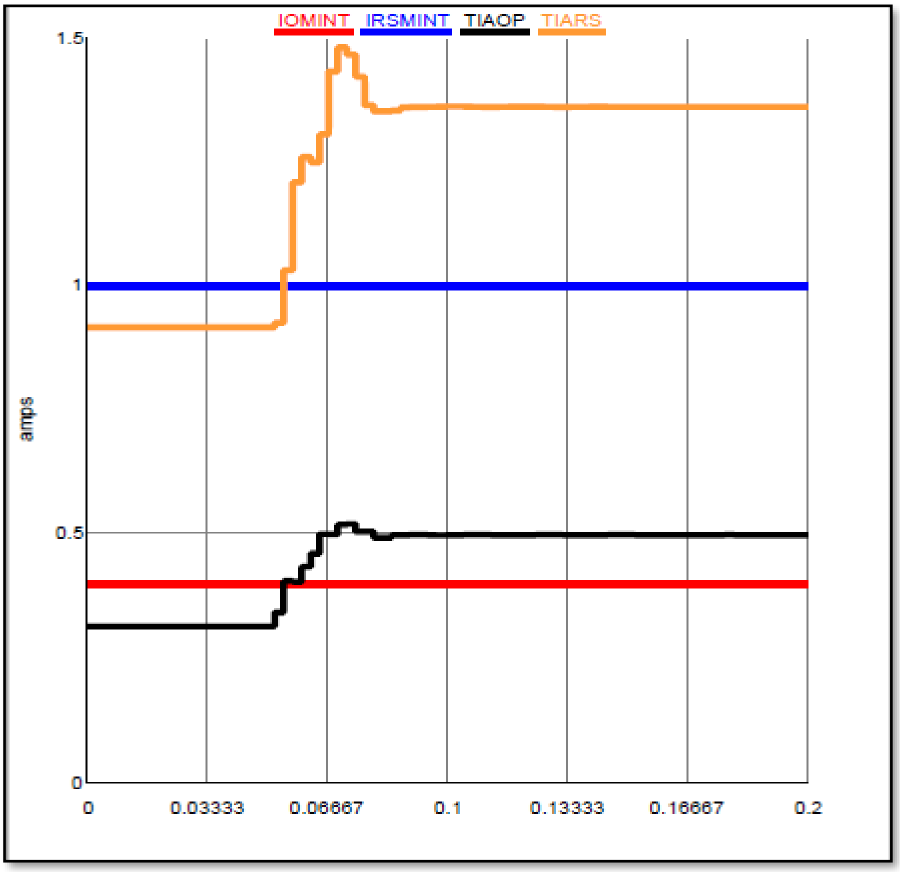


Figure 7.47 Operating and restrain currents for a Phase to ground fault at a position of Fault 2

The secondary output currents of the 11kV current transformers (CT2) are shown for the three phases (IBUR2A, B and C) in Figure 7.48 below.

The status of the protection switch (SWPROTON) is shown. A digital high level indicates the protection switch is in the on position and a low level indicates the protection is switched off.

The position where the fault is applied is shown with digital inputs ApplyGrFlt1 and ApplyGrFlt2. The digital input ApplyGrFlt2 is high indicating the fault is applied at a position of Fault 2. A single phase fault on the A-Phase is applied.

Output 1 (OUT1) is a trip signal issued by the 87 differential protection function. Output 2 (OUT2) is a trip signal issued by the instantaneous over current 50P function. TRIP is the signal to open the circuit breaker, and a high signal is indicating a trip signal is issued.

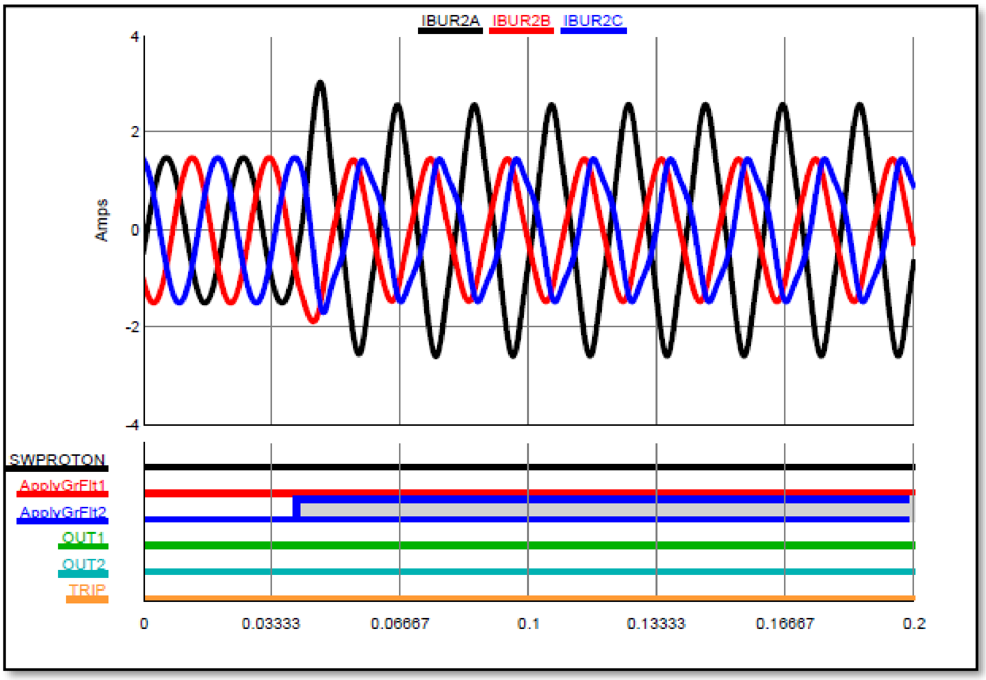


Figure 7.48 TRFR1 currents during A-Phase to ground fault

No trip signal is issued from both differential and over current protection due to the fault being out of the protection zone. This is the correct operation that is expected.

7.8.3.5.2 The behaviour of the Differential relay during a phase to phase fault applied out of the protection zone

A fault is applied between the A and B Phases in the system with parallel power transformers. The fault is applied to the 11kV bus bar (position Fault 2). It is shown above in section 7.8.3.2.4 that the highest fault current occurs for a phase to phase type fault when only Transformer 1 connected.

The result of the experiment is monitored in RTDS Runtime to show the operating and restrain currents.

The next graph of the Differential (87) function, operating and restrain currents are shown in Figure 7.49 with the Transformer 1 A Phase Operating current (T1AOP), A Phase restrain current (T1ARS), Transformer Min Restrain current (IRSMINT) Transformer slope 1 and slope 2 breakpoint setting (S1S2T), Transformer 1 slope 1 origin setting (IORGS2T) and Transformer Minimum Operating current setting (IOMINT) shown.

The operating current as well as the restrain current for the A-Phase increase correctly above the minimum operating current during the fault. The operating and restrain current are much higher as for the case of a single phase to ground fault. It is also shown that the fault current is not cleared by the protection.

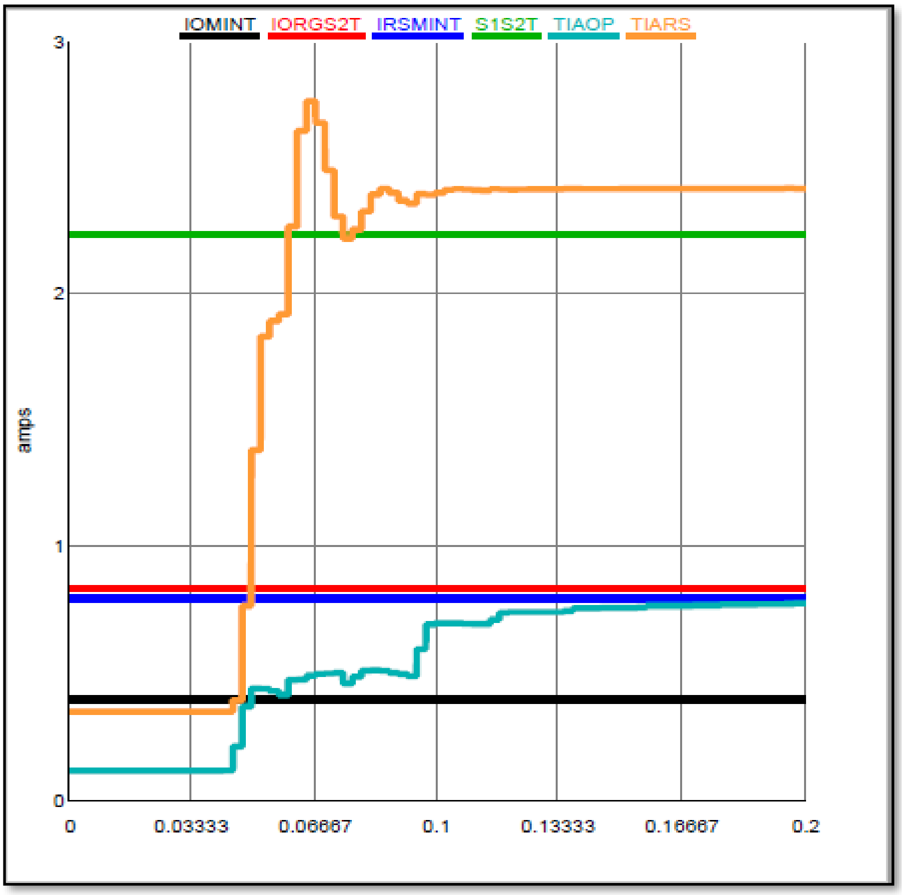


Figure 7.49 Operating and restrain currents for a phase to phase fault at a position of Fault 2

The secondary output current of the 11kV current transformers (CT2) is shown for three phases (IBUR2A, B and C) in Figure 7.50 below.

The status of the protection switch (SWPROTON) is shown in an off position.

The digital input ApplyGrFlt2 is high indicating the fault is applied at a position of Fault 2.

A phase to phase fault is applied between the A and B-Phases.

No trip signal issued by the 87 differential protection function (OUT1) or the instantaneous over current 50P function (OUT2).

No signal to open the circuit breakers are issued as the digital signal is low for the trip output (TRIP). The protection must stay stable for this position of the fault and not issue a trip. This result for the experiment is therefore correct due to the fault being outside the protection zone.

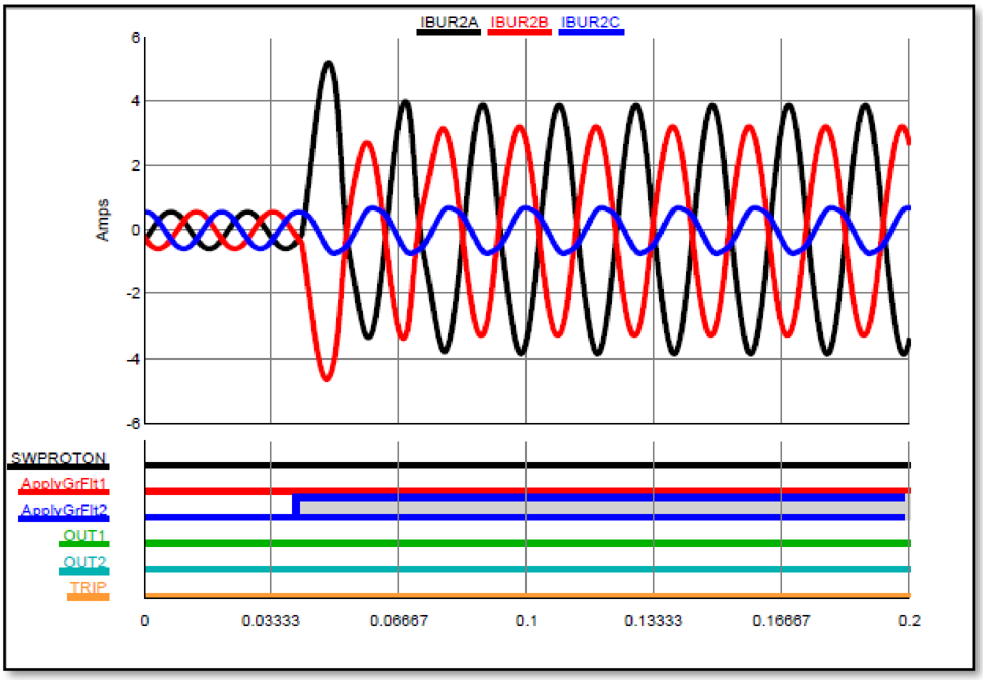


Figure 7.50 TRFR1 fault currents during a phase to phase fault at a position 2

7.8.3.5.3 The behaviour of the Differential relay during a three phase fault applied out of the protection zone

A fault is applied to all three phases in the system with parallel power transformers. The fault is applied to the 11kV bus bar (position Fault 2). It is shown above in section 7.8.3.2.4 that the highest fault current occurs for a three phase type fault when only Transformer 1 is connected.

The results of the experiment are monitored in RTDS Runtime to show the operating and restrain currents.

The next graphs of the Differential (87) function, operating and restrain currents are shown in Figure 7.51 with the Transformer 1 A Phase Operating current (T1AOP), A Phase restrain current (T1ARS), Transformer Min Restrain current (IRSMINT) Transformer slope1 and slope 2 breakpoint setting (S1S2T), Transformer 1 slope 1 origin setting (IORGS2T) and Transformer Minimum Operating current setting (IOMINT) shown.

The operating current as well as the restrain current for the A-Phase increase correctly above the minimum operating current during the fault. The operating and restrain currents are much bigger than for the case of a single phase to ground fault. It is also shown that the fault current is not cleared by the protection.

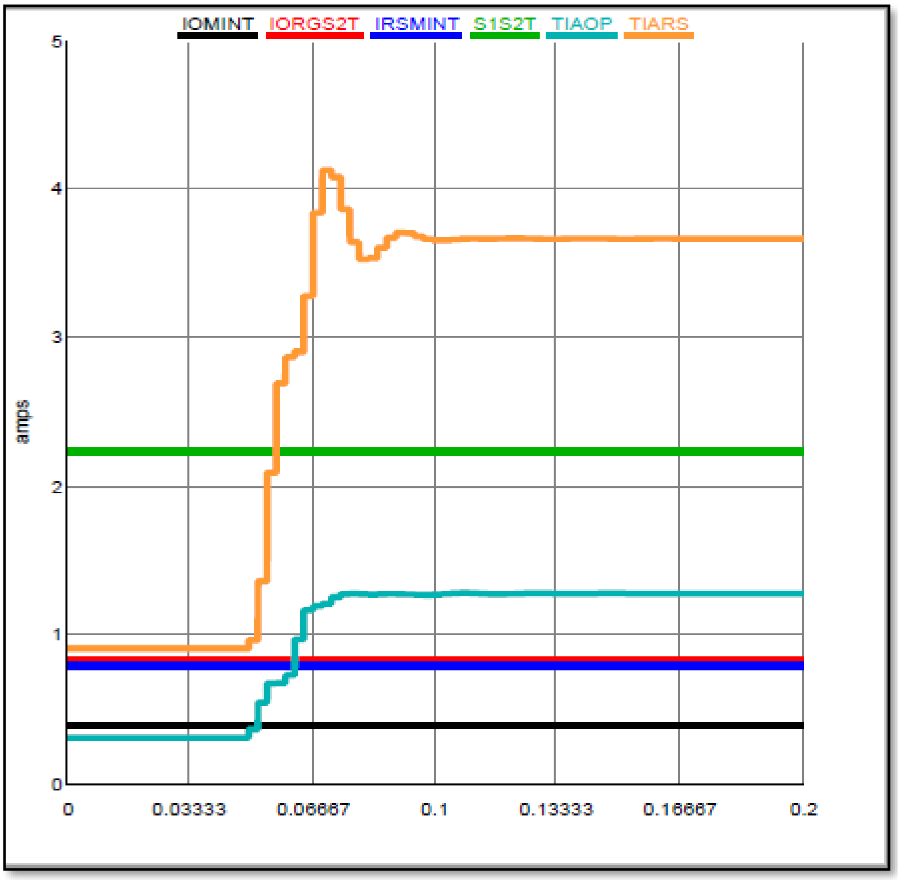


Figure 7.51 Operating and restrain currents for a three phase fault at a position of Fault 2

The secondary output currents of the 11kV current transformers (CT2) are shown for three phases (IBUR2A, B and C) in Figure 7.52 below.

The status of the protection switch (SWPROTON) is shown in an off position.

The digital input ApplyGrFlt2 is high indicating the fault is applied at a position of Fault 2.

A three phase fault is applied.

No trip signal issued by the 87 differential protection function (OUT1) or the instantaneous over current 50P function (OUT2).

No signals to open the circuit breakers are issued as the digital signal is low for the trip output (TRIP). The protection must stay stable for this position of the fault and a trip will not issued. This result for the experiment is therefore correct due to the fault being outside the protection zone.

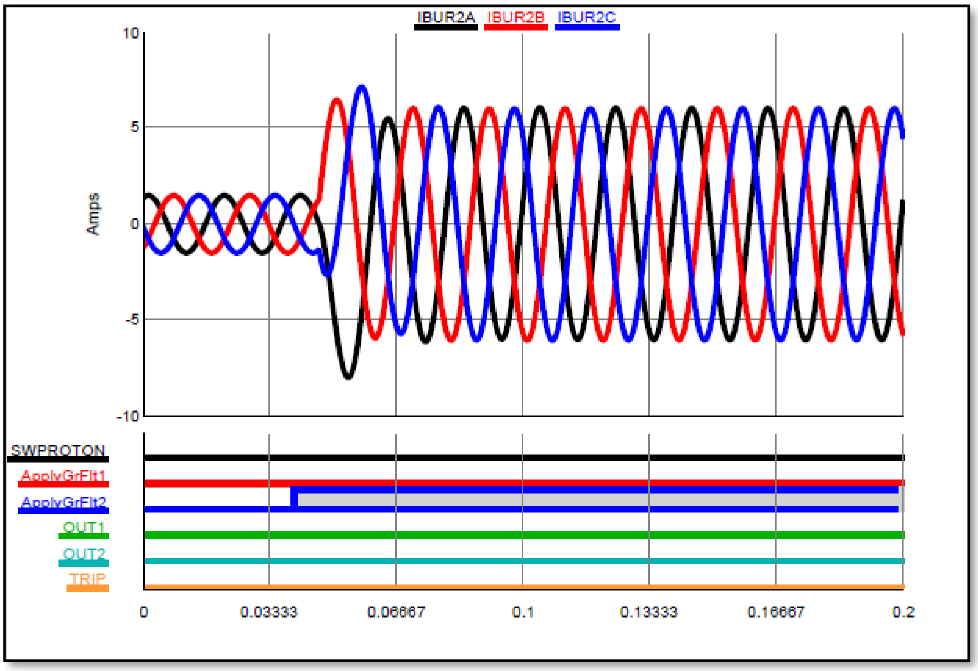


Figure 7.52 TRFR1 currents during a three phase fault at a position 2

RTDS Runtime results for the Differential relay measured for different types of faults are shown in Table 7-8 below. The operating current is higher than the minimum operating current setting of 0,4 Amp. The Differential protection function stays stable when the fault current increases. I operate increases but stays lower as the restrain current.

Table 7-8 Differential operating / restrain currents for different types of faults outside the protection zone

Type of fault	I operate	I restrain
Single phase to ground fault applied to the A-Phase	0,52	1,48
Phase to Phase fault applied between the A and B-Phases	0,778	2,76
Three phase faults	1,28	4,13

RTDS Runtime results for the fault currents measured for different types of faults are shown in Table 7-9 below. The highest peak current during the first cycle is measured at the secondary side of the CT. The CT has a ratio of 2000/1. The Differential protection function stays stable when the fault is applied outside the protection zone.

Table 7-9 Faults currents measured at Transformer 1 11kV CT for different types of faults at the 11kV Busbar.

Type of fault	Fault Current (Amp)
Single phase to ground fault applied to the A-Phase	3,04
Phase to Phase fault applied between the A and B-Phases	5,16
Three phase faults	7,89

7.8.3.6 The behaviour of the Differential relay during faults applied inside the protection zone.

A single phase to ground type of fault is applied to the system at the 132kV Busbar. The fault is inside the protection zone (FLT1) shown in the Figure 7.40 above, for the Case C. The following two cases are evaluated:

- The protection is switch off; the circuit breakers are not tripped when the protection relays issue a trip signal.
- The protection is switched on; the circuit breakers are tripped when the protection issues a trip signal.

The secondary output currents of the 132kV current transformer (CT1) are measured for the three phases (A, B and C).

It is expected that the results for this section will show that the protection should operate during the faults and issue a trip during the faults due to the fault being inside the protection zone.

The protection settings for the protection relay are verified and optimised using these results.

7.8.3.6.1 The behaviour of the Differential relay during a single phase to ground fault applied in the protection zone with the protection switched off.

A fault is applied to the A-Phase in the system with parallel power transformers to the 132kV bus bar in the system (position of Fault 1).

The results of the experiment are monitored in RTDS Runtime for the operating and restrain currents.

The graph of the Differential (87) function, operating and restrain currents are shown in Figure 7.53 with the Transformer 1 A Phase Operating current (T1AOP), A Phase restrain current (T1ARS), Transformer Min Restrain current (IRSMINT) and Transformer Minimum Operating current (IOMINT) shown.

The operating current as well as the restrain current for the A-Phase increase correctly above the minimum operating current during the fault on the A-Phase. The operating current is now larger than the restrain current. This is expected due to the fault being in the protection zone. It is also shown that the fault current is not cleared by the protection.

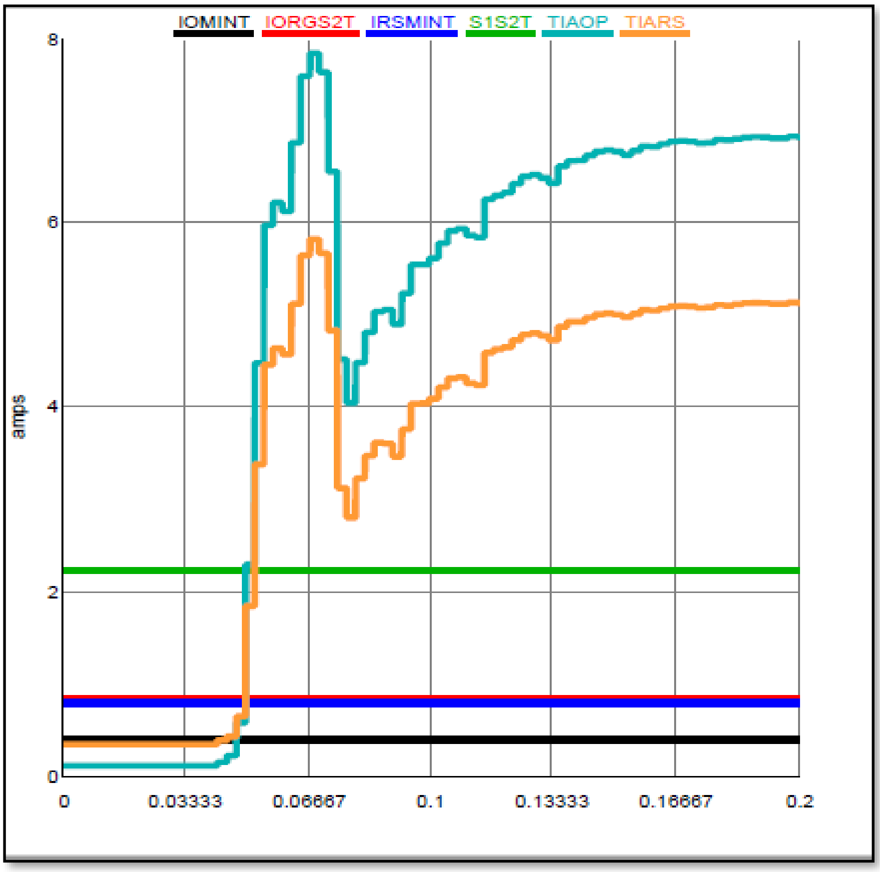


Figure 7.53 TRFR1 87 operating and restrain currents for a Phase to ground fault at position Fault 1

The secondary output currents of the 132kV current transformer (CT1) are shown for the three phases (IBUR1A, B and C) in Figure 7.54 below.

The status of the protection switch (SWPROTON) is shown. The digital low level indicates the protection switch is in the off position.

The digital input ApplyGrFlt1 is high indicating the fault is applied at a position of Fault 1. A single phase fault on the A-Phase is applied.

A trip signal is issued by the 87 differential protection function (OUT1) and a trip signal is issued by the instantaneous over current 50P function (OUT2). TRIP is the signal to open the circuit breaker, and a low signal is indicating a trip signal is not issued due to the protection switch being in the off position. The fault current is sustained because the fault is not removed by opening the circuit breakers to clear it.

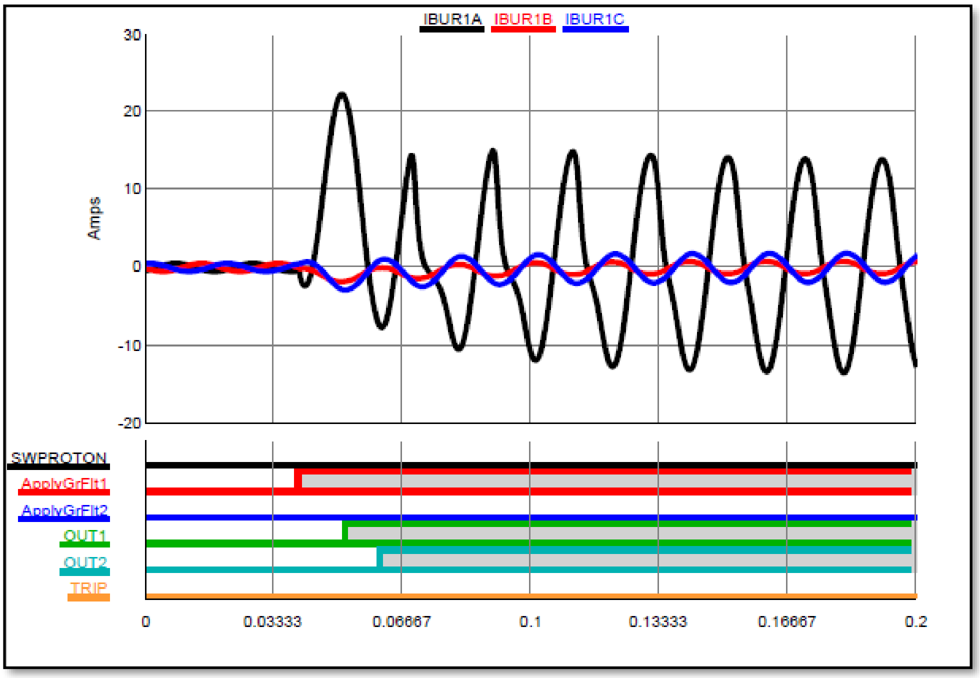


Figure 7.54 TRFR1 currents during A-Phase to ground fault at a position of Fault 1

Both the differential and over current protection issue a trip signal due to the fault being in the protection zone. This is the correct operation that is expected.

7.8.3.6.2 The behaviour of the Differential relay during a single phase to ground fault applied in the protection zone with the protection switched on.

The two transformers are connected in parallel and both sources are connected. A fault is applied to the A-Phase in the system with parallel power transformers to the 132kV bus bar in the system (a position of Fault 1).

The result of the experiment is monitored in RTDS Runtime to show the operating and restrain currents.

The graphs of the Differential (87) function, operating and restrain currents are shown in Figure 7.55 with the Transformer 1 A Phase Operating current (T1AOP), A Phase restrain current (T1ARS), Transformer Min Restrain current (IRSMINT) and Transformer Minimum Operating current (IOMINT) shown.

The operating current as well as the restrain currents for the A-Phase increases correctly above the minimum operating current during the fault on the A-Phase. The operating current is larger than the restrain current. This is expected due to the fault being in the protection zone. It is also shown that the fault current is cleared by the protection.

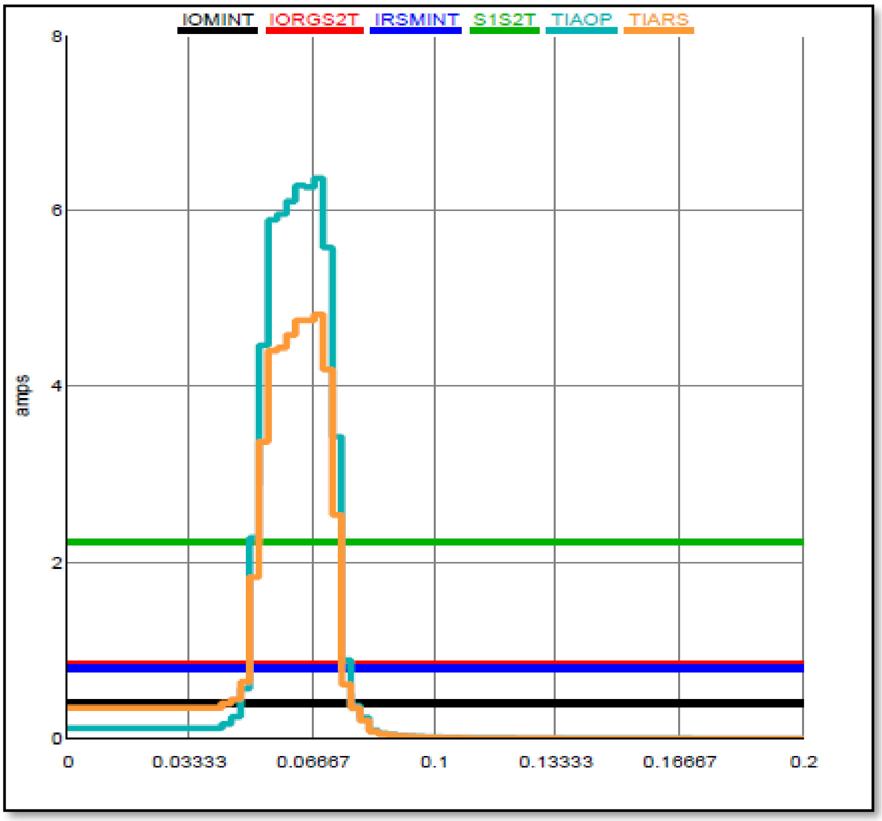


Figure 7.55 TRFR1 87 operating and restrain currents for a Phase to ground fault at a position of Fault 1

The secondary output currents of the 132kV current transformer (CT1) are shown for the three phases (IBUR1A, B and C) in Figure 7.56 below.

The status of the protection switch (SWPROTON) is shown. The digital high level indicates the protection switch is in the on position.

The digital input ApplyGrFlt1 is high indicating the fault is applied at a position of Fault 1.

A single phase fault on the A-Phase is applied.

A trip signal is issued by the 87 differential protection function (OUT1) and a trip signal is issued by the instantaneous over current 50P function (OUT2). TRIP is the signal to open the circuit breaker, and a high signal is indicating a trip signal is issued due to the protection switch being in the on position. The fault current is by opening the circuit breakers to clear the fault.

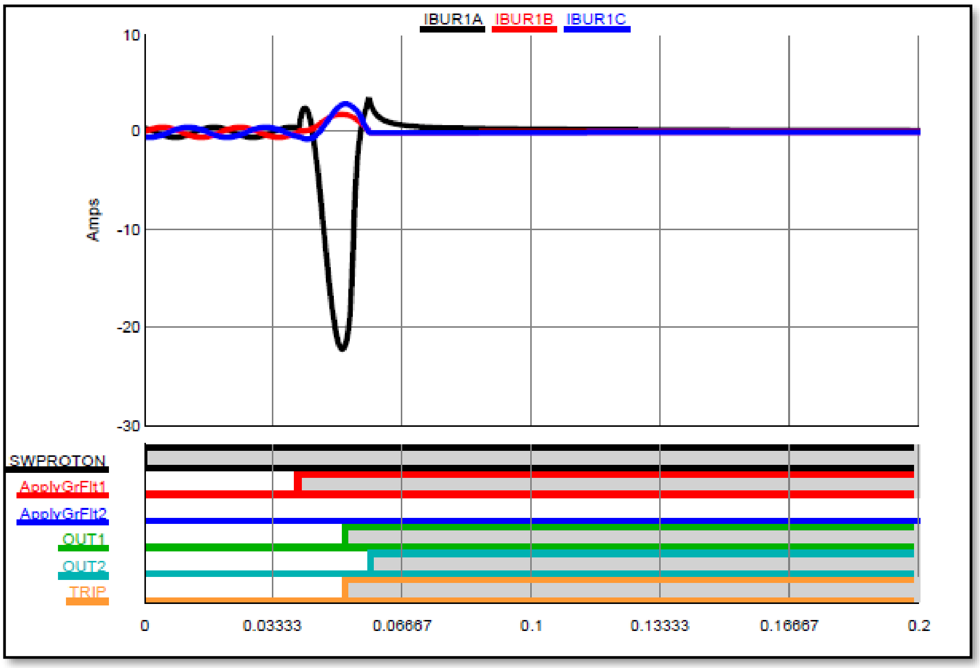


Figure 7.56 TRFR1 currents during A-Phase to ground fault at apposition of Fault 1

Both the differential and over current protection issues a trip signal due to the fault being in the protection zone. This is the correct operation that is expected.

7.8.4 Test-bench D

The system has a source connected to the 132kV (SRC1) bus bar. The 11kV bus bar has 2 x Bus Sections, 1 x 11kV load and 1 x 11kV Source (SRC2) are connected to the 11kV bus bar sections. A Bus Section circuit breaker (BS1) connects the two bus sections.

Two cases are considered:

- The first is for the Case D1 with Sampled Values (SV) to simulate a system using Merging Units. A lower burden on the current transformer is used.
- The second is for the Case D2 where no SV is used. A higher burden on the current transformer is used.

Experiments are done for:

- Normal load conditions
- Fault applied at a position FLT2
- Fault applied at a position FLT1

The RTDS RSCAD Runtime model of the simulation Case D, for the cases of parallel power transformers without using SV, is shown in Figure 7.57 below. The system is the same as for Case C with the exception that Sampled Values are not used. The instrument transformers produced analogue signals proportional to the real-time primary system voltage and current signals. These signals are taken to the RTDS/RSCAD Differential and Over Current protection relays. This setup is used for experiments to compare results of a system where SVs are used (Case C) with a system where SV is not used (Case D).

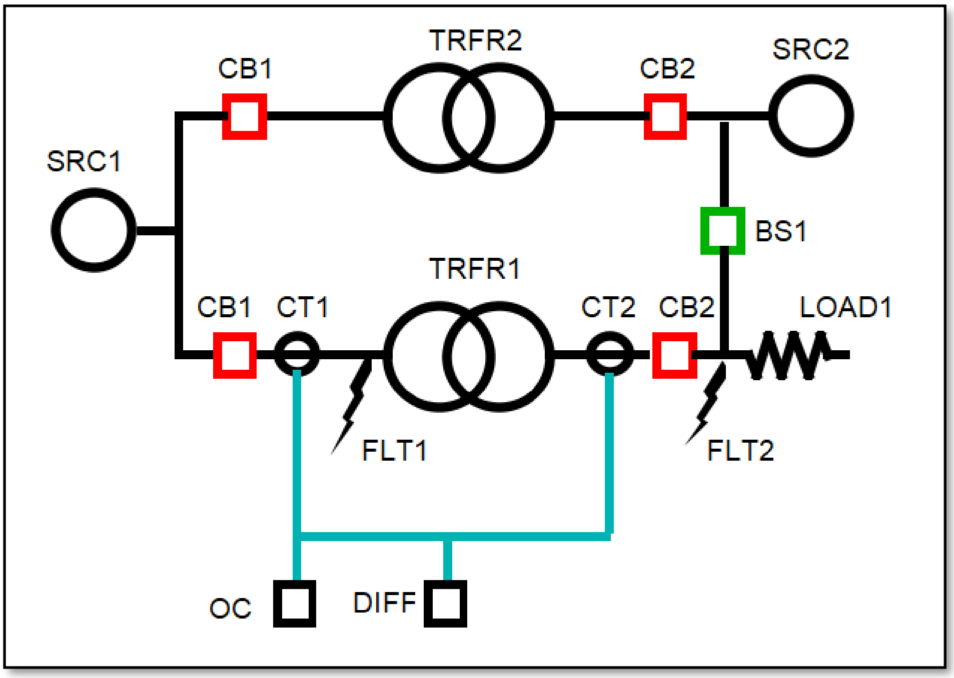


Figure 7.57 RTDS RUNTIME Case D for Test-bench D with TRFR 1 & 2 without SV

7.8.4.1 Current transformer burden

The Current Transformers (CTs) are used for protection systems when currents several times higher than the rated current are measured during system fault conditions.

The knee-point voltage and exciting current are important specifications for protection class CTs.

The CT knee-point voltage requirement is a function of the total circuit resistance.

VK = f (RCT, RL, RRP) (2-1)

Where:

VK = Required CT knee-point voltage (volts)

RCT = Resistance of the current transformer secondary winding (ohms)

RL = Resistance of a single lead from the relay to current transformer (ohms)

RRP = Impedance of a relay phase current input

The resistance of the CT secondary winding is specified and determined at the design stage of the CT. The 132kV HV CT with 200/1 ratio modelled in the RSCAD software has an internal resistance of 0,8 ohm and the MV CT with 2000/1 ratio has an internal resistance of 8 ohm.

The impedance of the relay inputs is fixed.

The lead resistance depends on the wire cross sectional area and distance of the IED from the CT. 2.5mm^2 and 4 mm^2 annealed copper wire is normally used in power system protection application.

The electrical resistance of the copper wire can be calculated by using the equation (7-3) below.

$$R = \rho\ (L/A) \text{ in ohm } (\Omega) \qquad (7\text{-}3)$$

Where:

R is the resistance in ohms (Ω),

L is the length in metres (m),

A is the cross sectional area in square metres (m^2),

ρ is the resistivity constant (rho) = $1{,}72 \times 10^{-8}$ for annealed copper wire at 20°C.

The resistance of 100m 2.5mm^2 annealed copper wire is calculated to be 0.688 ohm and 100m 4mm^2 to be 0.43 ohm using the equation. Note that this is at 20°C. The resistance is temperature-dependent thus when the temperature rises, the resistance will increase. A typical rule applies to a 3-phase (4-wire) connection between the CTs and the IED by multiplying the distance by a factor of 1.2.

The Burden of the IEDs are very low.

The Merging Unit used on the test-bench has a rated burden of < 0.05 VA at nominal current (In).

The P645 Transformer protection and control IED has a rated burden of <0.2 VA at nominal rated current (In).

Case D1 is where Sampled Values are used. The Merging Unit is installed close to the CT and the length off the copper wire lead used is 50m.

Case D2 is where conventional copper wires are used from the CT to the protection relay in the control room. A length of 500m is used for calculating the copper wire burden on the CT.

The following burden values used in the experiments for the two cases are shown in Table 7-10 below.

Table 7-10 Current Transformer burden

Case	Burden series resistance in ohm	Burden series inductance in Henry (H)
Case D1 (50m)	0,335	0,11e-3
Case D2 (500m)	3,35	1.1e-3

7.8.4.2 The behaviour of the current transformer during normal conditions.

The system is under normal load condition. The 132kV Transformer 1 Current Transformer (CT1) is monitored. A CT ratio of 200/1 is used.

The CT burden current and voltage are shown in Figure 7.58. CT1 is shown for the Case D2 with a high burden and CT11 for the Case D1 with a low burden.

IBUR1A and IBUR11A are the A-Phase secondary currents monitored. It is shown that the currents are the same and only IBUR11A is visible.

The burden voltages CTBUR1A and CTBUR11A are not the same as a result of the different circuit resistance.

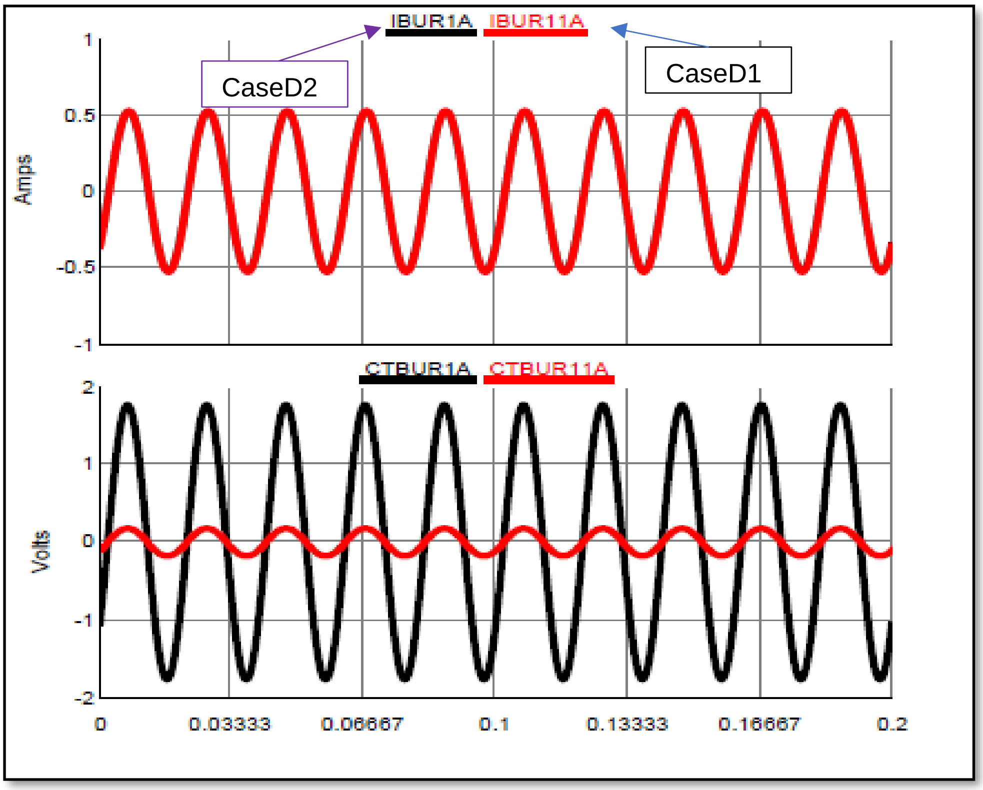


Figure 7.58 Current Transformers 1 under load condition

The CT knee-point voltage is a function of the total circuit resistance thus a 1,75V knee-point voltage is produced with a total burden of 3,35 ohm and a current of 0,523.

Table 7-11 CT Burden voltage under load conditions

Case	Wire length	CT	Secondary current (Amp)	Burden Voltage (Volt)
Case D1	50m	CT11	0,523	0,176
Case D2	500m	CT1	0,523	1,76

7.8.4.3 The behaviour of the current transformer during fault (FLT2) conditions.

The system is under normal load condition when a fault is applied to the A Phase at a position of FLT2.

The 132kV Transformer 1 Current Transformer (CT1) is monitored.

The CT burden voltages are shown in Figure 7.59. CT1 is shown for the Case D2 with a high burden and CT11 for the Case D1 with a low burden.

IBUR1A and IBUR11A are the A-Phase secondary currents monitored. It is shown that the currents are the same and only IBUR11A is visible.

The burden voltages CTBUR1A and CTBUR11A are not the same as a result of the different circuit resistances. The higher circuit resistance results in a much higher burden voltage.

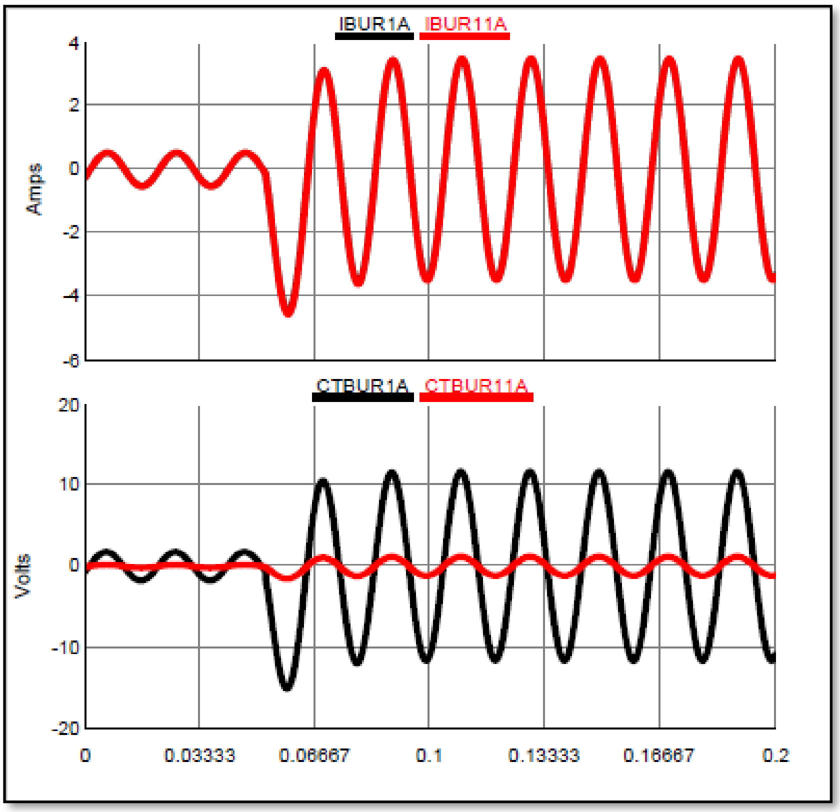


Figure 7.59 Current Transformers currents and voltages under a fault condition at FLT2

The CT knee-point voltage is a function of the total circuit resistance thus a 15 V knee-point voltage is produced with a total burden of 3,35 ohm and a current of 4,477.

Table 7-12 CT Burden voltage under fault FLT2 condition

Case	Wire length	CT	Secondary current (Amp)	Burden Voltage (Volt)
Case D1	50m	CT11	4,477	1,53
Case D2	500m	CT1	4,477	15,1

7.8.4.4 The behaviour of the current transformer during fault (FLT1) conditions.

The system is under normal load condition when a fault is applied to the A Phase at position FLT1.

The 132kV Transformer 1 Current Transformer (CT1) is monitored.

The CT burden voltage is monitored in Figure 7.60. CT1 is shown for the Case D2 with a high burden and CT11 for the Case D1 with a low burden.

IBUR1A and IBUR11A are the A-Phase secondary currents monitored. It is shown that the currents are not the same. They are the same during the first cycle. IBUR1A saturates during the second cycle, the sinusoidal wave from is distorted and the secondary current produced is less than IBUR11A. IBUR1A is not reflecting the real power system current. The burden voltages CTBUR1A and CTBUR11A are not the same as a result of the different circuit resistances. The CT1 saturates during the high burden voltage.

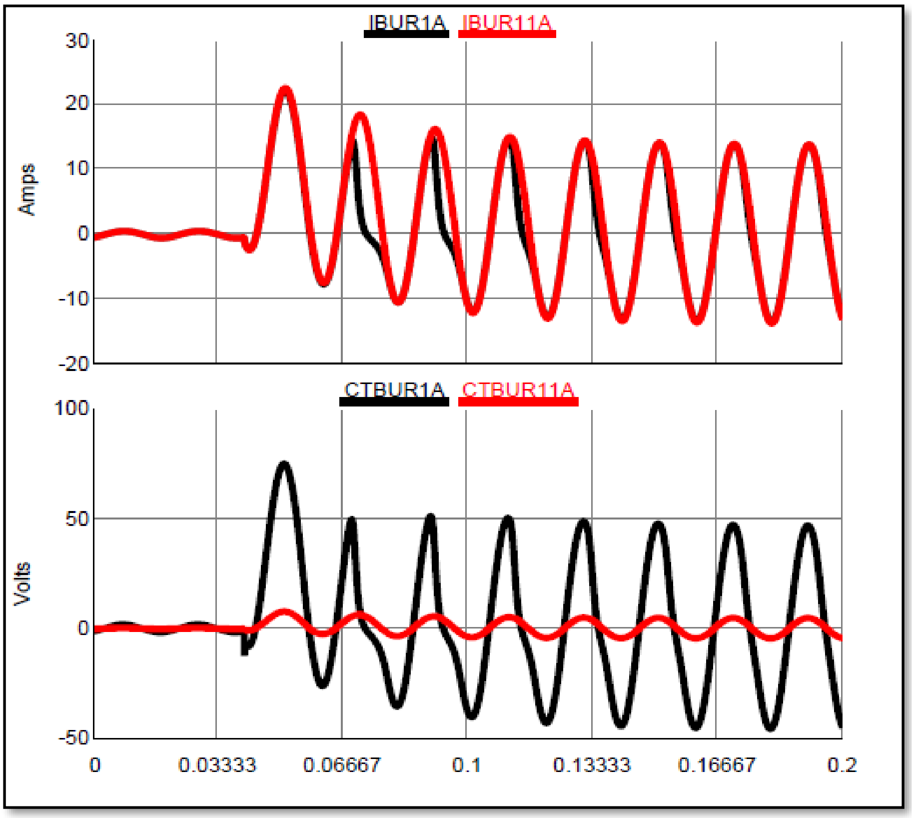


Figure 7.60 Current Transformers currents and voltage under a fault condition at FLT1

The CT knee-point voltage is a function of the total circuit resistance thus a 74,47 V knee-point voltage is produced with a total burden of 3,35 ohm and a current of 22,23.

Table 7-13 CT Burden voltage under fault FLT2 condition

Case	Wire length	CT	Secondary current (Amp)	Burden Voltage (Volt)
Case D1	50m	CT11	22,23	7,56
Case D2	500m	CT1	22,23	74,85

Merging Units can be installed closer to the current transformers in the yard compared to the distance between the protection IED in the relay room and the current transformers in the yard. These different distances have an influence on the lead resistance, total burden and thus knee point voltages.

The result show that using merging units is influencing the total circuit resistance and a lower circuit resistance results in a lower current transformer burden voltage. The specifications and class for current transformers can therefore be different when Merging Units are used.

A 10 VA class 5P20 protection current transformer with a nominal output current of 1 amp must be accurate at 20 times rated current when connected to a 10 VA burden. The CT burden voltage will therefore be 200V.

A 5 VA class 5P10 protection current transformer with a nominal output current of 1 amp must be accurate at 10 times rated current connected to a 5 VA burden. The CT burden voltage will therefore be 50V.

A more economical current transformer can be specified when a Merging Unit is used.

7.9 Conclusion

The IEC 61850 standard for communication networks and systems is used to implement IEC 61850-9-2 sampled values for a typical substation system with parallel power transformers.

In this chapter, different test-benches are setup and discussed. The configurations of Merging Units (MUs), a transformer protection Intelligent Electronic Device (IED) and Ethernet equipment are shown. Experimental results of the developed protection scheme are discussed.

The Real-Time Digital Simulator (RTDS) is used to run the real-time power system model and do simulations. IEC 61850-9-2 Sampled Values (SV) streams are published from the RTDS as well as using stand-alone MUs, external to the RTDS.

It is shown that Analogue Merging Units (AMUs) publish successfully IEC 61850-9-2 Sampled Value (SV) streams on the Ethernet network.

A Micom P645 transformer differential protection IED as well as a differential protection function configured in the RTDS RSCAD are used for experimentation. The P645 is used to measure the SV streams but is was not possible to use it to test the protection function.

The RTDS GTNET_SV9−2 component published IEC 61850−9−2 Sampled Value (SV) streams successfully on the Ethernet network. The MiCOM P645 IED subscribes to the SV streams and measured the analogue signal correctly.

The RTDS RSCAD developed transformer protection component is tested successfully.

The RTDS IEC 61850-9-2 SV streams are used to show that the burden on the Instrument Transformers is less when using MU and SV streams compared to copper wired instrument transformers.

8 CHAPTER EIGHT
CONCLUSION AND RECOMMENDATION

8.1 Introduction

The IEC 61850 standard for communication networks and systems for Power Utility Automation (PUA) is used by many Utilities in substations since the standard was published. The abstract data models defined in IEC 61850 can be mapped to mostly three protocols:

- Manufacturing Message Specification (MMS),
- Generic Object Oriented Substation Event (GOOSE) and
- Sampled Measured Values (SMV).

Most Utilities implemented the standard by mappings data models to MMS and GOOSE protocols (Semjan & Ji, 2019). The SMV protocol is not used to implement sampled values using part 9-2 of the standard.

This research is to determine what aspects are important and need to be considered for implementing SMV for a typical substation with parallelly connected power transformers. The problems solved in this thesis is discussed in section 8.2.

The deliverables are discussed in section 8.3 under sub sections of literature review, theoretical background, strategy, Real-Time RSCAD, power transformer protection, tap changer voltage control and the different test-benches.

Recommendations are made in section 8.4 under sub sections discussing Ethernet networks for substations, time synchronisation, protection and control schemes, digital and analogue process interface, IEDs, auxiliary supplies, logical nodes, protection settings and application philosophies, instrument transformer requirements, transient power system conditions and tools required.

Future work is discussed under section 0 and the application of the thesis deliverables under section 8.6

8.2 Problems solved in this Thesis

The main research problem is to investigate the IEC 61850-9-2 standard related to Specific Communication Service Mapping (SCSM) in the Substation Automation System (SAS). The IEC 61850-9-2 process bus is implemented using merging units and sampled values in a substation where the IEC 61850 standard is used.

8.2.1 Design based problems

This research work developed a complete monitoring, protection, and voltage control system for parallel power transformers based on IEC 61850-9-2 process bus. Sampled values are used together with the status of high voltage equipment for the protection and control of parallel power transformers. To complete this, the following design based sub-problems are solved:

8.2.1.1 Merging Units

Merging Units (MUs) are configured to produce Sampled Values (SV) according to the IEC 61850-9-2 standard and publish the messages on a process bus network. The MUs are connected to the communication network via Ethernet fibre optic cables using 100BaseFX LC connectors.

1 PPS time synchronisation is realised via a separate fibre optic ST connector for each MU.

8.2.1.2 Transformer protection

A transformer protection scheme is designed that uses sampled value message streams for current measurement inputs. The protection relays are simulated in the Real-Time Digital Simulator (RTDS). The transformer scheme protection settings automatically change according to the power system network arrangement. The scheme monitors the status of the circuit breakers and uses the open/close status of the circuit breakers to determine the network arrangement.

8.2.1.3 Tap changer controller

A tap changer controller is simulated in the RTDS using the RSCAD software. The simulation is done for a system with parallel transformers. The controller uses the open/close status of circuit breakers to determine if the transformers are connected in parallel. A Master-Follower controller scheme is tested successfully.

8.2.2 Implementation based problems

8.2.2.1 Communication network

The substation communication network is extended to the yard for process bus application. The process bus network can be a separate new network, or it can be connected to an existing station bus network. When an existing substation is upgraded to implement a new process bus, the new MUs are connected to existing communication network or to a new network. New network switches are required, or spare communication ports is required on existing switches.

The MUs and the transformer protection IED used for the test-bench have fibre optic 100BaseFX connectors. A network switch is required that have the same 100BaseFX connectors to connect the optic fibre cables from the MUs and IED to the communication network.

The same communication network is used in the test-bench for sampled values and other communication traffic. The Virtual LANs (VLANs) method is used for the test-bench. VLANs are used to separate different types of traffic that share the same bandwidth on physical medium at the data link layer.

The Quality of Service (QoS) technique, specifies a priority value, that can be used by QoS to priorities the traffic. IEC 61850 prescribes that GOOSE and SV frames are priority-tagged. The priority 4 is used for the SV messages in the test-bench communication network.

The data bandwidth required for the sampled values is much more than the traditional substation communication network. The network switch ports are configured to allow for filtering, that reduce the traffic to end devices, by letting through only those messages with the correct VLAN identifiers and priority tags.

A Star network topology is used for the test-bench communication network.

8.2.2.2 Redundancy

Different redundancy protocols are available in the market. The IEDs and MUs must be ordered with the correct communication ports to be able to implement the protocol selected. The IED and MUs used for the test-bench had single ports for connection to the process bus network. The Parallel Redundancy Protocol (PRP) could therefore not be used.

Main and backup protection relays use separate current transformer cores for each of the protection devices, with conventual protection scheme designs. The designer has the choice to use the same sampled value stream for both main and back up protection relays. Separate Merging Units can be used for the main and back up protection relays. The same sampled value data is us for both differential and overcurrent protection relays in the test-bench.

8.2.2.3 IEDs

There is not many IED manufacturers that use sampled values for a tap change controller. The tap changer controller function can be built with scheme logic inside a transformer protection IED. The Logical nodes associated with automatic tap changer controller (ATCC) will not be available. Generic process I/O LN Name: GGIO can be used if the specific LNs are not available.

The RTDS RSCAD software is used for the test-bench setup, to build a tap changer controller, for parallel transformers. The LNs related to an automatic tap changer controller is not available in the RSCAD software and the LN GGIO is used for GOOSE messages.

The control circuit for controlling the transformer cooling fan motors can be included in the control circuit at the process bus level. Sensors or transducers are required to transmit temperature analogue signals using the proper LNs for the GOOSE messages. This data can be used as an input into a programmable automation controller in the IED used for controlling the transformer cooling fans. This was not implemented for the test-bench as these types of devices are not available in the laboratory and sampled values is the focus for the research.

8.2.2.4 Synchronisation

PTP is preferred over SNTP to be used for process bus networks time synchronization using the communication network as medium.

The Merging Units allowed for SNTP as well as 1 PPS time synchronization. A 1 PPS time synchronisation source was used via a separate fibre for the synchronization.

The P645 IED has an IRIG-B input with BNC connector available for time synchronization. The IRIG-B signal is supplied from the network switch.

The network switches support 1 PPS or IRIG-B. It also supports PTP and SNTP over the network.

8.3 Deliverables

The aim of the research project is to develop and implement a strategy, methods and algorithms for monitoring, protection and voltage control of parallel power transformers based on IEC 61850-9-2 process bus.

To realise the above aim, the following objectives are satisfied:

8.3.1 Literature Review

A literature review of primary and secondary substation equipment is provided in Chapter 2.

The secondary substation equipment is reviewed under sub sections of section 2.2 for substation control systems, substation communication networks, network protocols, time synchronization, equipment, merging units and power transformer protection and control. Magnetising inrush, over current, restricted earth fault and differential protection is reviewed under the section 2.2.7 for transformer protection. Automatic voltage control and tap changer control is reviewed for transformer control.

Primary substation equipment is reviewed under section 2.3 with sub sections for instrument transformers and earthing transformers.

The review of a real-time digital simulation is done under section 2.4.

8.3.2 Theoretical Background

Theoretical background of the IEC 61850 functions and communication interfaces, data modelling, the SCL language, the SCL file types, the communication services and Digital substation Ethernet technology is provided in Chapter 3.

8.3.3 Strategy

A plan of action is developed as a strategy for the design of a monitoring, protection and voltage control scheme of power transformers. The strategy is shown in Figure 8.1.

A Single Line Diagram (SLD) of the substation to be modelled is required to identify the bays and other primary substation equipment that will be protected and controlled. A fault level is required to choose Current Transformer (CT) ratios. The source, power transformer size and impedance influence the fault level.

The next step was to determine the protection and control requirements. This influences the Intelligent Electronic Devices (IEDs) and Merging Units (MUs) required.

The Ethernet network design was determined by deciding on the type of time synchronisation, the network topology and the network redundancy required. The network design influences the requirements for the IEDs, MUs and network switches.

Lastly, the equipment was configured and tested

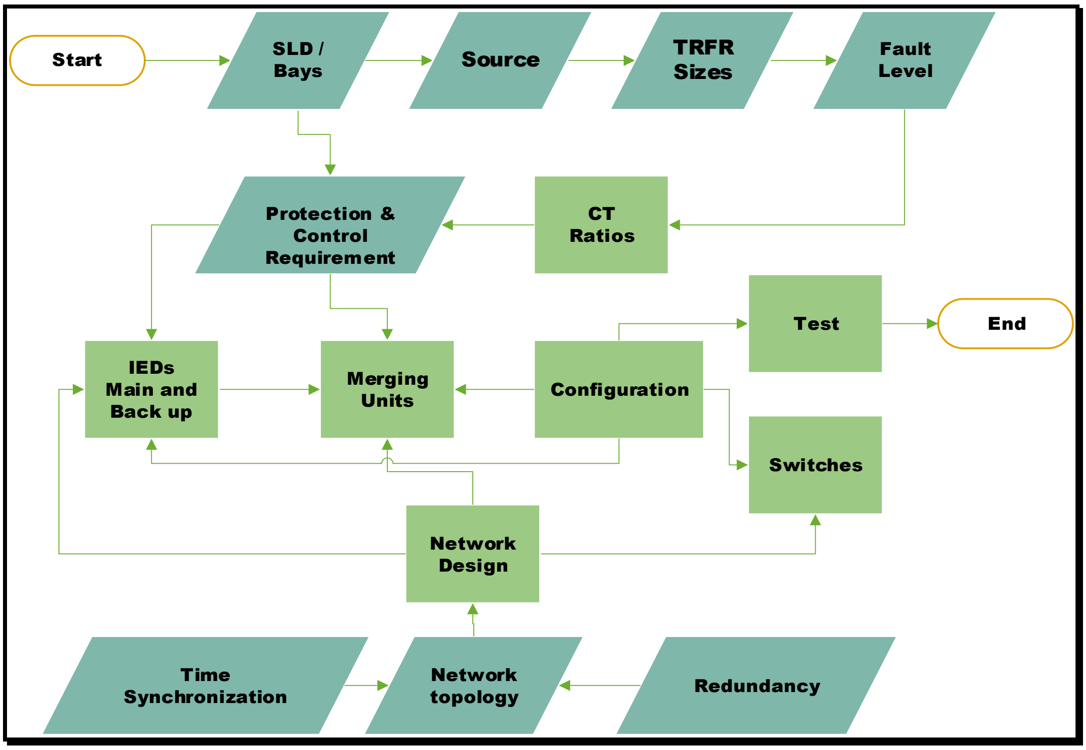


Figure 8.1 Strategy for protection and control scheme design

8.3.4 Real-Time RSCAD

The RSCAD® software allows the configuration, execution, and analysis of real-time simulations. A Real-Time RSCAD simulation was performed for the parallel power transformer system. Power source models, power transformer models, load models and instrument transformer models are configured for the power system model.

Differential protection, instantaneous over current protection, tap changer controller and sampled value models are configured to simulate a protection and control scheme for the system of power transformers.

8.3.5 Power Transformer Protection

Design and implementation of the protection scheme for parallel power transformers based on IEC 61850-9-2 process bus is implemented in Chapter 5.

The RSCAD software differential protection function, overcurrent protection function and IEC 61850 -9-2 LE sampled values were implemented and tested.

The protection system simulation results show that:

- The designed protection scheme operates correctly as required.
- The power transformer protection settings can successfully be adapted when the system configuration for parallel power transformers is changed.
- Digital Sampled Values were successfully produced by the RTDS GTNET card. They were published and measured on the Ethernet network.

8.3.6 Tap Changer Voltage control

Design and implement the IEC 61850 standard based voltage regulating IEDs to control on load tap changers of parallelly connected power transformers is discussed in Chapter 6. It is shown that the power transformer tap changer controller operates successfully as was expected:

- The developed logic circuit is correctly determining when the transformers is connected in parallel according to the open/close status of circuit breakers.
- The Master-Follower mode operates correctly when the transformers are connected in parallel.
- The Manual and Automatic modes operate correctly.

8.3.7 Test-bench

The development of the test-bench for real-time implementation and testing of the developed system using tests with a Real-Time Digital Simulator, Merging Units and a transformer protection IED was done.

Physical Merging Unit devices as well as the RTDS GTNET SV components were used to publish sampled values.

8.3.8 Software used for the Test-bench setup

Different software is used to configure the test-bench components and measure the sampled values on the process bus. The software is used to develop models of the considered power system, controllers and logic algorithms as part of the investigations and building of the test-bench. The developed software is described in Table 8-1.

Table 8-1 Software used

Software	Chapters	Developed models and functions
RSCAD® Draft and Runtime	4	Develop power system model and configure power system components, Configure instrument transformer components, Run and control the simulation case, Measure and capture simulation results.
RSCAD® Draft and Runtime	5	Configure protection relay components, Develop setting group selection logic, Configure GTNET SV component to produce sampled values, Run and control the simulation case, Measure and capture simulation results.
RSCAD® Draft and Runtime	6	Configure RSCAD tap changer controller component, Develop master-follower tap changer controller logic, Run and control the simulation case, Measure and capture simulation results.
MiCOM S1 Agile, Alstom Agile MU configurator	7	Configure the standalone Alstom Analogue Merging Unit IEDs
Easergy Studio	7	Configure the Schneider Electric MiCOM P645 transformer protection IED
Moxa web console	7	Configuration of the Moxa PT-7728 PTP Ethernet switch
Rugged telnet session	7	Configuration of the Ruggedcom RSG2288 Ethernet Switch

Wireshark network packet analyser	7	Capture sampled values Ethernet network packets and display the detailed packet data
Omicron SVScout	7	Visualizing Sampled Values (SV) streams, Subscribes to the SV streams, Displays the waveforms of the primary voltages and currents in an oscilloscope view. Generate a report to summarise the SV measurement information.

8.3.9 Experiments

Experiments with the test-bench were conducted for various scenarios using the RTDS simulated Merging Units (MUs) and conventional instrument transformers signals. The MUs sampled values were measured and evaluated using the RTDS simulated current and voltage signals.

The experimental results do not show that the protection relay is performing better when sampled values is used. The A/D conversion is done in the MU before the data is multicast to all the IED subscribers. In the absence of MUs, the IED will do the A/D conversion in the control room.

The results show that using Merging Units does have a lower burden on instrument transformers and this can have an influence on the performance of the protection systems.

8.4 Recommendations

The experiment results are analysed and used to make recommendations on the proposed system for protection and control of parallel power transformers according to the IEC 61850 standard

8.4.1 The substation communication network

The following different aspects are considered for the design of the network:

- the physical network,
- network topology,
- redundancy.

The Process bus and station bus can use two separate Ethernet networks or the same physical layer network but with separate data link layers for different VLANs.

The proposed system has separate networks for the process and station bus. This allows to have different network topologies for the different communication busses. The backbone network can for example have a ring connected network switches while the bay switches can be star connected to the end node devices. The IEDs connecting to both networks have to have enough network communication ports. The P645 IED used in the test-bench has separate network ports to be able to connect to the separate station bus and process bus networks.

The SV messages of the process bus require more data to be transferred. The process bus can be designed to cater for 1 Gbit/s physical layer while the station bus network only requires 100Mbit/s network. The different types of fibre optic cables, single or multimode, as well as the bit rate required used different types of communication ports. The physical network therefore needs to be carefully planned as the communication ports of the devices such as switches and IEDs need to be specified when they are procured.

The network topology depends on the type of network redundancy used. Rapid Spanning Tree Protocol (RSTP), Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are bus redundancy architecture that can be implemented. The IEDs, Merging Units (MUs) and other devices connecting to the networks need to be able to use these technologies. The P645 IED and MUs used in the test-bench setup did not support these redundancy architectures. Redundancy can be obtained by duplicating the networks and the devices. Main 1 and 2 devices can be connected to separate communication networks. The PT-7728 network switch supports RSTP and propriety Turbo Ring protocols for communication network redundancy. Using the propriety protocols, brings restriction to work only with certain manufactures.

A process bus implementation is not recommended where point to point fibre optic connections between the merging unit and the IED is used as it will require additional communications ports on the devices. It may also limit future expansion. In the example of a bus zone protection scheme, when a new bay is added the protection IED will need to connect to a new merging unit. Another example is where the IED of a new bay requires to subscribe to receive a bus bar voltage from an existing merging unit.

8.4.2 Time Synchronization

The devices connected in a process bus network need an internal clock to be synchronized with a substation GPS clock. The synchronization is performed through IRIG-B or indirectly over a network using SNTP or PTP protocols. PTP has better accuracy and is considered more suitable for Process Bus applications.

PTP uses the same Ethernet medium as the data communications for the time synchronization information communication. PTP reduces the cabling infrastructure requirements when compared to IRIG-B, as there is no need of dedicated time synchronization network. IRIG-B has limitations on the amount of the devices to be connected and the distance from the clock to the end devices in the yard.

It is recommended to use PTP where available on devices. IRIG-B should be used if PTP is not available for process bus time synchronization.

8.4.3 Protection, Monitoring and Control.

The complete transformer protection and tap changer voltage control are included in the system of parallel power transformers based on IEC 61850 and using part 9-2 for the process bus.

The process bus is not limited to the analogue process interface where analogue current and voltages are converted to digital communication using IEC61850-9-2 Sampled Values. The binary process interface where circuit breaker status and control, tap position indication and tap drive control, winding and oil temperature indication all need to be included in the complete IEC 61850 application on the process bus level.

It is therefore recommended to use not only Sampled Values (SV) but to use GOOSE and analogue GOOSE messages to implement IEC61850 at the process level.

8.4.4 Digital Process Interface

The digital process interface (digital GOOSE) needs to be included on the process bus level. Switchgear is an example of primary plant in the yard that must be included. IEDs that can monitor a circuit breaker are available on the market. The Logical Nodes available in the IEDs are very important when selecting these IEDs for the process interface. The IED may have the appropriate LNs for the breaker open and close statuses. Other statuses for example the SF6 gas pressure, trip circuit status, spring status are important for the protection system. Therefore, it is necessary for the IED to have these LNs too. It is also important that these devices can control the switchgear using GOOSE messages and not only to monitor and send status information.

The digital process interface is also important for the control of the other plants in the substation. The tap changer control is a good example where it can be utilised. The changer information is shared between parallel transformers in a system and GOOSE messages are used to control the transformer tap changers.

8.4.5 Analogue Process Interface

The analogue process interface (Analog GOOSE) uses Sampled Values for the power system current and voltage values, but Analog GOOSE can for example be used to send transformer oil temperature or winding temperature values to the protection and control system. The temperature values can be used for condition monitoring but also for fan control of the cooling system.

8.4.6 IEDs

The Test-bench Transformer P645 IED is connected to the process bus. The IED receives SV for the power system current and voltage levels from the Merging Units in the yard, reducing copper wiring in the yard.

Different type IEDs can be connected to the process bus.

8.4.6.1 Protection IED

The test-bench transformer IED has Resistor Temperature Device (RTD) inputs that connect PT100 RTD probes to measure temperatures and Current Loop Inputs and Outputs (CLIO) analogue inputs and outputs (e.g. 4 to 20 mA) that can be used for various transducers such as pressure and temperature transducers.

These RTD and CLIO inputs require wiring from the yard equipment such as a transformer to the IED in the control room. This IED must be installed close to the equipment to replace or reduce copper wiring in the yard.

It is recommended to rather place Process Interface Units (PIUs) that converts the analogue signals to digital messages, close to the yard equipment. The Protection IED subscribes to this Analogue GOOSE messages published by the PIUs.

8.4.6.2 Voltage regulating IED

The voltage regulating IED that controls the On Load Tap Changer (OLTC) of the power transformer needs to be included when the IEC 61850 standard is implemented on the process bus level. It is recommended that the IED is installed close to the transformer tap change drive or transformer marshalling kiosk to limit the length of copper wiring.

The voltage regulating IED measures the system voltages and currents depending on functions required. These inputs can be received from a Merging Unit using sampled values or from another IED using analogue GOOSE messages.

A system current measurement is required for load compensation and Over Current (O/C) blocking functions. A Protection IED can send the blocking signal to the regulating IED using GOOSE messages.

Information must be shared between parallel operating transformers. The transformers can operate in master-follower mode. Parallelly connected transformers can also operate in circulating current mode. Voltage control with the circulating current method aims to minimize this circulating current. Current measurements and transformer reactance information is shared between the transformers (Gajić et al., 2010). The regulating IED also needs system information e.g. switch status to determine if the transformer is connected in parallel or single operating. This information can be shared between the transformers with digital GOOSE and analogue GOOSE messages.

The position of the transformer tap changers is required for the regulating IED, but the information is also required for the SCADA system. GOOSE or MMS messages can be used to share this information.

8.4.6.3 Merging unit

Sampled values can be sent from the MU in two modes per IEC 61850-9-2, depending on the application. 80 samples per cycle (or 4000 samples/s) is used for protection application and 256 samples per cycle is used for waveform recording, power quality and metering.

Unique protection may require higher sampling rates. Traveling wave line protection requires high-resolution voltage and current recording with a 1 MHz sampling rate to record and analyse high-frequency transients, such as traveling waves from faults, switching events, etc.

8.4.7 Auxiliary supply

The auxiliary power for the IEDs in the substation panels is normally provided from a secure supply realised with a changeover between a main and backup auxiliary voltage supply. Some IEDs and network switches have option for dual power supplies.

It is recommended that the power supply for the process interface devices and merging units in the yard must also be done from a secure auxiliary DC voltage.

8.4.8 Logical Nodes

Detailed information regarding the IEC61850 implementation of the IED is described inside the conformance documents. The Modelling Information Conformance Statement (MICS) is one document that contains the declaration of the used Logical Node (LN) types. The logical nodes and all data attributes contained are named according to a standardised semantic.

A GOOSE Control Block (GoCB) must be defined, a data set is needed that contains the data objects and data attributes to be sent, in order to publish GOOSE messages

The On Load Tap Changer (OLTC) control functionality is not implemented in accordance with IEC 61850 Standard in the test-bench IED. The two logical nodes representing the OLTC mechanism and regulator, namely YLTC and ATCC, are not available in the IED. The LN representing the cooling group control, namely CCGR is also not implemented. It is possible to build these functions inside the IED with Programmable Scheme Logic (PSL) but it will not be possible to send GOOSE messages with these data specific to the YLTC, ATCC and CCGR LNs.

Logical nodes (LGOS & LSVS) to supervise GOOSE and SV messages are not available in the test-bench IED (Munos et al., 2018). Generic process input and output LNs namely GGIO, can be used if the specific LNs are not available but this is not preferred.

8.4.9 Protection settings philosophy

Differential protection IEDs must be highly sensitive on internal faults and at the same time stable and reliable for external fault conditions. The sensitivity of Differential protection is related to issues with mismatched CTs, CT saturation, lead resistance and tap settings.

The whole tap range of the transformer is normally considered when applying protection settings. The transformer operates at specific tap settings for long periods. An adaptive differential protection algorithm can include the transformer winding tap-position information into the protection IED algorithm.

The shorter distance from the MU to the instrument transformer decreases the influence of the sum of factors such as CT saturation and lead resistance on the biased low impedance percentage differential protection.

High fault levels need to be considered when a CT ratio is selected to ensure that CTs do not saturate during fault conditions. This may result in greater mismatched CTs between primary and secondary side of the power transformer. MUs with lower burdens on the CT allows that better CT ratios is selected, and this eliminate the mismatch.

8.4.10 Protection application philosophy

Two protection devices using the same CT core increase the burden on that core when long copper wire cable runs is used from the CT in the yard to the IED in the control room.

Different protection and control devices for example differential, back up over current, tap changer and bus zone may use the same sample value measurement without increasing the burden on the CT core.

8.4.11 Instrument transformer requirements

Class X type of CTs with high knee-point voltages is preferred by protection engineers for Differential, REF and Bus Bar protection to ensure CTs do not saturate and keep the protection stable for out of zone faults.

Normal class 10P protection CTs with a lower Volt-Ampere (VA) specification can be adequate when used together with the Merging Units.

8.4.12 Transient power system conditions

Electrical transients occur for many different reasons, but some examples are when the circuit breakers are switched, transformers are energised, during system faults and lightning. Power generators and now also the distributed energy sources have an impact on the transient response of power systems. Power system protection normally needs to operate during this transient period. The instrument transformer needs to accurately reproduce the power system voltages and currents to measured quantities to be sent to the IEDs. The Merging Unit is thus required to sample the voltage and currents and produce the correct digitized output for the protection IEDs to operate correctly (Blumschein et al., 2018).

Further studies are required to determine the performance of the Merging Units when they are subjected to electrical power system transients.

8.4.13 Substation yard

The environmental conditions impact the decisions on the design of the substation automation system and can increase the cost of the project.

The ambient temperature can have an impact on were to install the IED, MUs and communication equipment like network switches. This equipment can be installed in specific designed yard junction boxes or small buildings were the temperature effect can be controlled.

The requirements towards the fibre optic trenches may be different from those for the normal cable trenches. The amount of fibres, and if redundant communication networks can share the same route or trench, are important to consider. The fibre optic may need special protection against rodents or other animals that can damage the fibres.

8.4.14 Tools

Software tools are important to monitor and setup a communication network for a process bus (Pereda & Amezaga, 2019). It is helpful not to only monitor the sampled value messages on the network but to visualise the sample value messages as well.

Part 6 of IEC 61850 standard specifies a System Configuration description Language (SCL) file format for describing system, substation automation, IED and communication system configurations. Engineering configuration tools shall be interoperable between different manufacturers (Jinshan et al., 2017). Different tools were used for GOOSE and SV configuration, protection settings and programmable scheme logics in the IEDs.

The software engineering tools are important criteria in selecting product for the substation automation system when different IED manufacturers are involved.

8.5 Future work

IEDs to be installed on high voltage equipment such as switchgear and power transformers need more development and research in order to fully utilise the IEC 61850 standard on the process bus level. The Logical Nodes (LNs) implemented in the IEDs are an important element in the successful implementation of a digital substation and an IEC 61850 process bus network. The LNs for transformer oil temperature or winding temperature data and other process interface data can be used for the protection and control systems. The temperature data can be used for condition monitoring but also for fan control of the cooling system.

The use of the Merging Units and the sampled values will influence past protection application and settings philosophies but also will provide new opportunities in the future. The performance of Merging Units to transient system conditions need to be studied further.

The differences between the data sampling in an IED and the MU is the control on the sampling rate. The IED generally uses frequency tracking and the MU uses a fixed number of samples per cycle at the nominal frequency. Research is required to determine if these differences have an influence on the protection system.

This research work was on Merging Units and conventional instrument transformers. Non-Conventional Instrument Transformers (NCITs) have other advantages over the conventional instrument transformers that need to be researched (Kumar et al., 2016). NCIT and sensors deployment is important for future implementations of digital high voltage substations.

8.6 Application of the thesis deliverables

The deliverables of the research work can be applied in:

- The Centre for Substation Automation and Energy Management systems of the Department of Electrical Engineering,
- Power Utilities and other establishments using power systems and digital sub stations in the Electrical Supply Industry.

The research work on the thesis leaded to development of a laboratory test-bench where students can learn and understand the basics of the IEC 61850-9-2 sampled values principles. The test-bench components such as the IEDs, RTDS, standalone Merging Units and Ethernet equipment can be used for future research applications.

The test-bench can be used to demonstrate during course work for students at the University, the basics of digital substations using a process buss network with IEDs, Merging Units and Ethernet equipment.

The research work indicated where equipment is getting outdated and future equipment will be required for research work in IEC 61850-9-2 process bus.

The research work showed the importance and benefits of a RTDS and Hardware-in-the-loop testing. It provides an environment for the testing of digital substation components connected to a simulation of a power system. Individually components or a whole system can be tested, prior to deployment in a utility network. The RTDS provide a way to examine the effects that the process bus communication network has on the protection system operation.

8.7 Publication

Pieters W.D, R. Tzoneva (2019) Investigation of an IEC 61850 standard-based process bus implementation of a protection and control scheme for parallelly connected transformers, Sent to Journal of Engineering, Design and Technology (JEDT), January 2020.

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APPENDIX A

The IEC 61850 SCL Language & File types

A.1 IEC 61850 SCL language

Part 6 of IEC 61850 specifies a file format, of the System Configuration description Language (SCL). The SCL is used for describing IED, substation automation and communication system configurations. The SCL is also used to describe the substation equipment and power system functions through logical nodes. The SCL is used to exchange IED capability descriptions, and substation automation system descriptions using IED and system engineering tools. This data exchange shall be interoperable between an IED configuration tool and a system configuration tool from different manufacturers. The configuration language is based on the Extensible Markup Language (XML).

The SCL object model has three basic parts, a substation structure part, a product or IED structure part and a communication structure part. The substation part and the product part form hierarchies. The overview of the SCL object model is shown in Figure A.1.1 (IEC, 2009: 20) by using UML notation.

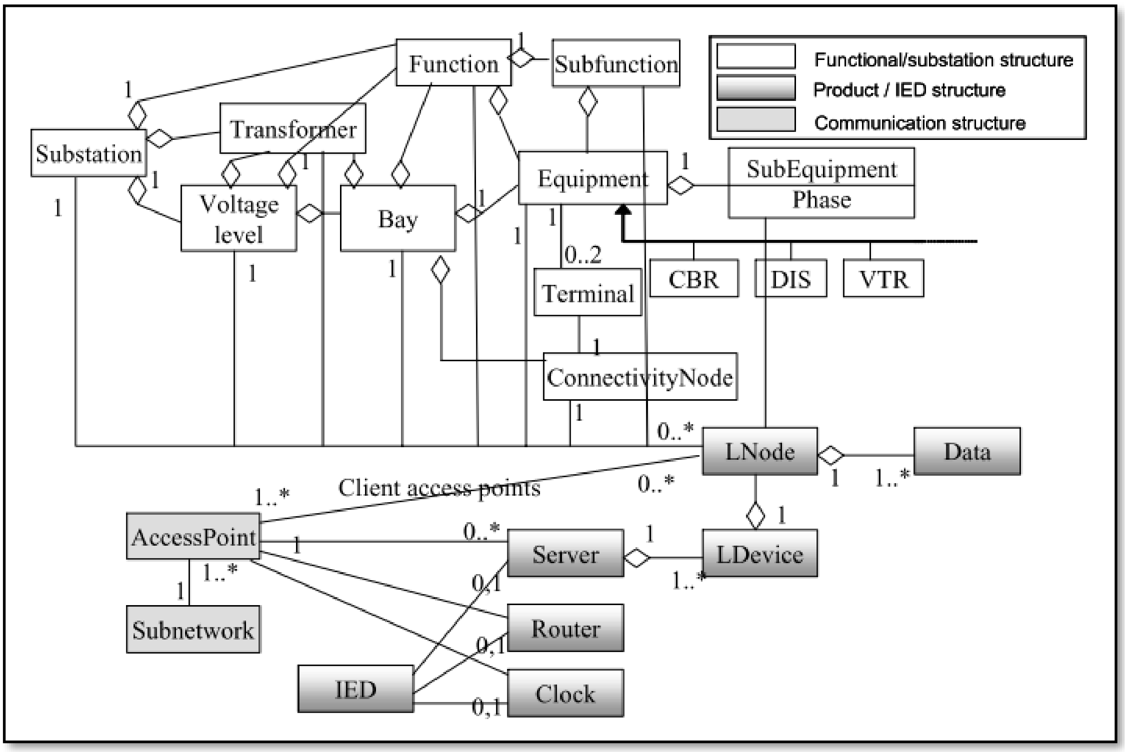


Figure A.1.1 SCL object model IEC 61850-6 (IEC, 2009: 20)

A.1.1 Substation model

The substation part describes the functions of the switch yard equipment. The substation equipment on a single line level is shown with the connections between the equipment.

Functions in the substation represented by LNs can be attached as functional objects at each substation function level.

The following substation objects of the functional structure are used in the SCL model: Substation, Voltage Level, Bay, Equipment, Sub Equipment, Connectivity Node, Terminal, Function, Subfunction.

Circuit breaker, disconnector, current and voltage transformer are examples of equipment.

A Power Transformer is a special equipment that can be associated with a Substation, Voltage Level or Bay. A Power Transformer can have Transformer windings as equipment.

Different primary devices are connected to a Connectivity Node. Examples are: equipment connecting nodes within a bay or bus bars connecting several bays.

A.1.2 Product model

The product structure represents all substation automation related objects such as IEDs, logical devices and logical nodes.

The product model consists out of an IED, Server, Logical Devices (or LDevice), Logical Nodes (or LNode), and Data Objects (or DO).

The IED performs SA functions by means of logical nodes (LNs) and communicates via a communication system with other IEDs in the SA system.

A Server is the communication entity within an IED and the communication access point to the Data of the logical devices (LD) and logical nodes (LN) contained in the server.

A LN may receive data as a client and provide data as a server.

A.1.3 Communication system model

The communication structure contains communication-related object types such as access points and subnetworks. The communication model is not a hierarchical model like the substation and product models.

A Subnetwork is the connecting node for direct communication between access points. All access points connected to a subnetwork can communicate with all others on the same subnetwork. A client connected to a subnetwork only have access to servers connected to that subnetwork.

An IED with a router function can connect to two different subnetworks by using two access points. A router provides access to services which use a networking layer. Services such as GSE and sampled value messages are not allowed to cross from one subnetwork to another.

An IED with master clock function is used to synchronize the internal clocks of all IEDs connected to a subnetwork.

A.2 SCL file types

There are different purposes for SCL data exchange and Part 6 of the standard defines six types of SCL files each having a different file extension. The data exchange using these files between a system configuration tool and an IED configuration tool is also defined.

A sender creates or produces a SCL instance for processing or to be consumed by a receiver.

The System Configurator is a system level engineering tool that is used to import or export configuration files.

- The fist type of file that a system tool receives is a System Specification Description (SSD) file. This file contains complete specification of a substation automation system including single line diagram for the substation and its functionalities. The SSD file will have a substation part where voltage levels, bays and equipment like transformers, circuit breakers, disconnectors and instrument transformers are specified. The functionality like protection, measurement and control is specified by the logical nodes. No association to IEDs is defined.
- The second type of SCL file that a system configurator tool can receive is an IED Capability Description (ICD) file: This file defines the complete capability of an IED and needs to be supplied by each manufacturer. The file contains an IED section, an optional communication section and an optional substation part.
- The system configurator can also generate a Substation Configuration Description (SCD) file by using the SSD file and the different ICD files to make the complete system configuration. The system configurator is not IED dependent. The System configurator is responsible for the communication addressing and the data flow between IEDs.

A secondary system can be split into different parts. (e.g. a substation can be split into a high-voltage level and medium-voltage level), Such a system part is called a project. The engineering of communication data flow between projects is allowed and some interfacing data must be exchanged between the projects.

- The file used to exchange data between system configurators of different projects is a System Exchange Description (SED) file. The system configurator can send and receive SED files.

The IED Configurator is an engineering tool that is used to import files from an IED to the engineering tool. Specific settings or configurations files can be generated with the engineering tool and exported to the IED. The IED Configurator can be manufacturer-specific.

- The SCL file describing the IED project specific configuration and capabilities is called an Instantiated IED Description (IID) file. The IED configurator can be used to modify the data model, parameter and configuration values of the ICD file for a new ICD file, or a project specific IED instance by means of an IID file. The ICD and IID files may contain preconfigured data sets and control blocks. The data sets and control blocks for an IID file produced from an SCD file, shall remain unchanged against the SCD file.

- The IED configurator can also create a Configured IED Description (CID) file: The CID file contains a mandatory communication section of the addressed IED.

The IED configurator is responsible for binding incoming data from other IEDs as defined within an imported SCD file to internal signals, e.g. by means of the SCL Input section, and for generating and loading the IED instance specific configuration data, which a CID file could be a part of.

The IED configurator is responsible for the IEDs configuration and data model. It is not allowed to change any data flow- and communication-related definitions. It is therefore not allowed to directly modify a system description (SCD) file.

APPENDIX B

The IEC 61850 Communication services

B

B.1 Abstract communication service interface (ACSI)

Model Driven Engineering (MDE) is according to Overbeek (2006: 3) the new trend in software engineering. MDE uses models as core principle for software engineering. The Object Management Group (OMG) develops modelling languages and provides Model Object Facility (MOF) as a core element for the Model Driven Architecture (MDA)(Overbeek, 2006: 3).

The OMG meta-model hierarchy has four levels (M0-M3), At the M3 top level the meta-meta model defines a language for specifying a metamodel. The meta model is at level M2 and defines a language for specifying models at level M1. M1 models define a language that describes semantic. M0 level models contains run-time instances of the model elements (Object Management Group, 2017: 2).

The OMG meta model hierarchy is used for the ACSI model in the conceptual model of IEC 61850. The top level meta-meta model definitions is a list of base types and rules how to build the meta model and hierarchical structures. The meta model defines generic model classes for logical nodes, data objects and common data classes including their services(IEC, 2010b; Ozansoy et al., 2009). The ACSI model also provides domain type models at level M1 and instance models at level M0 in part 7-2 of the IEC 61850 standard(IEC, 2010a)

B.1.1 The meta model

The meta model comprises classes for the description of data models and information exchange models.

a. Information modelling classes

The following overall classes are defined: Server, Logical device, Logical node and data objects.

All other ACSI models are part of the server. A server communicates with a client and sends information to peer devices.

Each of these models is defined as a class and the classes comprise attributes and services.

Examples models are GenLogicalNodeClass model and GenDataObjectClass model

Services for the GenLogicalNodeClass model are: GetLogicalNodeDirectory and GetAllDataValues

Services for the GenDataObjectClass model are: GetDataValues, SetDataValues, GetDataDirectory and GetDataDefinition

b. Information exchange modelling classes

The ACSI includes the following models for data objects and data attributes services: Data set, Substitution, Setting group control, Report control and logging, Control blocks for generic substation events, Control blocks for transmission of sampled values, Time and time synchronization, File system and Tracking.

- A Data Set is the grouping of data objects and data attributes. A data set can be used to directly access information for reporting, logging, GOOSE messaging and sampled value exchange.
- Setting group control model defines switching between setting groups and how to edit setting groups.
- Report control and logging describe the conditions for generating reports and logs. Two types off classes are defined for the report control block, buffered and unbuffered. Each class has associated services. The Buffered Report Control Block (BRCB) has for example the following services: Report, GetBRCBValues and SetBRCBValues.
- The Generic Substation Event (GSE) model provides the distribution of the same substation data to more than one device by using multicast or broadcast services. The information exchange is based on a publisher to subscriber mechanism. Two control classes are defined, Generic Object Oriented Substation Event (GOOSE) and Generic Substation State Event (GSSE). GOOSE supports the exchange of common data organized by a data-set and GSSE provides state change information in bit pairs. The model provides for a GOOSE Control Block (GoCB) with attributes and services. The following are examples of attributes: GoCBName, GoCBRef, GoEna, GoID,DatSet,ConfRev, NdsCom and DstAddress. The attribute GoEna can be set to TRUE or FALSE to indicate that the GoCB is enabled to send GOOSE messages. The following services are defined for the GOCB: SendGOOSEMessage, GetGoReference, GetGOOSEElementNumber, GetGoCBValues and SetGoCBValues.
- The transmission of sampled values model and the Control blocks for transmission of sampled values (SVCB) provide for the information exchange of data set values based on a publisher/subscriber mechanism. The publisher at the sending side writes the values in a local buffer and the subscriber read the values from the buffer. It is important that the values are time stamped. Two methods to exchange sampled values between a publisher and one or more subscribers is possible, muticast and unicast. The multicast-application-association method uses a multicast sampled value control block (MSVCB) and the two-party-application- association method uses a unicast sampled value control block (USVCB) The following services are possible SendMSVMessage, GetMSVCBValues and SetMSVCBValues

B.1.2 ACSI mappings to Manufacturing Message Specification (MMS)

Specific communication service mapping (SCSM) is a standardised procedure which provides the mapping of ACSI services and objects onto a particular protocol stack or communication profile. (IEC, 2003b: 22). Part 8-1 of the IEC 61850 standard specifies the SCSM of the objects and services of the ACSI, IEC 61850-7-2) to Manufacturing Message Specification (MMS), ISO 9506 and ISO/IEC 8802-3 frames.

The SCSM uses the 7-layer OSI reference model (ISO/IEC 7498-1) where layering of communication functions is defined. The layers are grouped in an application profile (A-Profile) and transport profile (T-Profile)

The upper three layers of the ISO A-Profile consist out of application, presentation, and session layers. The lower 4 layers of the ISO T-Profile consist out of the transport, network, datalink and physical layers. The combination of A and T-profiles is specified for each SCSM.

Each SCSM consists of:

- the mapping of the abstract specifications of IEC 61850-7 series on the real elements of the stack being used, and
- the implementation specification of functionality, which is not covered by the stack being used.

The Server, Logical device and Logical node objects models of 61850 as well as the generic substation event model (GSE) can be mapped to MMS (IEC, 2011b).

B.2 Server class model

The ACSI Server class is mapped to an MMS Virtual Manufacturing Device (VMD) object. Each VMD has a communication Service Access Point (SAP) through which MMS services such as control and monitoring can be exchanged. Each server object shall contain one or more MMS domain objects.

B.3 Logical device (LD) model

The ACSI logical device class, IEC 61850-7-2 GenLogicalDeviceClass is mapped to an MMS domain object. The domain object may have subordinate object that is uniquely named. The logical device objects and services are represented by the MMS domain object. Each physical device domain shall contain at least a LLN0 and a LPHD logical node.

B.4 Logical node (LN) class model

The ACSI logical node class, GenLogicalNodeClass maps to a single MMS NamedVariable. The MMS NamedVariable has a hierarchy of the MMS TypeDescription consists of multiple levels of components. The DataObject of the LN can have Functional Constraints (FC) with

Functionally Constrained Data (FCD) The FCD will determine the MMS NamedVariable ComponentName and ComponentType. The MMS named variables shall be created through the concatenation of the component names separated by “$”. The LN with data objects and FC will be represented by the MMS named variable <LNVariableName>$<FC>$<LNDataObjectName1>$<SubDataObjectName1> (e.g. MMXU1MXA$phsA). The data attributes DataAttr of the DataObjects is mapped in a similary to the DataObjects. The data attribute name is also included within the hierarchy <LNVariableName>$<FC>$<LNDataName1>$<AttributeName1>$<subDataAttributeName1> (e.g. XBCR1STPos$origin$orCat).

B.5 The Generic Substation Event (GSE) model

The GOOSE Control, as defined in IEC 61850-7-2, shall be mapped to an MMS GOOSE Control Block (GoCB). The GoCB MMS structure defines component names with MMS TypeDescription. The following are examples of MMS GoCB components, each having a type description: GoEna, GoID, DatSet, ConfRev, NdsCom, DstAddress, MinTime, MaxTime and FixedOffs.

GOOSE services such as the GetGoCBValues service shall be mapped to the MMS read service and SetGoCBValues service shall be mapped to the MMS write service.

This SCSM uses a specific scheme of re-transmission to achieve reliability for the SendGOOSEMessage service. The re-transmitting of the same data is done with gradually increasing SqNum and retransmission time between GOOSE messages.

APPENDIX C

Communication Network Architecture

C

Different architectures can be implemented in a digital substation communication network. The architecture will depend on the budget available as well as the reliability and availability requirements. The most common used architectures are cascaded, star, ring and a combination of them.

C.1 Cascaded Architecture

The Bay IEDs can be connected to an Ethernet switch in a sub-system. The first bay switch is connected to a station switch and the rest of the switches are connected cascaded to each other where. each Ethernet switch is connected to the next switch via one of its ports. The IEDs have a single network port and are connected to the network with one link.

A typical cascaded architecture is illustrated in Figure C.1.1.

Each switch adds to the system latency (Ingram, Steinhauser, et al., 2012; Mekkanen et al., 2014). The maximum number of switches that can be connected, depends on the system latency which can be tolerated.

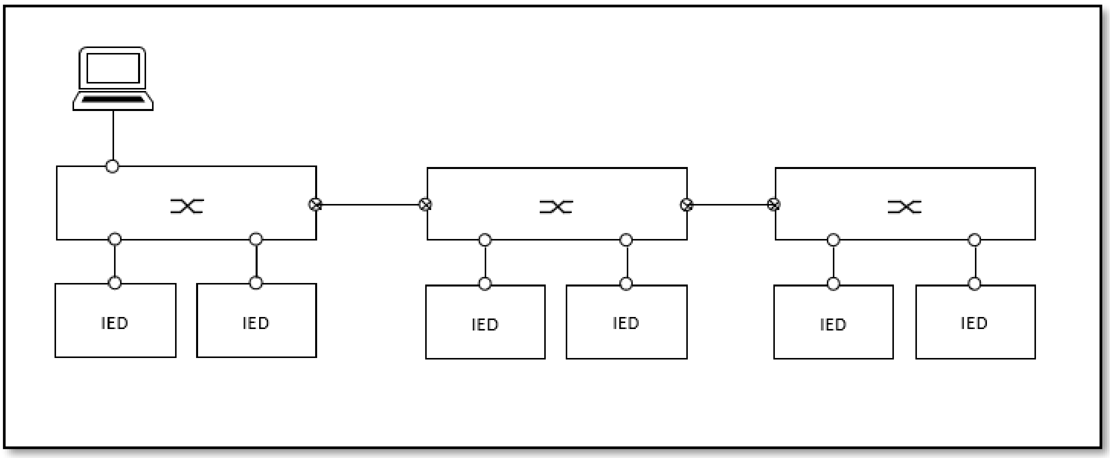


Figure C.1.1 Cascaded Network

The system availability must also be considered. The non-redundant switches and the cascaded architecture give the lowest reliability according to studies (Younis, 2016).

This architecture is simple but with a generally higher latency.

C.2 Star Architecture

All the IED are connected to a single central multi-port Ethernet switch.

A typical star architecture is illustrated in Figure C.2.1.

The IEDs have a single network port and are connected point to point to the network with one link.

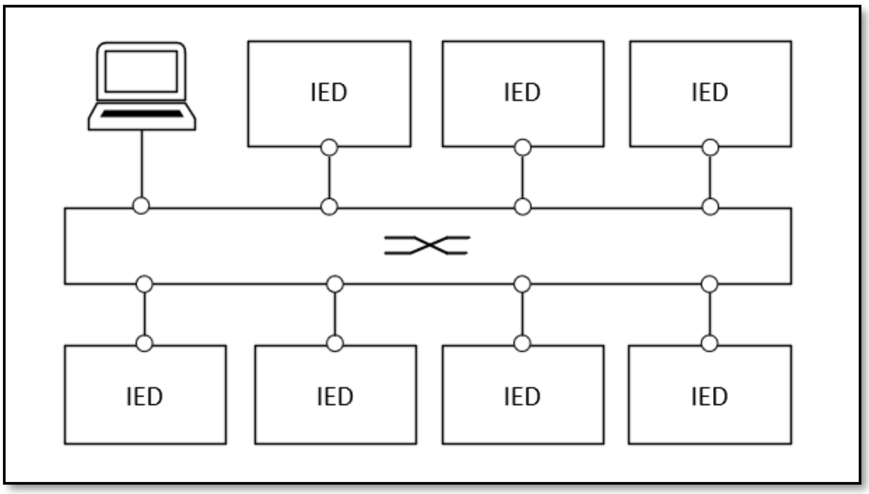


Figure C.2.1 Star Network

This architecture is simple but the switch as a single point of failure can be a problem. Redundancy can be improved by duplicating the system.

C.3 Ring Architecture

The ring architecture is very similar to cascaded architecture. The chain of switches is closed from the last switch to the first switch to form the ring.

A typical ring architecture is illustrated in Figure C.3.1.

The ring architecture creates message loops. Messages could circulate indefinitely in these loops and all the available bandwidth will be used as a result. A manage switch is required to prevent the communication loops. Managed switches are more expensive than standard switches.

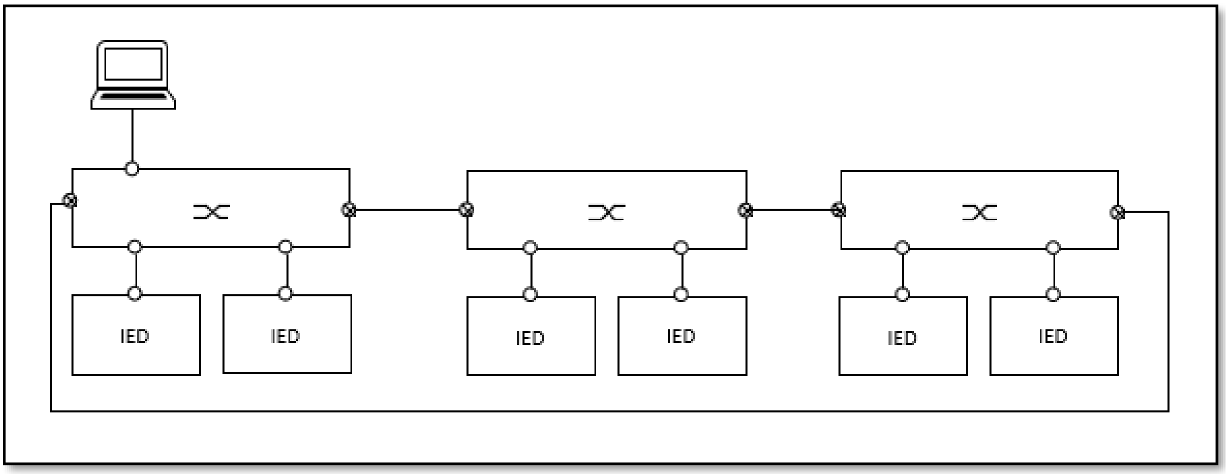


Figure C.3.1 Ring Network

The ring architecture has an advantage over a star architecture due to not having the network switch as a single point of failure, but it is not as simple and more expensive than the star architecture.

APPENDIX D

Network redundancy protocols

D

Redundant network connections are essential when designing high availability communication networks. Different mechanisms and protocols can be implemented in substation communication networks to obtain redundancy and to have high availability by keeping the outage time as short as possible. The outage time that can be tolerated can depend on the type of substation, how critical it is for the power system and the importance and supply contract of the customer. IEC 62439-1:2010 is applicable to high-availability automation networks based on the ISO/IEC 8802-3 (IEEE 802.3) Ethernet technology. Rapid Spanning Tree Protocol (RSTP) and MSTP are network spanning tree redundancy protocols. Parallel Redundancy Protocol (PRP) and High Availability Seamless Redundancy (HSR) are bus redundancy architecture proposed by the IEC 62439-3 standard (Igarashi et al., 2015: 3; Kumar et al., 2015b).

D.1 Spanning Tree Protocol (STP)

A Rapid Spanning Tree Protocol (RSTP) is an improved and faster version of STP. A Spanning tree topology such as RSTP consist out of a Root Bridge, Designated Switches and End Nodes connected in a LAN in such a way that all equipment is connected and there are no loops.

RSTP uses two communication links or loops from the source to destination. The redundant links are temporary disabled until a failure in the primary link occurs. RSTP will enable the secondary link when a primary link fails.

Any switch in a network can be a Root Bridge but only one Root Bridge can exist at a specific time. The priority part and MAC address of a switch or bridge ID can be selected. The switch with the lowest value priority will be the Root Bridge. The lowest MAC address will be used to select a Root Bridge if two switches have the same priority. The Designated switch is responsible to forward information from the Root bridge to the End Node (Wojdak, 2003).

(Goraj & Harada, 2012) reason that one of the disadvantages of RSTP, is that Ethernet root switch failures can be non-deterministic in highly meshed networks and is recommended to be avoided using RSTP in highly meshed networks for substation automation.

Another spanning tree protocol, MSTP, allows multiple instances of Spanning Tree Protocol on Virtual LANs. In a single physical network, there can be multiple VLANs, each with their own instance of Spanning Tree Protocol. An example could be where GOOSE applications are logically segregated to a separate VLANs.

D.2 Parallel Redundancy Protocol (PRP)

Parallel Redundancy Protocol (PRP) uses parallel communication networks to obtain redundancy. PRP duplicates all transmitted data via two Ethernet ports for each device or node. Each port is connected to a separate independent Local Area Network (LAN). PRP continuously check the redundancy to avoid network failures

The node of a PRP device with two communication ports is called a doubly attached node (DANP). Within a node, both ports are merged at the link layer and present themselves to the upper protocol stack as one single network interface with the same MAC address. PRP devices regularly supervise the network configuration to ensure that the two LANs are not connected. The supervision is done by using supervision frames.

DANP sends the same frame on both LANs. The data frame has a six-octet trailer added, which contains a protocol identifier and a sequence number. The destination nodes receive the first frame of a pair and discard the duplicate frame on the base of its source address and on its sequence number.

Nodes with a single port called Singly Attached Nodes (SAN) can be connected to separate LANs of a PRP network using a Redundancy Box (RedBox) and have redundancy. SAN can, without the Redbox, connect to only one of the networks and this will not have redundancy.

D.3 High Availability Seamless Redundancy (HSR)

HSR is specified in Clause 5 of IEC 62439-3:2012 standard and provides redundancy with seamless failover time in case of network failure. No topology reconfiguration is required to recover the communication. HSR topologies are compatible with the Ethernet standard IEEE802.3.

HSR also duplicates all transmitted data via two Ethernet ports for each device or node like with PRP but all ports are connected daisy chained to the same network. The same data frame is sent from the sending node in two directions and the two frames are received by the receiving node from two directions. Each node receives a message on one port and forward the message on the other port. The message sequence number in the header is used by the source to reject the message when it reaches the source again to prevent any looping.

HSR does not require the duplication of networks for redundancy as with PRP. The node of a HSR device with two communication ports is called a Doubly Attached Node (DANH). Within a node, both ports are merged at the link layer and present themselves to the upper protocol stack as one single network interface with the same MAC address.

The cost of the HSR network will be less due to less hardware that is required. The network does not have to be duplicated and the HSR network does not require switches.

SAN devices or nodes can only be connected to the HSR network using a RedBox.

Disadvantages of an HSR ring and particularly related to process bus and multicast sampled value frames is that all frames will have to be processed twice by every IED connected in the HSR ring, even if the IED is not subscribed to receive the message. More processing power will be required for the two Ethernet ports. The network will also have twice less available bandwidth because of the duplication of the data frames in the network. Every DANH requires a time to receive and forward a message. This time delay will increase and is depending on the amount nodes in the HSR ring.

APPENDIX E
Physical Layer

E

The physical layer defines specifications of the data physical transmission medium. The IEC 61850 caters for future development and therefore is not specific on the communication medium and required speed. It usually considers networks with copper and fibre physical layers and 100 Mbit/s and 1 Gbit/s bit rates.

Fibre has the advantage of galvanic isolation over copper. Each medium has a specific price, bandwidth and distance that it can cover. The distance that can be covered decreases with increasing data rate

IEC 61850 assumes that communication is full-duplex and auto-negotiated. The peer ports are configured to recognize automatically the polarity, the duplex setting and highest common speed.100Mbit/s copper, 100Mbit/s and 1Gbit/s optical fibre as physical layers is discussed in Appendix C.

E.1 100 Mbit/s (100BASE-FX) Optical Fibre

100BASE-FX is a version of Fast Ethernet over optical fibre. It uses a 1300 nm near-infrared (NIR) light wavelength transmitted via two strands of optical fibre, one for receive (RX) and the other for transmit (TX). The maximum length is 2 kilometres for full-duplex over multi-mode optical fibre. Multi-mode optical fibre is recommended because the communication equipment used over multi-mode optical fibre is less expensive than that for single-mode optical fibre. The recommended optical cable is multimode 50 µm (50/125) fibres, where the fibre has a core size of 50 micrometres (µm) and a cladding diameter of 125 µm.

A typical single-mode optical fibre has a smaller core diameter than multi-mode fibre, between 8 and 10.5 µm and a cladding diameter of 125 µm. The maximum length is 10 km over single mode fibre.

The transition between the core and cladding can be sharp, which is called a step-index profile, or a gradual transition, which is called a graded-index profile

ST connectors are widely used where individual connectors are used for RX and TX. The individual optical cables need to be labelled for identification. No identification is required when paired cables and LC connectors are used.

E.2 100Mbit/s Copper

Copper has the lowest cost and can be used inside cabinets where electromagnetic interference is low, over distances shorter than 100m and when galvanic isolation is not required.

The recommended cable is Cat5e with two twisted pairs and with RJ45 connectors

E.3 1 Gbit/s (1000BASE-X) Optical Fibre

1000BASE-X is used in industry to refer to Gigabit Ethernet transmission over fibre, where options include 1000BASE-SX, 1000BASE-LX, 1000BASE-LX10.

1000BASE-SX is a standard for operation over multi-mode fibre using a 770 to 860 nm, near infrared (NIR) light wavelength, for a maximum length of 550 m using a 50 µm multi-mode fibre. 1000BASE-LX10 is practically identical to 1000BASE-LX, but achieves longer distances up to 10 km over a pair of 10 µm single-mode fibre

APPENDIX F
Data Link layer

F

The data link layer or layer 2 is the second layer of the seven-layer Open Systems Interconnection (OSI) model. It defines the protocol for the transmission of data frames and to establish and terminate a connection between two physically connected devices. The data link layer has two sublayers: logical link control (LLC) and media access control (MAC).
A media access control address (MAC address) is a 48-bit address space and a unique identifier assigned to network interface controllers (NIC) for communications at the data link layer.

F.1 Unicast and multicast MAC addresses

Each frame carries a source and destination address. The Institute of Electrical and Electronics Engineers (IEEE) allocates the source addresses to the manufacturers. The destination address can be unicast, multicast or broadcast.
A frame sent to one receiver is called unicast. The least significant bit of the first octet of an address is set to 0 (zero). In IEC 61850, the MMS traffic uses unicast addresses.
A frame sent to a group of destinations is multicast and the least significant bit of the first octet is set to 1. The IEC61850, GOOSE and SV traffic use multicast addresses. Packets sent to a multicast addresses are received by all devices on a LAN that has been configured to receive it. This set of devices is called a multicast domain.
A broadcast is sent to all nodes on the local area network. A device will receive all traffic if the receiving controller is set to be in promiscuous mode.

F.2 Layer 2 switch

A bridge is often referred to as a layer 2 switch. A bridge is a type of network device that works on the OSI Layer 2. Data frame enters the bridge on ingress ports and leave the bridge on egress ports. When a frame enters the bridge on an ingress port it will use the MAC address to determine on which egress ports the frames are to be forwarded to.

F.3 MAC address filtering

MAC address filtering is traffic control mechanism that reduces the traffic that an end device handle. The bridge sends only the relevant part of the traffic to the end device. End devices normally do not filter traffic except if their controller is able to decode the MAC addresses. In IEC 61850, the MAC address filtering only reduces the MMS traffic, since the GOOSE and SV traffic is multicast.

F.4 Multicast filtering

A bridge does not apply MAC address filtering to multicast traffic, since the multicast frames are forwarded on all egress ports.

The network is flooded by multicast messages if not filtered. This results in excessive bandwidth consumption and unnecessary processing of unwanted traffic by IEDs or end devices. Multicast filtering can reduce the traffic to end devices by letting through only those multicast addresses the end device is interested in. The end devices normally have no multicast filtering ability, so the edge port on the bridge does the filtering on their behalf. A bridge port uses a configurable multicast filtering table to know which multicast addresses may egress from that port.

F.5 Virtual LANs (VLAN) traffic control

VLANs is a method to separate different types of traffic that share the same bandwidth on physical medium at the data link layer (OSI layer 2). The protocol most commonly used to configure VLANs is IEEE 802.1Q. The IEEE 802.3 frames carry a header, called the VLAN tag, 32-bit field between the source MAC address and the Ether Type fields of the original frame.

The header consists out of a 16-bit field Tag Protocol Identifier (TPID) and a 16-bit field Tag Control Information (TCI).

The TPID field is set to a value of 0x8100 to identify the frame as an IEEE 802.1Q-tagged frame. This field is located at the same position as the EtherType field in untagged frames and used to distinguish the frame from untagged frames.

Tag control information (TCI) field contains the following sub-fields, 3-bit field Priority Code Point (PCP), 1-bit field Drop Eligible Indicator (DEI) and 12-bit field VLAN identifier (VID).

The VID with hexadecimal reserved value 0x000 indicates that the frame does not carry a VLAN ID and is called a priority tag. The priority tag specifies only a priority in the PCP and DEI fields.

A default VID value 0x001 is often reserved for a network management VLAN.

F.6 Quality of Service (QoS)

Priority tagging (IEEE 802.1p) and VLANs are specified in the same standard IEEE 802.1Q and share the same tag, but they are separate concepts.

The QoS technique, class of service (CoS) is the 3-bit field PCP and specifies a priority value of between 0 and 7 that can be used by QoS to priorities the traffic. Priority means that a bridge that receives several frames simultaneously will forward the highest priority frames and queue the other lower priority frames. IEC 61850 prescribes that GOOSE and SV frames are priority-tagged. The value 1 is the lowest priority mark and priority 7 is the highest. Default priority is 4 for GOOSE and SV message given in IEC61850-9-2 but different priority can be assigned for GOOSE and SV messages.

F.7 Bridge port filtering

The bridge needs to be VLAN-aware to recognise the frames with the IEEE 802.1Q tag. The bridge ports need to be configured or set to allow the frames to enter. This can be done by a Port VLAN member set (PVMS) or VLAN ID table. Frames will not be allowed to ingress when a frame does not have a VLAN ID that is a member in the PVMS of that port. According to IEEE 802.1Q-2011, A bridge port can be set to admit the following frames:

- only VLAN-tagged frames;
- only untagged and priority-tagged frames;
- all frames (not VLAN-aware).

Manufacturers have different names for the port types in the port settings to admit the different types of frames. (E.g. Edge, Access, Trunk or Hybrid) The port can have its own Port Priority Code Point (PPCP) and Port VLAN identifier, (PVID). The port Native VLAN is the assigned VLAN number for the PVID. The port will use its default PPCP and PVID if the ingress frame does not have an IEEE 802.1Q-tagged frame.

An ingress frame can have a value between 1-7 for the PCP, (priority tagged), but VID = 0 (no VLAN). The port ignores its own PPCP, uses the frame PCP and inserts its PVID to form the VLAN tag.

The option to admit all frames or VLAN un-aware, must be used when an IED connected to a port, sent tagged (GOOSE, SV) and untagged (MMS) messages.

The egress from a port of a bridge is also controlled by the Port VLAN Member Set (PVMS). This port will forward the frames tagged or untagged.

An egress port sends the frame only if the frame VID belongs to the port membership set PVMS.

The port sends the frame without a change if it is configured to forward tagged frames. The port removes the VLAN tag including the PCP if it is configured to forward untagged.

F.8 Static and Dynamic VLAN configuration

Static VLAN configuration is done by using a network management and configuration tool to assign the priority PPCP and PVIDs to all device ports.

Dynamic VLAN configuration can be done by using protocols such as Generic VLAN Registration Protocol (GVRP) or Multiple VLAN Registration Protocol (MVRP). All devices broadcast their configured VLAN settings and dynamically learn the rest of the VLANs configured elsewhere in the network via GVRP. Dynamic allocation requires that all bridges and nodes support this protocol.

Dynamic VLAN configuration simplifies the replacement of bridges. Traffic bursts during initialization and reconfiguration can occur.

It is recommended by TR 61850-90-4 Technical report that substation automation should avoid dynamic VLAN assignment.

APPENDIX G

Time Synchronization

G

The equipment status collected at the process level by protection and control devices needs to be time stamped and published in a frame format on the substation communication network. All the devices therefore need an internal clock that is synchronized with a substation GPS clock. The synchronization is performed through IRIG-B, or indirectly over a network using one of several standards.

The IEC 61850 standard recommends the Network Time Protocol (NTP) as synchronization method. The NTP time accuracy (0.1 to 1 ms) can be considered enough for data acquisition and control applications but not for Sampled Values. Timing classes are defined in IEC 61850-5 standard (International Electrotechnical Commission, 2013: 68). The IEEE came up with IEEE 1588 standard (De Dominicis et al., 2011) to synchronize multiple devices over a network where their clock is in master/slave mode (Bhardwaj et al., 2014: 4). A single network implementation can be accomplished by using IEEE 1588 Precision Time Synchronization Protocol (PTP) (Skendzic et al., 2007: 5). IRIG and PTP can be considered as better alternatives to NTP for process bus application.

G.1 IRIG time codes

The IRIG time codes were originally developed by the Inter-Range Instrumentation Group (IRIG), part of the Range Commanders Council (RCC) of the US Army. The latest version is IRIG standard 200-04, “IRIG Serial Time Code Formats,” updated in September 2004.

IRIG-B has the capability to provide a 1µs time synchronization accuracy.

Typically, the signal transmission of modulated IRIG-B is over Coaxial cable or Shielded twisted-pair cable. Unmodulated IRIG-B can be transmitted over Coaxial cable, Shielded twisted-pair cable or optical fibre.

The name of an IRIG code format consists of a single letter plus 3 subsequent digits. The letters (A,B,D,E,G and H) are used for six IRIG Time Code Formats and one of them is IRIG-B. The different formats have different pulse or bit rates. IRIG-B has a pulse rate of 100 PPS.

IRIG time code signals may be the first digit indicating if the signal is Unmodulated (DC level shift, no carrier signal), Modulated (amplitude-modulated, sine wave carrier) or Modified Manchester (amplitude-modulated, square wave carrier). The second digit identify the carrier frequency and the third digit coded expressions. There are three functional groups of bits in the IRIG-B time code: Binary Coded Decimal (BCD),Control Functions (CF) and Straight Binary Seconds (SBS). The BCD group contains time information including seconds, minutes, hours and days, recycled yearly. The BCD time-of-year code (BCDTOY) reads zero (0) hours, minutes, seconds, and fraction of seconds. The BCD year code (BCDYEAR) counts year and cycles to the next year on January 1st of each year and will count to year 2099. The CF group contains year, time quality, leap year, pending leap seconds, parity and a set of bits reserved for user applications. The (optional) SBS time-of-day code consists of the total elapsed seconds, recycling daily (Cyber Sciences Inc, 2017). It is therefore required to confirm that all devices connected support the same version of IRIG-B.

The number of devices to be synchronized and the distances between devices affect the IRIG-B system architecture.

G.2 Simple Network Time Protocol (SNTP)

IEC 61850 proposes the implementation of time synchronization on a LAN using a simple network time protocol (SNTP). SNTP is a simplified version of NTP (Network Time Protocol) that uses User Datagram Protocol (UDP) on port 123 as its transport layer to send datagrams in a client-server scheme. Both unicast and broadcast SNTP can be supported in an IED. The IED acts as a SNTP client to request and receive time values from a SNTP server in a SNTP unicast mode. The client uses the transmit and arrival times to calculate the offset between itself and the SNTP server.(Wester & Adamiak, 2011)

The SNTP client assumes that the delays are symmetrical in both directions, but this can be different depending on the data traffic (Ussoli & Prytz, 2013).

The SNTP time synchronization system uses the substation communication network. The performance of the network switches and the loading of the network can influence the accuracy of the SNTP synchronization system.(JV & Gao, 2008: 3)

In the first edition of the IEC 61850 Standard it was proposed to perform synchronization of devices in the substation by using SNTP. SNTP provides an accuracy of only 1 ms compared to the 1µs of IRIG-B. Micro second accuracy is required for synchronized IEC 61850-9-2 Sampled Values. The IEC61850-9-2LE document proposed a separate synchronization network in 1pps or IRIG-B format.(Igarashi & Santos, 2014a)

G.3 Precision Time Protocol (PTP)

The Precision Time Protocol (PTP) is a protocol used to synchronize clocks throughout an Ethernet Local Area Network (LAN) using the same Ethernet medium as the data communications for the time synchronization information communication. When compared to IRIG-B, PTP reduces the cabling infrastructure requirements as there is no need of dedicated network for time synchronization information (Kanabar et al., 2012). PTP messages may use the User Datagram Protocol over Internet Protocol (UDP/IP) for transport. PTP was originally defined in the IEEE 1588-2002 standard and adopted by IEC 61588-2004, entitled “Precision clock synchronization protocol for networked measurement and control systems (IEC, 2004). In 2008, IEEE 1588-2008 was released as a revised standard; also known as PTP Version 2. The second edition of the IEC 61850 Standard proposes the use of PTP defined by the IEEE 1588v2 to cater for micro second accuracy that is required for synchronized IEC 61850-9-2 Sampled Values. Version 2 was more flexible and created potential incompatibility between devices. A profile was necessary to ensure device interoperability and that the specific needs of electric utility automation are met. The IEEE Std C37.238™-2011 profile was published to facilitate adoption of IEEE Std 1588-2008 for power system applications requiring high precision time synchronization(IEEE, 2011). The two versions of IEEE Std 1588 are not compatible and it is therefore not possible to have Version 1 and 2 devices in the same network (Watt et al., 2015).

The IEEE 1588 standards describe a master-slave architecture for synchronising clocks. The time master broadcasts a sync message containing its reference time to the slaves.

G.4 Different PTP Clocks

Different clocks are described in this architecture (Mallela et al., 2016). An ordinary clock (OC) can be either the master or slave clock. IEDs are typically slave-only clocks. A time distribution system can consist out of one or more communication network segments in a system and a synchronization master is selected for each of the network segments. The top-level master clock is called a Grand Master Clock (GMC) which is usually connected to a reference signal (GPS or atomic clock) The different network segments is connected by a Boundary Clock (BC) that can accurately synchronize one network segment to another. The BC has a slave port synchronized by a master clock in one segment and a master port that sends the PTP time synchronization message in another segment. A BC functionality is typically built into PTP-aware network components such as switches, bridges and routers.

Sync message sent through a network suffers network delay consisting of link and residence delays. Transparent clocks (TC) measure the peer to peer and end to end delays. A TC uses a peer-to-peer delay mechanism to calculate the link delay in a network between the clocks in PTP-aware devices. A TC also measures the residence delay which is the length of time a PTP message takes to travel through a device as it is routed from the ingress port to the egress port. Hybrid Clocks (HC) combine a transparent clock and an Ordinary Clock (IEC, 2013c; Watt et al., 2015).

G.5 Time gateways

Time gateways can be used to mix PTP and SNTP in the same network. It is not compulsory to replace all the existing SNTP devices when upgrading an existing time synchronization networks to PTP for microsecond accuracy. Time gateways are transparent two-port devices which are inserted in the network to perform the time conversion from IEEE 1588 PTP to SNTP (Ferrari, Flammini & Rinaldi, 2011; Ferrari et al., 2012).

Time gateways may constitute a valid alter-native to the full replacement of an old device, when high synchronization accuracy is required, or large networks must be implemented.

APPENDIX H

IEC 61850 IED Configurator

H

The MiCOM S1 Studio software provides a tool, the IED Configurator V7.1.0.0 to configure the files and transfer them to and from a MiCOM IED. The configuration can be done offline or online. MiCOM Configuration Language (MCL) files are vendor-specific, containing a single device IEC61850 configuration information. The data file which contains the IED's IEC 61850 configuration information has a .mcl file extension.

A new MiCOM configuration is created when the IED operates in an offline mode from a template or an IED Capability Description (ICD) file. The IED model number is used to choose the ICD file. The IED Configurator is shown in Figure H.1.

The ICD file is selected and opened in the Configuration tool. The main area is shown on the left side window. The detail of selected category is shown on the right-hand side. The IED configuration can also be extracted from the IED online.

The edited configuration file must be validated before it is sent to the device. The right-hand lower pane shows lists of Errors, Warnings and Messages.

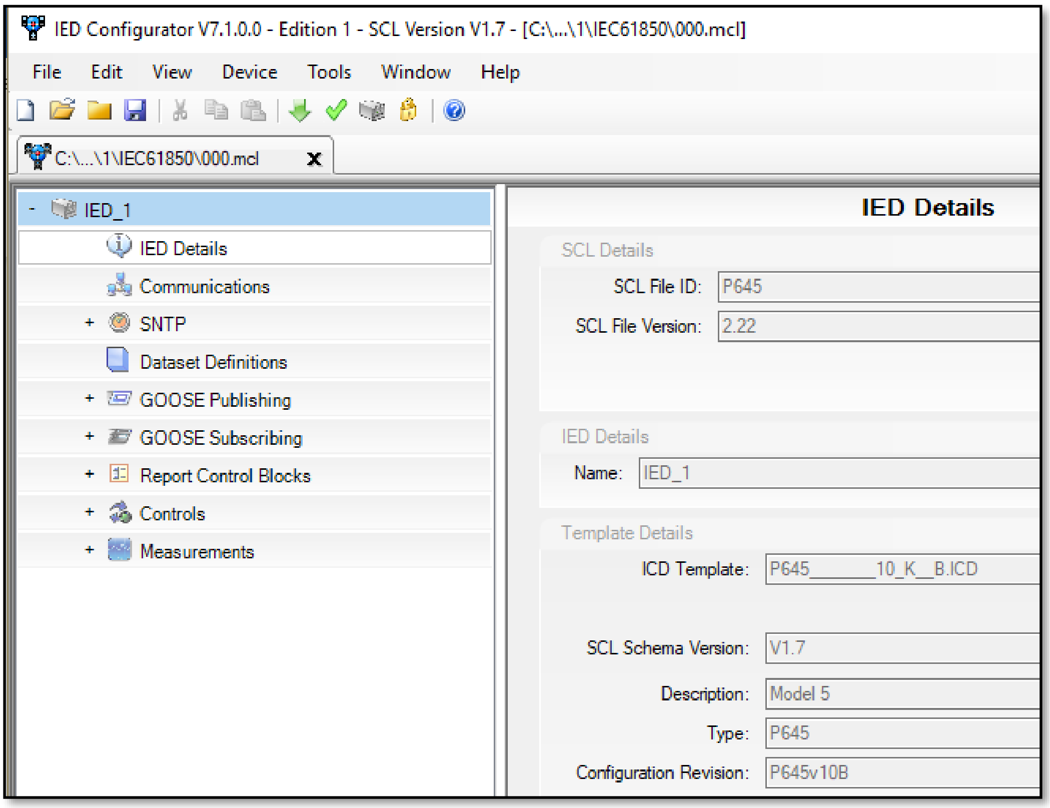


Figure H.1 IED Configurator

The configurable items are categorised into groups in the Editor left-hand window. The Groups are IED details, Communications, SNTP, Dataset Definitions, GOOSE Publishing, GOOSE Subscribing, Report Control Blocks, Controls and Measurements.
The sub-sections in the right-hand side window provide details on each configurable item type. The Item can be Read only or Editable.
The configuration file can be created as new from and ICD file or opened from a configured SCL/MCL file. The items in the sub-sections in the right-hand side window will be read only when an already configured MCL is opened. The Manual Editing Mode must be used if it is necessary to edit these configuration files. Some items will be editable in the Manual Editing Model. A new configuration file will be edible when it is open from a template ICD file.

H.1 IED Details

The IED details tab, displays general configuration and data about the IED and selected ICD Template file. The IED Details are shown in Figure H.1.1.

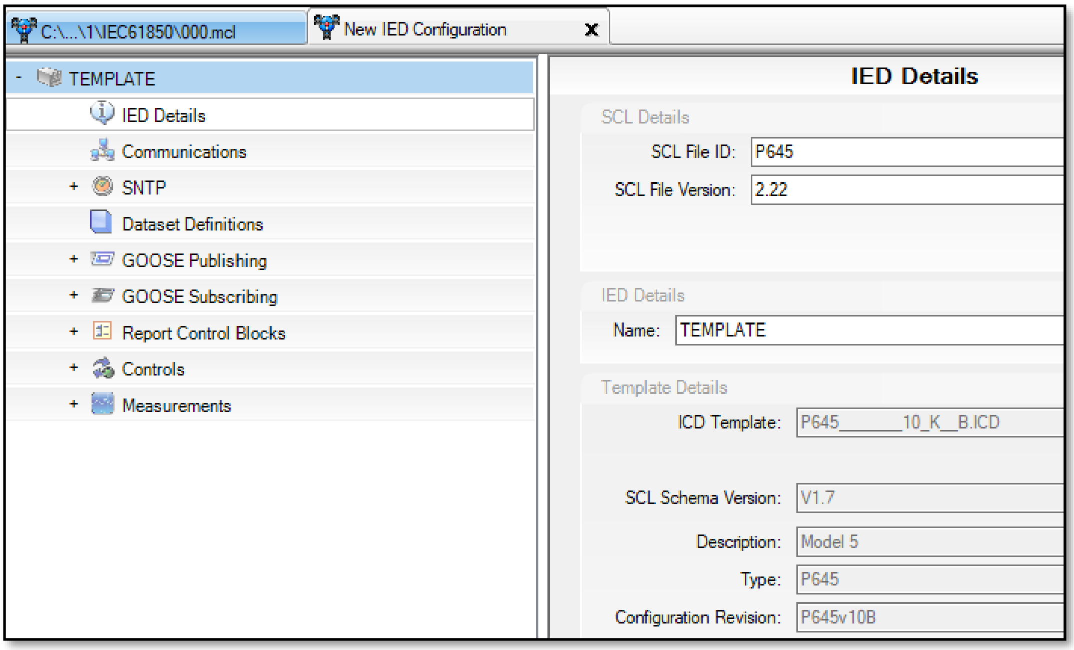


Figure H.1.1 P645 IED Details

The IED name is configurable but some greyed out data e.g. the ICD Template data is not user configurable.

H.2 Communications

The communication configuration is shown in Figure H.2.1.

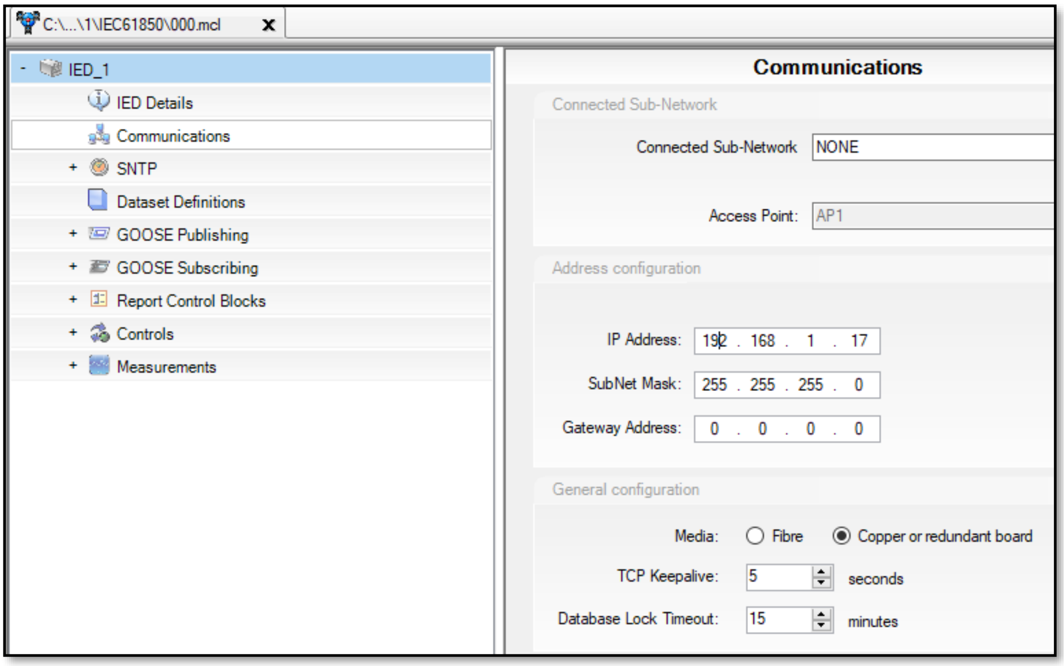


Figure H.2.1 P645 Communications

Connected Sub-Network displays the Sub-Network name to which the IED is connected. An IED can only subscribe to GOOSE messages published by IEDS that are connected to the same Sub-Network. The Sub-Network name is taken from the Communications section of a configured SCL file.

The Access Point data is read only and displays the physical port name for the MiCOM IED. It is taken from the IED AccessPoint section of the ICD template file. This data is not stored in MCL data and therefore not sent to the MiCOM IED.

The IP address and IP SubNet mask of the P645 is configured when a new file is opened. When a configured MCL file is opened, it is taken from the *ConnectedAP Address* section of the configured SCL file.

The IP address of any gateway or proxy device, to which the P645 is connected was not configured and left at its default unconfigured value of 0.0.0.0. When a configured MCL file is opened, this data is taken from the ConnectedAP Address section of the configured SCL file.

The communication media used to connect the P645 to other IEDs is configured for a copper or fibre optic Ethernet interface. The ConnectedAP/PhysConn section of the configured SCL file is used.

TCP Keepalive Packets can be used to determine if a connection is still valid. The frequency between 1-20 second is configured for the P645 to use to send a TCP Keepalive message.

Database Lock Timeout configure the time that the P645 will wait during an active connection link without receiving any messages. The P645 will reverts to its default state, resetting any password access that was enabled after a timeout. The configured data is taken from the IED/AccessPoint/Server section of a configured SCL file. A valid setting is configured in a range of between 60 to 1800 seconds. This parameter is only application to MiCOM IEDs that supports setting changes over the IEC61850 interface.

H.3 SNTP

The configuration of SNTP is divided into the generic configuration within the IED and the configuration of two external SNTP time servers. The IED will attempt to synchronise with the time servers. The General SNTP configuration is shown in Figure H.3.1.

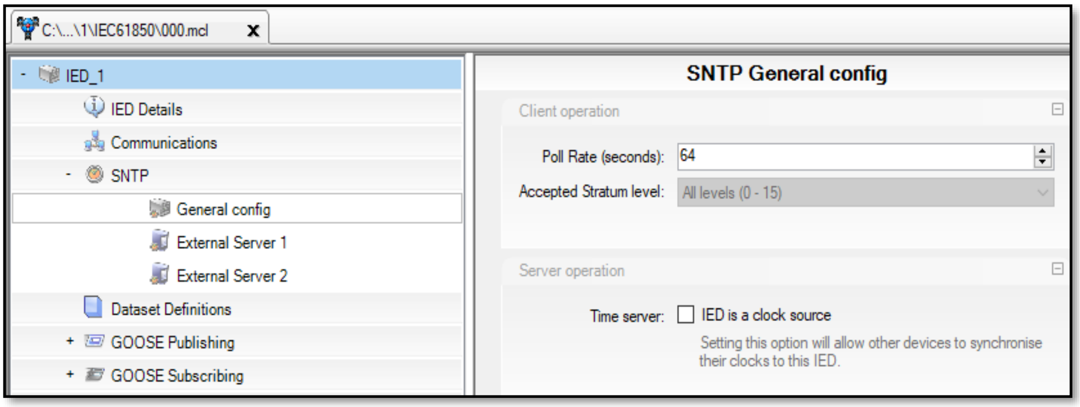


Figure H.3.1 P645 SNTP Configuration

The Poll Rate sets the interval in seconds at which the MiCOM IED requests time synchronisation from the selected SNTP servers.

Accepted Stratum level can be specified that SNTP servers must meet for the MiCOM IED to accept time synchronisation responses. A Response with an unacceptable Stratum will be discarded.

The IED can be configured to act as a Time server for other devices. The configured value is taken from the IED/AccessPoint section of the configured SCL file.

A main and backup external SNTP time server can be configured. This configuration of the first external time server is shown in Figure H.3.2. The configuration of the second time sever is identical to the first.

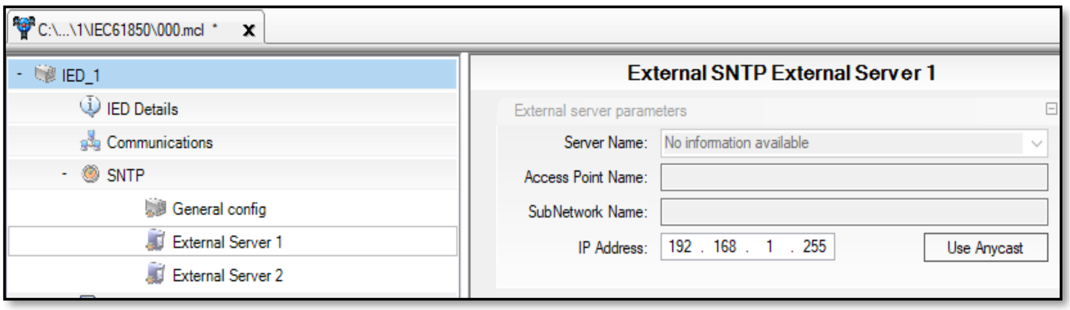


Figure H.3.2 P645 External SNTP Server

Server Name, Access Point and Sub Network Name data will be displayed for a configured IED if the configuration is opened from a configured SCL file. The MiCOM IED will attempt to synchronise its clock with this device. The data is READ-only. This is not stored in MCL data nor sent to the MiCOM IED.

The IP Address of the device that is providing SNTP Time synchronisation services can be set. Pressing the Anycast button, shown in the configuration window above, will automatically set the SNTP Server IP address to the broadcast address of the Sub Network that the MiCOM IED is connected to.

H.4 Dataset Definitions

A Dataset can be added in the Dataset definitions window. The location of the dataset is required to be specified. A dataset can be created within any Logical Node of the IEDs data model. The initial character of the dataset name must be an alphabetic character while the remainder of the name can be either alphanumeric or the underscore symbol. The dataset name must be unique within the Logical Node it is contained. The name value is derived from the Dataset section of the selected Logical Node location in the configured SCL file.

A dataset in LLN0 with 3 elements is shown in Figure H.4.1. The Functionally Constrained Data Attributes (FCDAs) contained in the dataset are shown in the contents window. The size of a GOOSE message cannot be larger than the maximum allowable size of an Ethernet frame. The percentage of dataset capacity used by the selected items is shown with the GOOSE Capacity gauge.

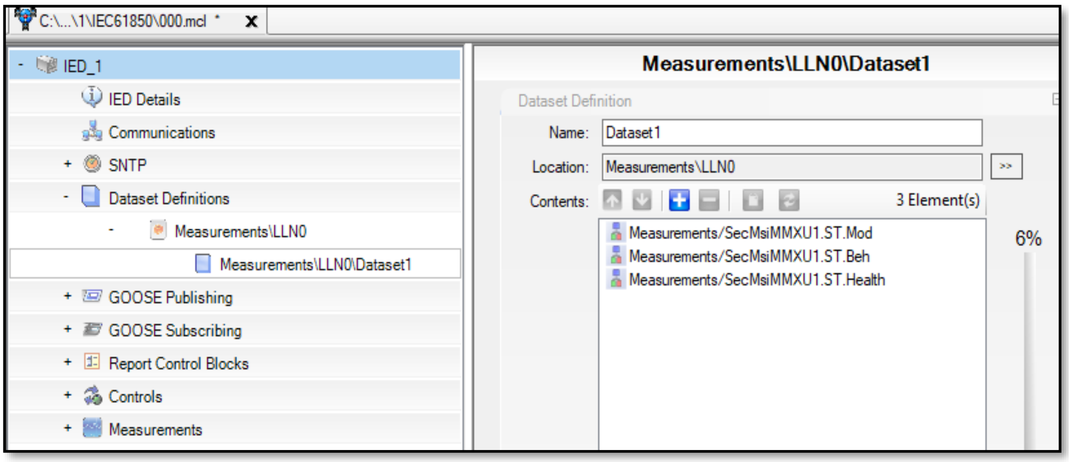


Figure H.4.1 P645 Dataset

H.5 GOOSE Publishing

8 x GOOSE control blocks (GoCB) can be configured for publishing. The first part is to configure the network parameters for a GoCB shown in Figure H.5.1. The values are taken from the Connected AP/GSE section of the configured SCL file.

The multicast MAC address to which the GoCB publishes GOOSE messages is configured. The first four octets (01 – 0C – CD – 01) are defined by the IEC61850 standard for multicast messages.

The Application ID or AppID to which the GoCB will publish GOOSE messages is configured as a hexadecimal value with a setting range of 0 to 3FFF.

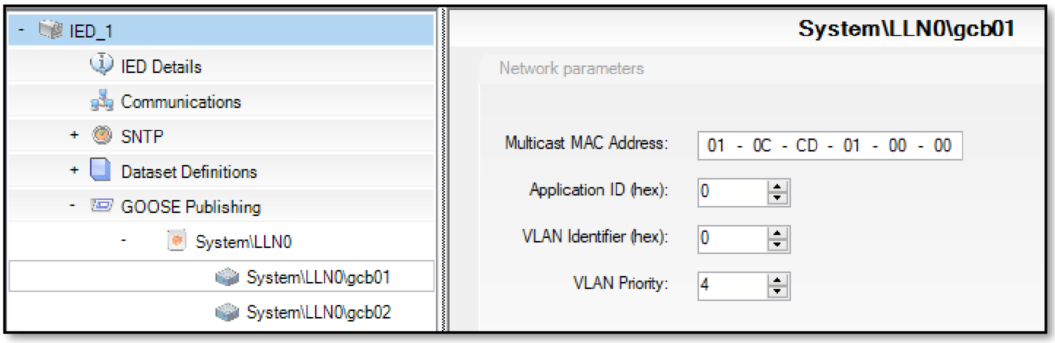


Figure H.5.1 GOOSE Publishing - Network Parameters

VLAN Identifier configures the VLAN (Virtual LAN) on to which the GOOSE messages are published. The default value is set if no VLAN is being used.

VLAN Priority configures the VLAN Priority of published GOOSE messages. The VLAN priority has a setting range of 0 to 7 (Lowest priority = 0, highest priority = 7).

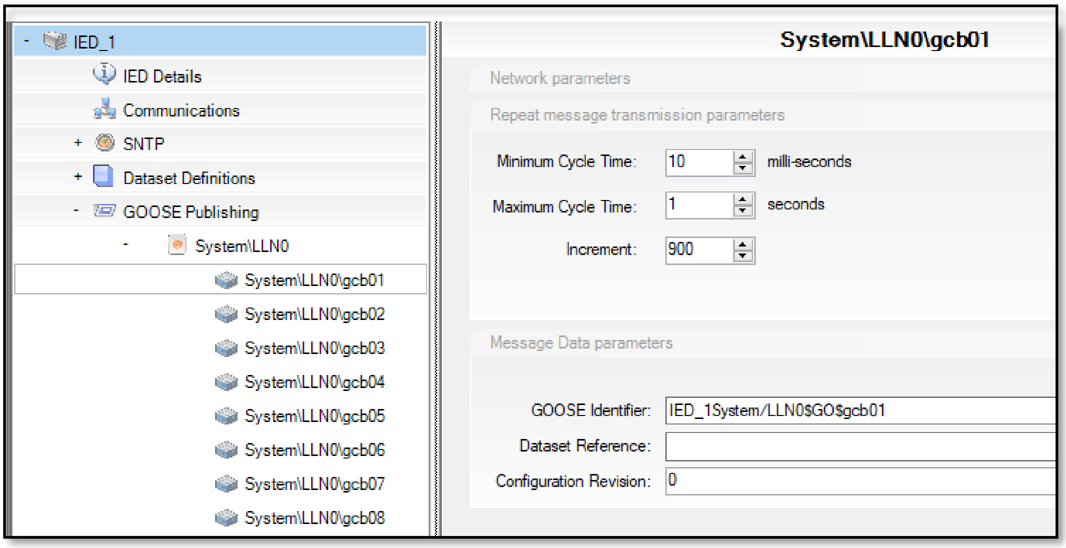


Figure H.5.2 GOOSE Publishing-Message parameters

The next part of the GOOSE configuration configures the repeat message transmission parameters. Minimum and Maximum Cycle Times is determined. The Minimum Cycle Time between the first message being transmitted and its first repeat retransmission and has a setting range of 1 to 50 milliseconds. The Maximum Cycle Time has a setting range of 1 to 60 seconds.

The Increment determines the step-up rate at which the repeat message transmission intervals change from the Minimum Cycle Time to the Maximum Cycle Time. A higher increment number will result in a shorter period to reach the Maximum Cycle Time. The setting ranges from 0 to 999.

The GOOSE Identifier (GoID) is a 64-character name of the published GOOSE message. The initial character must be an alphabetic character and the rest of the name can be either alphanumeric or the underscore symbol. The GoID must be unique for the entire system.

Dataset Reference configures a Dataset to be included in published GoCB message. The datasets must belong to the same Logical Node as the GoCB.

The Configuration Revision must be incremented should there be any change to the dataset to identify the change in configuration to others listening to the published message.

H.6 GOOSE Subscribing

GOOSE Subscription configuration is based on Mapped inputs and Unmapped inputs.

GOOSE Subscribing of a mapped GOOSE Virtual Input is deliberated first. 64 Virtual inputs can be configured. The first input is shown in Figure H.6.1

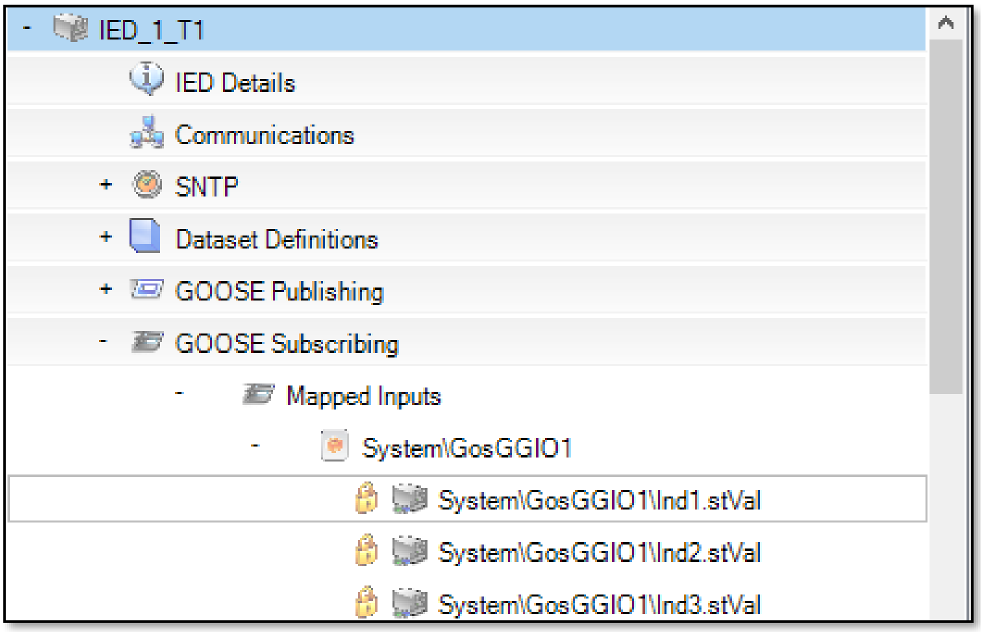


Figure H.6.1 GOOSE Subscribing-Input 1

The configuration page for the first Virtual Input is shown in Figure H.6.2. The first part of the configuration page is about the source network parameters. This multicast MAC address and the Application ID (AppID) of the publishing GoCB is configured. The second part is the GOOSE source parameters.

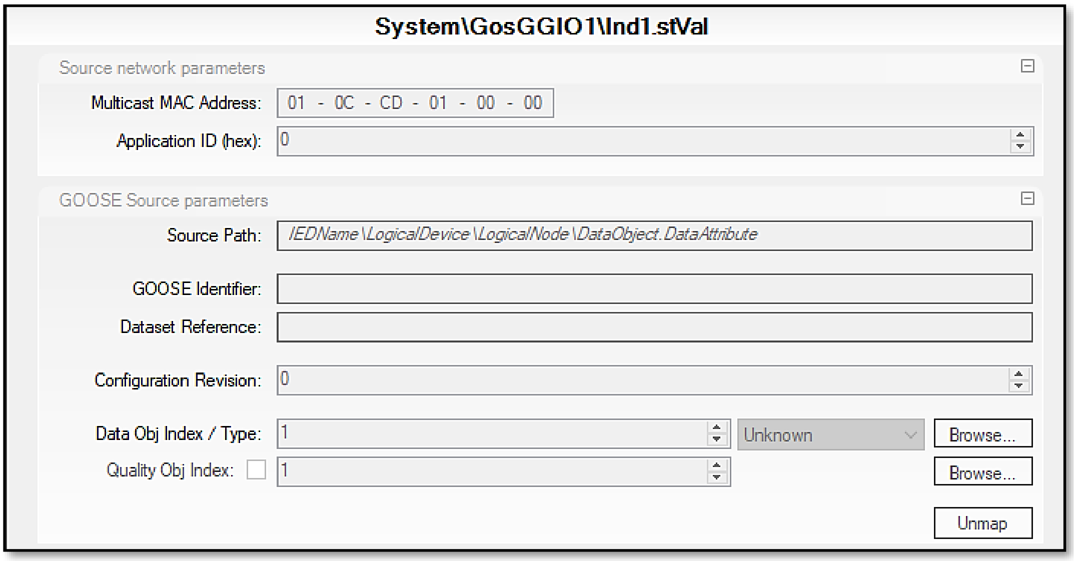


Figure H.6.2 GOOSE Subscribing – Source

The last part is to configure the destination parameters. This is shown Figure 8.2.

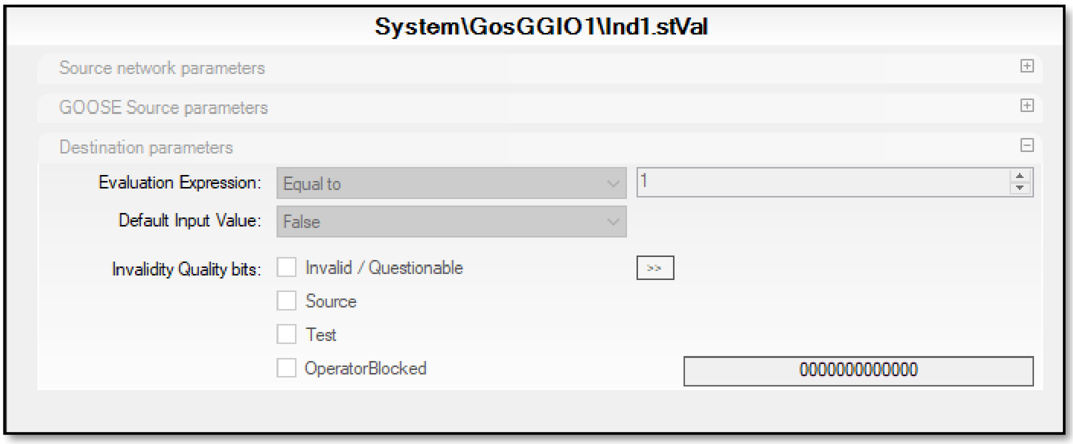


Figure 8.2 GOOSE subscribing – Destination

Default Input Value of the Virtual input can be configured to False, True, or Last know value. This configured value will be used when no messages are received from the configured GOOSE publisher.

H.7 Report Control Blocks

IEC61850 supports the Buffered and Unbuffered types of Report Control Blocks.

The IED will buffer the events for transmission when buffered reporting is used. The DATA are not lost due to transport flow control constraints or loss of connection.

With Unbuffered reporting, the IED will send a report but the delivery to the client is not guaranteed. The report data may be lost if no association exists, the transport data flow is not fast enough, or the network connection is lost.

The Report ID, Dataset reference and configuration revision is configured as in Figure H.7.1.

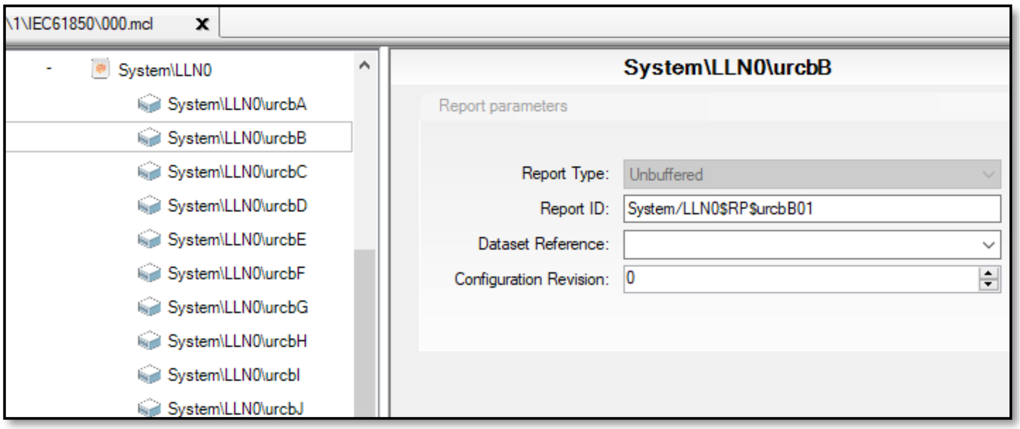


Figure H.7.1 Report Control Block

Dataset Reference configures the Dataset whose contents is to be included in the generated reports from the RCB. Only datasets that belong to the same Logical Node as the RCB can be selected.

H.8 Controls

The configuration of each Control Object within the IEDs data model is possible. The Trip/Close control of a Circuit Breaker can be configured by selecting the Control Model to be Direct Operate or Select Before Operate.

An additional layer of security onto control operations can be added by configuring the Uniqueness Of Control. The Uniqueness Of Control allows only 1 Control Object throughout the entire system to operate at any one time.

The sboTimeout parameter, configures the Select Before Operate timeout. The operate must follow the select command before the configured time or otherwise the Control Object is reset to an unselected state. Figure H.8.1 shows the configuration page with the selected Control Object.

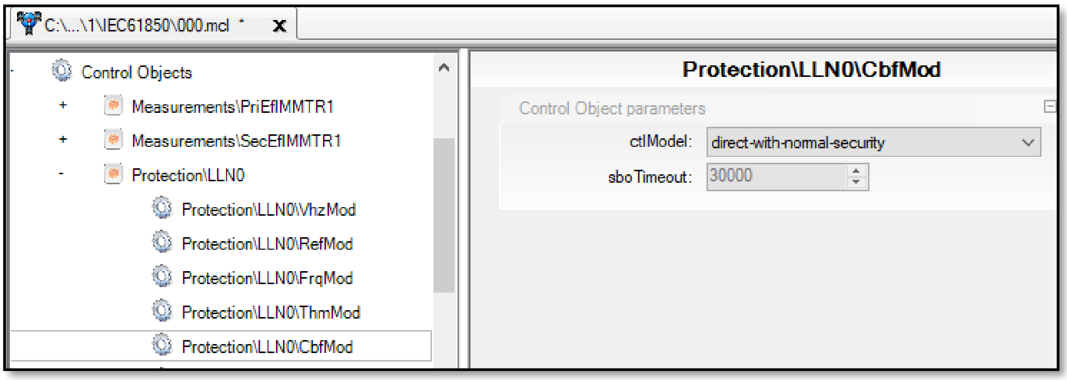


Figure H.8.1 Control Object configuration

The operation of Uniqueness of Control uses GOOSE and its configuration is very similar to GOOSE Subscribing.

H.9 Measurements

The configuration of measurement object is done in this category. Figure H.9.1 shows the configuration of the A phase current of PriMsiMMXU1.

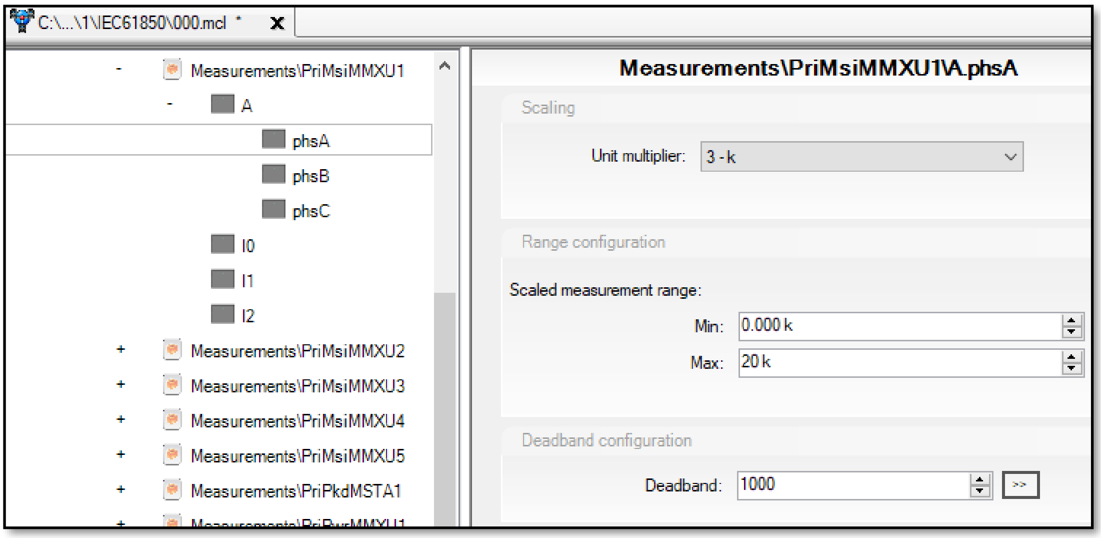


Figure H.9.1 Measurement Object

Unit multiplier configures the value that the measurement value will be scaled when read or reported. A Unit multiplier with a setting of 3 or kilo, will report a value of 2 when 2000 amp is measured.

The Min / Max range configures the minimum and maximum values of a measurement object. The min and max values are used together with the deadband value to calculate the magnitude a measurement must change by in order to be updated/reported to a client.

The deadband is a percentage change measurements range in units of 0.001% based upon the measurements range. A deadband of 0 means the measurement is updated instantaneously. The deadband must be specified as a percentage change or as an absolute change. A deadband of 1000 specifies a percentage change of 1 percent.

APPENDIX I

Configuration of Network equipment

I

A MOXA PowerTrans PT-7728 series and a RUGGEDCOM RSG2288 managed Ethernet switch are used to set up the substation automation test-bench and connect the different components to the process bus network.

The PT-7728 series Ethernet switch is used to connect the Alstom Agile Merging Units (AMU) to the process bus.

The RSG2288 managed Ethernet switch is used to connect the MiCOM P645 Transformer protection and control device to the process bus. The PT-7728 and RSG2288 are connected to each other. The Acer Aspire ES 15 personal laptop computer is connected to the RSG2288 but can be connected to the PT-7728 as well.

I.1 Moxa PT-7728_PTP

The PT-7728 has a modular design were 4 slots supports modules with different port configurations to cater for 1 slot Gigabit and 3 slots Fast Ethernet.

The switch has dual isolated redundant power supplies to increase the communications reliability.

The Analogue Merging Units (AMUs) are connected to the PT-7728 network switch in the test-bench. The 100BASE-FX version of Fast Ethernet over optical fibre is used with a 1300 nm near-infrared (NIR) light wavelength transmitted via two strands of optical fibre, one for receive (RX) and the other for transmit (TX).

Full-duplex over multi-mode 50 µm (50/125) optical fibre is used. Multi-mode optical fibre is used over short distances because the communication equipment used over multi-mode optical fibre is less expensive compared to single-mode optical fibre.

ST connectors are used on the PT-7728 network switch where individual connectors are used for RX and TX to connect the optical fibre from the AMUs. LC Connectors are used on the AMU.

The PT-7728's configuration settings can be access using the serial console, Telnet console, and web console. A Main menu with folders in the left navigation panel is used to go to different configuration pages.

I.1.1 Basic settings

The web console is used to display the port settings page is shown in Figure I.1.1.

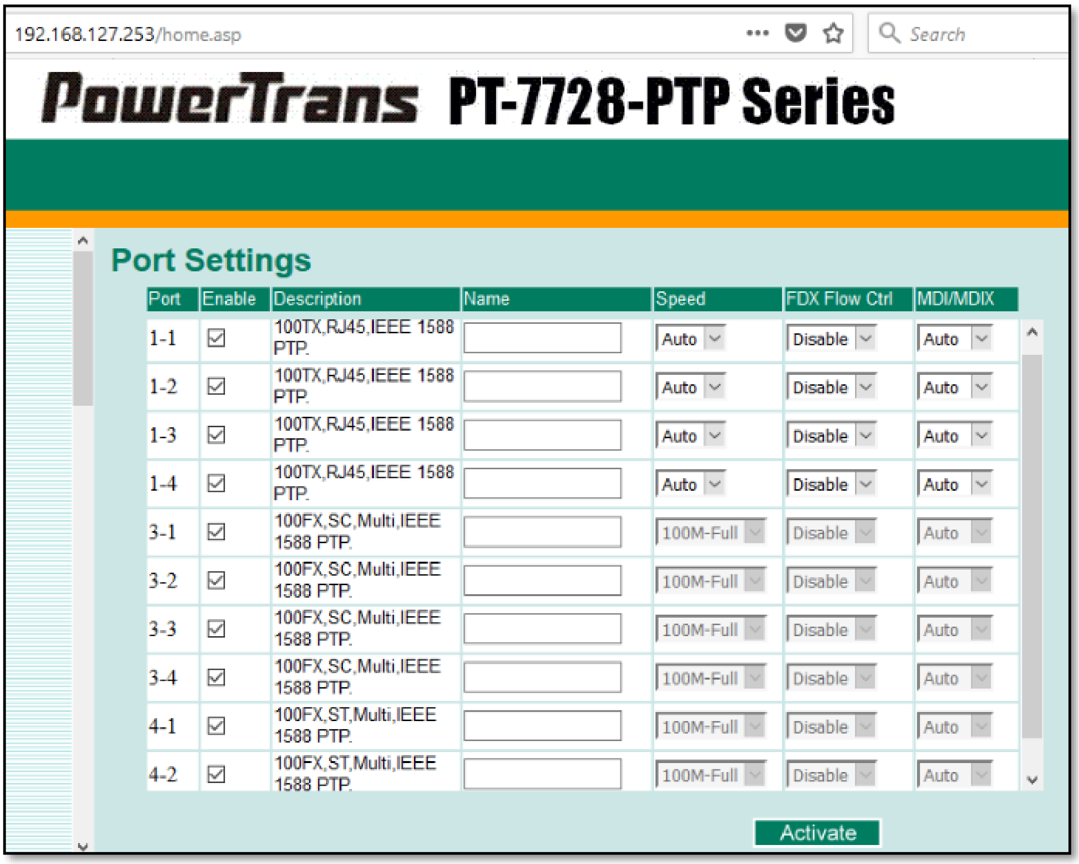


Figure I.1.1 PT-7728 Port Configuration

Each of the ports can be disabled. Enabling the port allows data transmission through the port. Ports 4-1 and 4-2 are used to connect the AMUs. Speed, FDX Flow Control and MDI/MDIX are not configurable for these ports. 100BASE-FX version of Fast Ethernet over optical fibre (OF) must be used on both sides of the OF connection, at the switch port as well as the port on the AMU

Network parameters are configured and are shown in Figure I.1.2.

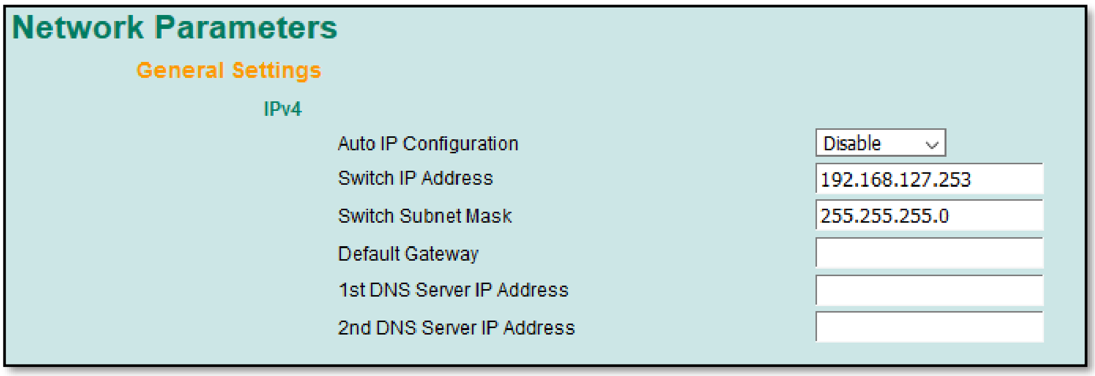


Figure I.1.2 PT-7728 Network Configuration

The PT-7728's IP address can be set manually or automatic by a DHCP or BootP server.

The switch IP address and Subnet Mask were set to default values. A Gateway can be configured for a router that connects the LAN to an outside network. A primary and secondary DNS Server IP address can be set. A Gateway was not used as part of the test-bench setup and was not configured.

The PT-7728 does not have a real-time clock. The Current Date, Time, Daylight savings time and NTP time server on the LAN is configurable. The IP or domain address can be used for the time server. Figure I.1.3 shows the page for configuring the system time.

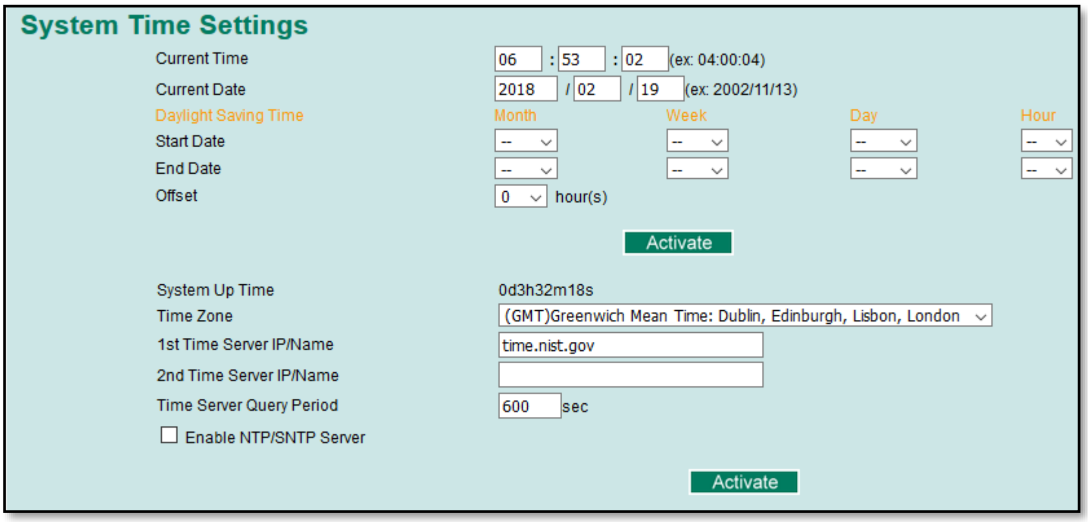


Figure I.1.3 PT-7728 Time settings

I.1.2 Port Trunking

Port trunking can be used to combine up to 8 ports between two PT-7728 switches. The full duplex 100BaseTX ports can be used to trunk links together to increase the bandwidth to quadruple between two switches. Trunking also provides redundancy if one link fails and enables the sharing of load across multiple links. Port trunking was not configured as only one PT-7728 switch was used in the test-bench setup.

I.1.3 Communication redundancy

The PT-7728 supports Rapid Spanning Tree Protocol (IEEE-802.1w), Turbo Ring and Turbo Ring V2 protocols for communication network redundancy. Turbo Ring and Turbo Ring V2 are Moxa proprietary protocols for managed switches and cannot be used in the test-bench setup where the other switch is a Ruggedcom RSG2288 switch. Communication redundancy was not configured, simulated and tested.

I.1.4 Traffic periodization

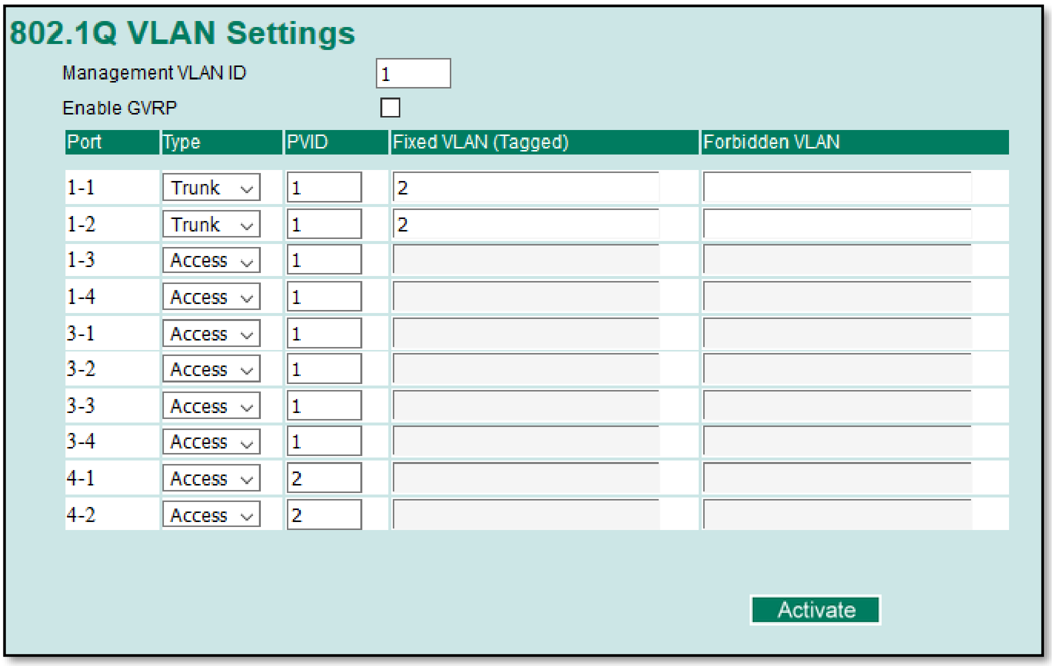
The PT-7728's traffic prioritization capability provides Quality of Service (QoS) to prioritize network traffic to ensure high priority data are transmitted and passed through the switch with minimum delay. The PT-7728 can inspect both IEEE 802.1p/1Q layer 2 CoS tags, and even layer 3 Type Of Service (TOS) information. The IEEE 802.1Q tags are removed when the packets pass through a router and can therefore only be used on a LAN and not across routed WAN links. The 4-byte tag immediately follows the destination MAC address and Source MAC address in the data frame.

a Layer 3 marking scheme that uses the DiffServ Code Point (DSCP) field in the IP header to store the packet priority information can be used. No extra tags are required in the packet. DSCP uses the IP header of a packet and therefore priority is preserved across the Internet

I.1.5 Virtual LAN

The PT-7728 has Virtual LAN (VLAN) and traffic prioritization capability to recognise 802.1Q VLAN packets which are used to carry VLAN identification as well as IEEE 802.1p priority information. VLAN settings are shown in Figure I.1.5.1. VLAN configuration is achieved by using trunk or access ports settings.

The Access Port setting is used when the port connects to a single device that is not tagged. Port 4-1 and 4-2 connected to AMUs are set to be Access ports for the test-bench setup. The default port PVID is set to the VLAN the device belongs to. The PT-7728 will insert this PVID into this packet to help the next 802.1Q VLAN switch recognizes it when the ingress packet of this Access Port egresses to another Trunk Port.


802.1Q VLAN Settings

Management VLAN ID: 1

Enable GVRP

Port	Type	PVID	Fixed VLAN (Tagged)	Forbidden VLAN
1-1	Trunk	1	2	
1-2	Trunk	1	2	
1-3	Access	1		
1-4	Access	1		
3-1	Access	1		
3-2	Access	1		
3-3	Access	1		
3-4	Access	1		
4-1	Access	2		
4-2	Access	2		

Activate

Figure I.1.5.1 PT-7728 VLAN

The Trunk Port setting is used for ports that connect to a LAN that consists of untagged devices/tagged devices and/or switches. A PVID can be assigned to a Trunk Port. The untagged packet on the Trunk Port will be assigned the port default PVID as its VID.

A router or Layer 3 switching device with connections to both VLANs needs to be installed If devices connected to a VLAN need to communicate to devices on a different VLAN.

I.1.6 Multicast filtering

Multicast filtering is useful for publisher/subscriber communications that use multicast messages. The filtering ensures that only subscribers groups receive multicast traffic. Network devices only forward multicast traffic to the ports that are connected to registered subscribers.

The PT-7728 achieves multicast filtering by using Internet Group Management Protocol (IGMP) Snooping, GARP Multicast Registration Protocol (GMRP), and adding a static multicast MAC manually. GMRP is a MAC-based multicast management protocol, whereas IGMP is IP-based. Other network devices are required to support IGMP and GARP protocols if these protocols are used for multicast filtering. Static multicast groups can be added manually.

The other switch used in this test-bench network supports IGMP and GARP protocols.

I.2 Ruggedcom RSG2288

The MiCOM P645 IED is connected to the RSG2288 network switch on the Ethernet network.

Two separate IEC 61850 network connections are made for the station bus and process bus IEC 61850-9-2 LE interfaces from the P645 IED to the RSG2288 network switch.

I.2.1 Network connections

The rear Ethernet board on the P645 IED for the IEC61850 station bus interface provides for two types of communication ports. 10BaseT/100BaseTX communication using a RJ45 connector connecting to a Screened Twisted Pair (STP) copper cable and 100Base FX fibre optic interface ,1310 nm multi-mode 50/125 μm with ST connectors is available. An additional 9-2 Ethernet board allows a path with IEC61850-9.2LE Ethernet link with optical fibre or RJ45 connector to copper wire. The 100BASE-FX version over optical fibre is used with a 1300 nm, multi-mode 50/125 μm with ST connectors via two strands of optical fibre, one for receive (RX) and the other for transmit (TX).

The RSG2288 used in the test-bench setup only provides for 1000BASE-FX version optical fibre LC Connectors. The 1000BASE-FX type of fibre optic communication used on the RSG2288 is not compatible with the 100BASE FX type of communication on the P645 IED. The RJ45 Connectors were therefore used instead.

I.2.2 The ROS user interface

The RSG2288 is embedded with the Rugged Operating System (ROS). A laptop computer can be connected directly to the RS232 console port to access the device.

The RSG2288 can be configured using a telnet session or web interface. The default administrator username and password are "admin".

100BaseTX communication using one of the RJ45 connector ports was used to connect the laptop computer with STP copper cable to the RSG2288.

A screenshot is shown with the product information in Figure I.2.2.1 used to configure the RSG2288.

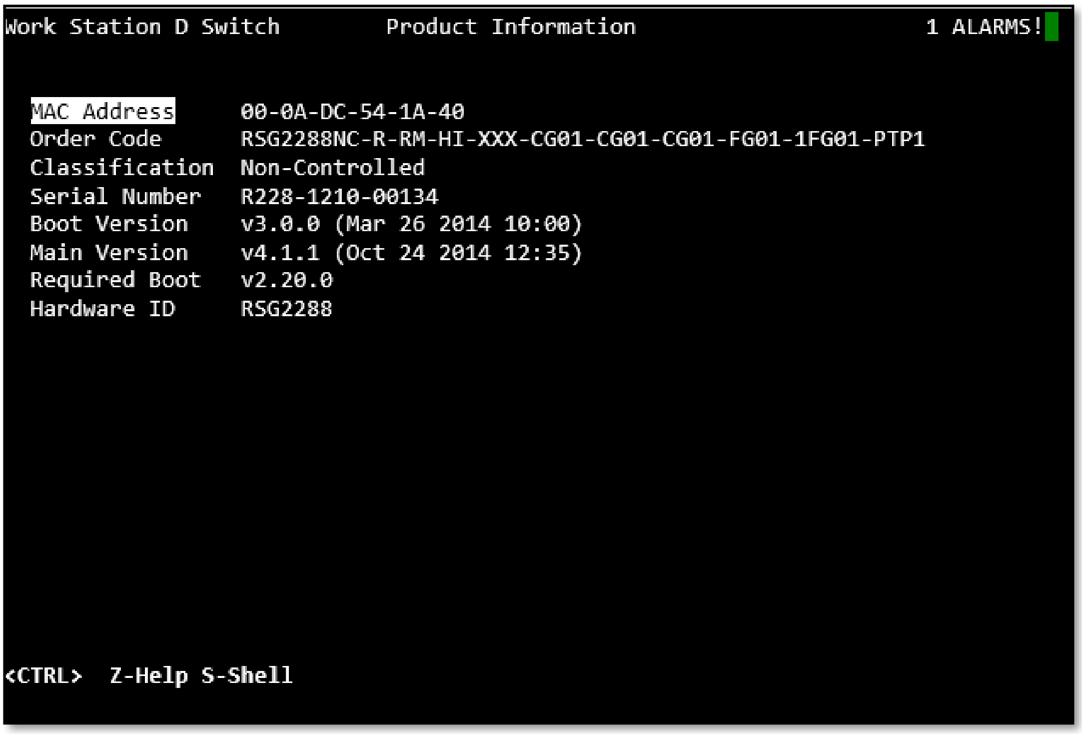


Figure I.2.2.1 RSG2288 Telnet session

A telnet interface configuration page, Figure I.2.2.2 shows the top level of the menu hierarchy which can be expanded to a lower-level for each configuration sublevel.

Figure I.2.2.2 RSG2288 ROS Main level

I.2.3 Administration

The sub levels of Administration level are shown in Figure I.2.3.1. The levels enable the user to set up the network configuration and set the switch administration parameters.

Figure I.2.3.1 RSG2288 Administration

The IP interface parameters can be set to configure IP connection parameters such as address, network, and mask.

The user can configure different IP interface for each VLAN. The RSG2288 supports the configuration of 255 IP interfaces. One of the interfaces is configured to be the management interface.

The following IP services are only available through the management interface: TFTP server, SNMP server, Telnet server, SSH server, RSH server, Web server, authentication using a RADIUS server, DHCP client, and BOOTP client.

In VLAN unaware mode, only one IP interface can be configured.

On non-management interfaces, only static IP addresses can be assigned. On the management interface, the user can choose from the following IP Address types: Static, DHCP, BOOTP and Dynamic. Static IP Address type refers to the manual assignment of an IP address while DHCP, BOOTP and Dynamic IP Address types refer to the automatic assignment of an IP address.

A static IP address was used for the test-bench setup, Figure I.2.3..

Figure I.2.3.2 RSG2288 IP Interfaces

I.2.4 Ethernet ports

The sub levels of Ethernet ports level are shown in Figure I.2.4.1. The levels enable the user to configure port physical parameters as well as other parameters that include alarms, diagnostics and status viewing. Configuring of port rate limiting, Port Mirroring and Link-Fault-Indication (LFI) is possible.

Backup Ethernet ports and having main and backup links used in the event of a link failure was not configured and tested in the test-bench setup.

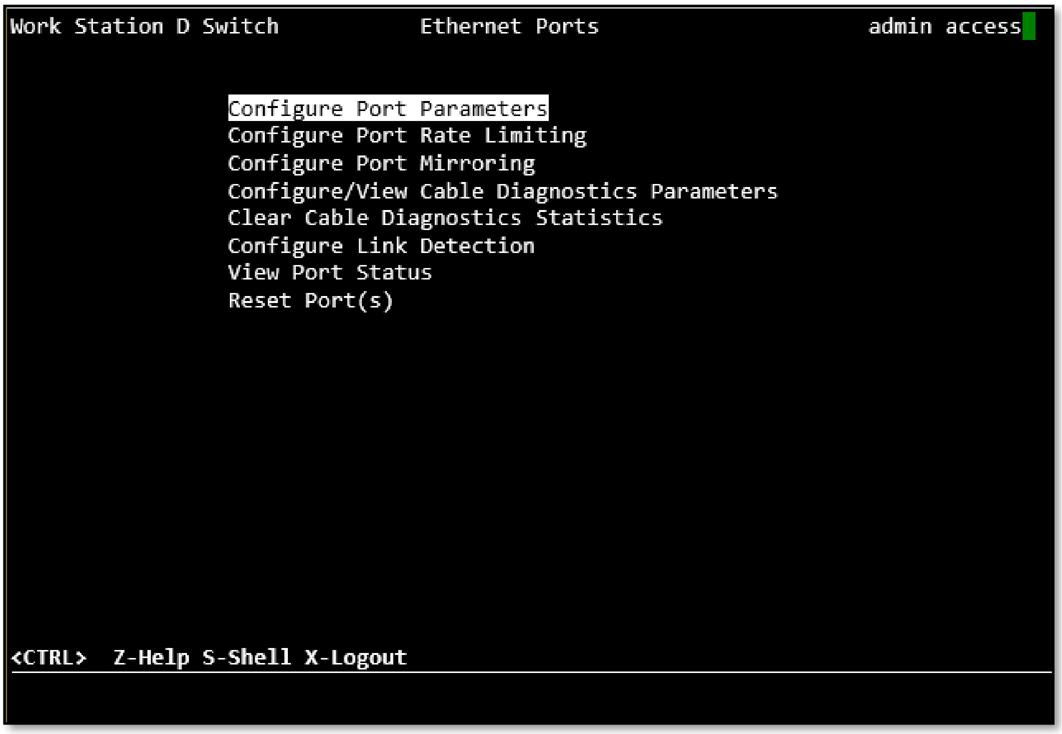


Figure I.2.4.1 RSG2288 Ethernet Ports

The configuration of the Ethernet ports is shown in Figure I.2.4.2. Each of the ports can be disabled. Enabling the port allows data transmission through the port. This state column indicates that all ports are enabled.

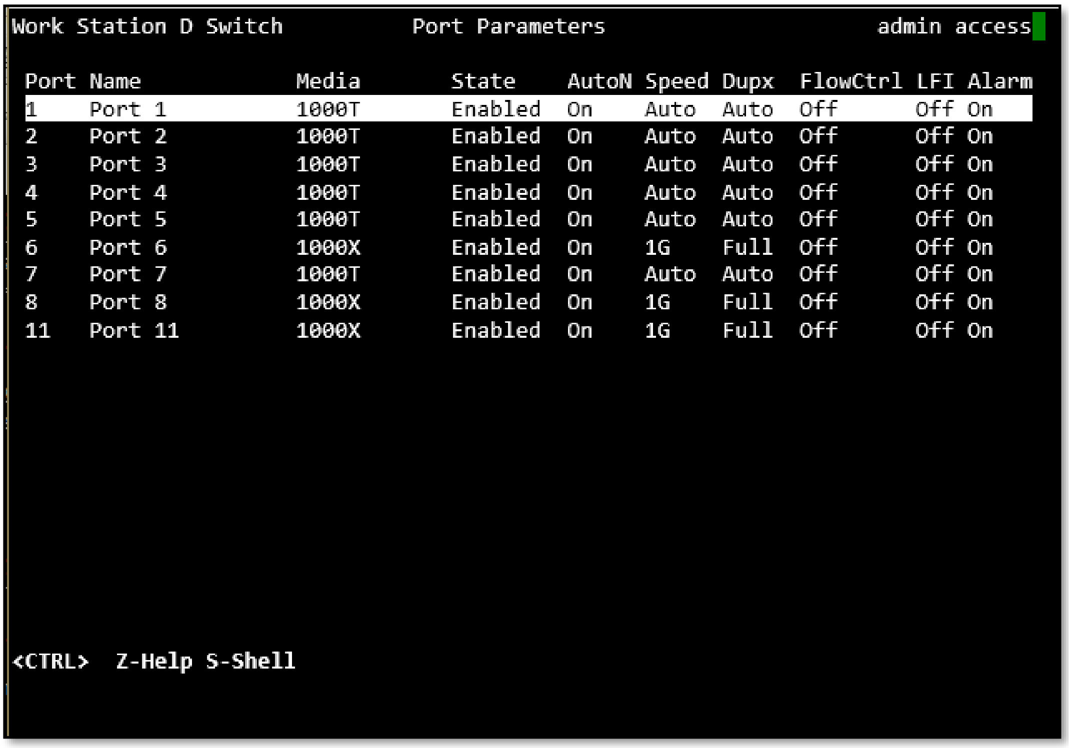
Ports 1-5,7 are 1000T RJ45 copper ports and ports 6,8 and 11 are 1000X fibre optic LC ports. Port 2 is connected to the Moxa PT-7728 switch. Ports 1 and 4 are used to connect the P645 IED and port 3 is used to connect the laptop PC for the test-bench set up. The 1000X fibre ports could not be used due to the P645 IED having only 100BASE-FX ports.

Enable or disable IEEE 802.3 auto-negotiation is done by selecting AutoN on or off. Enabling auto-negotiation results in speed and duplex mode being negotiated upon link detection; both end devices must be auto negotiation compliant. The fiber optic media do not support auto-negotiation and is configured to full-duplex mode. Full-duplex operation requires both ends to be configured as such.

The Speed can be selected to Auto, 10 / 100Megabit-per-second or 1 Gigabit-per-second. The speed is fixed to 1 Gbps for the fibre optic ports on the RSG2288 and cannot be connected to the 100Mbps for the fibre optic ports on the P645 IED.

Flow Control is useful for preventing frame loss during times of severe network traffic. This setting can be useful for a process bus application where severe network traffic with sampled value frames can be expected. The receiving device will send PAUSE frames to the sending device to pause transmission of data for a period, when the port is selected to full-duplex mode.

Link-Fault-Indication (LFI) can be switched on or off. The transmission of the link integrity signal when the receiving link has failed can be inhibited by enabling LFI.


Work Station D Switch   Port Parameters   admin access

Port	Name	Media	State	AutoN	Speed	Dupx	FlowCtrl	LFI	Alarm
1	Port 1	1000T	Enabled	On	Auto	Auto	Off	Off	On
2	Port 2	1000T	Enabled	On	Auto	Auto	Off	Off	On
3	Port 3	1000T	Enabled	On	Auto	Auto	Off	Off	On
4	Port 4	1000T	Enabled	On	Auto	Auto	Off	Off	On
5	Port 5	1000T	Enabled	On	Auto	Auto	Off	Off	On
6	Port 6	1000X	Enabled	On	1G	Full	Off	Off	On
7	Port 7	1000T	Enabled	On	Auto	Auto	Off	Off	On
8	Port 8	1000X	Enabled	On	1G	Full	Off	Off	On
11	Port 11	1000X	Enabled	On	1G	Full	Off	Off	On

<CTRL> Z-Help S-Shell

Figure I.2.4.2 RSG2288 Port Parameters

The Ethernet port status is shown in Figure I.2.4.3. The link status whether it is up or down, the speed and the duplex status are indicated for each port. The figure shows links connected to ports 1,2 and 3 to be up. Port 2 is connected to the Moxa PT-7728 switch, Port 1 for sampled values streams is connected the P645 IED and port 3 is connect to the laptop PC. The auto-negotiation is enabled for these ports and results in speed and duplex mode being negotiated upon link detection and connected at a speed of 100Mbps and full duplex.

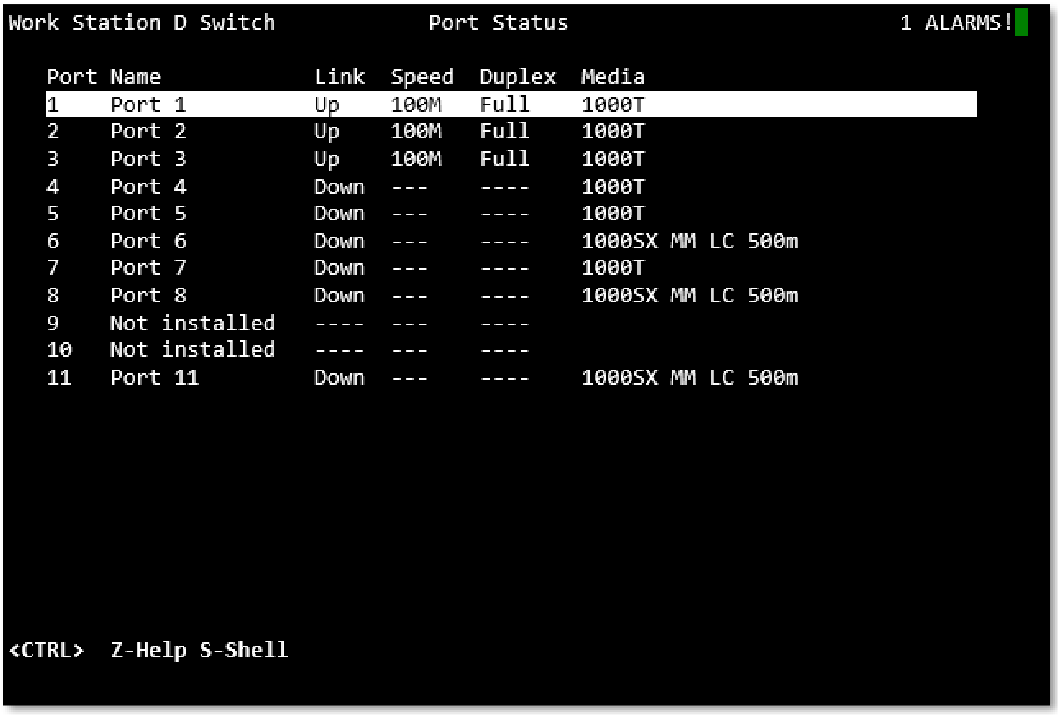


Figure I.2.4.3 RSG2288 Port status

I.2.5 VLAN Operation

Tagged frames with 802.1Q (VLAN) tags specified with a VLAN identifier (VID) =2 is used for the IEC61850-9-2 sampled value streams sent from the Merging Units in the test-bench setup.

When the RSG2288 switch receives a tagged frame, it extracts the VID and forwards the frame to other ports in the same VLAN.

The port VLAN configuration is shown in Figure I.2.5.1. Each port can be configured to be a type of Edge or Trunk.

An Edge port attaches to a single end device and carries traffic on a single pre-configured VLAN.

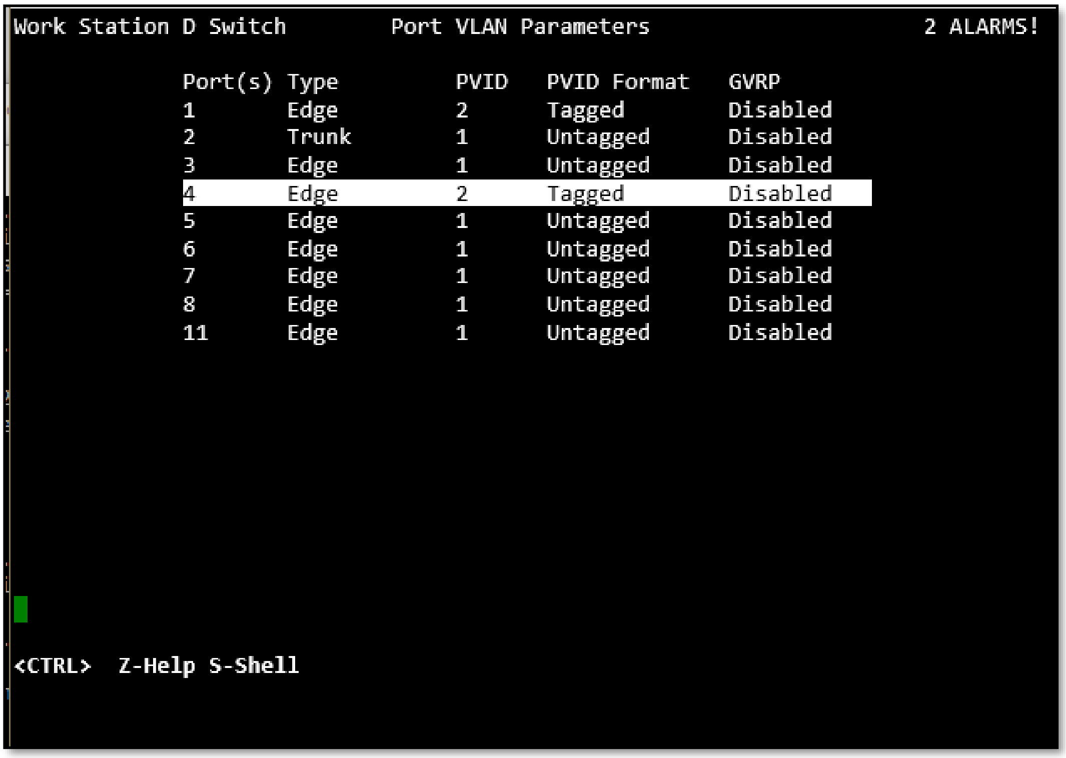
Port 1 is connected to the P645 IED and requires receiving the Sampled values stream on VLAN 2. It is therefore configured as an Edge port with PVID=2 and tagged frames.

Trunk ports are part of the network and carry traffic for all VLANs between switches. Trunk ports are automatically members of all VLANs configured in the switch and will carry information of both VLANs 1 & 2. Port 2 is connected to the Moxa PT-7728 switch and is configured to be a Trunk port.

All traffic on the network must belong to a specific VLAN. Management traffic is carried on the management VLAN. The management VLAN is configurable. The defaults VLAN 1 was used for the test-bench setup.

Port 3 is used to connect the laptop PC. The PC is used to configure the switch and must be able to send and receive traffic on VLAN 1. It is therefore configured as an Edge port with PVID=1 and untagged frames. Port 4 is used to connect the PC to monitor the Sampled Values streams on VLAN 2. It is therefore configured as an Edge port with PVID=2 and tagged frames.

GVRP was not enabled for the ports and the ports were manually configured for the VLANs. GVRP is a standard protocol built on GARP (the Generic Attribute Registration Protocol) to automatically distribute VLAN configuration information in a network. Each switch in a network needs only to be configured with local VLAN requirement and dynamically learns the rest of the VLANs configured elsewhere in the network via GVRP. The trunk connected Moxa PT-7728 switch in the network needs to be a GVRP-aware switch in order to use this function.



Work Station D Switch   Port VLAN Parameters   2 ALARMS!

Port(s)	Type	PVID	PVID Format	GVRP
1	Edge	2	Tagged	Disabled
2	Trunk	1	Untagged	Disabled
3	Edge	1	Untagged	Disabled
4	Edge	2	Tagged	Disabled
5	Edge	1	Untagged	Disabled
6	Edge	1	Untagged	Disabled
7	Edge	1	Untagged	Disabled
8	Edge	1	Untagged	Disabled
11	Edge	1	Untagged	Disabled

<CTRL> Z-Help S-Shell

Figure I.2.5.1 RSG2288 Port VLAN Parameters

I.2.6 Multicast filtering

Multicast Filtering can be configured in the RSG2288 using the following methods: Static Multicast Groups, Internet Group Management Protocol (IGMP) snooping and IEEE standard GARP Multicast Registration protocol (GMRP).

Static Multicast filtering were configured manually for the test-bench setup. The other Moxa PT-7728 switch in the test setup network supports IGMP and GMRP and this could also be used for the setup of the Multicast groups. The multicast destination MAC Address configured in the Merging Units to identify SV data streams were manually configured in the RSG2288 to test and show that only these SVs will be allowed to pass through the RSG2288 switch to be sent to the P645 IED.

These multicast MAC addresses of the SV streams are shown in Figure I.2.6.1.

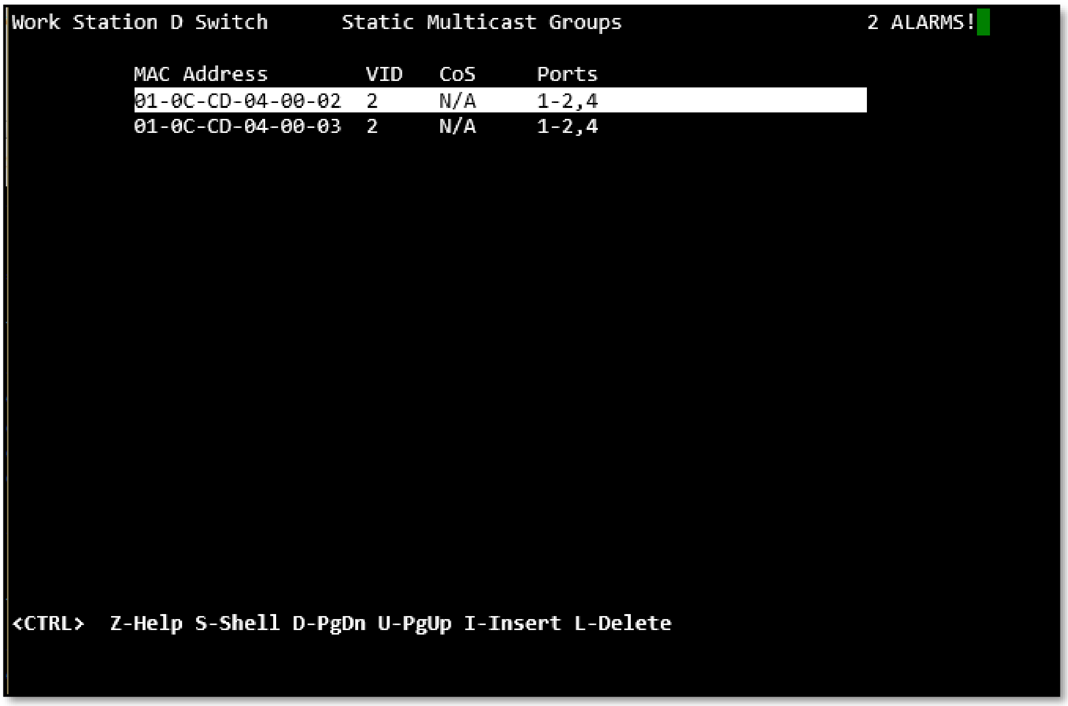


Figure I.2.6.1 RSG2288 Static Multicast Groups

I.2.7 MAC Address

The MAC addresses learned by the switch can be viewed in the MAC address tables.

The VLAN Identifier of the VLAN on which the MAC address operates is shown in Figure I.2.7.1.

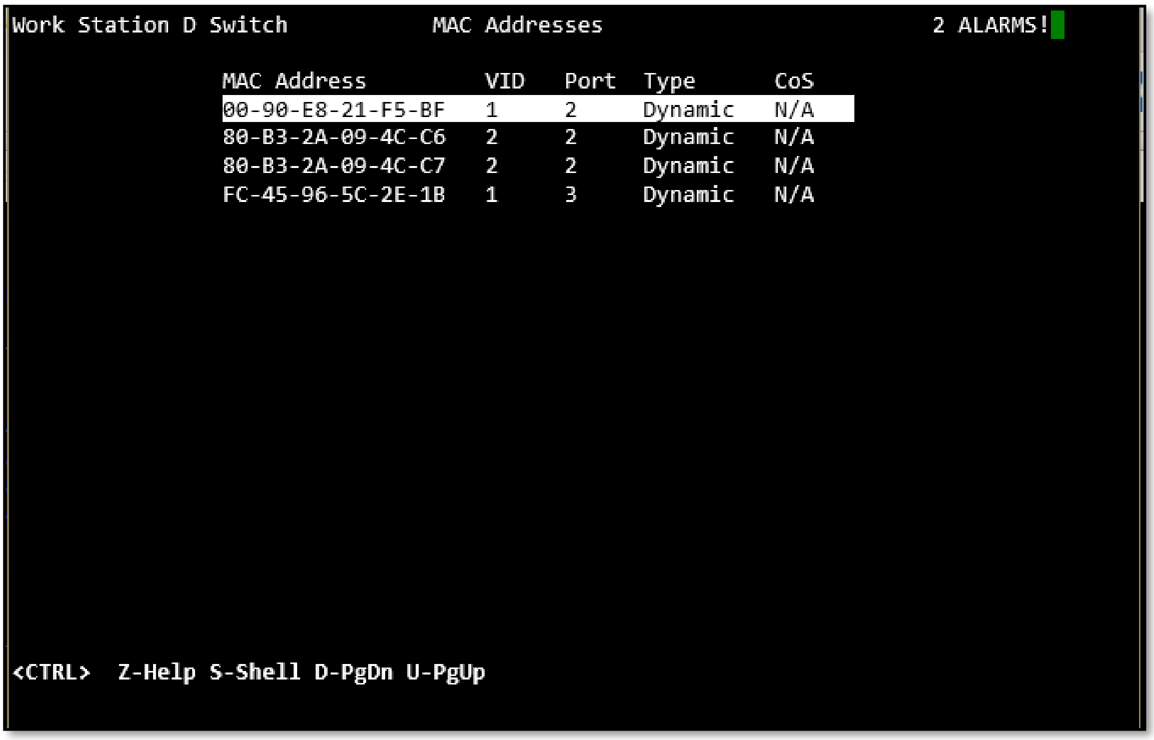
The Type Synopsis describes if the MAC address has been learned as Static or Dynamic by the switch.

STATIC - the address has been learned as a result of a Static MAC Address Table configuration or some other management activity and cannot be automatically unlearned or relearned by the switch.

DYNAMIC - The address has been automatically learned by the switch and can be automatically unlearned.

CoS Synopsis specifies what Class of Service is assigned to frames carrying this address as source or destination address. It can be N/A, Normal, Medium, High, Crit.

N/A option prioritizes traffic based on the priority value in the VLAN tag or based on the default priority configured in Port CoS Parameters.



Work Station D Switch MAC Addresses 2 ALARMS!

MAC Address	VID	Port	Type	CoS
00-90-E8-21-F5-BF	1	2	Dynamic	N/A
80-B3-2A-09-4C-C6	2	2	Dynamic	N/A
80-B3-2A-09-4C-C7	2	2	Dynamic	N/A
FC-45-96-5C-2E-1B	1	3	Dynamic	N/A

<CTRL> Z-Help S-Shell D-PgDn U-PgUp

Figure I.2.7.1 RSG2288 MAC Addresses