PHD

Protection Performance Study for Secondary Systems with IEC61850 Process Bus Architecture

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Protection Performance Study for Secondary Systems with IEC61850 Process Bus Architecture

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Abstract

Following the introduction of the microprocessor into the power system protection field, modern microprocessor based numeric relays have developed very rapidly in the last 20 years, and modern power system protection schemes are virtually all based on microcomputers technology.

The International Electro-technical Commission (IEC) recently launched the standard IEC61850, "Communication Networks and System in Substation", which is having a major impact on the structure of new protection systems and schemes. In itself it describes the concepts for sub-station communications covering protection, control and metering functions. However, although it is going to have a major impact on the power systems communications, it will also influence the design of future protection systems.

There will also be a host of other opportunities and advantages that can be realised. These include easier upgrading, refurbishment and replacement of sub-station protection. They also provide for greater use of general purpose Intelligent Electronics Devices (IEDs), self-healing systems, and plug and play type facilities.

The Ethernet based communication network for data transfer between process level switchyard equipment and bay level IEDs, the process bus, is defined in IEC61850 Section 9-2. This process bus facilitates the communication of two types of real-time, peer-to-peer communication messages. Generic object-oriented substation event messages, the GOOSE messages and the data sample values, SVs which include the measured currents and voltages. Although this standard describes the message structures and the timing requirements, it does not describe the process bus topology.

This work describes different LAN topologies that can be used in the design of process bus for protection systems. It considers the implications of the different structures on the operation of the protection scheme and how these relate to the operational strategy of different operators.

It provides an assessment of the data handling capabilities of the system and how the demands of the protection system can be met. Several potential problem areas are identified and analyzed. The probabilistic nature of these systems is discussed and the implications explained.

It also provides an insight into the implementation of the alternative topologies and their performance when applied to a transmission line feeder protection and transformer protection.

The digital substation and the implementation of IEC61850 are fundamental to the future of protection ‘relays’. There are many pointers to the potential directions that these systems will develop and the skills required for the protection engineers of the future.

This project is seeking to overcome some of the ownership challenges presented by modern protection and control (P&C) devices, which have an inherent short life due to their dependence on modern electronics and software.

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Finally, I would like to take this opportunity to express my deepest thanks to my family especially to my beloved parents for their endless encouragement and affection in my ten-year study period.

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List of Abbreviations

IEC	International Electro-technical Commission
IED	Intelligent Electronic Device
LAN	Local Area Network
GOOSE	Generic Object Oriented Substation Event
SV	Sample Value
P&C	Protection and Control
AS^3	Architecture of Substation Secondary System
CT	Current Transformer
VT	Voltage Transformer
FAT	Factory Acceptance Tests
MU	Merging Unit
WG	Working Group
HV	High Voltage
CBC	Circuit Breaker Controller
DBB	Double Bus Bar
MC	Mesh Corner
ERTS	Emergency Return To Service
LCC	Local Control Cubicle
SCT	Supplier Site Commissioning
SAT	Site Acceptance Test
PDSA	Post Delivery Support Agreement
TP	Transmission Procedure
SICAP	Substation Information, Control & Protection
NG	National Grid
GPS	Global Positioning System
MP	Main Protection
BP	Backup Protection
BCU	Bay Control Unit
M	Metering
PMU	Phase Measurement Unit
PB	Process Bus

SB	Switch Box
CTMP	Measurement Class CT
RTDS	Real Time Digital Simulator
DAS	Data Acquisition System
SAS	Substation Automation System
UCA	Utility Communication Architecture
ISO	International Standards Organization
OSI	Open System Interconnection
TC	Technical Committee
EMS	Energy management System
API	Application Program Interface
SIDM	System Interfaces for Distribution Management
EMS	Distribution Management System
DER	Distribution Energy Resources
ACSI	Abstract Communication Service Interface
CDC	Common Data Class
SCSM	Specific Communication Service Mapping
SCL	Substation Configuration Language
XML	eXtensible Makeup Language
SSD	System Specification Description
ICD	IED Capability Description
SCD	Substation Configuration Description
CID	Configured IED Description
GSE	Generic Substation Event
GSSE	Generic Substation State Event
MMS	Manufacturing Messaging Specification
CSMA/CD	Carrier Sense Multiple Access with Collision Detection
VLAN	Virtual LAN
HMI	Human Machine Interface
SCADA	Supervisory Control And Data Acquisition
RTU	Remote Terminal Unit
AMU	Analogue Merging Unit
DMU	Digital Merging Unit
EHV	Extra High Voltage

MTT	Mean Trip Time
STP	Spanning Tree Protocol
RSTP	Rapid Spanning Tree Protocol
SNTP	Simple Network Time ProtocolReliability
NTP	Network Time Protocol
PTP	Precision Time Protocol
RBD	Reliability Block Diagram
PDU	Protocol Data Unit
APDU	Application Protocol Data Unit
ASDU	Application Service Data Unit
ETE	End-To-End
GTNET	Giga-Transceiver Network Communication Card
POW	Point On Wave
PUR	Permissive Under-Reach

List of Symbols

Failure rate	λ
Reliability Function	R
Period under consideration	t
Availability	A
Mean time to failure	$MTTF$
Mean time to repair	$MTTR$

Chapter 1

Overview of AS^3 Project

THIS chapter briefly describes the background, motivation, objectives, and contribution of this work. It also provides an overview of the thesis.

1.1 Introduction

IEC61850 is the new approved international standard for communication in substations. It enables integration of all protection, control, measurement and monitoring functions within a substation, and additionally provides the means for high-speed substation protection applications, interlocking and intertripping. It combines the convenience of Ethernet with the performance and security which is essential in substations, and also offers new possibilities for maximising economic and effective utilisation of the transmission asset and network.

IEC61850 has already made a significant impact on the development of different devices or systems used in the substation. All major substation protection and control equipment manufacturers have products the implement different forms of IEC61850 communication to simplify integration in substation automation systems and improve the functionality of the system, and reduce the overall system cost at the same time. New protection solutions are also being developed in order to take full advantage of the functionality supported in the new standard.

To take full advantages of this new technology, National Grid Electricity Transmission launched the Architecture of Substation Secondary System (AS^3) [1]. This project is seeking to overcome some of the ownership challenges presented by modern protection and control (P&C) devices, which have an inherent short life due to their dependence on modern electronics and software. This will be achieved by implementation of a process bus.

Compared with the substation primary plants and instrument transformers which generally remain in-service for long life-cycles, renewed only when physically or mechanically life-expired, the secondary systems (P&C equipments) are often changed more frequently. The short life of P&C equipment means that during the typical 40 year asset life of primary switchgear the secondary equipment needs to be replaced at least once and probably twice. Based on the statistics from UK construction, currently achievable replacement rate for protection and control systems is about 5% per annual. It would take around 20 years to complete a whole cycle of a replacement. However, the modern P&C equipments asset life is 15 years, and in many cases, they only last 10 years due to the availability of technical support and technology change. In addition, the replacement and maintenance of substation secondary equipment may also lead to downtime, which negatively influences the overall availability of the substation. One factor which contributes to this problem is the complex wiring required for the installation of a relay. Another possible contributing factor is relay obsolescence. If a new relay has to be installed, it may require a new configuration in order to communicate with the existing substation equipment, and this may not be possible without the use of expensive protocol converters. Normally, outages for replacement of P&C devices are eight weeks in duration and National Grid would like to reduce these to typically one to two weeks.

One way to overcome the problem is to develop a new architecture for substation secondary systems by deploying some new technologies such as standard interface modules, process bus and IEC61850 communication protocol. The deployment of IEC61850 process bus technology will allow ongoing substation secondary equipment retrofitting (refurbishment) projects to proceed whilst limiting the duration and frequency of circuit outages, required to facilitate the work. Once the new technology is installed, secondary equipment renewals occurring mid-life in the primary plant lifecycle can be undertaken in a safer, quicker and easier way with much reduced outages of primary systems.

This will also enable vendor interoperability and easier modification and extension of the secondary schemes, particularly allowing reconfiguration and feature enhancement by software means, rather than the modification of wiring as would have been the case in the past. As the new secondary systems transmit data of CT and VT analogue signals via the process bus, this poses no safety risks of opening CT circuits, and hence improving the safety when the protection replacement is carried out with primary circuit in service.

To improve installation and commission of protection systems and to aid lifetime management issues, the following design features are required which can be provided by the AS^3 project:

a) Standard Interface or “switching boxes” must be provided as the secondary interface to primary switchgear.

b) An architecture must be provided which satisfies some Standard Rules.

c) Installation practices need to be simplified.

d) Factory Acceptance Tests (FAT) need to be the main form of commissioning and on site testing and commissioning needs to be simplified.

e) A means of upgrade and maintenance of the systems including a means of physical isolation needs to be inherent in the design.

To achieve all the requirements, AS^3 project in divided into 13 working groups which are listed below:

- WG1: Current Policy & Practice Review
- WG2: Strategy Analysis (Risk assessment, Business case)
- WG3: Implementation Strategy
- WG4: Architecture & Reliability
- WG5: Protection Performance Study
- WG6: I/O Standardisation
- WG7: IEC61850 Configuration/Merging Unit (MU) Specifications
- WG8: Test & Commissioning Philosophy
- WG9: Safety & Operation

- 4 WGs with National Grid main suppliers/alliances (ABB, ALSTOM, Mitsubishi & Siemens)

This project is part of WG5 and is concerned with the implementation of the digital sub-station for power system local protection and control. In particular it explores the implementation of IEC61850 9-2 which proposes an Ethernet based communication network between switchyard equipments and bay level protection and control, P&C. This process bus connects transducers and actuators to Intelligent Electronic Devices (IEDs), which are responsible for the decision making. The process bus, an Ethernet LAN, facilitates the communication of time-critical messages, including SV and GOOSE messages.

1.2 Standard Interfaces

Standard interface "switching boxes" with a 40 year asset life need to be specified across the supplier base. The switching box is designed to fit between the high voltage (HV) equipment hardwired secondary interface and the AS^3 system merging units and circuit breaker controllers. The merging unit is the direct interface to the process bus. The switching box simplifies safety isolation for work on both HV and/or secondary equipment and allows for short outage durations during asset replacement of the shorter life MUs, CBCs, process buses and IEDs. In the substation, the process bus will use fibre optic equipment.

The switching box will be a combination of separate types of switching units; Current Transformer (CT), Voltage Transformer (VT) and General Input/Output Disconnection. The number and types used will depend on the bay configuration.

With reference to Figure 1-1, the HV equipment side external wiring is directly connected to switching units, which then connect to a bay standard marshalling field using plugs and sockets. The protection and control side external wiring interface with the process bus (the merging unit and circuit breaker controller) is connected by plugs and sockets to the other side of the marshalling field. The marshalling field should be made standard for a particular bay type and can be used both on site and for factory acceptance testing [1].

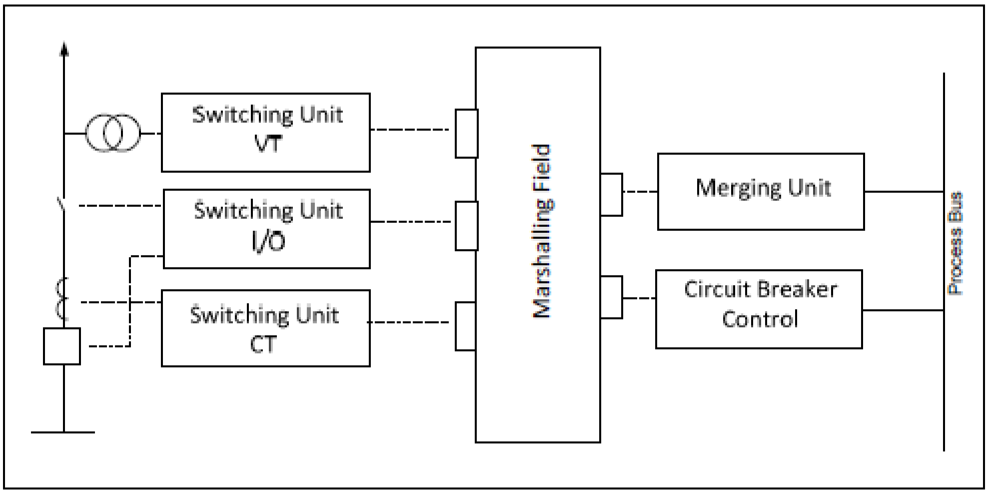

Figure 1-1 Switching unit connection

The means of physical isolation shall be suitable for use as a “point of isolation” in the National Grid Electricity Safety Rules.

1.3 Process Bus Architecture

To aid lifetime management issues the system architecture on the process bus must be designed to allow simple disconnection – switch box or merging unit isolation particular to an IED.

For example, first and second main protection systems should have separate merging units and process buses. Physical isolation of hardwired interfaces and the ability to disconnect LAN switches whilst keeping most of the protection systems in service is a necessity to minimise the risks of incidents to the utility. These are part of the National Grid Company’s “Golden Rules” [2].

Primary aims of AS^3 process bus architecture are:

A. Allow replacement of faulty IED with minimum outage requirements.

B. Allow secondary refurbishment of a bay with minimum outage requirement.

C. Simplify isolation procedures between primary and secondary systems.

D. Reduce risks of mal-operation.

Each protection bay type should be based on a standard architecture. Primary equipment associated with a bay will contain circuit breakers, isolators, voltage transformers (VTs), Current Transformers (CTs), Interposing Transformers, and Earth Switches.

The number and layout of the primary equipment will vary with the type of bay, for example a double busbar (DBB) or a mesh corner (MC).

The inputs and outputs of the primary equipment shall be routed through switching boxes, this provides isolation of the primary equipment from the protection equipment and vice versa.

There are seven golden rules which must be followed in the design of the process bus Architecture [2]:

1. *The design principles of the AS^3 scheme must be standard for all bay types – DBB feeder, DBB Bus Section, DBB Bus Coupler, MC Mesh Corner, MC Transformer, MC Feeder.*

   The number of process buses, the means of collating information, the means of isolation, and the means of tripping shall be identical in philosophy across bay types.

2. *The switching box should be located as close as possible to the Primary equipment*

   Analogue and digital signals are to be converted to SVs on to the bay process buses by merging units. These shall be installed as close as possible to the primary equipment to provide the greatest saving in copper cabling. CT merging units shall be normal resolution for protection and control CTs, and high resolution for measurement CTs.

3. *No single activity on the MAIN 1 system shall affect the MAIN 2 system.*

4. *No single failure shall result in the loss of control of more than one bay.*

5. *Physical facilities shall be available to isolate a bay for testing (Protection & Control).*

Switching boxes, test/normal switches and gateway LAN switches shall be provided.

6. *The Protection and Control application/philosophy shall be functionally identical to the existing bay solution currently provided by National Grid suppliers.*

There shall be 3 IEDs on a standard bay – MAIN 1, MAIN 2, and bay controller.

The IEDs shall trip their own bay circuit breakers directly via the process bus and CBCs.

The IEDs shall trip other busbar bay circuit breakers via the process bus, gateway switch and busbar process bus.

7. *All trip signals shall be received by the breakers within 10ms (excluding intertrip send).*

The gateway switches shall provide isolation for the protection bay as well as a connection to the busbar process bus for passing on tripping to keep the transfer trip time across bays to a minimum.

1.4 Installation

For current feeder protection asset replacement schemes, outages of six weeks are the norm with 3-4 weeks spent on installation. The time is generally taken up by interfacing with existing systems using hardwiring, and engineering of one off issues such as Emergency Return to Service (ERTS). An additional constraint applies when the new protection cannot be installed in situ pre-outage.

To improve installation times significantly, it is suggested the following requirements.

A. Pre-Outage works should be maximised. Previous asset replacement over the last 10 years should have freed significant room in relay rooms allowing pre-outage installation of panels and other works. Where this is not possible this will likely increase installation times by up to 1 week.

B. Standard interface “switching boxes” need to be specified across the supplier base. This should minimise hardwired interfaces. ERTS can be easily achieved by the use of standard plugs and sockets (or similar) to connect the merging units to the “switching boxes”.

C. Merging units/CBCs and switching boxes should be placed as close to the plant interface as possible. The use of suitable weatherproof marshalling kiosks or small dispersed relay rooms may need to be considered for sites without existing dispersed relay rooms or Local Control Cubicles (LCCs). There may be such sites where wiring to the common relay room can be retained - dependant on the suitability of the existing marshalling of cross site cables. New bays added to such sites would likely require a dispersed relay room.

D. Connections from the merging unit to the IED’s should be either fibre optic or Ethernet cable to minimise hardwiring.

Initial installation of a switching box and AS^3 bay solution with 1-4 above implemented should be possible in two weeks outage. Note that two – three weeks pre-outage work may be required to fit relay panels, cabling, Site Acceptance Testing and Stage 1 commissioning. Subsequent installation of a bay solution to an existing switching box should be possible in circa one week outage.

1.5 Test and Commission

For feeder protection asset replacement schemes within National Grid, outages of six weeks are the norm with 2-3 weeks spent on commissioning. The time is generally taken up by testing of hardwire interfaces and hardwiring in cubicles, witnessing supplier SCT sheets, fault finding, trip and alarm tests, settings loading verification [3], and stage 2 commissioning; all as per National Grid Procedure TP106 [4].

To improve testing and commissioning times significantly it is suggested the following is required in addition to the points in 1.4 above:

A. FAT testing needs to be the major part of the commissioning process with the full involvement of National Grid commissioning engineers. Testing of fibre interfaces on site should be minimal to ensure correct connections. The FAT should be carried out on the contract specific hardware using a fully connected system. This shall comprise functional testing and include all interfaces.

B. All hardwiring installed or interfered with should be fully tested on site in line with current National Grid procedures. It is thus advantageous to reduce this as much as possible.

C. IEC61850 "emulators" should be engineered across the supplier base to simplify FAT testing.

D. Suppliers should have 'test platforms' available within their FAT facilities that emulate exactly the switching box interface. This ensures a standard approach for connections during the FAT.

E. Supplier Site Commissioning Test (SCT) sheets should be part of the FAT test.

F. The supplier should ensure a general Site Acceptance Test (SAT) is carried out on site for all delivered hardware and interface connections prior to installation to the “switching boxes”. This should simply ensure the hardware is not damaged and include minimal overlap tests.

G. To ensure correct operation of the protection functions it is suggested that generic functional SCT sheets are provided by National Grid to formalise the trip and alarm tests. These tests should be carried out by National Grid and should take up to two days.

Settings Load Verification and Stage 2 Commissioning would complete the testing and commissioning prior to return to service.

Initial testing and commissioning of a switching box and AS^3 bay solution with the above implemented should be possible in two weeks circuit outage.

Subsequent testing and commissioning of a bay solution to an existing switching box should be possible in circa one week.

1.6 System Upgrade

Upgrades or replacements to IEDs and or merging units/CBCs under a Post Delivery Support Agreement (PDSA) should be relatively straightforward provided the following is applied or adhered to:

A. FAT testing of the IED is carried out with sufficient overlap.

B. The system is designed to allow simple disconnection – switch box or merging unit isolation particular to an IED. For example first and second main systems should have separate merging units and LANs.

C. Testing on site for fibre interfaces is minimal to provide correct connection and transfer of a signal over the network between associated IEDs.

D. The use of outages should be minimised by the design.

E. Prior to returning to service the normal Transmission Procedure TP107 [5] procedures must be followed on site to ensure the correct settings and configurations are loaded i.e. file comparisons.

F. Following upgrade or replacement sufficient on load testing is carried out to ensure that, as a minimum, the device is correctly reading both power systems values and plant status , is stable and is in full communication both local and any remote ends.

1.7 Maintenance

Maintenance shall comprise the following:

A. Secondary injection of each switching box to prove AC quantities both at the merging units and the IEDs.

B. Testing of hardwired I/O from the switching box to the merging units and IEDs.

C. Trip testing of all Main Protection IED’s.

A Suitable means of interrogation of the IEDs and process bus using an IEC61850 emulator is to be provided.

Test/Normal switches to assist general maintenance and fault investigation are to be provided on all IEDs and Merging Units.

1.8 Overview of WG5 – Protection Performance Study

1.8.1 Introduction

The project of protection performance study is undertaken by the University of Bath and the University of Manchester, which is sponsored by National Grid, ALSTOM Grid, Scottish and Southern Energy and Scottish Power.

The aim of the project is to investigate, quantify and optimise the level of security, dependability and operating speed in secondary schemes with an appropriate IEC61850 process bus topology on a National Grid's mesh substation as shown in Figure 1-2.

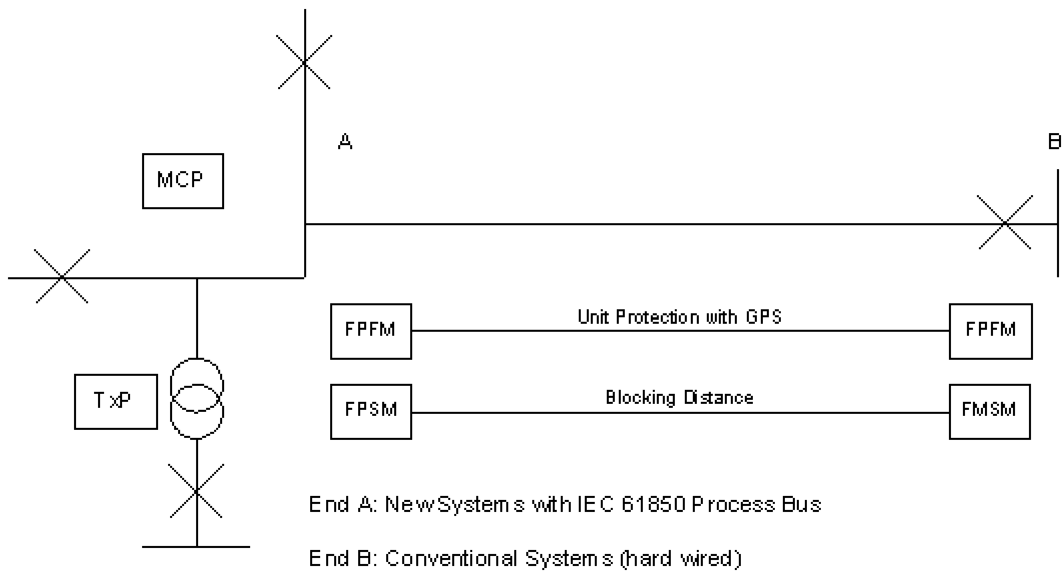

Figure 1-2 National Grid mesh substation

1.8.2 Protection Schemes Applied in the Mesh Substation

A mesh station is a type of primary substation configuration that is economical in its use of circuit breakers. Although there are many variants, the typical configurations are single switch and four switch meshes, the names inferring the number of circuit breakers used to accomplish the layout.

A mesh corner is where busbars connect circuit breakers, transformers and feeders. A four switch mesh has four mesh corners as shown in Figure 1-3. Feeders or transformers connect to mesh corners via motorized disconnectors to provide individual isolation and it is possible to have more than one transformer connected to the mesh corner. A mesh corner would typically have a feeder and up to two transformers connected which means with four circuit breakers. A station could be built with 4 feeder and 8 transformer circuits. If a circuit breaker requires maintenance, it may be taken out of the mesh without any loss of supply.

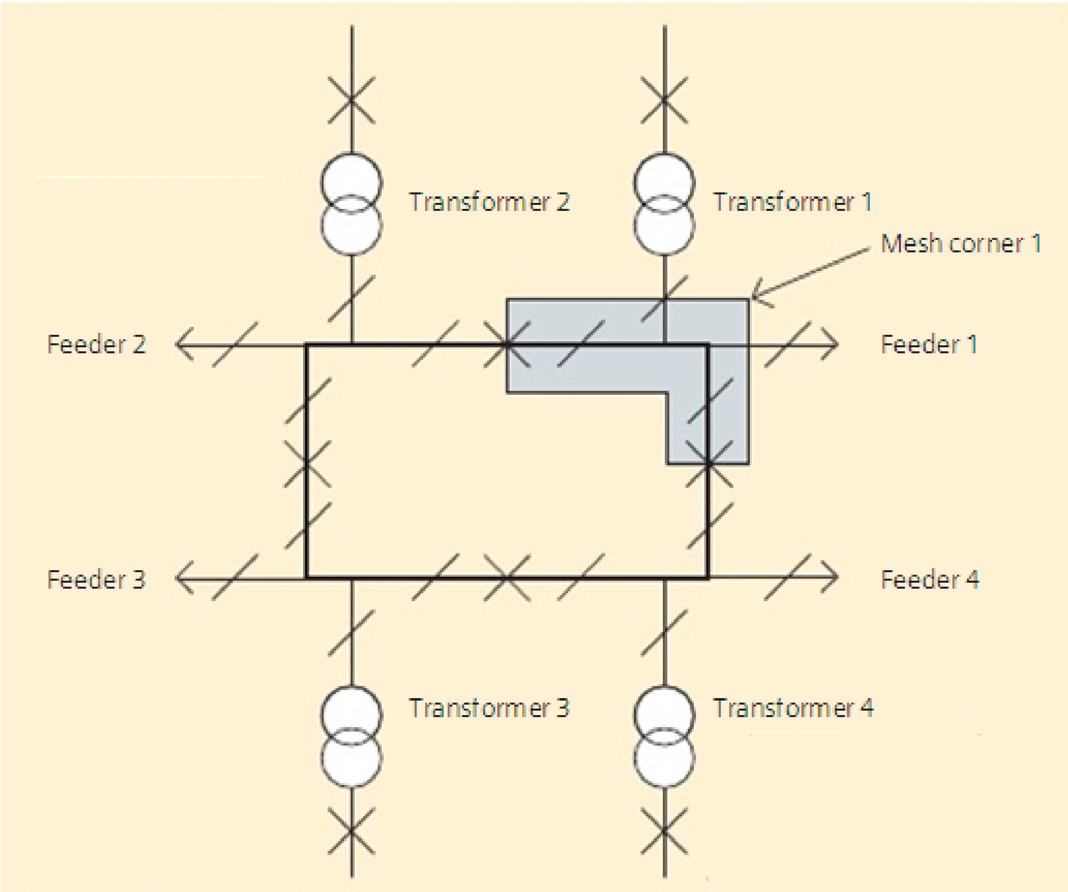

Figure 1-3 The four switch mesh substation

The main differences between the protection arrangements at a mesh substation compared to those at a double-busbar substation concern the protection provided for the busbar. At a mesh substation, the number of circuit breaker required to be tripped in the event of a busbar fault is much smaller than at a double-busbar substation and the operational consequences of an inadvertent operation of the busbar protection are very much less severe, hence there is no need for a “two out of two” logic in the tripping sequence. The busbar protection at a mesh substation is normally of the high impedance differential type and is arranged in a “one out of two” logic.

The National Grid mesh station has one mesh corner which is connected to a feeder and a transformer similar as the mesh corner 1 in Figure 1-3. In the project, the mesh corner will be protected by an IEC61850 based mesh corner protection relay. The transformer will be protected by an IEC61850 based transformer protection relay. The feeder will be protected by the current differential and distance protection schemes. In these schemes, the local end of the feeder is equipped with the IEC61850 based protection relays, and the remote end of the feeder is equipped with the conventional protection relays.

The study assesses the security, dependability and operating speed of the process bus based protection schemes, and compares them with the traditional hardwired schemes. The lab tests are also be carried out to verify the performance. As a precursor to wide deployment of the philosophy in AS^3 project, it must be ensured that the performance of the protection and control schemes using IEC61850 meets or exceeds that of its hardwired Substation Information, Control & Protection (SICAP) predecessors.

1.8.3 Implementation Plan

The project is managed under the steering group consisting of representatives from all parties, University of Bath, University of Manchester, National Grid, ALSTOM Grid, Scottish and Southern Energy and Scottish Power, delivering agreed deliverables annually in line with agreed project plan-detail in development with steering group:

- Two full-time PhD students, Mr. Xin Sun supervised by Dr. Miles Redfern at University of Bath and Ms. Li Yang supervised by Professor Peter Crossley at University of Manchester, work on this project, with specialist support from ALSTOM Grid and NG for applications of the new protection and control system.

- ALSTOM Grid has free issued the new protection relays and built the panels. The Panels are listed in Table 1-1 below.

Table 1-1 Panels and protection relays issued by ALSTOM Grid

Name of Panel	Components	Quantity
Feeder Local Panel	IEC61850 based MiCOM P545 Distance Protection Relay,	1
	IEC61850 based MiCOM P545 Current Differential Protection Relay	1
	MiCOM P594 GPS Synchronization Unit	1
Remote Local Panel	Conventional MiCOM P545 Distance Protection Relay,	1
	Conventional MiCOM P545 Current Differential Protection Relay	1
	MiCOM P594 GPS Synchronization Unit	1
HV Transformer Panel	IEC61850 based MiCOM P643 Transformer Protection Relay,	1
	IEC61850 based MiCOM P841 Multifunction Line Terminal IED	1
LV Transformer Panel	IEC61850 based MiCOM P643 Transformer Protection Relay	1
	MiCOM P594 GPS synchronization unit	1
Mesh Corner Panel	IEC61850 based MiCOM P645 Mesh Corner Protection Relay	1
	IEC61850 based MiCOM P841 Multifunction Line Terminal IED	1
	MiCOM P594 GPS Synchronization Unit	1

- Both universities develop their abilities for detailed system testing and demonstration.

The task of the University of Bath is testing and analyzing the protection performance of feeder bay and transformer bay.

- Detailed Scope-Responsibility matrix and project plan have been developed and are managed by the project steering group and progress meetings are held quarterly.

- Interaction with AS^3 project and team via planned workshops, conferences and seminars to all participants.

- NG’s site engineers and the development engineers from key manufactures are invited to comment on the new secondary systems during lab tests.

1.9 Design of the Process Bus Architecture

1.9.1 Introduction

A standard process bus architecture which can achieve the four primary aims and obey the seven golden rules of AS^3 project must be established, before the protection performance study take place.

1. Allow replacement of faulty IED with minimum outage requirements.

2. Allow secondary refurbishment of a bay with minimum outage requirement.

3. Simplify isolation procedures between primary and secondary systems.

4. Reduce risks of mal-operation.

5. The design principles of the AS^3 scheme must be standard for all bay types – DBB feeder, DBB Bus Section, DBB Bus Coupler, MC Mesh Corner, MC Transformer, MC Feeder.

6. The switching box should be located as close as possible to the Primary equipment.

7. No single activity on the MAIN 1 system shall affect the MAIN 2 system.

8. No single failure shall result in the loss of control of more than one bay.

9. Physical facilities shall be available to isolate a bay for testing (Protection & Control).

10. The Protection and Control application/philosophy shall be functionally identical to the existing bay solution currently provided by National Grid suppliers.

11. All trip signals shall be received by the breakers within 10ms (excluding intertrip send).

Therefore, each party of the working group puts forward their own standard process bus architecture design. In the process bus architecture design of the University of Bath, each protection IED (main protection, backup protection and bay control unit) and its associated MUs and CBCs are connected to one dedicated process bus, which makes the different protection schemes are totally separated and independent.

After working with WG4 – Architecture & Reliability (PhD student Miss Uzoamaka Anombem supervised by Doctor Haiyu Li at the University of Manchester working on this project), a process bus architecture has been finally proposed and have already been agreed by National Grid.

Figure 1-4 illustrated the substation communication system within feeder bay which adopts the standard process bus architecture.

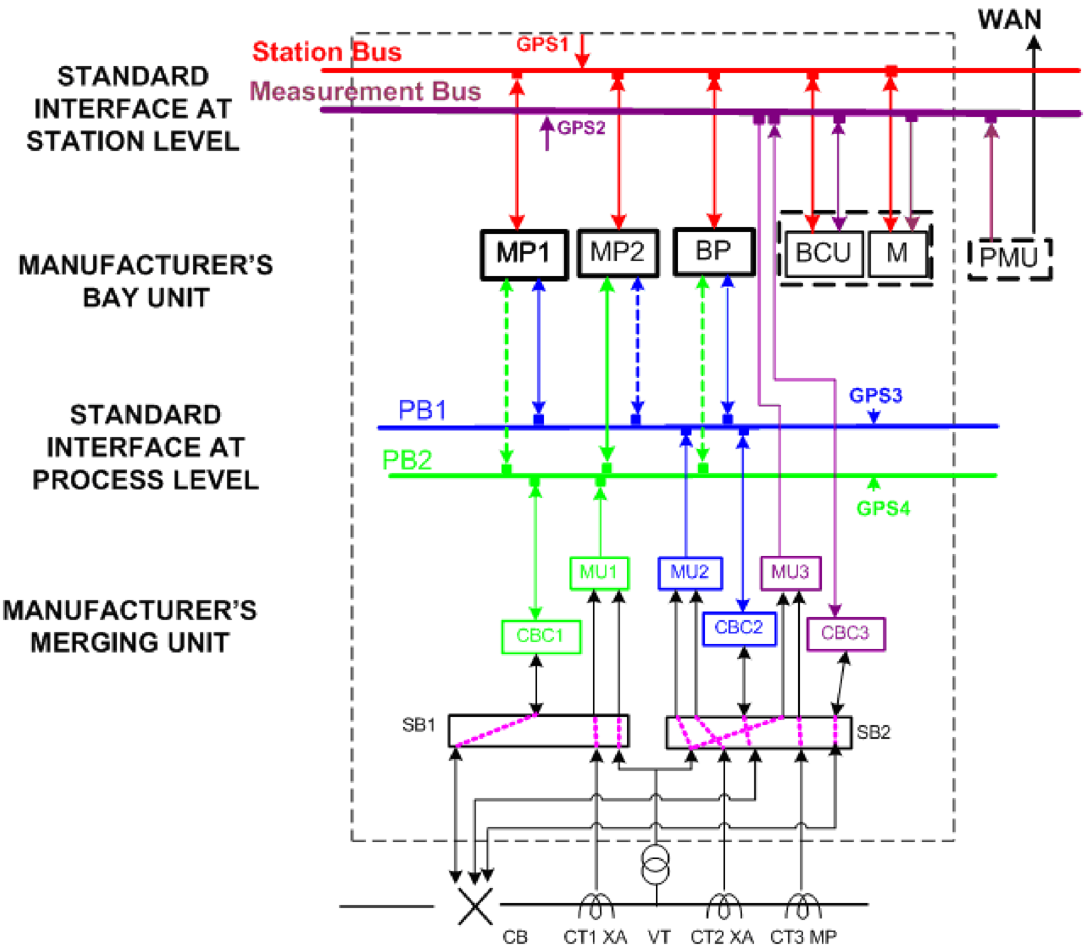

Figure 1-4 Communication system within feeder bay using the proposed standard process bus architecture

Where:

MP: Main Protection;

BP: Backup Protection;

BCU: Bay Control Unit;

M: Metering;

PMU: Phase Measurement Unit;

PB: Process Bus;

GPS: Global Position System;

MU: Merging Unit;

CBC: Circuit Breaker Controller;

SB: Switch Box;

CTMP: Measurement Class CT;

VT: Voltage Transformer;
CB: Circuit Breaker.

The blocks on PB1 and PB2 are Ethernet switches, and the blocks on Station Bus and Measurement Bus are gateway switches.

The gateway switches shall provide isolation for the protection bay as well as a connection to the busbar process bus for passing on tripping instruction and to keep the transfer trip time across bays to a minimum.

In this process bus architecture, each CT and VT is connected to a MU, while each CB is connected to a CBC. The MU1 and CBC1 are connected to the bay process bus 1, while the MU2 and CBC2 are connected to the bay process bus 2. There is a switch box between each CT/VT and MU and also between each CB and CBC, which is used for isolation purposes. The protection IEDs, MP1, MP2 and BP, are connected to the process bus and station bus. The dashed arrow shows the bay level IED process bus connections are not dedicated, which can be switch to the other process bus when necessary. Therefore, the MAIN 1 and MAIN 2 are totally separated and independent. The BCU, M and PMU devices are connected to the measurement process bus. The measurement CT MU and CBC are connected via a gateway switch to the measurement process bus.

Figure 1-5 illustrated the substation communication system for the feeder bay and the transformer bay.

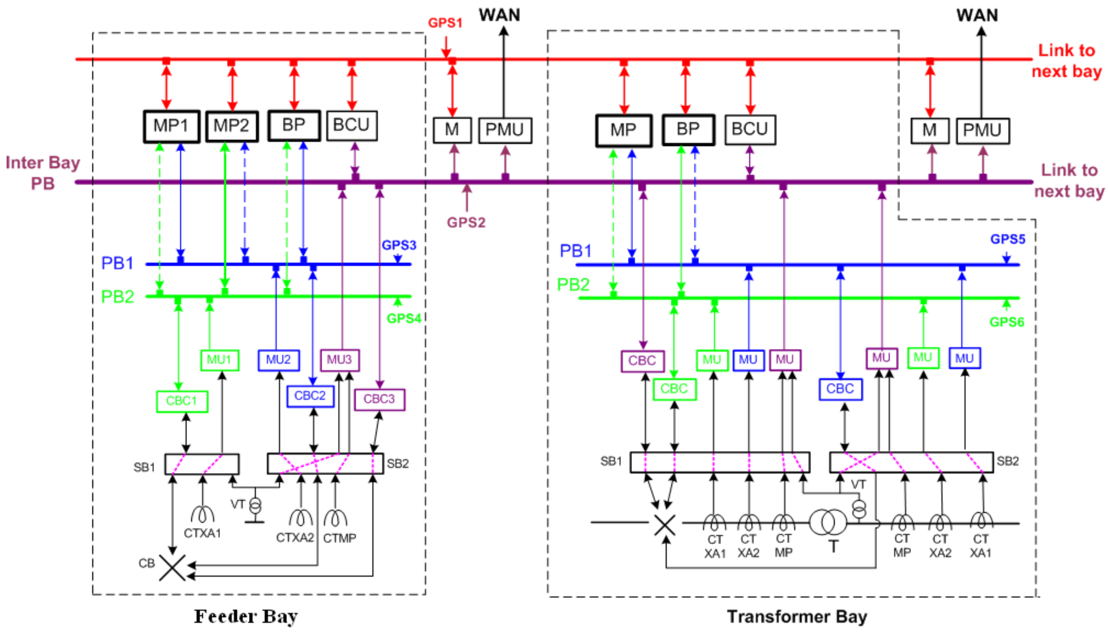

Figure 1-5 Communication system of feeder bay and transformer bay using the proposed standard process bus architecture

In the transformer bay, the MP and the BP are connected to PB1 and PB2 respectively, which are independent. There is one inter bay process bus which is the measurement bus in this substation communication system.

Therefore, the complete communication system of the mesh corner substation is derived as shown in Figure 1-6.

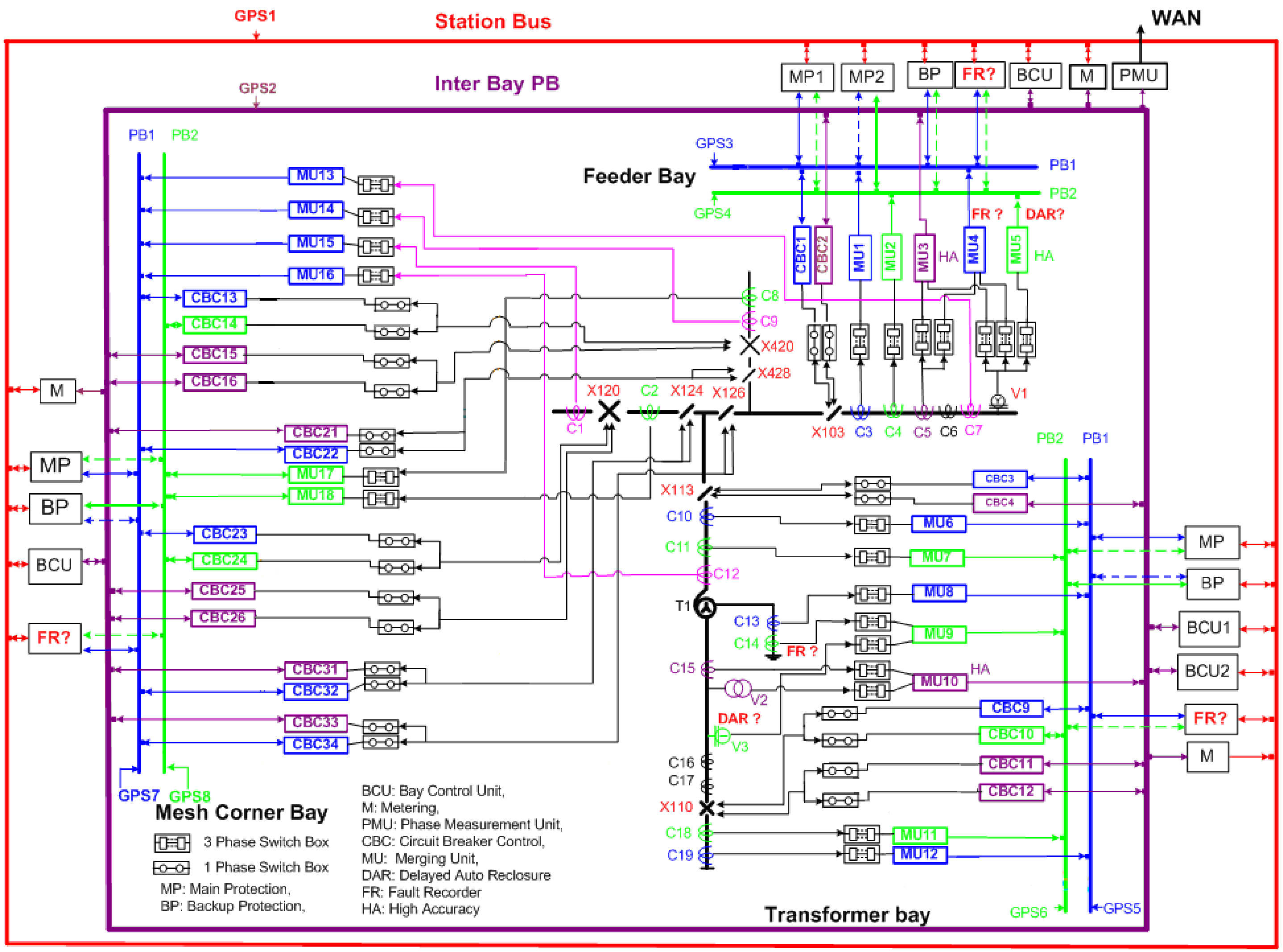

Figure 1-6 Communication system of mesh corner substation using the proposed standard process bus architecture

In the feeder bay, the MP1, BP and associated MUs and CBCs are connected to PB1, the MP2 and associated MUs and CBCs are connected to PB2, which makes the feeder MAIN1 and MAIN2 protections totally separated and independent.

In the transformer bay, the MP and associated MUs and CBCs are connected to PB1, the BP and associated MUs and CBCs are connected to PB2, which makes the transformer main and back up protections totally separated and independent.

In the mesh corner bay, the MP and associated MUs and CBCs are connected to PB1, the BP and associated MUs and CBCs are connected to PB2, which makes the mesh corner main and back up protections totally separated and independent.

Three phases switch box is used to isolate CT/VT and MU. One phase switch box is used to isolate CB and CBC.

All the BCUs used for control and monitoring of switchgear, transformers and other equipments in the substation, metering devices, PMU and associated MUs and CBCs are connected to the inter bay measurement PB. A station bus is used to provide primary communications between the IEDs, which provide the various station protection, control, monitoring, and logging functions. All the process buses and the station bus are synchronized by GPS.

1.9.2 Advantages of the Standard Process Bus Architecture

The main advantages of this process bus architecture are described below in terms of the four primary aims and seven golden rules of AS^3 project.

1. Allow replacement of faulty IED with minimum outage requirements.

   With the application of switching box, two independent bay process buses and gateway switches, the, any single faulty IED can be replaced without an outage or impacting any other IEDs.

2. Allow secondary refurbishment of a bay with minimum outage requirement.

The secondary system of a bay can be refurbished without an outage.

3. Simplify isolation procedures between primary and secondary systems.

The primary system of a bay can be refurbished in an isolated way.

4. Reduce risks of mal-operation.

By using the independent MAIN 1 and MAIN 2 protection systems, each protection IED is capable of tripping the circuit breaker. Therefore, the risk of mal-operation is reduced.

5. The design principles of the AS^3 scheme must be standard for all bay types – DBB feeder, DBB Bus Section, DBB Bus Coupler, MC Mesh Corner, MC Transformer, MC Feeder.

The process bus architecture is proposed as a standard for all bay types.

6. The switching box should be located as close as possible to the Primary equipment.

The switching box is capable of being located next to the Primary equipment

7. No single activity on the MAIN 1 system shall affect the MAIN 2 system.

The MAIN 1 and MAIN 2 systems are totally separated and independent.

8. No single failure shall result in the loss of control of more than one bay.

All the BCUs are connected to the inter-bay process bus and station bus through gateway switches. Any single failure would influence one BCU at most.

9. Physical facilities shall be available to isolate a bay for testing.

The application of switching box and gateway switches can fulfil this requirement.

10. The Protection and Control application/philosophy shall be functionally identical to the existing bay solution currently provided by National Grid suppliers.

The new substation communication system will not influence the protection and control schemes that the substations are using at the moment.

11. All trip signals shall be received by the breakers within 10ms (excluding intertrip send).

This rule will be tested and demonstrated in the following chapters

1.10 Objectives and Contributions of This Study

This research is focusing on the communications needs associated with the protection scheme for an EHV mesh-corner operated by a transmission network operator. The main objectives of this project are shown below:

1. The design and implementation of the different process bus topologies as applied to the mesh-corner protection.

As described in section 1.9 above, the double bay process bus architecture (PB1 and PB2) is established. However, there are different Ethernet LAN topologies which can be applied on the design of PB1 and PB2.

In this study, the mesh-corner substation model is built by using the Real Time Digital Simulator (RTDS) software. Different process bus communication systems are built for the University of Bath’s RTDS hardware and IEDs.

2. The reliability and availability analysis of the different process bus communication topologies.

The reliability and availability of the different process bus topologies are calculated and analyzed before tested on the experiment platform.

3. The performance of an Ethernet switched communication networks in terms of communications volume and latency.

Different process bus topologies are modelled by using the OPNET communication network simulation tool. The latency of each process bus topology is estimated in terms of the communication volume.

4. The effects on the protection scheme performance in respect to limitations in the communications volume and its latency.

Adopting different process bus topologies, the performance of the protection relays with different protection schemes are evaluated in terms of the communication volume.

The main contributions of this study can be summarized below:

1. Configuration of various existing and new substation automation system, SAS, process bus structures.

2. Modelling of these using commercially available simulation tools. These configurable IED models allow the engineers to easily build SAS network model with different topologies for all kinds of substations, so that the dynamic performance issues could be studied and rules could be developed to guide the SAS network planning and design.

3. Investigation of the impact of the various process bus structures on the power system network operator's primary operation aims and the golden rules.

1.11 Thesis Outline

The rest of this thesis is organized as follows:

Chapter two describes the development, concept, and major benefits of IEC61850. It also compares the conventional substation protection system with the IEC16850 based protection system.

Chapter three evaluates the performance of IEC61850 based and conventional relays using a commercial Test Universe. Two feeder protection schemes, distance and current differential protection schemes, are involved in the tests. The trip times of both relays are recorded and mean trip times are calculated.

Chapter four describes three different process bus topologies, their implementations and their relative advantages and disadvantages. It also puts forward mean time to failure and availability analysis of a transmission line protection scheme using different Ethernet based process bus topologis based on the reliability block diagram method, RBD.

Chapter five evaluates the performance of SV messages over the three Ethernet switch based process bus topologies by using OPNET communication network simulation tool. In these tests, ETE delay of the SV messages under normal and process bus overload conditions are simulated.

Chapter six evaluates the performance of different protection schemes, which include distance protection scheme, feeder current differential protection scheme and transformer current differential protection scheme, with cascaded, star and ring process bus architecture using RTDS Simulator. It also examines the performance of the IEC61850 relay when the data transfer traffic on the process bus exceeds its capability and data packets are therefore lost.

Chapter seven summarizes the key findings from the research and the major contributions of the work and provides some potential research topics in IEC61850.

Chapter 2

Introduction of IEC61850

THIS chapter introduces the development, concept, and key benefits of IEC61850.

2.1 IEC61850 – Communication Networks and Systems in Substation

2.1.1 The Development of IEC61850

Communication has always played a critical role in the real-time operation of the power system. In the beginning, the telephone was used to transmit the transmission line loads back to the control centre, and also to dispatch the instructions to be performed by the operators at substations. Telephone-switching based remote control units were carried out as early as the 1930's and were able to provide status and control for a few points. As digital communications in substations became practical in the 1960's, the data acquisition systems (DAS) were installed to automatically collect measurement data from the substations. Because bandwidth was limited, DAS communication protocols were only optimized to operate over low-bandwidth communication channels. Therefore, the time that it would take to configure, map and document the location of the various data bits received by the protocol was relatively long, which was the "cost" of this optimization.

Since the mid 1970s, power system engineers have sought ways to use microprocessors to improve the control, protection, and monitoring of power system substations. This led to the rapid development of the modern microprocessor relays. The microprocessors combine the advantages of semiconductor technology with the flexibility of the digital computer. Software offers considerable flexibility in scheme logic and the possibility of switching selectable scheme logics and operating characteristics. Hardware provides for general purpose system and standardized protection platforms. It enables relays to be easily modified to meet new and varied requirement of particular customers, by changing the software without the need to redesign the relay's hardware.

Modern microprocessor relays integrate multiple functions, such as protection, control, automation, metering, digital fault recording and reporting, and are therefore able to efficiently accommodate various power system services. For this reason, they are also referred to as Intelligent Electronic Devices (IEDs) which are widely used in today's electrical protection systems.

The development of IEDs and network communication technologies led to the success of substation automation system (SAS), which could facilitate the effective substation monitoring, local & remote control, protection, primary equipment condition monitoring and many other functions that couldn't be easily realized with conventional protection and control devices.

Since stepping into a digital era, literally thousands of analogue and digital data points are available in a single IED and the communication bandwidth is not a limiting factor any more. At present, it is common that the communication data paths between substations and master can operate at 64,000 bits per second, and it is obvious that it will migrate to the data paths with much higher rates. With this migration in technology, the "cost" component of a data acquisition system has now become the configuration and documentation component. Therefore, a key component of a communication system is able to describe themselves from both a data and services (communications functions that an IED performs) perspective. Other key requirements include:

- High-speed IED to IED communication
- Network operation throughout the utility enterprise
- High-availability
- Guaranteed delivery times
- Standards based
- Multi-vendor interoperability
- Support for Voltage and Current samples data
- Support for File Transfer
- Auto-configurable / configuration support

- Support for security

The absence of a common communication protocol has already become a major deterrent for the use of communication in SAS. Until recently, manufacturers were using their own proprietary communication protocols. Therefore, a huge investment was needed to develop costly and complicated protocol converters [6]. It has been estimated that across that information technology industry around US$82 billion was spent on application integration in 1998, which amounted to 40% of the corporate IT budgets [7]. To address these SAS issues, an international communication standard is imperative.

The work on the development of a next generation communication architecture began with the establishment of the Utility Communication Architecture (UCA) in 1988. The result of this work was a profile of recommended protocols for the various layers of the International Standards Organization (ISO) Open System Interconnection (OSI) communication system model. This architecture resulted in the definition of a profile of protocols, data models and abstract services definitions that became the UCA. The concepts and fundamental work done in UCA became the foundation for the International Electrotechnical Commission (IEC) Technical Committee Number 57 (TC 57), this developed and maintained international standards for power system control, distribution automation, teleprotection, and associated information exchange for real-time and non-real-time information, used in the planning, operation and maintenance of power systems. Working Group 10 (WG10) of TC 57 launched the International Standard – IEC61850 – Communication Networks and Systems in Substations in 1995, and the first edition issued in 2002. The scope of each IEC61850 related working group is described below.

1. TC 57 Working Group 10: Power systems IED communication and associated data models [8]

Scope: To develop communication standards for substations – Functional architecture and general requirements.

2. TC 57 Working Group 13: Energy management system application program interface (EMS – API) [8]

Scope: To produce standard interface specification for “plug-in” application for an electric utility power control centre Energy management System (EMS) or other system performing the same or similar functions. A “plug-in” application is defined to be software that may be installed on a system with minimal effort and no modification of source code. This standard facilitates installation of the same application program on different platforms by reducing the efforts currently required.

3. TC 57 Working Group 14: System interfaces for distribution management (SIDM) [8]

Scope: Identify and establish requirements of standard interfaces of a Distribution Management System (DMS) based on an interface architecture. The standard is the first in a series of standards that, taken as a whole, define Distribution Management Systems. Subsequent standards will be developed in accordance with the interfaces defined in this task.

4. TC 57 Working Group 15: Data and communication security [8]

Scope: Undertake the development of standards for security of the communication protocols defined by the IEC TC 57.

5. TC 57 Working Group 17: Communications Systems for Distribution Energy Resources (DER) [8]

Scope: Undertake the development of IEC61850 information models to be used in the exchange of information with distributed energy resources (DER).

6. TC 57 Working Group 18: Hydroelectric power plants – Communication for monitoring and control [8]

Scope: IEC61850-7-410 is part of the IEC61850 series. This part of IEC61850 specifies the additional common data classes, logical nodes and data objects required for the use of IEC61850 in hydropower plant.

7. TC 57 Working Group 19: Interoperability within TC 57 in the long term [8]

Scope: Harmonization of IEC61850 and common information model

The standard IEC61850 "Communication networks and systems in substation" has been published by IEC between 2003 and 2005. This global communication standard for the SAS, defines the communication protocol, data format, and the configuration language, thus provides the interoperability within power substation. In an IEC61850 based substation automation system, the cables which carry binary or analogue information between different equipments will be replaced with a standardized communication.

2.1.2 The Scope and Outline of IEC61850

The stated scope of IEC61850 was communications within the substation. The document defines the various aspects of substation communication network in 10 major sections as show in Table 2-1 [9].

Table 2-1 Scope of IEC61850

Part #	Title
1	Introduction and Overview
2	Glossary of Terms
3	General Requirements
4	System and Project Management
5	Communication Requirements for Functions and Device Models
6	Configuration Description Language for Communication in Electrical Substations Related to Intelligent Electronic Devices (IEDs)
7	Basic Communication Structure for Substation and Feeder Equipment
7.1	- Principles and Models
7.2	- Abstract Communication Service Interface (ASCI)
7.3	- Common Data Classes (CDC)
7.4	- Compatible Logical Node Classes and Data Classes
8	Specific Communication Service Mapping (SCSM)
8.1	- Mapping to MMS (ISO/IEC 9506 – Part 1 and Part 2) and to ISO/IEC 8802-3
9	Specific communication Service Mapping (SCSM)
9.1	- Sample Values over Serial Unidirectional Multidrop Point-to-Point Link
9.2	- Sample Values over ISO/IEC 8802-3
10	Conformance Testing

Part 1 and 2: Provide an overview to the IEC61850 standard and contain the glossary of the terminology used in the different parts of the standard [10].

Parts 3, 4, and 5 of the standard identify the general and specific functional requirements for communications in a substation. These requirements are then used as forcing functions to aid in the identification of the services and data models needed, application protocol required, and the underlying transport, network, data link, and physical layers that will meet the overall requirements [11].

From a system perspective, a significant amount of configuration is required to put all the pieces together and make them work. In order to facilitate this process and eliminate the human error, part 6 defines a Substation Configuration Language (SCL) which is based on the eXtensible Makeup Language (XML) to describe the configuration of IEC61850 based system. SCL specifies a hierarchy of configuration files that enable multiple levels of the system to be described in unambiguous and standardized XML files. The various SCL files include system specification description (SSD), IED capability description (ICD), substation configuration description (SCD), and configured IED description (CID) files. All these files are constructed in the same methods and format but have different scopes depending on the need.

Part 7 provides the basic communication structure for substation and feeder equipment, including the principles and data models, the Common Data Classes (CDC), the Abstract Communication Service Interface (ACSI) and the compatible logical node and data classes [12] [13] [14].

To ease understanding, the data model of the IEC61850 IED can be viewed as a hierarchy of information as shown in Figure 2-1. The categories and naming of this information is standardized in the IEC61850 specification.

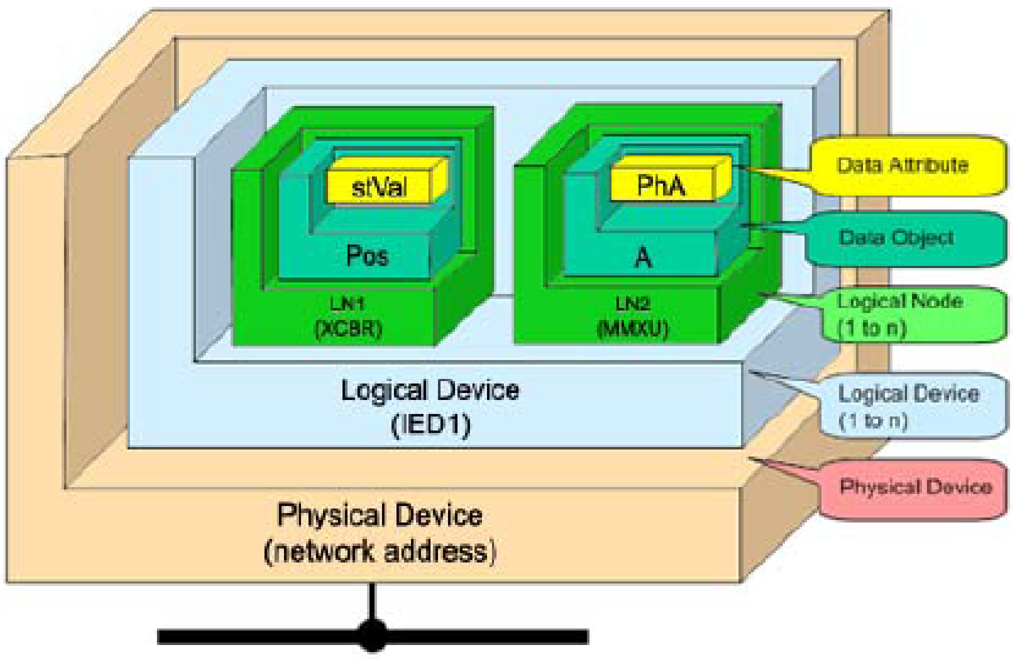

Figure 2-1 Data model layers in IEC61850

The levels of this hierarchy can be described as follows:

1) *Physical device:* identifies the actual IED within a system. Typically the device's name or IP address can be used (for example **Feeder_1** or **10.0.0.1**).

2) *Logical device:* identifies groups of related Logical Nodes within the Physical Devices.

3) *Wrapper/logical node instance:* identifies the major functional areas within the IEC61850 data model. Either 3 or 6 characters are used as a prefix to define the functional (wrapper) while the actual functionality is identified by a 4 character Logical Node name suffixed by an instance number. For example, **XCBR1** (circuit breaker), **MMXU1** (measurements), **FrqPTOF2** (overfrequency protection, stage 2)

4) *Data object:* this next layer is used to identify the type of data you will be presented with. For example, **Pos** (position) of Logical Node type **XCBR.**

5) *Data attribute:* this is the actual data (measurement value, status, description, etc.). For example, **stVal** (status value) indicating actual position of circuit breaker for Data Object type **Pos** of Logical Node type **XCBR**.

"Abstracting" the definition of the data items and services which can create data items/objects and services that are independent of any underlying protocols is the major architectural construction that IEC61850 adopts. The abstract definitions allow "mapping" of the data objects and services to any other protocol which can meet the data and service requirement. The definition of the abstract services is found in IEC61850 part 7.2. The two relevant ACSI services are show below:

1. Transmission of sampled values model

MULTICAST-SAMPLE-VALUE-CONTROL-BLOCK:
SendMSVMessage; GetMSVCBValues; SetMSVCBValues

UNICAST-SAMPLE-VALUE-CONTROL-BLOCK
SendUSVMessage; GetUSVCBValues; SetUSVCBValues

2. Generic substation event model (GSE)

Generic Object Oriented Substation Event (GOOSE):
SendGOOSEMessage; GetGoReference; GetGOOSEElementNumber; GetGoCBValues; SetGoCBValues

Generic Substation State Event (GSSE):
SendGSSEMessage; GetGsReference; GetGSSEDataOffset; GetGsCBValues; SetGsCBValues

The abstraction of the data objects (referred to as Logical Nodes) is found in IEC61850 part 7.4. Because most data objects are made up of common pieces, such as Status, Control, Measurement and Substitution, etc. the concept of CDC is developed to define common building blocks for creating the larger data objects. The CDC elements are defined in part 7.3. In short, the part 7 achieves the naming of the massive data and forming of data objects and services.

The abstract data and object models of IEC61850 define a standardized method of describing power system devices that enables all IEDs to present data using identical structures that are directly related to their power system function. The ACSI models of IEC61850 define a set of services and the responses to those services that enable all IEDs to behave in an identical manner from the network behaviour perspective. While the abstract model is critical to achieving this level of interoperability, these models need to be operated over a real set of protocols that are practical to implement and that can operate within the computing environments commonly found in the power industry.

IEC61850 Part 8.1 defines the mapping of the abstract data object and services onto the Manufacturing Messaging Specification (MMS) of ISO9506 [9]. MMS is the only public (ISO standard) protocol that has proven implementation track record that can easily support the complex naming and service models of IEC61850. Although

IEC61850 can be theoretically mapped to any protocols, this mapping can get very complex and cumbersome when IEC61850 objects and services are tried to be mapped to a protocol that only provides read/write/report services for simple variables that are accessed by register numbers or index numbers. That was the reason why MMS was chosen for UCA in 1991 and kept for IEC61850.

In addition to the mapping to the application layer, IEC61850 Part 8.1 defines profiles for the “other” layers of the communication stack that are dependent on the service provided which is shown in Figure 2-2. the Sampled Values and GOOSE applications map directly into the Ethernet data frame thereby eliminating processing of any middle layers; the MMS Connection Oriented layer can operate over TCP/IP or ISO; the Generic Substation Status Event (GSSE) is the identical implementation as the UCA GOOSE and operates over connectionless ISO services; all data maps onto an Ethernet data frame using either the data type “Ethertype” in the case of Sampled Values, GOOSE, TimeSync, and TCP/IP or “802.3” data type for the ISO and GSSE messages. IEC61850 Part 8.1 defines which is known as the station bus.

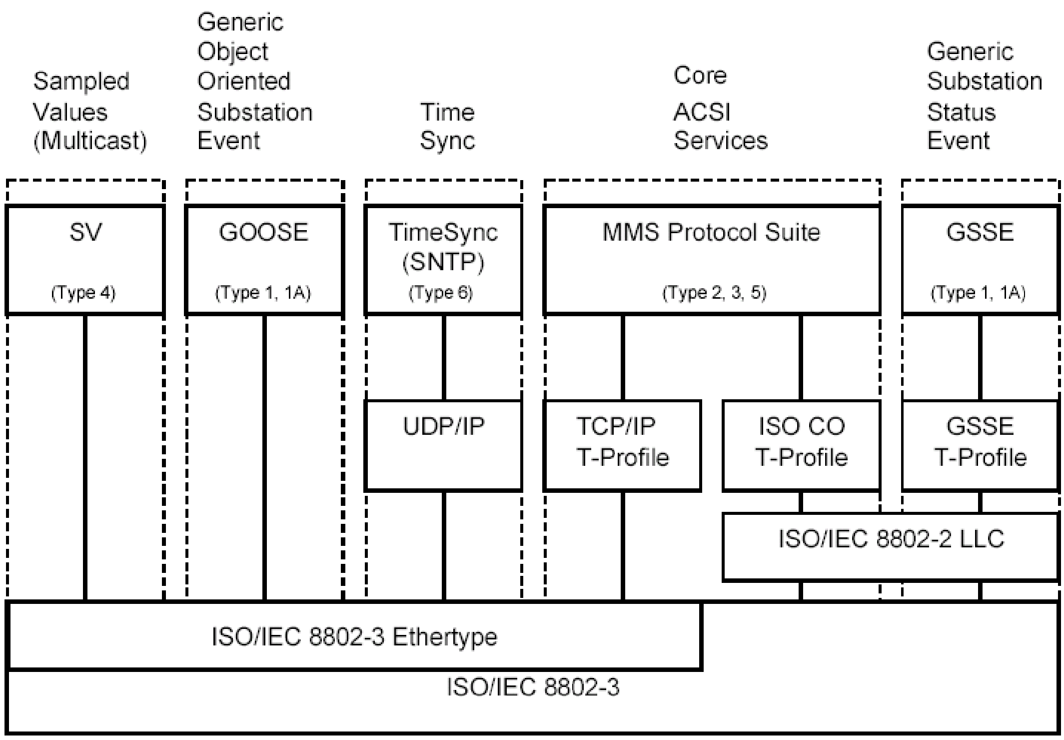

Figure 2-2 Overview of IEC61850 functionality and associated communication profiles

IEC61850 Parts 9.1 and 9.2 define the mapping of the Sample Measured Values (unidirectional point-to-point and bi-directional multipoint accordingly) onto an Ethernet data frame [16]. The IEC61850 part 9.2 defines what has become known as the process bus.

The IEC61850 part 9.2 is only restricted to the mapping of the ASCI model for the transmission of sampled values. However, to get full benefit of the process bus, additional ASCI models need to be supported in accordance to the IEC61850 part 8.1. In short, IEC61850 parts 9.2 and 8.1 can be used onto the process bus simultaneously.

Finally, the IEC61850 part 10 defines a testing methodology in order to determine "conformance" with the numerous protocol definitions and constraints defined in the document [9].

The standard defines and offers much more than just a protocol. It provides:

- standardized models for IEDs and other equipment within the substation;
- standardized communication services (the methods used to access and exchange data);
- standardized formats for configuration files;
- peer-to-peer (e.g. relay to relay) communication.

The standard includes mapping of data onto Ethernet. The use of Ethernet in the substation offers many advantages, the most significant ones are shown below [17].

- high-speed data rates (currently 100Mbit/s, rather than 10's of kbits/s or less used by most serial protocols);
- multiple masters (called "clients");
- Ethernet is an open standard in every-day use.

2.1.3 The Application of the Process Bus

Ethernet technology has evolved from the initial CSMA/CD (Carrier Sense Multiple Access with Collision Detection) mechanism to native switched-base Ethernet, which is almost collision free [18]. This advanced networking protocol can now be designed with deterministic transmission times, suitable for real-time and mission-critical tasks. Contemporary switched Ethernet Local Area Networks (LANs) is able to create a full-duplex and collision-free communication environment, by means of twisted paired optical fibre cables and separate Ethernet switch. Therefore, the development of Ethernet technology provides an opportunity to design a new communication system for power system protection applications.

The IEC61850 part 8.1 and part 9.2 defines two real-time peer-to-peer communication messaging protocol which are GOOSE messages and Sample Value (SV) messages. Both GOOSE and SV messages behave in a multicast mode which permits simultaneous delivery of the same event message to multiple recipient IEDs through the process bus which is an Ethernet LAN.

Hardwired interface between the primary transducers and the secondary protection devices is the basis of the existing protection system. IEC61850 introduces a communication based interface between instrument transformers, circuit breakers and IEDs. According to the concept of IEC61850, a substation distribution protection system is separated into three distinct levels: substation level, bay/unit level and process level. The three levels of functional hierarchy of IEC61850 are shown in Figure 2-3. These include:

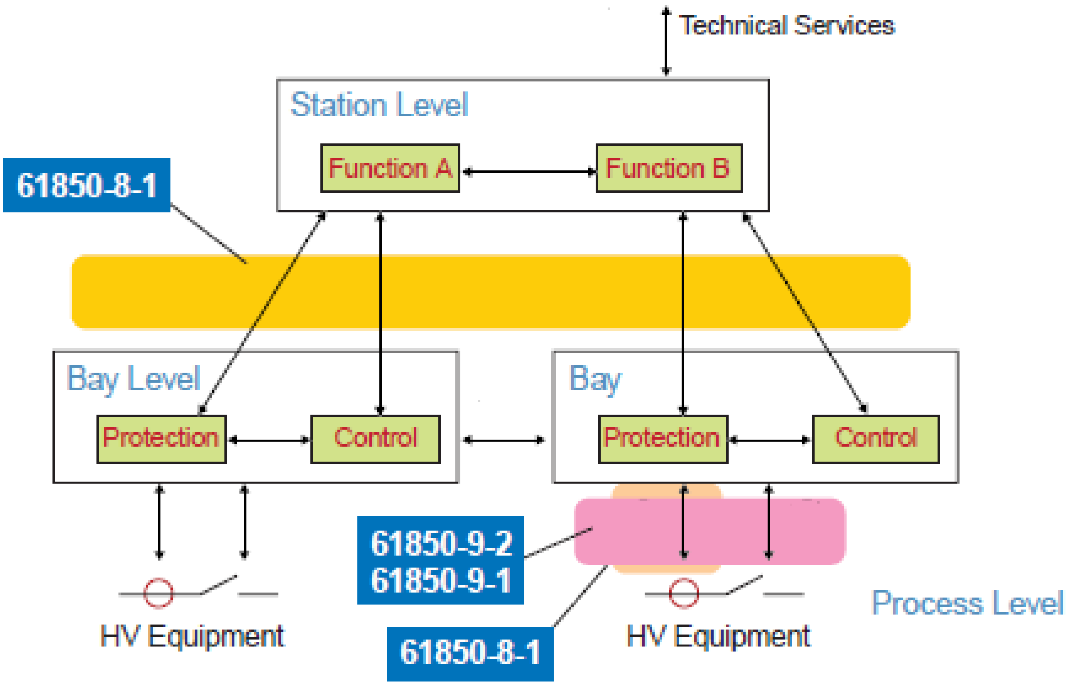

Figure 2-3 Functional hierarchy of IEC61850 based SAS

- Process level: This level includes switchyard equipments such as CTs / VTs, Remote I/O, actuators, etc.

- Bay level: Bay level includes protection and control IEDs of different bays.

- Station level: The functions requiring data from more than one bay are implemented at this level.

In the process layer, all the information such as instrument transformer output and status from breakers and switches are gathered. IEC61850 defines the collection of these data through two different protocols. Part 9.1 defines a Unidirectional Multidrop Point-to-Point fixed link carrying a fixed dataset. Part 9.2 defines a configurable dataset which can be transmitted on a multi-cast basis from one publisher to multiple subscribers.

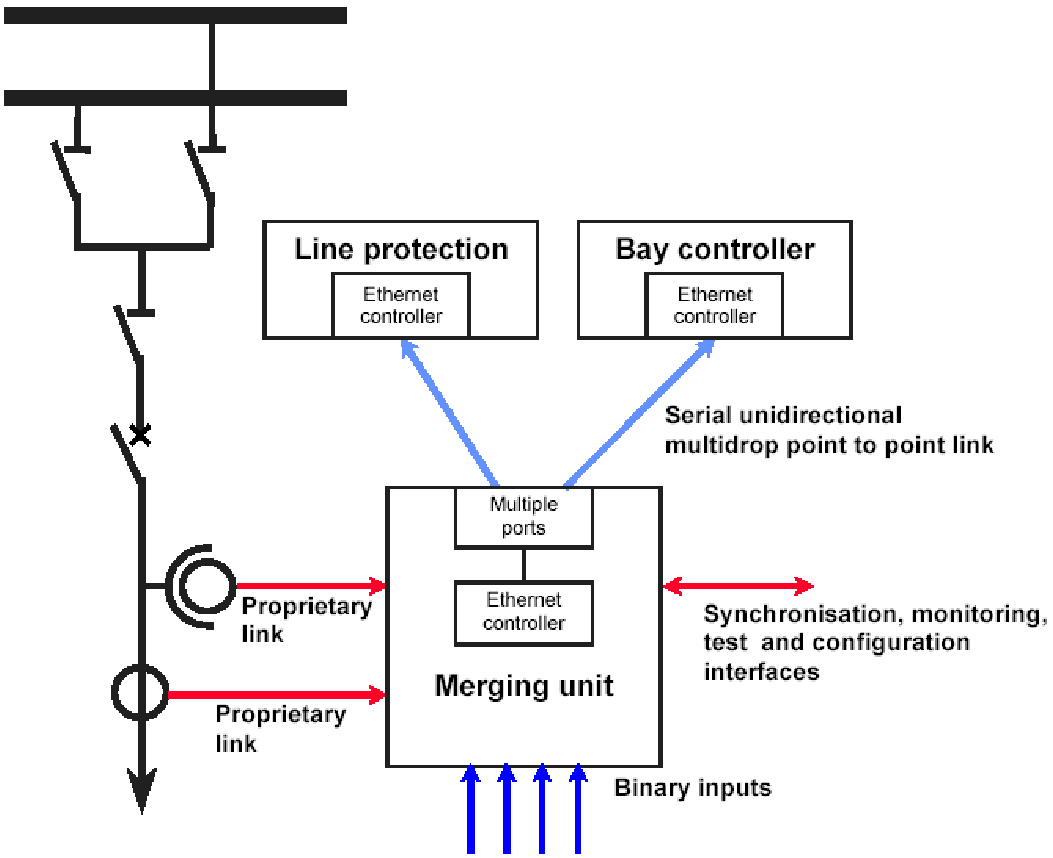

Figure 2-4 Process bus concept [9]

Figure 2-4 illustrates the basic concept of the process bus. The interface of the instrument transformers which include both conventional and non-conventional ones with different types of substation protection, control, monitoring and recording equipment is through a device which is called Merging Unit (MU). The Merging Unit is defined in IEC61850-9-1 as: "Merging unit: interface unit that accepts multiple analogue CT/VT and binary inputs and produces multiple time synchronized serial unidirectional multi-drop digital point to point outputs to provide data communication via the logical interfaces." The Merging Units sample the signals at an agreed, synchronized rate. Therefore, any IED can input data from multiple MUs and automatically align and process the data. There is an implementation agreement that defines a base sample rate of 80 samples per power system cycle for basic protection and monitoring and a "high" rate of 256 samples per power system cycle for high-frequency applications such as power quality and high-resolution oscillography.

Merging Units have the following functions:

- signal processing of all sensors - conventional or non-conventional;
- synchronization of all measurements - 3 currents and 3 voltages;
- analogue interface – high and low level signals, IEC61850 9-2;
- digital interface - IEC 60044-8 [9].

IEC61850 part 9.1 specifies a preconfigured or “universal” dataset as defined in IEC60044-8. This dataset includes 3-phase voltage, bus voltage, neutral voltage, 3-phase currents for protection, 3-phase currents for measurement and two 16-bit status words. Note that the analogue data values are mapped into 16 bits register in this mapping.

IEC61850 part 9.2 is a more generalized implementation of SV data transfer. In part 9.2, the dataset or “payload” is user-defined by using the SCL. As a dataset, data values of various sizes and types can be integrated together.

However, IEC61850-9-2 is restricted to the transmission of SVs. To get full benefit of the process bus, the transmission of GOOSE messages need to be supported in accordance to the IEC61850 8-1 [19] [20] [21]. In this manner, the Circuit Breaker Controllers (CBC) which receive the GOOSE messages from protection IEDs to control the circuit breakers are able to share the process bus Ethernet LAN with the MUs.

In brief, the data from conventional or optical/electronic sensors as well as status information is collected and converted to digital representation, and formatted for subsequent transmission via the process bus LAN [22]. The collection points can be redundant Ethernet switches that support Ethernet priority and Ethernet Virtual LAN (VLAN) [23]. Process Level information is then communicated over the LAN to the protection and control devices which are located at the Bay/Unit Level. Protective functions are performed at the Bay Level. By applying the new standard, an integrated protection system can be established.

2.2 IEC61850 Based Substation Protection System

2.2.1 Conventional Substation Systems

The existing protection schemes are based on hardwired interface between the primary substation equipment, such as transformers, breakers, instrument transformers, etc. and the secondary protection and control devices [24] [25] [26]. A simplified diagram of the communication architecture of conventional strategy is shown in Figure 2-5.

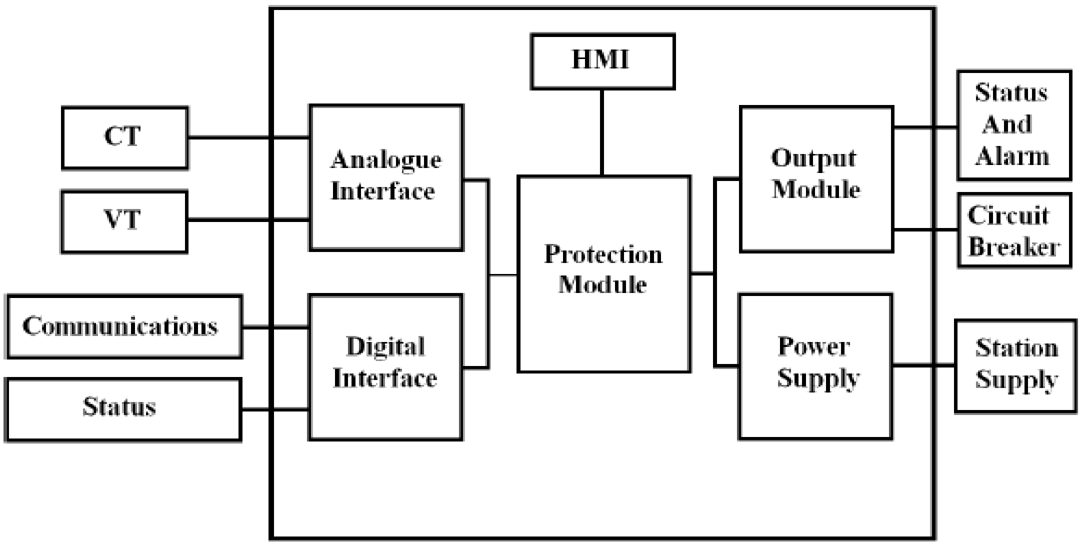

Figure 2-5 Communication architecture of a conventional substation protection system

In the conventional strategy, the CTs and VTs will transfer the analogue values or digital values to the interface module which includes both the analogue and digital input module through hardwires. After processing of the protection module, the output module will send control commands to other electrical equipments, such as trip a circuit breaker, also through hardwires. The Human Machine Interface (HMI) is directly installed in the protection relay in this strategy.

Considering the requirements for redundancy in protection functions, in conventional protection systems numerous primary and backup protection devices need to be installed, wired to the substation equipments.

The interface requirements of the relays are separate from these of the metering devices. As a result, they need their own instrument transformers which allow a wide dynamic range of fault currents.

2.2.2 The Integrated Protection System

The modern microprocessor relays (IEDs) are able to accomplish more protection functions within one protective device. There are functionalities in different units, such as protection, metering, automation, control, digital fault recording and reporting. This research of integrated function is focused on the protection of individual components, not multiple apparatuses. Recently, the dramatic development in signal processing ability of hardware platform, the availability of suitable communication schemes and the introduction of non conventional instrument transformers has enabled the establishment of new concepts of power system protection. Therefore, the research of the new integrated protection system is encouraged, which is considered unsuitable in the past. The results show that the information obtained from multiple power system components can be used for new protection principles and schemes, which could have significant benefits over the existing techniques [27] [28] [29].

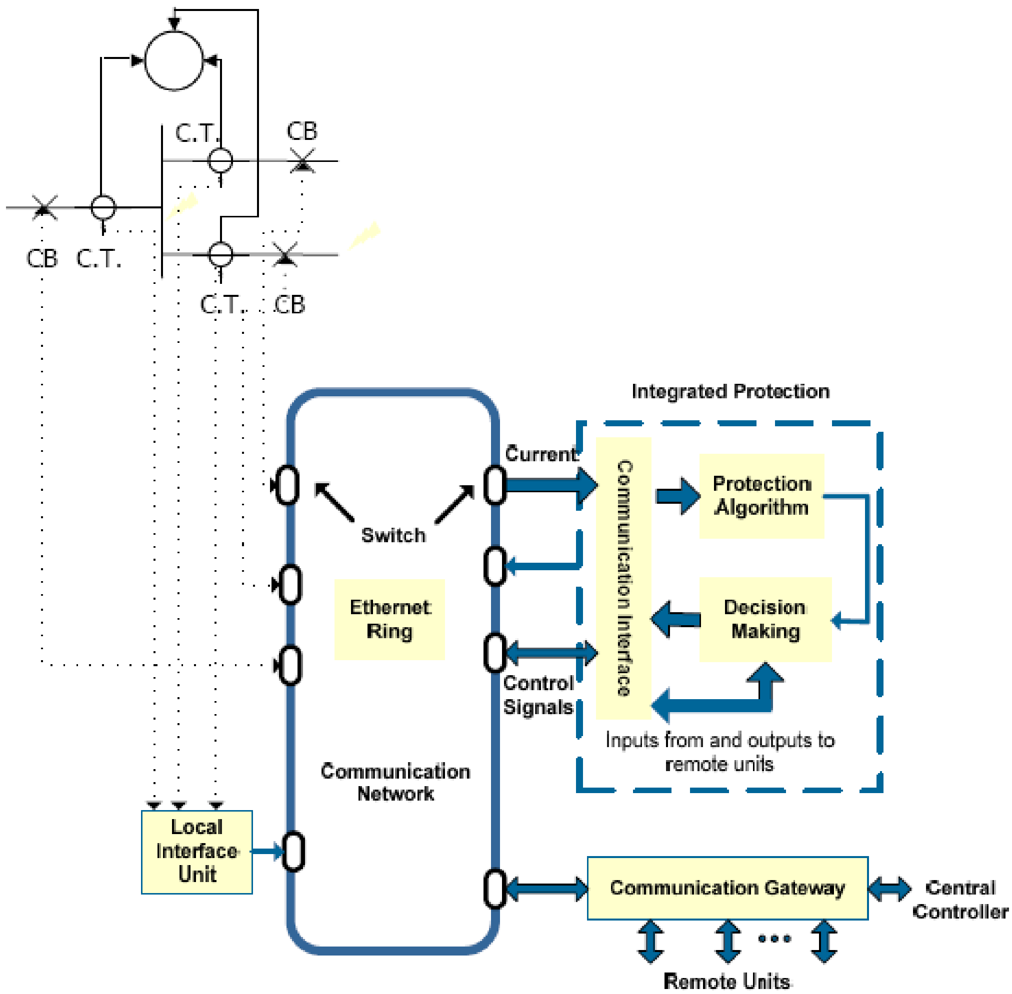

Figure 2-6 Communication architecture of a conventional substation protection system

Figure 2-6 illustrates a new advanced protection scheme which integrates all the protection functions for a substation busbar into one relay to form a centralized protection system. In this system, all the essential measured information collected from multiple lines in the substation busbar are sent to a centralized integrated relay unit through a redundant communication network for the implementation of multi-protection functions. In the fault situation, the relay would process the data and then send trip commands and control signals back to the circuit breakers to trip the faulty line. Therefore, real time and dependable transmission of the sampled values and trip signals through the network becomes an essential part of the integrated protection communication system.

2.2.3 IEC61850 Based Substation Systems

By applying the IEC61850 based solutions, a significant improvement in functionality and reduction of the cost of integrated substation protection and control systems can be achieved. In these solutions, the interface of the instrument transformers which include both conventional and non-conventional ones with different types of substation protection, control, monitoring and recording equipment is through a Merging Unit. MUs could be physically located either in the field or in the control house.

It is very important to be able to interface with both the conventional and non-conventional sensors in order to allow the implementation of the system in both existing and new substations.

A simplified diagram of the communication architecture of an IEC61850 based substation protection system is shown in Figure 2-7.

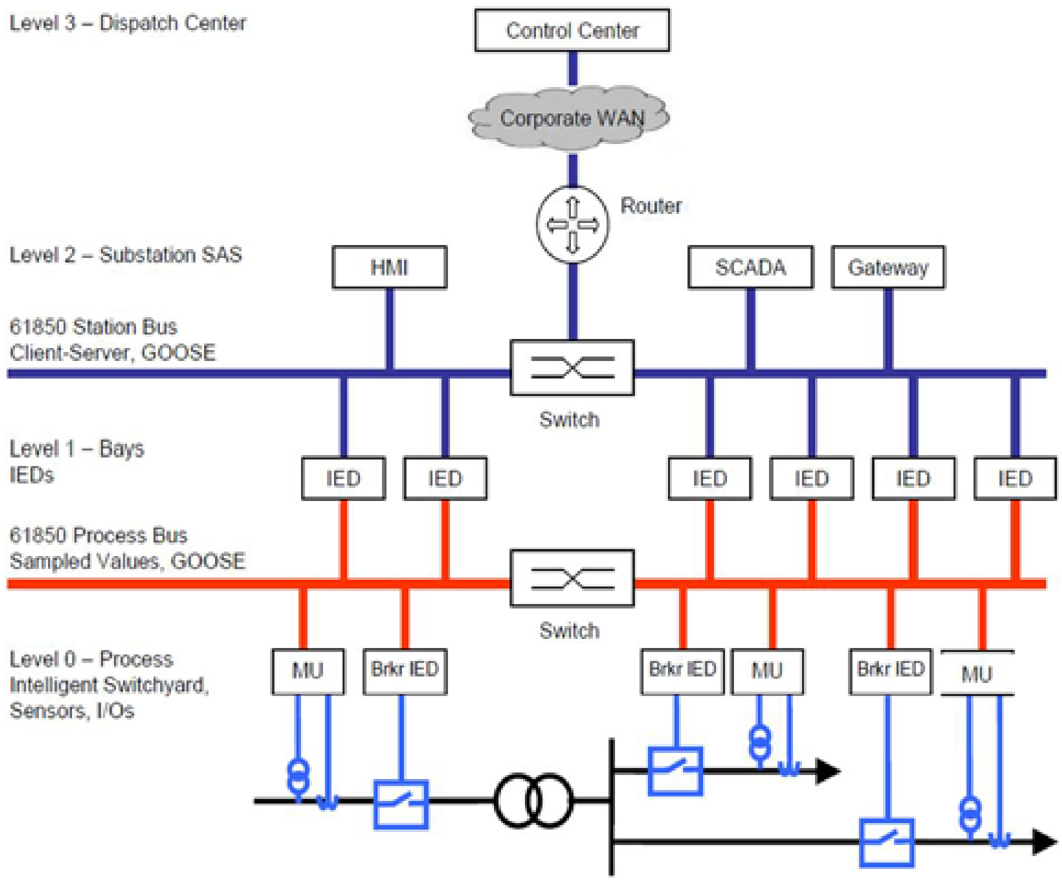

Figure 2-7 Communication architecture of an IEC61850 based substation protection system

In this architecture, the MUs multicast sets of sampled values and status information of breakers and switches to multiple IEDs in the substation through the process bus. Ethernet switches deliver datasets to only those switch ports/IEDs that have subscribed to the data.

After receiving the sampled values, the protection IEDs process the data and make decisions regarding the fault detection, faulted phase selection and protection operation, and then transmit the instructions as required. The typical actions include operating their relay output or sending a high-speed peer-to-peer GOOSE message to other IEDs in order to trip a breaker or initiate some other protection or control functions, such as breaker failure protection, autoreclosing, etc.

At the substation level, the station bus provides primary communications between the various Logical Nodes, which provide the various station protection, control, monitoring, and logging functions.

Finally, this architecture supports remote network access for all types of data. As all communication is network enabled, multiple remote “clients” will desire access the wide variety of available information. Typical clients would include local HMI, operations, maintenance, engineering, and planning. The remote access point is one logical location to implement security functions such as encryption and authentication. This implementation unburdens the individual IEDs from performing encryption on internal data transfers but still provide security on all external transactions.

2.2.4 Future Developments in IEC61850 Based Protection Schemes

IEC61850 has grown out of the world of computing and communications. Many of the future developments in protection relaying and the associated areas of sub-station control and metering will mirror developments in computing. The overriding driving forces will be financial, in terms of lower equipment prices, ease of manufacture, lower installation costs, ease of installation, ease of commissioning, maintenance, updating, and finally de-commissioning and replacement with future systems.

There are many challenges in the general management of protection and control schemes which will have to be re-examined in adopting the concepts included in IEC61850.

Health and safety considerations are paramount in the management of protection systems. Electrical systems are inherently dangerous and several elements associated with protection are potentially a health and safety hazard. CTs are the obvious example.

Any activity associated with the protection systems has a potential impact on the working of the primary plant. If a system outage can be avoided, there are great cost savings. Can maintenance and refurbishment work be undertaken with the primary plant remaining live? It is achieved in the world of computer networks, therefore how can it be done in power systems?

Although the computing and communications world provides an existing roadmap, there will be situations where power system and protection considerations will demand different solutions. Also, different utilities will demand solutions which meet their particular considerations. The software solutions preferred by the computer worlds may not be acceptable to all power system and protection engineers. In some cases, hardware isolation may be demanded.

Relay development is one area where there may well be many interesting developments. Will the 'relay' of the future be recognised as a relay as understood today?

Modern relays, albeit invariably microprocessor based and fully equipped for high level communications, still resemble the relays of many generations ago. They have inputs from current and/or voltage transducers, they have output closing contacts, they have a decision making capability and they have a human-machine interface.

In the 'relay' shown in Figure 2-8, the protection IED is interfaced to the current and voltage transducers via merging units and the process bus. The output closing contacts are also interfaced using the process bus, merging units and actuators. The IED is reduced to the processing element and the human-machine interface, as shown in Figure 2-9.

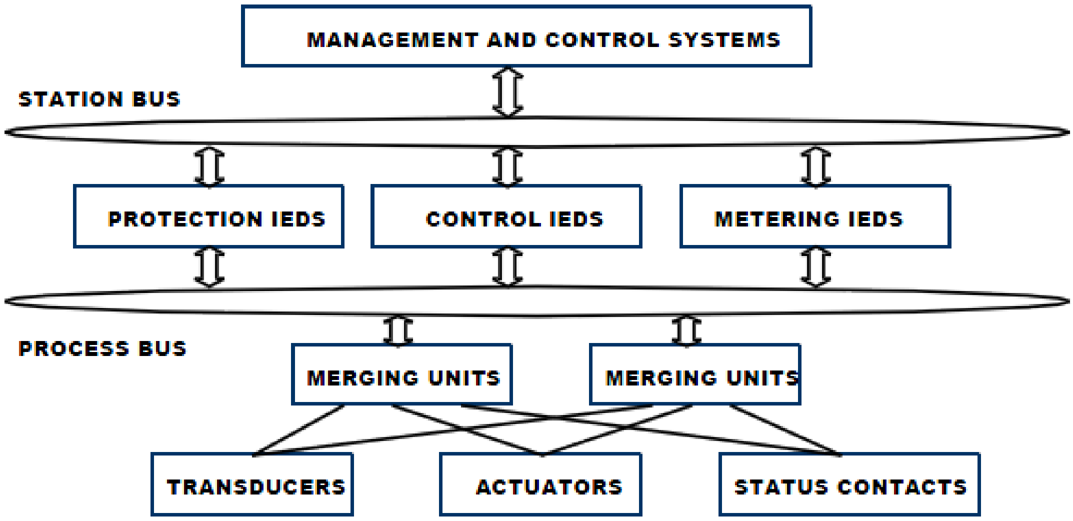

Figure 2-8 The substation communication system

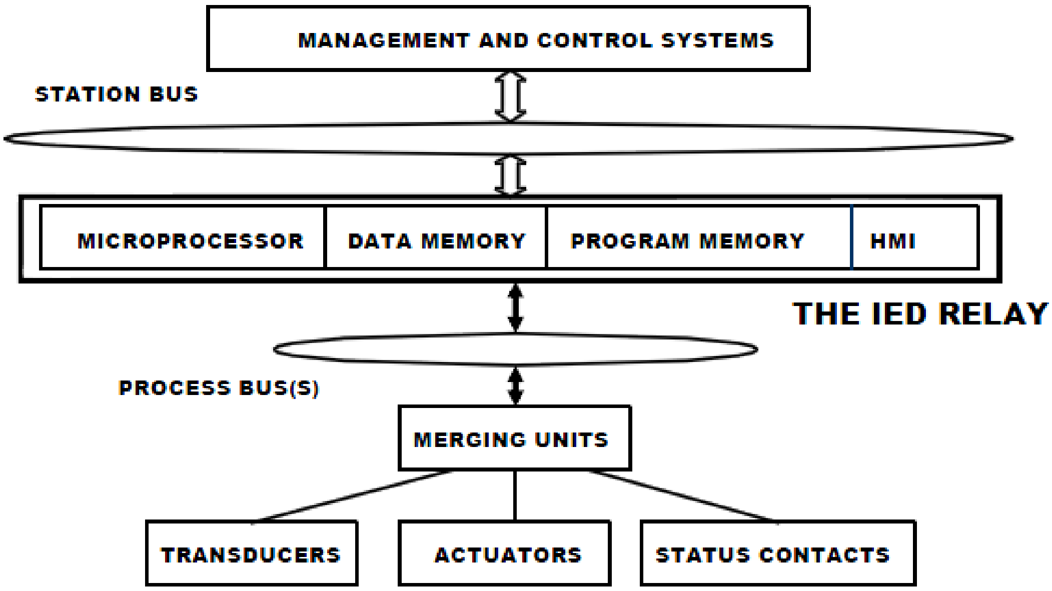

Figure 2-9 The IEC61850 application of IED relay

The immediate opportunity is to relocate the physical human-machine interface. The human-machine interface need not be a dedicated piece of hardware, but simply one of many screens included in the management and control system. Whenever an engineer needs to examine settings, they could access the screen either in the control centre or in the sub-station. This would include facilities to adjust settings and extract any stored data.

The ‘relay’ or protection IED will consist of a suitable processing unit alone, a protection processor. It could be a dedicated protection system processor, or if developments follow the trends seen in the computer world, it is more likely that it will be a general purpose processor system, designed for the environment and more than capable of handling the variety of tasks that it could be called upon to undertake.

This development would immediately provide a cost saving in terms of ‘relay’ hardware. A general purpose IED would be expected to satisfy a variety of protection, control and metering duties. Its specific role would be defined by the software it uses. This commonality of hardware would immediately offer further potential cost savings.

This would also provide a cost saving in terms of housing the ‘relay’ systems since there would be no need to have general access to the equipment to examine the front panel for the human-machine interface.

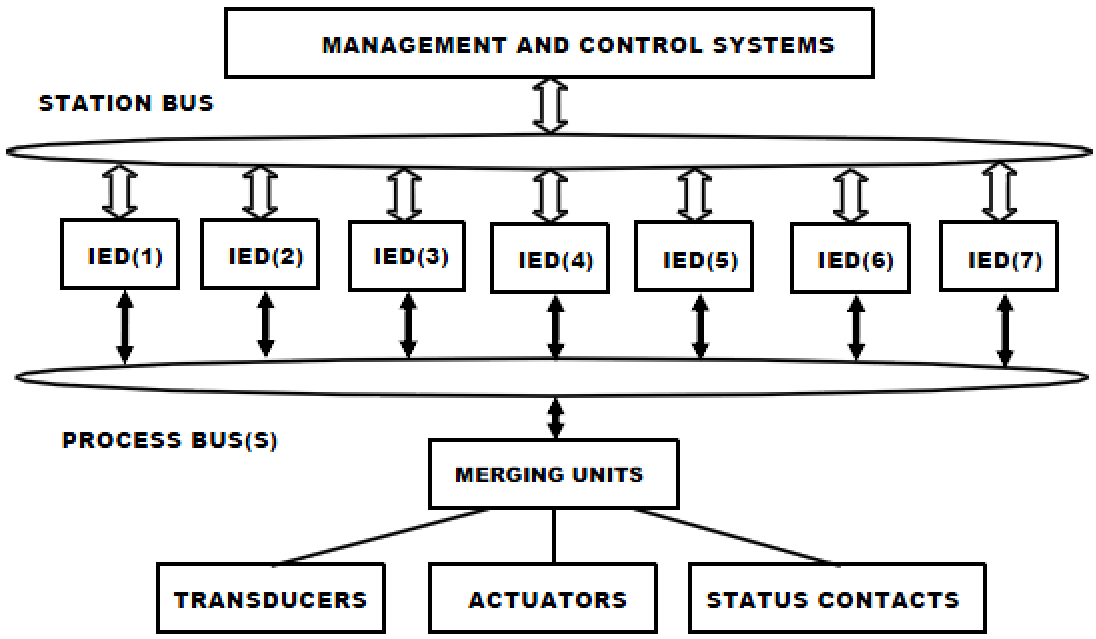

Figure 2-10 The use of multiple IEDs

The system using a variety of IEDs providing the processing capability for protection, control and metering is illustrated in Figure 2-10. The specific role of each IED would be defined by the specific system configuration as set by the system designer or operator. All of these IEDs will be designed for the sub-station environment. Provided that they have the processing capability, they could perform protection, control or metering duties.

Similar considerations could be adapted for merging units, transducers, actuators and status contacts. The concepts of ‘plug and play’ could be adopted by the sub-station designers.

Accepting the fundamental requirement that the IEDs must have the ability to handle the processing required for the specific applications, the choice of processor or processors becomes irrelevant. This ensures that they are future proofed and earlier IEDs can be replaced by more modern equivalents.

Similarly, IEDs from different manufacturers should be interchangeable, including devices from new entrants to the market. The over-riding considerations being are they designed for the sub-station environment and are they able to undertake their duties.

In addition to the aims of IEC61850, such a system provides a platform for the realisation of automatic self-healing protection, control and metering systems. Built in testing facilities are virtually universal in microprocessor based equipment. Should an IED’s application detect that that device is suspect and could be faulty, this could be communicated to the management and control systems and that IED could be flagged for replacement. This could be done by system engineers or it could be done under a predefined automatic procedure. Again, such procedures are available in today’s computer systems. If accepted by the power system engineers, they could be readily adopted.

A further opportunity is the provision of automatic adaptive protection. The sub-station’s management and control systems will have direct communications with local protection and control as well as communications with other systems, hence there will be the opportunity of using this to automatically reassess protection settings and change them as appropriate.

2.3 Benefits of IEC61850

Justifying substation automation investments is one of the significant challenges which the substation engineers face. The positive impacts of automation which includes operating costs, increased power quality, and reduce outage responses are well known. However, little attention is paid to how a communication standard could impact on the cost of building and operating the substation. Former communication protocols were typically developed with the dual objectives of providing the necessary functions required by electric power systems while minimizing the number of bytes used by the protocol. That was because when many of those protocols were initially developed, severe bandwidth limitations were typical for the serial link technology of 10 to 15 years ago. Later, as the Ethernet and modern networking protocols like TCP/IP became widespread, these protocols were adapted. The approach provided the same basic electric power system capabilities as the serial link version while bringing the advantages of modern networking technologies to the substation. But this approach has fundamental flaw; the protocols being used were still designed to minimize the bytes on the wire and do not take advantage of the dramatic increase in bandwidth of modern networking technologies which provide a higher level of functionality that can significantly reduce the implementation and operational costs of substation automation.

IEC61850 is not a former serial link protocol recast onto TCP/IP-Ethernet. IEC61850 was designed from the ground up to operate over modern networking technologies and delivers an unprecedented amount of functionality which is not available from former communication protocols. The unique characteristics of IEC61850 have a direct and positive impact on the cost to design, build, install, commission, and operate power systems. To better understand the specific benefits, some of the key features and capabilities of IEC61850 will be examined and then how these result in significant benefits that cannot be achieved with the former approaches will be explained.

2.3.1 Key Features

The features and characteristics of IEC61850 that enable numerous advantages to all involved in the power industry. Some of these characteristics are seemingly small but are able to make tremendous impacts on substation automation systems. For instance, the use of VLANs and priority flags for GOOSE and SV enable much more intelligent use of Ethernet switches which cannot be achieved with other approaches. Therefore, some of the key features that provide significant benefits to users are listed below [9].

- **Use of a Virtualized Model.** The virtualized model of logical devices, logical nodes, ACSI, and CDCs enables definition of the data, services, and behaviour of devices to be defined in addition to the protocols that are used to define how the data is transmitted over the network.

- **Use of Names for All Data.** Every element of IEC61850 data is named using descriptive strings to describe the data. Legacy protocols, on the other hand, tend to identify data by storage location and use index numbers, register numbers and the like to describe data.

- **All Object Names are Standardized and Defined in a Power System Context.** The names of the data in the IEC61850 device are not dictated by the device vendor or configured by the user. All names are defined in the standard and provided in a power system context that enables the engineer to immediately identify the meaning of data without having to define mappings that relate index numbers and register numbers to power system data like voltage and current.

- **Devices are Self-Describing.** Client applications that communicate with IEC61850 devices are able to download the description of all the data supported by the device from the device without any manual configuration of data objects or names.

- **High-Level Services.** ACSI supports a wide variety of services that far exceeds what is available in the typical legacy protocol. GOOSE, GSSE, SV, and logs are just a few of the unique capabilities of IEC61850.

- **Standardized Configuration Language.** SCL enables the configuration of a device and its role in the power system to be precisely defined using XML files.

2.3.2 Major Benefits

By understanding and taking full advantage of the key features of IEC61850 described above, significant benefits of IEC61850 can be realized [9].

- **Eliminate Procurement Ambiguity.** Not only can SCL be used to configure devices and power systems, SCL can also be used to precisely define user requirement for substations and devices. Using SCL a user can specify exactly and unambiguously what is expected to be provided in each device that is not subject to misinterpretation by suppliers.

- **Lower Installation Cost.** IEC61850 enables devices to quickly exchange data and status using GOOSE and GSSE over the station LAN without having to wire separate links for each relay. This significantly reduces wiring costs by more fully utilizing the station LAN bandwidth for these signals and construction costs by reducing the need for trenching, ducts, conduit, etc.

- **Lower Transducer Costs.** Rather than requiring separate transducers for each device needing a particular signal, a single merging unit supporting SV can deliver these signals to many devices using a single transducer lowering transducer, wiring, calibration, and maintenance costs.

- **Lower Commissioning Costs.** The cost to configure and commission devices is drastically reduced because IEC61850 devices do not require as much manual configuration as legacy devices. Client applications no longer need to be manually configured for each point they need to access because they can retrieve the points list directly from the device or import it via an SCL file. Many applications require nothing more than setting up a network address in order to establish communications. Most manual configuration is eliminated drastically reducing errors and rework.

- **Lower Equipment Migration Costs.** Because IEC61850 defines more of the externally visible aspects of the devices besides just the encoding of data on the wire, the cost for equipment migrations is minimized. Behavioural differences from one brand of device to another is minimized and, in some cases, completely eliminated. All devices share the same naming conventions minimizing the reconfiguration of client applications when those devices are changed.

- **Lower Extension Costs.** Because IEC61850 devices do not have to be configured to expose data, new extensions are easily added into the substation without having to reconfigure devices to expose data that was previously not accessed. Adding devices and applications into an existing IEC61850 system can be done with only a minimal impact, if any, on any of the existing equipment.

- **Lower Integration Costs.** By utilizing the same networking technology that is being widely used across the utility enterprise the cost to integrate substation data into the enterprise is substantially reduced. Rather than installing costly RTUs that have to be manually configured and maintained for each point of data needed in control centre and engineering office application, IEC61850 networks are capable of delivering data without separate communications front-ends or reconfiguring devices.

- **Implement New Capabilities.** The advanced services and unique features of IEC61850 enable new capabilities that are simply not possible with most legacy protocols. Wide area protection schemes that would normally be cost prohibitive become much more feasible. Because devices are already connected to the substation LAN, the incremental cost for accessing or sharing more device data becomes insignificant enabling new and innovative applications that would be too costly to produce otherwise.

Chapter 3

Protection Performance Study with Standard Protection Test Equipment

THIS chapter evaluates the performance of conventional protection system and IEC61850 based protection system using standard protection test equipment.

3.1 Introduction

The implementation of IEC61850 in the substation can be defined as partial, hybrid and complete. Partial implementation is defined as the case that the IED supports only station bus communications, while the analogue signals are based on conventional hard wiring. Hybrid implementation is the case that the IED has process and station bus interface, but the execution of the trip function is based on hard wires between the relay outputs and the breaker trip coil. Complete implementation means that the IED has communication based interface only. The difference between the complete implementation and the hybrid case is that tripping is achieved by a GOOSE message sent to the breaker control device that performs the actual breaker tripping [30], [31].

Before the design and evaluation of different process bus topologies, the basic performance of the IEDs needs to be tested and demonstrated. The results of these tests could be used as a benchmark for the future investigation.

In this chapter, the three different implementations of the IEC61850 based IEDs and the conventional hardwired protection relays are tested by using the commercial test set. For the relays with the IEC61850-9-2 SV interface, a simple star process bus topology is adopted as shown in Figure 3-1.

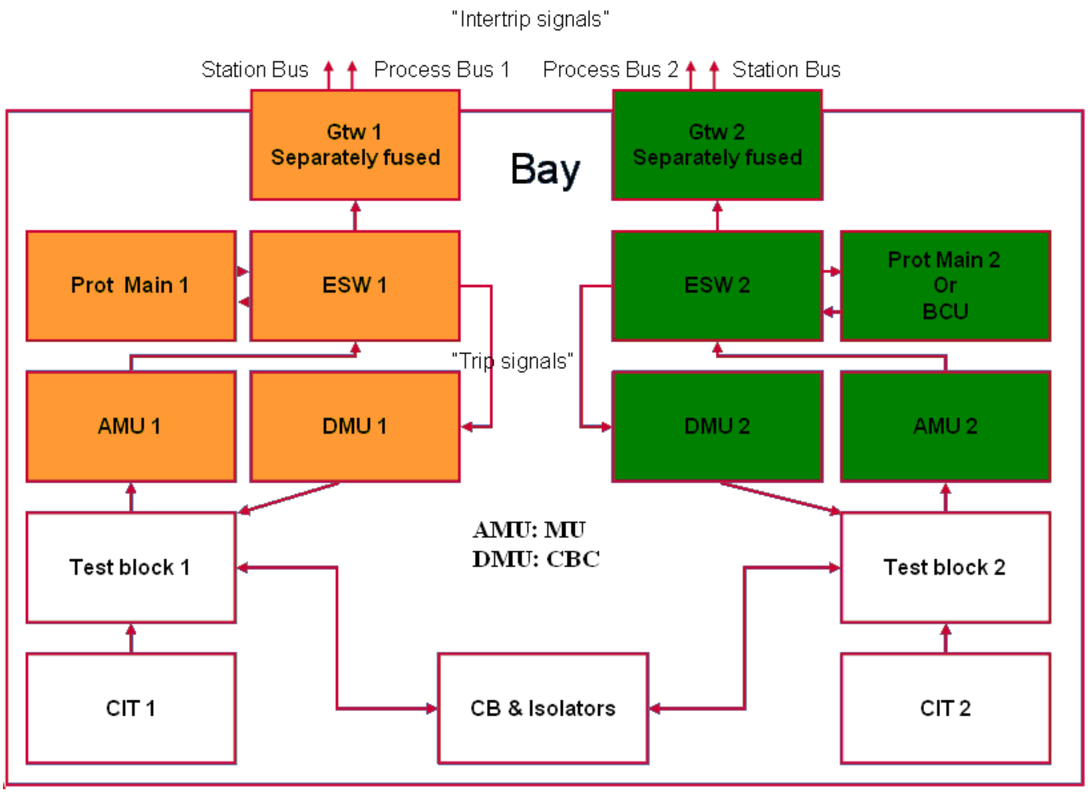

Figure 3-1 ALSTOM proposed process bus architecture

3.2 Commercial Test Set

Test sets used in such applications are required to have the functionality to perform coordinated and precisely synchronised tasks as a part of a distributed, system wide test facility.

The utilisation of system configuration information, the GOOSE mechanism, Sampled Values and Client/Server SCADA Communication introduce several new issues for testing the next generation of relays [32]. The most obvious change is the different way of wiring to obtain the signals. The availability of machine readable, system wide configuration information enables new, automated procedures for the configuration of tests.

The system configuration language implemented by IEC61850 standard defines a file format that describes the components of the substation and the protection and automation system in a way that allows most of the engineering tasks to be performed automatically.

The commercial test universe hardware and software used the OMICRON CMC 256+ as shown in Figure 3-2, are very well adopted in protection relays testing. It utilise the NetSim (Network Simulator) Software [32], which provides predefined Test Cases and Network Configurations to perform the tests. Standard network configurations with a simple parameter setup allow instant “click and run” simulations with signal outputs via the test set. Figure 3-3 shows the utilisation of system configuration information for testing a “stand-alone” relay.

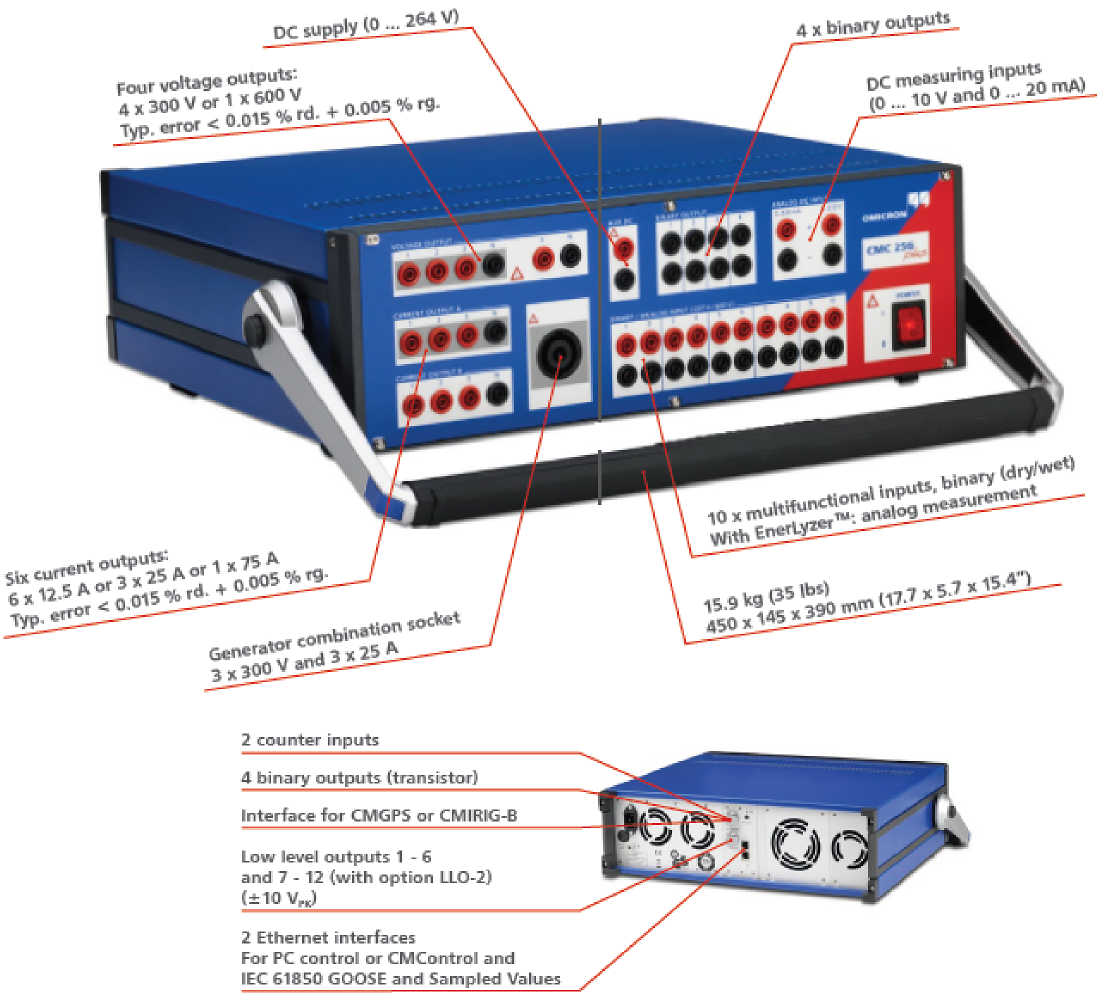

Figure 3-2 OMICRON CMC 256+ test set

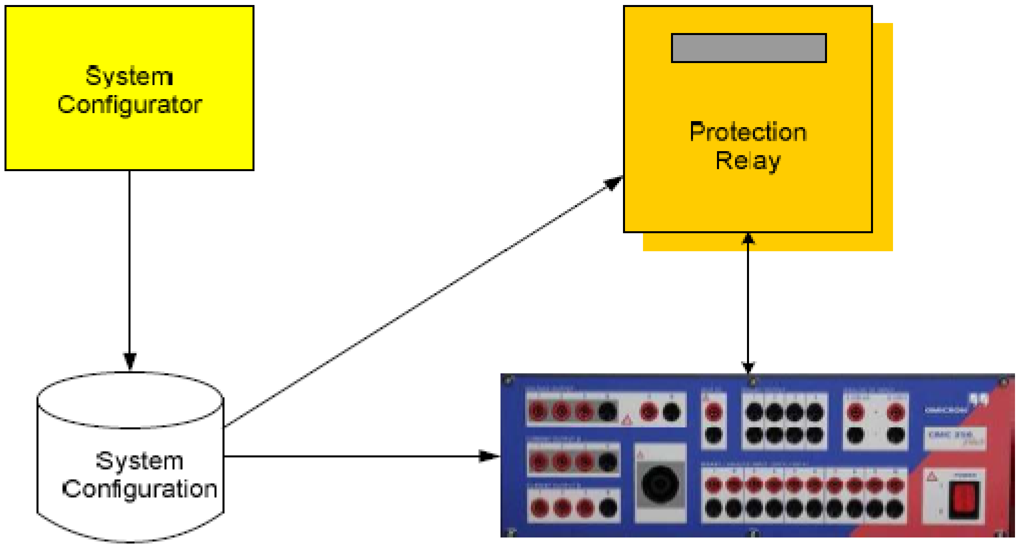

Figure 3-3 Usage of configuration information for testing

By “wiring” protective relays and test sets through the substation network, the test configuration is transformed into the networked world. Figure 3-4 shows a simplified, “fully-networked” protection testing layout based on a complete implementation of IEC61850.

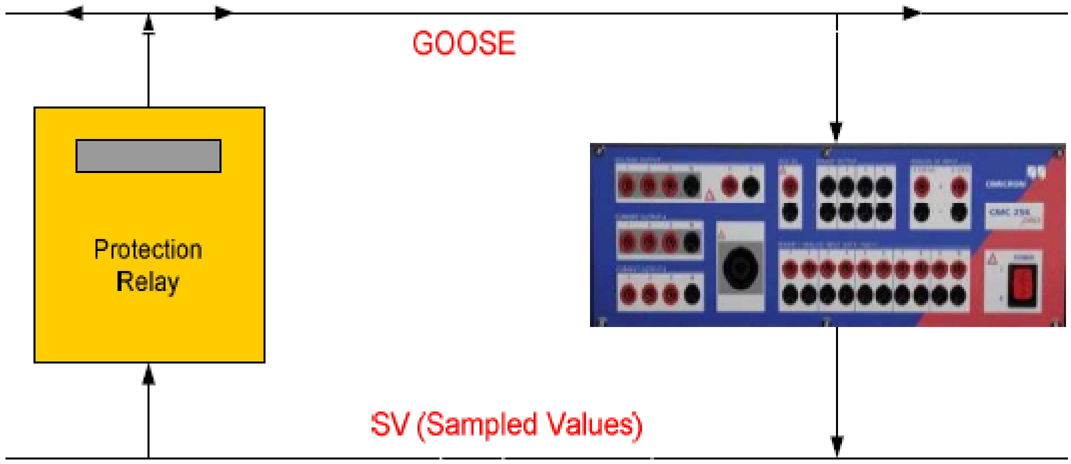

Figure 3-4 “Fully Networked” protection testing

The test equipment can be connected to the GOOSE massages and the feedback from and stimulus to the devices under test that was formerly exchanged via binary I/Os, can be established by wiring the test equipment to the substation network. This test equipment is able to simulate the merging units by generating Sampled Values and publishing them on the network to be subscribed by the devices under test.

This networked testing system is similar to the classical testing of protection functions. The protection functions of the relays still work in the same way. For example, testing a distance protection will be performed by using similar fault scenarios and assessment criteria as before. Many aspects of the test configuration can be efficiently supported by using the substation configuration information.

It is important that a test system preserves the working environment from classical testing and allows the re-use of existing test procedures for use with IEC61850.

In addition, the substation devices provide a lot of additional information to be used for SCADA purposes. With IEC61850, these data are all served in a standardised way. By using a generic tool that works with relays, additional status data (e.g. specific pick-up information) can be examined. This will provide extended depth of testing.

System tests were and are already performed to a certain extent. Prominent examples are the End-to-End tests for sophisticated line protection schemes. With the availability of substation wide configuration data, the feasibility of tests involving more devices is very much facilitated. Test with multiple points of test signal injection and measurement of response will become easier to implement in IEC61850 installations.

This chapter will focus on the testing of feeder protection schemes, the Feeder Local Panel (LB) and the Feeder Remote Panel (RB) is shown in Figure 3-5. The OMICRON CMC256+ test set provides analogue signals to remote hardwired relays and IEC61850 SVs signals to the local IEC61850 relays, as shown in Figure 3-6. The upper Local (LT) and Remote (RT) relays in the panels are configured as a Feeder Main-1 current differential scheme whilst the lower Local (LB) and Remote (RB) relays are configured as Feeder Main-2 distance scheme.

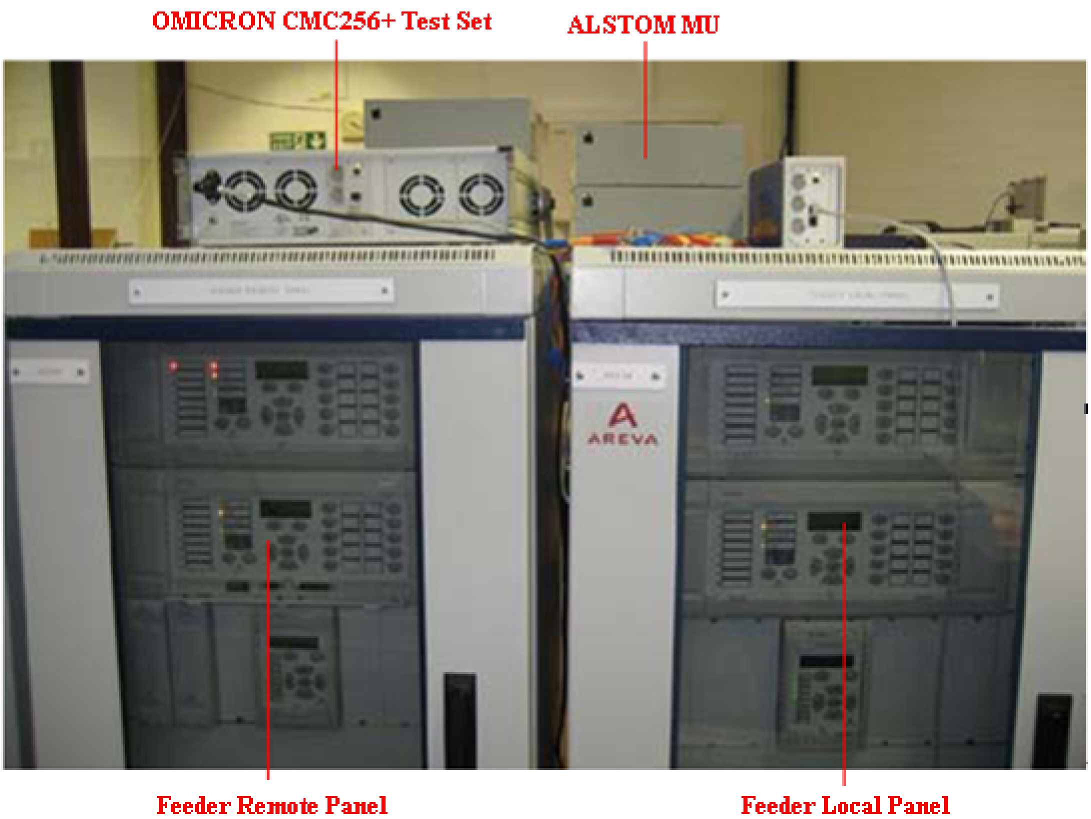

Figure 3-5 Feeder Local Panel (IEC61850) and Feeder Remote Panel (hardwired)

Figure 3-6 Test setup for feeder local and remote protection schemes

3.3 Distance Relay Test

The protection performance of RB conventional relay and LB IEC61850 based distance relay is demonstrated using the OMICRON CMC 256+ test set fitted with both conventional, current and voltage amplifiers, and IEC61850, Ethernet, SV outputs. The operating performance and characteristics of the RB hardwired relay are verified by injection with CMC 256+ test set applying analogue signals to the IED. The LB IEC61850 relay is injected with SVs also applied by the test set. Both relays have the IEC61850-8-1 interface, hence can be configured to send GOOSE trip message to the test set. The connections to the LT relay are shown in Figure 3-7.

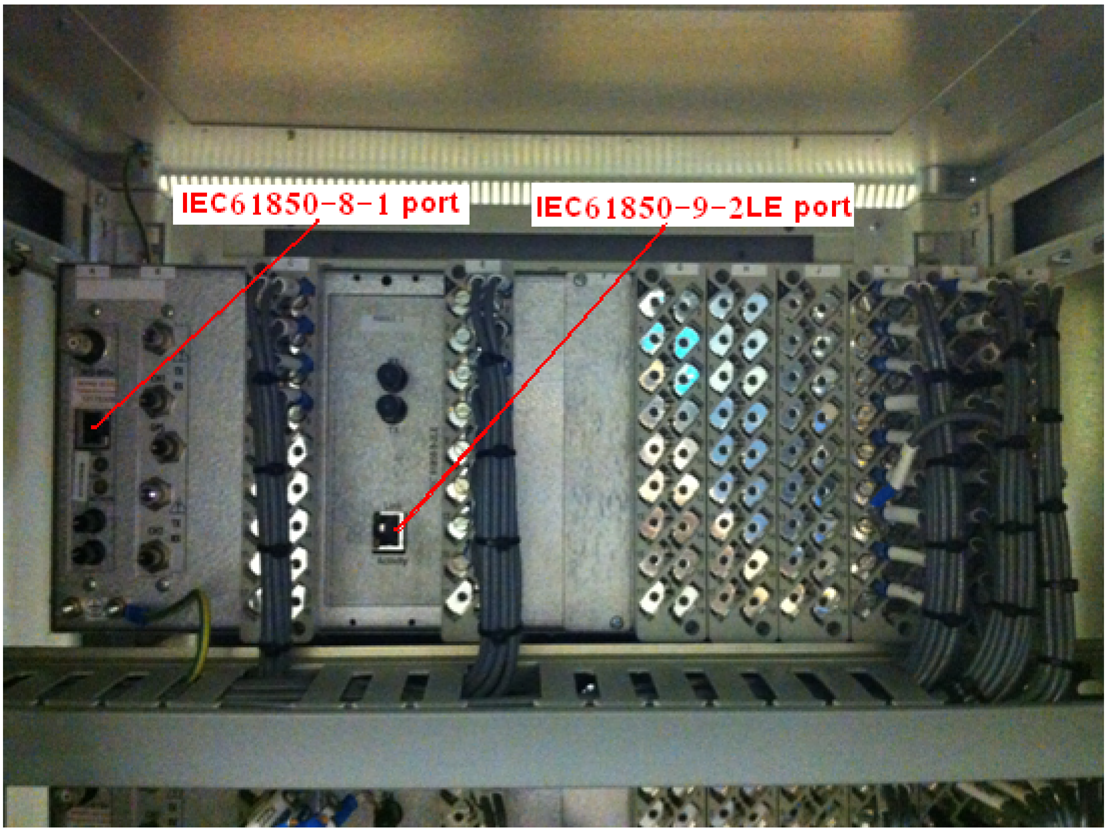

Figure 3-7 LT IEC61850 based distance relay rear view

Therefore, four different scenarios can be derived, which are:

- Scenario 1: Analogue input and Digital output – conventional hardwired;
- Scenario 2: SV input and Digital output - hybrid implementation of IEC61850;

- Scenario 3: Analogue input and GOOSE output – partial implementation of IEC61850;

- Scenario 4: SV input and GOOSE output – complete implementation of IEC61850.

In these scenarios, all the components (PC, OMICRON, RB and LB relay) are connected to central Ethernet switch with the standard 100/1000TX electrical cables with RJ45 connectors using a star process bus topology. The connection diagrams of the four scenarios are shown below.

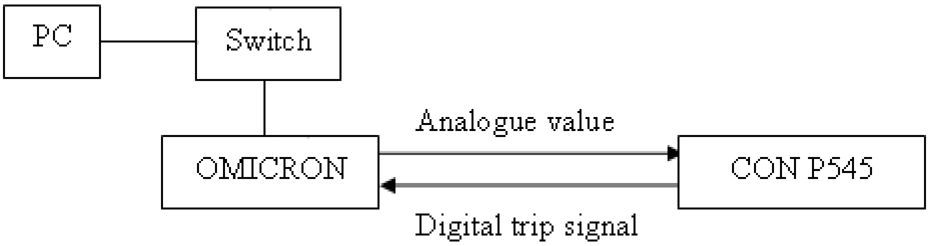

Figure 3-8 Connection diagram of scenario 1

In scenario 1, the CMC 256+ test set provides analogue signals to the conventional relay using the current and voltage amplifiers. The relay is configured to send digital trip signal to the test set. The CMC 256+ IEC61850 9-2LE interface card and a supervisory PC are connected to a central Ethernet switch.

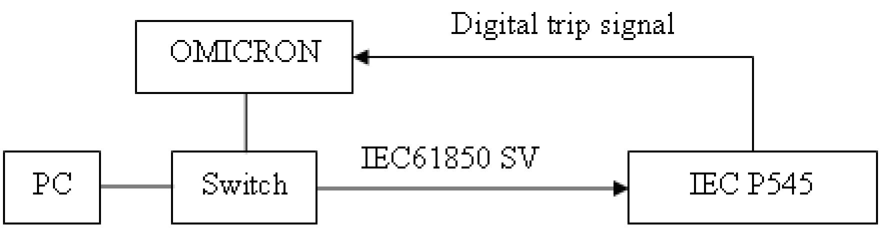

Figure 3-9 Connection diagram of scenario 2

In scenario 2, the CMC 256+ test set provides SVs to the IEC61850 relay using the IEC61850 9-2LE interface card. The relay is configured to send digital trip signal to the test set. The CMC 256+ IEC61850 9-2LE interface card and a supervisory PC are connected to a central Ethernet switch.

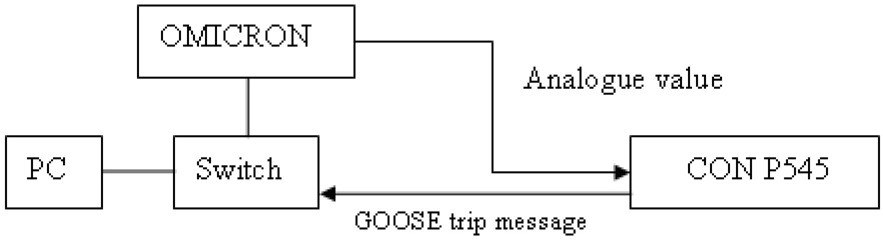

Figure 3-10 Connection diagram of scenario 3

In scenario 3, the CMC 256+ test set provides analogue signals to the conventional relay. The relay is configured to send GOOSE trip message to the test set. The CMC 256+ IEC61850 9-2LE interface card, the relay IEC61850-8-1 interface card and a supervisory PC are connected to a central Ethernet switch.

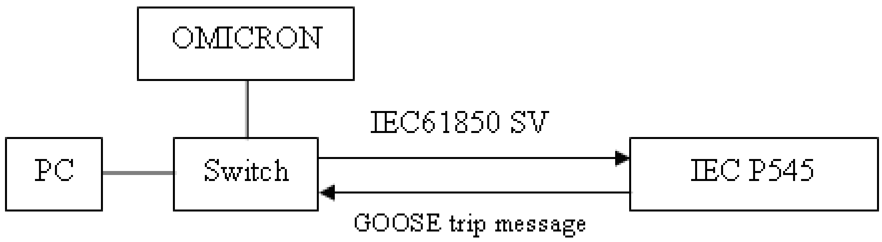

Figure 3-11 Connection diagram of scenario 4

In scenario 4, the CMC 256+ test set provides SVs to the IEC61850 relay. The relay is configured to send GOOSE trip message to the test set. The CMC 256+ IEC61850 9-2LE interface card, the relay IEC61850-9-2LE interface card, the relay IEC61850-8-1 interface card and a supervisory PC are connected to a central Ethernet switch.

The main parameters of the relays and are shown in Table 3-1.

Table 3-1 Parameters of the distance protection relays for OMICRON test

Item	Value
f nom	50.00 Hz
No. of phases	3
V primary	275.0 kV
V secondary	110.0 V
I primary	1.000 kA
I secondary	1.000 A
Z1 Ph. Reach	80 km
tZ1 Delay	0s
Z2 Ph. Reach	150 km
tZ2 Delay	200ms
Z3 Ph. Reach	250 km
tZ3 Delay	600ms
Line length	100.0 km
Line impedance	10 Ω
Line angle	70°
kZN residual comp	1
kZN residual angle	0°

Details of the faults used for the testing are shown in Table 3-2.

Table 3-2 Outline of distance relay test with OMICRON

Fault Type	Phase A to ground
Pre-fault Time	2s
Test Point	40 km, 115 km, 200 km.

"Shot, check and search" test is repeated 100 times on the each test point. The shot test locations are shown in Figure 3-12. Circle A, B, and C represents protection Zone 1, Zone 2, and Zone 3 respectively. The crosses are the fault locations which are all on angle (70°). The trip times of the relays are recorded as shown in Table Appendix-1

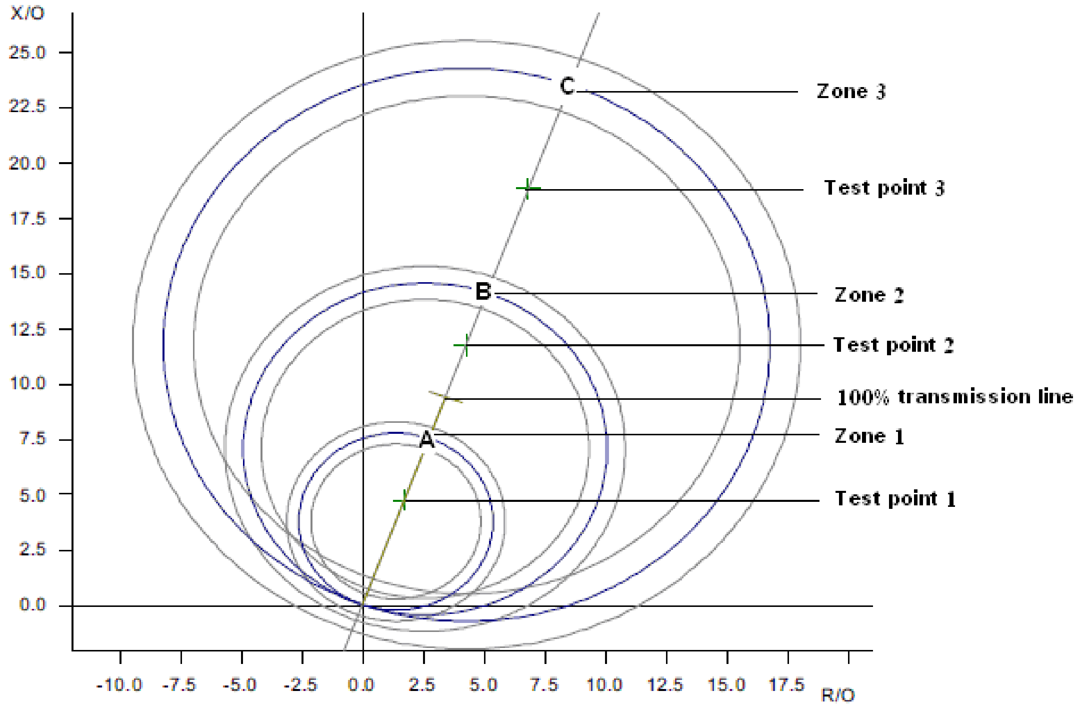

Figure 3-12 Short test for three different zones

The mean trip time (MTT) for each fault point is calculated as shown in the Table 3-3.

Table 3-3 The MTT for each test point

Fault Point	Scenario 1 MTT	Scenario 2 MTT	Scenario 3 MTT	Scenario 4 MTT
40 km	18.635 ms	19.1 ms	16.163 ms	17.29 ms
115 km	217.171 ms	218.076 ms	214.317 ms	215.096 ms
200 km	616.927 ms	617.829 ms	614.252 ms	615.059 ms

It can be observed from Table 3-3 that scenario 3 (Analogue input and GOOSE output) provides the shortest MTT of 16.163 ms, 214.317 ms and 614.252 ms respectively. Scenario 2 (SV input and Digital output) provides the longest MTT of 19.1 ms, 218.076 ms and 617.829 ms respectively.

Comparing scenario 1 (Analogue input and Digital out) with scenario 3 and scenario 2 with scenario 4 (SV input and Digital out), the GOOSE trip signal is about 2.685 ms faster than the digital trip signal on average, which indicates that the GOOSE message digitization process of the relay is faster than the digital trip signal processing.

Comparing scenario 1 with scenario 2 and scenario 3 with scenario 4, the analogue input is about 0.831 ms faster than the SV input on average. which will be further investigated in the next section.

In conclusion, the results indicate that the conventional and IEC61850 based distance protection relay have a similar performance and respond with similar tripping times.

3.4 Current Differential Relay Test

3.4.1 Introduction

The test set is configured to generate SV data stream for the LT IEC61850 based current different relay and an analogue signal for the RT conventional current differential relay. Since the analogue signals and the SVs signals are synchronized, phase offsets are due to the latency of the communication LAN and the digitizing process of the receiving IED.

Standard 100/1000TX electrical cables with RJ45 connectors are used to connect the LT and RT relay to the Ethernet communication networks. A fibre optic link is used for the communication between the two relays.

In the test, both relays are synchronized by the GPS synchronization unit. The synchronization technique will be described in the next section, and configured to send GOOSE trip signals and digital trip signals to the CMC 256+ test set interfaces. Therefore, the four scenarios can be tested in parallel. The connection diagram of the test system is illustrated in Figure 3-13.

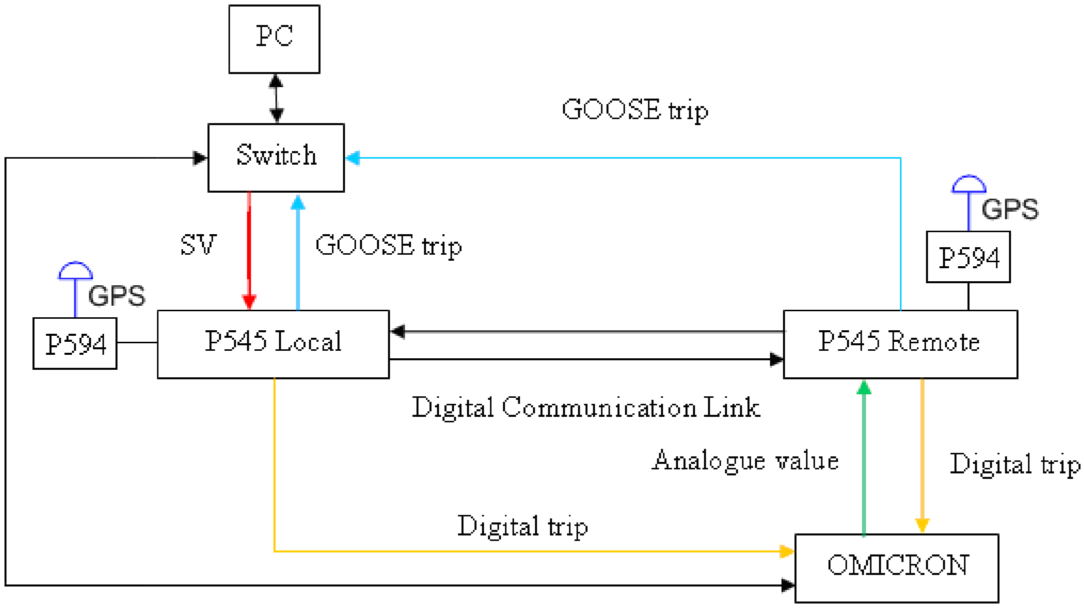

Figure 3-13 Connection diagram of current differential scheme test system

3.4.2 Time Alignment of Current Vector

A. Time alignment of current vectors without GPS input (Traditional Technique)

This section relates to the relay when the GPS synchronisation is not used.

To calculate differential current between line ends it is necessary that the current samples from each end are taken at the same moment in time. This can be achieved by time synchronising the sampling, or alternatively, by the continuous calculation of the propagation delay between line ends. The relay has adopted this second technique.

Consider a two-ended system as shown in Figure 3-14

Two identical relays, A and B are placed at the two ends of the line. Relay A samples its current signals at time tA1, tA2 etc., and relay B at time tB1, tB2 etc. Note that the sampling instants at the two ends will not, in general, be coincidental or of a fixed relationship, due to slight drifts in sampling frequencies [33].

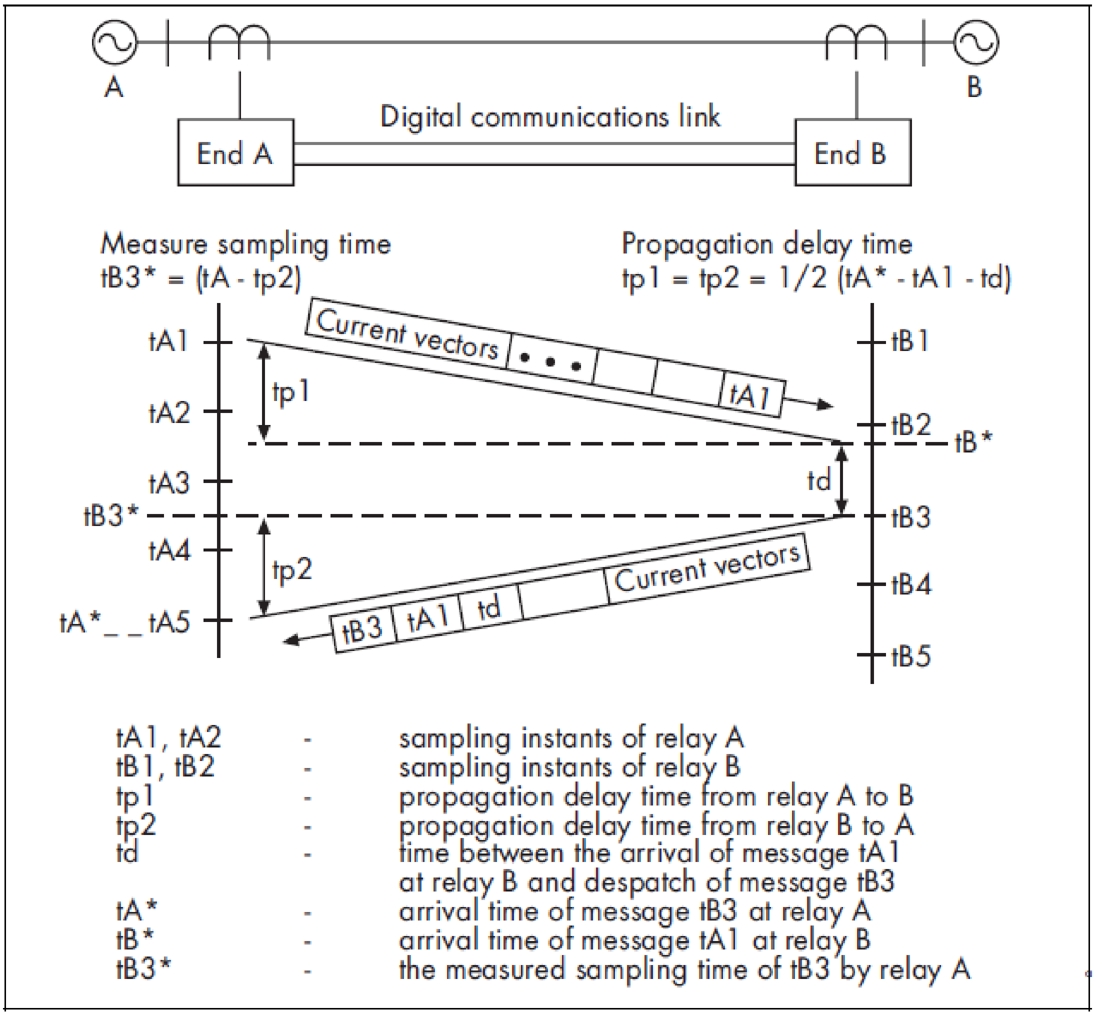

Figure 3-14 Propagation delay measurement

Assume that at time tA1, relay A sends a data message to relay B. The message contains a time tag, tA1, together with other timing and status information and the current vector values calculated at tA1. The message arrives at end B after a channel propagation delay time, tp1. Relay B registers the arrival time of the message as tB*.

Since relays A and B are identical, relay B also sends out data messages to end A. Assume relay B sends out a data message at tB3. The message therefore contains the time tag tB3. It also returns the last received time tag from relay A (i.e. tA1) and the delay time, td, between the arrival time of the received message, tB*, and the sampling time, tB3, i.e. td = (tB3 - tB*).

The message arrives at end A after a channel propagation delay time, tp2. Its arrival time is registered by relay A as tA*. From the returned time tag, tA1, relay A can measure the total elapsed time as (tA* - tA1). This equals the sum of the propagation delay times tp1, tp2 and the delay time td at end B.

Hence,

$$(tA^{*} - tA1) = (td + tp1 + tp2) \tag{3-1}$$

The relay assumes that the transmit and receive channels follow the same path and so have the same propagation delay time. This time can therefore be calculated as:

$$tp1 = tp2 = \tfrac{1}{2}(tA^{*} - tA1 - td) \tag{3-2}$$

Note that the propagation delay time is measured for each received sample and this can be used to monitor any change on the communication link.

As the propagation delay time has now been deduced, the sampling instant of the received data from relay B (tB3*) can be calculated. As shown in Figure 2, the sampling time tB3* is measured by relay A as:

$$tB3^{*} = (tA^{*} - tp2) \tag{3-3}$$

In Figure 2-13, tB3* is between tA3 and tA4. To calculate the differential and bias currents, the vector samples at each line end must correspond to the same point in time. It is necessary therefore to time align the received tB3* data to tA3 and tA4. This can be achieved by rotating the received current vector by an angle corresponding to the time difference between tB3* and tA3. For example a time difference of 1ms would require a vector rotation of 1/20 * 360° = 18° for a 50Hz system.

As two data samples can be compared with each data message, the process needs to be done only once every two samples, thus reducing the communication bandwidth required. Note that the current vectors of the three phases need to be time aligned separately.

B. Time alignment of current vectors with GPS input

The relay make use of the timing information available from the GPS system to overcome the limitation of the traditional technique, and thus allow application to communications that can provide a permanent or semi-permanent split path routing.

A 1 pulse per second output from a GPS receiver is used to ensure that the re-sampling of the currents at each relay occurs at the same instant in time. The technique is thus not dependant on equal transmit and receive propagation delay times; changes in one or both of the propagation delay times also do not cause problems.

The GPS technique is taken further, however, to overcome concerns about the reliability of the GPS system. Consider a similar two ended system to that of Figure 3-13 where the re-sampling instants (tAn, tBn) are synchronised using the GPS timing information. Note that Figure 3-15 demonstrates a case where the communications path propagation delay times are not the same.

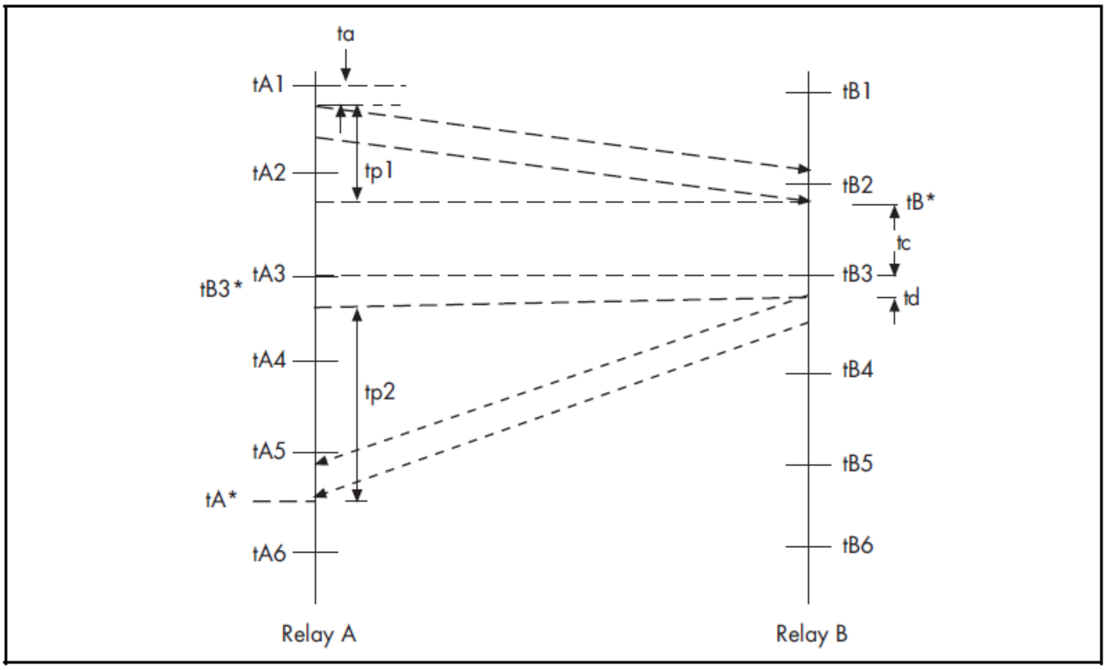

Figure 3-15 Data transmission

Relay A can measure the total elapsed time = (tA* - tA1). This equals the sum of the propagation delay times tp1 and tp2, the delay in sending out the initial message ta, and the delay time tc+td at end B.

Hence

$$tp1 + tp2 = tA^{*} - tA1 - ta - tc - td \tag{3-4}$$

However, because of the GPS synchronisation of the re-sampling instants, tA3 is at the same instant as tB3 (therefore tB3* = tA3). Using this knowledge, the receive path delay can be calculated.

$$tp2 = tA^{*} - tA3 - td \tag{3-5}$$

Using the same process, the relay can also calculate tp1.

In the event of the GPS synchronising signal becoming unavailable, the synchronisation of the re-sampling instants at the different ends will be lost and the sampling will become asynchronous. However, time alignment of the current data can still be performed, by measuring the total elapsed time (as per the traditional measurement technique) and using the memorised value of tp2 prior to the GPS outage. If the overall propagation delay sum of tp1 + tp2 has not changed significantly since the GPS synchronising signal became unavailable, then the communication path has not been switched and tp2 remains valid. This “fallback” strategy ensures protection continuity even in the event of antenna vandalism, maintenance error, extremely adverse atmospheric conditions etc – all of which could result in GPS outage. Note that tp1 and tp2 do not need to be equal for the fallback strategy to become operational [33].

3.4.3 Results and Discussion

If the manual adjustment of the delay compensation in the LT relay is disabled, then under the healthy system conditions, the observed results from the front LCD of the relays indicate that SV data stream is about 20° (1.11ms) lagging the hardwired analogue signal, which can result in a different current of 292A~338A. It proves the conclusion in the previous section that analogue input is faster than the SV input on average.

The OMICRON software SV scout is able to calculate the average time offset of the communication LAN. The transmission of the SVs from the CMC 256+ test set to the PC network card resulted in an average LAN latency of 80μs, which would mean a phase shift of less than 1.5°, as shown in figure 3-16. Subtracting the LAN latency, the time offset introduced by the IEC61850 9-2 digitization process of the protection IED is approximately 1ms, which results that the analogue input is faster than the SV input. As the operating time of a distance relay should be ≤20ms [33], considering the worst case which is scenario 2 in section 3.3, the SV input delay is tolerable.

The angle difference and differential current can be reduced significantly (2°, 20A) by applying manual compensation to LT relay.

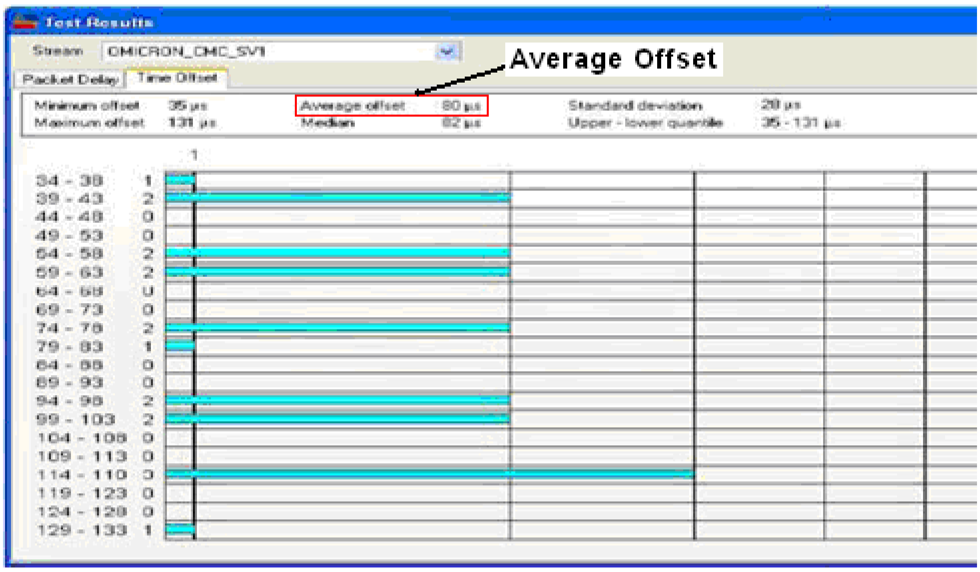

Figure 3-16 Time offset for direct connection to the network card

The tripping characteristics of the current differential protection scheme are shown in Figure 3-17.

The characteristic is determined by four protection settings:

Is1: The basic differential current setting which determines the minimum pick-up level of the relay.

k1: The lower percentage bias setting used when the bias current is below Is2 .This provides stability for small CT mismatches, whilst ensuring good sensitivity to resistive faults under heavy load conditions.

Is2: A bias current threshold setting, above which the higher percentage bias k2 is used.

k2: The higher percentage bias setting used to improve relay stability under heavy through fault current conditions.

The tripping criteria can be formulated as:

For $|Ibias| < Is2$ $$|Idiff| > k1 \cdot Ibias + Is1 \quad (3\text{-}6)$$

For $|Ibias| > Is2$ $$|Idiff| > k2 \cdot Ibias - (k2 - k1) \cdot Is2 + Is1 \quad (3\text{-}7)$$

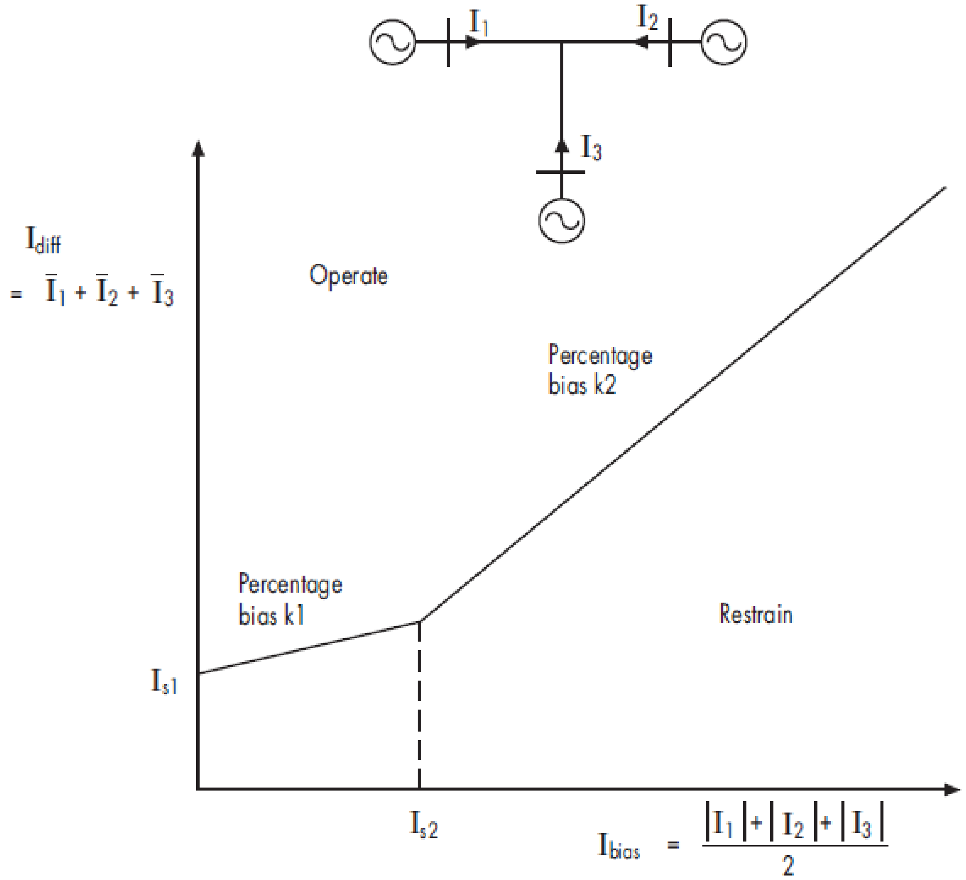

Figure 3-17 Current differential bias characteristic

The main parameters of the relay and are shown in Table 3-4.

Table 3-4 Parameters of the relay

Item	Value
f nom	50.00 Hz
No. of phases	3
V primary	275.0 kV
V secondary	110.0 V
I primary	1.000 kA
I secondary	1.000 A
Is1	200A
K1	30%
Is 2	2000A
K2	150%
Line length	100.0 km
Line impedance	10Ω
Line angle	70°
kZN residual comp	1
kZN residual angle	0°

Details of the faults used for the testing are shown in Table 3-5.

Table 3-5 Outline of current differential relay test

Fault Type	Phase A to ground
Pre-fault Time	2s
Test Point	I diff=1000A, I bias=1500A

The test is repeated 100 times. The trip time of the relays is recorded as shown in Table Appendix-2.

The MTT of the four scenarios is shown in Table 3-6 below.

Table 3-6 MTT of the four scenarios

Scenario No.	Scenario 1	Scenario 2	Scenario 3	Scenario 4
MTT	26.241 ms	25.921 ms	23.426 ms	23.587 ms

Similar as the distance relay test, it can be observed from Table 3-6 that scenario 3 (Analogue input and GOOSE output) provides the shortest MTT of 23.426 ms. Scenario 2 (SV input and Digital output) provides the longest MTT of 26.241 ms. signal.

Comparing scenario 1 (Analogue input and Digital out) with scenario 3 and scenario 2 with scenario 4 (SV input and Digital out), the GOOSE trip signal is about 2.575ms faster than the digital trip signal on the average.

Comparing scenario 1 with scenario 2 and scenario 3 with scenario 4, the latency of the analogue input is almost the same as the SV input, because of the manual compensation of the relays.

3.5 Conclusions

The results of the protection performance tests with the commercial test set indicate:

- The average latency of the communication LAN is 80μs. Star topology is adopted in the tests, hence the LAN latency may vary for different process bus topologies.

- The time offset introduced by IEC61850 9-2 digitization process of the protection IED is approximately 1ms. It results that the analogue input is faster than the SV input on average. As the operating time of a distance relay should be ≤20ms, considering the worst case which is scenario 2 in section 3.3, the SV input delay is tolerable.

- The GOOSE trip signal is about 2.6 ms faster than the digital trip signal on average, which indicates that the GOOSE message digitization process of the protection IED is faster than the digital trip signal processing.

In conclusion, the conventional and IEC61850 based relay have a similar performance and respond with similar tripping times. The results may be different if protection IEDs from different manufacturers are adopted.

Chapter 4

Reliability and Availability Analysis of Process Bus Topologies

THIS chapter describes three Ethernet switch based process bus topologies and compares the different process bus topologies in the light of the reliability and availability analysis.

4.1 Process Bus Configurations for IEC61850 Based Substation

In this chapter, three basic Ethernet LAN topologies are introduced, which will be applied in the following bay process bus design.

4.1.1 Cascaded Topology

A typical cascaded topology is illustrated in Figure 4-1. In this architecture, each Ethernet switch is connected to the previous switch and/or next switch in cascade via one of its ports. The maximum number of switches, which can be cascaded, depends on the worst case delay (latency) which can be tolerated by the system.

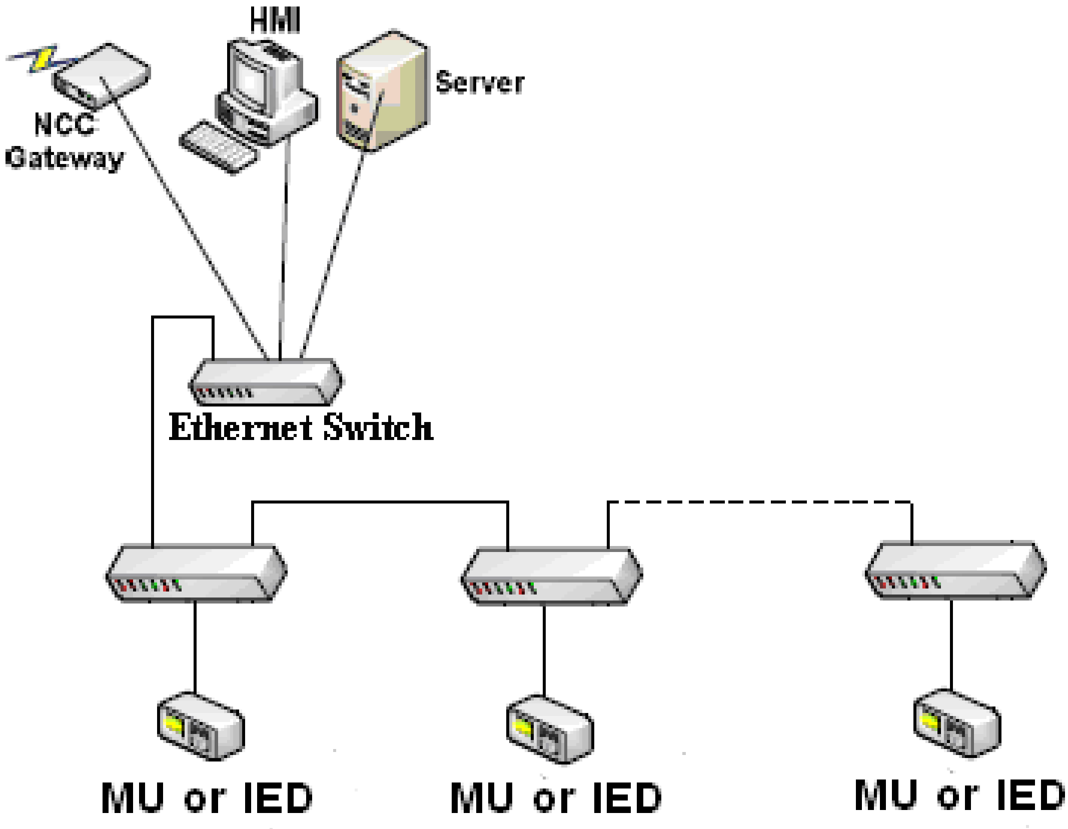

Figure 4-1 Cascaded topology

This architecture is simple and less expensive than others, however, the latency is generally higher.

4.1.2 Star Topology

In the star topology as shown in Figure 4-2, each component is directly connected to a common central node, a multiport Ethernet switch. The message transmission latency for Ethernet switch based star topology has capability to comply with the requirement of IEC61850. However, all IEDs in this architecture are connected to the single central Ethernet switch which produces an inherent weak point in the scheme.

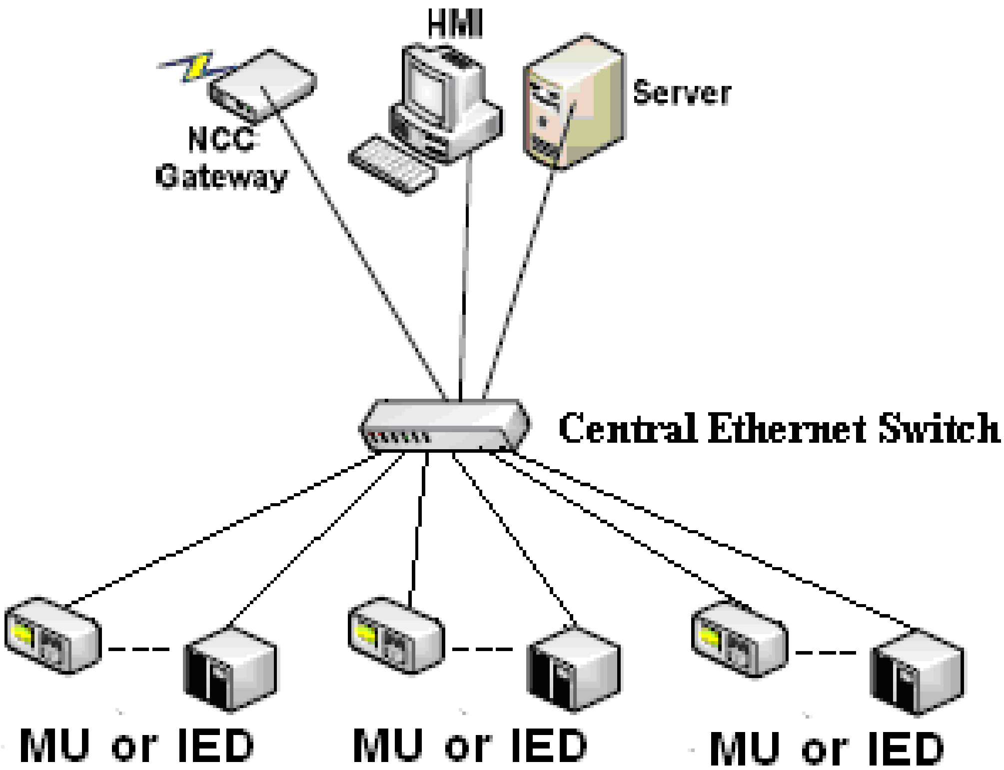

Figure 4-2 Star topology

4.1.3 Ring Topology

As show in Figure 4-3, the ring topology is very similar to cascaded topology except that the chain of switches is closed from the last switch to the first switch to form the ring. Standard Ethernet switches do not support “loops”, since messages could circulate indefinitely in a loop and use all the available bandwidth. Therefore, managed switches are required for this architecture [34].

Managed switches take into consideration the potential for loops and implement a Rapid Spanning Tree Protocol algorithm.

The Spanning Tree Protocol (STP) is a network protocol that ensures a loop-free topology for any bridged Ethernet local area network. The basic function of STP is to prevent bridge loops and the broadcast radiation that results from them. Spanning tree also allows a network design to include spare (redundant) links to provide automatic backup paths if an active link fails, without the danger of bridge loops, or the need for manual enabling/disabling of these backup links.

In 2001, the IEEE introduced Rapid Spanning Tree Protocol (RSTP) as IEEE 802.1w. RSTP provides significantly faster spanning tree convergence after a topology change, introducing new convergence behaviours and bridge port roles to do this. RSTP was designed to be backwards-compatible with standard STP [34].

While STP can take 30 to 50 seconds to respond to a topology change, RSTP is typically able to respond to changes within $3 \times$ Hello times or within a few milliseconds of a physical link failure. The so-called Hello time is an important and configurable time interval that is used by RSTP for several purposes; its default value is 2 seconds [35].

Standard IEEE 802.1D-2004 incorporates RSTP and obsoletes the original STP standard [36]. This protocol allows switches to detect loops and internally block messages from circulating in the loop. It also allows reconfiguration of the network following a communication network fault.

The advantage of the ring topology is that it has the potential to provide better availability because IEDs can still communicate even if any one of the ring connections and/or Ethernet switches fail. However, this architecture is more costly and complex when compared to the cascaded or star topology.

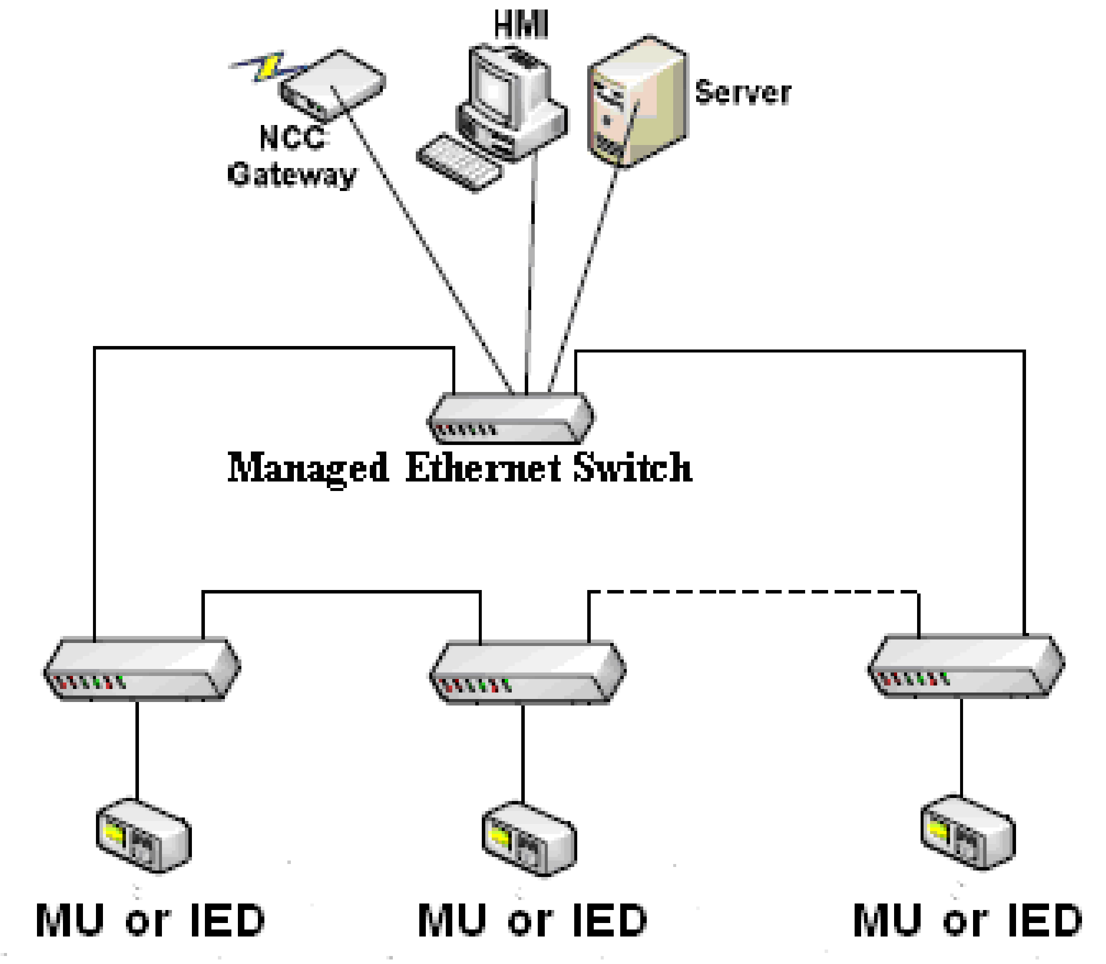

Figure 4-3 Ring topology

4.1.4 Time Synchronization of Merging Units

The merging units described in IEC61850 9-1 are used to digitize multiple analogue CT/VT output and multicast the sampled values to bay the level IEDs through the process bus. This stream of sampled values must be synchronized so that the protection function can use several streams from independent MUs. IEC61850 proposes the implementation of time synchronization on LAN using a Simple Network Time Protocol, SNTP [16].

SNTP is a less complicated version of Network Time Protocol (NTP) which is a networking protocol for clock synchronization between computer systems over packet-switched, variable-latency data networks. NTP can usually maintain time to within tens of milliseconds over the public Internet [37], and can achieve 1 ms accuracy in local area networks under ideal conditions [38].

When a better time synchronization is requied, the timing accuracy of 1 μs can be achieved using IRIG-B synchronization signal in compliance with IEEE 1588.

The Precision Time Protocol (PTP) described in IEEE 1588 is a protocol used to synchronize clocks throughout a computer network. On a local area network it achieves clock accuracy in the sub-microsecond range, making it suitable for measurement and control systems [37].

Therefore, an external time synchronization source is assumed to be connected to the MUs for the reliability calculations in all the process bus topologies.

4.2 Reliability and Availability Analysis of Process Bus Topologies

4.2.1 Device Reliability and Availability

The failure rate "λ" of electronic components is assumed to remain constant during normal operating period, therefore exponential distribution is valid for the reliability and availability analysis of IEC61850 based SAS devices [38] [39] [40] [41]. The equations that estimate device reliability and availability are shown below.

$$R(t) = e^{-\lambda t} \tag{4-1}$$

$$MTTF = \int_0^\infty R(t)dt = \frac{1}{\lambda} \tag{4-2}$$

$$A = \frac{MTTF}{MTTF + MTTR} \tag{4-3}$$

where:

R is the reliability function

t is the period under consideration (years)

A is the device availability

MTTF is mean time to failure (years), the mean value of exponential distribution. It will be used to represent device reliability in this paper

MTTR is mean time to repair. It is the time taken to detect and repair each failure.

4.2.2 System MTTF and Availability using Reliability Block Diagram

The Reliability Block Diagram, RBD, for each configuration shows the logical connection of functioning components needed to fulfil a specific system function [42] [43] [44] [45].

From the reliability point of view, components are connected in series if they all must work for the successful functioning of the system and only one component needs to fail for the system failure as shown in Figure 4-4.

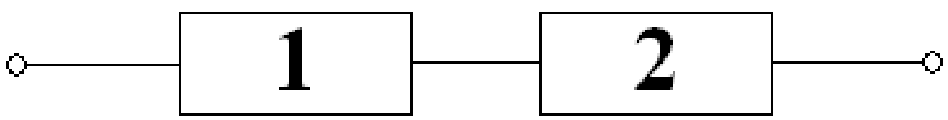

Figure 4-4Series system with two components

The reliability function of the series system is

$$R_s = R_1(t)R_2(t) = e^{-(\lambda_1+\lambda_2)t} \tag{4-4}$$

Therefore the MTTF of the series system is

$$MTTF_s = \int_0^\infty R_s(t)dt = \frac{1}{\lambda_1+\lambda_2} = \frac{MTTF_1 \cdot MTTF_2}{MTTF_1 + MTTF_2} \tag{4-5}$$

The availability of the series system is

$$A_s = A_1 \cdot A_2 \tag{4-6}$$

In contrast, if only one needs to be working for successful functioning of the system or all must fail for system failure, components are connected in parallel from the reliability assessment as shown in Figure 4-5.

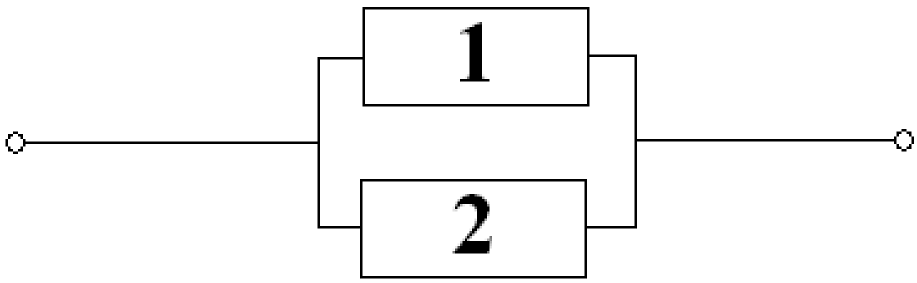

Figure 4-5 Parallel system with two components

The reliability function of the parallel system is

$$\begin{aligned} R_p(t) &= R_1(t) + R_2(t) - R_1(t)R_2(t) \\ &= e^{-\lambda_1 t} + e^{-\lambda_2 t} - e^{-(\lambda_1+\lambda_2)t} \end{aligned} \tag{4-7}$$

Therefore the MTTF of the parallel system is

$$\begin{aligned} MTTP_p &= \int_0^\infty R_p(t)dt = \frac{1}{\lambda_1} + \frac{1}{\lambda_2} - \frac{1}{\lambda_1+\lambda_2} \\ &= MTTF_1 + MTTF_2 - \frac{MTTF_1 \cdot MTTF_2}{MTTF_1 + MTTF_2} \end{aligned} \tag{4-8}$$

The availability of the parallel system is

$$A_s = A_1 + A_2 - A_1 \cdot A_2 \tag{4-9}$$

4.2.3 Feeder Bay Study

The particular interest in this project has been the reliability and availability of a typical transmission substation feeder bay. The mean time to failure and the availability for a test system were calculated using above methodology.

The feeder bay is considered to use a dual main scheme with MAIN 1 and MAIN 2 protection IEDs. Each protection IED has separate MUs and circuit breaker control IEDs.

The MTTF and availability values for the reliability calculations are tabulated in Table 4-1 [47] [48] [49]. These MTTF and availability values for the components have been derived from industry norms and provide a basis for the subsequent calculations. They are not based on the analysis of any specific equipment.

Table 4-1 MTTF and availability considered for each component

SAS component	MTTF (years)	Availability
Protection IED	16	0.999660016
Control IED	16	0.999660016
MU	16	0.999660016
Ethernet Switch	62.5	0.999912337
TS	16	0.999660016

The basic assumption is that failure modes are independent from each other. Generally, the MTTF value of the communication links is considered to be high enough to be ignored in the calculation [50] [51] [52]. A MTTR of 48 hours is used in the availablity calculation [53] [54] [55]. The MTTF and availability values of the principal components used in the reliability calculation of different process bus topologies are shown in Table 4-1.

4.2.4 MTTF and Availability for Cascaded Topology

In this architecture, each IED has a single Ethernet switch, and a time synchronization unit is connected to the MU directly. The communication architecture of feeder bay is shown in Figure 4-6.

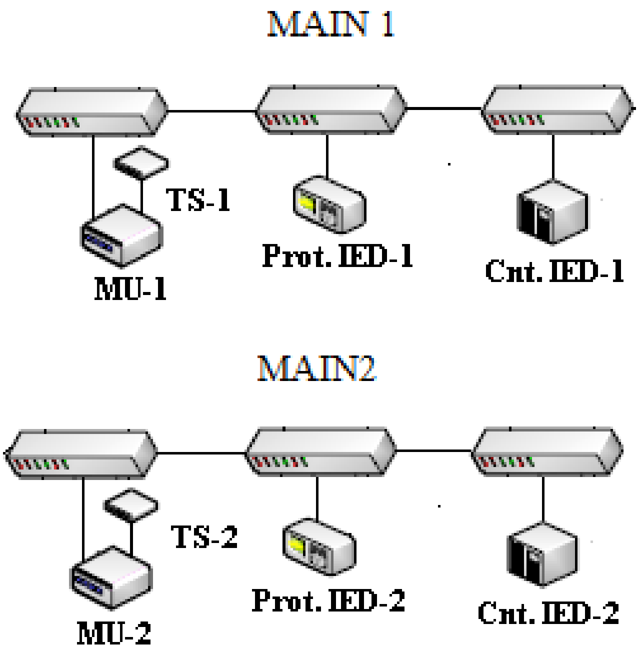

Figure 4-6 Cascaded topology for feeder bay

In the protection scheme, there are MAIN 1 and MAIN 2 protections which are independent. Both schemes provide a trip instruction to the breaker. Take MAIN 1 protection for example; the dedicated Protection IED-1, control IED-1, MU-1 and three Ethernet switches are connected in series in reliability block diagram. Either MAIN 1 and MAIN 2 are required to be healthy to maintain the feeder protection function, therefore MAIN 1 and MAIN 2 are connected in parallel in the RBD for MTTF and availability calculation as shown in Figure 4-7.

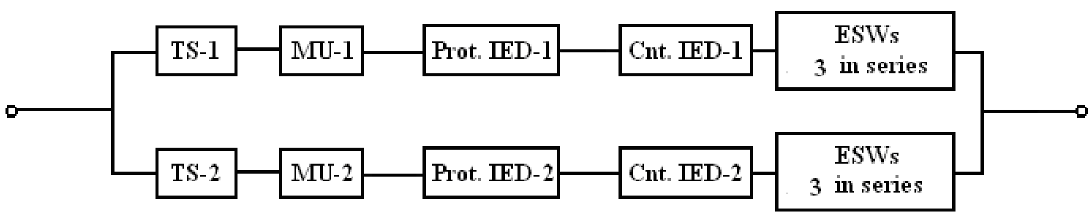

Figure 4-7 RBD of MTTF and availability calculation for cascaded topology

Using the data in Table 3-1, the results of MTTF and availability calculation for the cascade configuration are $MTTF_{cascade}$ is 5.034 years and the $A_{cascade}$ is 0.999997369.

4.2.5 MTTF and Availability for Star Topology

In the star topology, all the IEDs are connected to a central Ethernet switch. The two schemes, Main 1 and Main 2 monitor the power system and provide trip instructions to the circuit breaker. The communication architecture of feeder bay is shown in Figure 4-8.

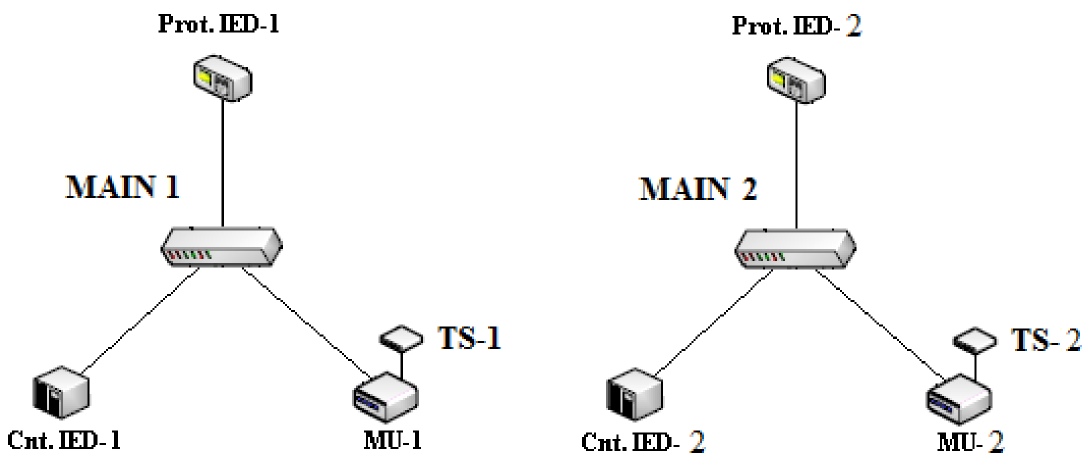

Figure 4-8 Star topology for feeder bay

For the analysis of cascaded topology, the reliability block diagram of star topology is shown in Figure 4-9.

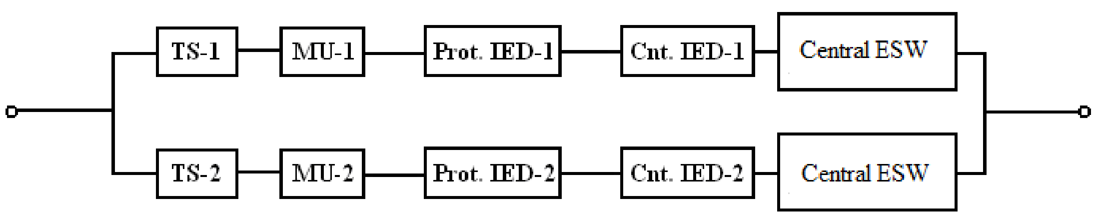

Figure 4-9 RBD of MTTF and availability calculation for star topology

The results of MTTF and availability calculation for the star configuration are $MTTF_{star}$ is 5.639 years and the A_{star} is 0.999997907.

4.2.6 MTTF and Availability for Ring Topology

In the ring topology, each set of IEDs is connected to a single managed Ethernet switch, and all the Ethernet switches in the scheme are connected in a loop, as shown in Figure 4-10. Main 1 and Main 2 have separate loops, and both provide a tripping instruction to the circuit breaker.

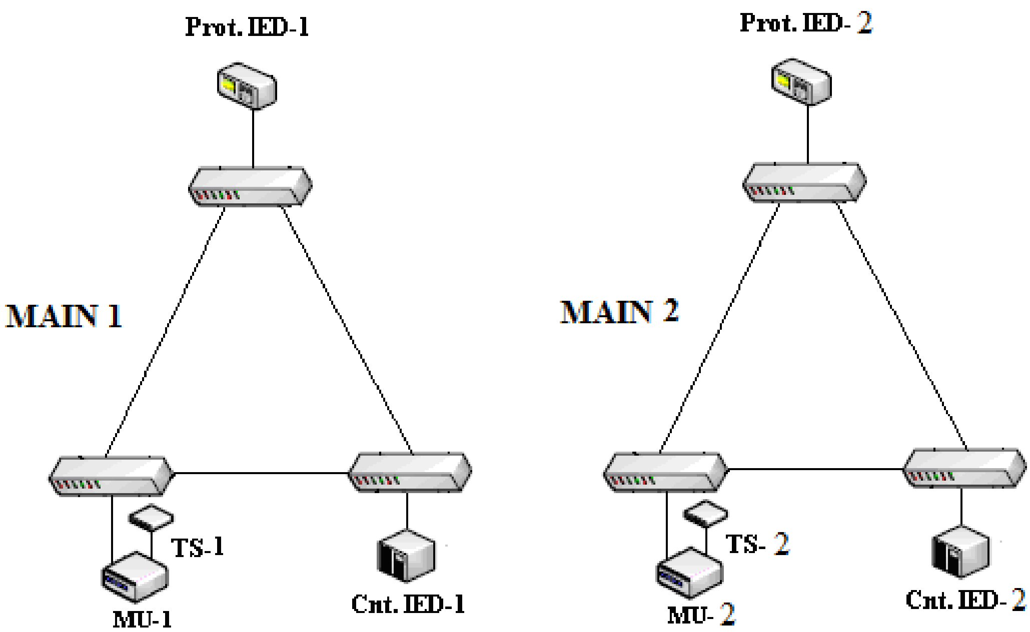

Figure 4-10 Ring topology for feeder bay

The reliability block diagram for ring communication network is similar to that for the cascaded topology. The RBD for the ring scheme are shown in Figure 4-11.

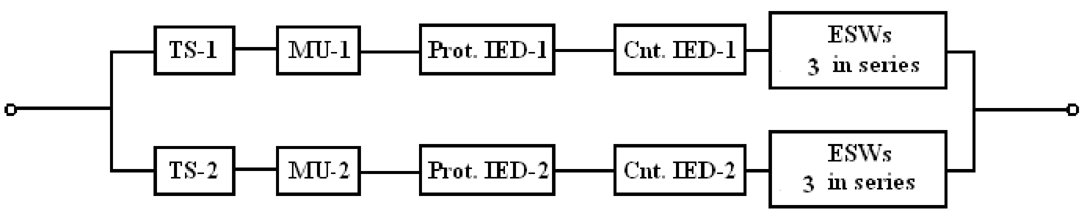

Figure 4-11 RBD of MTTF and availability calculation for ring topology

The additional feature of the ring topology is that with the help of the RSTP within the managed Ethernet switch, the communication network can be reconfigured in case any communication cable which is used to connect the Ethernet switches in the scheme fails. This means the faulted scheme will still be functional after the failure.

Therefore, single failure of the communication cable will not influence the MTTF of the protection system.

The results of MTTF and availability calculation for the first failure of the ring configuration are $MTTF_{ring}$ is 5.034 years and the A_{ring} is 0.999997369.

For the protection application, it is questionable whether the scheme should remain operational after a first failure event and therefore whether it should be taken out of service whenever a failure occurs. Using a dual main configuration, should either Main 1 or Main 2 suffer a failure, the other scheme will provide viable protection.

The MTTF and availability of different process bus topologies are summarized in Table 4-2.

Table 4-2 MTTF and availability of different process bus topologies

Process bus topology	MTTF (years)	Availability
Cascaded	5.034	0.999997369
Star	5.639	0.999997907
Ring (first failure)	5.034	0.999997369

It can be observed from Table 4-2 star topology provides the highest MTTF of 5.639 years and the highest availability of 0.999997907. This architecture has the weakness that the failure of the central Ethernet switch will lead the entire communication system collapse. Cascaded topology provides the MTTF of 5.034 years and the availability of 0.999997369. If the MTTF of the communication links is ignored in the calculation, ring topology provides the same MTTF and availability as cascaded topology. However, ring topology requires managed Ethernet switches with RSTP, which makes this architecture more expensive and complicated comparatively.

Chapter 5

Modelling and Simulation for Performance Evaluation of Process Bus Topologies

THIS chapter evaluates the performance of SV messages over three Ethernet switch based process bus topologies by using OPNET communication network simulation tool.

5.1 Introduction

In this chapter, the latency of the SV messages transmission over the three Ethernet switch based process bus topologies, cascaded, star and ring topology, is evaluated in terms of the communication volume, by using the OPNET Modeller which is a network modelling and simulation tool [56].

OPNET Modeller is capable of accelerating the R&D process for analyzing and designing communication networks, devices, protocols, and applications. It allows users to analyze simulated networks to compare the impact of different technology designs on end-to-end behaviour. The Modeller incorporates a broad suite of protocols and technologies, and includes a development environment to enable modelling of all network types and technologies including [57] [58]:

- VoIP
- TCP
- OSPFv3
- IPv6
- Others

Key features of OPNET Modeller:

- Fastest discrete event simulation engine among leading industry solutions
- Hundreds of protocol and vendor device models with source code are contained in the complete OPNET Model Library
- Object-oriented modelling
- Hierarchical modelling environment
- Discrete Event, Hybrid, and optional Analytical simulation

- 32-bit and 64-bit fully parallel simulation kernel
- Grid computing support for distributed simulation
- Optional System-in-the-Loop to interface simulations with live systems
- Realistic Application Modelling and Analysis
- Open interface for integrating external object files, libraries, and other simulators
- Integrated, GUI-based debugging and analysis

5.2 Building of IED Models

Three types of generic IEDs are modelled for this performance study, which are circuit breaker Controller (CBC), merging unit (MU), and combined protection & control (P&C) IED [59] [60] [61]. In the SAS, those IEDs provide the following general functions. The MU processes and combines the signal from field CT and VT. Then it transmits the digital voltage and current output to the process bus. The CBC, which not only controls the breaker's open/close but also monitors the state and condition of the circuit breaker, receives the trip/close command from the P&C IEDs and sends state change event to corresponding protection IEDs also through the process bus. The P&C IED, a universal device, integrates the protection and control functionalities for the bay unit in the substation [62] [63] [64]. The above unit models are constructed on OPNET Modeller, and the modelling work are shown below.

5.2.1 Modelling of MU

The modelling of merging unit is based on IEC61850 9-1. The Ethernet broadcast address is used as a default destination address although this model also supports unicast and multicast. The user could configure the sample rate, start time, stop time, packet size, address, and multicast group address if multicast is used as the transmission type. The communication stack for merging unit IED is very simple. It contains an application layer, Ethernet layer, and physical layer. Figure 5-1 shows the node model configuration of MU. The small squares in the model represent the process models. OPNET Modeller has the Node Model Editor and Process Model Editor which facilitate the model design.

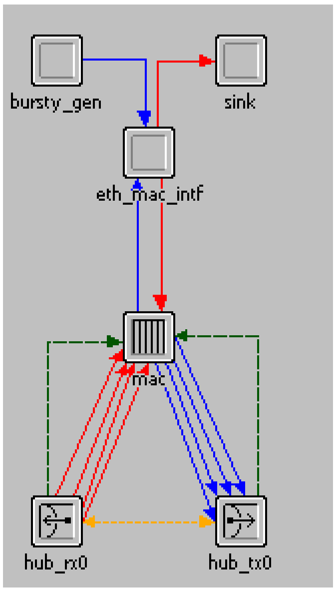

Figure 5-1 MU model configuration [56]

The bursty_gen module represents higher layer users who submit data for transmission. It uses an ON-OFF pattern for traffic generation.

The sink processor represents higher layers and simply accepts incoming packets that have been processed through the mac (medium access control) process.

The hub_rx0 and hub_tx0 modules serve as the process bus link interface. These modules are set to transmit and receive at a data rate of 100 Mbits/second.

The mac process handles both incoming and outgoing packets. Incoming packets are decapsulated from their Ethernet frames and delivered to a higher level process. Outgoing packets are encapsulated within Ethernet frames and when the deference flag goes low, a frame is sent to the transmitter. This process also monitors for collisions, and if one occurs, the transmission is appropriately terminated and rescheduled for a later attempt.

There is only one way of connecting this MU IED to P&C IEDs, which is through the process bus[65] [66] [67]. In the simulation, MU is connected with P&C IEDs directly using Ethernet switch, which will only use one communication port of the MU.

The application layer includes the bursty_gen which generates Ether-type protocol data unit (PDU) as shown in Figure 5-2 at a configurable sampling rate. This PDU contains an application protocol data unit (APDU) which may contain number of ASDUs [66] [68] [69]. Each ASDU again contain four current values and four voltage values as specified in the standard.

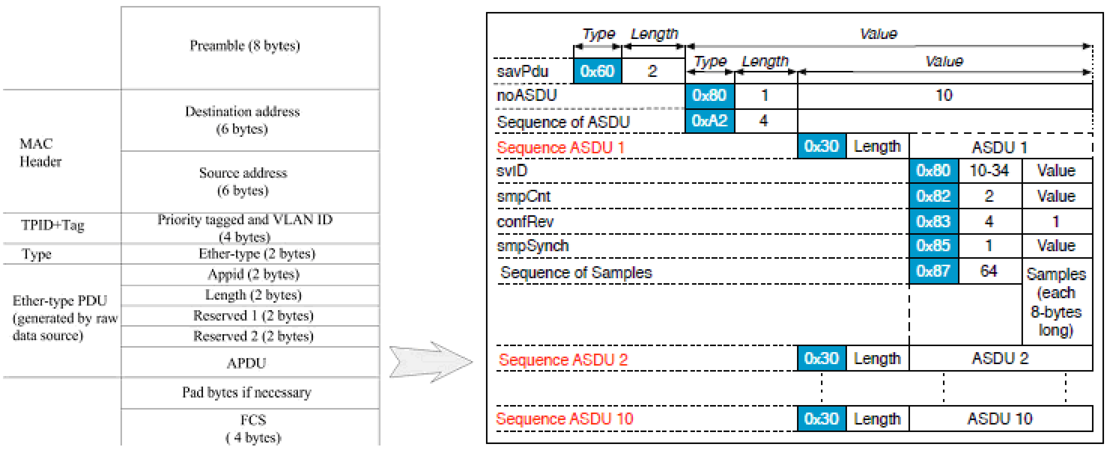

Figure 5-2 Raw data sample Ethernet frame

The Ethernet layer consists of the eth_mac_intf and mac modules. The Ethernet protocols and algorithms are implemented in those modules. The Ether-type APDU passed from the application layer are addressed, priority tagged according to IEEE 802.1Q [70] [71]. The priority tagging allows to separate time critical messages from low time requirement busload. The raw data messages should be tagged with high priority.

The physical layer allows connecting this IED to a process bus using 10 Mb/s, 100Mb/s, 1 Gb/s or 10 Gb/s link depending on the type of transmitters and receivers this module uses.

5.2.2 Modelling of CBC and P&C IED

The functionalities of P&C IED is to receive the SV messages from the MU, send GOOSE trip messages to CBC, and calculate the end-to-end (ETE) delay. ETE delay is the time between the creation of the message at the application layer of the sending unit and the arrival of the message at the receiving unit's application layer. The CBC is to receive the GOOSE trip message, send multicast GOOSE state event to other P&C IEDs. The size of the GOOSE is smaller than the SV message, and the number of messages per second is lower. At 100 Mbps, GOOSE messages do not normally play a crucial role in the overall network load. In the simulation, only the performance of the transmission of SV messages is evaluated, therefore it has been assumed that there are no GOOSE messages in the process bus.

5.3 Feeder Bay Study

The process bus performance of the MAIN protection for the three process bus topologies as described in chapter 4 of a typical transmission substation feeder bay is evaluated. The sampled value packet ETE delay is simulated by applying the cascaded, star and ring process bus topology respectively.

In the cascaded topology model as shown in Figure 5-3, each component, MU, P&C IED and CBC, is connected to its own Ethernet switch and these are connected in a chain. The model is built on a $10\text{m} \times 10\text{m}$ zone as the numbers indicate in the diagram. In this model, the P&C IED subscribes the SVs published by the MU, the CBC can be configured to send GOOSE messages to the P&C IED, and generic Ethernet switch models which support RSTP are used to represent the switches in this network.

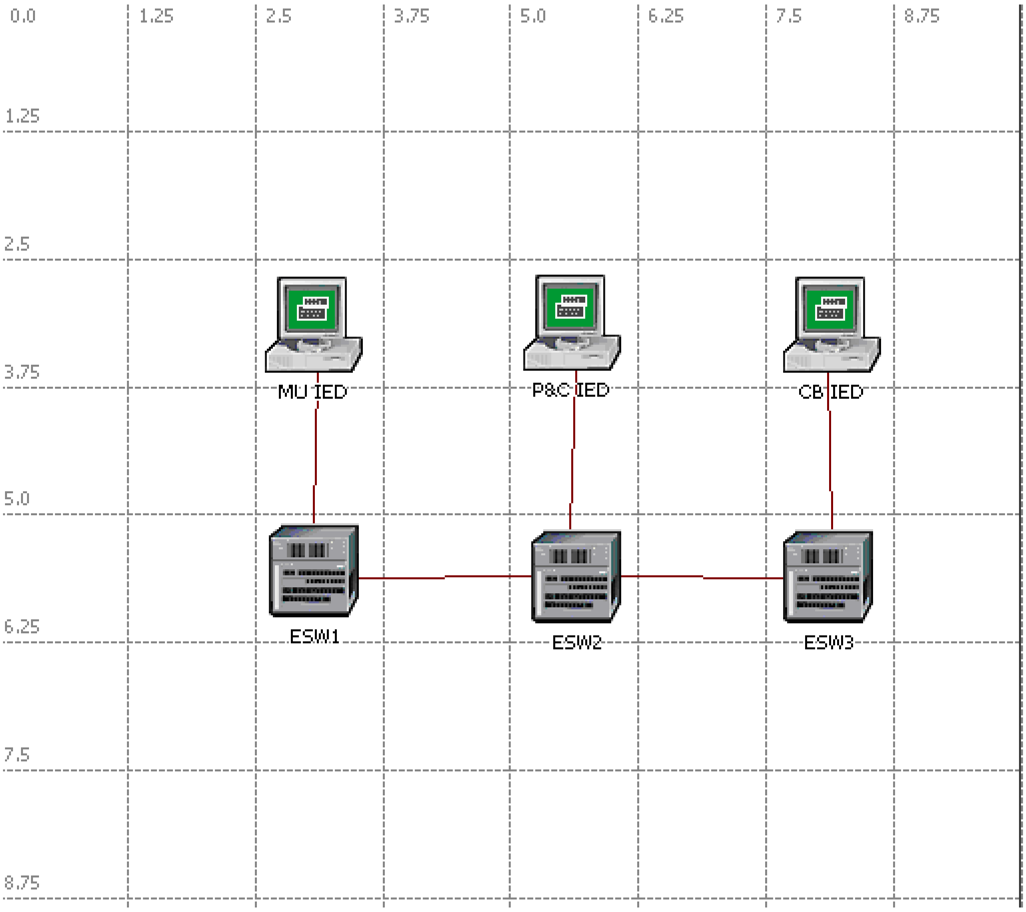

Figure 5-3 Cascaded topology model for feeder bay

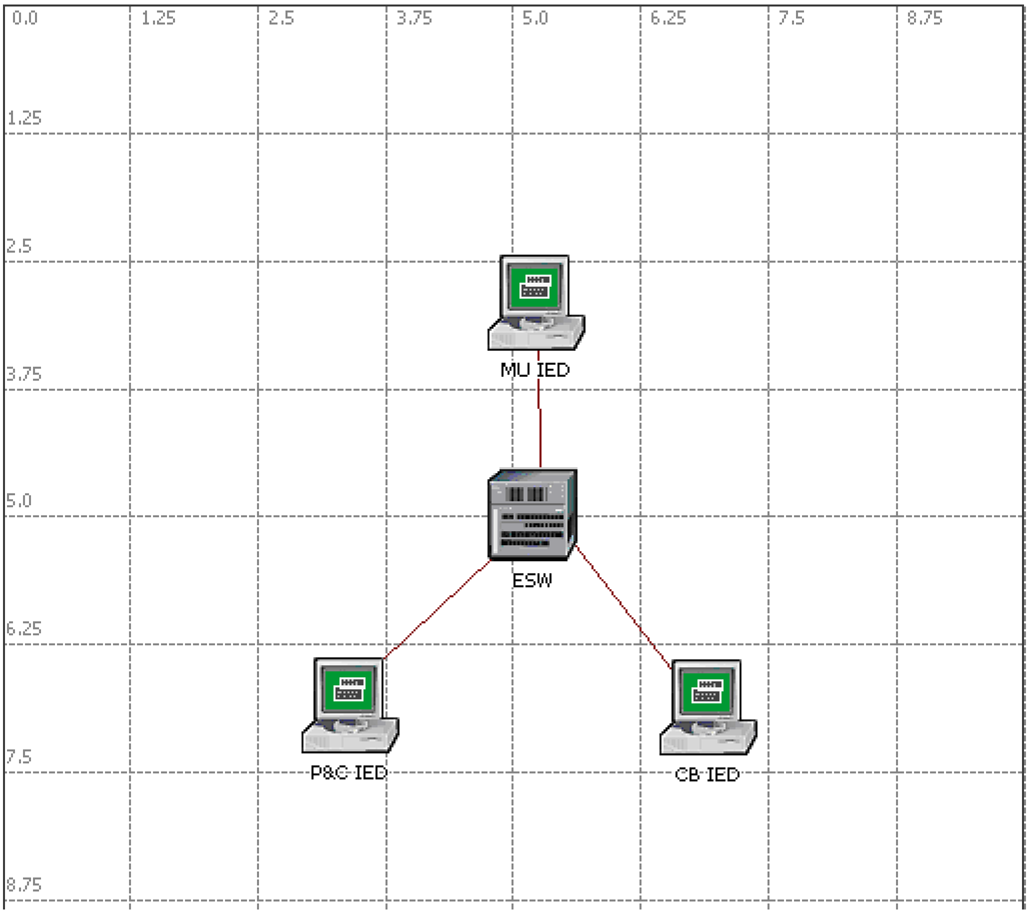

Figure 5-4 Star topology model for feeder bay

In the star topology model as shown in Figure 5-4, all the components, MU, P&C IED and CBC, are connected to a central Ethernet switch.

In the ring topology model as shown in Figure 5-5, as with the cascade topology model, each component, MU, P&C IED and CBC, is connected to a single Ethernet switch, but the chain is then connected to form a ring.

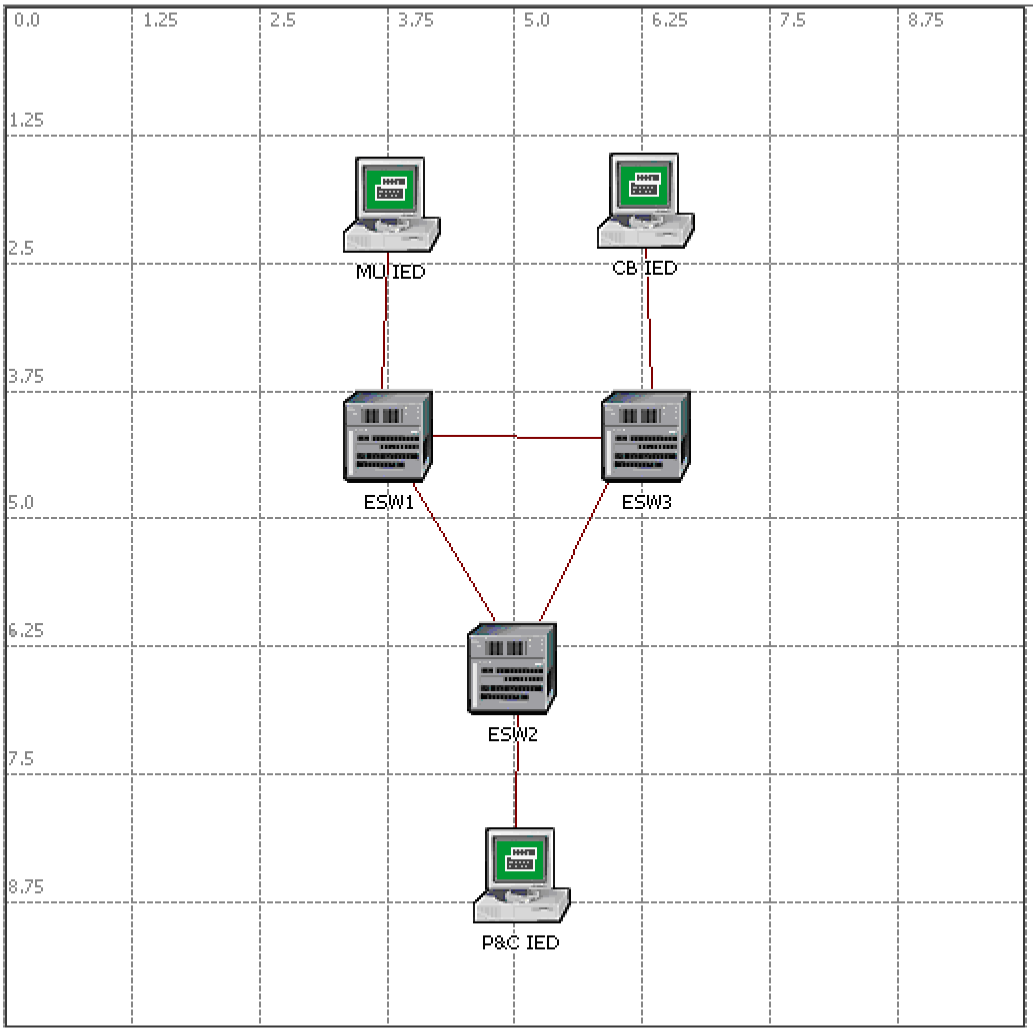

Figure 5-5 Ring topology model for feeder bay

The SV packet version used in this project is the IEC61850 9-2 LE [16]. An IEC61850 9-2LE SV packet has only one ASDU in the APDU, which contain one set of current values (phase A, phase B, phase C and neutral) and one set of voltage values. Considering the 2 bytes gap each frame in APDU, the size of an IEC61850 9-2LE SV packet is 138 bytes - 162 bytes in terms of Figure 5-2.

Assuming the svID frame is 10 bytes, the size of an IEC61850 9-2LE SV packet can be calculated as 138 bytes per sampled value. The inter-frame gap is 96 bits, hence the SV Ethernet frame width is therefore 1200 bits, which is 150 bytes. For a 50 Hz power system, applying 80 samples per cycle, the sampling frequency is 4000 Hz. The parameters for OPNET simulation are tabulated in Table 5-1.

Table 5-1 Parameters for OPNET simulation

Parameters	Default Values
Communication link Data rate	100 Mbps
Sampling frequency	4000 Hz
Message size	150 bytes
ESW packet service rate	0.5 Mega packets per second
Each Ethernet cable length	15 meters
Simulation Duration	10 minutes

After the simulation, the SV packet ETE delay of different process bus topologies are summarized in Table 5-2.

Table 5-2 SV ETE delay of different process bus topologies

Feeder process bus topology	Sampled value packet delay (ms)
Cascaded	0.048348
Star	0.031576
Ring	0.048375

It can be observed from Table 5-2 the star topology provides the shortest SV ETE delay of 0.031576 ms. The cascaded topology provides the ETE delay of 0.048348 ms, and the ring topology provides almost the same ETE delay of 0.048375 ms as cascaded topology.

According to IEC61850, the acceptable maximum communication delay for the time-critical messages, SVs and GOOSE, is 3 ms [16]. Therefore, the SV ETE delay of the MAIN protection for a feeder bay using the three different process bus topologies is tolerable.

5.4 Process Bus Overload Simulation

In all of the above tests, the process bus was operated well within its specified capabilities. The data traffic consisted of the samples values derived from one MU. In a practical application, the process bus traffic would be expected to be greater as more units, both merging units and P&C IEDs would be connected to it.

The SV Ethernet frame width is therefore 1200 bits. Using a 100 Mb/s process bus, with a 50 Hz power system and a sampling rate of 4000 samples/s, theoretically the max number of merging units that it can support is approximately 20. With any more than this, the bus would be overloaded and data would be lost.

For the overload test, multiple MUs are connected to the process bus. These MUs are programmed to generate data streams from an increasing number of sources thus increasing the traffic on the process bus.

5.4.1 Star Topology Overload Test

The SV ETE delay is measured as the key indicator of its response to the increasing traffic on the process bus. The configuration of the test system model is shown in Figure 5-6.

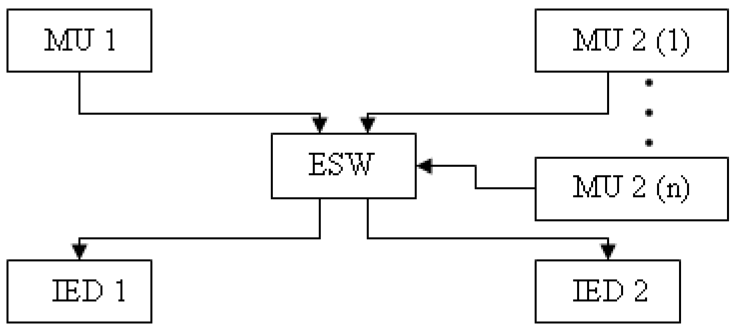

Figure 5-6 Configuration of the star topology system model

In this model, P&C IED 1 is assigned to MU 1 and P&C IED 2 is assigned to MU 2. Increasing the number of MU 2, thus the traffic on the process bus is increased. The SV ETE delay of P&C IED 1 is measured, the results are tabulated in Table 5-3.

Table 5-3 SV ETE delay of star topology

Number of MU IED	Sampled value packet delay (ms)
1	0.031576
2	0.047165
3	0.047165
4	0.047165
5	0.047165
6	0.047165
7	0.062765
8	0.062765
9	0.078365
10	0.078365
11	0.078365
12	0.078365
13	0.078365
14	0.078365
15	0.093965
16	0.093965
17	0.093965

The results shows that, before the number of MUs reaches 18, the SV ETE delay increases from 0.031576 ms to 0.093965 ms. When it reaches 18 (86.4 Mbps), which is 86.4 % of the process bus data rate (100 Mbps), the SV ETE delay starts to increase with time rapidly. As shown in Figure 5-7, the Ethernet delay increased over 0.5 seconds, after 8 seconds of the simulation. If more than 18 MUs are connected to the network, the Ethernet delay may even longer. Therefore, according to the simulation, the max number of MUs that the star process bus topology can tolerate is 17.

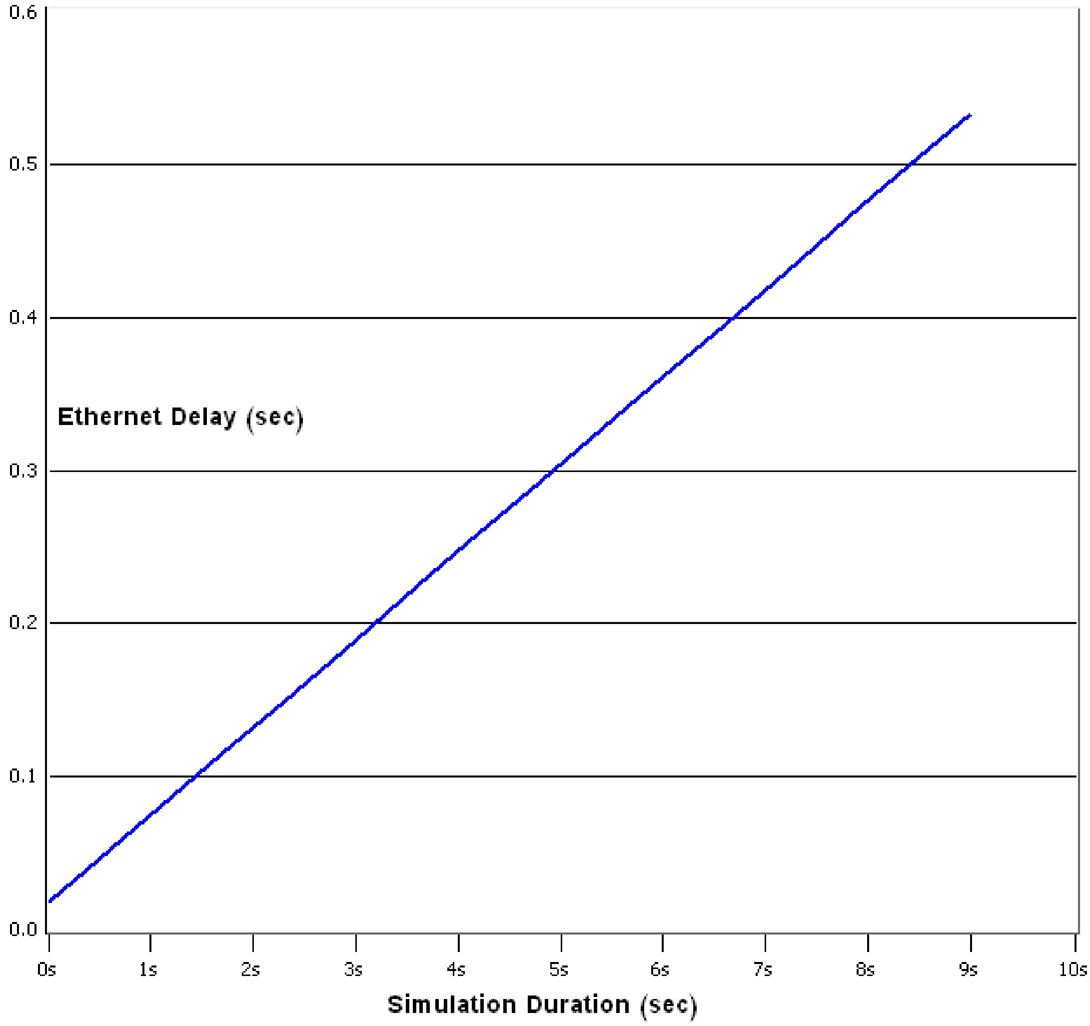

Figure 5-7 SV ETE delay of 18 MUs on the star process bus

5.4.2 Cascaded Topology Overload Test

Similar as the star topology test, the configuration of the cascaded topology test system model is shown in Figure 5-8.

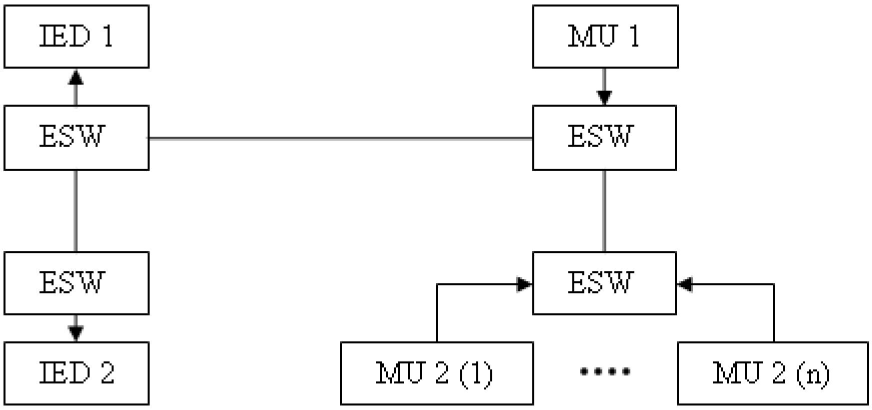

Figure 5-8 Configuration of the cascaded topology system model

The results of SV ETE delay of P&C IED 1 are tabulated in Table 5-4.

Table 5-4 SV ETE delay of cascaded topology

Number of MU IED	Sampled value packet delay (ms)
1	0.048348
2	0.048348
3	0.048348
4	0.048348
5	0.048348
6	0.048348
7	0.048348
8	0.048348
9	0.048348
10	0.048348
11	0.048348
12	0.048348
13	0.048348
14	0.048348
15	0.048348
16	0.048348
17	0.048348

Before the number of MUs reaches 18, the SV ETE delay remains at 0.048348 ms. When it reaches 18, the SV ETE delay starts to increase with time. As shown in

Figure 5-9, the Ethernet delay increased over 0.4 seconds, after 8 seconds of the simulation. Therefore, the max number of MUs that the cascaded process bus topology can tolerate is 17.

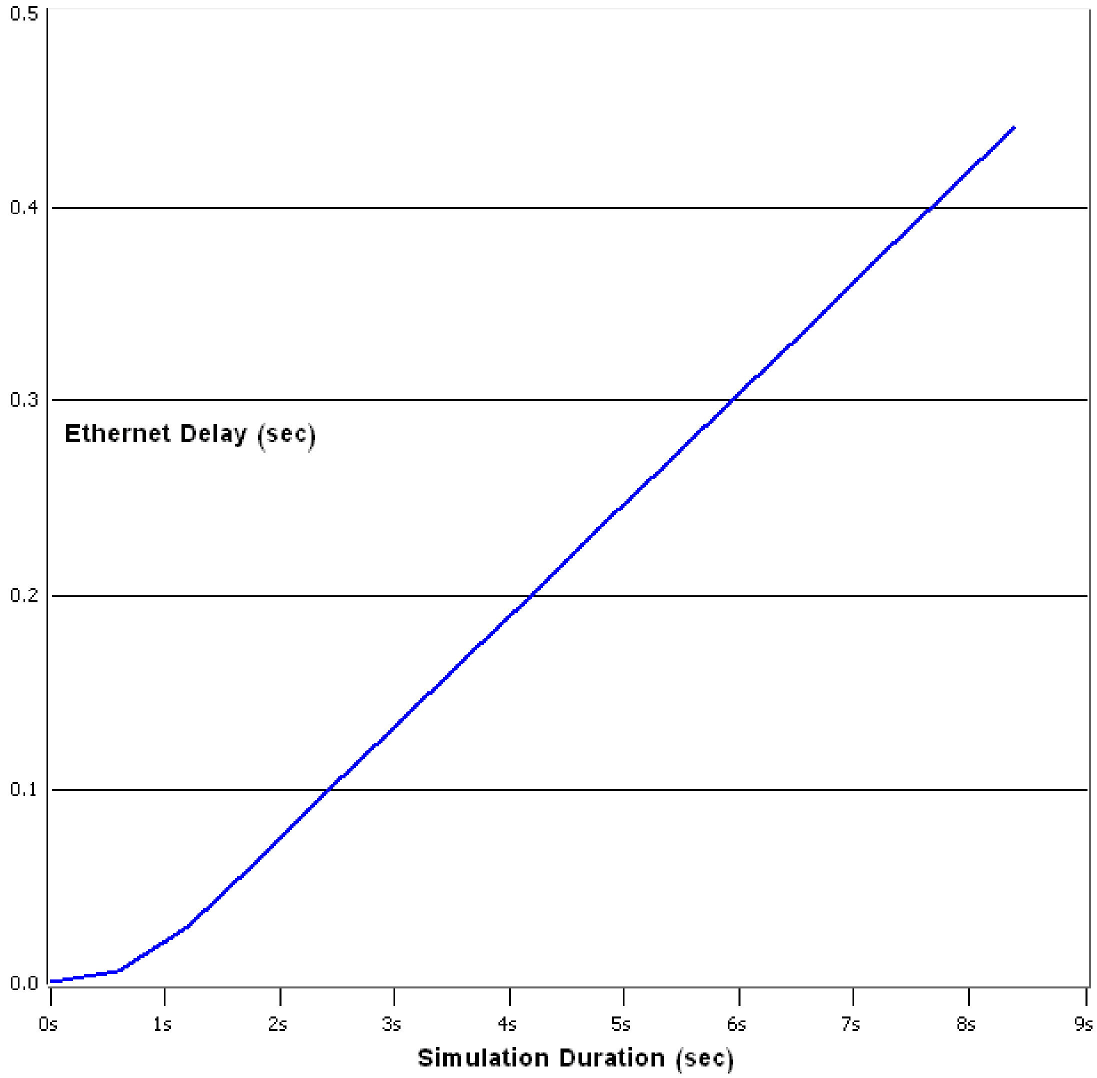

Figure 5-9 SV ETE delay of 18 MUs on the cascaded process bus

5.4.3 Ring Topology Overload Test

The configuration of the test system model is shown in Figure 5-10. The results of SV ETE delay are tabulated in Table 5-5.

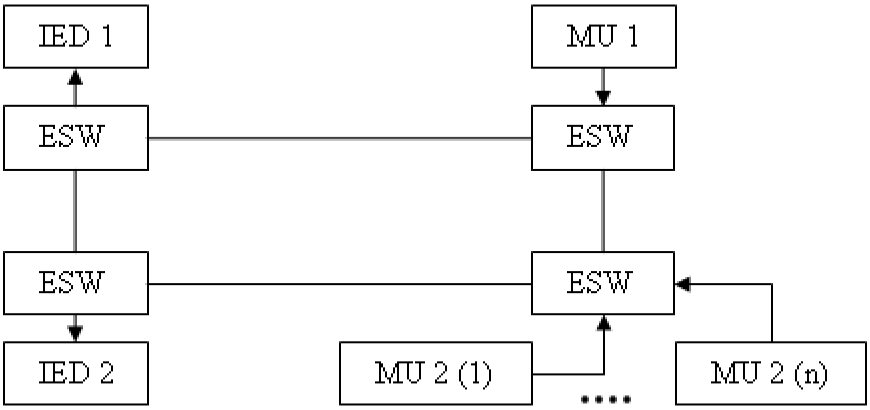

Figure 5-10 Configuration of the ring topology system model

Table 5-5 SV ETE delay of ring topology

Number of MU IED	Sampled value packet delay (ms)
1	0.048375
2	0.048375
3	0.048375
4	0.048375
5	0.048375
6	0.048375
7	0.048375
8	0.048375
9	0.048375
10	0.048375
11	0.048375
12	0.048375
13	0.048375
14	0.048375
15	0.048375
16	0.048375
17	0.048375

Similar as the cascaded topology test, before the number of MUs reaches 18, the SV ETE delay remains at 0.048375 ms. When it reaches 17, the SV ETE delay starts to increase with time. As shown in Figure 5-11, the Ethernet delay increased over 0.25

seconds, after 8 seconds of the simulation. Therefore, the max number of MUs that the ring process bus topology can tolerate is 17.

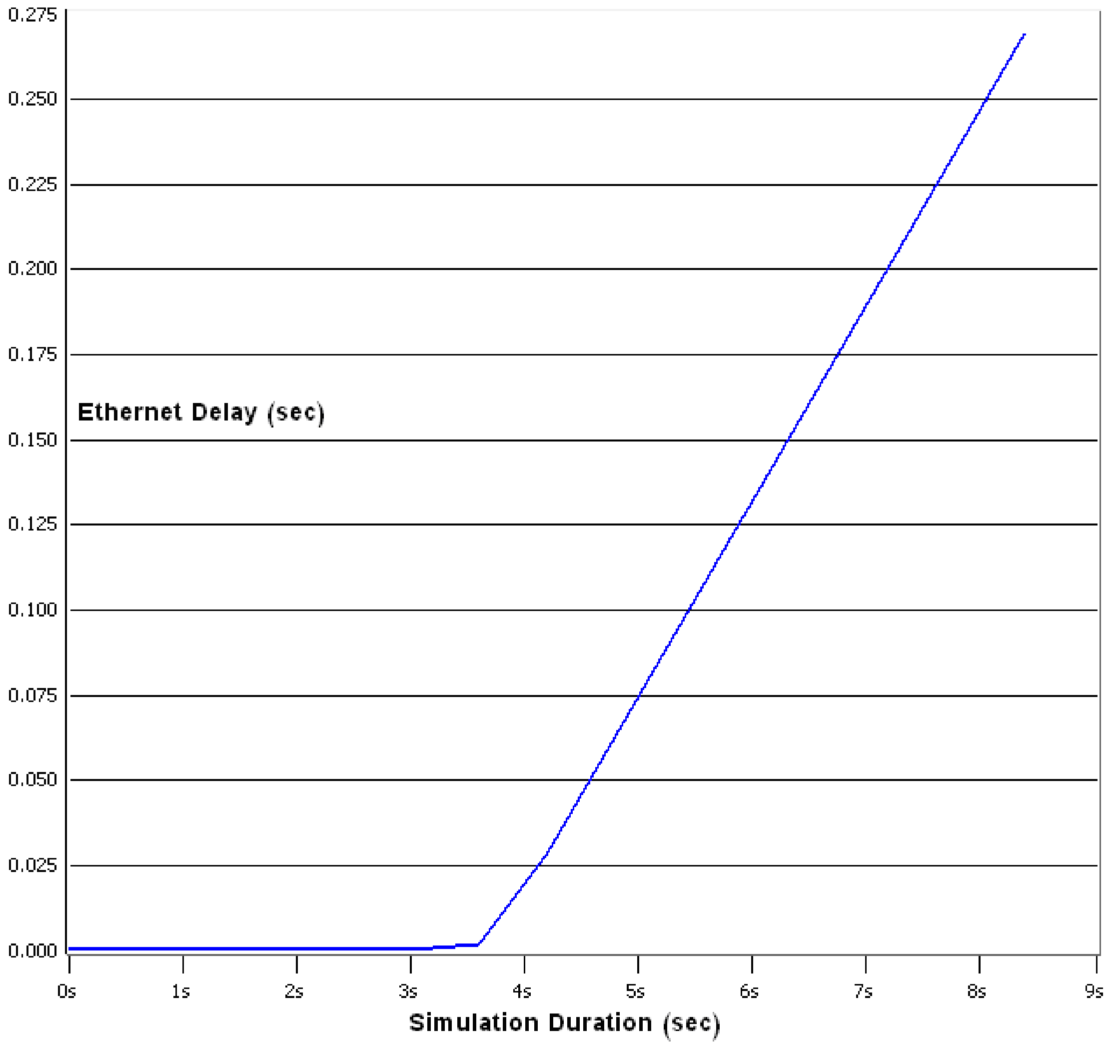

Figure 5-11 SV ETE delay of 18 MUs in the ring process bus

5.5 Conclusions

The OPNET Modeller simulation based feed bay study shows that star topology provides the shortest SV ETE delay of 0.031576 ms. Cascaded topology provides the ETE delay of 0.048348 ms, and the ring topology provides almost the same ETE delay of 0.048375 ms as cascaded topology. As the acceptable maximum communication delay for the time-critical messages, SVs and GOOSE, is 3 ms, the SV ETE delay of the MAIN protection for a feeder bay using the three different process bus topologies is tolerable.

The process bus overload test shows that before the traffic on the process bus topologies, cascaded, star, and ring, reaches 85% of the communication link data rate (100 Mbps), the star topology provides the SV ETE delay between 0.031576 ms and 0.093965 ms. The cascaded topology provides the ETE delay of 0.048348 ms, and the ring topology provides almost the same ETE delay of 0.048375 ms as cascaded topology. Therefore, before the process bus is saturated, the SV ETE delay of the three different process bus topologies is also tolerable.

When the traffic on the process bus topologies reaches 85% of the communication link data rate, the SV ETE delay starts to increase with time rapidly. That is because the bandwidth utilization efficiency [69] of the OPNET Ethernet switch model is 85%, the results may be different in the reality by using the real Ethernet switch, which will be discussed in chapter 6.

Based on the OPNET studies, as the process bus overload simulation results show, the max number of MUs that the three process bus topologies can tolerate is 17.

In conclusion, the SV ETE delay of cascaded, star, and ring process bus topology within the number limit of the MUs will not influence the operation of the protection communication system.

Chapter 6

Protection Performance Study with RTDS Simulator

THIS chapter evaluates the performance of different protection schemes with cascaded, star and ring process bus topology using RTDS Simulator.

6.1 Introduction of RTDS Simulator

The Real Time Digital Simulator (RTDS) [72] is designed specifically to simulate electrical power systems and to test physical equipment such as control and protection devices. Numerous analogue and digital input and output channels, with optical isolation and high accuracy, provide for flexible interconnections with the simulator. The modular design enables simulation hardware to be customized for specific study needs and yet give the flexibility for future expansion.

6.1.1 Conventional RTDS Testing System

Figure 6-1 demonstrates the application of RTDS in the conventional analogue signal based system. The RTDS simulates the power system and generates the required voltages and current signals to the amplifiers through a D/A converter [73] [74] [75]. The RTDS also exchanges the circuit breaker status, relay trip and re-closure signals with the conventional protective relay under test via a binary I/O interface.

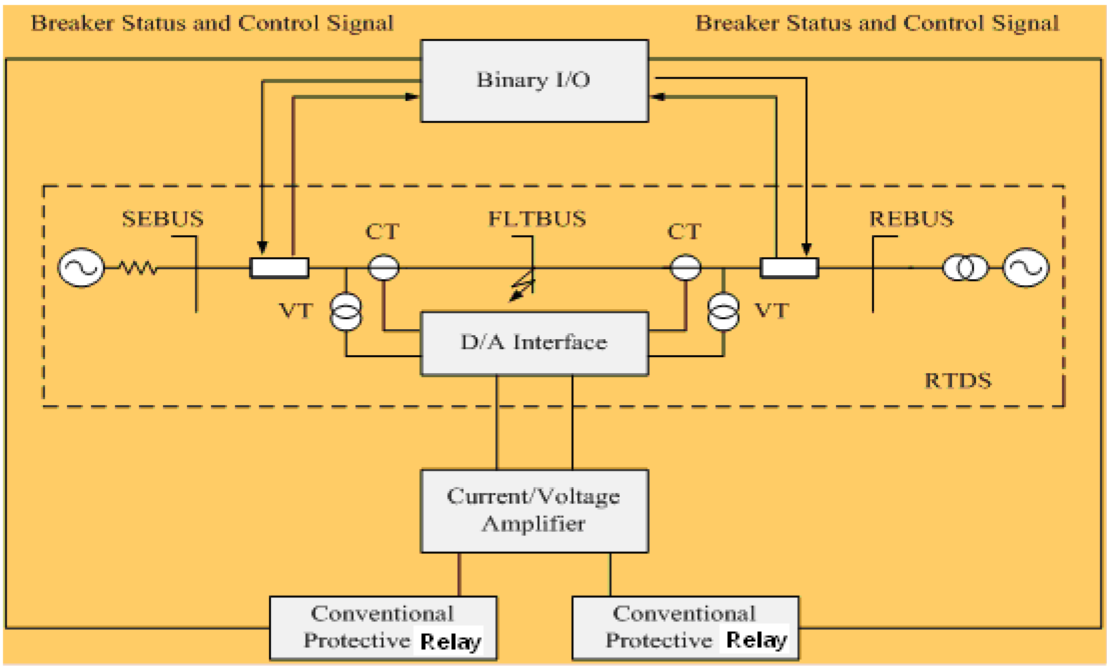

Figure 6-1 Analogue signal based RTDS test system

The amplifier receives low level signals from the RTDS and amplifies them to a level compatible with the input module of the relays. The amplifier is composed of some analogue components which have the ability to carry high currents and voltages, V_{nom}, V_{peak}, I_{nom}, I_{peak} [76] [77] [78]. As a result, only a limited number of relays can be connected to a RTDS system at one time through the amplifiers, this constrains the capability of a RTDS system for relay testing.

6.1.2 Design of a New RTDS Testing System

A significant advantage of the IEC61850 system compared with the conventional system is the replacement of analogue and binary signals with Ethernet messages. Merging Units work as an access from the instrument transformers to the digital ports of relays through Ethernet utilising a specific data format in accordance with IEC61850 protocols. The simulation data generated by the RTDS can be injected to the IEC61850 compatible relays by a data format conversion. This is achieved by introducing a "Conversion Interface Module". There is no need for the D/A interface unit and the current and voltage amplifiers. Figure 6-2 is a schematic diagram of RTDS close-loop testing design [79] [80].

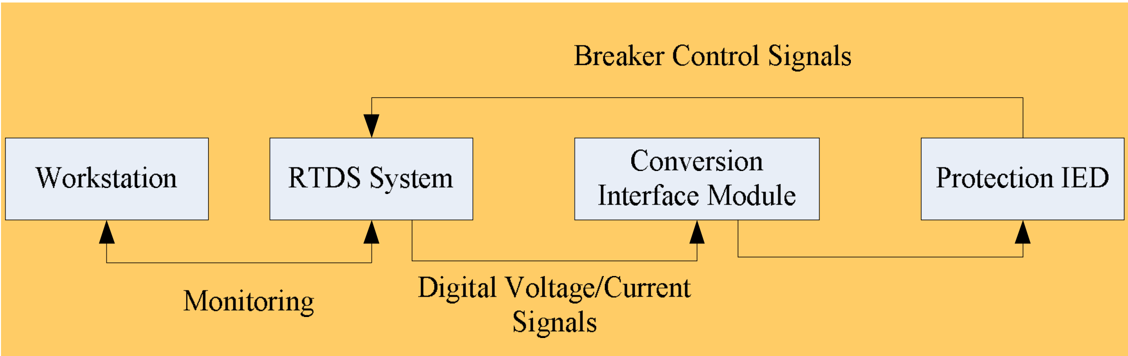

Figure 6-2 Schematic diagram of RTDS close-loop testing design

This conversion interface module (CIM) has the ability to access the digital simulation signals generated by the RTDS directly and converts these data to an IEC61850 compatible format. These data can now be injected to the Protective IED for testing purpose.

The connection between the RTDS system and the CIM can be configured as analogue to accommodate the existing testing system as an integration phase.

Otherwise, this connection can be configured as digitised which means there is a direct connection between the RTDS system and the CIM. This is shown in Figure 6-3.

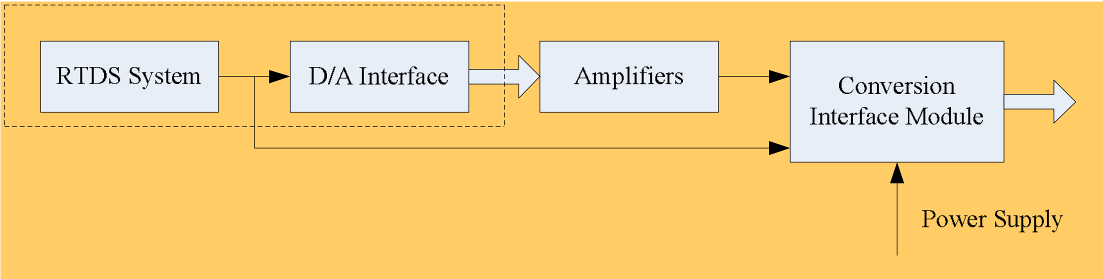

Figure 6-3 Connection diagram between RTDS system and CIM

6.1.3 Implementation of this new RTDS testing system

Equipped with the Giga-Transceiver Network Communication Card (GTNET) [81] which is shown in Figure 6-4, RTDS can fully support the IEC61850 based system testing. The GTNET can provide real time communication to and from the simulator via Ethernet. Different firmware versions are used to accommodate IEC61850 GSE binary messaging, IEC61850 9-2 sampled values, playback of large data files stored on a PC hard disk and DNP communication, a SCADA protocol commonly used in substations.

As shown in Figure 6-5, the simulated data (digital signals) generated by the RTDS system are transferred to the GTNET_SV card, where the data is sampled, time-stamped and converted to a IEC61850 compatible format and broadcasted to the Ethernet. The subscribed device is able to access its required data from the Ethernet. This effectively eliminates the D/A interface and the current and voltage amplifiers. It is worth noting that, for protective relays that need more than one current or voltage sampled values, every node involved requires a GTNET_SV card.

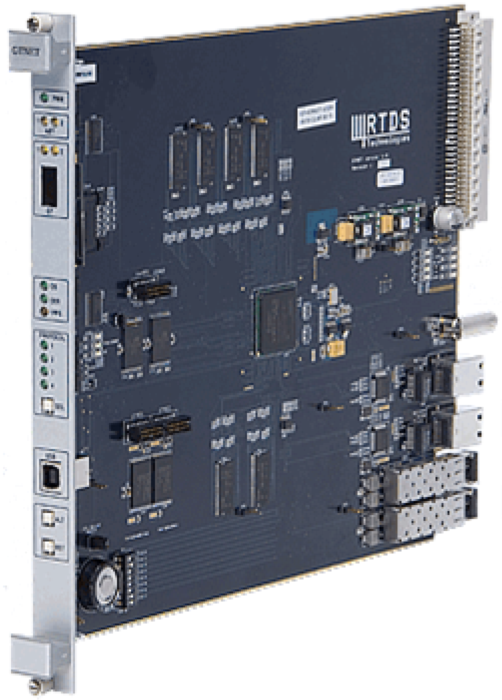

Figure 6-4 The GTNET card

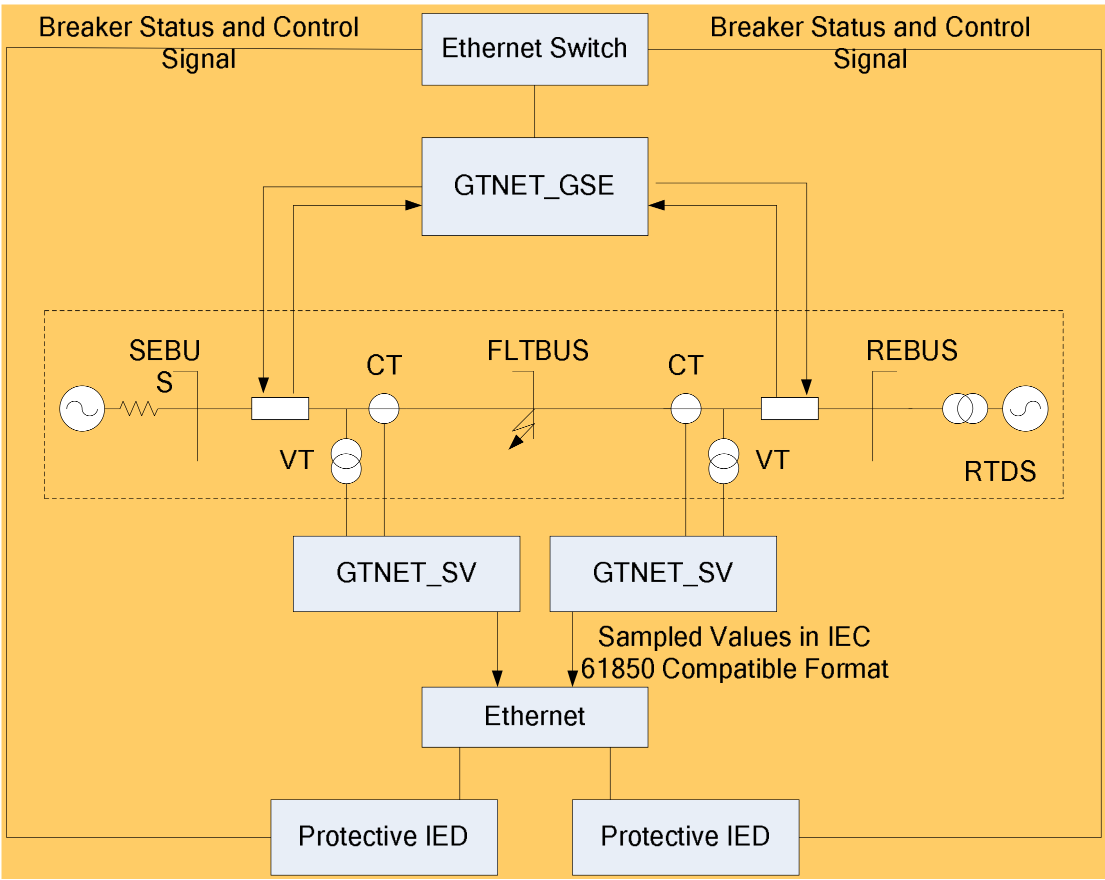

Figure 6-5 RTDS test system using GTNET cards

The GTNET_GSE card is utilised to exchange breaker status and substation control signals. It supports both GOOSE and GSSE messages but cannot support them simultaneously. In the GOOSE mode, an IED configuration file (*.scd) is generated to configure the GTNET card using the substation configuration language. The configuration information can be inputted to the GTNET card directly in the GSSE application [82] [83].

With the process bus, the relay has no physical current, voltage or contact inputs, so there is no corresponding hardware to check. The hardware performing a somewhat analogous function, the optical transceivers, PHY chip (it takes a frame of data and turn it into a string of bits for transmission over the connecting medium – a process called serialization.), etc., are continuously self-tested with signal level margin detectors and with data security codes (i.e. CRC, Cyclic-Redundancy-Code), so there is little if any value in further testing the relay's process bus input/output hardware. The firmware that implements the measuring elements and scheme logic is continuously checked again by CRC, and the processors by watchdog timers.

This chapter will focus on the testing of feeder protection schemes and the transformer protection scheme with different process bus topologies. The Feeder Local Panel (LB) and the Remote Local Panel (RB) are shown in Figure 6-6 As with the other commercial test equipment, the RTDS simulator provides analogue signals to the remote hardwired relays and IEC61850 SVs signals to the local IEC61850 relays. It also provides SVs signals to the HV transformer relays. The upper Local (LT) and upper Remote (RT) relays of the panels are configured as the Feeder Main-1 current differential scheme whilst lower Local (LB) and lower Remote (RB) relays are configured as Feeder Main-2 distance scheme. The RTDS test system is shown in Figure 6-7.

Figure 6-6 Feeder Local Panel (IEC61850) and Feeder Remote Panel (hardwired)

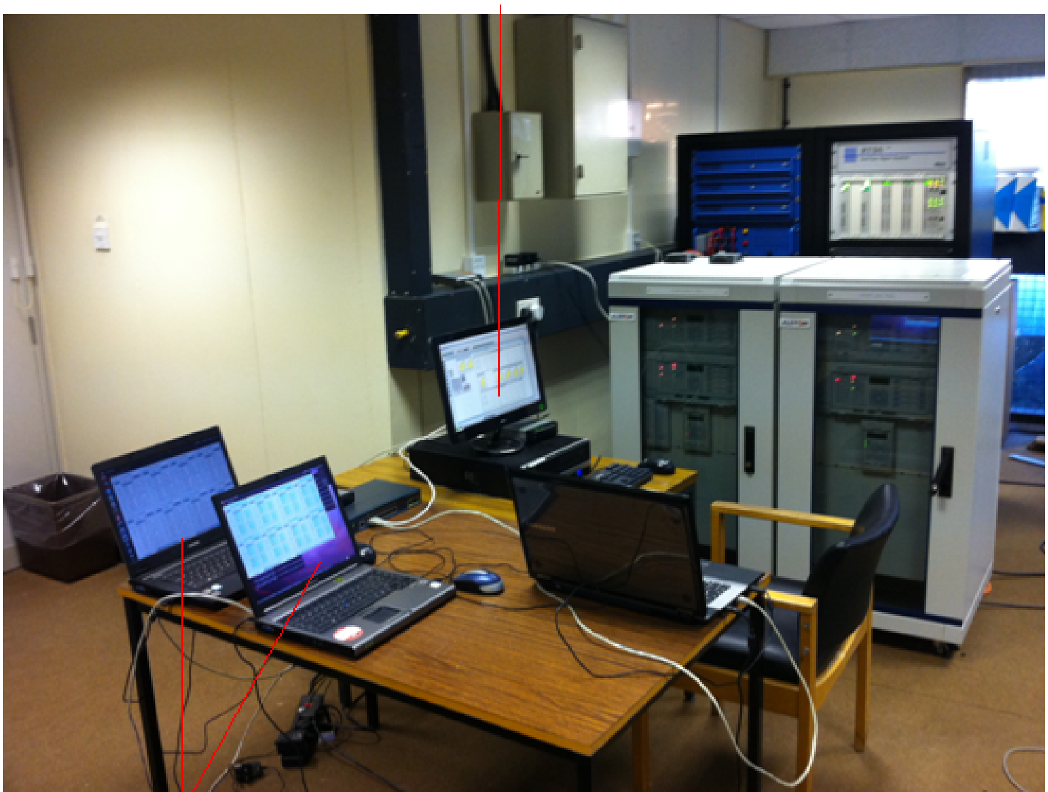

Figure 6-7 RTDS test bed for the protection schemes

6.2 Current Differential Protection Scheme Test

The performance of an EHV current differential protection scheme with different process bus topologies is demonstrated using the RTDS simulator fitted with both conventional, current and voltage amplifier, and IEC61850, Ethernet, SV outputs. The modelled transmission system, shown in Figure 6-8, consisted of the protected 100km line, with similar lines connected to both the local and remote ends and 1 GVA sources connected to them. The local end is configured as the digital substation with the LT IEC61850 protection and the remote end uses a RT conventional relay.

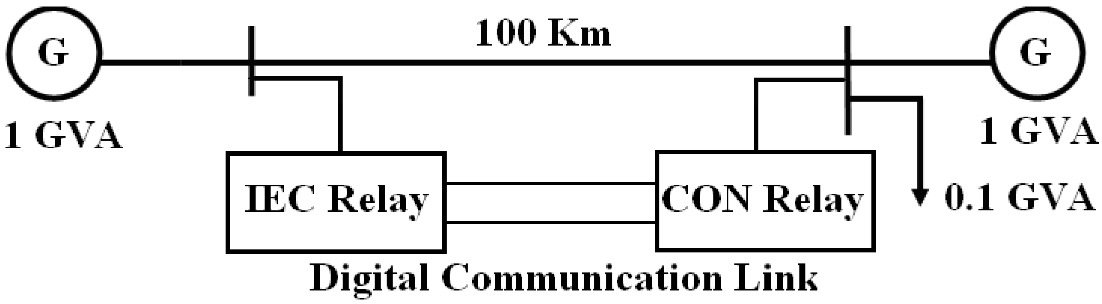

Figure 6-8 Modelled power transmission line for the current differential scheme test

The RTDS is configured to generate an IEC61850 9-2LE SV data stream using "PhsMeas1" with 8 elements, 4 currents and 4 voltages. The digitised current and voltage data streams are provided by the RTDS, separate merging units are not required.

Standard 100/1000TX electrical cables with RJ45 connectors are used to connect the IEC61850 relay to the Ethernet communication networks. A fibre optic link is used for the communication between the two relays. Both relays are synchronized by the GPS synchronization units. There are only GTNET_SV cards equipped on the RTDS, so both relays are configured to send digital trip signal to the RTDS digital input interface. The RTDS measured and reported the relays' tripping times.

If the manual adjustment of the delay compensation in the LT relay is disable and both relays are injected the voltage and current values of the local end, then under the healthy system conditions, the observed results from the front LCD of the relays indicate that SV data stream is about 17.5° (0.97ms) lagging the hardwired analogue signal. This can result in a different current of 539.9A~588.5A. The same conclusion as with the other commercial test set can be drawn that the time offset introduced by the IEC61850-9-2 digitization process is approximately 1ms. The angle difference and differential current can be reduced significantly (3°, 47A) by applying manual compensation to the LT relay.

The main parameters of the relay and transmission line are shown in Table 6-1.

Table 6-1 Parameters of relay and transmission line for current different scheme test

Item	Value
f nom	50.00 Hz
No. of phases	3
V primary	400.0 kV
V secondary	110.0 V
I primary	1.000 kA
I secondary	1.000 A
Is1	500A
K1	30%
Is 2	5000A
K2	150%
Line length	100.0 km
Line impedance	26.75Ω
Line angle	86°
kZN residual comp	0.67
kZN residual angle	-5.000°

Details of the faults used are shown in Table 6-2.

Table 6-2 Outline of current differential scheme test

Fault Type	Phase A to ground
Prefault Time	2s
Fault Point	15 km, 50 km, 85 km
Point On Wave	0°, 45°, 90°

6.2.1 Current Differential Protection Scheme Test Using Cascaded Topology

In this architecture, each component, the IEC61850 based relay, the RTDS IEC61850 9-2LE interface card and a supervisory PC is connected to its own Ethernet switch and these are connected in a chain. The communication architecture of the protection scheme is shown in Figure 6-9.

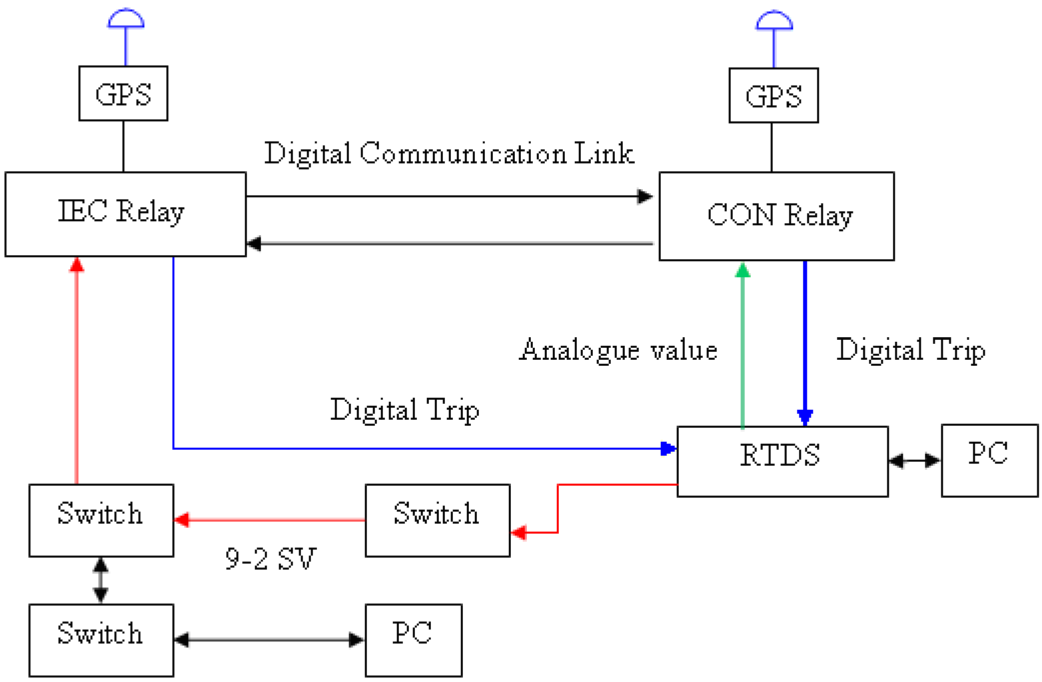

Figure 6-9 Configuration of current differential scheme test using cascaded topology

In the tests, faults are applied at each fault point with different points on wave, POW. Each test is repeated ten times and the mean trip time, MTT, is calculated. The trip times for both the IEC61850 based relay, IEC, and the conventional relay, CON, are recorded as shown in the Table 6-3 below.

Table 6-3a Trip times of current differential scheme test using cascaded topology (15km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
23.6	25.35	21.6	24.55	23.65	25.5	23.05	25.95
23.6	25.2	24.25	24.5	24	25.05	25.1	24.1
24.55	24.45	22.3	24.5	25.35	26.25	25.4	23.8
25.35	25.35	22.4	24.85	24.2	25.95	26.1	23.2
25.6	25.15	22.9	26.7	24.1	25.15	25.1	24
25.95	25.7	22.4	24.3	24.35	27.55	26.75	24.15
27.7	25.35	22.6	26.15	25.1	27.3	26.6	25.85
27.25	27.05	25.3	24.55	25.95	27.05	24.85	25.85
22.45	24.25	24.5	25.25	26.55	24.3	22.2	23.75
22.2	24.2	24.9	24.3	25.5	25	23.1	25.1

Table 6-3b Trip times of current differential scheme test using cascaded topology (50km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
25.45	25.3	25.05	27.1	24.05	25.45	27.75	26.4
25.4	24.95	26.9	26.15	25.3	25.85	28.35	27.5
26.5	26.6	23.6	23.3	24.2	26.6	29.2	26.2
26.75	27.1	26.05	24.6	25.65	26.4	26.45	28.4
25.5	26.9	24.85	25.3	24.8	24.9	26.3	27.75
25.75	26.3	24	25.55	25.2	26.55	26.35	27.55
25.85	28.2	26.1	25.65	25.3	27.15	26.45	27
26.6	28.45	25.8	23.9	25.45	26.6	29.8	27.4
23.7	25.35	26.05	26.55	24.15	23.35	28.75	28.05
23.85	26.35	26.2	26	24.7	24.35	28.5	28.65

Table 6-3c Trip times of current differential scheme test using cascaded topology (85km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
24.65	22.95	24.5	25.85	25.1	22.9	25.2	25.15
25.55	24.6	25.65	26.55	25.4	24.25	27.6	26.1
24.45	25	26.4	24.2	25.4	24.8	26.95	26.05
24.4	25.25	24.4	22.5	22.9	25.05	27.35	27.25
24.6	25.1	24.7	23.5	23.65	24.45	23.4	26.55
26.05	25.55	24.95	23.3	23.6	25.45	25.75	24.1
25	26.8	27.05	25.25	24.1	25.7	24.5	24.75
26.8	26.8	26.2	23.3	22.6	27	25.35	23.65
26.2	27	23.6	24.8	23.3	25.7	26.15	24.4
22.65	26.55	23.45	25.55	24.85	24.85	25	24.3
24.65	22.95	24.5	25.85	25.1	22.9	25.2	25.15

The MTT for the cascaded topology is shown in Table 6-4.

Table 6-4a MTT of current differential scheme test using cascaded topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	24.825	25.205	23.315	24.965	24.875	25.91	24.825	24.575

Table 6-4b MTT of current differential scheme test using cascaded topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	25.535	26.55	25.46	25.41	24.88	25.72	27.79	27.49

Table 6-4c MTT of current differential scheme test using cascaded topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	25.035	25.56	25.09	24.48	24.09	25.015	25.725	25.23

6.2.2 Current Differential Protection Scheme Test Using Star Topology

In the star topology, all the components are connected to a central Ethernet switch giving the communication architecture shown in Figure 6-10.

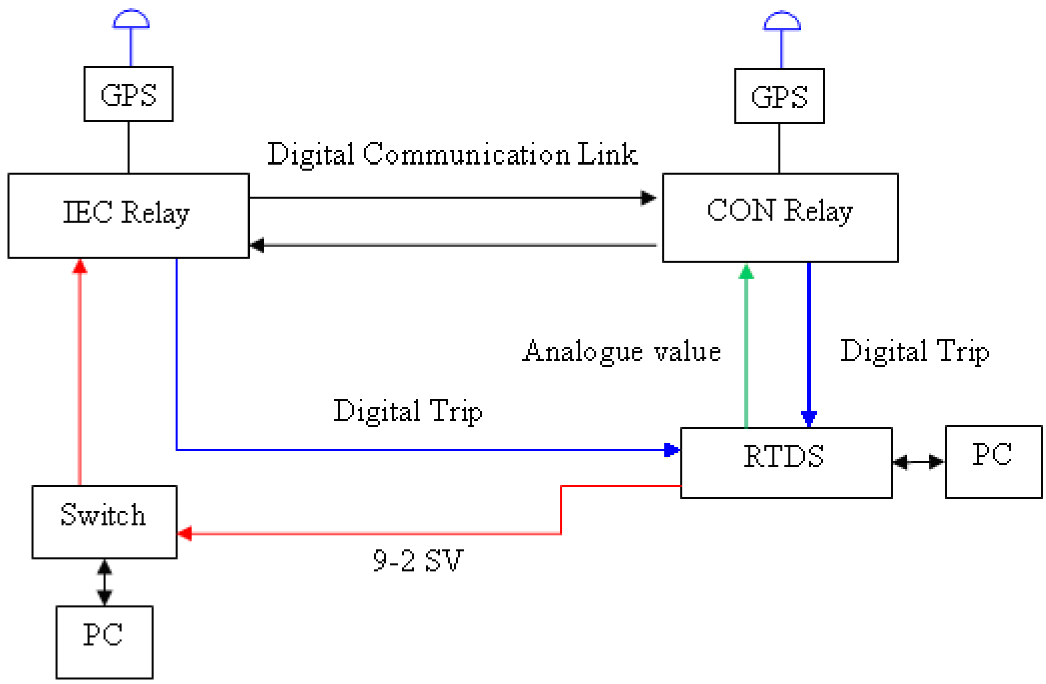

Figure 6-10 Configuration of current differential scheme test using star topology

The trip times of both relays are shown in Table 6-5.

Table 6-5a Trip times of current differential scheme test using star topology (15km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
23.6	25.45	24.9	27.85	26.25	24.35	23	25.25
23.3	24.7	25.05	27.1	21.6	24.55	23.2	26.9
23.5	25.95	26.85	27.3	22.25	23.8	24	27.3
25.6	26	24.9	23.1	22.5	24.5	23.15	25.75
25.7	26.45	24.45	25.4	22.8	24.05	23.05	26.4
25.15	25.55	22.85	23.35	23.05	26.55	24.35	26.5
25.8	25.55	21.8	25.55	24.65	24.9	25	24.1
27.4	27.9	22.15	25.25	24.25	26.3	26.1	25.1
27.55	28.15	22.9	26.7	24.9	23	24.3	24.95
25.55	23.8	27.05	25.45	23.85	23.25	24.6	25.3

Table 6-5b Trip times of current differential scheme test using star topology (50km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
25.95	27.5	24.15	24.9	24.7	22.55	29.4	29
25.6	27.2	25	25.05	23.9	22.8	25.5	29.7
26.8	28.05	26.55	26.15	25.75	24.8	26.65	29.75
25.9	26.95	25.35	25.55	26.8	24.5	27	29.05
23	27.1	24.4	25.2	23.2	24.85	26.1	26.15
26.25	25.4	26.35	26.1	21.8	25.9	25.95	27.25
22.8	24.75	25.25	23.85	21.95	26	26.4	28.4
25	27.95	25.35	24.55	24.15	25.9	27.8	27.75
25.2	26.55	25.8	23.05	24.75	26.3	29.55	26.15
25.9	27.2	23.5	24.9	23.8	26.3	29.45	27.95

Table 6-5c Trip times of current differential scheme test using star topology (85km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
24	24.25	25.25	23.25	25.75	25.2	24.2	26.35
25.95	24.5	26.05	27.05	23.35	25.9	24.9	26.95
26.15	24.6	21.8	22.95	23.25	24.45	25.2	24.75
25.95	26	21.65	23.9	23.7	25.45	24.2	27.05
25.6	26.6	22.3	25.55	23.95	25.6	24.45	24.05
26.05	26.5	23.05	23.8	25.2	25.35	25.6	23.45
27.65	25.35	22.75	25.5	25.45	27.25	24.85	24.5
26.65	25.25	23.05	26.3	25.2	27.55	26.45	23.15
27.3	26.9	23.85	24.35	25.35	26.75	27.5	25.8
26.1	23.65	23.4	24.45	25.55	28.2	26.05	25.25
24	24.25	25.25	23.25	25.75	25.2	24.2	26.35

The MTT for the tests are shown in Table 6-6.

Table 6-6a MTT of current differential scheme test using star topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	25.315	25.95	24.29	25.705	23.61	24.525	24.075	25.755

Table 6-6b MTT of current differential scheme test using star topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	25.24	26.865	25.17	24.93	24.08	24.99	27.38	28.115

Table 6-6c MTT of current differential scheme test using star topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	26.14	25.36	23.315	24.71	24.675	26.17	25.34	25.13

6.2.3 Current Differential Protection Scheme Test Using Ring Topology

In the ring topology, as with the cascade architecture, each component is connected to a single Ethernet switch, but the chain is then connected to form a ring using a managed switch, as shown in Figure 6-11.

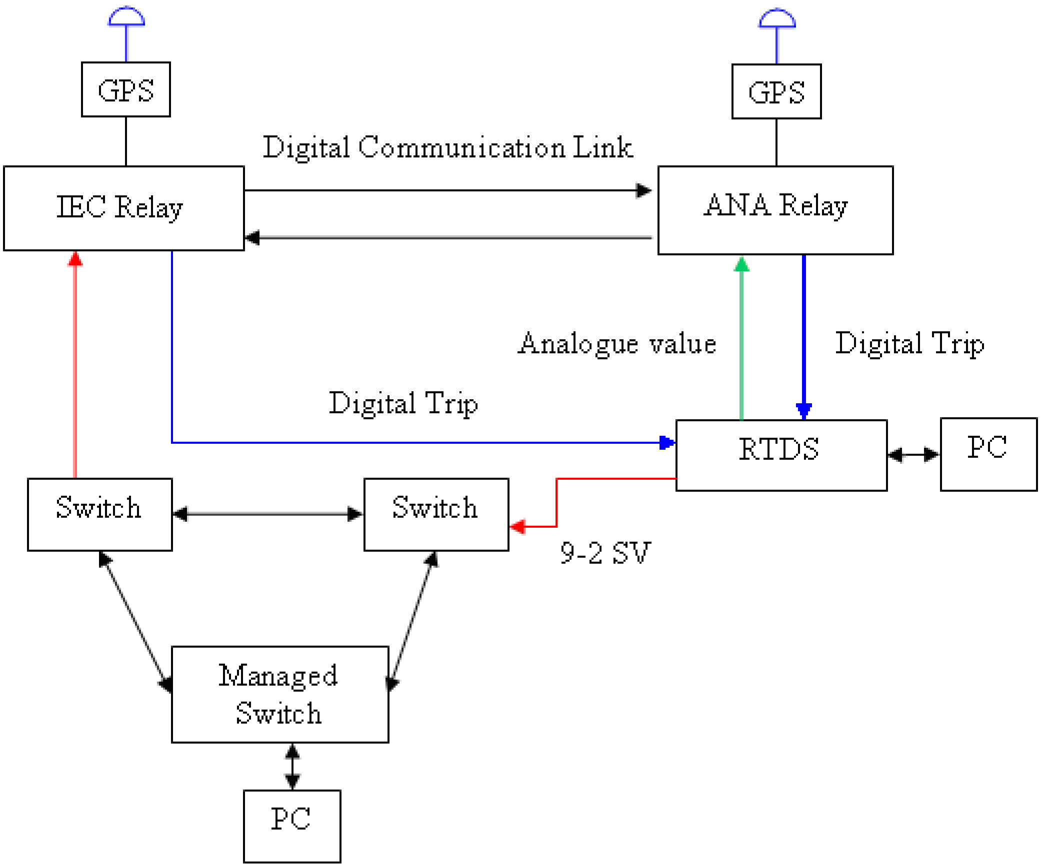

Figure 6-11 Configuration of current differential scheme test using ring topology

The test results for the ring topology are shown in Table 6-7 below.

Table 6-7a Trip times of current differential scheme test using ring topology (15km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
26.6	26.1	23.6	23.8	24.4	24.8	21.7	26.3
22.65	25.6	24.45	23.5	25.1	25.3	26.6	26.2
22.85	26.15	25.1	24.55	27.15	27.05	25.55	24.2
23.35	25.8	23.9	25.15	26.95	24.85	22.45	24.3
23.95	27.55	24.85	25.8	25.85	21.8	23.05	24.8
24.65	27.8	25.5	25.75	21.5	24.1	22.2	24.65
25.15	27.35	26.25	26.3	21.8	23.1	22.45	26.3
24.8	25.35	24.05	26.45	22.9	23.15	22.5	25.65
25.6	25.15	24.2	25.65	22.8	23.6	23.8	25.15
26.1	25.25	25.6	27.2	23.9	24.05	24.5	25.95

Table 6-7b Trip times of current differential scheme test using ring topology (50km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
25.65	25.1	22.95	23.35	25.8	25.95	25.6	22.9
24.95	25.65	25.05	24.5	26.1	26.5	26.35	23.15
26.3	26.4	25.25	24.05	24.4	26.15	27.25	24.1
23.25	27.25	26.3	25.45	24.7	27.7	26.5	24.05
23.15	25.65	25	25.45	23.4	22.6	27.05	24.2
24.35	22.8	23.5	25.25	23.85	21.95	23.1	23.75
25.15	23.9	25.15	24.3	23.1	22.9	24.55	26.75
25.05	24.55	25.3	27.25	23.1	24.65	25.7	27.45
24.75	24.1	25.45	25.95	22.45	23.9	24.6	26.2
25.25	25.2	22.35	23.1	23.7	23.5	25.35	25.45

Table 6-7c Trip times of current differential scheme test using ring topology (85km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
27.4	26	26.25	27.05	23.4	23.8	24.15	26.6
25.85	26.25	21.85	24.95	23.85	24.05	25.05	23.95
25.15	23.55	23.6	21.5	24.35	23.65	26.45	23.55
25.2	24.45	24.1	23.2	23	23.7	26.9	24.95
25.65	25.85	24.1	23.9	23.6	25.4	26.4	25.5
24.5	25.55	24.2	24.2	23.45	26.7	26.1	24.7
26.2	25.6	24.55	22.95	23.25	26.45	26.1	26.85
26.55	27.55	24.2	24.9	25.4	26.95	26.15	26.3
23.8	27.25	23.05	24.9	26.95	26	26.65	27.6
22.75	23.9	22.45	25.05	27.4	25.5	23.75	25.45
27.4	26	26.25	27.05	23.4	23.8	24.15	26.6

The MTT for the ring topology tests is shown in Table 6-8 below.

Table 6-8a MTT of current differential scheme test using ring topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	24.57	26.21	24.75	25.415	24.235	24.18	23.48	25.35

Table 6-8b MTT of current differential scheme test using ring topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	24.785	25.06	24.63	24.865	24.06	24.58	25.605	24.8

Table 6-3c MTT of current differential scheme test using ring topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	25.305	25.595	23.835	24.26	24.465	25.22	25.77	25.545

Using a managed switch with its RSTP system enables the ring to be closed. This enables the communications to be maintained in the event of a unit failure.

Although this self-healing ability of the ring topology provides additional functionality, it can be argued that it is contrary to the philosophy of the Main A – Main B protection described in the golden rules [2]. In this, should any part of either the Main A or Main B protection scheme fail, that scheme should be taken out of service leaving the other to provide the required level of protection. A ‘process bus failure alarm’ would alert operators of the need for repair and any risk of spurious operation would be avoided.

6.3 Distance Protection Relay Test

The performance of the protection of RB conventional and LB IEC61850 based distance protection relay was demonstrated using the RTDS simulator. The modelled transmission system, shown in Figure 6-12, consisted of the protected 100km line, with one similar line connected to the local end and two lines connected to the remote end. 5 GVA sources connect to both ends. The local end is configured as the substation with the both IEC61850 and conventional protection in order to compare their performance. The relays used were ALSTOM Grid P545, the remote with the conventional design and the local with the IEC61850 design.

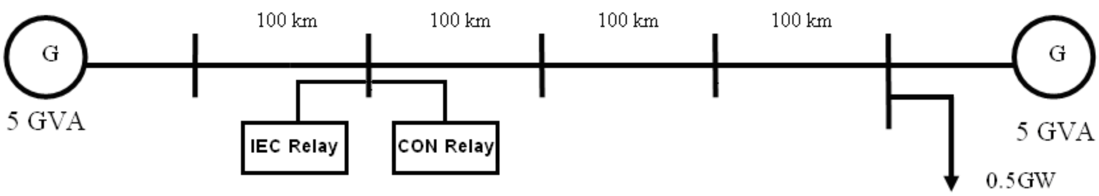

Figure 6-12 Modelled power transmission line of P545 distance relay test

The test connection diagram is shown in Figure 6-13. The switch is the focus for the 9-2 SV channel from the RTDS, the SV connection to the relay and the connection to the PC.

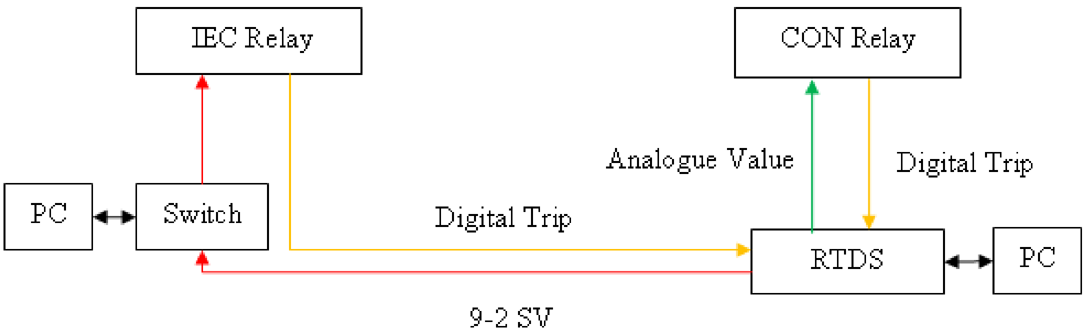

Figure 6-13 Connection diagram of distance relay test

The main parameters of the relay and transmission line are shown in Table 6-9.

Table 6-9 Parameters of the relay and transmission line

Item	Value
f nom	50.00 Hz
No. of phases	3
V primary	400.0 kV
V secondary	110.0 V
I primary	1.000 kA
I secondary	1.000 A
Z1 Ph. Reach	80 km
tZ1 Delay	0s
Z2 Ph. Reach	120 km
tZ2 Delay	200ms
Z3 Ph. Reach	250 km
tZ3 Delay	600ms
Z4 Ph. Reach (reverse)	-30km
tZ4 Delay	100ms
Line length	100.0 km
Line impedance	26.75Ω
Line angle	86°
kZN residual comp	0.67
kZN residual angle	-5.000°

Details of the faults used for the testing are shown in Table 6-10. 9 fault points are chosen, which are next to the boundaries of the 4 protection zones.

Table 6-10 Outline of distance relay test

Fault Type	Phase A to ground
Prefault Time	2s
Fault Point (measured from substation)	-45 km, -15 km, 15 km, 50 km, 85 km, 110 km, 130 km, 230 km, 270 km
Point On Wave	0º, 45º, 90º, 135º

In the test, each fault point with different POW is tested 10 times. The trip time of both the IEC61850 based relay and conventional relay is recorded as shown in the Table 6-11 and Table 6-12 below.

Table 6-11a Trip times of IEC61850 based distance relay (-45km)

Fault Point: -45 km	-45 km	-45 km	-45 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no

Table 6-11b Trip times of IEC61850 based distance relay (-15km)

Fault Point: -15 km	-15 km	-15 km	-15 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
116.6	121.1	125.2	118.1
117.8	123.1	124.6	123.1
115.8	120.6	125.3	123.3
116.3	123.5	122.2	124.1
116.1	122.6	123.9	120.9
116.5	122.2	123.6	122.4
116.6	121.3	120.7	122.6
117.9	115.5	124.1	122.8
116	121.1	124.5	124.6
115.1	115.4	122.8	122.4

Table 6-11c Trip times of IEC61850 based distance relay (15km)

Fault Point: 15 km	15 km	15 km	15 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
17.2	15.45	17.75	18.2
16.8	15.75	24.6	18.85
17.05	15.45	23.1	22.85
16.15	16.5	21.05	21.6
17.25	17.2	17.8	17.85
16.9	18	16.85	18.15
17.65	21.95	17.4	18.75
16.9	20.55	22	17.55
17.65	19.1	21.9	16.4
18.15	18.95	18.2	17.95

Table 6-11d Trip times of IEC61850 based distance relay (50km)

Fault Point: 50 km	50 km	50 km	50 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
16.55	16.75	18.35	17.3
16.9	15.95	17.25	18.25
17.9	16.5	17.75	17.75
18.25	15.75	18.25	17.6
18.2	15.75	18.5	17.95
17.55	16	19.2	16.8
19.05	16.35	17.1	17.85
21	14.9	18.5	18.2
21.45	15.35	18.2	17.9
17.4	19.75	17.8	17.6

Table 6-11e Trip times of IEC61850 based distance relay (85km)

Fault Point: 85 km	85 km	85 km	85 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
216.2	215	217	216.8
216.1	215	217.7	216.8
217.6	214.5	216.4	215.3
215	213.7	216.9	216.1
216	215.3	216.9	216.2
215	216.2	216.9	216
215.2	215.4	215.7	216.5
216.7	214.7	217	217.2
215.3	215.7	217	216.6
216	221.9	218.5	216.6

Table 6-11f Trip times of IEC61850 based distance relay (110km)

Fault Point: 110 km	110 km	110 km	110 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
227.3	227.7	246.5	229.2
229.7	221.7	252.2	235.2
226.3	226.7	252.5	233.4
227.7	226.9	245.2	227.8
226.9	228	242.5	233.3
226.1	227.8	235.9	233.9
228.6	228.3	242.9	228.2
229.1	226.7	239.8	229.5
225.7	227.7	235.7	233.9
228.8	228.1	239.6	234

Table 6-11g Trip times of IEC61850 based distance relay (130km)

Fault Point: 130 km	130 km	130 km	130 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
616.3	616.8	616.8	617
616.7	618	617.3	616.8
616.6	617.3	616.8	618.3
616.1	615.5	617.7	616.6
615.7	615.2	615.3	615.1
616	614.9	616.5	616.2
616.3	614.9	617.3	615.4
615.9	613.5	615.4	618.1
616.5	613.9	617.8	618
615.4	614.6	619.2	617.1

Table 6-11h Trip times of IEC61850 based distance relay (230km)

Fault Point: 230 km	230 km	230 km	230 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
629.4	627.6	641.4	636.1
627.8	626.9	637.9	633.5
626.8	626.5	648.4	633.6
626.9	628.8	650.3	634.3
629.9	628.5	650.1	629.3
627.6	626.1	638.4	629.4
628.6	628.1	642	628.2
628.8	628.7	642.5	629.1
627.7	627.3	649.2	636.2
628	628.6	655.5	633.9

Table 6-11i Trip times of IEC61850 based distance relay (270km)

Fault Point: 270 km	270 km	270 km	270 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no

Table 6-12a Trip times of conventional distance relay (-45km)

Fault Point: -45 km	-45 km	-45 km	-45 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no

Table 6-12b Trip times of conventional distance relay (-15km)

Fault Point: -15 km	-15 km	-15 km	-15 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
114	117.9	118.1	116.1
114.8	116.6	117.8	118.3
114.1	115.8	118.9	116.2
115	116	116.7	115.7
115.4	115.5	117.7	117
114.3	116.1	117	117.1
115.4	116.1	118.1	116.1
115.8	115.6	119	116.8
114.7	117	118.1	118.3
114.5	117.8	117.1	116

Table 6-12c Trip times of conventional distance relay (15km)

Fault Point: 15 km	15 km	15 km	15 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
15.35	14	16	17
15.3	14.35	17.5	16.55
16.05	13.75	17.65	16.55
17.09	15.75	16.9	17.2
15.3	15.9	15.75	17.1
16.55	16.05	16.85	17.55
15.6	15.6	17.5	17.55
17.25	16.35	18.3	16.6
14.95	17.15	16.75	16.9
17.05	16.05	17.25	17.6

Table 6-12d Trip times of conventional distance relay (50km)

Fault Point: 50 km	50 km	50 km	50 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
17.15	15.5	16.9	17.7
15.7	15.3	18.3	16.8
16.15	14.75	17.6	17.15
16.4	15.75	16.25	16.25
15.65	15.7	17.35	17.2
17.35	15.4	16.8	18.55
17.5	15.6	17.75	16.65
17.1	15.8	16.45	17.2
14.85	17.75	17.95	16.5
15.75	18.1	17	17.15

Table 6-12e Trip times of conventional distance relay (85km)

Fault Point: 85 km	85 km	85 km	85 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
215.1	213.5	217.2	215.9
214.6	215.1	215.9	215.6
214.8	213.6	215.7	214.4
216	214	215.3	215
215.3	214.9	215	216.4
213.9	214.5	214.9	214.4
214.8	215	214.5	214.6
214.7	214.1	215.4	216.5
214.6	215.6	215.7	215.2
215.4	220.4	215.4	216.3

Table 6-12f Trip times of conventional distance relay (110km)

Fault Point: 110 km	110 km	110 km	110 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
226.5	223	237.7	226.3
226.8	224.8	238.2	232.7
228.1	228.7	236.1	233.3
228.5	230.6	238.6	227.5
227.4	226.8	236	226.6
228.6	231.6	235.3	225.8
227.7	231.3	238	226.3
228.2	229.9	237	227.1
226.8	228.4	237	227.4
227.1	227.7	236.6	227.3

Table 6-12g Trip times of conventional distance relay (130km)

Fault Point: 130 km	130 km	130 km	130 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
615.7	612.8	616.1	615.9
614	616.1	613.2	617.6
613.9	619.5	614.5	615.9
614	615	614	617.6
614.5	614.2	615.1	615.7
614.9	613	614.9	615.5
615.8	613.3	615.3	615.8
615.4	613.9	617.3	617.2
614.2	612.6	615.1	616.5
614.3	613.7	616	617.4

Table 6-12h Trip times of conventional distance relay (230km)

Fault Point: 230 km	230 km	230 km	230 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
628.4	630.9	645.8	637.5
627.2	624.5	646.2	637
627.3	622.6	646.5	636
628.7	623.4	656.1	637
628.1	627.8	655.7	636.1
628	626.2	655	637.8
629.8	631.6	655.5	636.7
627.9	630.7	653.5	636.7
629.8	627.8	656.5	636
626.8	628.3	655.1	637.2

Table 6-12i Trip times of IEC61850 conventional relay (270km)

Fault Point: 270 km	270 km	270 km	270 km
POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no
no	no	no	no

The MTT of the IEC61850 based and conventional relay is show in Table 6-13.

Table 6-13a MTT of IEC61850 based distance relay and conventional relay (-45km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	no	no	no	no	no	no	no	no

Table 6-13b MTT of IEC61850 based distance relay and conventional relay (-15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	116.47	114.8	120.64	116.44	123.65	117.85	122.43	116.76

Table 6-13c MTT of IEC61850 based distance relay and conventional relay (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	17.17	16.049	17.89	15.495	20.065	17.045	18.815	17.06

Table 6-13d MTT of IEC61850 based distance relay and conventional relay (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	18.425	16.36	16.305	15.965	18.09	17.235	17.72	17.115

Table 6-13e MTT of IEC61850 based distance relay and conventional relay (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	215.91	214.92	215.74	215.07	217	215.5	216.41	215.43

Table 6-13f MTT of IEC61850 based distance relay and conventional relay (110km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	227.62	227.57	226.96	228.28	243.28	237.05	231.84	228.03

Table 6-13g MTT of IEC61850 based distance relay and conventional relay (130km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	616.15	614.67	615.46	614.41	617.01	615.15	616.86	616.51

Table 6-13h MTT of IEC61850 based distance relay and conventional relay (230km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	628.15	628.2	627.71	627.38	645.57	652.59	632.36	636.8

Table 6-13i MTT of IEC61850 based distance relay and conventional relay (270km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	IEC	CON	IEC	CON	IEC	CON	IEC	CON
MTT	no	no	no	no	no	no	no	no

The results indicate that the two relays have a very similar performance and respond with similar tripping times.

As the MTT of 110km and 230km shown, the trip may become slower when the fault happens next to the boundary of the protection zone.

Because of the 17.5° (0.97ms) lagging of the SV signal to the hardwired analogue signal, the response of the conventional relay is faster than the IEC61850 based relay.

6.4 Distance Protection Scheme Test

The performance of an EHV distance protection scheme with different process bus topologies was demonstrated using the RTDS simulator. The modelled transmission system, shown in Figure 6-14, consisted of the protected 100km line, with similar lines connected to both the local and remote end and 5 GVA sources connected to them. The local end was configured as the digital substation with the IEC61850 protection. The conventional relay was located at the remote end.

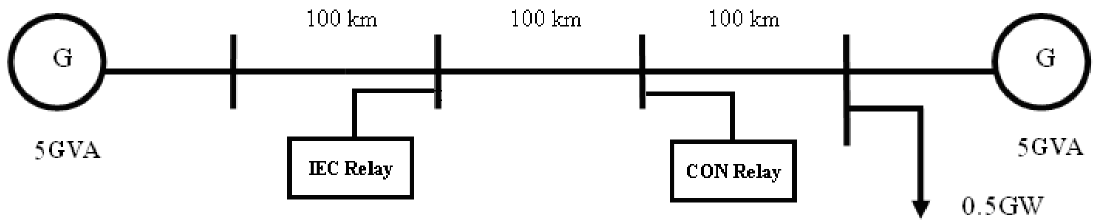

Figure 6-14 Modelled power transmission line of distance protection scheme test

The relays were configured as a permissive under-reach protection scheme (PUR) which is shown in Figure 6-15. The communication channel for a PUR scheme was keyed by operation of the under-reaching zone 1 elements of the relay. If the remote relay has detected a forward fault upon receipt of this signal, the relay will operate with no additional delay using the PUR scheme. Faults in the lines end zone, 20% of the protected line, are therefore cleared with no intentional time delay.

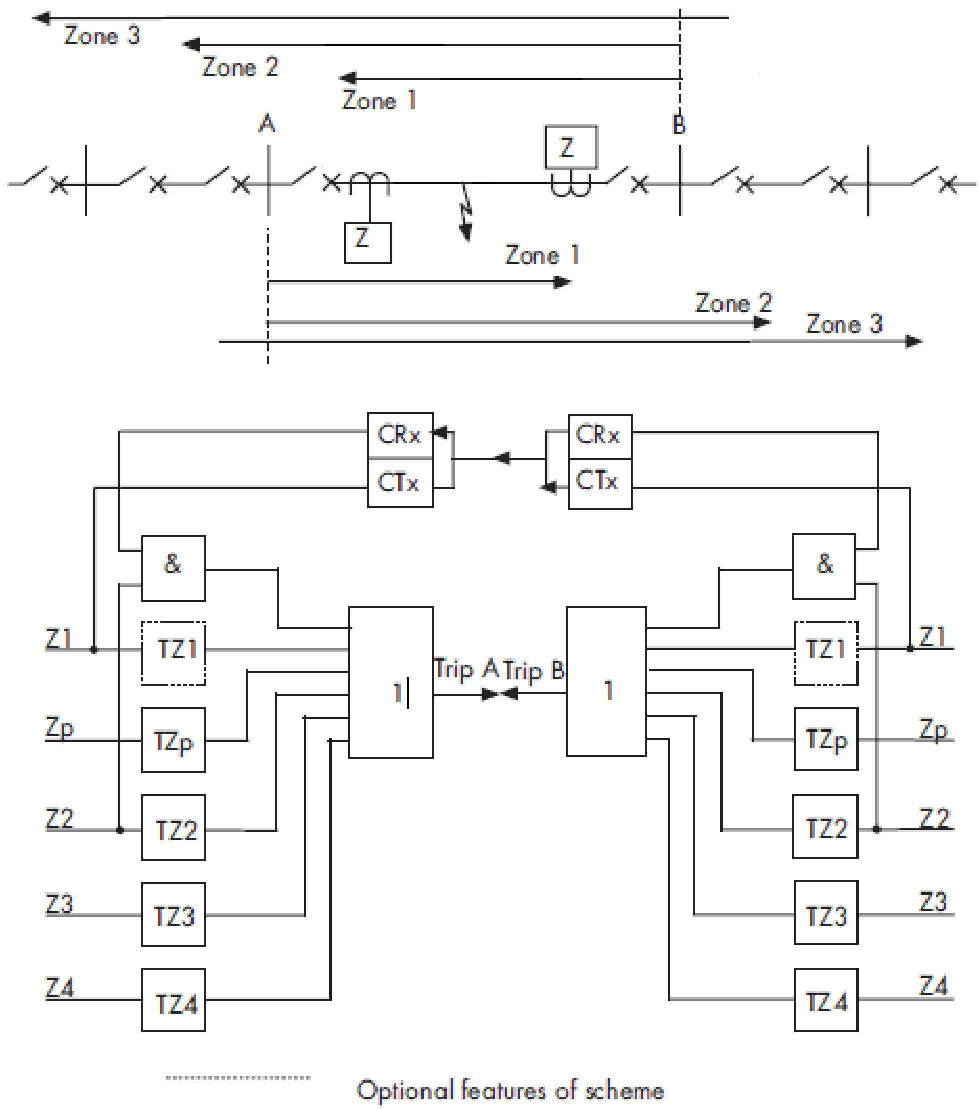

Figure 6-15 Permissive under-reach protection scheme characteristic

Standard 100/1000TX electrical cables with RJ45 connector are used to connect the local IEC61850 based relay to the Ethernet communication network. Fibre optic communication was used to achieve the communication between the two relays. Both relays were configured to send their digital trip signals to the RTDS digital input interface. The RTDS measures and reports the relays' tripping times.

The main parameters of the relay and transmission line are shown in Table 6-14.

Table 6-14 Parameters of relay and transmission line for distance scheme test

Item	Value
f nom	50.00 Hz
No. of phases	3
V primary	400.0 kV
V secondary	110.0 V
I primary	1.000 kA
I secondary	1.000 A
Z1 Ph. Reach	80 km
tZ1 Delay	0s
Z2 Ph. Reach	150 km
tZ2 Delay	200ms
Z3 Ph. Reach	250 km
tZ3 Delay	600ms
Z4 Ph. Reach (reverse)	-50 km
tZ4 Delay	100ms
Line length	100.0 km
Line impedance	26.75Ω
Line angle	86°
kZN residual comp	0.67
kZN residual angle	-5.000°

Details of the faults used for the testing are shown in Table 6-15.

Table 6-15 Outline of distance protection scheme test

Fault Type	Phase A to ground
Pre-fault Time	2s
Fault Point (measured from digital substation)	-25 km, 15 km, 50 km, 85 km, 115 km
Point On Wave	0º, 45º, 90º

6.4.1 Distance Protection Scheme Test Using Cascaded Topology

The communication architecture of the protection scheme is shown in Figure 6-16.

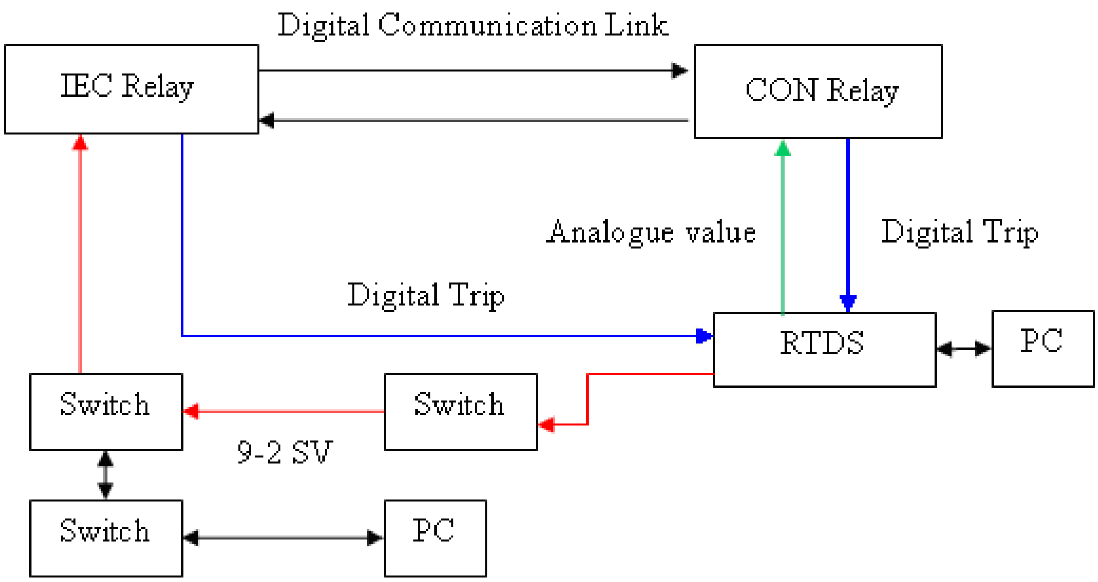

Figure 6-16 Configuration of distance protection scheme test using cascaded topology

In the tests, faults are applied at each fault point with different points on wave, POW. Each test is repeated ten times and the MTT is calculated. The trip times for both the IEC61850 based relay, IEC, and the conventional relay, CON, are recorded as shown in the Table 6-16 below.

Table 6-16a Trip times of distance protection scheme test using cascade architecture (-25 km)

Fault Point: -25 km	-25km	-25 km	-25 km	-25 km	-25 km	-25 km	-25 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
225.7	116.8	222.1	118.2	238.6	122.4	227.9	123.9
225.7	115.8	223.5	119.8	226.4	124.1	226.5	118
227.9	116.5	225.2	121.6	235.1	124.1	227.4	121.7
226.6	116	223.4	121.7	235.8	124.7	227.4	121.8
225.5	115.9	224.2	120.4	235.3	124.2	227.1	122.6
226.1	116.7	221.7	116.6	235.3	122.3	228.8	122
225	117.8	221.7	116	237	122.1	231.7	122.8
226.4	115	222.6	118.8	236.8	124	228.6	121.2
226.6	115.5	222.5	118.9	235.1	120.6	229.1	121.4
227	116.7	222.7	115.7	236.4	124.4	227.8	122.9
The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay.							

Table 6-16b Trip times of distance protection scheme test using cascade architecture (15 km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
24	16.2	23.25	16.5	23.4	16.6	21.2	15.75
21.55	15.3	22.05	16.5	23.05	16.4	24.1	16.5
22.75	16	22.5	15.65	23.55	17.2	20.9	15.7
23.1	15.8	22.15	15.4	22.25	16.65	24.25	17.1
23.45	16.85	22.15	16.05	22.85	17	24.15	17.15
23.35	17.2	22.9	15.6	22.4	18.25	24.7	17.85
22.65	16.25	22.75	16.4	22.45	16.9	24.45	17.15
24.65	16.45	23.3	15.8	23.1	17.35	25.05	17.95
21.1	15.5	23.3	15.2	22.6	16.45	23.15	16.9
21.6	15.1	23.3	16.65	23.5	16.6	23.8	17.15
The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay.							

Table 6-16c Trip times of distance protection scheme test using cascade architecture (50 km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
16	14.95	17.7	17.2	17.15	17.95	17.85	17.35
16.45	15.75	17.4	16.45	19.15	18.1	16.05	17.65
17	15.85	17.25	17.65	16	17.2	15.95	16.75
15.95	16.6	17.45	18	17	17.75	16.65	17.15
15.55	19.15	17	17.8	16.5	17.05	18	18.15
16.25	17.05	15.65	17.1	17.7	17.35	17.1	17.45
15.55	15.3	17.2	16.7	17.4	17.9	16.65	18.05
15.6	17.45	16.65	16.95	18.45	17.9	16.15	16.15
17.1	16.05	16.2	17.35	17.7	17.55	16.55	16.35
15.1	15.15	15.85	17.65	17.15	18.35	17.05	16.55
The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay.							

Table 6-16d Trip times of distance protection scheme test using cascade architecture (85 km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
15.9	23.7	15.95	25.1	16.2	24.2	16.55	23.6
15.8	24.05	15.25	22.45	15.3	23.5	15.85	22.8
16	21.15	15.9	23.4	15.2	21.9	16.65	24.6
16	21.8	16.1	25.55	15.45	22.9	16.2	22.9
15.1	22.95	16.25	25.8	15.95	22.75	15.7	23.5
15.1	21.7	16.4	22.85	15.85	22.6	16.8	24.4
16.05	23.2	16.75	24.3	16.3	23.95	16.15	24.7
16.5	23.85	16.5	23.85	15.95	23.75	17	25.05
14.95	20.8	16.7	24.15	16.05	22.85	16.2	23.1
15.4	24.15	15.15	23.45	16.65	23.6	18.55	25.8
The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay.							

Table 6-16e Trip times of distance protection scheme test using cascade architecture (115 km)

Fault Point: 115 km	115km	115 km	115 km	115 km	115 km	115km	115 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
116.9	222.7	115.2	215.8	118.9	217.6	117.8	222.3
116	223.4	121	217.3	119.7	216.6	119.6	223.1
115.5	221.9	119.6	218	119.1	216.3	115.6	216.4
115.8	222.2	118	216.5	122.7	217	121.1	216.8
115.5	224.4	117.9	217.2	122.9	216.3	123	216.2
116.1	220.5	119.1	217	121.1	216.3	116.1	223
116.4	220.9	115.1	215.6	121.9	214.8	123.1	217.8
115.8	221.3	116	216.4	125	215.7	117.2	217.2
116.9	221.5	118.5	217.5	122.5	216.5	116.4	223.2
116.8	221.6	118.4	218.2	125.2	217.3	123.8	220.9
The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay							

The MTT of both relays using cascaded topology is shown in Table 6-17.

Table 6-17a MTT distance protection scheme test using cascaded topology (-25km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	226.25	116.27	222.96	118.77	235.18	123.29	228.23	121.83

The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay. The fault point was next to the zone 2 boundary of the conventional relay, which made the trips slower.

Table 6-17b MTT distance protection scheme test using cascaded topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	22.82	16.065	22.765	15.975	22.915	16.94	23.575	16.92

The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the conventional relay were about 7 ms slower than the IEC61850 relay.

Table 6-17c MTT distance protection scheme test using cascaded topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	16.055	16.33	16.835	17.285	17.42	17.71	16.8	17.16

The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay, therefore the trip times of the two relays were similar.

Table 6-17d MTT distance protection scheme test using cascaded topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	15.68	22.735	16.095	24.09	15.89	23.2	16.565	24.045

The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the IEC61850 relay were about 7 ms slower than the conventional relay.

Table 6-17e MTT distance protection scheme test using cascaded topology (115km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IEC	CON	IEC
MTT	116.17	222.04	117.88	216.95	121.9	216.44	119.37	219.69

The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay. The fault point was next to the zone 2 boundary of the IEC61850 relay, which made the trips slower at 0º POW.

6.4.2 Distance Protection Scheme Test Using Star Topology

The communication architecture is shown in Figure 6-17.

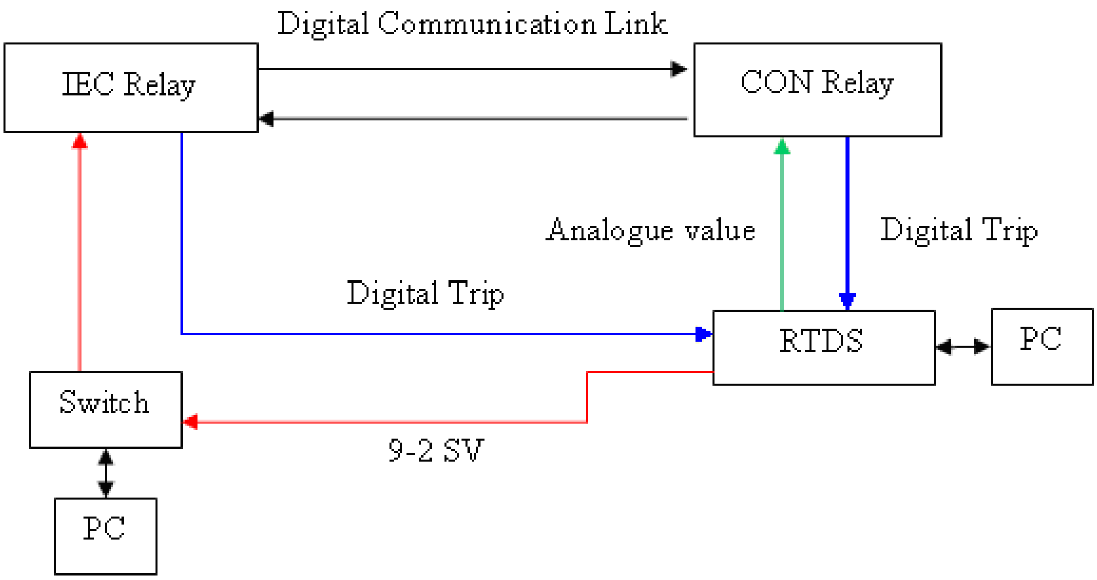

Figure 6-17 Configuration of distance protection scheme test using star topology

The trip times of both relays using star topology are shown in Table 6-18.

Table 6-18a Trip times of distance protection scheme test using star architecture (-25 km)

Fault Point: -25 km	-25km	-25 km	-25 km	-25 km	-25 km	-25 km	-25 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
225.2	118.1	222.7	117.4	238.4	120.6	231.7	122.1
225.7	116.2	221.9	118.7	236.2	121.2	228.8	122.6
225.9	116.4	223.5	117.2	226.5	122.5	229	123.2
227.9	117.1	224	118	237	121.2	227.1	122.5
227.6	118.7	223.8	116.4	235.7	122.6	227.2	120.2
226.8	116.7	224.1	117.7	236.1	123.2	227.1	122
226.5	116.1	226	117.3	237.8	119.8	229	122.9
226.6	117.9	222	114.5	236.8	122.2	226	121.5
225.7	115.8	223.5	118	235.5	123.6	228.5	124.1
226.9	116.4	222.7	118.2	239.6	122	229.3	120.1
The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay.							

Table 6-18b Trip times of distance protection scheme test using star architecture (15 km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
23	16.75	21.1	15.65	22.85	16.4	25.35	17.85
23.25	17.85	21.55	16.2	22.35	15.25	23.15	16.85
23.6	15.8	21.5	16.5	22.45	16.45	22.35	16.15
22.4	15.7	21.3	15.15	22.2	16.1	23.55	16.7
22.2	15.25	21.75	15.8	23.1	16.2	22.75	17.55
21.95	15.05	22	16.65	23.3	16.1	23.4	17.7
22.75	15.7	21.85	16.45	24.15	15.55	25.75	18.1
20.6	15.45	22.4	16.3	23.75	16.4	25.25	15.95
23.4	16.45	21.95	16.15	22.55	16.2	24.35	16.45
23.4	16.25	22.1	15.85	23.5	16.45	24.4	16.25
The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay.							

Table 6-18c Trip times of distance protection scheme test using star architecture (50 km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
17	15.9	17	17.15	17.65	16.1	16.6	17.75
16.45	15.7	16.7	18.05	17.2	16.95	16.9	16.45
16.5	15.95	17.2	16.9	16.3	19.65	18.3	17.25
15	16.4	17.05	18.15	16.85	18.1	17.45	17.7
15.85	16.55	16.7	16.85	16.7	17.05	17.15	17.9
16.5	16	16.5	17.75	16.5	16.7	16.45	17.15
16.55	16	16.75	18.15	18.2	20.5	16.55	18
14.9	17.6	16.95	16.05	17.85	18.1	17.2	17
16	16.8	17.05	17.6	18	17.4	17.45	18.35
16.85	14.95	17.05	16.3	16.65	16.6	16.5	16.6
The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay.							

Table 6-18d Trip times of distance protection scheme test using star architecture (85 km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
15	24.4	16.1	26.8	16.6	24.05	15.3	23.25
16.05	23.85	16.85	25.65	15.95	23.15	15.2	21.95
14.6	21.95	17.4	24.6	17.25	23.7	17.6	24.35
15.45	22.75	15.35	22.3	17.25	22.95	15.8	24.8
15.4	24.65	16	22.65	17.1	23.7	16.5	25
15.1	20.65	16.85	22.5	17.5	25.05	15.5	22.4
17.2	23.9	15.75	23.1	17.55	23.3	16.6	24.8
16	21.85	16.5	22.65	16.55	23.45	16.8	25.25
16.45	25.15	15.75	23.25	16.5	24.4	17.3	26.15
15.5	23.05	16	23.75	18.75	26.55	15.8	22.9
The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay.							

Table 6-18e Trip times of distance protection scheme test using star architecture (115 km)

Fault Point: 115 km	115km	115 km	115 km	115 km	115 km	115km	115 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
118.5	222.2	115.9	217.3	122.8	217.4	118.9	217.1
117.2	224.2	116	215.5	119.6	216.6	117.4	217.3
116.3	223.2	116.1	218.5	117.3	216.2	124.1	223.7
115.8	224.1	115.2	215.8	120.8	215.9	123.7	216.74
115.3	224.9	116.4	214.9	125.4	217.5	121	222.9
116.1	224.1	115.3	216.9	123.5	215.7	119.5	216.4
115.1	226.1	115.6	219.9	125.9	216.3	116.9	214.6
116.1	223.8	116	216.7	119.1	216	118.3	216.2
117.2	224.2	115.7	216.4	118.6	215.4	119.3	215.4
116.7	223.4	1118.3	216.3	125.3	216.3	117.6	215.8
The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay							

Summary of the results using MTT of both relays with star topology is shown in Table 6-19.

Table 6-19a MTT distance protection scheme test using star topology (-25km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	226.48	116.94	223.42	117.34	235.96	121.89	228.37	122.12

The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay. The fault point was next to the zone 2 boundary of the conventional relay, which made the trips slower.

Table 6-19b MTT distance protection scheme test using star topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	22.655	16.025	21.75	16.07	23.02	16.11	24.03	16.955

The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the conventional relay were about 7 ms slower than the IEC61850 relay.

Table 6-19c MTT distance protection scheme test using star topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	16.16	16.185	16.895	17.295	17.19	17.715	17.055	17.415

The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay, therefore the trip times of the two relays were similar.

Table 6-19d MTT distance protection scheme test using star topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	15.675	23.22	16.255	23.725	17.1	24.03	16.24	24.085

The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the IEC61850 relay were about 7 ms slower than the conventional relay.

Table 6-19e MTT distance protection scheme test using star topology (115km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	116.43	224.02	216.05	216.82	121.83	216.33	119.67	217.61

The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay. The fault point was next to the zone 2 boundary of the IEC61850 relay, which made the trips slower at 0º POW.

6.4.3 Distance Protection Scheme Test Using Ring Topology

The communication architecture is shown in Figure 6-18.

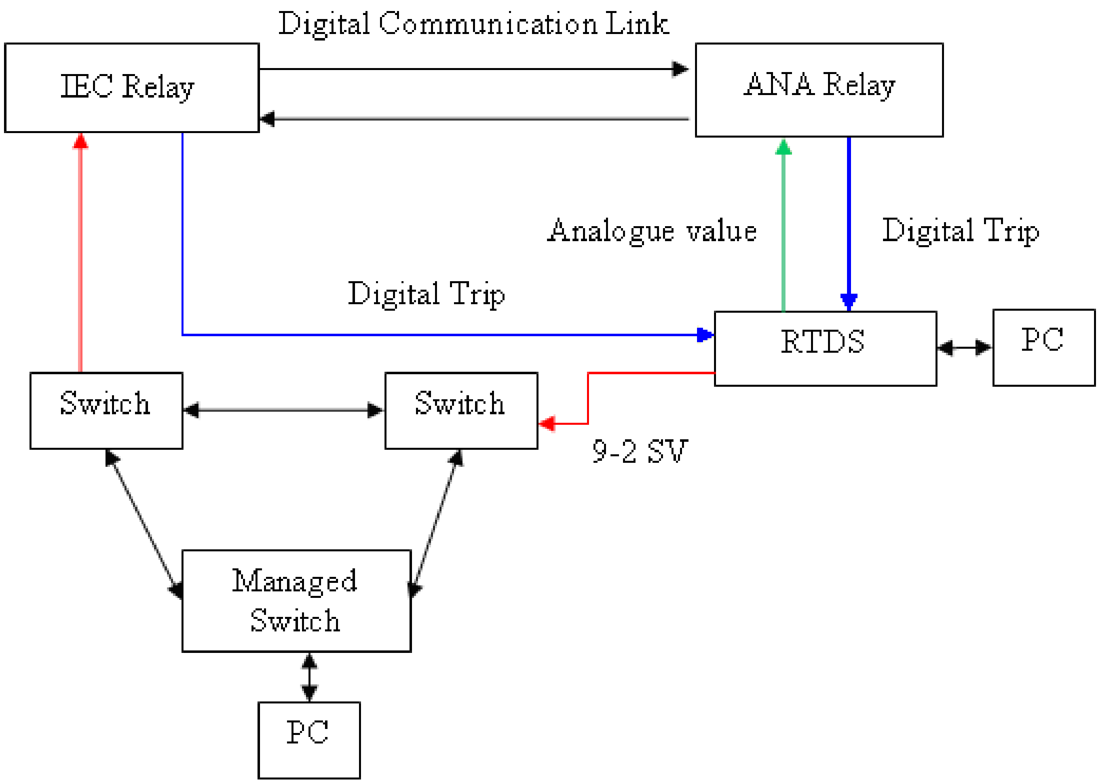

Figure 6-18 Configuration of distance protection scheme test using ring topology

The trip times of both relays using star topology are shown in Table 6-20.

Table 6-20a Trip times of distance protection scheme test using ring architecture (-25 km)

Fault Point: -25 km	-25km	-25 km	-25 km	-25 km	-25 km	-25 km	-25 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
226	116.5	225	117.4	237.4	120.5	227.8	121.5
226.9	115.7	222.5	119.4	238	124.7	228.7	122.7
226.3	116.1	222.9	117.7	238.9	122.8	226.9	122.6
227.5	117.4	225.3	114.7	237.2	123.2	227.1	120.7
225.9	115.1	227.7	122.7	228.5	121.1	228	121.1
227.1	115.9	223.2	117.8	235.2	122.1	227	121
226.5	117.3	221.4	118.5	234.5	121.3	228.9	123.4
226	118.5	220.9	117.3	236.5	122.5	228.1	123.3
226.7	116.5	223.8	116.9	238.8	120.7	228.1	122.3
227.2	117	224.6	121	235.7	123.2	231.1	117
The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay.							

Table 6-20b Trip times of distance protection scheme test using ring architecture (15 km)

Fault Point: 15 km	15 km	15 km	15 km	15 km	15 km	15 km	15 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
22.25	16.4	22.55	15.9	24.25	16.8	24.8	17.95
21.9	15.8	19.85	15.6	24.25	16.95	26.15	17.25
21.55	14.9	23.25	16.2	24.45	17.55	22.75	16
21.25	16.75	23.45	15.3	24.2	17.25	22.55	16.15
21.55	15.25	24.55	16.2	23.1	16.45	21.7	16.45
22.5	16.5	20.2	15.75	24.8	18.45	23.75	16.3
22.25	16.3	24.85	16.65	23.9	16.4	23.7	17.9
22.15	16.7	24.65	16.25	24.7	17.25	23.4	16.85
22.8	15.85	24.05	16.95	24.25	17.15	22.8	17.9
23.2	16.45	23.35	14.6	22.75	15.85	22.85	16.75
The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay.							

Table 6-20c Trip times of distance protection scheme test using ring architecture (50 km)

Fault Point: 50 km	50 km	50 km	50 km	50 km	50 km	50 km	50 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
17.8	16.45	16.8	17.4	17.85	17.1	17.3	18.65
15.75	17.25	15.95	16.6	18	17.3	16.9	17.55
15.75	15.4	17.7	17.15	17.1	17.35	17.65	16.75
15.95	15.3	17.3	15.65	17.25	17.85	16.65	19.1
15.6	16.15	16.65	16.25	17.6	18.2	16.05	17.95
16.05	16.4	16.6	16.9	17.95	18	16.65	17.55
15.65	16.85	17.1	17.2	16.7	18	16.85	17.15
15.6	16.2	17.25	18.3	17	16.6	16.3	16.7
17.35	16.75	17.15	16	16.1	16.75	16.95	17.05
16.4	16.1	16.5	17	16.95	17	18	17.6
The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay.							

Table 6-20d Trip times of distance protection scheme test using ring architecture (85 km)

Fault Point: 85 km	85 km	85 km	85 km	85 km	85 km	85 km	85 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
15.55	22.35	17	24.65	16.4	25.8	17.05	21.4
16.25	25.45	16.5	25.85	15.8	21.7	15.1	22.35
16.4	24.85	16.25	24.05	17.2	25.25	15.25	22.85
15.8	25.2	16.05	24.25	17.15	24.9	16.4	22.55
15.75	21.7	15.95	23.65	16.9	24.9	16	22.15
15.1	22.3	16.55	24.6	17	25.8	15.7	22.75
15.25	21.6	16.2	23.25	17.4	25.35	15.25	23.4
16	22.25	16.45	23.05	17.35	23.5	16.55	24.1
15.95	21.25	15.6	22.2	18.3	25.15	16.4	23.4
15.6	23.45	16.05	24.55	15.85	24.4	15.95	23.75
The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay.							

Table 6-20e Trip times of distance protection scheme test using ring architecture (115 km)

Fault Point: 115 km	115km	115 km	115 km	115 km	115 km	115km	115 km
POW: 0º	0º	45º	45º	90º	90º	135º	135º
Relay Type: CON	IEC	CON	IEC	CON	IEC	CON	IEC
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
116	223.6	117.6	221.7	120.3	216.1	117.1	216.3
116.1	221.6	122.8	218.1	121.7	217	118.1	221.9
116.5	221.8	117.9	223.2	122.7	215	118.3	223.8
115.7	222.9	125.7	216.2	117.6	215.5	118.6	214.6
117.1	222.6	123.8	216	118.7	216.3	125.2	217.7
115.3	223.1	116.5	214.9	122.6	215.5	117.7	218.1
115.2	221.1	118.9	215.3	121.2	216	122.6	222.2
116.5	222.6	120.7	215.9	120.9	215.6	117.8	221.7
116.2	221.9	121.5	216.9	119.5	217.5	121.6	222.9
118.8	222.9	118.4	217.9	119.8	215.8	118.8	216
The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay							

The MTT of both relays using star topology is shown in Table 6-21.

Table 6-21a MTT distance protection scheme test using ring topology (-25km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	226.61	116.6	223.73	118.34	236.07	122.21	228.17	121.56

The tripping times were zone 4 times for the IEC61850 relay and zone 2 times for the conventional relay. The fault point was next to the zone 2 boundary of the conventional relay, which made the trips slower.

Table 6-21b MTT distance protection scheme test using ring topology (15km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	22.14	16.09	23.075	15.94	24.065	17.01	23.445	16.95

The tripping times were zone 1 times for the IEC61850 relay and PUR carrier assisted times for the conventional relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the conventional relay were about 7 ms slower than the IEC61850 relay.

Table 6-21c MTT distance protection scheme test using ring topology (50km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	16.19	16.285	16.9	16.845	17.25	17.415	16.93	17.605

The tripping times were zone 1 times for both the IEC61850 relay and the conventional relay, therefore the trip times of the two relays were similar.

Table 6-21d MTT distance protection scheme test using ring topology (85km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	15.765	23.04	16.26	24.01	16.935	24.675	15.965	22.87

The tripping times were zone 1 for the conventional relay and PUR carrier assisted times for the IEC61850 relay. Because of the communication delay between the two relays and processing of the PUR scheme, trips of the IEC61850 relay were about 7 ms slower than the conventional relay.

Table 6-21e MTT distance protection scheme test using ring topology (115km)

POW	0º	0º	45º	45º	90º	90º	135º	135º
Relay	CON	IEC	CON	IEC	CON	IET	CON	IEC
MTT	116.34	222.41	120.38	217.61	120.5	216.03	119.58	219.52

The tripping times were zone 2 times for the IEC61850 relay and zone 4 times for the conventional relay. The fault point was next to the zone 2 boundary of the IEC61850 relay, which made the trips slower at 0º POW.

6.5 Transformer Current Differential Protection Relay Test

The performance of an EHV transformer current differential protection relay with different process bus topologies was demonstrated using the RTDS simulator. The modelled transmission system, shown in Figure 6-19, consisted of the protected transformer, with a 100 km line connected to the local end and a 1 GVA source connected to it. The low voltage end was configured as the digital substation with the HV IEC61850 based transformer protection. Both the low voltage and high voltage sides of the transformer used IEC61850 9-2 connection. Each side is for a different GTNET card.

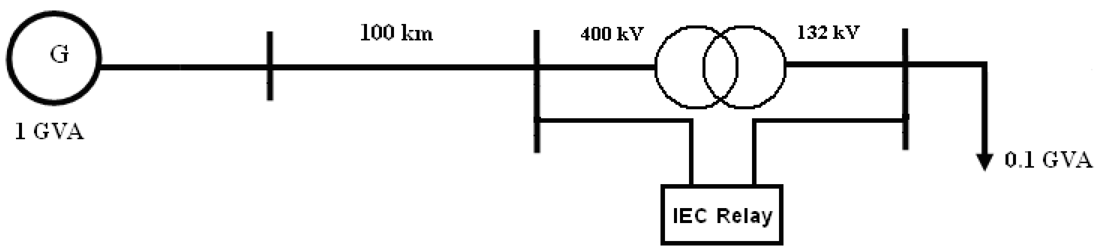

Figure 6-19 Modelled power transmission line for the transformer current differential protection relay test

The tripping characteristics of the current differential protection relay are shown in Figure 6-20.

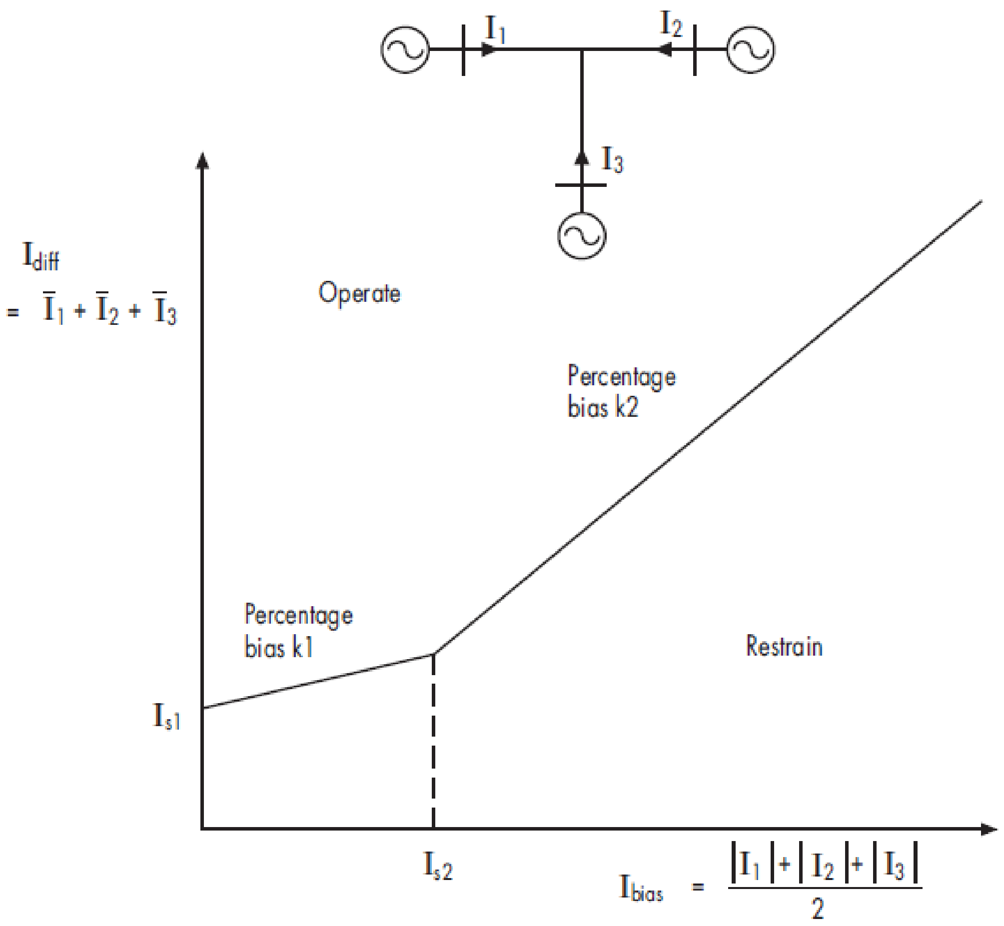

Figure 6-20 Current differential bias characteristic

Standard 100/1000TX electrical cables with RJ45 connectors were used to connect the IEC61850 relay to the Ethernet communication networks. The relay is configured to send digital trip signal to the RTDS digital input interface. The RTDS measures and reports the relays' tripping times.

The main parameters of the relay and transmission line are shown in Table 6-22.

Table 6-22 Parameters of relay and transmission line for transformer relay test

Item	Value
f nom	50.00 Hz
No. of phases	3
HV nominal	400 kV
HV connection	Y-Wye
LV nominal	132 kV
LV connection	Y-Wye
Leakage inductance	0.2 PU
Transformer rating	100 MVA
Is1	2.000 PU
K1	30%
Is 2	10.00 PU
K2	80%
Line length	100.0 km
Line impedance	26.75Ω
Line angle	86°
kZN residual comp	0.67
kZN residual angle	-5.000°

Details of the faults used are shown in Table 6-23.

Table 6-23 Outline of transformer current differential relay test

Fault Type	Phase A to ground
Prefault Time	2s
Fault Point	HV primary side
Point On Wave	0º, 45º, 90º, 135º

6.5.1 Transformer Current Differential Protection Relay Test Using Cascaded Topology

The communication architecture of the transformer protection is shown in Figure 6-21. The transformer relay subscribes both the HV and LV SVs with one IEC61850-9-2 LE network card.

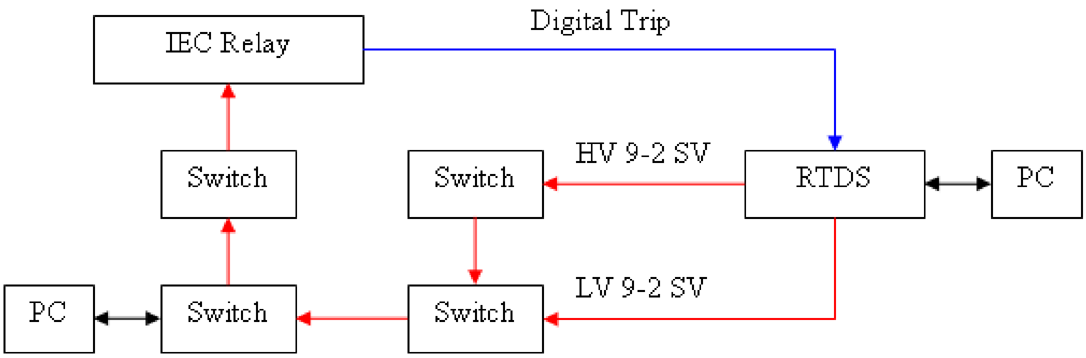

Figure 6-21 Configuration of transformer protection relay test using cascaded topology

In the tests, faults were applied at primary side of the transformer with different points on wave, POW. Two SV data streams (high voltage side and low voltage side) were provided by the RTDS. Each test was repeated ten times and the mean trip time, MTT, was calculated. The trip times are recorded as shown in the Table 6-24 below.

Table 6-24 Trip times of transformer relay test using cascaded topology

POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
13.1	13.45	12.95	16.6
14.35	13.25	12.25	16
12.5	13.1	12.05	15.85
12.5	13.1	11.85	15.8
14.25	12.7	11.9	16.5
14.4	13.4	11.6	15.9
14	12.5	13.2	16.4
14.65	13.1	13.7	15.35
14.9	12.45	11.25	15.3
14.1	12.65	13.5	15.45

The MTT for the cascaded topology is shown in Table 6-25.

Table 6-25 MTT of transformer relay test using cascaded topology

POW	0º	45º	90º	135º
MTT	13.875	12.97	12.425	15.915

6.5.2 Transformer Current Differential Protection Relay Test Using Star Topology

The communication architecture of the transformer protection is shown in Figure 6-22.

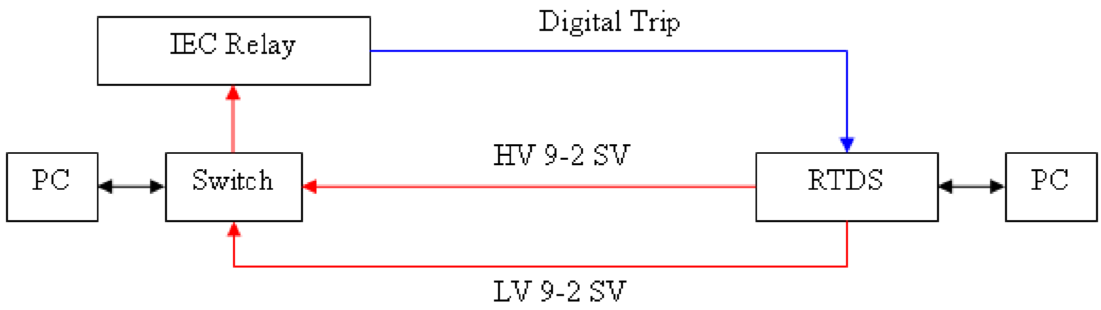

Figure 6-22 Configuration of transformer protection relay test using star topology

The trip times are recorded as shown in the Table 6-26 below.

Table 6-26 Trip times of transformer relay test using star topology

POW: 0º	45º	90º	135º
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
12.95	11.45	12.7	16.8
12.85	11.4	12.3	16.05
13.05	11.85	12.4	15.8
13	11.1	12.75	16.1
12.8	11.8	12.9	16.6
12.75	11.65	12.45	14.75
15.45	11.2	13.85	15.9
13.75	11.5	12.3	15.65
15.15	11	11.75	15.6
14.25	10.7	11.85	15.45

The MTT for the star topology is shown in Table 6-27.

Table 6-27 MTT of transformer relay test using star topology

POW	0º	45º	90º	135º
MTT	13.6	11.365	12.525	15.87

6.5.3 Transformer Current Differential Protection Relay Test Using Ring Topology

The communication architecture of the transformer protection is shown in Figure 6-23.

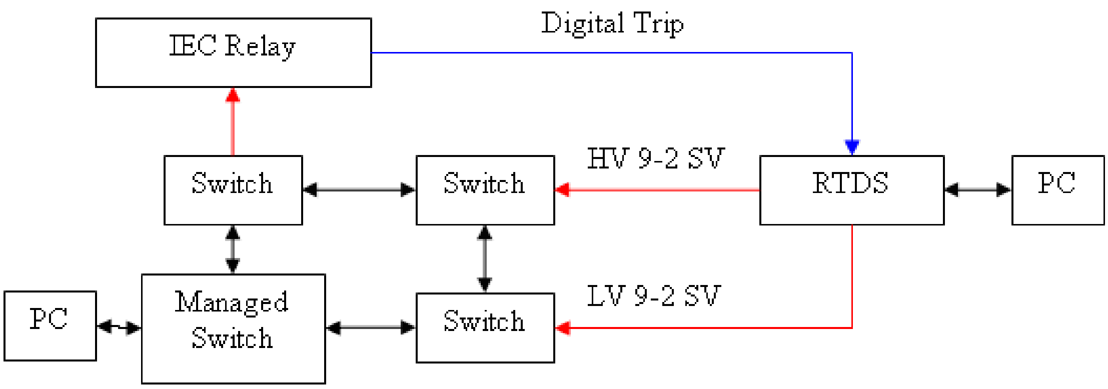

Figure 6-23 Configuration of transformer protection relay test using ring topology

The trip times are recorded as shown in the Table 6-28 below.

Table 6-28 Trip times of transformer relay test using ring topology

POW: 0°	45°	90°	135°
Trip time (ms)	Trip time (ms)	Trip time (ms)	Trip time (ms)
14	12.65	12.9	14.95
14.55	12.85	12.8	15.35
13.3	12.85	12.75	15.15
13	13.1	13.15	18.1
13.15	12.55	12.95	16.05
14.85	12.8	12.85	15.55
14.7	12.65	12.55	15.8
14.65	11.85	12.5	15.4
14.6	11.55	12.1	15.6
14.95	11.35	12.3	15.2

The MTT for the ring topology is shown in Table 6-29.

Table 6-29 MTT of transformer relay test using star topology

POW	0º	45º	90º	135º
MTT	14.175	12.42	12.685	15.715

6.6 Process Bus Overload Test

6.6.1 Introduction

Following the process bus overload simulation in chapter 5, for the process bus overload test, multiple Ethernet sources were connected to the process bus. These data sources provide data streams which were similar to those generated by IEC61850 merging units.

Based on the OPNET studies, as the process bus overload simulation results show, when the traffic on the process bus topologies reaches 85% of the communication link data rate, the SV ETE delay starts to increase with time rapidly, and the max number of MUs that the three process bus topologies can tolerate is 17.

The performance of LB distance protection relay is demonstrated using an “A” phase to ground fault at the mid-point of the protected transmission line with a point-on-wave of 0 degrees. The modelled transmission system is shown in Figure 6-24. The main parameters of the relay and transmission line are shown in Table 6-1.

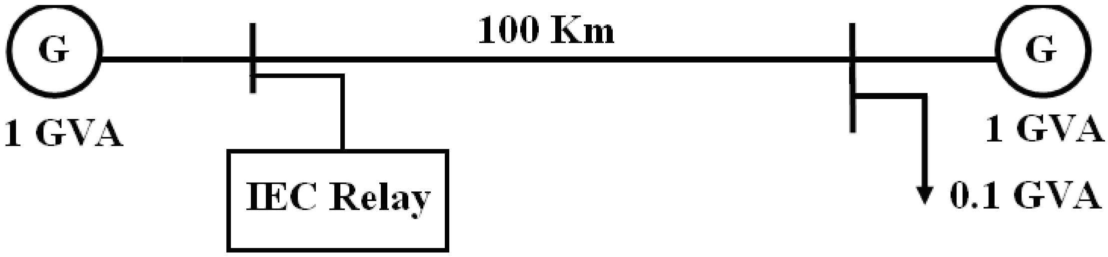

Figure 6-24 Modelled power transmission line for process bus overload test

6.6.2 VLAN Priority of SV Ethernet packet

IEEE 802.1Q is the networking standard that supports Virtual LANs (VLANs) on an Ethernet network. The standard defines a system of VLAN tagging for Ethernet frames and the accompanying procedures to be used by bridges and switches in handling such frames. The standard also contains provisions for a quality of service prioritization scheme commonly known as IEEE 802.1p and defines the Generic Attribute Registration Protocol.

In the Ethernet frame, there is a 3-bit field which is Priority Code Point (PCP). It refers to the IEEE 802.1p priority and indicates the frame priority level. Values are from 0 (best effort) to 7 (highest); 1 represents the lowest priority. These values can be used to prioritize different classes of traffic (voice, video, data, etc).

The default VLAN priority of a SV Ethernet packet is 4. In this case, changing the priority level of the SV packet generated by the RTDS to a higher level, the Ethernet switch will differentiate it from other SV packets and guarantee it not to be influenced by the process bus overload. Therefore, the VLAN priority level of SV streams were all set to 4 in the test.

6.6.3 Process Bus Overload Test Using Star Topology

For this test, multiple Ethernet sources are connected to the star switch. The test system configuration is as shown in Figure 6-25. These simulators are programmed to generate data streams from an increasing number of sources thus increasing the traffic on the process bus.

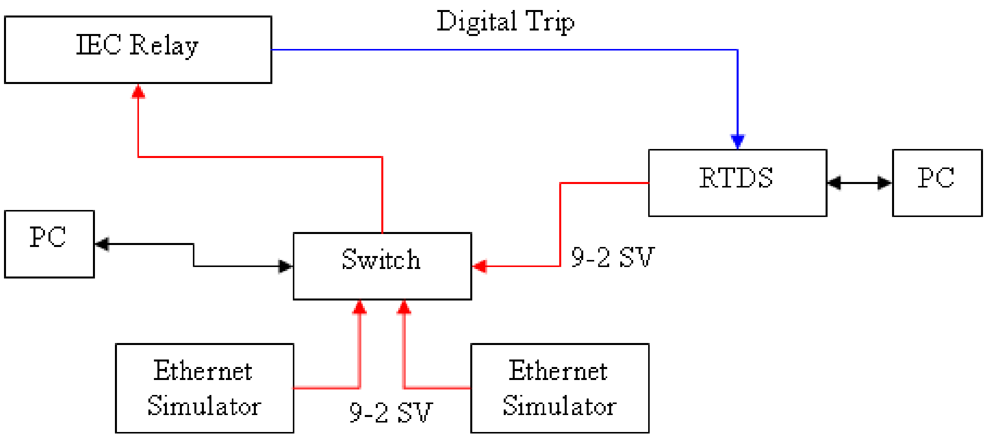

Figure 6-25 Configuration of process bus overload test using star topology

Using Wireshark Network Analyzer, the sample value packets published by the Ethernet Simulator are captured as shown in Figure 6-26. As the size of the Ether-type PDU is 113 bytes, according to Figure 5-2, the size of this sample value packet is 143 bytes. The inter-frame gap is 96 bits, the SV Ethernet frame width is therefore 1240 bits.

The svID is the logical node name of the IED assigned to the MU. The range of this frame is 10 to 34 bytes. As the length of the svID may be different, the size of the PDU could change in different applications. In this case, the size of svID "Areva_MUEthDRS1" is 15 bytes, which makes the size of the PDU 5 bytes bigger than the one used in OPNET simulation.

Using a 100 Mb/s process bus, with a 50 Hz power system and a sampling rate of 4000 samples/s, the max number of merging units that it can support has been shown to be 20, which means the process bus load will reach its full capacity (actually 99.2 Mb/s) when 20 SV data steams transmitted through the process bus. This is an ideal estimation.

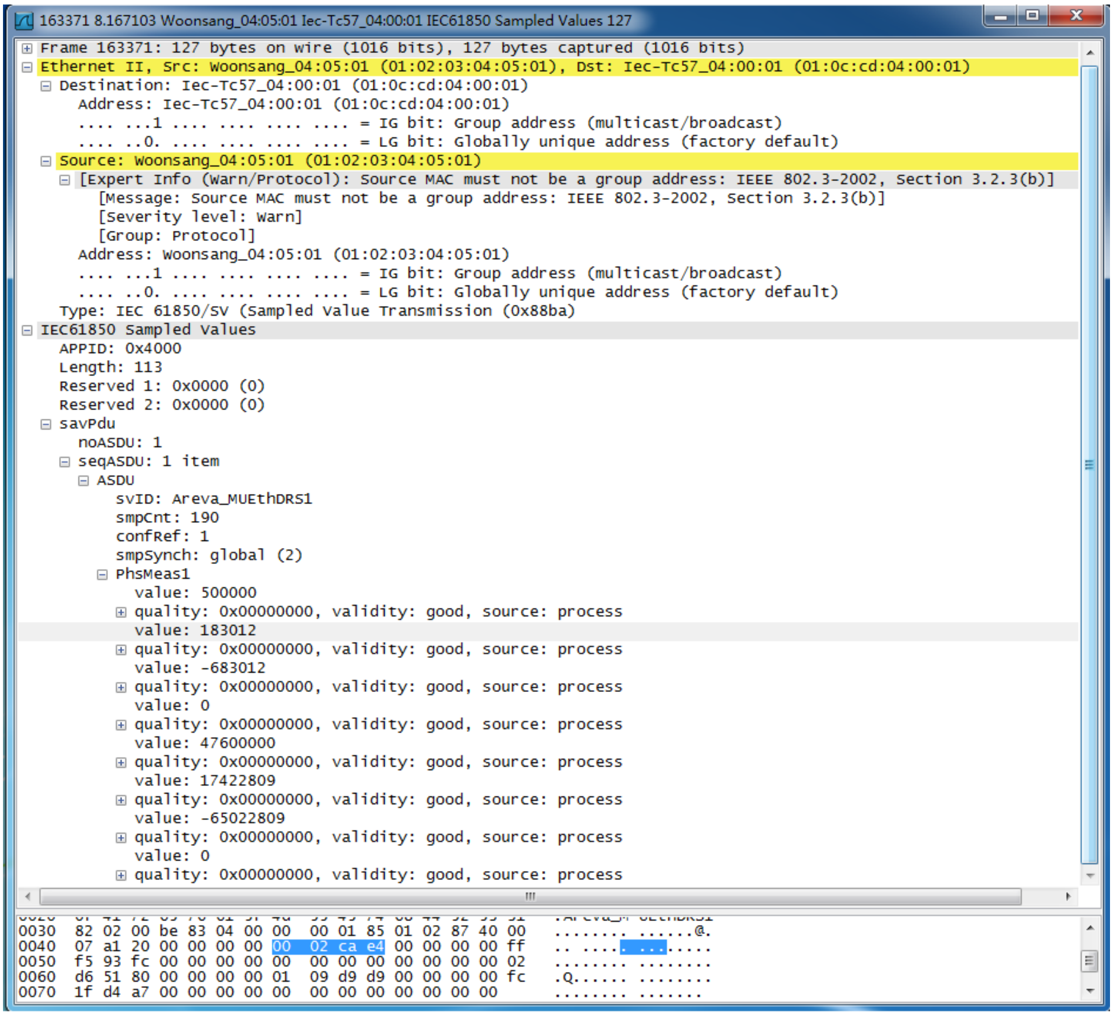

Figure 6-26 Sampled value packet frames captured by Wireshark Network Simulator

The traffic on the process bus is increased and the effect on the IEC61850 relay's tripping times are monitored and recorded as shown in Table Appendix-3. The MTT is shown in Table 6-30.

Table 6-30a MTT of process bus overload test using star topology (1 to 20 SVs)

1 SV MTT	5 SV MTT	10 SV MTT	15 SV MTT	19 SV MTT	20 SV MTT
16.221	16.007	16.986	16.175	16.119	16.02

Table 6-30b MTT of process bus overload test using star topology (21 to 40 SVs)

21 SV MTT	25 SV MTT	30 SV MTT	35 SV MTT	40 SV MTT
23.183	35.493	45.565	50.606	53.6

The results show that the MTT of the IEC61850 based relay starts to increase when 21 SVs are injected into the process bus, which makes the traffic load reaches over its full capacity and lead to the congestive collapse.

Congestion collapse is a condition which a packet switched computer network can reach, when little or no useful communication is happening due to congestion. Congestion collapse generally occurs at choke points in the network, where the total incoming traffic to a node exceeds the outgoing bandwidth [84].

When a network is congestion collapse, it has settled (under overload) into a stable state where traffic demand is high but little useful throughput is available. Throughput is the average rate of successful message delivery over a communication channel [84].

Therefore, there are high levels of packet delay and loss, caused by routers discarding packets due to the output queues are full, and general quality of service is extremely poor under such condition. It can be observed from the Table 6-30 and Table 6-31 that some of the trips are longer than the normal value (16 ms) due to congestion collapse of the process bus LAN, and under such condition the trip times increase as the data traffic load is increased.

The results for different traffic levels are shown in Figure 6-27.

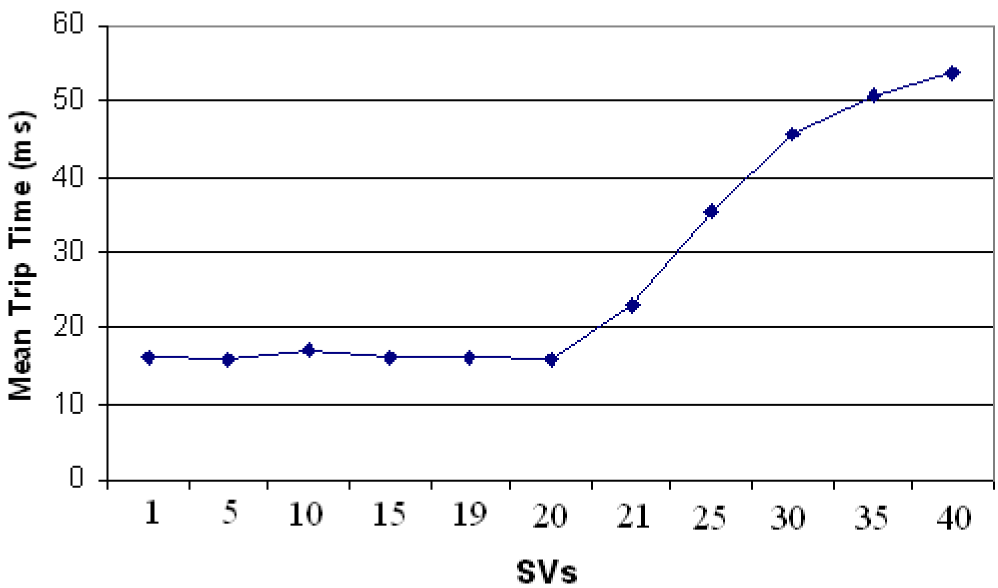

Figure 6-27 MTT with respect to the loading of the star process bus traffic

The results show that the MTT of the IEC61850 based relay starts to increase after the process bus load reaches its full capacity, which is different from the results of OPNET Modeler based process bus overload simulation. It means that the bandwidth utilization efficiency of the real Ethernet switch is 100% rather than 85%. For these tests, there is no evidence of any failure to trip.

6.6.4 Process Bus Overload Test Using Cascaded Topology

The test system configuration is as shown in Figure 6-28.

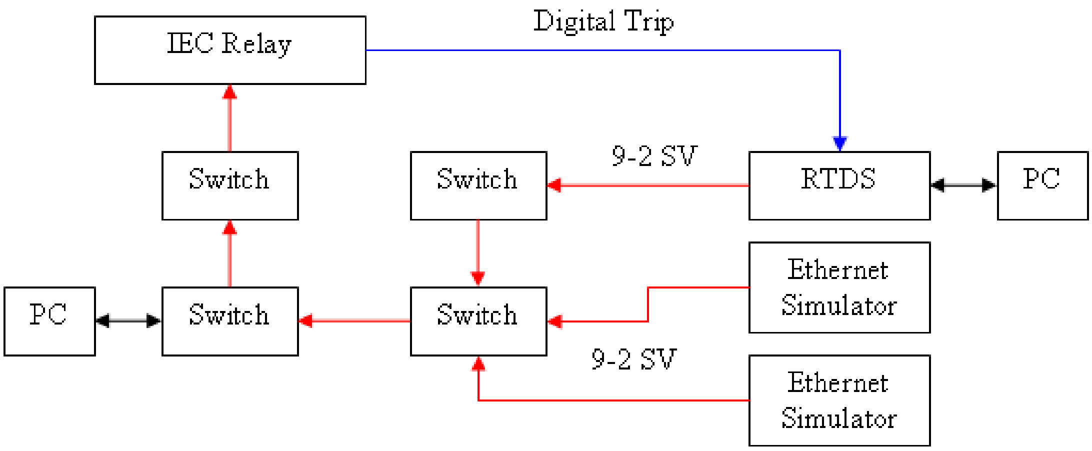

Figure 6-28 Configuration of process bus overload test using cascaded topology

The tripping times are monitored and recorded as shown in Table Appendix-4. The MTT is shown in Table 6-31.

Table 6-31a MTT of process bus overload test using cascaded topology (1 to 20 SVs)

1 SV MTT	5 SV MTT	10 SV MTT	15 SV MTT	19 SV MTT	20 SV MTT
16.705	16.135	16.176	16.443	16.399	16.191

Table 6-31b MTT of process bus overload test using cascaded topology (21 to 40 SVs)

21 SV MTT	25 SV MTT	30 SV MTT	35 SV MTT	40 SV MTT
24.215	34.253	50.577	55.52	51.053

The results for different traffic levels are shown in Figure 6-29.

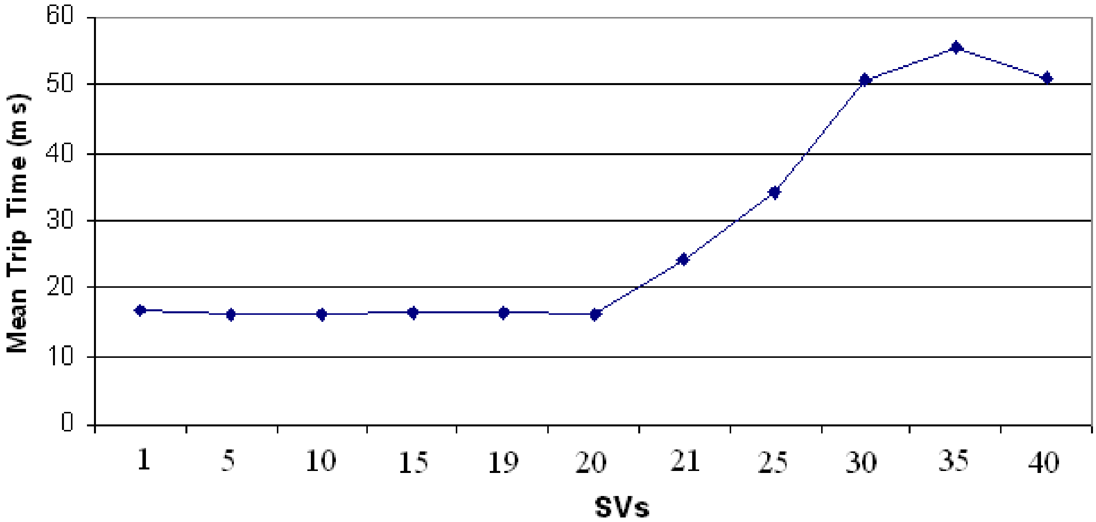

Figure 6-29 MTT with respect to the loading of the cascaded process bus traffic

6.6.5 Process Bus Overload Test Using Cascaded Topology

The test system configuration is as shown in Figure 6-30.

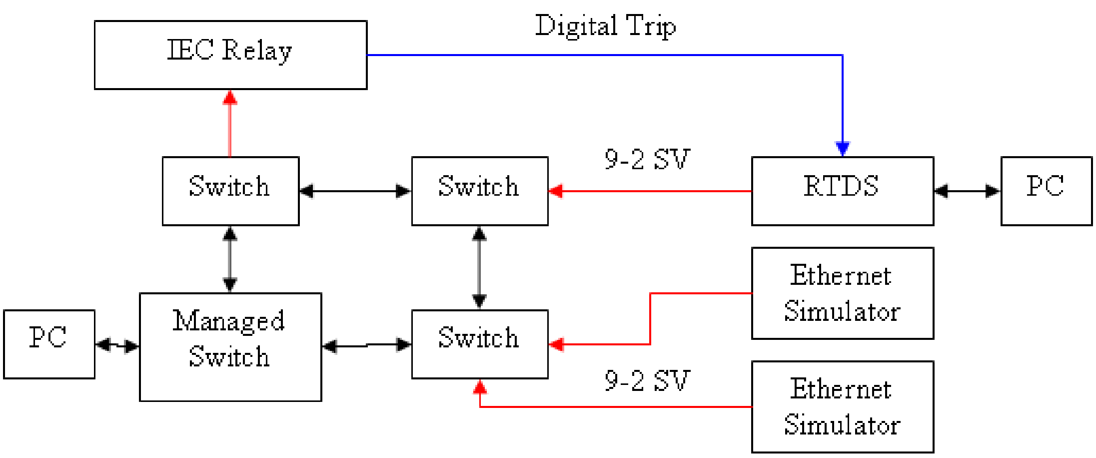

Figure 6-30 Configuration of process bus overload test using ring topology

The tripping times are monitored and recorded as shown in Table Appendix-5. The MTT is shown in Table 6-32.

Table 6-32a MTT of process bus overload test using ring topology (1 to 20 SVs)

1 SV MTT	5 SV MTT	10 SV MTT	15 SV MTT	19 SV MTT	20 SV MTT
15.975	16.489	16.254	16.654	16.937	16.549

Table 6-32b MTT of process bus overload test using ring topology (21 to 40 SVs)

21 SV MTT	25 SV MTT	30 SV MTT	35 SV MTT	40 SV MTT
23.049	32.361	47.157	48.902	49.86

The results for different traffic levels are shown in Figure 6-31.

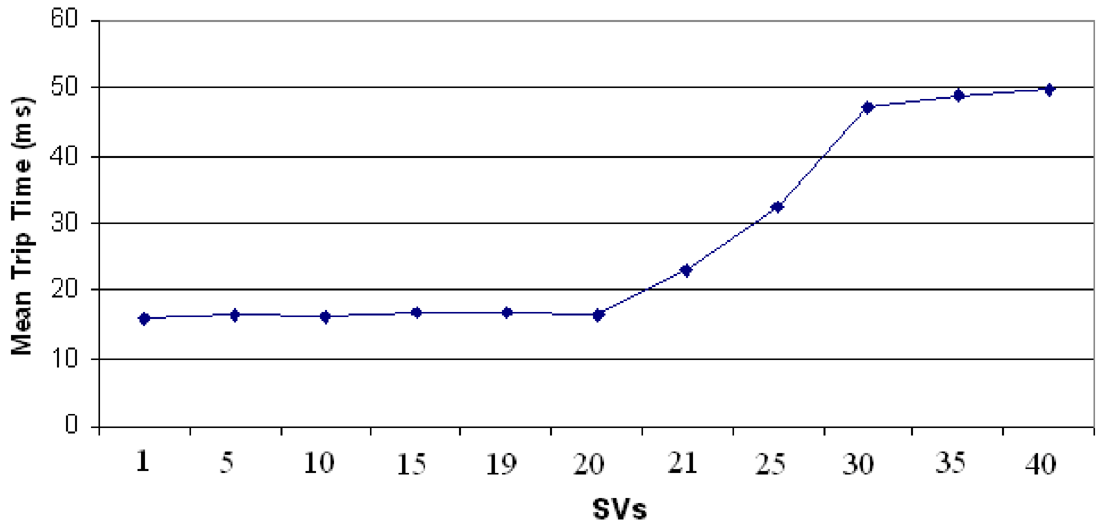

Figure 6-31 MTT with respect to the loading of the ring process bus traffic

6.7 Conclusions

The performance of IEC61850 protection schemes using the three different process bus topologies is investigated with an RTDS real time simulator modelling EHV transmission systems. The protection schemes include feeder distance protection scheme, feeder current differential protection scheme and transformer current differential protection scheme.

The tests demonstrate that the IEC61850 based relays and the conventional relays had a very similar performance and responded with similar tripping times. The time offset introduced by the IEC61850-9-2 digitization process is approximately 1ms. Differences of the tripping times for the three different process bus topologies are small.

Tests to investigate the IEC61850 relay's performance when the process bus traffic is overloaded demonstrate a consistent performance until the process bus is congestion collapse. The bandwidth utilization efficiency of the real Ethernet switch is 100% of the communication link data rate (100Mb/s). Under the congestion collapse condition, the protection becomes slower and the tripping times are increased.

Chapter 7

Conclusion and Future Work

THIS chapter summarizes the thesis by outlining the major contributions and findings from the research, and also presents future works that can be done to improve the technology.

7.1 Conclusion

The aims of IEC61850 are to reduce costs, respond to the increasing demands for communications and to provide for standard protocols available from different manufacturers. There are also aims to provide for future proofed equipment, interoperability of equipment from different manufacturers and easing the management of future power system substation equipment.

These aims can be met and if the road-maps provided by the computer and communications systems are followed. There will also be a host of other opportunities and advantages that can be realised. These include easier repair, refurbishment and replacement of sub-station protection, control and metering equipment. They also provide for greater use of general purpose IEDs, self-healing systems, and plug and play type facilities.

IEC61850, the communications standard for the digital substation, has provided the basis for future protection and control systems. The communications buses, which are fundamental to the operation of these schemes have presented challenges to protection scheme designers as to the type of system architecture which can be used.

In order to reducing the outages for replacement of the secondary equipments which are typically eight weeks in duration to one – two weeks, National Grid Electricity Transmission launched the Architecture of Substation Secondary System (AS^3). This aim will be achieved by implementation of a process bus.

Therefore, four primary aims and seven golden rules are proposed for the design of the process bus architecture by the National Grid.

Primary aims of AS^3 process bus architecture are:

A. Allow replacement of faulty IED with minimum outage requirements.

B. Allow secondary refurbishment of a bay with minimum outage requirement.

C. Simplify isolation procedures between primary and secondary systems.

D. Reduce risks of mal-operation.

Seven golden rules for the design of the process bus Architecture are:

1. *The design principles of the AS^3 scheme must be standard for all bay types – DBB feeder, DBB Bus Section, DBB Bus Coupler, MC Mesh Corner, MC Transformer, MC Feeder.*

2. *The switching box should be located as close as possible to the Primary equipment*

3. *No single activity on the MAIN 1 system shall affect the MAIN 2 system.*

4. *No single failure shall result in the loss of control of more than one bay.*

5. *Physical facilities shall be available to isolate a bay for testing (Protection & Control).*

6. *The Protection and Control application/philosophy shall be functionally identical to the existing bay solution currently provided by National Grid suppliers.*

7. *All trip signals shall be received by the breakers within 10ms (excluding intertrip send).*

Cooperating with WG4, Architecture & Reliability, a process bus architecture is proposed, which has already been agreed by National Grid. This process bus architecture as shown in Figure 7-1 contains two bay process buses (PB1 and PB2) which are connected to the MAIN 1 and MAIN 2 protection respectively, which makes them totally separated and independent.

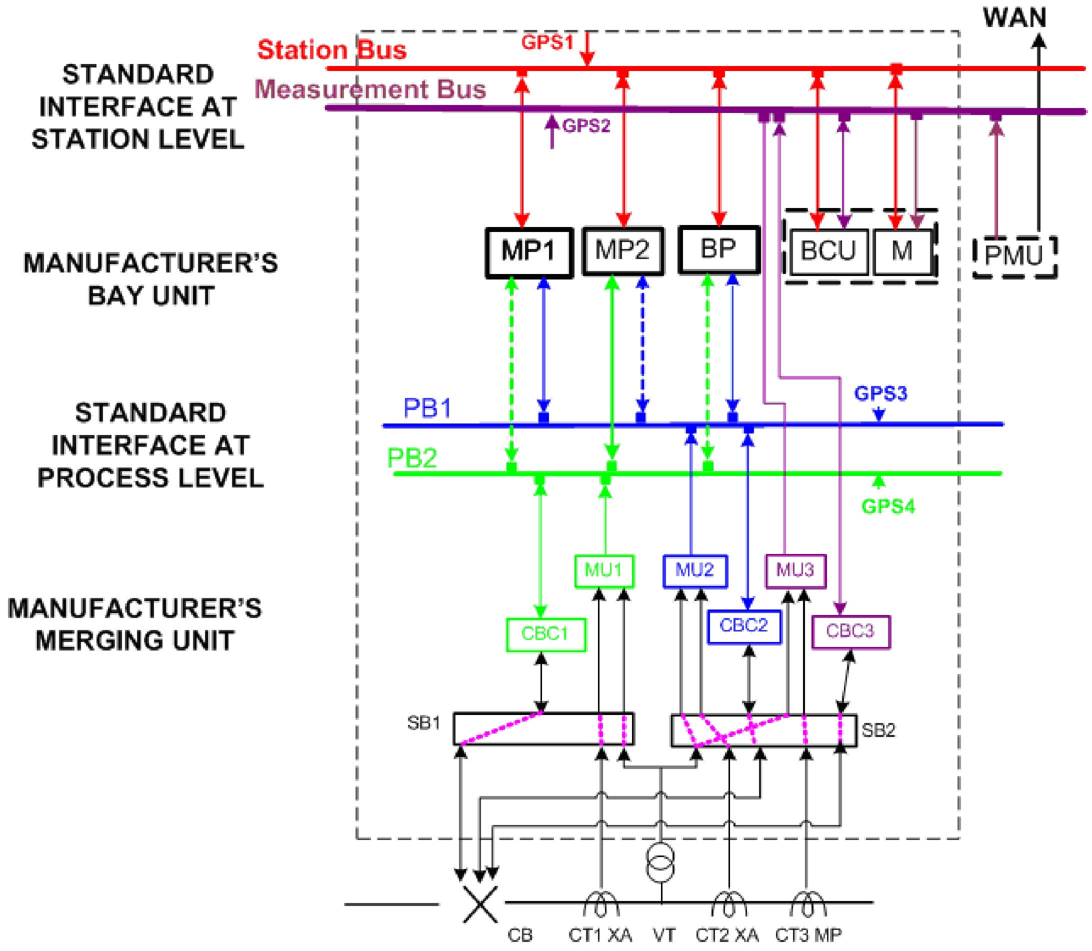

Figure 7-1 Substation communication system using the proposed standard process bus architecture

The main advantages of this process bus architecture are described below in terms of the four primary aims and seven golden rules of AS^3 project.

12. Allow replacement of faulty IED with minimum outage requirements.

With the application of switching box, two independent bay process buses and gateway switches, the, any single faulty IED can be replaced without an outage or impacting any other IEDs.

13. Allow secondary refurbishment of a bay with minimum outage requirement.

The secondary system of a bay can be refurbished without an outage.

14. Simplify isolation procedures between primary and secondary systems.

The primary system of a bay can be refurbished in an isolated way.

15. Reduce risks of mal-operation.

By using the independent MAIN 1 and MAIN 2 protection systems, each protection IED is capable of tripping the circuit breaker. Therefore, the risk of mal-operation is reduced.

16. The design principles of the AS^3 scheme must be standard for all bay types – DBB feeder, DBB Bus Section, DBB Bus Coupler, MC Mesh Corner, MC Transformer, MC Feeder.

The process bus architecture is proposed as a standard for all bay types.

17. The switching box should be located as close as possible to the Primary equipment.

The switching box is capable of being located next to the Primary equipment

18. No single activity on the MAIN 1 system shall affect the MAIN 2 system.

The MAIN 1 and MAIN 2 systems are totally separated and independent.

19. No single failure shall result in the loss of control of more than one bay.

All the BCUs are connected to the inter-bay measurement process bus and station bus through gateway switches. Any single failure would influence one BCU at most.

20. Physical facilities shall be available to isolate a bay for testing (Protection & Control).

The application of switching box and gateway switches can fulfil this requirement.

21. The Protection and Control application/philosophy shall be functionally identical to the existing bay solution currently provided by National Grid suppliers.

The new substation communication system will not influence the protection and control schemes that the substations are using at the moment.

22. All trip signals shall be received by the breakers within 10ms (excluding intertrip send).

As described above, this proposed process bus architecture is capable of achieving the four primary aims and obeying the seven golden rules, but leaves two questions still unanswered.

- What Ethernet LAN topology will be used in the bay process buses?
- Whether all trip signals shall be received by the breakers within 10ms (excluding intertrip send) or not?

This work describes and evaluates three different process bus topologies which are cascaded, star, and ring topology. The performance of IEC61850 protection scheme using these topologies is investigated with different simulation tools. Conclusions are drawn below.

I. Reliablity and availability analysis of process bus topologies

The three process bus architecures are evaluated from the reliability point of view and the MTTF and availability of the feeder bay process bus topologies are calculated. It is found that star topology provides the highest MTTF of 5.639 years and the highest availability of 0.999997907. This architecture has the weakness that the failure of the central Ethernet switch will lead the entire communication system collapse. The cascaded topology provides the MTTF of 5.034 years and the availability of 0.999997369. Considering the first failure, the ring topology provides the same MTTF and availability as cascaded topology. However, ring topology requires managed Ethernet switches with RSTP, which makes this architecture more expensive and complicated comparatively.

II. Modelling and simulation for performance evaluation of process bus topologies

The OPNET Modeller simulation based feeder bay study shows that the star topology provides the shortest SV ETE delay of 0.031576 ms. The cascaded topology provides the SV ETE delay of 0.048348 ms, and the ring topology provides almost the same SV ETE delay of 0.048375 ms as cascaded topology.

According to IEC61850, the acceptable maximum communication delay for the time-critical messages, SVs and GOOSE, is 3 ms. The size of the GOOSE message is smaller than the SV message, and the frequency is lower, hence the SV and GOOSE ETE delay of the MAIN protection for a feeder bay using the three different process bus topologies are small and tolerable.

III. Protection performance study with commercial test set and RTDS simulator

The tests with both commercial test set and RTDS Simulator demonstrate that the IEC61850 based relay and the conventional relay have a similar performance and respond with similar tripping times. It can be concluded that the latency of the process bus is small.

The time offset introduced by the IEC61850-9-2 digitization process of the protection IED is approximately 1ms. It results that the analogue input is faster than the SV input on average. As the operating time of a distance relay should be ≤20ms, considering the worst case which is scenario 2 in section 3.3, the SV input delay is tolerable. The GOOSE trip signal is about 2.6 ms faster than the digital trip signal on average, which indicates that the GOOSE message digitization process of the protection IED is faster than the digital trip signal processing.

IV. Process bus overload test

The OPNET process bus simulation results shows that because the bandwidth utilization efficiency of the OPNET Ethernet switch model is 85%, when the traffic on the process bus topologies reaches 85% of the communication link data rate, the SV ETE delay starts to increase with time rapidly. The max number of MUs that the three process bus topologies can tolerate is 17.

The process bus overload tests to investigate the IEC61850 relay’s performance when the process bus traffic is overloaded demonstrate a consistent performance until the process bus is congestion collapse. The bandwidth utilization efficiency of the real Ethernet switch is 100% of the communication link data rate (100Mb/s). Under the congestion collapse condition, the protection becomes slower and the tripping times are increased. The max number of MUs that the three process bus topologies can tolerate is 20.

7.2 Future Work

The Ethernet standards comprise several wiring and signalling variants of the OSI physical layer in use with Ethernet. The original 10BASE5 Ethernet used coaxial cable as a shared medium. Later the coaxial cables were replaced by twisted pair and fibre optic links in conjunction with hubs and switches. Data rates were periodically increased from the original 10 megabits per second to 100 gigabits per second.

The new Gigabit Ethernet provides a great opportunity for the design of process bus topologies. More complicated topologies can be evaluated, for example, the mesh topologies.

Mesh topology is a type of computer network setup, where each of the computers and devices in the network are interconnected to one another. This allows most of the transmissions to be distributed, even if any one of the connection goes down. The connection between the devices and different nodes (computers) is made through hops. Some of the devices and nodes are connected through single hop and some are connected with more than one hop. In a full mesh topology, every node is connected to every other node in the network. When data is traveling in a mesh network, the network is automatically configured to take the shortest route to reach the destination. In other words, the data is transferred through least number of hops.

Mesh topologies involve the concept of routes. Unlike the cascaded, star and ring topology, messages sent on a mesh network can take any of several possible paths from source to destination. (Recall that even in a ring, although two cable paths exist, message can only travel in one direction.) The advantages of mesh topologies are:

- There are dedicated links used in the topology, which guarantees, that each connection is able to carry its data load, thereby eliminating traffic problems, which are common, when links are shared by multiple devices.

- It is a robust topology. When one link in the topology becomes unstable, it does not cause the entire system to halt.

- If the network is to be expanded, it can be done without causing any disruption to current users of the network.

- It is possible to transmit data, from one node to a number of other nodes simultaneously.

- Troubleshooting, in case of a problem, is easy as compared to other network topologies.

- This topology ensures data privacy and security, as every message travels along a dedicated link.

With the upgrade of protection IED which can support the Gigabit Ethernet, the mesh process bus topologies are worth being investigated in the future.

As concluded in the previous section, The time offset introduced by the IEC61850-9-2 digitization process of the protection IED is approximately 1ms. The GOOSE trip signal is about 2.6 ms faster than the digital trip signal on average. The results may be different if using protection IEDs from different manufacturers. Therefore, various protection IEDs should be involved in the protection performance study in order to improve the IEC61850-9-2 processing power and interoperability of the IEDs.

IEEE 1588 has already been considered to be the next step in the development of the substation communication system synchronization. IEEE 1588 provides fault tolerant synchronization for different clocks along the same network. There is very little bandwidth consumption, processing power, and setup. IEEE 1588 accomplishes all of this by using the PTP (precision time protocol). The time protocol synchronizes all clocks within a network by adjusting clocks to the highest quality clock. IEEE 1588 defines value ranges for the standard set of clock characteristics. The Best Master Clock (BMC) algorithm determines which clock is the highest quality clock within the network. The BMC (grandmaster clock) then synchronizes all other clocks (slave clocks) in the network. If the BMC is removed from the network or is determined by the BMC algorithm to no longer be the highest quality clock, the algorithm then redefines what the new BMC is and adjusts all other clocks accordingly. No administrator input is needed for this readjustment because the algorithm provides a fault tolerant. It is designed for applications that cannot bear the cost of a GPS receiver at each node, or for which GPS signals are inaccessible. The new standard needs to be investigated by applying on the synchronization of multiple MUs with only one GPS receiver.

Appendix 1

The trip times of the four scenarios for the distance relay test using the commercial test set are shown in Table Appendix-1. The four scenarios are:

- Scenario 1: Analogue input and Digital output – conventional hardwired;
- Scenario 2: SV input and Digital output - hybrid implementation of IEC61850;
- Scenario 3: Analogue input and GOOSE output – partial implementation of IEC61850;
- Scenario 4: SV input and GOOSE output – complete implementation of IEC61850.

Table Appendix-1 Trip time of the four scenarios for distance relay test

Fault Point	Angle	Scenario 1 trip time (ms)	Scenario 2 trip time (ms)	Scenario 3 trip time (ms)	Scenario 4 trip time (ms)
40 km	70.00 °	17.4	16.7	13.7	17.5
40 km	70.00 °	19.9	20.1	17.6	19.6
40 km	70.00 °	19.6	20.1	15.9	20
40 km	70.00 °	19.4	20	15.7	20.5
40 km	70.00 °	18.2	17.9	15.4	14.3
40 km	70.00 °	19.6	20.2	14.8	17
40 km	70.00 °	20.3	19.5	17.5	16.3
40 km	70.00 °	20	19.3	17.3	17.2
40 km	70.00 °	18.1	19.5	17.4	16.6
40 km	70.00 °	18.5	19.4	17.1	16.2
40 km	70.00 °	20	19.2	19.4	17.5
40 km	70.00 °	18.1	19.5	15.7	18
40 km	70.00 °	19.3	19.6	15.6	15.8
40 km	70.00 °	18.9	20.3	13.8	17.3
40 km	70.00 °	17.5	19	18	16.8
40 km	70.00 °	20	19.6	16.2	20.2
40 km	70.00 °	17.8	20.2	13	15.7

40 km	70.00 °	18.5	20.3	13.1	18.3
40 km	70.00 °	18.3	19.8	18.8	20.3
40 km	70.00 °	18.6	19.1	15.8	19
40 km	70.00 °	18.1	16.4	16.3	16.1
40 km	70.00 °	17.8	20.2	19.6	20.3
40 km	70.00 °	18.7	19	15.1	18.7
40 km	70.00 °	18.5	18.2	14.9	15.3
40 km	70.00 °	19.3	19.3	15	14.2
40 km	70.00 °	18.4	19.3	15.2	20.4
40 km	70.00 °	19.1	18.5	15.5	16.8
40 km	70.00 °	19.3	16.3	15	18
40 km	70.00 °	17.3	19.9	18.4	14
40 km	70.00 °	18.5	16.8	13.9	16.2
40 km	70.00 °	17.5	19.9	18.6	16
40 km	70.00 °	18.6	20.5	17	19.9
40 km	70.00 °	17.7	19.1	15	16.2
40 km	70.00 °	18.6	18.7	17	15.3
40 km	70.00 °	18.2	18.7	14.3	16.5
40 km	70.00 °	17.4	19.1	15.8	19.5
40 km	70.00 °	18.5	17.6	17.5	19.8
40 km	70.00 °	19.5	17.2	17.8	17.5
40 km	70.00 °	20.5	16.2	13.5	16
40 km	70.00 °	18.3	20.5	20	18.2
40 km	70.00 °	19.1	18.1	15.5	16.8
40 km	70.00 °	19.3	17.7	18.3	17.8
40 km	70.00 °	19.4	19	14.6	15.9
40 km	70.00 °	18.5	19.6	15.6	15.9
40 km	70.00 °	20.7	18.8	15.8	17
40 km	70.00 °	16.5	18.6	15	15.9
40 km	70.00 °	19.1	20.1	19	15.8
40 km	70.00 °	22.5	19.9	14.7	20.5
40 km	70.00 °	18.6	18.7	17.1	19.1

40 km	70.00 °	16.9	19.1	16.6	16.6
40 km	70.00 °	19	19.2	14.8	17
40 km	70.00 °	16.3	19.3	14.9	15.8
40 km	70.00 °	18.6	19.3	15.4	17.3
40 km	70.00 °	18.5	19.4	17	16.8
40 km	70.00 °	16.8	18.2	15.1	17.9
40 km	70.00 °	19.8	19.4	17.7	15.8
40 km	70.00 °	19.8	19.8	15.4	17.1
40 km	70.00 °	18.3	20.4	14.6	14.5
40 km	70.00 °	17.7	19	15.9	15.2
40 km	70.00 °	17.6	17.8	15.4	13.6
40 km	70.00 °	19.1	19.7	15.7	16.3
40 km	70.00 °	16.7	17.9	15.5	20.1
40 km	70.00 °	17.3	19.6	18.8	19.6
40 km	70.00 °	19.3	19.3	15.2	16.8
40 km	70.00 °	20.9	18.8	15.6	17.1
40 km	70.00 °	20.3	18.8	17.3	15.5
40 km	70.00 °	18.8	16.2	15.8	17.9
40 km	70.00 °	19	19.7	17.7	20.2
40 km	70.00 °	17.8	18.8	15.6	16.2
40 km	70.00 °	18.6	19	17.2	16.2
40 km	70.00 °	20.4	20.3	16	18.8
40 km	70.00 °	17.5	19.5	16.2	16.2
40 km	70.00 °	17.5	19.1	15.9	15.9
40 km	70.00 °	19.1	20.3	18.2	16.7
40 km	70.00 °	17	19.6	15.8	20.1
40 km	70.00 °	18.6	20.1	15.3	17.1
40 km	70.00 °	18.9	19	14.8	16.8
40 km	70.00 °	16.4	19.1	18.8	15.9
40 km	70.00 °	18.2	19.6	15.3	14.4
40 km	70.00 °	17.2	19.6	16.4	15.5
40 km	70.00 °	21.2	18	15.3	17.5

40 km	70.00 °	18.6	18	19.3	20.2
40 km	70.00 °	21.3	19.7	14.6	17.3
40 km	70.00 °	18.1	18.1	14.8	19.7
40 km	70.00 °	18.6	19	17	19.6
40 km	70.00 °	18.9	19.2	18.5	16.8
40 km	70.00 °	19.2	19.7	14.3	16.8
40 km	70.00 °	17.3	19.8	16.4	17.8
40 km	70.00 °	16.6	20.3	18.3	16.3
40 km	70.00 °	18.2	18.9	15.7	16.8
40 km	70.00 °	17.7	20.1	13	18.6
40 km	70.00 °	17.4	18.9	16.3	18.6
40 km	70.00 °	19.6	19.5	15.2	16.8
40 km	70.00 °	16.6	19	17	17.7
40 km	70.00 °	18.5	19.5	15.2	16.2
40 km	70.00 °	19.8	19.2	17.5	18.4
40 km	70.00 °	19.9	17.6	15.6	15.9
40 km	70.00 °	18	19.6	15.3	18
40 km	70.00 °	19.7	19.9	16.1	17.5
40 km	70.00 °	18.9	19.9	15.1	17.9
115 km	70.00 °	217.7	218.4	214.1	215.3
115 km	70.00 °	215.9	218.4	211.6	214.6
115 km	70.00 °	217.2	218.3	216.4	218.8
115 km	70.00 °	217.7	217.4	213.5	218.3
115 km	70.00 °	216.6	218.9	216.3	215
115 km	70.00 °	216.7	217.6	214.4	214.6
115 km	70.00 °	216.9	218.3	215.5	215
115 km	70.00 °	217.9	218.8	213.8	213.9
115 km	70.00 °	216.5	218.4	215.7	213.1
115 km	70.00 °	216.4	218	214.8	214.4
115 km	70.00 °	215.1	216.6	215.3	214.4
115 km	70.00 °	216.4	217.5	213	214.2
115 km	70.00 °	216.8	217.4	218.4	215.8

115 km	70.00 °	217.5	216.8	215.5	216.5
115 km	70.00 °	217.3	217.6	212.9	216.2
115 km	70.00 °	216.5	218.6	212.4	214.5
115 km	70.00 °	218.5	219.9	213.9	213.1
115 km	70.00 °	217.5	219.2	214.8	214.5
115 km	70.00 °	218.1	218.5	214	216
115 km	70.00 °	215.5	217.9	211.8	217.4
115 km	70.00 °	216	218.5	212.5	214.7
115 km	70.00 °	217.7	216.6	214	214
115 km	70.00 °	217.5	216.6	216.6	215.1
115 km	70.00 °	218.2	218.5	213.3	213.1
115 km	70.00 °	215.9	216.9	216	215.7
115 km	70.00 °	218.5	219.4	215.6	216.5
115 km	70.00 °	217.1	217.6	214	216.1
115 km	70.00 °	215.9	219.4	213	215.7
115 km	70.00 °	215.9	218.3	214.2	212.2
115 km	70.00 °	217.2	218.3	213.8	214.4
115 km	70.00 °	214.6	215.4	215.7	214.8
115 km	70.00 °	216.9	217.1	214.2	215
115 km	70.00 °	216.1	216.9	215.7	216.8
115 km	70.00 °	216.4	219.6	213.8	213.9
115 km	70.00 °	218.4	218.9	216.6	216.6
115 km	70.00 °	218.3	218.7	215.1	214.5
115 km	70.00 °	217.5	217	213.5	219
115 km	70.00 °	217.6	220	213.1	213.4
115 km	70.00 °	215.9	217.3	211.9	215.5
115 km	70.00 °	217.1	217.4	213.1	215.3
115 km	70.00 °	216.1	216.7	213.1	214.1
115 km	70.00 °	218	218	214	214.5
115 km	70.00 °	218.2	219.9	216.2	216.5
115 km	70.00 °	217.5	220.2	215	217.9
115 km	70.00 °	218.2	217.1	215.5	213.1

115 km	70.00 °	218.1	219.5	212.6	214.6
115 km	70.00 °	218.7	219.9	212.2	216
115 km	70.00 °	216.6	217.6	216.9	215.5
115 km	70.00 °	217.8	217.3	214.7	213.4
115 km	70.00 °	217	218.8	213.4	216.7
115 km	70.00 °	217.3	217.8	214.8	215.1
115 km	70.00 °	218.8	217.5	212.4	215
115 km	70.00 °	218.9	217.5	213.8	216.5
115 km	70.00 °	217.8	218.2	213.2	216.1
115 km	70.00 °	217.3	216.7	214.1	215.5
115 km	70.00 °	216.5	217.9	213.5	216.5
115 km	70.00 °	216.4	216.9	215.4	215.9
115 km	70.00 °	216.7	218.3	214.2	214.6
115 km	70.00 °	216.2	216.9	216.3	213.8
115 km	70.00 °	221.7	216.3	212.6	215.4
115 km	70.00 °	218.2	216.7	213.8	215
115 km	70.00 °	217.3	215.9	214.7	214.3
115 km	70.00 °	217.7	219.3	214	215
115 km	70.00 °	216.7	219.3	214	214.7
115 km	70.00 °	214.8	219.2	212.7	216.6
115 km	70.00 °	216	219.4	214.1	217
115 km	70.00 °	218.9	216.9	218.6	215
115 km	70.00 °	215.8	219.9	213.3	215.6
115 km	70.00 °	216.1	217.2	216.2	216.4
115 km	70.00 °	214.9	218.9	215.2	214.6
115 km	70.00 °	218.3	218.4	217.9	215.7
115 km	70.00 °	216.5	220.2	214.3	215.2
115 km	70.00 °	217.5	218.9	213.2	214.4
115 km	70.00 °	217.1	217.8	215.5	212.9
115 km	70.00 °	216.3	217	213.6	213.7
115 km	70.00 °	217.3	218.5	215.1	213.7
115 km	70.00 °	217.4	218.4	213.8	214.7

115 km	70.00 °	214.9	218.5	214.4	213.5
115 km	70.00 °	216	219	213.6	213.9
115 km	70.00 °	216.4	216.8	214	214.5
115 km	70.00 °	217.3	218.4	214.7	213.5
115 km	70.00 °	215	218.6	213.3	215.2
115 km	70.00 °	218	218.4	215.4	214.2
115 km	70.00 °	217	218.2	212.3	215.8
115 km	70.00 °	215.7	216	217.8	214.3
115 km	70.00 °	216	219	213	216.9
115 km	70.00 °	217.1	217.3	215.2	212.3
115 km	70.00 °	216.7	217.4	212.8	215.6
115 km	70.00 °	217.7	218.1	214.9	216.2
115 km	70.00 °	216.5	217.9	211.3	213
115 km	70.00 °	219.5	218.2	214	214.7
115 km	70.00 °	216.9	219.7	217.5	213.7
115 km	70.00 °	219.7	219.1	212.5	214.7
115 km	70.00 °	217.8	219.7	216.3	215.7
115 km	70.00 °	217.1	218.1	214.6	213.4
115 km	70.00 °	218.5	217.2	213.2	214.6
115 km	70.00 °	218.3	216.9	212.6	216.7
115 km	70.00 °	220.7	219.1	212.3	215.2
115 km	70.00 °	218.1	217.6	214	218
115 km	70.00 °	218.2	216.6	214.3	214.9
200 km	70.00 °	615.6	617	614.4	617.4
200 km	70.00 °	618.4	617.4	615.2	617.1
200 km	70.00 °	618	618.2	615.5	615.3
200 km	70.00 °	618.4	617.1	616.2	615.4
200 km	70.00 °	615.9	618.6	612.9	614.6
200 km	70.00 °	616.6	617	613.4	615.3
200 km	70.00 °	617.1	616.9	614.5	615.7
200 km	70.00 °	616.1	618.5	612.4	614.1
200 km	70.00 °	616.7	617	613.6	614.4

200 km	70.00 °	616.3	616.6	612.6	612.8
200 km	70.00 °	616.1	617.3	614.5	615
200 km	70.00 °	616.8	618.8	615.8	612
200 km	70.00 °	616	615.6	611.5	614
200 km	70.00 °	616	617.7	615.2	614.9
200 km	70.00 °	616	617.7	613.8	613.2
200 km	70.00 °	616.8	617.6	613.3	615.2
200 km	70.00 °	617	616.2	612.4	615.3
200 km	70.00 °	616.9	618.6	614.3	618.4
200 km	70.00 °	617.8	617.1	614.2	616.6
200 km	70.00 °	616.9	615.1	614.6	614
200 km	70.00 °	616.1	616.6	614.5	614.7
200 km	70.00 °	616.3	617	615.2	618.2
200 km	70.00 °	616.8	617.4	613.8	616.7
200 km	70.00 °	616.5	616.9	613	614.5
200 km	70.00 °	617	619.7	615.1	614
200 km	70.00 °	618	619.4	611.9	613.9
200 km	70.00 °	617.5	617	616.4	614.6
200 km	70.00 °	616.3	617.6	613.5	615.4
200 km	70.00 °	616.6	619.5	612.5	614.7
200 km	70.00 °	617.8	617.5	613.8	614.9
200 km	70.00 °	617.8	616.7	613.7	615
200 km	70.00 °	618.6	617.5	612.6	614.4
200 km	70.00 °	617.3	620.4	613	615.2
200 km	70.00 °	616.2	618.6	615.9	616.8
200 km	70.00 °	616.5	617.4	614.1	619.9
200 km	70.00 °	617	616	615	617.4
200 km	70.00 °	616.9	619	614.6	616.7
200 km	70.00 °	618.9	617	613.1	614.4
200 km	70.00 °	617.4	617.7	614	614.7
200 km	70.00 °	616.5	616.9	612.7	615
200 km	70.00 °	618	617	614.5	615.3

200 km	70.00 °	615.1	618.7	614.3	615.2
200 km	70.00 °	616.7	617.3	614.6	615.7
200 km	70.00 °	616.8	619.7	617.1	615.1
200 km	70.00 °	617.5	615.5	615	614.3
200 km	70.00 °	616.3	617.6	614.1	613.7
200 km	70.00 °	617.4	619.1	617.7	614
200 km	70.00 °	617	617.2	614.7	614.5
200 km	70.00 °	616.8	617.6	614.1	619.4
200 km	70.00 °	615.2	618.4	614.3	614.7
200 km	70.00 °	614.6	617.7	616.1	617.1
200 km	70.00 °	616.8	618.4	613.5	614.5
200 km	70.00 °	616.7	619.6	615.8	617.1
200 km	70.00 °	616.5	618.6	616.3	613.5
200 km	70.00 °	616.5	618.5	613.7	613
200 km	70.00 °	616	618.4	613.5	614.6
200 km	70.00 °	617.2	616.8	613.6	613.4
200 km	70.00 °	617.3	618	613.2	613.4
200 km	70.00 °	616.8	617.8	614	615
200 km	70.00 °	618.4	618.4	615.4	614.8
200 km	70.00 °	616.9	618.8	614.4	613.4
200 km	70.00 °	616.9	616.1	615.3	614.2
200 km	70.00 °	615.5	618.2	617.8	615.9
200 km	70.00 °	616.6	617.4	613.1	615.9
200 km	70.00 °	618.2	617.8	615	614.9
200 km	70.00 °	618.2	617.4	613.7	616.9
200 km	70.00 °	615.8	618.4	613.9	615.2
200 km	70.00 °	617.2	618.5	614	613.8
200 km	70.00 °	616	616.5	612.8	616.2
200 km	70.00 °	616.8	618.5	615.5	615
200 km	70.00 °	616.8	617.1	612.9	613.8
200 km	70.00 °	618.7	618.2	612.8	614.1
200 km	70.00 °	617.4	617.6	615.2	614.4

200 km	70.00 °	616.1	617.7	613.5	615.3
200 km	70.00 °	617.3	617	613	614.8
200 km	70.00 °	616.3	617.4	612.7	613.9
200 km	70.00 °	616.7	616.9	614.6	615.7
200 km	70.00 °	615.9	619.2	613.3	614.8
200 km	70.00 °	617.3	617.4	614.5	617
200 km	70.00 °	617.8	618.2	613.6	614.9
200 km	70.00 °	616.5	620	611.4	617.3
200 km	70.00 °	617.1	617.3	613.1	615.1
200 km	70.00 °	617.5	616.1	613.7	614.3
200 km	70.00 °	616.1	619.2	615.2	614.9
200 km	70.00 °	618	619	614.2	614.7
200 km	70.00 °	616.2	617.8	613.7	614.5
200 km	70.00 °	616.5	617.9	615.7	614.8
200 km	70.00 °	616.2	619.1	612.5	613.8
200 km	70.00 °	618.8	617.4	613.9	615.5
200 km	70.00 °	618.2	617.8	614.5	614
200 km	70.00 °	618.2	618.4	614.7	612.9
200 km	70.00 °	616.5	618.5	614.1	614.2
200 km	70.00 °	617.2	617.1	616.5	613.5
200 km	70.00 °	616.6	616.9	613.3	614.5
200 km	70.00 °	616.5	618.5	617.2	614.6
200 km	70.00 °	617.2	618.7	613.3	614.3
200 km	70.00 °	616.3	618	616.4	618.2
200 km	70.00 °	617.6	619.2	616.1	613.7
200 km	70.00 °	618.7	620	615.6	614
200 km	70.00 °	617.4	618.8	614.3	616.9

Appendix 2

The trip times of the four scenarios for the current differential relay test using the commercial test set are shown in Table Appendix-2.

Table Appendix-2 Trip time of the four scenarios for current differential relay test

Test No.	Scenario 1 trip time (ms)	Scenario 2 trip time (ms)	Scenario 3 trip time (ms)	Scenario 4 trip time (ms)
1	27.4	26.7	23.9	23.8
2	29.2	25.7	25.5	23.3
3	27	27.2	24.2	28.4
4	25.7	26.7	22.5	23.2
5	23.4	25.9	19.8	26.6
6	25.2	25	22	21.9
7	25.5	26.3	22.4	22.8
8	24.4	23.7	21.2	21
9	28	24	25.4	21.5
10	27.4	25.3	24.3	22.3
11	25	25.8	21.9	26.6
12	28.1	25.7	24.1	23.4
13	27.5	27.4	27.7	24.6
14	27.8	25.8	26.8	27.5
15	26	23.3	22.6	21.3
16	26	26.8	23.5	23.4
17	28.4	27.7	25	24.6
18	24.7	24.7	21.7	21.7
19	25.8	29.4	22.6	27.4
20	25.6	26.5	22.2	23.4
21	24.6	27.3	21.4	26.4
22	26.8	27	24	24.1
23	25.1	27.6	22	29.3
24	27.3	31.3	24.8	30.5

25	28	24.1	25.8	21.6
26	25.5	23	22.4	22.5
27	26.6	26.1	23.5	23.1
28	28.4	26.4	27.6	27.8
29	27.3	24.9	23.7	22.7
30	27.7	26.7	25	23.7
31	25.3	22.9	22.4	23
32	28.5	28.9	28.7	29
33	26.4	23.5	23.1	21.2
34	24.1	27.6	23.5	24.4
35	26.9	26.7	23.7	23.6
36	25.6	24	23	23
37	26.4	25.9	23.1	22.9
38	24.2	24.7	21.2	21.2
39	27.9	27.3	24.4	24.2
40	24.8	24.7	21.6	21.7
41	24.8	24.1	23.7	23.4
42	25.7	24.8	22.9	21.3
43	26.6	25.2	23.2	22.4
44	25.6	25.9	22.6	22.6
45	28	24.5	25.1	21.1
46	23.9	25.1	20.7	22.4
47	29.8	28.1	26.1	24.5
48	26	28.9	22.9	28.8
49	26.2	27.6	25.8	28.2
50	26.4	24.4	23.2	21.8
51	25.8	26.4	24.4	25.9
52	25.6	24	22.4	21.1
53	25.5	27.3	22.2	24.6
54	26.4	23.8	24.3	22
55	27.8	25.2	25.4	22.4
56	23.9	25.2	20.7	23.3

57	27.3	25.9	23.8	22.4
58	25.3	27.9	22.1	24.2
59	25.9	25.5	25.1	21.9
60	26.4	25.5	23.4	22.8
61	23.2	26.4	20.1	23.5
62	25.4	27.5	23.1	23.9
63	26.9	23.4	23.8	20.3
64	24.4	27.4	21.1	24.6
65	27.8	25.9	26.7	22.9
66	24.9	27.9	21.7	24.7
67	27.3	25.7	23.6	22.3
68	27	24.6	23.7	21.7
69	25.7	27.8	22.5	24.2
70	27.4	25.3	26.3	22.4
71	27.3	24.8	23.9	22.7
72	27.5	26	26.5	23
73	24.3	26.3	21.3	23.4
74	25.4	24	23.9	20.8
75	26.7	26.1	23.4	22.9
76	26.8	26.4	23.9	23
77	24.1	26.9	20.7	24.4
78	28.8	24.6	25.3	24.8
79	24.6	27.4	21.1	24.4
80	26.8	26.5	23.7	22.8
81	26.4	27	23.4	25.9
82	25.9	26.9	22.6	23.6
83	23.8	23.3	20.5	20.2
84	28.1	26.2	26.8	22.6
85	24.3	25.1	21.3	21.8
86	27.8	22.5	24.5	19.5
87	28.1	26.5	25.1	27.6
88	28.6	26.9	25.4	23.6

89	24.4	25.1	22.1	24.4
90	25.1	26.6	21.8	23
91	27.8	27.1	24.1	23.6
92	27.1	23.6	24.5	22.9
93	25.8	27.7	22.4	25.6
94	23.5	24.3	19.9	21.4
95	25.6	28	22.2	24.6
96	26.6	28.4	23.6	26.1
97	26.5	25.7	23.4	22.5
98	26.4	24.2	22.9	21.2
99	26.6	24.6	23.5	21.1
100	25	26	22.1	23.1

Appendix 3

Increasing the traffic on the star topology process bus by injecting SVs into the process bus, the tripping times of the IEC61850 distance relay are shown in Table Appendix-3.

Table Appendix-3a Trip times of process bus overload test using star topology (1 to 20 SVs)

1 SV Trip Time	5 SV Trip Time	10 SV Trip Time	15 SV Trip Time	19 SV Trip Time	20 SV Trip Time
15.75	16.55	16.65	14.5	16.7	16.05
16.85	16.2	16.15	15	16.25	16
16.25	16.4	15.4	15.5	16	15.4
16.45	18.25	15.5	16.15	16.15	16.25
15.35	16.4	16.35	15.6	16.5	17.35
15.2	15.6	17.1	15.35	15.4	16.55
16.35	15.5	16.95	16.9	16.25	17.05
16.35	14.7	17.05	16.4	16.85	14.7
16.4	15.75	16.15	16.05	14.55	15.65
15.45	15.55	15.5	15.2	16.35	16.2
16.75	15.5	17.35	15.25	15.55	16.25
15.4	16.05	14.95	15.4	15.65	16.4
15.3	15.95	15.35	15.65	16.1	15.65
15.05	15.9	16.3	15.3	16.45	14.8
15.8	15.05	16.1	16.7	16.05	15.85
15.45	17.9	15.55	16.25	15.1	16.6
15.9	15.9	16.4	16.8	17.6	17.1
16.45	16.6	30.95	16.25	16.4	16.5
16.5	16.85	16.75	15.7	17.95	15.15
16.15	16.7	15.55	15.85	17.1	16.7
15.35	14.45	16.9	16.85	17	16.05
16.35	15.3	15.5	16.3	14.55	16.65

16.35	16.25	16.8	15.7	15.95	16.25
16.3	16.3	15.7	15.75	17.1	15.6
16.55	16.65	29.95	15	15.75	15.05
14.9	16.05	15.95	15.35	16.05	15
15.3	15.2	14.75	16.2	15.6	16.35
15.1	15.7	15.6	29.45	16.05	16.4
15.6	15.45	16.4	15.25	15.45	16.6
16.2	15.5	17.4	15.95	17.55	15.45
15.95	16.8	17	15.55	16.85	16.4
16.45	16.15	15.35	15.35	16.25	15.45
15.6	16.3	16.45	15.85	14.85	15.4
15.55	15.7	15.7	16.35	15.8	16.3
16.3	16.75	15.95	16.55	15.65	16.4
16.65	15.3	29.75	15.1	17.7	18
16.65	14.8	16.95	15.3	14.6	17.05
16.1	15.35	15.35	15.65	15.5	14.6
15.65	14.8	15.1	16.15	16.25	17.1
17.1	15.5	15.05	17.6	16.15	15.75
16.1	16.15	15.95	17.1	14.85	16.35
15.65	16.1	16.65	15.95	15.55	15.5
30.15	16.2	16.9	15.8	15.7	15.7
14.65	15.95	16.65	15.5	16.25	15.75
16	17.3	15.95	16.3	15.85	14.55
15.9	15.8	15.4	17	17.4	15.95
15.8	16.7	16	16.25	16.15	16.1
16.3	16.2	17	16.55	16.4	16.1
16.05	16.2	16.15	16	16.05	15.9
15.3	16.15	17	15.25	16.15	15.05

Table Appendix-3b Trip times of process bus overload test using star topology (21 to 40 SVs)

21 SV Trip Time	25 SV Trip Time	30 SV Trip Time	35 SV Trip Time	40 SV Trip Time
49.3	61.75	28.9	46.7	159.6
46.85	51.25	46.75	47.4	49.75
51.2	31.85	45.95	32.45	45.6
15.85	32.35	46.8	64.45	49.5
15.1	29.9	50.05	47.6	50
17.3	16.45	51.4	72	17.15
16	15.6	15.85	18.2	59.2
15.35	46.45	71.4	47	57.85
16.2	51.05	47.25	50.2	46.6
16.05	52.15	20	256.2	23.85
51.95	50.25	51	19.1	19.4
16.5	50.5	33.85	22.2	47.55
15.65	17.35	43.95	47.15	51.7
16.95	23.25	48.8	46.35	46.05
16.45	47.4	36.9	48.55	50.05
31.3	50	50.89	48.9	50.3
17.95	16.95	44.65	51.7	50.1
21.65	49.9	50.35	51.65	55.7
16.6	52.5	67.4	46	65.85
16.35	49.6	29.2	16.8	47.2
29.85	34.2	47.9	56.3	28.3
16.1	60.5	50.35	42.35	46.2
15.65	14.8	47.3	29.8	50.1
15.85	49.15	49.65	34.85	77.45
16.1	45.5	48.95	52.75	45.45
44.15	45	49.35	50.55	52.5
14.9	16.2	47.05	49.05	50.3
15.65	31.7	29.5	45.75	49.25
15.9	31.3	45.9	47.2	50.4

15.7	46.4	66.55	51.25	46.75
15.7	14.7	26.8	48.15	188
15.95	22.85	45.3	69.7	54.8
16.2	49.45	65.8	51.25	135
16.35	16.1	45.35	51.1	45.85
15.95	47.85	49.6	19.15	51.55
16.3	16.35	45.7	48.6	39.95
29.55	15.15	50.75	49.15	56.55
15.65	16.55	52.25	51.8	46.25
18.7	28.2	49.45	16	36.25
47.1	15.6	16.85	50.3	46.05
37.05	39.95	48.5	63.45	17.15
48.5	48.95	66.4	49.25	45.6
16	29.6	33.8	49.25	49.7
17.1	28.15	44.85	71.4	46.35
16.5	16.6	51.4	51.15	29
16.9	46.1	48.3	65.55	48.6
17.25	29.6	23.4	48.65	49.9
16.8	23.1	51.3	51.15	55.1
45.6	48.85	51	34.55	49.1
39.6	49.7	47.6	50.25	49.55

Appendix 4

Increasing the traffic on the cascaded topology process bus by injecting SVs into the process bus, the tripping times of the IEC61850 distance relay are shown in Table Appendix-4.

Table Appendix-4a Trip times of process bus overload test using cascaded topology (1 to 20 SVs)

1 SV Trip Time	5 SV Trip Time	10 SV Trip Time	15 SV Trip Time	19 SV Trip Time	20 SV Trip Time
16.25	17.2	15.8	17.8	17.25	16.6
16.35	16	15.3	16.45	16.2	15.3
16.75	15.85	15.25	16.9	16.3	16.15
15.35	15.75	16.1	16.35	16.15	16.05
16.15	16.9	16.45	16.15	16.6	16.4
15.45	16.55	15.75	15.85	16.7	17.2
15.1	16.8	15.45	15.85	15.35	15.6
17.05	15.4	17.75	15.6	14.95	16.4
16.4	14.95	15.7	15.45	15.75	16
16.25	14.75	16.4	15.6	15.75	15.25
16.2	16.2	17.15	17	16.2	16.7
15.1	16.15	16.45	16.55	16.2	16.25
15.75	15.55	16.25	16.1	16.65	16.35
15.7	17	15.85	16.55	17.1	16.95
16.8	15.05	15.75	15.5	16.9	16.35
15.9	16.1	16.4	16.6	15.7	18.2
16.05	16.6	16.65	16.3	16	16.5
15.75	17.4	15.85	17.35	16.85	16.5
17.4	17.15	15.7	16.3	16.5	16.6
15.45	16.95	16.5	17.1	16.85	16.45
16	15.8	16	16	14.75	15.75
16.3	15.4	17.2	15.35	14.95	14.95

15	15.95	15.9	16.05	16.35	15.65
18.95	16.15	16.2	27.6	16.25	15.55
17.25	15.35	16	16.55	16.1	15.75
16.15	15.8	15.55	15.95	15.9	15.5
17.2	16.2	17.15	14.85	15.3	15.2
16	16.65	16.85	16.45	15.8	15.5
15.95	16	16.6	16.35	16.05	15.65
16.4	16.3	16.15	15.9	15.65	15.8
16.7	15.75	16.6	15.95	24.2	15.7
16.3	16.1	15.8	17.2	16.4	16.15
16.2	16.8	15.1	16.6	16.5	16.55
15.95	16.9	16.1	16.1	17	16.85
15.75	15.2	15.95	15.25	15.8	16.65
16.55	16.25	16.1	15.85	16.3	14.65
16.3	15.15	16.6	15.55	16.55	15.4
16.15	16.2	16.4	16.9	15.6	16.5
15.9	16	17.3	14.85	15.9	16.25
16.9	16.9	16.1	15.9	15.65	15.6
16.6	16.35	15.7	16.55	15.7	15.9
16.05	15.65	16.9	16.9	16.65	19.05
15.85	15.25	16.35	16.25	17.2	16.2
28.95	16.65	16.55	16.05	16.3	17.3
15.55	16.2	15.75	15.3	19.65	17.05
16.15	17	16.7	18.45	15.15	16.4
27.55	15.9	16.55	16.25	16.4	15.65
16.75	16.45	15.25	17.35	17	15.55
16.1	16.35	15.55	15.1	16.25	16.5
16.6	15.8	15.35	15.4	16.7	16.55

Table Appendix-4b Trip times of process bus overload test using cascaded topology (21 to 40 SVs)

21 SV Trip Time	25 SV Trip Time	30 SV Trip Time	35 SV Trip Time	40 SV Trip Time
46.4	59.6	77.05	49.5	49.7
31.1	16.3	22.6	109.4	46.25
16.3	30.25	49.35	62.15	45.8
17.15	19.65	49.95	91.4	49.4
16.85	51.75	51.05	50.3	56.1
15.4	16.05	47.95	46.35	51.2
38.3	32.35	47.25	49.8	49.65
31.2	18.95	50.55	49.4	51.6
16.8	26.8	46.35	49.05	49.9
30.2	19.75	50.95	50.05	73.15
16.55	45.5	16.8	56.75	17.45
16.45	30.55	50.65	47.35	47.25
16.8	48.55	47.5	59.1	39.9
45.3	21.1	215.9	129.4	49.9
15.8	49.7	31.95	17.1	61.75
49.85	18.5	49	220.1	129.5
18.75	15.65	50	49.75	49.75
18.7	48.45	61.6	46.6	50.35
16.85	15.9	174.6	51.7	51.3
48.35	43.55	52.35	48.8	49.3
16.85	16.1	52.35	18.1	51.6
17.75	30.15	50.55	86.6	50.05
15.3	23.65	64.25	49.3	58.25
17.05	48.25	22.1	51.35	49.05
19.05	21.65	50.7	88.2	50.05
17.5	46.3	30.7	25.4	50.55
30.45	18.55	45.65	49.95	51.3
31.9	50.9	50.55	49.8	27.05
16.9	16.55	51.35	52.2	51.3

31.15	47.3	26.45	45.9	50.35
48.4	49.35	31.65	27.3	50
38.7	46.55	45.3	48.65	48.4
16.25	47.45	49.95	47.05	52.1
17.5	47.5	52	18.9	48.3
17.1	20.65	60.5	49.4	46.65
18.5	39.2	50.9	52	51.25
15.35	50.2	50.75	136.3	51.6
16.6	18.3	49.8	31.8	78.4
30.5	49.3	47.1	51.2	52.6
32.95	59.5	50.6	21.4	50.2
30.4	17.05	50.15	50.15	35.3
16.65	49.4	50.8	46.8	48.6
30.1	51.1	29.55	49.8	51.95
31.95	18.05	32.65	18.25	49.6
16.55	49.65	16.95	53.1	49.45
15.95	16.25	46.65	29.85	52.1
17.05	51.25	47	48.55	50.25
17.45	18.3	19.05	46.75	48.9
30.55	16.25	42.85	46.75	30.95
15.25	49.05	16.6	51.15	47.3

Appendix 5

Increasing the traffic on the ring topology process bus by injecting SVs into the process bus, the tripping times of the IEC61850 distance relay are shown in Table Appendix-5.

Table Appendix-5a Trip times of process bus overload test using ring topology (1 to 20 SVs)

1 SV Trip Time	5 SV Trip Time	10 SV Trip Time	15 SV Trip Time	19 SV Trip Time	20 SV Trip Time
16	15.4	16.65	15.85	16.1	15.9
14.9	15.5	14.85	18.3	15.65	16.7
16.8	16.8	16.4	18.35	15.65	16.65
16.2	16.1	15.6	15.45	17.2	15.15
16.95	16.55	16.35	16.4	16.25	14.95
17.3	17	17.15	16.35	15.8	15.35
16.5	16.3	18.5	17.4	16.45	16.65
16	14.55	16.45	24	16.65	16.6
15.45	15.4	15.4	17.05	16.1	17.7
15.35	16.05	16.75	15.75	16.5	15.9
15.15	15.6	15.35	16.05	19.45	15.55
14.9	15.85	15.2	16.25	15.45	16.55
15.4	16.6	14.6	16.55	30.45	16.05
16.4	17.15	15.5	16.65	15.75	16.3
15.8	16.4	16.4	17.1	16.6	16.8
16	16.15	15.75	14.5	16.5	14.9
15.9	15.9	16.2	15.75	17.45	15
15.4	16.2	15.9	16.25	15.75	15.05
15.9	16.45	15.8	15.3	16.2	15.3
15.75	16.95	16.2	15.4	16.3	16.7
15.55	28	16.2	15.5	17.15	16.05
16	16.8	16.3	15.6	16.65	30.95

16.05	15.7	16.9	15.6	31.75	16.75
16.65	16.65	16.3	15.95	18.95	15.1
16.05	17.05	16.25	16.4	16.15	16.5
16.5	15.65	18.4	15.75	16.15	16.65
15.5	15.4	15.8	15.7	16.25	16.4
15.75	15.5	16.4	16.7	16	17.8
15.3	15.3	15.65	16.15	17.6	15.55
15.3	16.4	15.65	15.9	15.4	15.4
16	16.6	15.65	32.35	15.85	15
16.45	16.45	16.2	15.85	16.8	15.55
15.3	16.2	15.45	15.1	16.4	16
16.55	16.25	16	17.65	15.65	16.75
15.65	15.95	15.85	15.75	15.4	15.9
15.95	17.05	15.7	16.35	15.7	15.8
17.1	16.25	18.95	18	16.5	14.95
17.1	16.45	17.65	15.9	16.55	16.5
17.25	16.4	16.2	16.3	14.95	16.05
16.15	15.65	15.95	16.05	14.6	24.75
15.85	16.15	15.95	16.25	15.6	16.6
15.95	15.5	15.4	16.6	16.15	16.9
15.4	16.05	16.05	17	16.75	16.75
14.95	18.55	16.65	17.15	16.1	15.5
15	16.05	16.7	14.65	17.5	16.85
16.25	15.8	16.3	15.9	17.6	16
16.7	17.7	15.95	15.9	15.45	16.4
16.4	17.3	15.95	15.8	16.5	15.2
15.55	16.75	15.65	15.3	16.35	17.45
16.5	16	19.65	14.9	16.15	15.65

Table Appendix-5b Trip times of process bus overload test using ring topology (21 to 40 SVs)

21 SV Trip Time	25 SV Trip Time	30 SV Trip Time	35 SV Trip Time	40 SV Trip Time
15.1	53.05	30.25	48.8	47.5
50.25	46.8	51.75	51.2	48.55
16	16.2	51.35	44.85	29.4
16.6	16.55	44.85	50.95	70.95
16.5	47.25	50.15	34.35	50.35
14.8	50.05	50	46.45	52.5
17.1	51.5	46	51.55	83
15.25	18.8	49.7	49.9	75.45
17.65	45.6	45.9	19.2	47.4
32.15	38	47.25	29.6	50.5
16.7	51.6	19.85	57.4	50.7
17	46.55	38.65	49.75	54.4
16.85	16	32.5	49.65	20.9
47.6	15.4	49.8	49.55	23.7
15.5	50.05	50.15	51.25	49.7
16.1	18.4	61.2	37.65	51.7
23.6	33.05	49.9	49	46.5
17.5	50.25	47.9	26.35	51
15.5	17.15	50.9	48.8	58.35
48.25	50.4	55.25	49.15	63.95
16.35	17.05	47.3	52.7	46.3
16.8	49.9	15	50.35	49.95
15.85	27.05	19.05	49.75	48.55
46	16.75	44.9	30.8	58.4
17.2	39.8	27.1	30.2	47.85
15.5	16.9	77.95	48.9	48.3
19	30.4	51.35	44.9	68.6
16.5	30.6	46.7	50.4	47.2
15.7	49.65	30.75	40.15	50.65

19.1	49.7	18.3	36.95	47.55
16.8	18.8	49.1	53.65	49.85
36.9	31.9	45.8	50.6	49.8
16.15	47.35	52.45	46.85	36.8
31.45	16.45	46.45	45.1	16.8
17.55	50.4	51.4	105.8	50.55
16.1	15.85	38.6	49.05	50.85
17.75	15.15	31.3	49.7	53.15
19.15	17.65	49.9	63	48.55
18.95	29.4	49.4	53.75	49.85
16.25	15.95	17.1	42.9	78.1
30.4	47.4	27.9	51.45	28.2
16.55	16.85	35.8	48.9	47.1
46.4	49.5	31.3	50.05	48.2
17.8	48.1	49.05	45.85	49.65
46.25	17.7	30.65	46.95	51
31.05	16.4	30.05	48.8	47.3
16.75	15.5	279	131.3	50.05
16.95	18.45	36.3	46.4	50.55
48.3	18.45	54.2	34.55	49.6
30.95	50.35	50.4	49.95	47.2

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