

GENERIC SUBSTATION EVENT MONITORING BASED ON IEC 61850 AND IEEE 1588 STANDARDS

by

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KEYWORDS

Substation events, electromechanical protection device, IED, IEC 61850, IEEE 1588, Ethernet, GOOSE, sampled values, synchrophasor, PTP, electric utility, substation automation, decentralised state estimation, topology processing Hall Effect, electronics, embedded systems, Linux, kernel, device driver

ABSTRACT

Electricity has become not only an essential element to people's everyday life but also the most important power source to most industries and businesses. The continuously increasing demand of electricity consumption has resulted in a consistent expansion of power grid as it was seen in the past few decades. This in turn has dramatically increased the cost of electricity during the same period in Australia. In contrast, the recently recorded low economic activities and significant growth of rooftop photovoltaic has led to a reduction in the forecasted electricity demand in Australia. This has resulted a reduced number of network augmentation projects for most electric utilities across the country. Instead, the substation refurbishment work has become the focus for most electric utilities in the foreseeable future. Such sharp turning point of trend has placed an enormous challenge in front of electric utilities on how to make the power system operation more cost effective and preserve a high level of reliability and security. In response to the challenge, the integration of advanced technologies with the existing power system has been recognised as a viable solution. The international standard IEC 61850 for substation communication system has gained momentum globally to be implemented in power utility automation systems. The flexibility and vendor independent feature of the standard inspired a range of innovative approaches for power grid projects including substation refurbishment work.

This research aims to develop and verify a vendor independent device, which is named as substation event monitor, with the capability of interfacing the legacy and existing substation automation system equipment to the modern intelligent electronic devices (IEDs) over Ethernet network in a non-intrusive and cost effective manner. The substation event monitor is also equipped with the ability of providing synchronised time information at the accuracy level of ± 1 microsecond over the same communication infrastructure via IEEE 1588 standard, also called the Precision Time Protocol (PTP). The created device is suitable for substation refurbishment work and has the potential in many other utility applications, such as network state estimation and substation commissioning. This thesis takes a bottom-up approach to the form of information on the construction and verification of substation event monitor. It begins with the provision of the critical review on the detailed knowledge of both international standards of IEC 61850 and IEEE 1588. This work was needed because there is lack of concise, publicly available and informative material on these complex standards for power utility engineers. The thesis is then expanded with the in-depth design information on the developed prototype of substation event monitor. Finally, the verification results of the prototype device were produced at both component level and system level in this thesis. The provision of the comprehensive knowledge of the prototype device will

deliver confidence to utility engineers in considering the adoption of substation event monitor as a low cost, non-intrusive, IEC 61850 compatible and synchronised IED that meets the needs of substation refurbishment work and other potential power utility applications.

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LIST OF ABBREVIATIONS

1PPS	One Pulse Per Second
9-2LE	UCA User Group Implementation Guidelines for IEC 61850-9-2 Standard
AC	Alternating Current
ACSI	Abstract Communication Service Interface
AEMO	Australian Energy Market Operator
ASN.1	Abstract Syntax Notation One
BER	Binary Encoding Rules
BMC	Best Master Clock algorithm
CID	Configured IED Description
CDC	Common Data Class
CFI	Canonical Format Identifier
CT	Current Transformer
DA	Data Attribute
DC	Direct Current
DO	Data Object
DPC	Controllable Double Point
DS	Data Set
E2E	End-to-End
EPRI	Electric Power Research Institute
FAT	Factory Acceptance Testing
FC	Functional Constraint
FCD	Functional Constraint Data
FCDA	Functional Constraint Data Attribute
GGIO	Generic Process I/O
GMR	Giant Magneto-Resistive
GOOSE	Generic Object Oriented Substation Event
GPIO	General Purpose I/O
GPS	Global Positioning System

GSE	Generic Substation Event
HMI	Human Machine Interface
HSR	High availability Seamless Ring (IEC 62439-3 Standard)
HVDC	High Voltage Direct Current
ICD	IED Capability Description
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronic Engineers
IID	Instantiated IED Description
IP	Internet Protocol
IRIG-B	Inter Range Instrumentation Group Code B
ISO	International Standard Organisation
LD	Logical Device
LED	Light Emitting Diode
LLN0	Logical Node Zero
LN	Logical Node
LNPD	Logical Node Physical Device
MI	Magneto Impedance
MMS	Manufacturing Message Specification
MTTF	Mean Time To Failure
NCIT	Non-Conventional Instrument Transformer
NEM	National Electricity Market (Australia)
NIST	National Institute for Standards and Technology
NTP	Network Time Protocol (RFC 5905)
OSI	Open System Interconnection
P2P	Peer-to-Peer
PDU	Protocol Data Unit
PRP	Parallel Redundancy Protocol (IEC 62439-3 Standard)
PSRC	Power System Relaying Committee (IEEE Power and Energy Society)

PTP	Precision Time Protocol (IEEE 1588 Standard)
QoS	Quality of Service
SAS	Substation Automation System
SAT	Site Acceptance Testing
SCD	Substation Configuration Description
SCL	Substation Configuration Language
SCSM	Specific Communication Service Mapping
SED	System Exchange Description
SEM	Substation Event Monitor
SLD	Single Line Diagram
SSD	Substation Specification Description
SV	Sampled Values
TLV	Tag, Length, Value
TPID	Tag Protocol Identifier
UCA2.0	Utility Communication Architecture version 2.0
UDP	User Datagram Protocol
UTC	Coordinated Universal Time
VLAN	Virtual Local Area Network (IEEE 802.1Q Standard)
VT	Voltage Transformer
XCBR	Circuit Breaker Logical Node
XML	eXtensible Markup Language
WLS	Weighted Least Square
WG	Working Group

LIST OF PUBLICATIONS

Liu, Y., Zivanovic, R. and Al-Sarawi, S., 2014. Industrial Case Study of an IEC 61850 Standard Compatible and Synchronised Tripping Circuit Monitor for Electric Substations. *Symposium of Specialists in Electric Operational and Expansion Planning*, 18-21 May.

Liu, Y., Zivanovic, R. & Al-Sarawi, S., 2013. A synchronized generic substation events tripping circuit monitor for electric substation applications. *International Transactions on Electrical Energy Systems*, 24 October, Issue Wiley Online Library (wileyonlinelibrary.com), pp. 1-16. DOI: 10.1002/etep.1814

Liu, Y., Zivanovic, R. & Al-Sarawi, S., 2012. IEC 61850 Tripping Circuit Monitor with IEEE 1588 Synchronisation. *Australian Protection Symposium*, 21-22 August, pp. 1-10.

Liu, Y., Zivanovic, R. & Al-Sarawi, S., 2010. An IEC 61850 synchronised event logger for substation topology processing. *Australian Journal Electrical Electronics Engineering*, vol. 7, no. 3, pp. 225-233.

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CHAPTER 1 INTRODUCTION

This chapter provides an introduction of Substation Automation System (SAS) in electric utilities based on the general information of Australian transmission network. It also summaries the concerns of electric utilities under the current economic condition, which were the motivations and the drive for undertaking this research. Following from this is the provision of a set of objectives for this project. This chapter is concluded with an informative outline of the thesis.

1.1 Background

Electricity has become not only an essential element to people's everyday life but also the most important power source to most industries and businesses. However, the growing demand of power consumption has led to larger power grid, increased size of substations and higher operating voltages. Consequently, the cost of electricity in Australia has increased dramatically in the past decade. The pressure to minimise electricity price caused by the regulated electricity network projects has been identified by Australian Government in the document titled *Energy White Paper 2012* (Department of RET, Resources, Energy and Tourism, 2012).

Due to the above reasons, electric utilities face the challenge on how to make the power system operation more cost effective while preserving a satisfactory level of reliability and security (Kezunovic, et al., 2004). In response to the challenge, it is desirable to integrate advanced technologies with existing power system equipment. This desirable approach of deploying new technologies has also been encouraged in the *Energy White Paper 2012* (Department of RET, Resources, Energy and Tourism, 2012) by the Australian government. Among the advanced technologies in power industry, the ones that have been developed in the area of SAS allow the power network to be operated with more integrated information with significant improvements in the implementation of asset monitoring. These benefits has attracted enormous attention from the electric utilities around the world.

1.2 High Voltage Power Network

In general, high voltage power network can be further categorised as distribution network or transmission network. The distribution network are normally considered to be operated

between 415 V and 100 kV. The transmission network, which is a key infrastructure in power grid with higher reliability requirement, are generally considered to be operated at above 100 kV. In Australia, the transmission network are operated at 110 kV, 132 kV, 220 kV, 275 kV, 330 kV and 500 kV with an alternating frequency of 50 Hz. There are also three high voltage direct current (HVDC) connections in Australia namely, Terranora Interconnector between New South Wales and Queensland (operated at ± 80 kV), Basslink between Victoria and Tasmania (operated at ± 400 kV) and Murraylink between Victoria and South Australia (operated at ± 150 kV). The interconnected electricity network among Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania and South Australia form the National Electricity Market (NEM). This is shown in more detail in Figure A.1. The high power networks at both Northern Territory and Western Australia are operated independently under different market conditions and regulations. As it is shown in Figure A.1, the NEM is long and linear in comparison with the electricity network in Europe and North America. However, the NEM is over five thousand kilometres from far north of Queensland to Tasmania, and west to Adelaide and Port Augusta. It is the longest alternating current (AC) system in the world (AEMO, 2014). As a result, the amount of information that is required to operate such complex network is very large.

Electric substations, especially the ones in transmission networks, provide vital information to operate the NEM. It is sensible to realise the integration of the advanced technologies to those substations is the most effective approach to respond to the previously described challenges for electric utilities.

In general, electric substations include both primary and secondary equipment. The primary equipment such as power transformers, bus bars, circuit breakers and instrument transformers, which are arranged in switchyard. An example of these high voltage equipment is shown in Figure 1.1. These primary equipment are operated in an automated way via a SAS which is responsible for controlling, protecting, measuring and monitoring functions in substations. The devices that form the SAS are often referred to secondary equipment of substations. A photo of several SAS panels is shown in Figure 1.2. Different generations of protection devices, which are electromechanical relays, solid state relays, and microprocessor based relays, are employed in almost all modern SAS systems. In particular, the electromechanical relays are still in widespread use and continue to be manufactured and applied (Blackburn & Domin, 2007).

The opportunities for innovative approaches with the advancement in technology of both

primary and SAS systems exist throughout the substation. New technologies with reduced



Figure 1.1: High voltage substation primary equipment at switchyard



Figure 1.2: Substation automation system within control building

footprint and more environmentally friendly primary equipment, such as disconnecting circuit breaker, high voltage vacuum circuit breaker and non-conventional instrument

transformers, are becoming acceptable for electric utilities. More importantly, the revolutionary approach of implementing industrial Ethernet technology to SAS applications based on international standards has been well established by electric utilities (Liu, et al., 2013). Such approach, which is shown in Figure 1.3, enables the connectivity between the switchyard equipment (process level) and SAS equipment (station level) within a substation control building.

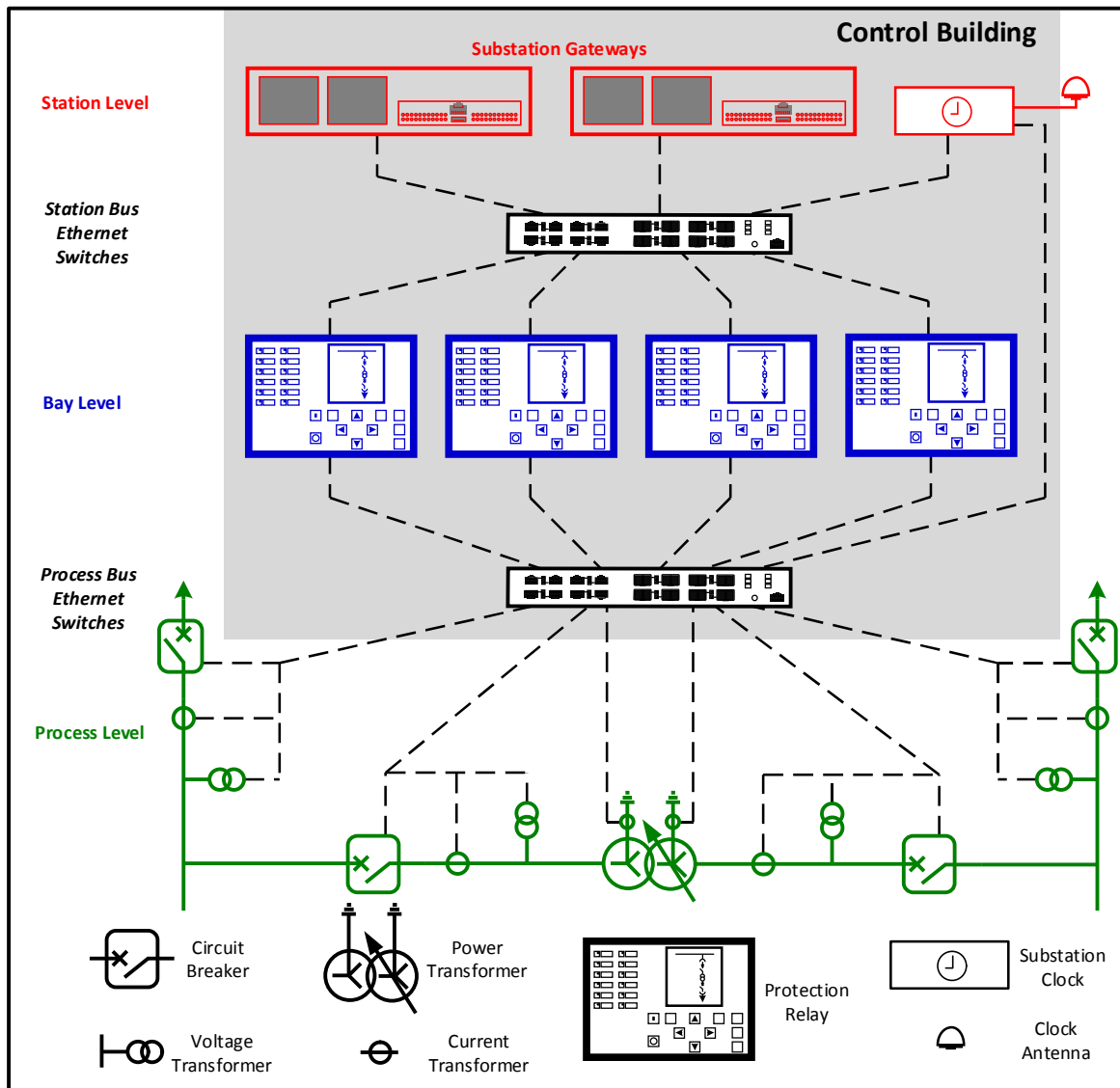


Figure 1.3: Substation connection structure

1.3 International Standards for Ethernet Technology Applications

Ethernet technology was first used in 1979 on vendor proprietary operating systems and computers (PSRC, 2005). As communication costs decreased, Ethernet communication became very cost effective in comparison with serial communication. In 1986, the Utility Communications Architecture (UCA), which is a trademark of Electric Power Research Institute (EPRI) was launched to investigate network communication requirements and

possibly provide new approaches for enterprise wide utility data communications (PSRC, 2005). As a result, a number of UCA demonstration projects were conducted in the beginning of 1992 and the produced recommendations were adopted in the Institute of Electrical and Electronics Engineers (IEEE) Technical Report 1550 (IEEE, 1999).

In parallel to the work progressed in North America, International Electrotechnical Commission (IEC) commenced 61850 project to define the next generation of standardised high-speed substation control and protection communications in 1995 (Technical Committee 57, 2003). The main objective of the IEC 61850 project, which is similar to that of the UCA project, is to establish interoperability among different vendor devices in SAS applications (PSRC, 2005). Due to the common goal and the harmonised work of both organisations, the experts formed joint task forces and published IEC standard 61850 where the UCA modelling, data definitions, data types and services were extended and adopted in different parts of the standard.

Since the first release of IEC 61850 standard, it has been two editions. The first edition was titled *Communication networks and systems in substations*. The second edition of IEC 61850, which is titled *Communication networks and systems for power utility automation*, updated the previous edition of the standards and extended the information model with focus on some new application areas, such as power quality events, condition monitoring, wind turbines, hydroelectric power plants and distributed energy sources (Zhu, et al., 2014). Therefore, the applications of IEC 61850 standard family is no longer limited to electric utilities, it is now applicable to wider energy industries including oil and gas due to the recognised benefits of interoperable communication system (Manassero, et al., 2013). In fact, the IEC 61850 standard family has been recommended for future smart grid developments by both the IEC and US National Institute of Standards and Technology (NIST) organisations (SMB Smart Grid Strategic Group, 2010) (NIST, et al., 2012). Although the term smart grid is not clearly defined, it was used to describe a grid as being able to predict, adapt, and reconfigure itself efficiently and reliably by George W. Bush (Momoh, 2012). The new developments of multifunctional IEDs and synchronised phasor (synchrophasor) measurement units certainly move the power network toward the realisation of smart grid. The synchronised and digitalised data coupled with advanced communication technology are envisaged to provide a better solution for situational awareness, decision support and control of power grid (Liu, et al., 2015). It is clear that one of the essential requirements for the new devices is the full support of IEC 61850 standard. At the same time, the engineers at power utilities are required to have much better

understanding on the complex interdependencies between cyber event and power domain when deploying the new devices (Liu, et al., 2015). Furthermore, the software tools that integrate and automate the IED data that is collected from substations are also required to be developed for better utilisation of the newly available data.

In order to achieve interoperability among different vendor devices, IEC 61850 standardised two most important aspects, information modelling and communication service mapping through the use of substation configuration language (SCL). The IEC 61850 standard defined a set of object oriented data models in provision of support for all substation functions, as well as the engineering process with the use of such data and service models (Ozansoy, et al., 2009). Two parts of IEC 61850 series of standards, IEC 61850-8-1 (Technical Committee 57, 2011) and IEC 61850-9-2 (Technical Committee 57, 2011), define fast, reliable and peer-to-peer communication services that map the abstract communications of the defined information model to Ethernet frames. The defined abstract communications in IEC 61850-8-1 and IEC 61850-9-2 are also known as Generic Object Orientated Substation Event (GOOSE) and Sampled Values (SVs) respectively. Moreover, the IEC 61850-8-1 standard also defines a communication service in client-server structure that maps the standardised data model to Manufacturing Message Specification (MMS) and Ethernet frame (Technical Committee 57, 2011).

In addition to the applications of IEC 61850 standard in digital SAS, all data acquisition process requires a system wide time reference, especially when comparing the data that is sampled from different sources. The requirement of synchronisation accuracy level for digital SAS is in the order of ± 1 microsecond (UCAIug, 2004). Both organisations of IEC and NIST have recommended the use of IEEE 1588 standard, which is also known as Precision Time Protocol (PTP), for highly accurate time synchronisation in digital SAS (Ingram, et al., 2012b). Due to the fact that PTP is also achieved via Ethernet, it has been considered as the most efficient method to meet the accurate time synchronisation requirement in SAS. IEC 61850, PTP and Ethernet are the three complementary standards that together define the future digital SAS (Ingram, et al., 2012b).

It is also worth stressing that the communication networks, especially the usage of fibre-optic communication in wide area network, enable the possibility of sharing the increasingly available information between substations and control centre in real time. The additional information might include more comprehensive data of plant's physical state and operating characteristics due to aging and maintenance activities that are vital in managing network

assets. The evolution in communication networks with the aid of the defined multivendor interoperability, fixed rate messaging and network based time synchronisation in international standards will further improve the efficiencies in operating power grid. The implementations of international standard and fibre-optic communication in local area network also reduce yard wiring and construction cost. As a result, numerous opportunities are created for improving the current practice in the aspects of operating and managing network assets in electric utilities.

1.4 Current Economic Outlook and Concerns

It is well established that the world's economy has taken deep down-turn since the global financial crisis (GFC). In Australia, economic activities have been recorded below trend growth rates for a number of years (The Treasury of Australian Government, 2014). Such phenomena has been reflected as the falling electricity demand in manufacturing, which is the largest user of electricity in Australia, by 3 per cent a year on average between the financial years of 2010-11 and 2012-13 (BREE, 2014). According to the Annual Report 2014 published by AEMO, a 1.1 per cent average annual decrease is forecast for the NEM electricity consumption in the next three years (AEMO, 2014). Later in 2014, AEMO also reported an annual average growth of 23.6 per cent in rooftop photovoltaic (PV) which has resulted a 2.9 per cent reduction in consumption from the NEM in the year of 2013-14 (AEMO, 2014). Inevitably, the lower demand and consumption forecasts have resulted in a reduction of network augmentation projects for most transmission and distribution network service providers in Australia.

In parallel, the household electricity prices have nearly doubled over the period from 2007 to 2014, while a 17 per cent increase in the consumer price index (BREE, 2014). On the other hand, business electricity prices have increased by 82 per cent from 2007 to 2014, while a 13 per cent increase in the producer price index (BREE, 2014). Because of the spiralling electricity price, the former Deputy Prime Minister and Treasurer, Wayne Swan, requested Productivity Commission to undertake an inquiry into electricity network frameworks in 2012. The inquiry was conducted with the focus of benchmarking arrangements and the effectiveness of the application by network businesses of the current regulatory regime for the evaluation and development of inter-regional network capacity in the NEM (Productivity Commission, 2013). As a result, the Productivity Commission has identified the key driver of the increased investment in generation and network capacity over the past five years was to satisfy the peak electricity demand in the market (Productivity

Commission, 2013). In other words, the purpose to build such robust network was to meet the demand that lasts possibly less than 1 per cent of the time (e.g. New South Wales), while the cost for the network has been spread across all consumers. At the end of the investigation, one of the recommendations to solve the problem was to modify the reliability requirements of the NEM (Productivity Commission, 2013). As a result, most of transmission and distribution network service providers in Australia have initiated changes in their planning methodology to accommodate such change. In South Australia, the transmission network service provider, ElectraNet Pty Ltd, has modified the connection point planning based on the use of 10 per cent probability of exceedance (POE) demand forecasts instead of the traditional peak demand forecast (ElectraNet, 2014). This means the changed reliability standard further contributes to the reduction of electricity network development projects for electric utilities.

The above facts have led to the conclusion that the existing electricity network capacity in Australia is capable of satisfying the electricity demand in the foreseeable future. This means the majority of the projects for electric utilities will be replacing or upgrading ageing assets on the existing network in the foreseeable future. In Australia, the term brownfield application is often refers to any substation refurbishment work. Conversely, the construction of a brand new substation is known as greenfield application.

In order to take the full advantage of the new technology in brownfield applications, the gap of communication interface capabilities between different generations of SAS equipment must be addressed. This is due to the recognised fact that the existing network assets lack enough capability to accommodate the implementation of advanced technologies (Li, et al., 2010). The substation event monitor was developed in the course of this research aims to address the gap by interfacing the existing or legacy equipment with the IEC 61850 standard compatible devices with no interruption to the existing systems for typical brownfield applications. It is also in the interest of this research is to explore other possible applications of the developed substation event monitor in utility network operations, such as network state estimation.

1.5 Research Objectives

The main objectives of this research are:

- To develop a non-intrusive sensing device that can be easily attached to existing equipment in substation for brownfield applications. This objective is to ensure that

the new IEDs work only with the boundary attributes of the existing system while its integrity is preserved.

- To understand the details of the new IEC 61850 standard for the incorporation of the technology to the development of the substation event monitor for the existing equipment.
- To understand the details of the new IEEE 1588 standard and its advantages over the commonly used synchronisation technologies in substations. This objective is also extended to the implementation of IEEE 1588 standard in the development of the substation event monitor.
- To explore opportunities in using the developed device for utility control centre applications, such as network state estimation.
- To provide detailed construction and performance testing information of the bridging device such that the created device is applied with confidence.

Once the above objectives are met, it is expected that the created substation event monitor will enhance the integration and engineering process in brownfield applications for electric utilities, as well as the applications in utility control centres.

1.6 Research Questions

In order to further guide the research to meet the above objectives, two research questions were framed as follows:

How to bridge the gap of different communication capabilities between different generations of SAS device to maximise the benefits of implementing IEC 61850 standard in brownfield applications for electric utilities?

How to assist and enhance the network state estimation process for electric utilities by applying the created substation event monitor at substation level?

1.7 Research Contributions

Several contributions have been made to the field of substation automation system through the course of this research. The recently published IEC 61850 standard is the outcome of more than 10 years of development and consists of 21 parts in the second edition. The missing of concise, informative and publicly available material about the complex standard for power utility engineers is addressed by providing critical review (practically oriented) of the fundamental knowledge of the standard in this thesis. This approach is further

extended to the review of fundamental knowledge on the operational mechanism and the implementation of IEEE 1588 standard. It is worth of stressing that the above information are also essential building blocks for the creation of the substation event monitor. The bottom-up approach in the construction of the substation event monitor prototype along with demonstrated performance assessment provides sufficient confidence of applying the device in utilities brownfield applications and other potential applications.

1.8 Outline of the Thesis

A thorough review of the existing literature and industry information in the fields of substation automation, IEC 61850 applications, precision timing and decentralised state estimation at utility control centre is presented in Chapter 2. The structured and detailed information of IEC 61850 standard is provided in Chapter 3. A review of currently used synchronisation technologies in electric substations and their horizontal comparison are expressed in Chapter 4. This chapter also explains in great detail of IEEE 1588 standard along with the comparison of the differences between the two versions of the standard. Chapter 5 and Chapter 6 provide detailed information of the construction of the substation event monitor and its performance assessments respectively. Chapter 7 illustrates the applications of the developed device in interfacing with existing system and decentralised state estimation. This thesis is concluded with Chapter 8. The appendixes contains additional information that are necessary to support the body of knowledge of this thesis. Details of citations in all chapters are provided in the list of references at the end of this thesis. The structure of the thesis is also illustrated in Figure 1.4.

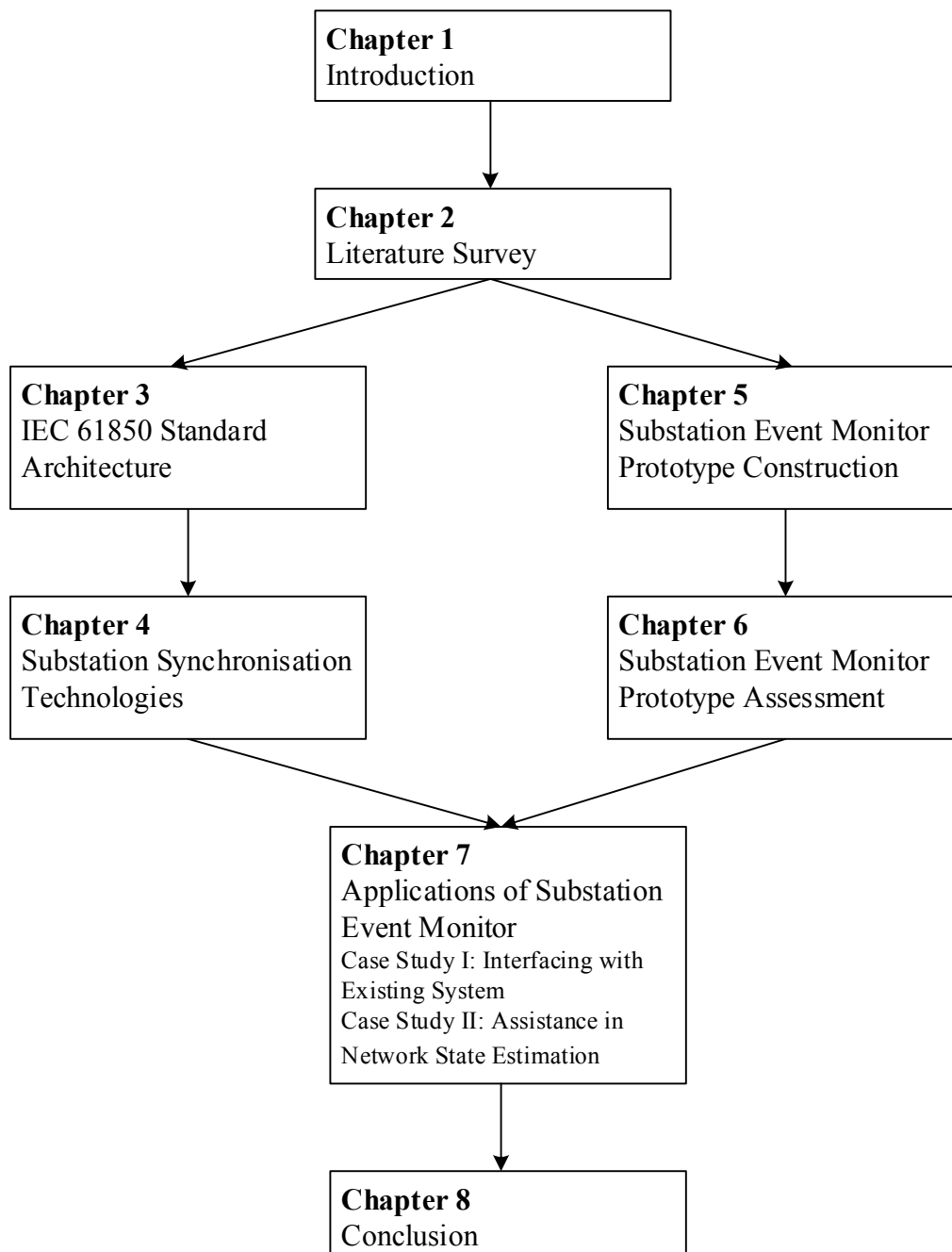


Figure 1.4: Thesis outline map

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CHAPTER 2 LITERATURE SURVEY

This chapter provides a summary of past research in the fields that are related to this thesis. The included information involves the details of utilities practice and implementation requirements. The source materials include research journals, industry magazines, conference papers and international standards. Section 2.1 provides background information with a brief review of substation automation system. Section 2.2 and 2.3 focus on the implementation of both IEC 61850 and IEEE 1588 standards. Section 2.5 introduces the concept of hierarchical state estimation with emphasis on substation level topology processing. This chapter is concluded with a summary of important aspects in the literature and the discussion of how the research presented in this thesis addresses the identified gaps.

2.1 Substation Automation System (SAS)

This section provides a brief history of SAS with a focus on power system protection and automation. The SAS has evolved significantly in the past decade especially after the introduction of IEC 61850 standard.

2.1.1 Power System Protection Relays

Relays have been used in almost all aspects of human activities that involves electricity, air conditioning, transportation, communication, space activities and many other areas. Power system protection is one of the more sophisticated applications of relays. The function of power system protection relays, or protective relays, is to initiate appropriate control circuit action once a defective line or apparatus or other power system condition of an abnormal or dangerous nature is detected. (Blackburn & Domin, 2007).

The protective relays can be broadly classified according to their implemented technology of construction as electromechanical relays, solid-state relays and microprocessor based relays (digital relays). The electromechanical relays have been dominating the electrical protection field for many years and still used for many purposes due to their proven reliable performance and low cost (Anderson, 1999) (Hewitson, et al., 2004). Most electromechanical relays are operated based on the rotation of the induction disk. Such disk is controlled by the induced torque that is sourced from the high fault current that overcomes the restraining spring and leads to operation. A high impedance bus differential

electromechanical relay is shown in Figure 2.1. It is an undeniable fact that the electromechanical relays lack of communication options (Blume, 2011). The solid-state relays were first proposed to be applied for distance protection and implemented with junction transistors by Adamson and Wedepohl (1956). However, the solid-state relays had not been well accepted in the electrical field due to their ‘static’ nature (Hewitson, et al., 2004). As the reliability of electronic components improved significantly, the microprocessor based digital relays is more preferred in modern SAS. In comparison with electromechanical relays, the digital relays are constructed with an emphasis on communication options, such as IEC 61850 standards. Although the earlier generations of relays are being slowly replaced with digital relays (Hewitson, et al., 2004), electromechanical relays are still in widespread use and continue to be manufactured and applied (Blackburn & Domin, 2007).

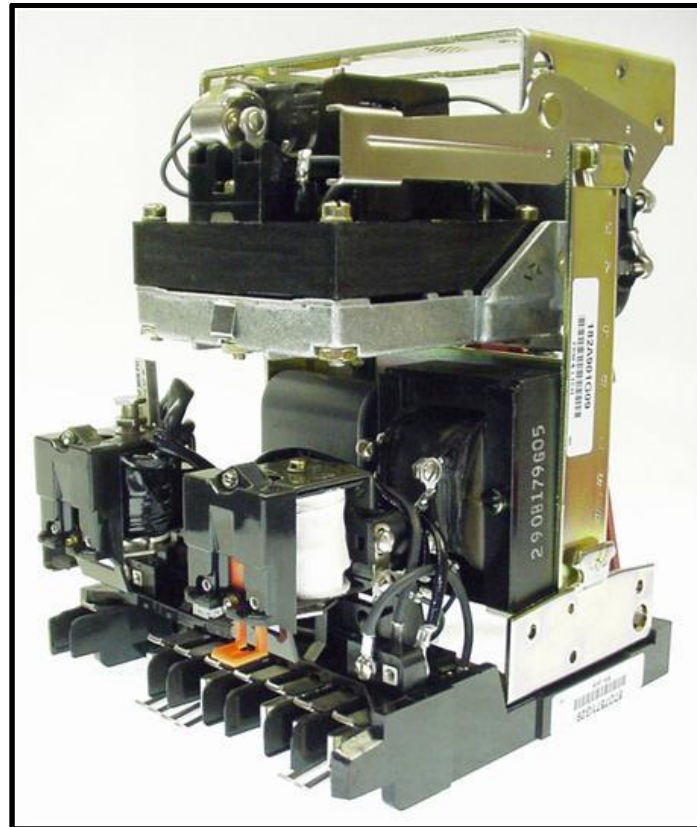


Figure 2.1: High impedance bus differential relay (ABB, 2014)

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2.1.2 Supervisory Control and Data Acquisition System

The Supervisory Control and Data Acquisition (SCADA) systems were introduced into the control rooms of electrical utilities in the 1970's (Fiedler & Swarthout, 1973). The first SCADA systems utilised data acquisition by panels of meters, lights and strip chart

recorders. The supervisory controls were realised by manually operating various control knobs. The modern SCADA systems often involves the Remote Terminal Units (RTUs) that are located at remote locations with the sole function of collecting required information for network operation purpose. The required information include both analogue measurements and digital status of power apparatus at the substation. The remotely collected information is transmitted to the network control centre via a communication system in a star connection model. Traditional SCADA communication system generally utilises Modbus or Distributed Network Protocol (DNP) 3.0 in power grids (Budka, et al., 2014). Because of the rapid development of Ethernet technology, more power utility users require to add Ethernet network feature over the traditional communication protocol (Midence, et al., 2009). Hence, there have been a large number of devices that are capable of establishing Modbus or DNP communication over Transmission Control Protocol/Internet Protocol (TCP/IP) on Ethernet network. Although the real-time Ethernet requires additional arbitration mechanisms to coordinate access to communication medium at present time (Carvajal, et al., 2014), it is envisaged that such applications will dominate the electricity industry in the future.

The data gathered by the RTUs at remote substations are generally polled periodically by the SCADA in the order of few seconds (Yang, et al., 2011a). Due to an overwhelming amount of measurement points in electric network, only reporting by exception for analogue signals and selected status information are transmitted to control centre for further processing (Kezunovic, et al., 2005b). One of the most important applications of the collected information at control centre is state estimation since the quality of its outputs affect other critical functions such as optimal power flow and stability evaluation (Sun, et al., 2013). In traditional state estimation, the status of substation switches and breakers are firstly processed to generate a network model of buses and lines (Singh & Glavitsch, 1991) (Alsac, et al., 1998). This is also referred to topology processing. The produced network model or a collection of substation topologies then becomes the basis of analogue measurements processing in order to calculate the best estimate of bus voltage magnitudes and phase angles (Sun, et al., 2013). Therefore, it is important to reduce any possible errors in status information collection phase as further state estimation is based on the assumption of a correct network topology.

2.2 IEC 61850 Standard Implementations

Since the publication of IEC 61850 standards, the applicable functionalities in SAS become

an area of active research. The core performance of GOOSE messaging on a SAS communication network have been studied and analysed by using event based simulation tools such as Optimised Network Engineering Tool (OPNET) modeller (Sidhu & Yin, 2007) (Liu, et al., 2014). The network latency of transferring GOOSE messages in a multi-vendor SAS platform is proved to be satisfactory (Mekkanen, et al., 2014). The performance of IEC 61850 peer-to-peer communication based protection scheme has been evaluated in laboratory environment by using test equipment such as Omicron test set (Ali, et al., 2012) (Ali & Thomas, 2011) (Stojcevski & Kalam, 2011) and Real Time Power System Simulation (RTDS) (Sidhu, et al., 2011). With the recognition of fast, reliable and secure feature of GOOSE messaging, important control functions such as bus transferring scheme is achieved in residual voltage transfer method (Sevov, et al., 2012) and main-tie-main (MTM) scheme (Ransom & Chelmecki, 2014). Wilson *et al.* (2013) further analysed the different approaches to reduce the coordination time in a MTM scheme and concluded the best result is achieved from the use of peer-to-peer GOOSE messaging to share required information between protection relays. The priority-based load shedding scheme in manufacturing campus is also achieved using GOOSE communication (Adamiak, et al., 2014). A reliable breaker fail protection scheme for a double bus bar substation using GOOSE messaging is proposed by Noran (2014) with the emphasis on simplified engineering process. The GOOSE message communication has also been implemented for arc-flash protection (Cabrera, et al., 2012) (Dixon, et al., 2013). The arc-flash protection relay sources the signal from the optical light sensors installed at the bus bar and generates tripping command as GOOSE messaging if both light and fault current are detected. Quick transmission of the tripping signal over high speed Ethernet network ensures a rapid isolation of bus fault that leads to minimum damage and disruption to the system (Dixon, et al., 2013). The relatively low-speed application, such as transformer tap changer control and monitoring, is also proposed and achieved by GOOSE message communication between voltage regulator IEDs (Sichwart, et al., 2013) (Parkh, et al., 2012) (Li, et al., 2010) (Yarza & Cimadevilla, 2014). The voltage regulation function requires a number of connections between the tap changer and controller IEDs for raise or lower commands, as well as transformer tap position information. The exchange of such information via GOOSE messages replaces the traditional hardwired multi-core copper cables. In addition, the information of measured current and voltage among the IEDs can be exchanged via analogue GOOSE messages in accordance with IEC 61850 standard (Gajic, et al., 2010).

The ability to perform relay-to-relay communications via Ethernet is not limited at local

substations, it also enables the implementation of innovative protection and control applications between substations (Brunello, et al., 2001). The concept of using GOOSE and Ethernet instead of proprietary communication to assist wide area protection scheme (e.g. line distance protection) is introduced by Apostolov (2008). Such concept has been implemented by Sun *et al.* (2014) and reported the clearing time of all faults to be within 20 cycles (333 ms). It is necessary to emphasise that the wide area protection and control functions via Ethernet communication must be carefully designed in order to avoid the degradation of the scheme performance (Jenkins & Dolezilek, 2011).

The use of IEC 61850 standard defined GOOSE messages is not limited to electric utilities. The use of peer-to-peer GOOSE messaging for wind farm system protection is also presented (Reichard, et al., 2007). In particular, the peer-to-peer GOOSE messaging has also been implemented in an offshore wind farm project with annual electricity production of 1.9 GWh in the United Kingdom (Goraj, et al., 2010). Furthermore, the use of GOOSE messaging has also been considered and proposed to oil and gas industry due to the benefit centred in interoperability among different vendors (Montignies, 2010) (Flores & Garcia, 2014). IEC 61850 communication system has also attracted pulp and paper industry for better energy management and profit yielding through co-generation, power distribution, load shedding and power system monitoring. The peer-to-peer GOOSE messaging allows for various protection schemes including directional blocking, transfer tripping and voting schemes in the application (Mazur, et al., 2013).

The impact of implementing SVs in substation protection schemes has been studied and evaluated by various authors, such as transmission line distance protection (Kanabar, et al., 2011) (Sun, et al., 2012) (Yang, et al., 2014) and current differential protection schemes (Crossley, et al., 2011) (Ingram, et al., 2014). The process level digital connections from instrument transformers and protection IEDs have been specified as 80 samples per cycle in the guideline document IEC 61850 '9-2 Light Edition' or '9-2LE' (UCAIug, 2004). However, commercial protection IEDs re-sample the incoming '9-2LE' stream to a fixed and lower rate (e.g. 48 samples per cycle) in order to use the same protection algorithms (Hossenlopp, et al., 2008). Further notable research has examined the techniques that could accommodate the loss of SV packets for digital protection scheme (Kanabar, 2011). The use of sampled values in protection applications consequently triggered the concern of protection system reliability. The assessment of process bus reliability by Tournier and Werner (2010) has resulted the highest Mean Time To Failure (MTTF) score from the dual star network that was implemented with Parallel Redundancy Protocol (PRP). The most

commonly used reliability modelling methods, Reliability Block Diagrams (RBDs), have also been used to evaluate SV applications in a substation (Kanabar & Sidhu, 2009).

The implementations of process bus in real world projects started through several trials in France, Canada and the UK (Hossenlopp, et al., 2008). A partial installation of the HardFiber system by General Electric (GE) at one of the substations of American Electric Power was reported in 2009 (Burger, et al., 2009). Another significant trial installation was conducted by Powerlink Queensland in Australia (Schaub, et al., 2011). This trial installation has reported good correlation on a single phase to ground fault waveform between non-conventional instrument transformer (NCIT) and conventional instrument transformer. Powerlink Queensland also completed a point-to-point connected process bus at Loganlea substation (Schaub, et al., 2012). There has been several full process bus implementations in China with most of the installed equipment being manufactured domestically (Chen, et al., 2011).

Other active areas of research on IEC 61850 standard implementation are centred at information modelling, such as modelling distributed energy resources for microgrid applications (Ustum, et al., 2012) (Andren, et al., 2014) and the harmonisation of IEC 61850 and Common Information Model (CIM as defined in IEC 61970 standard) (Santodomingo, et al., 2013) (Lee, et al., 2015). The IEC 61970 standard focuses on the vendor-neutral data modelling in Energy Management Systems (EMS) domain for power system applications. The unification of the two standards has been considered as a key success factor for the implementation of smart grid in the future (Lee, et al., 2015).

On the other hand, the reports of interfacing the legacy protective devices are very limited in the literature. Apostolov (2002) highlighted the importance of the integration of legacy devices into UCA 2.0 based systems via gateways. The document outlined the requirements of the gateways, especially the timing requirement on publishing the peer-to-peer GOOSE messages. Yi *et al.* (2007) also recognised the need of interfacing the legacy devices and proposed a software model for a universal gateway. The model was limited at very high level and being written in eXtensible Markup Language (XML) schema. The research conducted by Zhang *et al.* (2008) proposed the use of embedded systems to interface the vast number of legacy devices that are currently in service in China. However, the proposal is intrusive to the existing systems which brings complexity and difficulty for large brownfield applications.

2.3 Precision Timing for Power System Applications

The absolute necessity of time synchronisation for the investigation of power system events or wide area disturbances has been highlighted after the North-East blackout of 2003 (Apostolov, 2004) (Dickerson, 2007). More accurate timing information, in the order of 1 microsecond, is now required for the implementation of phasor measurement unit and sampled value process bus (UCAIug, 2004) (Brunner & Antonova, 2011). In modern SAS, four most commonly referred time synchronisation techniques are Network Time Protocol (NTP), Inter-Range Instrumentation Group time code B (IRIG-B), 1-Pulse-per-Second (1PPS) and recently developed Precision Timing Protocol (PTP) which is defined in IEEE 1588 standard. The details and further comparison of the above techniques are discussed in Chapter 4. IRIG-B and NTP are generally used in today's SAS functions, such as differential protection, fault recording and locating, for the distribution of absolute time reference (Steinhauser, et al., 2010). The 1PPS signal, which is defined in IEC 60044-8 standard, provides a clear specification of its usage without time of day information (Technical Committee 38, 2002). There are two revisions of PTP, namely IEEE 1588-2002 (PTPv1) and IEEE 1588-2008 (PTPv2). Although the PTPv2 improved robustness and accuracy, it is not backward compatible with PTPv1 due to the fundamental format change of exchanged messages (Han & Jeong, 2010). The most significant change in PTPv2 is the concept of transparent clock that is capable of calculating the residence time of the synchronisation message in a PTPv2 compatible Ethernet switch. PTPv2 standard also specified the use of PTP profiles with the purpose of allowing for specific parameter selections according to domain specific requirements (Technical Committee on Sensor Technology TC-9, 2008). As a result, the IEEE Power System Relaying Committee (PSRC) and Substation Committee (SUB) of IEEE Power and Energy Society (2011) published C37.238 standard for the customised PTPv2 profile to be used in power system applications. The customised profile defined performance requirements and a set of PTPv2 parameters with the purpose of optimising its use for power system applications and mandated the additional data to be exchanged during synchronisation (IEEE PES PSRC WG H7/Sub C7 Members and Guests, 2012). The implementation of PTPv2 for high accuracy time synchronisation in substations has been recommended by the smart grid road maps as discussed in Section 1.3. The fact that PTP is achieved via Ethernet network has been recognised as another significant benefit to be implemented with IEC 61850 standard through the same communication network infrastructure (Brunner & Antonova, 2011) (Steinhauser, et al., 2010). On the other hand, it is possible that the large amount of Ethernet traffic would affect the performance of

protection IEDs and PTP synchronisation accuracy (Ingram, et al., 2011). Therefore, the amount of traffic that would be sent to those devices shall be limited. A technique has been proposed by Ingram *et al* (2011) to take the advantage of the facts that GOOSE, SV and PTP traffics have been specified the use of virtual local area network (VLAN) frame tagging (IEEE Computer Society, 2006) and are multicast protocols. The technique is to apply a two levels of Ethernet traffic segregation using VLANs and multicast address filtering for large substations. In particular, the technique relies on the fixed allocation of multicast traffic addresses for the consistency and ease of commissioning and ongoing maintenance activities. The dynamic multicast filtering techniques, such as GARP Multicast Registration Protocol (GMRP) and Multiple MAC Registration Protocol (MMRP), have not been emphasised due to its limited implementation in Ethernet switch products.

The well-established technology of synchrophasor measurements provides an ideal system to monitor and control a power system especially during stress conditions (Begovic, et al., 2005). The main functions of the technology are to measure both power system voltages and currents over spread locations with precision timing and allow real time comparison of the measurements that leads to potential control actions. The collected measurements can also be analysed by network planning and performance engineers to achieve better grid stability. The synchrophasor data is also used for load modelling in order to comprehend the relationship between load changes and feeder supply voltage (Ledwich & Moyano, 2011). The IEEE synchrophasor standard C37.118 specified the basic measurement requirements and the criteria for data verification to ensure the ability to compare data from different devices (Martin & Carroll, 2008). Part 1 of C37.118 standard also outlined three time synchronisation techniques with an emphasis of the increasing deployment of PTPv2 for future developments (IEEE Power & Energy Society, 2011). Amelot *et al.* (2011) reported a testing dashboard that has been developed by US NIST to access the PTP performance in synchrophasor application. Owing to the described benefits, many researchers have devoted efforts on implementing PTP to synchrophasor measurements for SAS functions (Lixia, et al., 2011) (Carta, et al., 2011) (Castello, et al., 2013). Although the importance of time synchronisation has been highlighted when applying synchrophasor devices, recent experiments have indicated the potential spoofing attacks on global position system (GPS) clocks. Shepard *et al* (2012) reported the specified phase angle error in the IEEE C37.118 standard could be easily violated up to 70 degrees by a hardware based spoofing system. Further evaluations conducted by Akkaya *et al* (2013) also emphasised the potential consequences of cascading blackouts and damages to equipment as a result of

GPS clock spoofing attacks. Therefore, several techniques that could vastly improve GPS security have been recommended (Shepard, et al., 2012). These recommendations include placing cryptographic signatures in the navigation messages, spread- spectrum codes on GPS satellites and jamming detectors.

The reports on the real-world implementation of process bus technology with PTP synchronisation is currently limited in Chinese substations (McGhee & Goraj, 2010) (Zhao, et al., 2011). The recently energised process bus substation in Denmark employed 1PPS as synchronisation technique (Pavaiya, et al., 2014).

The deployment of PTP in other applications, such as nuclear fusion science (Soppelsa, et al., 2010) and ocean sensor systems (Rio, et al., 2012), has also been published. Lipinski *et al.* (2011) reported a White Rabbit extension of PTP that has been developed as Ethernet-based network synchronisation technique used in European Organisation for Nuclear Research (CERN). The synchronisation accuracy achieved by the application was noted in the range from ± 0.4 nanosecond to ± 200 nanoseconds.

2.3.1 Evaluation on the Performance of Precision Time Protocol

In comparison with other industry applications, the communication network condition with multicast traffic (i.e. GOOSE and SV messaging) makes the implementation of PTP in power systems unique. This leads to more comprehensive research in evaluating the PTP implementations. Giorgi and Narduzzi (2011) identified the relationship between the timestamping accuracy and the instability of a regulated clock. They proposed to use Kalman filter to improve the performance of slave clock and achieved positive results. Ingram *et al.* (2012a) accessed the synchronisation accuracy among the different synchronisation techniques and established the satisfactory results by using PTPv2 in substation environment. The same researchers then performed more tests on the PTPv2 implementation for process bus and recommended the selection of grand master clock with stable internal oscillator for power system applications (Ingram, et al., 2012b). Another interesting aspect from this research (Ingram, et al., 2012b) is the identification of the shortcoming in PTPv2 slave clock transient response under network event. This problem is potentially to be solved by using the proposed switching controller in embedded time synchronisation systems (Chao, et al., 2011). The analysis of the causes of perturbation in PTP implementation has been presented by Scheiterer *et al.* (2009). They have reported the effect of oscillator drifting on the accuracy of both master and slave clocks. This research further highlighted the necessity of deploying high quality master clock in power system

applications.

The concern of PTPv2 performance in a switched Ethernet network with high load of multicast traffic has been expressed by both De Dominicis *et al.* (2011) and Zarick *et al.* (2011). The researchers suggested to allocate higher priority for PTPv2 synchronisation messages in Ethernet network in order to meet the timestamping accuracy requirement. The results presented by Ingram *et al.* (2013b) proved that the higher priority of PTPv2 message only resulted in a slight improvement with high SVs network load when transparent clocks are used in the network. The performance of several PTPv2 transparent clocks has been reported by Burch *et al.* (2009). The dedicated PTPv2 test gears, which are capable of automating a range of tests centred in PTPv2 performance, are also commercially available (Calnex Insight and Innovation, 2014) (JDSU, 2014). It is unfortunate that the test sets, which are similar to Ethernet network test sets, are generally very expensive at the time of writing this document.

2.3.2 Reliability of Precision Time Protocol

The operation of electricity networks is generally regulated by a set of rules or codes in order to meet the required reliability standard (AEMC, 2014) (National Grid, 2014). The implementation of process bus technology for electric network protection is not exempted and the operation of sampled value protection schemes leads to the necessity of a highly reliable time synchronisation system. An established PTP time synchronisation system is relied on Ethernet network reliability and availability. The PTP implementation over the network redundancy protocol, Parallel Redundancy Protocol (PRP), was first analysed by Meier & Weibel (2007) and reported positive results. Tournier *et al.* (2009) also investigated the different alternatives of implementing PTP over High availability Seamless Ring (HSR) protocol, even though the two protocols are based on opposite operating principles. The concept of applying PTP over Redundancy Box (RedBox) was proposed by De Dominicis *et al.* (2011) and highlighted the need of enabling transparent clock functionality in RedBox devices in the future.

Another concern with the accuracy of PTP slave clock during master clock fail-over event was expressed by Ferrari *et al.* (2012). It was suggested by Bondavalli *et al.* (2013) that the slave clock could be free-running for hundreds of seconds due to the length of grand-master clock election process. However, the tests results presented by Ingram *et al.* (2013a) showed that the master clock election process usually takes less than ten seconds and the step change in slave clock only occurred if an offset exists between the redundant master clocks.

Bondavalli *et al.* (2013) developed a slave clock that is capable of estimating the error of grandmaster and possibly raising alarms if the error is above a set threshold. This slave clock could be utilised in the future for process bus or synchrophasor applications with better clock reliability monitoring capabilities.

2.4 Cyber Security Implications

As the technologies and innovations continue to revolutionise the electricity industry, the power system also becomes much more complex such that it undoubtedly presents many risks, especially malicious cyber-attack (Liu, et al., 2012). A power utility that implements IEC 61850 technology generally allows remote access to substation network from corporate environment for control and maintenance purposes. These access points are identified to be the potential sources of cyber vulnerabilities (Hong, et al., 2014). The same researchers also highlighted the possibility of performing unauthorised breaker operations by modifying GOOSE or SV data streams once the substation firewall has been compromised.

The international standard IEC 62351 is a series of technical specifications in cyber security aspects. This standard provides a range of techniques, which include Transport Layer Security (TLS) and role based access control, to prevent network based malicious activities. However, the stringent performance requirements on GOOSE and SV messages implies network authentication is the only suitable security measure for these types of traffic (Cleveland, 2012). IEC 62351-6 provided a mechanism that requires minimal computing power in order to digitally authenticate the messages. The Annex K of IEEE 1588-2008 standard defined an optional security mechanism using symmetric Media Access Control (MAC) functions. This feature provides group source authentication, message integrity and replay attack protection for PTP messages (Moreira, et al., 2013). The researchers also presented a number of challenges including the additional overhead of the security extension that might consume additional resources. Further studies on this subject proposed the usage of Secure Hash Algorithm 3 (SHA-3) in future versions of IEEE 1588 standard for the enhancements in security aspects (Moreira, et al., 2014).

2.5 Distributed Topology Processing in Substation Automation System

The purpose of real time power system modelling at network control centre is to generate a trustful representation of the current operating condition. The true representation of the network is determined by state estimator based on a centralised bus-branch network model (Mili, et al., 1999). The basis of the network model is the correctness of current topology of

system substations (Malbasa, et al., 2013). In the past, the detection of topology error has been achieved via least absolute value (LAV) method (Jabr & Pal, 2004) and artificial neural network approach (Manitsas, et al., 2012). The advent of new digital substations with the implementation of synchrophasor and micro-processor based IEDs provides a considerable amount of local data at substation level. The increasingly available information at substation was considered as the enhancements of SAS capabilities which lead to a more detailed modelling of switching devices (Silva, et al., 2013). This modelling improvement became the basis of decentralised state estimation concept.

A hierarchical state estimation architecture was proposed by Silva *et al.* (2013) to locally process substation level information and only transmit limited information that would be required for the coordination of data at regional control centre. The information at substation level include both state variables and substation topology. The proposal of producing robust topology at substation level has been conducted by Kezunovic *et al.* (2005a) (2005b). The researchers illustrated the deficiencies of current topology estimation methods via SCADA system and proposed the use of time correlated information at substation level to produce robust topology information and then form accurate network model. The research also highlighted the need of applying the topology processing technique over the new IEC 61850 and IEC 61970 standards in order to yield the highest benefit (Kezunovic, et al., 2005b). In order to monitor circuit breaker status as a part of topology processing in real time, Kezunovic (2006) proposed the use of a Circuit Breaker Monitor (CBM) module that is permanently connected to the circuit breaker. This solution is intrusive to the existing power system equipment, hence it is less cost effective in practical implementation. A more detailed two-level linear state estimation was presented by Yang *et al.* (2011a) (2011b). The researchers proposed the first level of state estimation can be calculated at substation level which is consist of the determination of local substation state via synchrophasor measurements and the verification of circuit breakers status. The resulted nodal topology is then ready to be transmitted to the control centre in which the second level of state estimation is resided. The control centre level state estimation is similar to the traditional method but is processed based on the distributed and verified information. Another more recent research work conducted by Sun *et al.* (2013) further highlighted the importance of the correct topology model obtained at process level. A software based data collection and processing platform at substation level has also been presented by Jakovljevic and Kezunovic (2002) (2003) for state estimation enhancement. However, the software model assumes the implementation of IEDs in the substation without the emphasis of interfacing

with existing substation equipment.

Brand and Wimmer (2009) proposed a distributed topology detection model based on connectivity analysis for a number of important substation applications, such as interlocking, zone protection, breaker fail protection and Current Transformer (CT)/Voltage Transformer (VT) plausibility check. This research is notable because it proposed to use GOOSE messaging for the distribution of node connectivity information. However, the authors did not emphasise the need of having a time synchronised substation topology during the integration of global system as it was underlined by other researches (Yang, et al., 2011a) (Kezunovic, 2006).

2.6 Summary

Protective relays have been used broadly in electricity industry in order to issue appropriate circuit control actions once an abnormal or dangerous condition is detected in power system. Different generations of the protective relays based on the manufactured technology co-exist and are in-service in modern SAS. The use of vendor independent digital interfaces via IEC 61850-8-1 and IEC 61850-9-2 standards over Ethernet is well established as industry standard. This has also triggered broader research in the implementation of the new communication standard. In particular, the use of GOOSE messaging is beyond electric utilities to other fields, such as oil and gas industry, as well as pulp and paper industry. The trials of process bus implementation have been conducted around the world and the recent result from Powerlink Queensland has indicated positive correlation between conventional and non-conventional instrument transformers under a recorded system fault. Although the implementation of the new IEC 61850 standard has been continuously improving, the legacy protective relays are still in widespread use in current power systems. The reported research by Zhang *et al.* (2008) further highlighted the need of interfacing with the legacy devices by taking the advantage of the new substation communication standard. However, the proposed integration method is intrusive to existing system which creates difficulties in brownfield applications.

The historical blackout event in the North America 2003 has proved the necessity of time synchronisation in power system. In comparison with the existing synchronisation technologies in electric substations, IEEE 1588 standard or PTP has been well recognised at international scale. The capabilities of achieving the synchronisation accuracy at sub-microsecond level and automatic path delay compensation through Ethernet network

secured the PTP implementation with the upcoming technologies such as process bus and synchrophasor measurements. The evaluations of PTP performance and reliability have been conducted by a number of researchers in the literature. The results of the evaluations have underlined the bright future of PTP standard and proposed several suggestions when it is implemented in electric substations.

This thesis aims to develop a non-intrusive device that is capable of translating the detected substation event into IEC 61850 standardised message in order to interface with legacy devices for brownfield applications. The additional implementation of IEEE 1588 standard also provides accurate time information for the detected substation events. Furthermore, the proposed system also has the potential of improving the commissioning process in substation refurbishment projects. The combination of IEC 61850 and IEEE 1588 standards also creates potential improvements in utilities' SCADA system, especially in state estimation process. The increasingly available information due to the use of new communication standard has also introduced the concept of decentralised state estimation. The research reports in the literature have highlighted the current deficiencies of the topology processing methods and proposed the possibility of using IEC 61850 standard for distributed topology detection model.

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CHAPTER 3 IEC 61850 STANDARD ARCHITECTURE

This chapter provides concise and informative knowledge on the core parts of the IEC 61850 standard. This knowledge is also necessary for enabling GOOSE communication during the development of substation event monitor. Prior to the detailed information of the standard, Section 3.1 provides an introduction of Open System Interconnection (OSI) model for easier understanding on the Ethernet communication of both IEC 61850 and IEEE 1588 standards. Section 3.2 begin with an overview of all the parts of the standard. The following subsections provide sufficient information on the three most essential aspects of the standard namely abstract data and services modelling, specific communication service mapping (SCSM) and substation configuration language (SCL).

3.1 Open System Interconnection (OSI) Model and Ethernet

Due to the universal need for an interconnecting system from different manufactures, the International Standard Organisation (ISO) developed the OSI reference model in 1990 (Smythe). The OSI model has defined seven network layers as shown in Figure 3.1. The layers are the logical representations of a communication network with the potential of breaking the total problem into smaller pieces (Zimmermann, 1980). Each layer wraps the lower layer and isolates them from the higher layer. Each individual layer provides services to an upper layer such that the highest layer offers a set of services to run user applications (Voelcker, 1986). Effectively, the user application initiates a communication by passing the message down through each layer while the functions of each layer add value by providing services to complete the communication. The OSI model is well supported and implemented by global companies, such as IBM, Boeing and General Motors. However, it is slowly replaced with other models. Although most of modern network technologies are not exactly matching the OSI model, nonetheless present a useful base when discussing any networking with the reference of the OSI model, especially to the names and the number of the model. A good example is the well-known TCP/IP which is a four layer model and can be coarsely mapped to the OSI model (Seth & Venkatesulu, 2008). This is also shown in Figure 3.1. The TCP, which manages both connection and data integrity, is considered as a transport layer protocol. The IP, which is responsible for delivery of data to the correct destination, is considered as a network layer protocol. The network interface layer in the TCP/IP model

is usually referred as Ethernet that is shown in Figure 3.1. The Ethernet, which is defined in ISO/IEC/IEEE 8802-3 standard (ISO, et al., 2014), is limited to the physical layer and data link layer of the OSI model (Diab & Frazier, 2006). In particular, the standard focuses on the sub-layer MAC between the two layers in the OSI model by specifying packet format and services. Each MAC packet is required to specify destination and source MAC addresses with the total size of 12 bytes. The MAC address is a unique hardware identifier embedded in every network interface card. The addresses specified in MAC packet plays an important role during the communication under IEC 61850 standard.

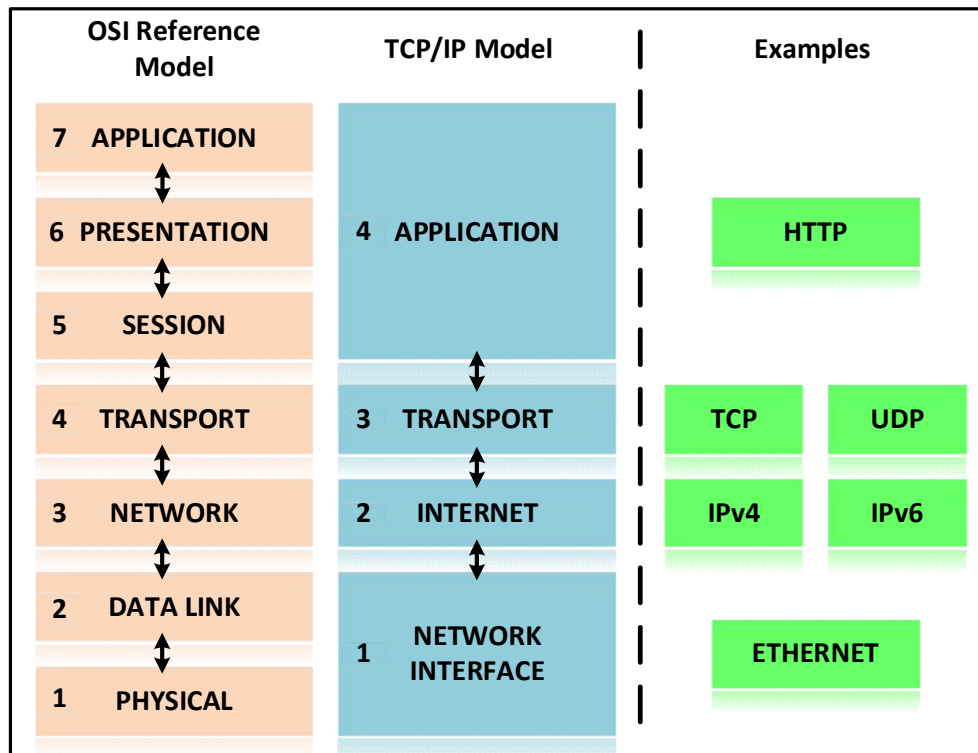


Figure 3.1: OSI model and Ethernet

3.2 IEC 61850 Standard Architecture

The IEC 61850 standard has been rapidly expanding since its publication. The current standard consists of 21 parts. The complete set of the standard is shown in Table 3.1. Parts 1 and 2 of the standard describes general information and provides the definitions of a number of terms used across the standard. Parts 3, 4 and 5 identified the general and specific functional requirements for the communications in a SAS. These requirements are used to further identify the data models, services and underlying communication protocols to be specified in the standard. Part 10 of the standard specifies the methods and abstract test cases that have to be performed to the target devices in order to ensure all the requirements are met. Parts 7-410 and 7-510 are two of the new members in IEC 61850 family with the

aim to extend the information model to hydroelectric plants and provide guidelines for the modelling concepts. IEC also published parts 7-420 and 90-7 as it recognises the growing need of having international standard to define the communication

Table 3.1: Structure of the IEC 61850 standard

Part #	Description
1	Introduction and overview
2	Glossary
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 IEDs
7-1	Basic communication structure – Principles and models
7-2	Basic communication structure – Abstract communication service interface (ACSI)
7-3	Basic communication structure – Common data classes
7-4	Basic communication structure – Compatible logical node classes and data classes
7-410	Basic communication structure – Hydroelectric power plants – Communication for monitoring and control
7-420	Basic communication structure – Distributed energy resources logical nodes
7-510	Basic communication structure - Hydroelectric power plants – Modelling concepts and guidelines
8-1	Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3
80-1	Guideline to exchange information from a CDC based data model using IEC 60870-5-101 or IEC 60870-5-104
9-2	Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3
90-1	Use of IEC 61850 for the communication between substations
90-4	Network engineering guidelines
90-5	Using IEC 61850 to transmit synchrophasor information according to IEEE C37.118
90-7	Object models for power converters in distributed energy resources (DER) systems
10	Conformance testing

and control interfaces of all Distributed Energy Resources (DER) including power converter-based DER systems. Parts 80-1, 90-1 and 90-5 provide guidelines of exchanging

information for wider area protection, monitoring and control applications. The part 90-4 is resulted from the growing demand of guidelines and specifications for engineering Ethernet networks for the full implementation of IEC 61850 standard.

In order to implement IEC 61850 series of standard in a substation project, three most important aspects must be understood, namely abstract definition of both data and services, specific communication service mapping (SCSM) and substation configuration language (SCL). These aspects are defined in parts 6, 7-x, 8-1 and 9-2 of the standard. The general structure and relationships between these parts during project implementation is shown in Figure 3.2. The following sub-sections will provide more details on the above aspects.

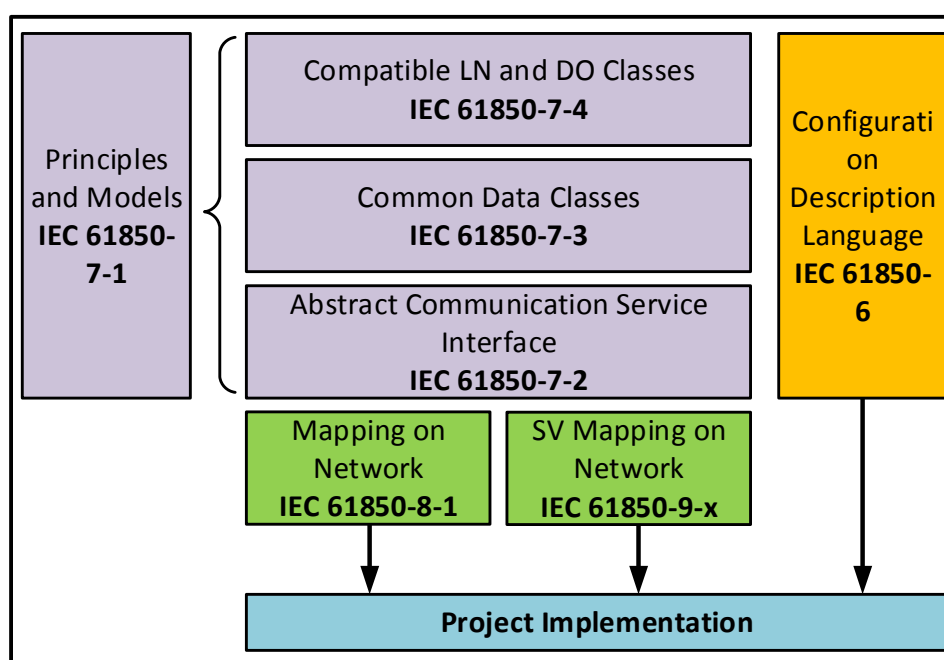


Figure 3.2: IEC 61850 implementation in typical project

3.2.1 IEC 61850 Abstract Architecture Overview

Part 7 of IEC 61850 standard, which is the core of the standard, defines the ‘abstract’ architecture that is embedded in both data modelling and communication service interface. The term ‘abstract’ means the standard is able to theoretically isolate the created data objects and services from any communication protocol (Ozansoy, et al., 2009), as long as the protocol is capable of handling the complex naming convention of the standard. With the emphasis on both SAS functionality domain modelling and the definition of the application data exchange, the customer specific applications are achievable through the vendor independent and predictable design that are specified in the IEC 61850 standard (Preiss & Wegmann, 2003). The standard IEC 61850-7-1 provides the conceptual outlook for both data modelling and communication service interface. The standards IEC 61850-7-3 and 7-

4 specified the details for data modelling, while IEC 6185-7-2 defines the communication service models.

3.2.1.1 IEC 61850 Data Modelling Approach

The fundamental difference between IEC 61850 standard and other legacy communication protocols is the provision of comprehensive model for SAS devices to organise data in a consistent manner across all manufactures. The principle of the modelling approach is the decomposition of both SAS functions and power system devices into a well-defined logical structure in Intelligent Electronic Devices (IEDs). The functional decomposition and power system equipment virtualisation introduced the concept named Logical Node (LN), which is the smallest entity to carry exchangeable information. IEC 61850-7-4 standard has predefined a number of groups of LNs to ensure the consistency of semantics. For example, LNs in Group ‘S’ (supervision and monitoring), ‘T’ (instrument transformers and sensors), ‘X’ (switchgear), ‘Y’ (power transformer) and ‘Z’ (further power system equipment) cover a range of devices in power system, while LNs in Group ‘C’ (control) and ‘P’ (protection) produce action commands to switchyard equipment. Each LN is a hierarchical object oriented model with a number of elements that define the LN’s characteristic and its logical relationship to some SAS function (Mackiewicz, 2006). An example of circuit breaker LN (XCBR) and its compositions are illustrated in Figure 3.3. The composed elements in a LN are defined as Data Object (DO) class, such as ‘Loc’ (local control), ‘OpCnt’ (operation counter), ‘Pos’ (switch position), ‘BlkOpn’ (block opening) and ‘BlkCls’ (block closing) for XCBR LN that are shown in Figure 3.3. Moreover, each DO class has been uniquely named in IEC 61850-7-4 standard (Technical Committee 57, 2010). Each type of DO within a LN conforms to the specification of a Common Data Class (CDC) which is also uniquely defined in IEC 61850-7-3 standard (Technical Committee 57, 2010). CDC specifies the exact information and services of the DO that shall be included for each LN. The elements within a DO is again uniquely defined as Data Attributes (DA) in the standard (Technical Committee 57, 2010), such as ‘stVal’ (status value), ‘q’ (quality) and ‘t’ (timestamp) for switch position DO that are shown in Figure 3.3. It is important to emphasise that the control function is introduced directly through IEC 61850-8-1 standard Edition 2 for the purpose of removing any mapping issue to underlying communication protocol. The second edition of IEC 61850-7-3 standard only enables the control services at the end of a number of CDCs (e.g. controllable double point – DPC) as controllable DOs. The control service ‘ctlVal’ (control value) for switch position DO, which is a DPC type, is shown as an example in Figure 3.3. Since each DA within a DO represents different SAS function, the individual

DA is also categorised into a corresponding Functional Constraint (FC) group (Technical Committee 57, 2010). For example, ‘stVal’ represents the status value of the circuit breaker that has been classified as a member of Status (ST) FC group, while ‘cdcNs’ (CDC name space) has been allocated to Extended definition (EX) FC group since it describes any specifically created CDC (Technical Committee 57, 2011) (Technical Committee 57, 2010). The definitions of FC groups are crucial in ACSI, in particular to access various DAs of the information model. To simplify the description of the information exchange services, the following two definitions are specified. The reference to a collection of DAs of one DO that has the same FC allocation is defined as Functional Constraint Data (FCD). Similarly, the reference to a single DA of a DO having the specific FC value is defined as Functional Constraint Data Attribute (FCDA). The usage of FCD and FCDA are described in Section 3.2.1.3.

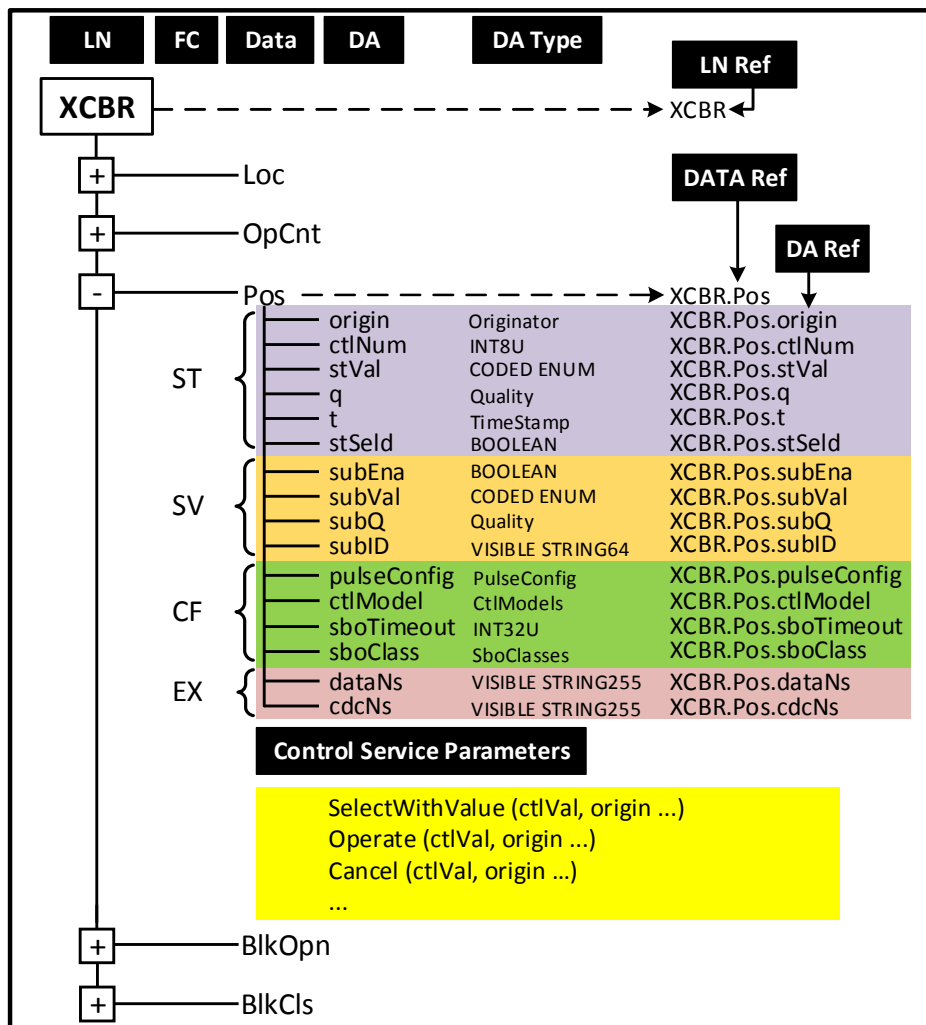


Figure 3.3: Hierarchical view of XCBR LN

From Figure 3.3, a simple example of the IED that contains the XCBR LN could be a circuit breaker management device. As a multi-functional device, the IED must contain a number

of LNs to support its functional needs. Among the LNs, several of them are grouped into a Logical Device (LD) within the IED based on its common features. It is possible but not necessary to see more than one LD in one IED or a physical device. In addition, the LDs can be further grouped into a server that represents the external visible behaviour of a physical device (Technical Committee 57, 2010).

There are two special LNs defined in IEC 61850-7-4, Logical Node Physical Device (LPHD) and Logical Node Zero (LLN0). LPHD represents the common issues of a physical device but it does not inherit any data from any other LNs (Apostolov, et al., 2003). LLN0 represents common data of the logical device (Technical Committee 57, 2011). The principle of using the two special LNs is that each LD must contain one LLN0 but LPHD is only required to be defined in the minimum of one LD in a physical device (Technical Committee 57, 2011). In the absence of LPHD in LDs, all LNs in the Group “L” shall be defined in the same LD of a physical device. It is also important to pay attention on LN Group ‘G’ for generic references. In particular, the Generic Process I/O (GGIO) in the LN group. The usage of GGIO is limited to the situation at which the modelled process device is not predefined in LN groups S, T, X, Y and Z (Technical Committee 57, 2010). Ling *et al.* (2014) suggested that GGIO can be used for fault signal, external node, device status and other alarm signal inputs and control outputs.

3.2.1.2 IEC 61850 Meta-Meta Modelling

The data modelling process described in the previous section is centralised in SAS functional domain. The information exchange service that is modelled in IEC 61850-7-2 relies on the data modelled in such domain to provide detailed definition of its semantics and syntax (Kostic, et al., 2005). In order to comprehend the relationship between data and communication modelling, it is necessary to describe Meta-Meta Modelling approach that has been rather implicitly defined in IEC 61850 standard. The term ‘meta-model’ is defined by Lehnhoff, *et al.* (2011) as a generic information model with embedded concept of a base object type (i.e. models to create models). The ‘meta-meta model’, which is one more level up according to IEC 61850-7-2 standard (Technical Committee 57, 2010), defines base types and rules on how to build the hierarchical structure. For example, the definition of the status value (stVal) data attribute must conform to the Generic Data Attribute Class (Meta Modelling) that is defined in IEC 61850-7-2, while the type of ‘stVal’ is coded as enumerate or ‘CODED ENUM’ that is defined in the Base Type (Meta-Meta Modelling) in IEC 61850-7-2 standard. Another meta-meta modelling level type definition is called

CommonACSI Types (ACSI stands for Abstract Communication Service Interface) that defines a number of generic types of information to be used in Part 7 of the IEC 61850 standard. The described example indicated the modelling principle is the multiple hierarchical levels exist beyond the present structure until it reaches the Base Type or CommonACSI Types that are defined in IEC 61850-7-2 standard.

3.2.1.3 Information Exchange Service Interface

In addition to the definitions of several information modelling classes (Meta Modelling level), IEC 61850-7-2 also specifies a range of information exchange modelling classes, such as Control, Control Block for Generic Substation Event (GSE), Control Block for Transmission of Sampled Values (SVs), Report Control and Logging (Technical Committee 57, 2010). A set of available services that is specified in each information exchange modelling class is called ACSI services. In essence, the ACSI services specify how to access and exchange the data that is modelled in IEDs. A minimum number of one ACSI server must be contained in an IED that supports IEC 61850 standard. The standardised services that are hosted in each server are still maintained at abstract level. As a result, the ACSI server can be considered as a 'black box', and other field devices or clients are capable of just referring to the abstract services to exchange the desired information without any further understanding of the IED.

The majority of the defined services are in the nature of client-server communication mechanism, where the information exchange model is mainly request and reply messages (Kostic & Frei, 2007). Some examples of such services are GetAllDataValues, GetDataDefinition, SetDataValues, etc (Technical Committee 57, 2010). The other defined service is in the nature of publisher-subscriber communication mechanism, where the information is communicated in a unidirectional fashion (i.e. multicast). Two most important applications of the multicast communication service are Generic Object Oriented Substation Events (GOOSE) messaging and the transmission of Sampled Values (SVs). The corresponding services for the two applications are SendGOOSEMessage and SendMSVMessage respectively (Technical Committee 57, 2010).

In order to configure communication services of reporting, logging, GOOSE and SVs, the concept of control block classes are introduced in IEC 61850-7-2 (Technical Committee 57, 2010). In the interest of this thesis, it is necessary to describe in greater detail the GOOSE control block and the publisher/subscriber information exchange mechanism.

Unlike reporting and logging, both GOOSE and SV messages are time-critical information in SAS. As a result, the GOOSE messaging was designed with the intention of simultaneous delivery of the event related information to more than one physical device in the system via multicast communication service. The GOOSE control block class defines the use of arbitrary data set (DS) for the distribution of information. Similar to GOOSE communication service, DS is also used in reporting, logging and SVs services. This is illustrated in Figure 3.4. The DS class is specified in IEC 61850-7-2 standard as an ordered group of FCDs or FCDAs references, which are essentially sourced from DOs, for the convenient of client (Technical Committee 57, 2010). The references are named as the members of the DS. The reason of introducing DS is due to a considerable number of LNs are usually defined in an IED to support the enabled SAS functions. Consequently, it became difficult to transmit all DOs and DAs during communication. The DS arrangement reduces the communication content only to the members of an organised DS. Hence, it improves the efficiency on the usage of communication bandwidth. In addition, the GOOSE control block class also defines a number of interrogation services, such as GetGoReference, GetGOOSEElementNumber and GetGoCBValues.

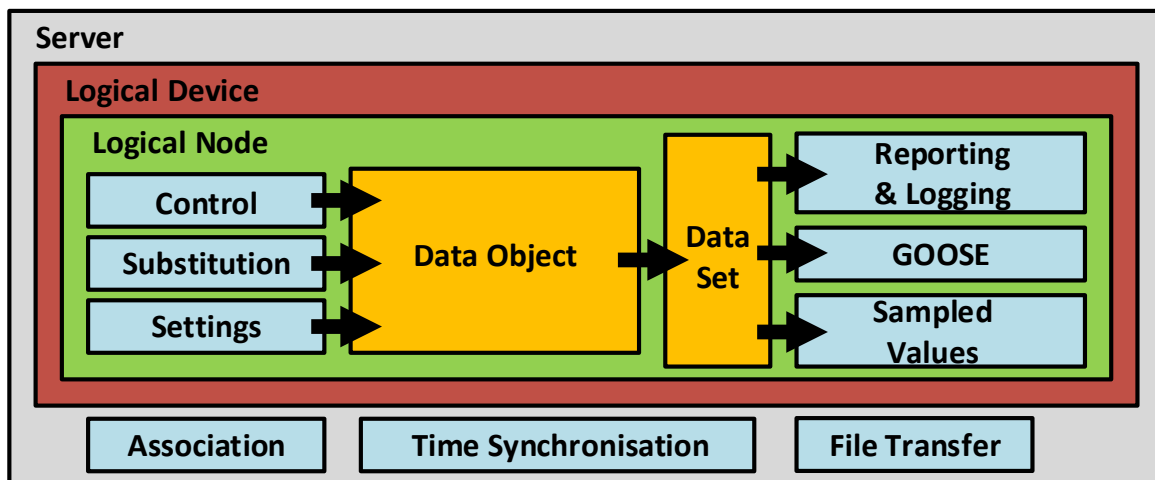


Figure 3.4: IED ACSI model

3.2.1.4 Object Naming and Referencing

Due to the complexity of the naming structure defined in the standard, the IEC 61850 standard specified few naming conventions to identify all data attributes. The most commonly used is called product related naming which is also partly shown in Figure 3.3. In order to reference the status of circuit breaker 'CB1' in the LD 'myLD' of a physical device 'IED1', the syntax of such data is defined as '*IED1myLD/CB1XCBR1.Pos.stVal*'. The symbol '/' is used to separate LD and LN. In the example, the LN name 'XCBR' is enhanced by a prefix 'CB1' and a suffix '1', which forms the object name 'CB1XCBR1'.

However, there is no standardisation of prefix and suffix that has been specified in IEC 61850 standard. It is important that the specified data names from IEC 61850-7-4 and DA names from IEC 61850-7-3 shall be used unchanged in the naming reference (Technical Committee 57, 2011). Another way to describe an object is called function related naming convention that could be used in the preliminary specification of the SAS. An example of such convention is '*SITIB1/CBIXCBR1.Pos.stVal*', where 'S1' is substation name, 'T1' is the name of voltage level, 'B1' is bay name and 'CB1' is still corresponding to the primary equipment. It is obvious that this naming convention will not be applicable during actual SAS implementation due to the missing product mapping. The other naming convention is commonly used for the specified information exchange services that are mapped to underlying communication protocols. Such naming convention indicates the FC group that the DA has been specified and inserts the information between LN name and DO name. An example of the convention is '*IED1myLD/CBIXCBR1\$ST\$Pos\$stVal*', where the '.' is replaced with '\$' symbol.

3.2.1.5 Application Example

A simple example to demonstrate the use of the above information model and communication services is illustrated in Figure 3.5. A feeder protection IED detected a multi-phase fault on the transmission line. The internal distance protection function (LN: PDIS) of the IED operated and actuated protection tripping condition function (LN: PTRC). As a result, the IED encoded the updated member of DS with value '*distIEDmyLD/CBIPTRC1.Tr.general = 1*' into GOOSE message and transmitted to the switchgear management IED via communication network. The switchgear management IED recognises the received GOOSE message and energised the tripping coil to the circuit breaker. Upon successful operation of the circuit breaker, the switchgear management IED receives the confirmation of open status through the circuit breaker auxiliary contact and updated the corresponding member of DS. Finally, the switchgear management IED encoded the updated such data as '*distIEDmyLD/CBIXCBR1\$ST\$Pos\$stVal = 2*' (represents circuit breaker OPEN state) into Manufacture Messaging Specification (MMS) message and reported to substation Human Machine Interface (HMI) via communication network. The HMI in turn updates the breaker status on its single line diagram (SLD) on the screen. There are other messages that must be exchanged on local communication network, as well as to the network control centre for the event. However, those messages will not be discussed for the purpose this illustration.

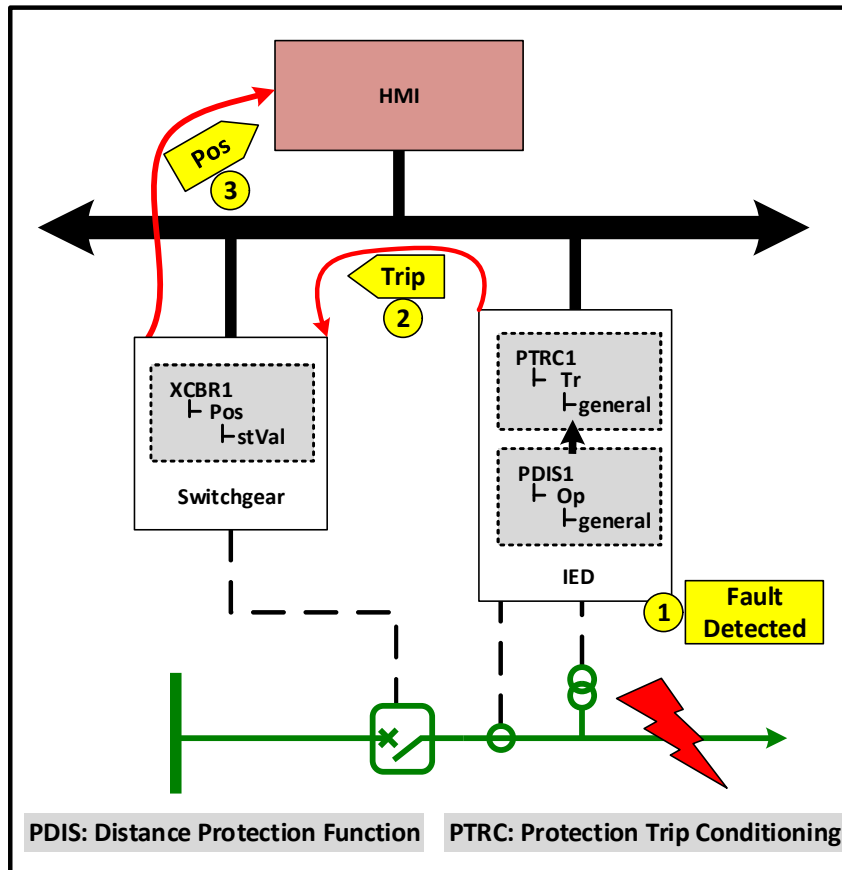


Figure 3.5: Real substation operation

The above example described how the IEDs exchange information via both abstract communication services and data models defined in IEC 61850 standard. It is clear that IEDs must map those data onto an underlying communication protocol in order to complete the communication. The mapping process is introduced in the following section.

3.2.2 Specific Communication Services Mapping (SCSM)

Three major ACSI services, GOOSE, SV and client/server communication, are mapped to real world communication protocol through SCSM which are introduced in IEC 61850-8-1 and 9-2 standards as it is illustrated in Figure 3.6. The client/server communication consists of read, write and report services. The read and write services are bidirectional communication between the client and server in 'request' and 'response' architecture. The report service is unidirectional communication from the server to the client. This communication architecture is mapped to MMS which is an application level (OSI model) messaging protocol. In contrast, the GOOSE and SV communication services are mapped directly to Ethernet communication protocol in multicast mechanism. These communication aspects will be described in more details in the following sections.

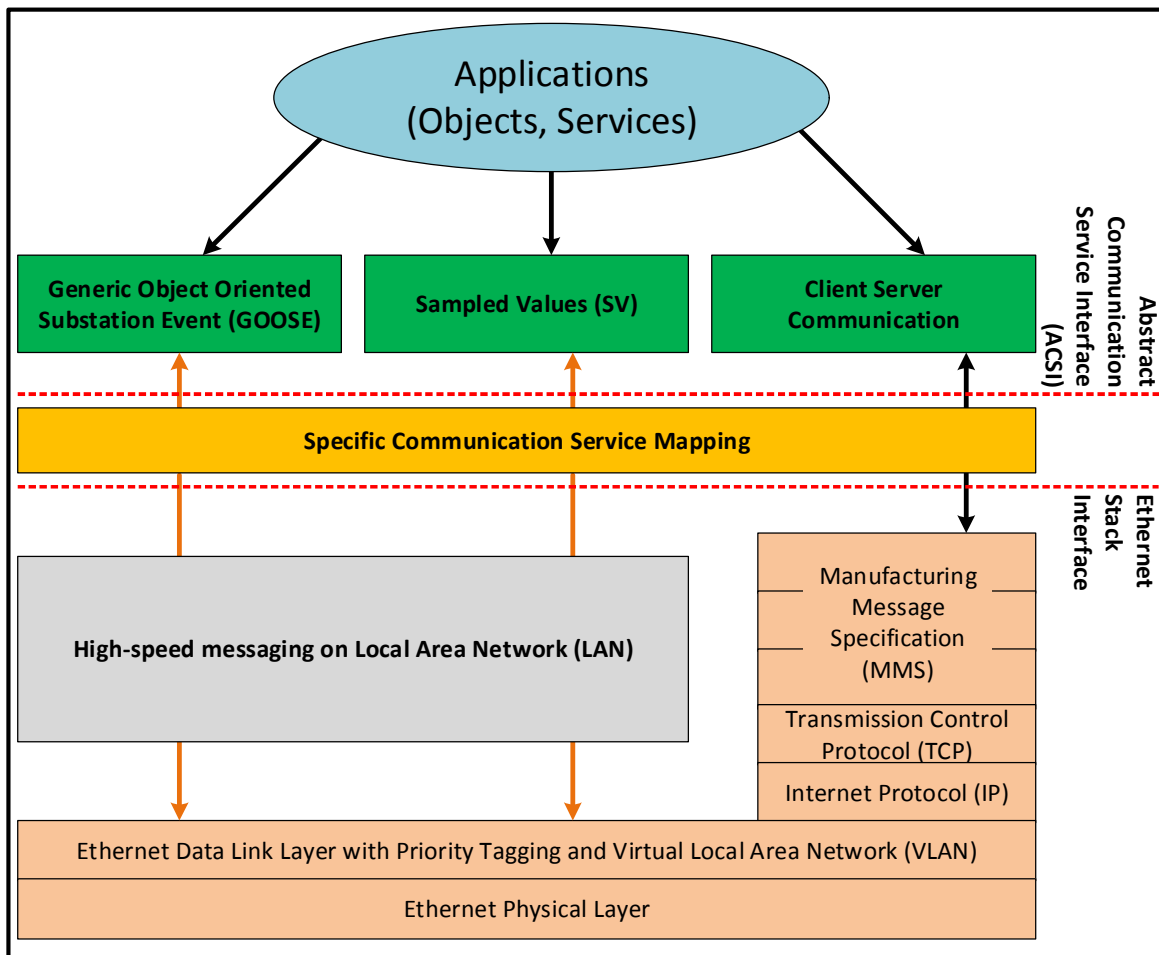


Figure 3.6: Special Communication Service Mapping (SCSM) to communication protocol

3.2.2.1 Communication Requirements

Among the demonstrated communication services, the GOOSE tripping messages and SV messages are considered as time-critical information for protection and control functions with higher timing and reliability requirements. The client/server communication is considered as mission-critical messages with high reliability requirement but has relaxed timing requirement. Edition 1 of IEC 61850-5 standard defines three performance classes: P1, P2 and P3 with the aim to specify the message transferring time for the exchange of time-critical information. The classes of P2 and P3 are applicable to high voltage transmission network (Technical Committee 57, 2005). Although these requirements are replaced with slightly different definitions in Edition 2 of the standard, they are still referenced by recent literature publications (Ingram, et al., 2014). The performance classes in edition 1 are further divided into twelve classes and the relationship between the performance class and voltage levels is removed in Edition 2 (Technical Committee 57, 2013). The performance requirements of message transferring time (TT) are more explicitly defined as seven classes, which are TT0 to TT6 as shown in Table 3.2, in IEC 61850-5

standard Edition 2 (Technical Committee 57, 2013). In particular, the tripping signals, which are carried by GOOSE messages, are required to be completed in 3 milliseconds. It is important to emphasise this is the deflection of total transfer time that is consist of network transfer time and the individual stack processing times of the GOOSE publisher and subscriber (Technical Committee 57, 2013). Of the total 3 millisecond, IEC 61850-10 specifies the percentage of time spent on each component as 20% on network transfer time and 40% on each stack processing time. This means each IED must spend less than 1.2 milliseconds to put GOOSE message onto the communication network in order to conform the transfer time requirement. Similarly, the exchange of raw analogue data, which are carried by SV messages, is also required to be completed in 3 milliseconds with high accuracy requirement on time synchronisation.

Table 3.2: Message transfer time classes

TT Class	Transfer Time [ms]	Application Examples
TT0	> 1000	Files, events, log contents
TT1	1000	Events, alarms
TT2	500	Operator commands
TT3	100	Slow automation interactions
TT4	20	Fast automation interactions
TT5	10	Releases, status changes
TT6	3	Trips, blockings

The reporting service, as indicated in Table 3.2, is required with much relaxed time span. However, it does not diminish the reliability requirement of message delivery.

3.2.2.2 *Manufacture Messaging Specification (MMS)*

The MMS protocol, which is defined in the ISO 9506 standard, was among the very few application level protocols to perform most functions that were requested by electric utilities in 1990s (Corporate Affiliate Program, 2001). In addition, the MMS service is based on TCP/IP point-to-point communication mechanism with in-built assurance on reliability (Clavel, et al., 2015), such as traffic flow and congestion control (Hopkinson, et al., 2009). Hence, it is satisfactory for substation communication requirement and was chosen to be implemented in the IEC 61850 standard. An example of MMS service request message, which was captured by open source network traffic analyser WireShark, is shown in Figure

3.7. The captured message is a confirmed request sent from a client to enable reporting service in a server. Figure 3.7 also demonstrated the hierarchical structure of the message that encapsulated the domain specific ACSI data in a seven-layer network frame according to the OSI model.

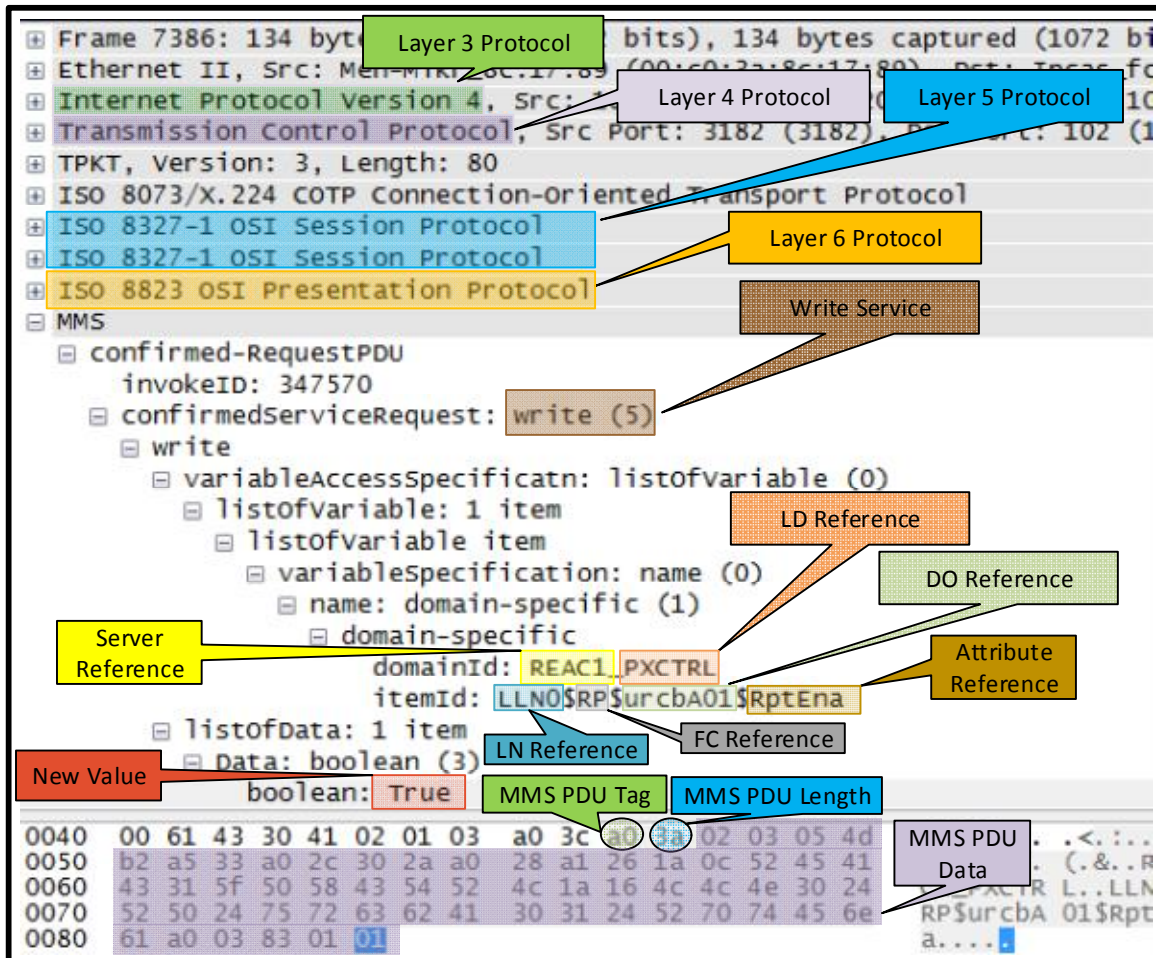


Figure 3.7: MMS write service message example

In general, communication protocols can be considered in two parts, Protocol Data Unit (PDU) formats and protocol exchange semantics (Tantiprasut, et al., 1997), in order to exchange information on a network. The latter component of the two parts defines the rules by which the protocol messages are exchanged on a network, while the former one is self-explanatory. The MMS communication protocol is written in Abstract Syntax Notation One (ASN.1) language (ISO, 2003) that defines both of the above parts. As the name implies, ASN.1 provides abstract representation of complex information structure without attaching to any protocol (Tantiprasut, et al., 1997). The PDU of the MMS service request message in Figure 3.7, which is written in ASN.1 (ISO 8824-1 standard), contains multiple levels of information. The abstract syntax in the PDU is encoded into a series of bytes and ready for transmission by following specific rules. It is also these rules that define how to encode the abstract syntax such as Boolean and String, as well as constructed types and structures

(Tantiprasut, et al., 1997). The encoding rules that were defined in conjunction with ASN.1 was named Binary Encoding Rules (BER) in ISO 8825-1 standard (Nilotpal, 1994) (Tantiprasut, et al., 1997). The BER employs a TLV (Tag, Length, and Value) technique to encode message syntax. The ‘tag’, which is 1 byte of information, identifies the type of the data being encoded according to the defined tag class. The principle of ‘tag’ encoding is shown in Figure 3.8. The ‘length’ is encoded in either simple or extended form to represent the size of the data at which the end of the information is understood by the recipient. If the data content is less than 128 bytes, the ‘length’ is encoded as one byte (as in simple form) with the most significant bit set to 0. Otherwise, the ‘length’ is encoded as multiple bytes (as in extended form) with the most significant bit set to 1 in the first byte. This will be demonstrated in the examples provided in the following sessions. The ‘Value’ contains the data content being encoded or another level of BER encoding as shown in Figure 3.9. Such encoding procedure is also indicated in Figure 3.7 by which the MMS PDU is encoded.

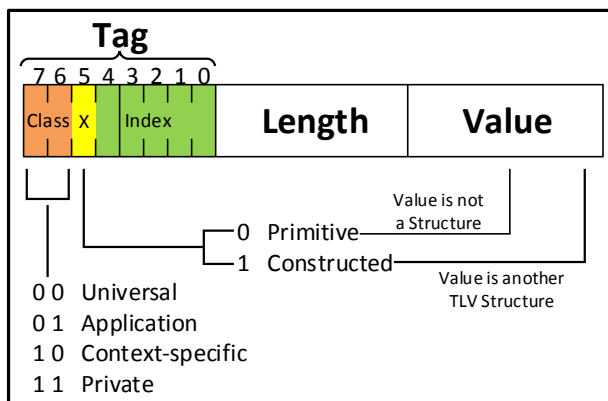


Figure 3.8: Tag encoding principle

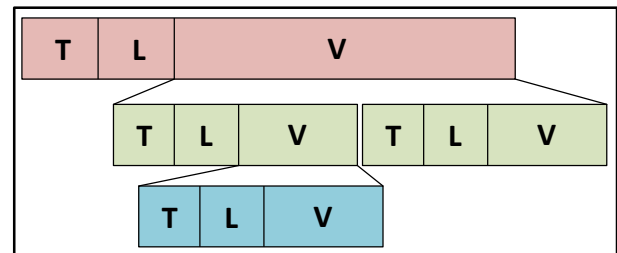


Figure 3.9: Value encoding under BER

A detailed illustration of MMS PDU information structure mapping is provided in Figure 3.10 according to ISO 9506-1 and 2 standards. The example demonstrated the construction of the MMS PDU in the message and the linkage among the elements in the message and the defined classes and services in the standard. The example also demonstrated how the MMS PDU information is encoded under BER. This is also useful in understating the encoding of GOOSE and SV messages. The keyword ‘IMPLICIT’ as defined by ASN.1 in the MMS message indicated the data content is context specific value that both the transmitter and receiver of the information understand the type of the data without an explicit definition in the message. This is the solution implemented by ASN.1 to directly allocate a tag value to the components of a dependent field, such as ‘CHOICE’ which does not specify a list of types (components) of data. In the example shown in Figure 3.10, the

implicit type of domain-specific information, which is a part of ‘ObjectName CHOICE’, is encoded as ‘a1’ (10100001 in binary). The Bits 0-4 of the binary coding indicate the information is indexed as ‘1’ in the ‘ObjectName’ class and the rest of the bits indicate the information is a constructed sequence. In ‘EXPLICIT’ encoding, both of the above information must be separately and explicitly defined in the message. Therefore, an extra two bytes shall be inserted in the encoded message. As a result, the use of ‘IMPLICIT’ tagging enables a shorter message to be transmitted through the communication network.

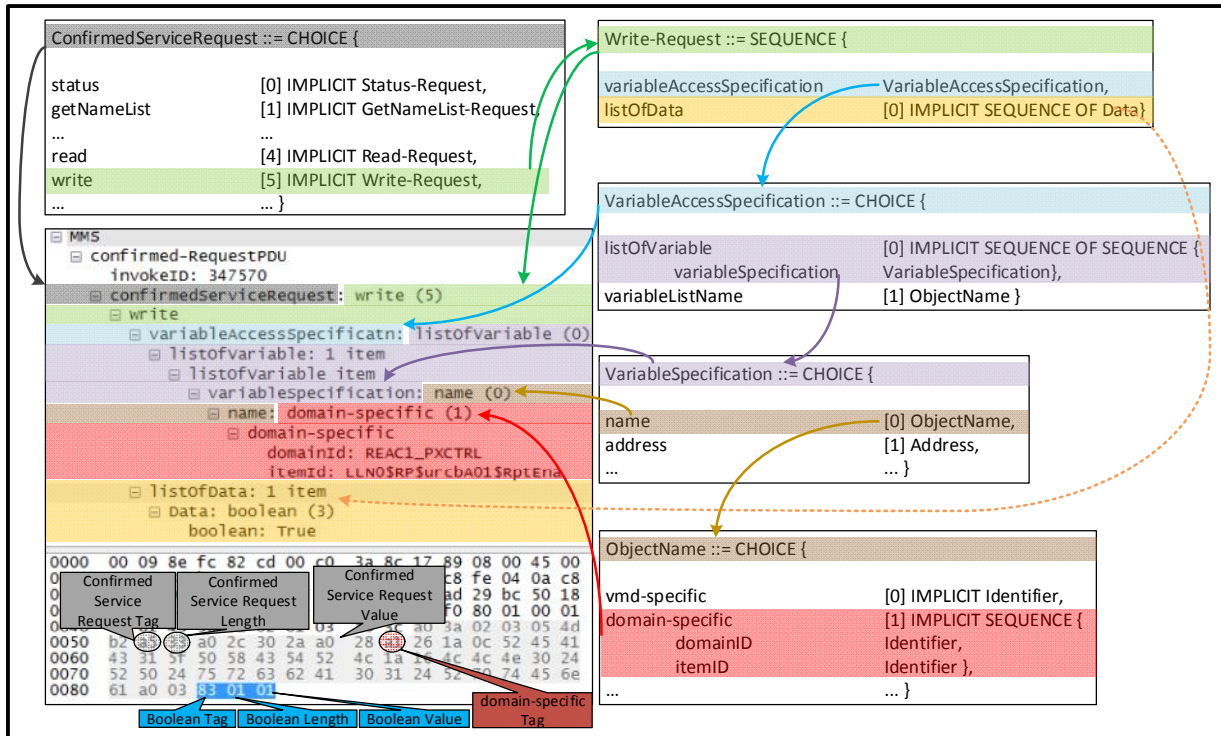


Figure 3.10: MMS message encoding illustration

3.2.2.3 Generic Object Oriented Substation Event (GOOSE)

Due to the time sensitive nature, the SendGOOSEMessage application of an IED or a server is mapped directly to Ethernet (i.e. layer 2 of the OSI model) (Technical Committee 57, 2011) without travelling through any higher layers. This mapping is also shown in Figure 3.6. Although such mapping satisfies the timing requirement, the reliability of the messages are not guaranteed (Eugster, et al., 2003). Therefore, the mechanism of GOOSE messages is designed as pessimistic in IEC 61850-8-1 standard. This means the GOOSE publishers retransmit the message regardless if the information in the reference DS has not been changed under the assumption that subscribers have not received the information. Additional reliability is provided through the information included in the GOOSE message, such as state number (StNum), sequence number (SqNum) and retransmission time (Technical Committee 57, 2011). The StNum is increased by 1 if the value is updated on

any member of the DS that is referenced by the GOOSE message. The SqNum is increased by 1 following a retransmission of GOOSE message and is defined as integer with the approximate maximum value of 4.3 billion. The value of SqNum is reset to 0 following a StNum change and reset to 1 when the counter is overflowed. The retransmission time is specified as four intervals T0, T1, T2 and T3. In a stable condition, GOOSE messages are retransmitted in the fixed time interval of T0. After an event, the GOOSE messages are retransmitted in the most intense time interval T1 and gradually relaxed to stable condition through the T2 and T3 intervals. The value of all retransmission time intervals shall be configured by the end user and not specified in the standard.

Due to the importance of the tripping signals in SAS, GOOSE messages are also prioritised in Ethernet network traffic via the implementation of IEEE 802.1Q standard. The main functions of the standard are to provide VLAN and network traffic priority tagging (Thrybom & Prytz, 2009) by inserting a tag of four bytes in Ethernet frame. The inserted tag is consist of Tag Protocol Identifier (TPID – 2 bytes), priority (3 bits), Canonical Format Identifier (CFI – 1 bit) and VLAN Identifier (VID – 12 bits). The value of TPID shall be defined as 0x8100 (hexadecimal) to indicate the message is IEEE 802.1Q-tagged frame for GOOSE messaging. CFI shall be defined as 0 for the GOOSE messages to be forwarded by switches in Ethernet networks. A VLAN is a virtual broadcast domain in a physically connected network (Wester & Adamiak, 2011). Each VLAN message is identified by inserting an identifier in the Ethernet message and can be spread across the entire communication network topology (IEEE 802.1 WG, 2014). The priority tag is often referenced as Quality of Service (QoS). The purpose of the priority tag is to ensure critical information is processed and delivered first by communication network participants (e.g. Ethernet routers and switches). The priority tag can be set from 0 (lowest priority) to 7 (highest priority). It is common practice that Ethernet switches are built with four priority class buffers, Low (0 & 1), Medium (2 & 3), High (4 & 5) and Critical (6 & 7). As a result, the incorporation of IEEE 802.1Q standard in IEC 61850 messaging improves the real time performance of the network with various traffic classes (Jasperneite, et al., 2007).

A captured GOOSE message is illustrated in Figure 3.11. In comparison with the captured MMS message, it is clear that the GOOSE message is mapped directly to Ethernet protocol (layer 2 of the OSI model) with the inserted IEEE 802.1Q tag. The captured GOOSE message is configured with VLAN identifier of 1 and priority tag of 4 (High). The Ethernet type field of the message is defined as 0x88B8 (hexadecimal) to indicate the GOOSE message is Type 1 or Type 1A tripping signal according to IEC 61850-8-1 standard

(Technical Committee 57, 2011). Similar to the captured MMS message in Figure 3.7, both GOOSE data and other control block class parameters (e.g. StNum and SqNum) are encapsulated in the Ethernet frame which is written in ASN.1 and encoded under BER.

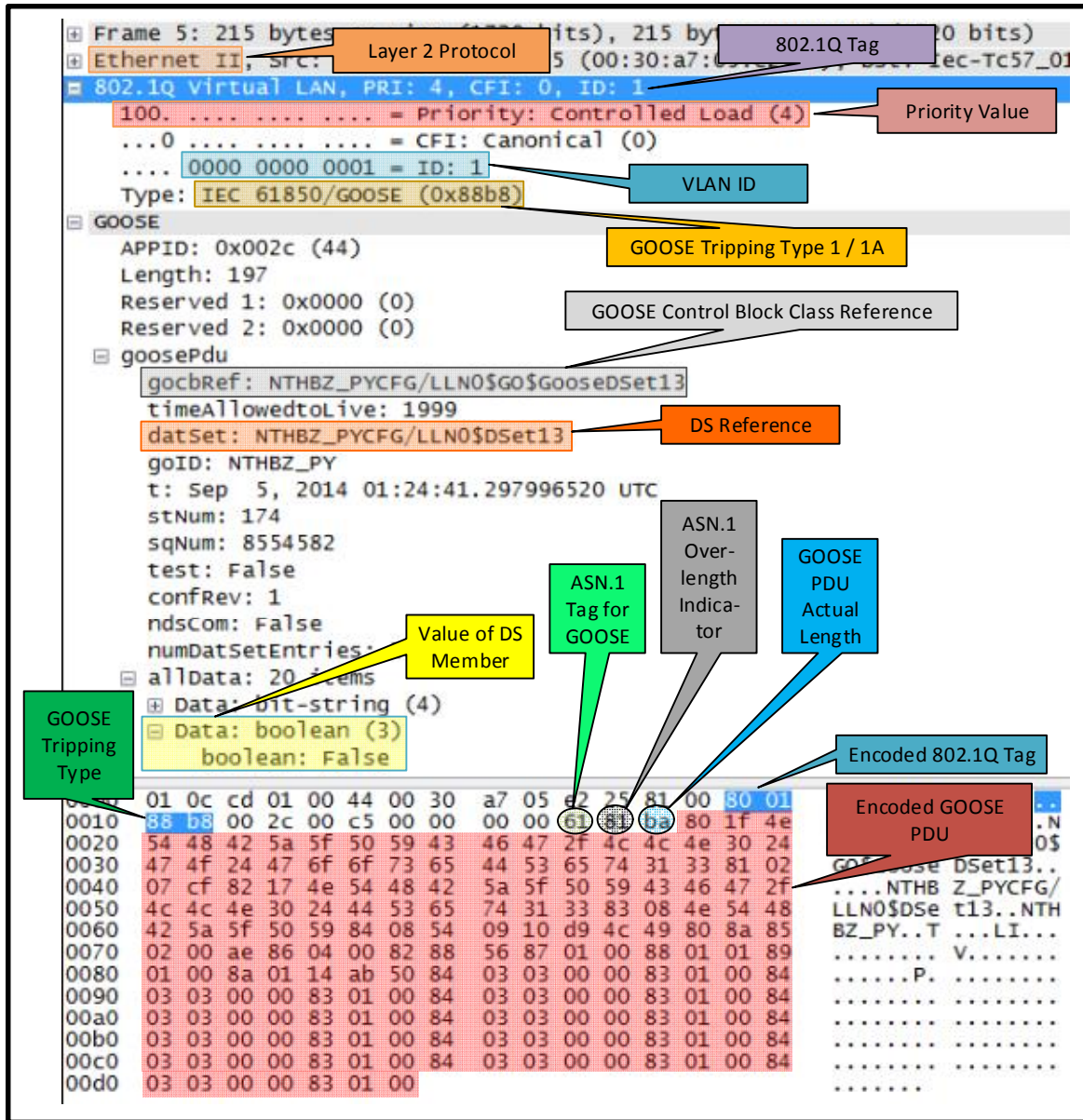


Figure 3.11: Captured GOOSE message

However, GOOSE encoding is not strictly based on ASN.1 and BER. The GOOSE PDU and associated services are based on the derived syntax, which is an adaptation of ASN.1 standard, defined in IEC 61850-8-1 standard. The second edition of IEC 61850-8-1 standard also defines the fixed length GOOSE message at which the size of each data element is specified. The encoding rules for GOOSE information structure is illustrated in APPENDIX B. In order to provide backward compatibility for GOOSE protocol, the implementation of fixed length GOOSE messaging is optional by IED manufactures.

3.2.2.4 *Sampled Values (SVs)*

Similar to GOOSE messages, the communication of SVs is mapped directly to Ethernet protocol as IEEE 802.1Q tagged Ethernet frames. This mapping is specified in IEC 61850-9-2 standard. In order to reduce the complexity of implementing SV communication, the 9-2LE guideline has specified data frame, sampling rate and time synchronisation requirements. It is clear that accurate time synchronisation across a substation is critical if a number of SV sources is considered in protection schemes. For this purpose, the 9-2LE guideline has specified the time synchronisation accuracy for SV implementation to be ± 1 microsecond.

In addition to the overhead of a standardised IEEE 802.1Q tagged frame, the 9-2LE compliant SV message is specified with its own overhead and a set of measurement data. It is worth mentioning that SV message is also based on ASN.1 and BER rules. The overhead of SV consists of a number of fields that identify the source of the data and a sample counter (SmpCnt). The sample counter acts as time reference for protection schemes. It is incremented by one each time a new sampled value is transmitted and re-set to zero when a whole second is reached. The difference between the transmission mechanism of GOOSE and SV is that the latter is not considered as pessimistic. It is possible that SV packets are lost in Ethernet network communication. The use of sample counter has been suggested by Zedeh *et al.* (2011) for estimating lost SVs for protection IEDs. The measurement data consists of four currents and four voltages data, which is in total of eight 4 bytes signed integers. Each measurement quantity is associated with 4 bytes quality information. As a result, each sampled value frame is counted for 126 bytes with 32 bytes for actual measurement data. The rest of 94 bytes are for communication and quality assurance purposes. The measurement data is generally transmitted via ‘merging unit’ device that implements at least one LNs of TCTR (current transformer) or TVTR (voltage transformer). A merging unit device is capable of digitalising conventional CT and VT outputs or converting NCIT outputs into SV stream. Provided that the merging unit devices are likely to be located in the yard, a separate synchronisation network is required to ensure the required time synchronisation accuracy is achieved. It is also important to emphasise that the process level LNs (e.g. TCTR, TVTR or XCBR) are single phase LNs. Hence, three of these LNs are required for a three phase system.

3.2.3 **Substation Configuration Language (SCL)**

The substation configuration language (SCL), which is the foundation of achieving

interoperability in SAS, is defined in IEC 61850-6 standard. The SCL is based on XML language to describe the configuration of IEC 61850 based systems. The first edition of IEC 61850-6 standard has specified four types of hierarchical SCL files, IED Capability Description (ICD), Configured IED Description (CID), Substation Specification Description (SSD) and Substation Configuration Description (SCD). The ICD file is the full description of IED's functionalities. It is generally extracted from IED configuration tool and imported into the system integration tool for substation configuration. The SSD file, which is exported from the system integration tool, describes the single line diagram of the substation with the allocated substation functions (LNs). By importing the ICD files and SSD file, the system integration tool generates the SCD file that includes the descriptions of all IEDs, configured communication and overall substation description. This SCD file is then imported by the IED configuration tool to extract the related information of the IED. The IED configuration tool finally generates the CID file and writes the configured information to the IED. As a result, each configured IED is capable of performing the required functions in a SAS. An additional two SCL files, Instantiated IED Description (IID) and System Exchange Description (SED), were also introduced in the second edition of IEC 61850-6 standard (Zhu, et al., 2014). The IID file is to solve the issues of IED modification after configuration which is an important file for brownfield applications in power system. The SED file is to enable the exchange of configuration data between different projects.

The standardised SCL files enable a consistent approach during engineering process in an IEC 61850 project. The only missing component during this process is the configuration of Ethernet communication network. It is common practice that the Ethernet switches are configured separately and manually outside of the IEC 61850 SAS engineering. It will be a significant optimisation if Ethernet switches are also included as IEDs and automatically configured via CID files similar to other IEDs in the future.

3.3 Summary

The IEC 61850 standard has evolved to a critical standard for power utilities with 21 parts in the past decade. This chapter provided a holistic view on IEC 61850 standard with the emphasis of the most critical aspects, abstract data and service modelling, SCSM and SCL. The practically oriented review on the standard not only offers concise and informative material about the complex standard for power utility engineers, but also establishes the fundamental building blocks for the development of substation event monitor.

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CHAPTER 4 SYNCHRONISATION TECHNOLOGIES

This chapter provides a comparison on four most popular synchronisation technologies in substations, Network Time Protocol (NTP), IRIG-B, 1-Pulse-per-Second (1PPS) and IEEE 1588 in Section 4.1. Through the requirements of synchronisation in future SAS configuration, this chapter focuses on the operating mechanism and features of IEEE 1588 or Precision Timing Protocol (PTP) in Section 4.2. This chapter is concluded with a short summary of major differences between the two versions of PTP protocols.

4.1 Substation Synchronisation Technologies

Many power system functions require accurate time information. The available technologies, such as NTP, IRIG-B and 1PPS, have been sufficient and worked well for most of the substation applications. The recently developed IEEE 1588 or Precision Time Protocol (PTP) provided another attractive option for substation synchronisation technique. Due to the fact that the PTP synchronisation is achieved via Ethernet network with very high accuracy, it has gained particular interest to be implemented together with the IEC 61850 standard in electric substations. However, it is still important to analyse the above synchronisation techniques and confirm if they are suitable for the time information requirement of developing the substation event monitor from power utilities' point of view.

4.1.1 Network Time Protocol (NTP)

The NTP is a networking protocol solely based on software method for clocks synchronisation between electronic devices using a data network. It is built on Internet Protocol (IP) and User Datagram Protocol (UDP). In terms of synchronisation accuracy, NTP's performance is in the range of a few milliseconds in local area network and rarely as good as 1 millisecond (Dickerson, 2007) due to the limited processing power of protection devices. This accuracy is sufficient to assign a certain absolute point of time to the rising edge of a 1PPS signal. Since there are two separate time reference signals (NTP and 1PPS), it requires two separate distributed cables to be installed. Therefore, such combined solutions are very seldom implemented in electric substations. As a time distribution mechanism, NTP is only suitable in applications for which the time synchronisation accuracy is required to be in the milliseconds range.

4.1.2 1-Pulse-per-Second (1PPS)

The digital 1PPS signal is a widely used reference signal for time synchronisation and it is supported by nearly every substation clock (Dickerson, 2007). The signal is a simple rectangular 1 Hz pulse of which rising or falling edge marks the beginning of a new second. The synchronisation accuracy of the pulse is in the range of a few nanoseconds. The cable delay that occurred during signal transmission results the overall synchronisation accuracy of 1 microsecond. The drawback of the 1PPS signal is that it does not contain any additional time information which allows linking the edge of the pulse to a specific absolute time. As a result, additional time information needs to be transported to the IEDs via a separate system (e.g. NTP) if required. Therefore, the 1PPS for time synchronisation in substations is constantly declining. However, the 1PPS signal is specified in the guideline of 9-2LE for the synchronisation of SVs. This is due to the SVs only requires the recognition of an accurate whole second to configure the sample counter for aligning the measurement data.

4.1.3 IRIG-B Code Synchronisation

The IRIG (Inter Range Instrumentation Group) time codes were original developed by a working group of the United States air force to allow standardised time coding of measurement data originating from different locations. Today, the IRIG code B (IRIG-B) is mostly used for civilian applications including electric power industry. Similar to the other five codes defined in the IRIG family, the IRIG-B code is a serial string protocol of which time information is communicated in a continuous stream of binary data. The IRIG-B code repeats each second with a total bit string of 100. Among the transmitted data, some are framing or synchronisation bits, some are assigned for time and some are available for control functions. Similar to 1PPS, the year data is not contained in IRG-B code. In addition, the original IRIG-B code only supports Coordinated Universal Time (UTC) format. In order to improve the performance in substations, the IRIG-B code was extended in IEEE 1344-1995 standard using the control bits field to provide an additional 2 digits of year information as well as local time zone, daylight saving and leap second[†]. However, the extended IRIG-B code is only supported by small amount of IEDs on the market, while many of them are still only compatible with the original IRIG-B time code.

The IRIG-B code is usually an amplitude-modulated signal with a 1 kHz carrier for most of the older IEDs. The modulated signal is usually distributed on either twisted pair wires or

[†] A leap second is a one-second adjustment that is occasionally applied to UTC (Coordinated Universal Time) in order to keep its time of day close to the mean solar time or sidereal time. The most recent leap second was inserted on June 30, 2012 at 23:59:60 UTC.

coaxial cables. Due to the difficulty of measuring zero-crossings during demodulation at the receiving end, the modulated IRIG-B code is generally capable of achieving a synchronisation accuracy of ten microseconds. For most of the relatively new IEDs, the DC Level Shifted (DCLS) or unmodulated IRIG-B is more common. The unmodulated IRIG-B is normally distributed at a level of 5 volts via sealed cables or optic fibres. The unmodulated IRIG-B signal is capable of reaching the synchronisation accuracy of 1 microsecond.

4.1.4 IEEE 1588 Standard

The origin of IEEE 1588 standard was proposed by Agilent Technologies in testing and measurement systems. The synchronisation method was developed and submitted as a suggestion for standardisation to the IEEE. As a result, the standard IEEE 1588-2002 that is known as PTP version 1 (PTPv1) was approved in September 2002 and adopted as an international standard by IEC under the label of IEC 61588 in 2004. In order to fulfil the new requirements of synchronisation, the project P1588 was started to specify a version 2 of the PTP. This new version of PTP was approved in March 2008 under the title IEEE 1588-2008. IEC has also followed the process and adopted this standard as IEC 61588 Edition 2.

Unlike 1PPS and IRIG-B signals, PTP is bidirectional network based system that is capable of providing compensations for network delays. The idea behind the development of PTP is to determine the time of transmission and reception of Ethernet messages with an accuracy that is comparable to that of a 1PPS or IRIG-B signal by using hardware level support in standard network connections. The network path delay can be determined and compensated using software, which is a similar concept to the NTP, once an accurate timestamp of an Ethernet messages is obtained. The hardware assisted approach differentiates PTP from the other techniques with the capability of delivering synchronisation accuracy in tens of nanoseconds (Dickerson, 2007).

Owing to the fact that the highly accurate IEEE 1588 synchronisation is achieved via Ethernet network infrastructure, it has been recognised as an ideal synchronisation approach in substations for smart grid applications by both Smart Grid Strategic Group (2010) and NIST (2012) organisations. The IEEE C37.238 standard also specifies how PTP will be used for power system applications by restricting options and mandating additional data to be transmitted in its 'power system profile'. Although PTP is capable of providing accurate timestamp to sampled values packets, the IEC 61850-9-2 standard is not forecasted to add the time information for each SV message.

4.1.5 IEC 61850 Standard Applications Timing Requirement

Under the IEC 61850 standard, the use of sampled values from non-conventional and conventional instrument transformers provide significant benefits to power utilities. The phase relationship or timing information between the measured current and voltage when using the sampled values is crucial for substation protection schemes. This means very high synchronisation accuracy must be guaranteed among substation devices at which the sampled values are acquired. This synchronisation accuracy requirement has generally been specified as ± 1 microsecond (UCAIug, 2004) (Brunner & Antonova, 2011). As a result, the synchronisation technologies of 1PPS, IRIG-B and PTP are all suitable for the timing requirement from accuracy perspective. However, PTP provides distinctive advantage of being realised over Ethernet network and compensating patch delay automatically. For this reason, PTP has been chosen for the development of substation event monitor. Hence, the operating principles and features of both PTP versions are introduced in the following sections.

4.2 PTP Operation Mechanism

The PTP clocks are running based on the concept of state machine when a clock starts up, it runs Best Master Clock (BMC) algorithm to determine the best clock on the network. The PTP defines the highest ranking clock as ‘grandmaster’ clock that synchronises all other ‘slave’ clocks on the network. If the grandmaster clock is removed from the network or its characteristics is changed in a way that it is no longer the best clock, the BMC algorithm re-evaluates the participating clocks and determines a new grandmaster clock. This provides a fault tolerant capability for the time source on the entire network. The result of the BMC algorithm includes a recommended state for the clock and updates the specification of clocks’ data sets.

The BMC algorithm in PTPv1 is achieved by exchanging synchronisation messages which is explained in later text. PTPv2 has improved the BMC algorithm by executing the selection process with dedicated announcement messages. The data comparison on the announcement messages between any two clocks on the network results the establishment of the synchronisation hierarchy.

It is clear that the synchronisation mechanism of PTP is according to master/slave architecture. The messages exchanged by network entities are mainly used to quantify two aspects, the offset between master and slave clocks, as well as the message transit delay

through the network. The synchronisation is considered to be achieved by running two procedures in parallel. The first procedure is responsible to execute the slave clock at the same pace as the master clock. This is also known as PTP syntonisation as shown in Figure 4.1.

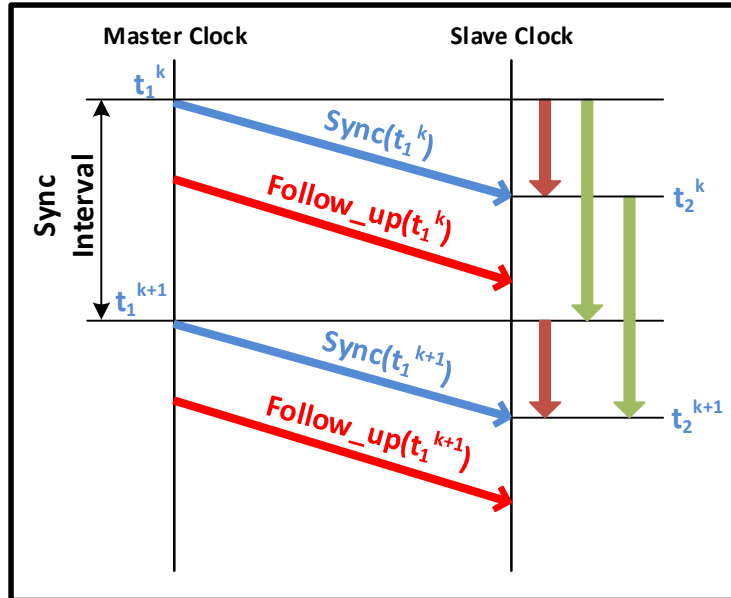


Figure 4.1: PTP syntonisation process

During syntonisation of PTPv1, the time master transmits a continuous stream of synchronisation messages. Each message is a 124 bytes packet that contains the estimate of the sending time t_1^k and additional clock characteristic information for BMC algorithm execution. The size of the synchronisation message is reduced to 44 bytes that only contains the estimated time information of t_1^k for synchronisation purpose in PTPv2. Since the BMC algorithm of PTPv2 is achieved via announcement messages, the synchronisation message can be configured with higher exchanging rate if it is required. In addition, the resolution of timestamp value in PTPv1 is limited to 1 nanosecond. This is improved to be 2^{-16} nanosecond in PTPv2. It is obvious that PTPv2 is designed with the capability of achieving higher level of synchronisation accuracy than PTPv1. This is also proved in Chapter 6.

The slave clock on the network receives the master synchronisation messages and records both the sending time t_1^k and the receiving time t_2^k in order to adjust its clock until the time intervals are equal on both clocks. This process is expressed as (4.1 and (4.2.

$$t_1^{k+1} - t_1^k = t_2^{k+1} - t_2^k \quad (4.1)$$

$$t_2^{k+1} - t_1^{k+1} = t_2^k - t_1^k \quad (4.2)$$

The standards offers two options to transport timestamp t_1^k from the master to the slave clock. One option is known as one-step mode. This configuration requires the master clock to insert the precisely measured time at which the synchronisation message leaves the clock. The other option is known as two-step mode. In this configuration, the master clock sends the synchronisation message with an estimated time value. In parallel to this process, the time master also sends a separate follow-up message that contains the precise time of when the previous message leaves the master as illustrated in Figure 4.1. The first option results a cleaner network traffic but requires the master clock to be equipped with the capability of inserting the precise timestamp during communication.

The second procedure of the synchronisation is to determine the delay of slave clock from the grandmaster. The process is achieved via measuring the two-way delay which is the round travelling time between the master and slave clocks as shown in Figure 4.2. For the downward path from the master to slave clock, t_1 and t_2 are available from the last synchronisation message. For the upward path, the timestamps are acquired by exchanging

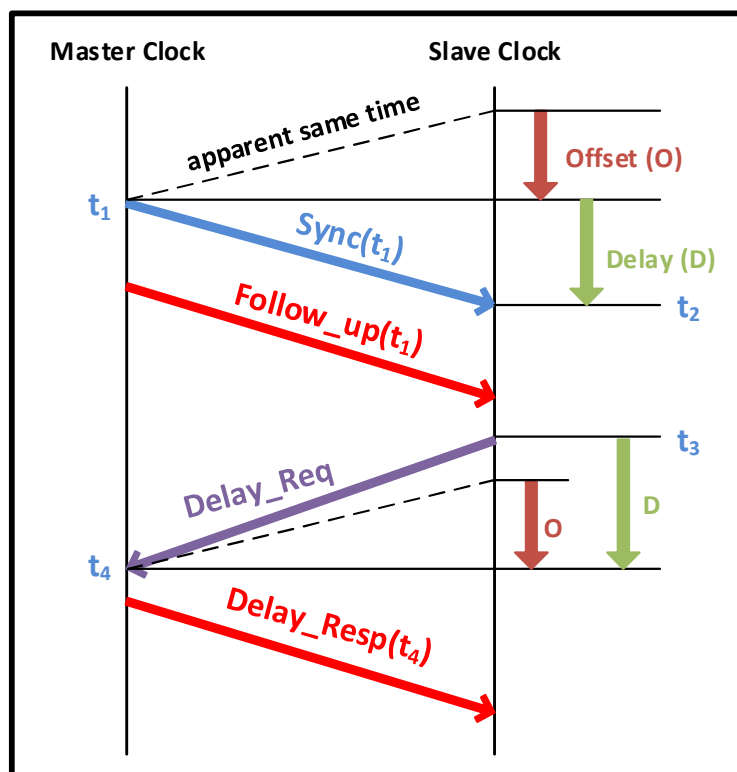


Figure 4.2: IEEE 1588 offset and delay measurement

delay request (Delay_Req) and delay response (Delay_Resp) messages between the two clocks. This occurs in a similar fashion as the syntonisation process. The purpose of the delay request message is to acknowledge the reception time t_4 of the master clock that is contained in the delay response message. Under the assumption of a symmetric transmission

path for both synchronisation and delay request messages, one way delay and offset from the master clock are calculated according to (4.3 and (4.4.

$$\text{Delay} = \frac{(t_2 - t_1) + (t_4 - t_3)}{2} \quad (4.3)$$

$$\text{Offset} = \frac{(t_2 - t_1) - (t_4 - t_3)}{2} \quad (4.4)$$

Due to the different message structures in the two versions of the PTP standard, the timestamp values are associated with different fields in the above messages. It is important to emphasise that the timestamp values t_2 and t_3 are not appeared in any of the messages as they are generated and used internally by the slave clock.

4.2.1 Message Timestamping Point

It is observed from the previous section that the precision of timestamp values has direct impact on the overall synchronisation accuracy. The PTPv2 standard has specified several locations with the reference of the OSI model at which the timestamp event could occur. It is obvious that the closer this timestamp point is to the actual network, the higher level of accuracy can be obtained in the timestamp value (IEEE Instrumentation and Measurement Society, 2008). This is because the fluctuations that is introduced by the upper layers of the OSI model is minimised. Hence, the ideal location for timestamp point is in the physical layer. In this case, the PTP devices shall be equipped with hardware timestamp assist circuitry just above or within the physical layer to achieve high level synchronisation accuracy. This requires all or part of the PTP code to be executed within the low level silicon without the involvement of device's operating system (IEEE Instrumentation and Measurement Society, 2008).

4.2.2 PTP Clock Types

There were two clock types introduced in PTPv1 standard, ordinary clocks and boundary clocks. An ordinary clock is defined as the synchronisation communication is achieved through a single communication path to other clocks. Conversely, a boundary clock is capable of establishing synchronisation communication with multiple clocks through distinctive communication paths. Therefore, boundary clocks are usually equipped with at least two ports, while ordinary clocks only have one. Since PTP messages are multicast traffic, the individual measurement result is not valuable when the delay of synchronisation path varies due to the queuing in network switches. This problem is resolved if network switches are boundary clocks. In this case, the switch allocates one port to be synchronised

with the master clock and the rest of its ports are used to synchronise a number of slave clocks that are attached to it.

The PTPv2 standard has introduced an additional concept of transparent clock. This clock is an Ethernet switch that is capable of measuring the residence time of PTP messages. The residence time is defined as the time of the PTP message has spent in the switch during communication. Since the residence time is only the difference between the entering and leaving timestamps, the transparent clock is not required to be synchronised with the master clock. The transparent clocks are sub-divided into two types, End-to-End (E2E) and Peer-to-Peer (P2P).

The E2E transparent clock accumulates the residence time in the correction field in synchronisation messages or associated follow up messages as it is illustrated in Figure 4.3.

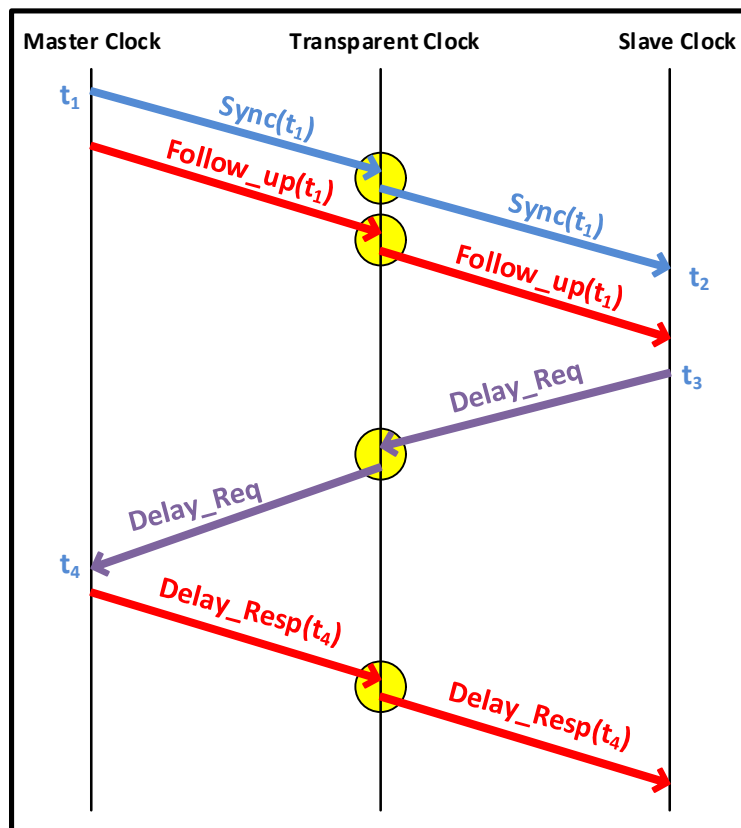


Figure 4.3: E2E transparent clock synchronisation

This mechanism ensures the precise correction of path delay when the PTP messages are received by the slave. The P2P transparent clock is able to not only measure the residence time, but also quantify the propagation delay of the port that is connected to receive PTP messages. The communication link delay is computed based on the exchange of peer-to-peer delay measurement messages as shown in Figure 4.4. This functionality requires all participants in the communication to support peer delay mechanism in order to be aware of

the link delay on each port of the P2P transparent clock. It is important to emphasise that the P2P transparent clocks only forward synchronisation and follow-up messages, while E2E transparent clocks forward all PTP messages. The correction field in the synchronisation or associated messages is updated with the residence time and the link delay of the receiving port. Moreover, the peer-to-peer delay measurement is not compatible with the mechanism based on delay request and response messages (IEEE Instrumentation and Measurement Society, 2008). As a result, the master clock only responds to peer delay request messages if P2P transparent clock is implemented.

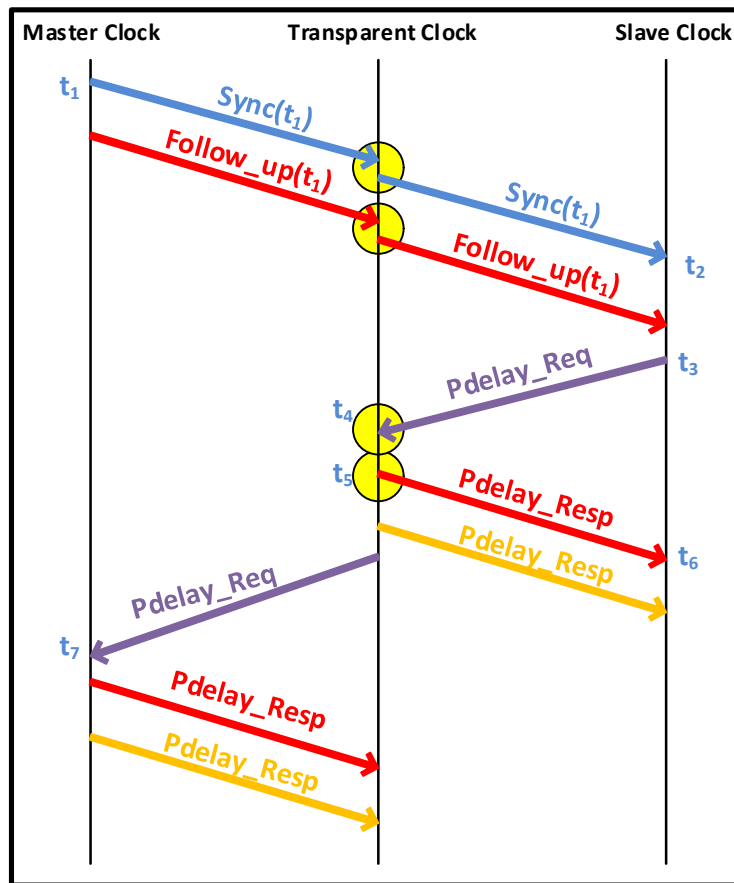


Figure 4.4: P2P transparent clock synchronisation

4.2.3 Summary of Major Differences of PTPv1 and PTPv2

Due to the changes of synchronisation message structure explained in previous sections, the PTPv2 is not backward compatible with PTPv1. It is also because of these changes in PTPv2, the exchange rate of synchronisation is configurable with more choices and typically set at higher rate than the communication of announcement messages. The updated version also improved the resolution of timestamp value and introduced the concept of transparent clock with additional delay measurement mechanism. The feature of customised profile and the use of extension fields in PTPv2 provided additional flexibility in the actual implementation.

The IEEE C37.238 standard has specified a customised PTPv2 profile to be used in power system applications. The IEEE C37.94 standard only selected the use of peer-to-peer delay measurement mechanism for the advantage of known path delay in the event of network element failure (Antonova, et al., 2012). The standard also specified the use of TLV extensions in the messages transmitted by PTPv2 network devices for better association with local time and better performance to react on network node failure events.

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CHAPTER 5 PROTOTYPE CONSTRUCTION

This chapter provides detailed information on the construction of the prototype of substation event monitor. It begins with the introduction of a list of requirements for the substation event monitor in Section 5.1. Section 5.2 provides an overview of the major components of the created device, namely Current Sensor, Electronic Board and Embedded System. The development and design principles of these major components are illustrated in great detail in Section 5.3, 5.4 and 5.5 respectively.

5.1 Prototype Construction Requirements

A list of requirements was developed based on the research objectives in Section 1.5 to guide the construction of the prototype of substation event monitor. These requirements are listed as follows:

- Develop non-intrusive design
- Achieve a cost effective device
- Develop simple and steady construction
- Establish communication according to IEC 61850-8-1 standard
- Use IEEE 1588 synchronisation with sub-microsecond accuracy
- Achieve an Overall system time accuracy of ± 1 microsecond
- Provide detailed performance evaluation through the testing results of each device component
- Demonstrate the developed device with other vendor's device

The above requirements form the basis of the substation event monitor design. They are also used as criteria for verifying the performance of the created device in Chapter 6.

5.2 Overall Structure

The substation event monitor consists of three major components, current sensor, electronic circuitry and embedded system, as shown in Figure 5.1. The current sensor is responsible of detecting any event that is associated with the ON/OFF state of state of DC current change in the hardwired system without disturbing the existing equipment. The electronic circuitry is to ensure the detected event signal is correctly received by the embedded system for

further processing. Among the three major components, embedded system is the core module of substation event monitor which is responsible for both time synchronisation and GOOSE message publication. Therefore, it is an essential criteria that the embedded system is equipped with hardware assisted time stamping function in order to achieve high level synchronisation accuracy as illustrated in Section 4.2.1. As a result, the embedded computer MPC8313E from Freescale Semiconductor (2011) was chosen for the design of the substation event monitor.

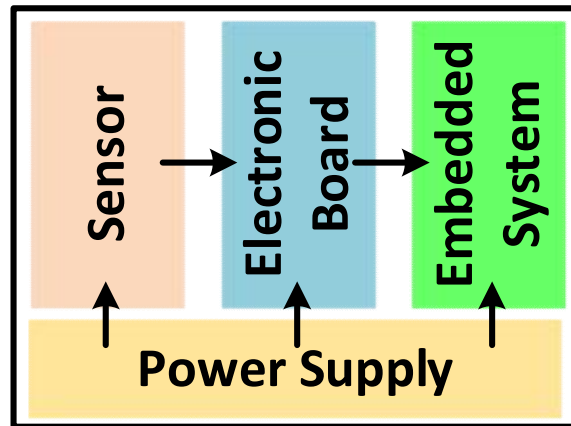


Figure 5.1: Substation event monitor overall structure

5.3 Current Sensor

In a typical substation, any tripping event or a status change of a target device (e.g. circuit breaker) is associated with a change of DC current in the control wire (Liu, et al., 2013). In order to fulfil the requirements of the current sensor for the system, a range of options have been considered. The available current sensing technologies include Shunt, Current Transformers, Rogowski Coil, Hall Effect, Giant Magnetoresistive (GMR) Effect and Giant Magneto Impedance (MI) Effect. Both Shunt and Current Transformers measurement approach require insertion a device in the current path which disturbs the existing system. Rogowski Coil is capable of measuring large currents with good linearity in relationship with the sensing current. It has been considered as a good candidate of NCIT to be used in high voltage substations. The Rogowski coil is also a contactless sensor that makes it as a potential candidate for this research project.

Hall Effect is the most common technology used for low current sensing and detection. A Hall Effect sensor contains a thin sheet of conducting material which is capable of developing a Hall voltage by being placed in a magnetic field. It is also a contactless sensor that can be applied to both DC and AC current sensing applications. Both GMR and MI

effects are emerging technologies and fairly complex even though they fulfil the non-intrusive requirement.

As a result, the Hall Effect technology has been chosen due to its contactless, low-cost, simple and well-known features. The principle of Hall Effect technology is based on Lorentz force. The sensor that has been chosen for this project is ratio-metric and linear Hall Effect sensor MH481ISQ manufactured by Magnesensor Technology (2015). The advantage of this sensor is that the quiescent output voltage (offset) and the magnetic sensitivity are proportional to the supply voltage. This feature enables simpler calculation of the output voltage during prototype calibration. In addition, the sensor has a wide operating range from -40°C to 105°C with the specified sensitivity of 2 mV/G .

The Hall Effect sensor was designed to be placed in gapped ferrite toroidal core as illustrated in Figure 5.2. This design is also known as open loop Hall Effect current transducer. The purpose of the gapped ferrite toroidal core is to concentrate the magnetic flux that is generated by the flowing current in the primary conductor. In this design, the Hall Effect sensor is connected to a power supply which causes the electrons to flow through the sensor conducting material. The mobile electrons are affected by the Lorentz force due to the external magnetic flux which is simply generated by the primary current (I_P) and concentrated by the gapped ferrite toroidal core. As a result, the mobile electrons are forced to move in a path along the sensor conducting material. Consequently, this develops a potential difference which is often referred to Hall voltage across the sensor conducting material.

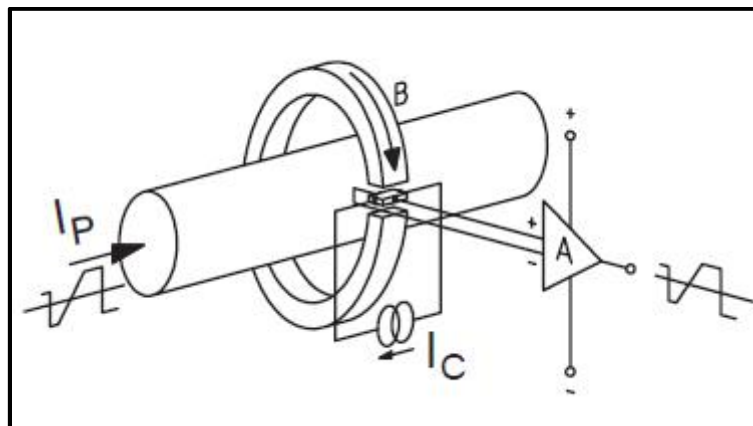


Figure 5.2: Illustration of open loop construction

An alternative design for the Hall Effect sensor is the closed loop current transducer which also involves an air gap at which the sensor is placed. The difference is that the closed loop design requires a secondary coil to be wound around the ferrite core. The secondary coil is

driven by the Hall voltage via an integrated amplifier within the sensor when there is a current in the primary conductor. The current in the secondary coil produces a flux with an equal amplitude but opposite direction. Therefore, the magnetic flux in the core is always driven to zero. The produced current in the secondary coil is equivalent of the primary current through the number of turns of the coil. The current output is converted into a voltage by connecting a measurement resistance to the secondary coil.

Each design has its advantages and limitations. The open loop design is more cost effective and much simpler to be made with split core than that of closed loop design. However, the open loop design is more sensitive to temperature changes. In contrast, the closed loop design provides more accurate measurements for the primary current and has the potential of generating faster response than that of the open loop design (Wang, et al., 2012). Provided that the main application of the project is to detect the change of DC current that is associated with tripping event and digital statuses in substation control building without the requirement of precise current measurements, the open loop design is preferred due to much simpler construction. The closed loop design is also recommended for further experiments in Section 8.3 due to the potential of having faster response time.

The magnetic flux density B at the gap of the core that is resulted from a primary current I can be calculated as:

$$B = \frac{\mu_0 \times I}{\delta} \quad (5.1)$$

where μ_0 is the permeability of free space and δ is the gap length of the core. The depth of the sensor is specified as approximately 1.6 mm (Magnesensor Technology, 2015). This leads to the design of the gap of approximately 1.7 mm to fit the sensor chip with 0.1 mm margin. Provided that most of the DC status signals are rated at 1 Amp (e.g. tripping signals) (IEEE PSRC, 1999), the magnetic flux density at the gap of the core (if applied) corresponds to 7.39 Gauss. The theoretical output voltage of the Hall Effect sensor is 2.515 V, which is the sum of the specified quiescent output voltage (2.5 V) and sensitivity (2 mV/Gauss) response.

In order to fulfil the non-intrusive requirement, both the core and the inserted Hall Effect sensor are mounted on a clamp as shown in Figure 5.3. The wires connected to the sensor are extended and secured within the clamp. A standard 3 pin connector was used to interface with the electronic board as described in the Section 5.4. It is important to emphasise that the ferrite core is split into half. The second cut of the core (other than the sensor gap) was

made as clean as possible. However, it is expected that the discontinuity and imperfection of the split may cause some losses of magnetic flux density. The magnitude and linearity of the sensor output voltage corresponding to the injected primary current is verified in Section 6.1.



Figure 5.3: Non-intrusive Hall Effect sensing clamp

5.4 Electronic Board

The electronics circuitry is divided into four sub-circuits based on its function, namely Amplification, Comparison, Pulse Generation and Voltage Control. These sub-circuits are described in detail in the following sections. The complete schematic of the electronic circuit is shown in APPENDIX C. The only drawback of the current design is the lack of polarity rectification on the output of the Hall Effect sensor for both directions of DC current flow. This is also recommended in Section 8.3 as future improvement.

5.4.1 Amplification

As it was observed in Section 5.3 that the output voltage of Hall Effect sensor is at millivolt level additional to the based voltage of the half supply voltage. This raises the necessity of amplifying the sensor output voltage for further processing. The quad operational amplifier from Texas Instruments LMC6484AIN (2015) was employed for this purpose due to its rail-to-rail performance. The microchip is supplied with the same +5V power supply and capable of operating from -40°C to 85°C . The designed amplifier circuitry is shown in Figure 5.4.

The calculation of the amplifier output is based on the following equations:

$$V_+ = V_- \quad (5.2)$$

$$\frac{V_{ref} - V_-}{R_1} = \frac{V_- - V_{out}}{R_2} \quad (5.3)$$

$$\frac{V_s - V_+}{R_3} = \frac{V_+}{R_4} \quad (5.4)$$

The above equations can be rewritten as (5.5):

$$V_{out} = -\frac{R_2}{R_1} \times V_{ref} + \left(1 + \frac{R_2}{R_1}\right) \left(\frac{R_4}{R_3 + R_4}\right) \times V_s \quad (5.5)$$

If the circuit is configured as $R_1=R_3$ and $R_2=R_4$, (5.5) can be further transformed into (5.6):

$$V_{out} = \frac{R_2}{R_1} \times (V_s - V_{ref}) \quad (5.6)$$

where the ratio of R_2 and R_1 is considered as the gain of the differential amplifier. The value of V_{ref} is configured as the quiescent output voltage of Hall Effect sensor.

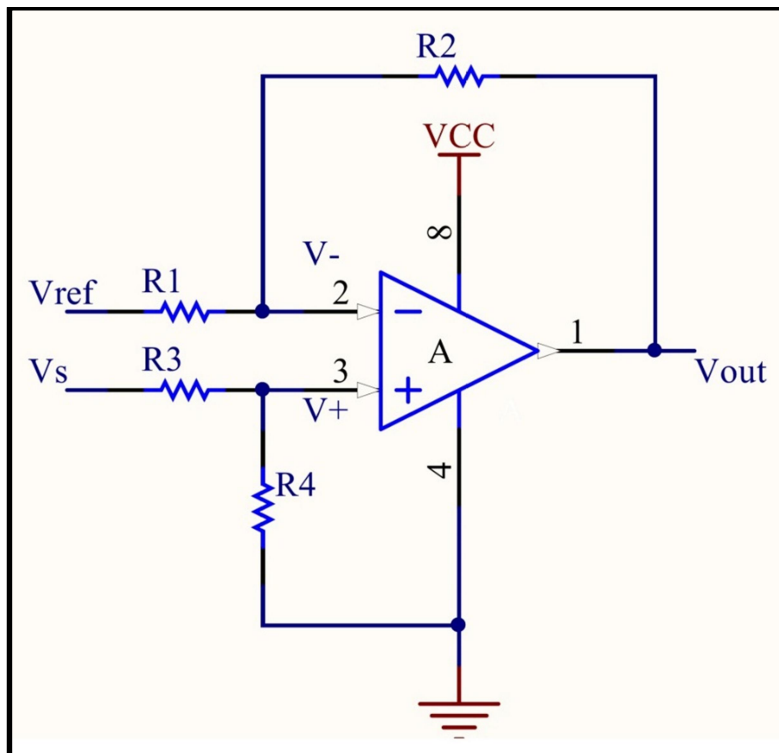


Figure 5.4: Differential amplifier circuit

As a result, the voltage difference caused by the primary current through the sensor clamp is amplified by the gain value that is set by both R_1 and R_2 . The final configurations of the resistor values in the differential amplifier design are:

$$R_1 = R_3 = 1 \text{ k}\Omega$$

$$R_2 = R_4 = 50 \text{ k}\Omega$$

with the equivalent gain of the circuit as 50.

5.4.2 Comparison

The amplified output signal is continuously passed to a Schmitt Trigger circuit for the purpose of generating a steady and clean output signal (+5V) when the Hall Effect sensor detects a DC current change in the attached wire. The same operational amplifier LMC6484AIN was used for this purpose. The designed Schmitt Trigger circuitry is shown in Figure 5.5.

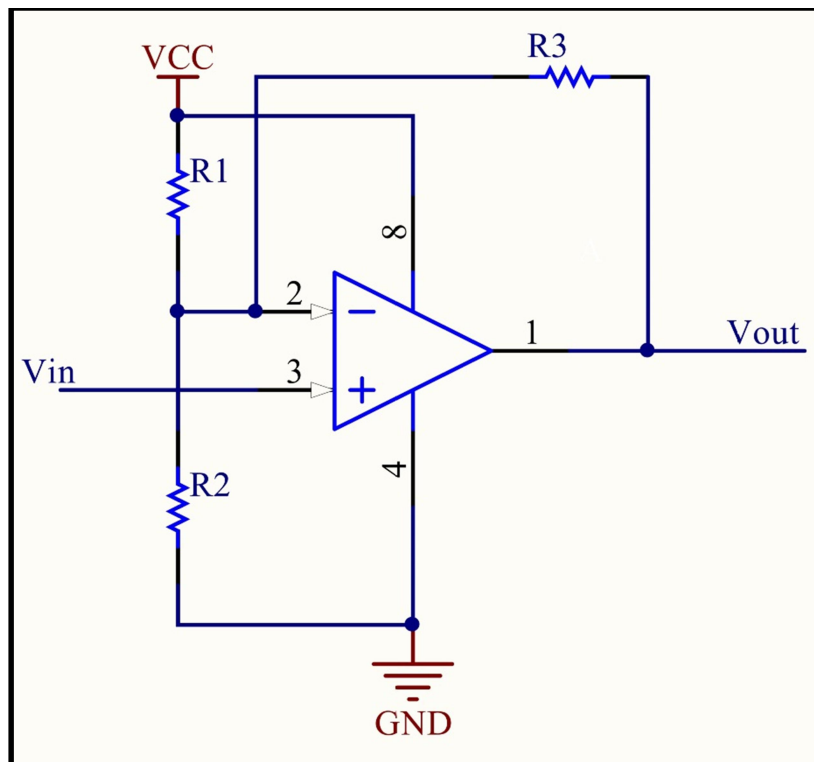


Figure 5.5: Comparator circuit

The hysteresis of the Schmitt Trigger can be calculated by the chosen values of resistors based on (5.7 and (5.8:

$$V_{TH} = \frac{V_{cc} \times R_2}{R_2 + \frac{R_1 \times R_3}{R_1 + R_3}} \quad (5.7)$$

$$V_{TL} = \frac{V_{cc} \times \frac{R_2 \times R_3}{R_2 + R_3}}{R_1 + \frac{R_2 \times R_3}{R_2 + R_3}} \quad (5.8)$$

where V_{TH} is the upper trigger threshold and V_{TL} is the lower trigger threshold. The hysteresis is defined as the difference between the triggering values and it is generally applied as 100

mV (Sedra & Smith, 2004).

The chosen resistor values for the trigger design are:

$$R_1 = 5 \text{ k}\Omega$$

$$R_2 = 4.1 \text{ k}\Omega$$

$$R_3 = 95 \text{ k}\Omega$$

This gives the upper threshold of 2.316 V and lower threshold of 2.2 V with the hysteresis of 116 mV. The chosen thresholds are based on the experiment result described in Section 6.2 where the Hall Effect sensor output voltage is 2.485 V with 560 mA primary current flow. Therefore, the designed Schmitt Trigger provides the overall current sensitivity of 495 mA without any wire turns on the current sensor. It is important to emphasise that the above thresholds can be easily adjusted if required.

5.4.3 Pulse Generation

A pulse is designed to trigger the user specific module of the embedded system if any sensor detected a digital status change. It is necessary to ensure all above generated signals are within the specified electrical characteristics in order to interface with the embedded system. As it is specified by the embedded system, the pulse is required to be at minimum of 280 nanoseconds (Freescale Semiconductor, 2011). The final design of the pulse width is 1 microsecond to secure the acceptance of the generated trigger. The designed schematic of the pulse generation is shown in Figure 5.6.

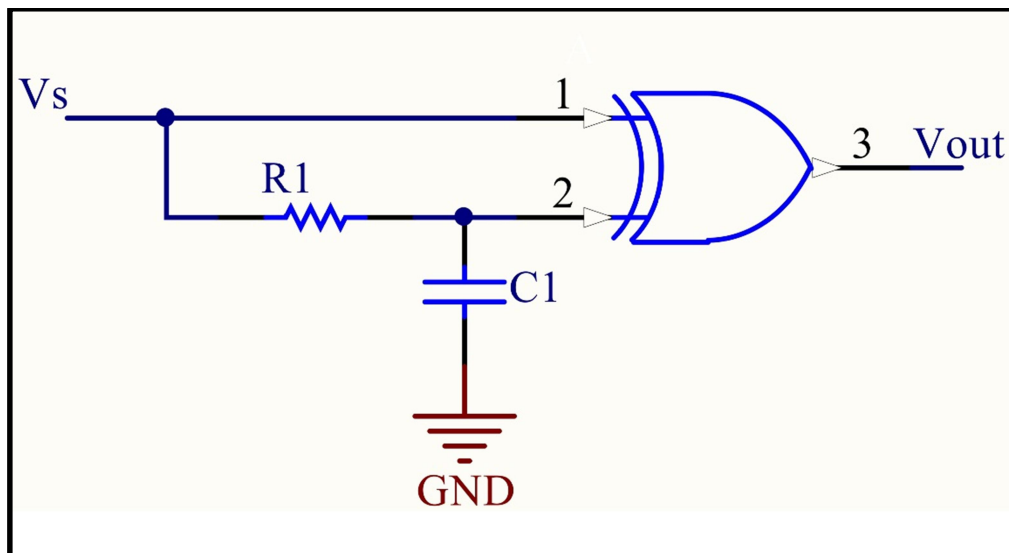


Figure 5.6: Pulse generation circuit

The selected microchip for the XOR gate is MM74HC86M from Fairchild Semiconductor (2015). The microchip is supplied with +5V and capable of operating from -40°C to 85°C . According to the logic truth table of XOR gate that is shown in Table 5.1, a pulse with the required width is achieved by introducing a corresponding delay which is calculated based

on the values of the resistor and capacitor. It is also worth of mentioning that either a rising or falling trigger signal will result the desired pulse to be generated from the circuit. This ensures that any activation or deactivation of a tripping event or status change in the monitored wire can be recognised by the following embedded system.

Table 5.1: XOR logic gate truth table

Inputs		Output
Low	Low	Low
Low	High	High
High	Low	High
High	High	Low

The calculation of the resistor and capacitor values is based on (5.9).

$$V_{IH} = V_S \times (1 - e^{-t/RC}) \quad (5.9)$$

where V_{IH} is the accepted logic ‘High’ input voltage, V_S is the supply voltage and RC is the time constant value determined by the resistance and capacitance. According to the microchip specification, the XOR gate recognises the input as logic ‘High’ at the magnitude of +3.5V when it is supplied by +5V (Fairchild Semiconductor, 2015). The 1 microsecond time requirement is effectively the capacitance charging time when the voltage across the capacitor reaches +3.5V. The final design of the time constant value based on (5.9) are:

$$R = 680 \Omega \quad C = 1.22 \text{ nF}$$

The generated pulse is verified in Section 6.2. The technique for pulse generation is selected over other alternative approaches due to its simplicity and the controlled accuracy of the generated pulse width.

5.4.4 Voltage Control

The electrical characteristic of all input signals to the embedded system are specified to be at the magnitude of +3.3V (Freescale Semiconductor, 2011). The output voltage magnitude of the previous electronics circuits, including the generated pulse, is stepped down from +5V to +3.3V through a AND logic gate by duplicating the signals as logic gate inputs.

The selected microchip for the AND gate is 74LCX08 from Fairchild Semiconductor (2015). The microchip is supplied with +3.3V from the embedded system board and capable of operating from -40°C to 85°C. The voltage magnitude as the output of this circuit is also verified in Section 6.2.

5.5 Embedded System Design

The design of embedded system is based on C programming language under Linux environment. The designed software was compiled and uploaded to the embedded system for the final testing and confirmation. Upon a brief introduction of Linux operating system, the following sub-sections describe the components of the designed software in the project with more detail.

5.5.1 Linux

Linux operating system is an open source software that is currently maintained by perhaps the world best software engineers (Sally, 2010). The software was first invented by Linus Torvalds with the purpose of creating a clean interface between the processor-dependent parts of the software and those that are architecture independent (Sally, 2010). The kernel, which is the core of Linux software, provides bridging information between the lower level hardware and user specific applications through device drivers. An overview structure of Linux kernel based on this project is shown in Figure 5.7.

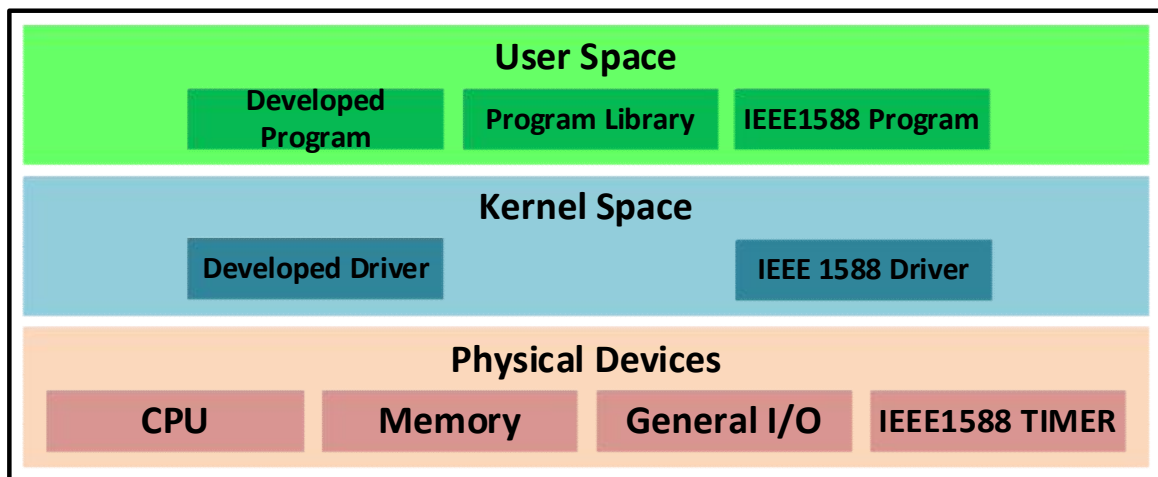


Figure 5.7: Linux kernel structure

The device drivers define the response of the hardware to external activities (e.g. a trigger signal) while hiding the details of how the device works completely from the user. The user performs a set of standardised calls which are independent of the specific driver. The mapping of those calls to the specific operations on real device is defined in the driver.

5.5.2 Embedded System Device Drivers

In Linux software, three fundamental device types are loosely defined, character device, block device and network interface. Each device invokes its device driver in kernel space. The Substation Event Monitor is classified as a character device since it creates data channels to access the required information from the embedded system hardware. This

process can be comprehended as reading files from the embedded system.

The developed character device driver includes a number of important functions which are initialised in the kernel space to prepare for later events. At the initialisation phase of the device driver, it looks up the embedded system device tree in order to configure the interrupt request (IRQ) number for the purpose of handling the interrupt pulse that is generated by the electronic circuitry. The IRQ number is used to register the interrupt handler in kernel space. The registry of interrupt handler is to take place when the device is first opened in the embedded system before the hardware interrupt is generated from the electronic circuitry. The character device is then registered in kernel space via the allocated major number that is defined in the device driver. This number is the identification of the installed device in kernel space. The following step of the initialisation phase is to request the access of the memory resources of both general purpose I/O registers and IEEE 1588 timer registers. This memory request process is demonstrated in the extracted code as follows:

```

    /* Mapping Timer Control Registers */
    if (!request_mem_region(TMR_CTRL, sizeof(struct gfar_1588), DRIVER))
    {
        err("request denied");
        return -ENODEV;
    }
    ptpts->regs = ioremap(TMR_CTRL, sizeof(struct gfar_1588));
    if (!ptpts->regs) {
        err("remap denied");
        release_mem_region(TMR_CTRL, sizeof(struct gfar_1588));
        return -ENODEV;
    }

    /* Mapping GPIO Registers */
    if (!request_mem_region(GPIO_BASE, GPIO_SIZE, DRIVER)) {
        err("request denied");
        return -ENODEV;
    }
    ptpts->gpio = ioremap(GPIO_BASE, GPIO_SIZE);
    if (!ptpts->gpio) {
        err("remap denied");
        release_mem_region(GPIO_BASE, GPIO_SIZE);
        return -ENODEV;
    }

```

It is worth stressing that any error during this process will result in a promoted error message and immediate release of the requested memory region. This process is also applied for requesting the interrupt channel and registering the interrupt handler in the kernel. The final steps of the initialisation phase are configuring the associated general purpose I/Os as inputs, enabling both IEEE 1588 timer functions and external trigger for timestamp event. These steps are achieved by writing particular values to the corresponding registers according to

the embedded system specification.

One of the most important functions defined in the developed device driver is to handle the interrupt received by the embedded system. The extracted code for this function is shown as follows.

```

/* Interrupt received */
if (val & TMR_TEVENT_ETS1) {
    /* Acknowledge the interrupt */
    out_be32(&ptpts->regs->tmr_tevent, TMR_TEVENT_ETS1);
    /* Acquire time information */
    ptpts->dat.ts_hi = in_be32(&ptpts->regs->tmr_etts1_h);
    ptpts->dat.ts_lo = in_be32(&ptpts->regs->tmr_etts1_l);
    /* Acquire sensors data */
    ptpts->dat.gpio_inputs = in_be32(ptpts->gpio + GPDAT);
    /* Wake up the reading process */
    wake_up_interruptible(&ptpts->wq);
    ptpts->event++;
}
return IRQ_HANDLED;

```

The event signal generated from electronic circuit is mapped to the external timestamp (ETS1) trigger of the TMR_TEVENT register. This event signal also causes a hardware interrupt to the programmable interrupt controller in the embedded system. The interrupt is cleared by writing the value 1 to the ETS1 trigger location in the TMR_TEVENT register. Following that, both data and timestamp information are stored in the predefined data structure. At the end of the handler, it awakes the reading process and makes the updated data to be available for the developed program in user space.

When the device driver is no longer required in the embedded system, it must be removed from kernel space. For this reason, the developed device driver includes an exit function to remove the device from the kernel and release the occupied resources.

Another important set of device drivers that is relevant to this project is for the implementation of PTP synchronisation. The main functions of these drivers are configuring PTP related registers, defining various hardware control functions and enabling 1-pulse-per-second (1PPS) output signal for accuracy verification. Although these drivers are complimentary in the employed kernel software, it is still necessary to make necessary changes in order to be functional with the PTP program in user space.

5.5.3 IEC 61850 IED Capability Description

As it was described in Section 3.2.3, the ICD file of an IED specifies its capabilities and information to be exchanged over the Ethernet network with other devices. The ICD file for

substation event monitor is specified as a logical device that contains the logical nodes of LLN0 and GGIO. The usage of GGIO in the prototype design is due to the missing of predefined logical node for the specific function of interfacing with legacy devices. In addition, the usage of GGIO for device status monitoring has also been suggested by Ling *et al* (2014). It is important to emphasise that the designed ICD file can be updated according to the function of the interfacing device or the monitored status signal. For example, if the legacy device is a distance protection relay, the GGIO in the designed ICD file can be replaced with PDIS logical node. The part of the ICD file that shows the embedded GGIO logical node is as follows.

```

<IED      name="TripMonitor"      type="ICDGEN"      manufacturer="UofA"
configVersion="0.1">
  <Services>
  <AccessPoint name="P1">
    <Server>
      <Authentication />
      <LDevice inst="TripMonitorLogicalDevice">
        <LN0 lnType="LLN0_0" lnClass="LLN0" inst="">
          <DataSet name="TripMonitorDataset">
            <GSEControl      name="Monitor"      desc="TripMonitor"
datSet="TripMonitorDataset" confRev="1" appID="Monitor" />
          </LN0>
          <LN lnType="GGIO_19" lnClass="GGIO" inst="1">
            <DOI name="Ind1">
              <DAI sAddr="LoggerChar1" name="stVal" />
              <DAI sAddr="LoggerStamp1" name="t" />
            </DOI>
            <DOI name="Ind2">
              <DAI sAddr="LoggerChar2" name="stVal" />
              <DAI sAddr="LoggerStamp2" name="t" />
            </DOI>
            <DOI name="Ind3">
              <DAI sAddr="LoggerChar3" name="stVal" />
              <DAI sAddr="LoggerStamp3" name="t" />
            </DOI>
          </LN>
          <LN lnType="LPHD" lnClass="LPHD" inst="1" />
        </LDevice>
      </Server>
    </AccessPoint>
  </IED>

```

The GGIO logical node contains three integer status inputs as status information which is defined as common data type of Integer Status (INS) according to IEC 61850-7-4 standard (Technical Committee 57, 2010). The status value (stVal) and timestamp (t) information are specified as required by INS data type in IEC 61850-7-3 standard (Technical Committee 57, 2010). The completed ICD file will be read by the software in embedded system for the purpose of publishing GOOSE messages.

5.5.4 Embedded System Software

Two main functions of the developed user space program are polling the information from kernel space and encoding the data into GOOSE messages according to the imported ICD file. The development of user space program is based on both C standard library and the IEC 61850 standard library provided by Omicron Electronics GmbH, Austria. The flow chart of the user space program is shown in Figure 5.8.

In order to establish the connection between the imported ICD file and user data, the program initialised six data attribute operations for device's information according to IEC 61850 standard library. The connection is established via the *sAddr* value specified in the ICD file for each sensor data. Any error during the binding process will result a promoted error message to the user and request for reloading the ICD file. Upon the successful binding process, the program requests a file descriptor which is the reference of the open file that has been made available in the user space by the device driver. The open file is where the digital status data and time information resides in embedded system. The program will be terminated and an error message will be promoted to the user if any error occurs during file descriptor request.

A raw socket on the Ethernet device of the embedded platform is then created by the user program. The raw socket provides the benefit of direct access to the underlying protocols (e.g. GOOSE messages). This enables the writing of Ethernet packets to the raw socket, hence the publication of device's GOOSE messages. In general, each GOOSE message is considered as two parts, header and payload. The header of GOOSE messages includes all the necessary information for GOOSE communication, such as source and destination MAC addresses, GOOSE control block reference, VLAN and the configured dataset reference. The payload of GOOSE messages is the user data, which is the digital status data and the timestamp of a detected event in this project. Subsequently, the program organises the GOOSE header and the initial payload data from the open file according to the structure of ASN.1 BER prior to the encoding process. All the organised data is then joined with an initialised Ethernet frame and ready for final encoding. An entry time is also recorded for statistics calculation in order to verify the device processing time of GOOSE publication. Finally, the encoded data according to BER rules is written to the raw socket for the completion of GOOSE publication.

The retransmission of GOOSE message without any detected event is scheduled as every 1 second (T_0). After a detected event, the retransmission of GOOSE message is scheduled as

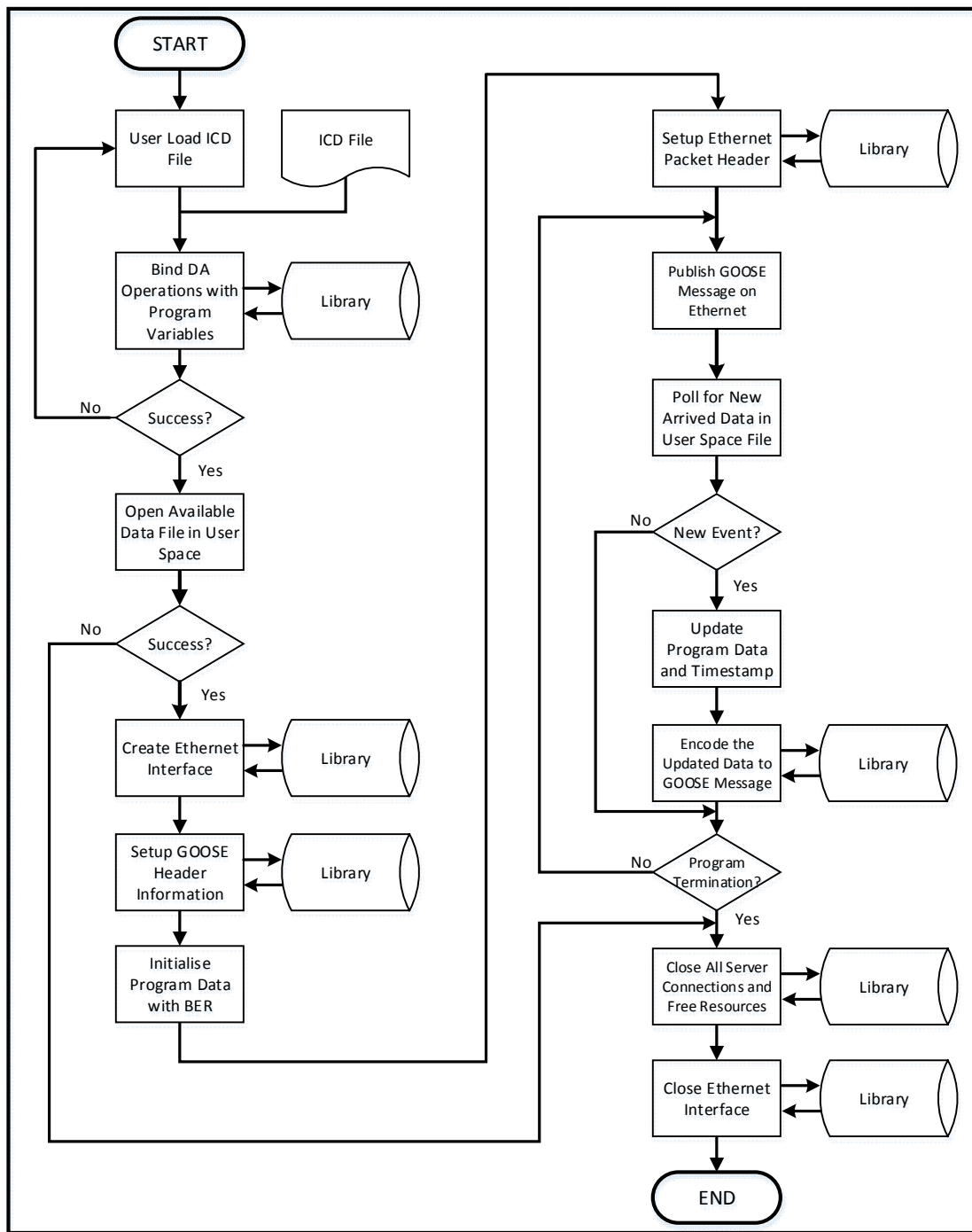


Figure 5.8: Program flow chart

100 milliseconds (T_1), 200 milliseconds (T_2), 800 milliseconds (T_3) then back to the heartbeat of T_0 . Within the infinite loop as shown on the right hand side of Figure 5.8, the program polls the status data from the open file in user space and checks for any event. If an event occurred, the updated data is encoded in GOOSE messages and published according to the described retransmission schedule. The user is able to terminate the program at any time. The program is designed to release all occupied resources upon the termination. Finally, the program closes the Ethernet interface of the embedded platform. The verification of GOOSE message publication is described in Section 6.6.

5.5.5 IEEE 1588 Synchronisation Program

In order to achieve full compatibility, both versions of IEEE 1588 standard are implemented in the project. Only one version can be executed at run time due to the differences in the corresponding device drivers. The synchronisation of PTPv1 is realised via the open source software PTPd version 1.1.0 (Mace, et al., 2015). The synchronisation of PTPv2 is achieved via commercial PTP software from IXXAT Automation GmbH (2015). The synchronisation tests performed on both versions of PTP software are illustrated in Section 6.3 and 6.4.

5.5.6 Completed Prototype

The completed prototype of substation event monitor is shown in Figure 5.9. The total cost of the device is approximately AUD\$280 with the majority of the expense on the MPC8313E platform. This fulfils the requirement of cost effective device that is listed in Section 5.1.

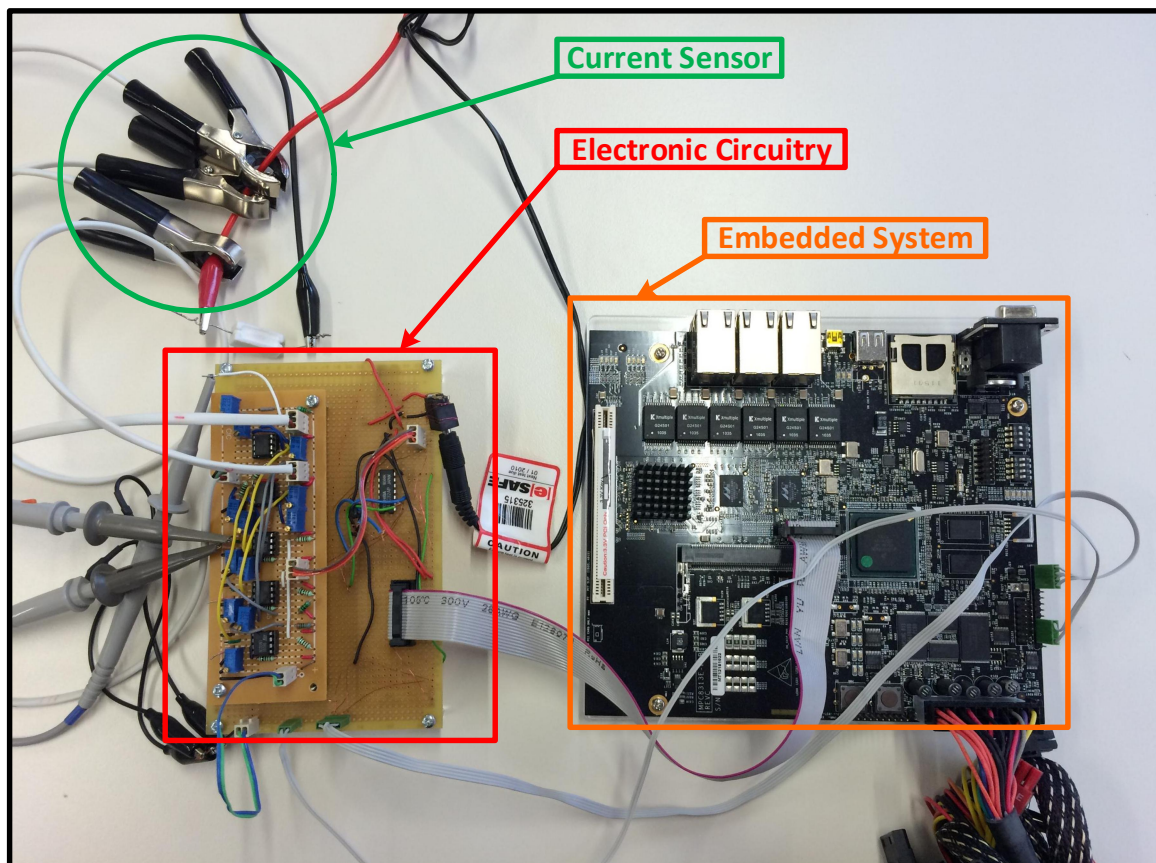


Figure 5.9: Substation event monitor prototype

5.6 Summary

This chapter described the detailed construction information of substation event monitor with the emphasis on the critical components, namely Current Sensor, Electronic Board and Embedded System. The functional requirements and design process are also provided. In

particular, the integration of Electronic Board and the software in Embedded System in order to publish IEC 61850 standard messages with synchronised timestamp is also demonstrated in the chapter. The detailed bottom-up design process provides sufficient confidence of applying the device in power utility applications.

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CHAPTER 6 PROTOTYPE VERIFICATION

This chapter provides detailed information of the assessment of the developed substation event monitor. Sections 6.1 and 6.2 demonstrate the testing results of Hall Effect sensor and electronic circuit. The verifications of the synchronisation accuracy through PTP are demonstrated in Sections 6.3 and 6.4. Following from this is the measurement of delays in the electronic circuit to ensure an overall system timing accuracy in Section 6.5. The published GOOSE message is validated in Section 6.6 according to the IEC 61850 standard. This chapter is concluded with the interoperability test with an independent vendor IED.

6.1 Hall Effect Sensor Output Voltage Verification

The purpose of this test is to verify the linearity of the Hall Effect sensor output voltage. The Hall Effect sensor clamp was attached to a DC circuit with the capability of ramping up the magnitude of the primary current in the wire. Table 6.1 shows both calculated and measured results of the Hall Effect sensor output that is corresponding to the different magnitude of current. The calculated voltage output is based on (5.1). The test results are also plotted in Figure 6.1 to show the linearity of sensor output signal.

Table 6.1: Hall Effect sensor output verification

Primary Current (mA)	Theoretical Output Voltage (V)	Measured Output Voltage (V)
0	2.479	2.479
200	2.481	2.482
400	2.483	2.485
600	2.485	2.488
800	2.487	2.491
1000	2.489	2.494
1200	2.490	2.497

Figure 6.1 has indicated that the strength of the measured output signal is lower than the theoretical outputs. This is due to the discontinuity and imperfection of the ferrite core split as it was expected. Also, the linearity of the measured output signals is consistent corresponding to the primary current in the conductor. This provided the foundation of the

following design of electronic circuitry.

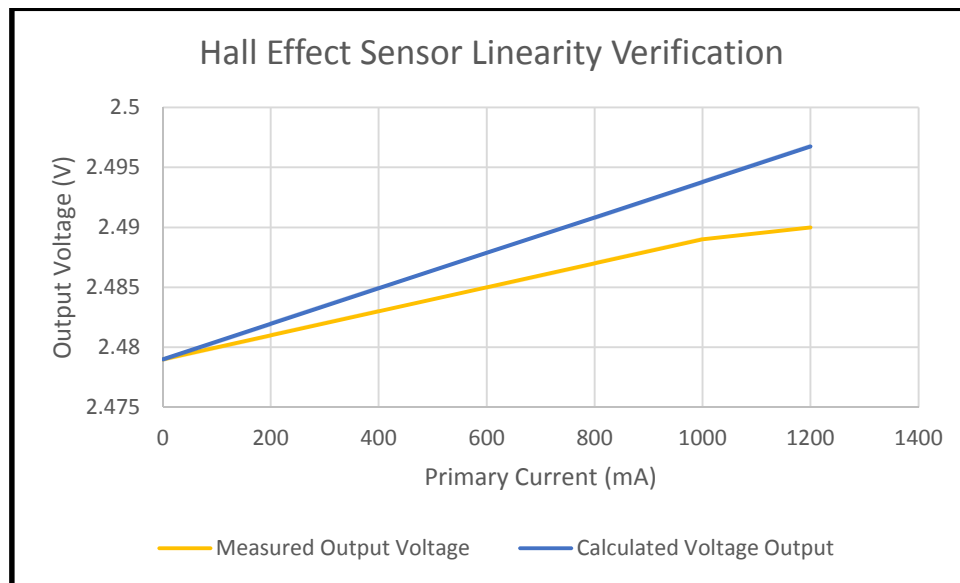


Figure 6.1: Hall Effect sensor output voltage verification

6.2 Electronic Circuits Verification

The aim of this test is to verify the output signals of electronic circuits are according to the original design intentions. The test was divided into individual tests according to the involved modules.

The signal amplification was validated by clamping the Hall Effect sensor to the same current ramping DC circuit. The measured signals with no current and 560 mA current flow in the wire are shown in Figure 6.2 and Figure 6.3 respectively. The measured gain was approximately 51 which is slightly higher than the design value of 50 due to the imperfection of the involved components.

The measured output signal from Schmitt Trigger is shown in Figure 6.4. The result indicated the overall sensitivity of the circuit is located at approximately 495 mA with the corresponding magnitude of the amplified signal as 2.32 V. It is worth mentioning that the sensitivity of the circuit is adjustable based on the employed resistor values of the Schmitt Trigger.

The 5 V Schmitt trigger output is in turn passed on to the logic gates in order to generate an interrupt pulse. The result of this part of the circuit is shown in Figure 6.5. The result demonstrated that the output of the circuit fulfils the requirement of 1 microsecond width and 3.3 V magnitude. It is important to emphasise that there are other options to achieve the same result as the chosen electronic circuit design. The current design is decided based on

the requirements of low cost, simplicity and quantifiable delay of the circuitry for synchronisation adjustment.

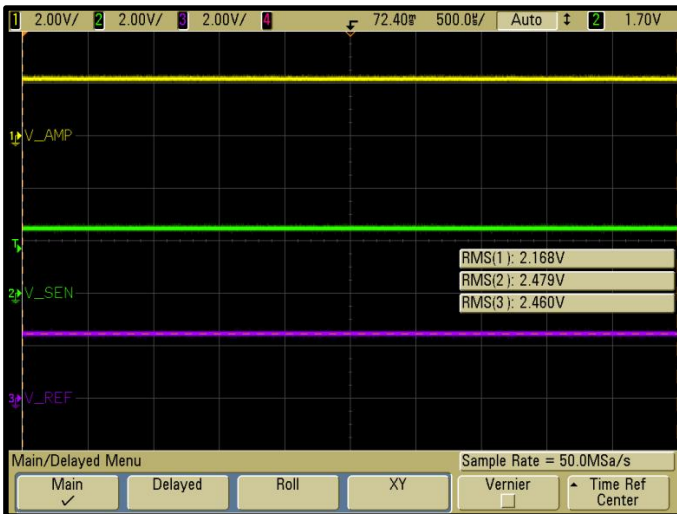


Figure 6.2: Measured amplification with zero current flow

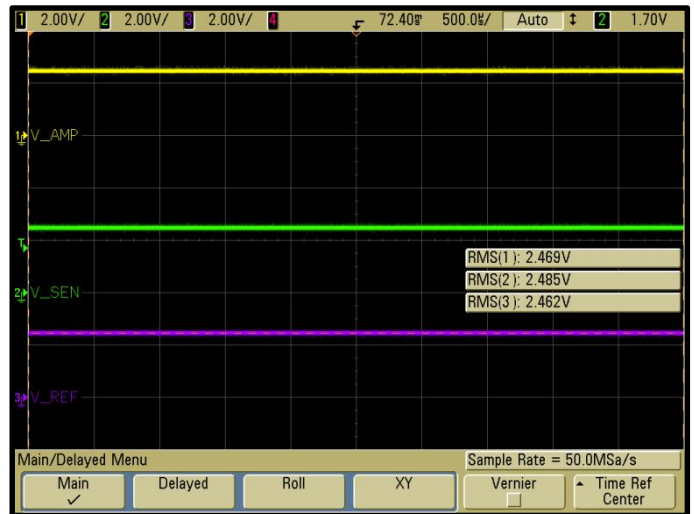


Figure 6.3: Measured amplification signal with 560 mA current flow

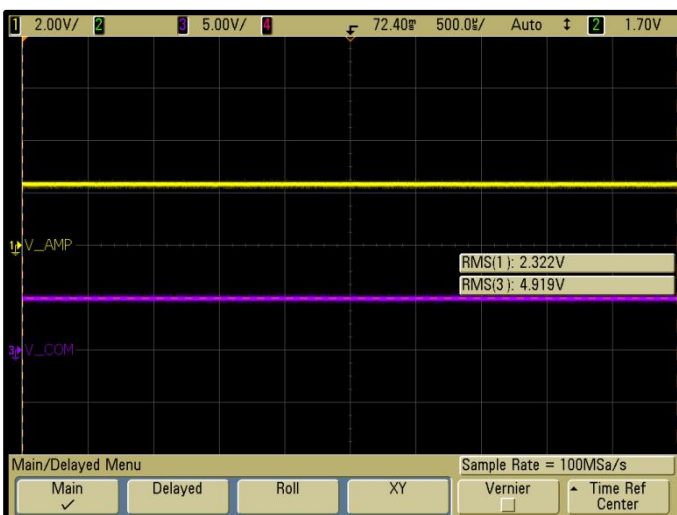


Figure 6.4: Measured Schmitt Trigger output at 490 mA

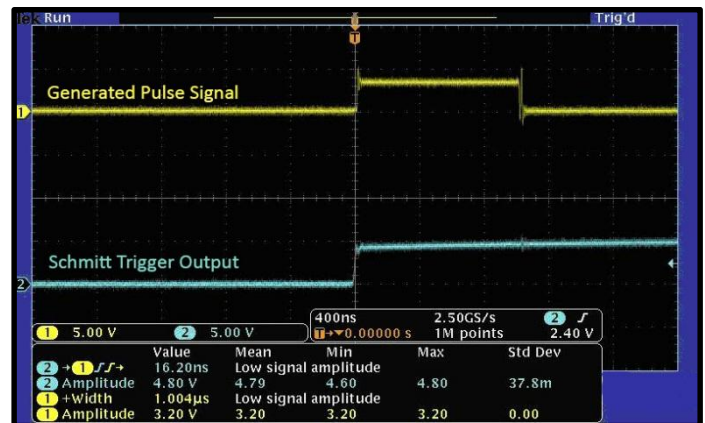


Figure 6.5: Electronic logic circuit measurement

6.3 PTPv1 Time Synchronisation Test

The goal of this test is to verify the synchronisation accuracy of the developed device via IEEE 1588-2002 (PTPv1). The setup diagram of this test is shown in Figure 6.6. The test involved two identical substation event monitors with the time master clock. The time master clock, Meinberg M600 PTPv1 (2015) time server, was connected to a GPS antenna to obtain an absolute time reference. All the involved devices are connected via the on board Ethernet switch of SEM1 which is acting as a boundary clock for SEM2 platform. An oscilloscope is configured to verify the time synchronisation accuracy by monitoring the 1PPS output signals from time master clock, SEM1 and SEM2 platforms with persistent display. Both SEM platforms are synchronised with time master clock via PTPd software.

The test was performed over 14 hours and the result is shown in Figure 6.7.

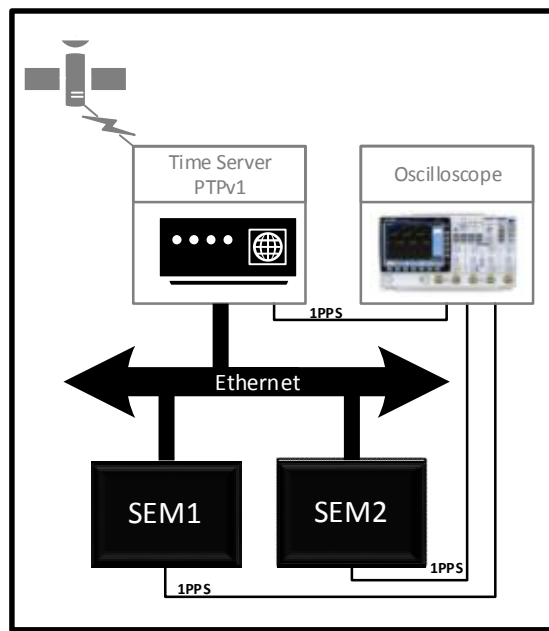


Figure 6.6: PTPv1 synchronisation test setup diagram

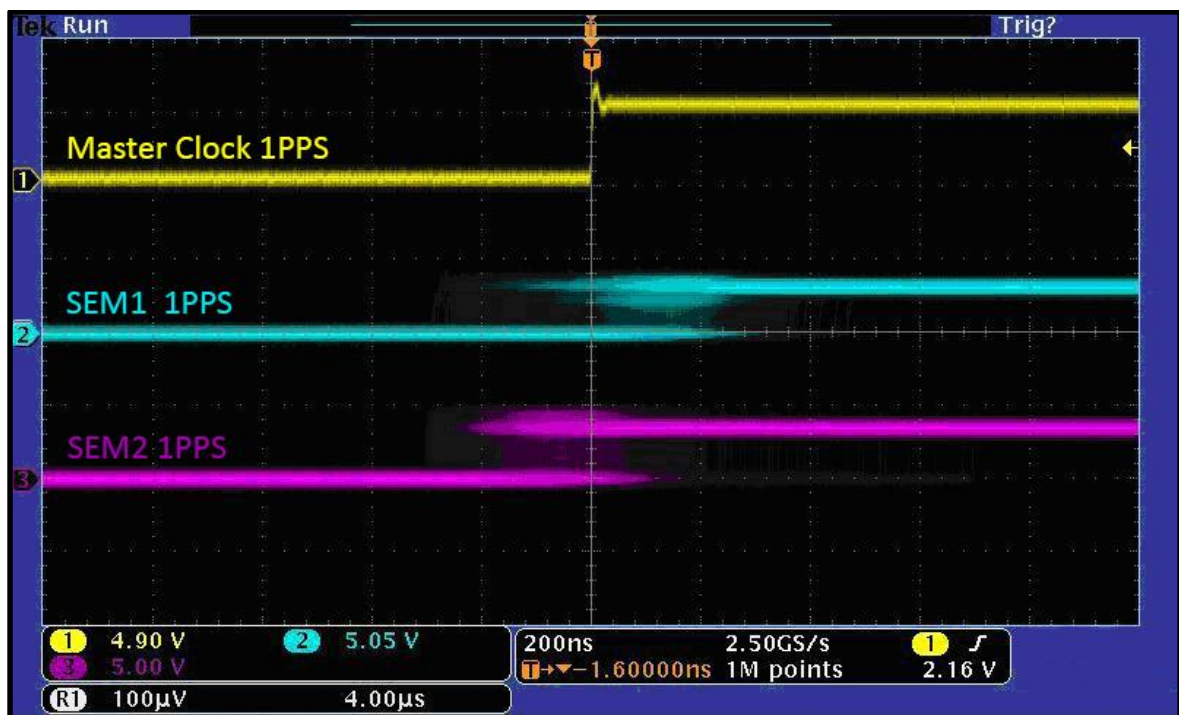


Figure 6.7: PTPv1 synchronisation test result

The result shown in Figure 6.7 demonstrated that the two 1PPS signals from the two SEM platforms are within the range of ± 200 nanoseconds from the 1PPS signal of the master. The test result also confirmed that the integration of PTPd software and the hardware timestamping feature of the embedded platform is capable of achieving sub-microsecond synchronisation accuracy. The only deficiency showed during the test is that the devices take approximately four minutes to reach three microseconds synchronisation accuracy at

start-up phase or if the time master clock is disconnected and reconnected to the network. This is due to the structure of synchronisation message that is described in Section 4.2.

6.4 PTPv2 Time Synchronisation Test

The goal of this test is to verify the synchronisation accuracy of the developed device via IEEE 1588-2008 (PTPv2). The setup diagram of this test is shown in Figure 6.8. The test is consist of one SEM platform and Meinberg M600 PTPv2 (2015) time server with a connected GPS antenna. The synchronisation was achieved by executing the PTPv2 software from IXXAT GmbH (2015) on the embedded system of the SEM. The synchronisation interval on both the master clock and the SEM platform was configured as

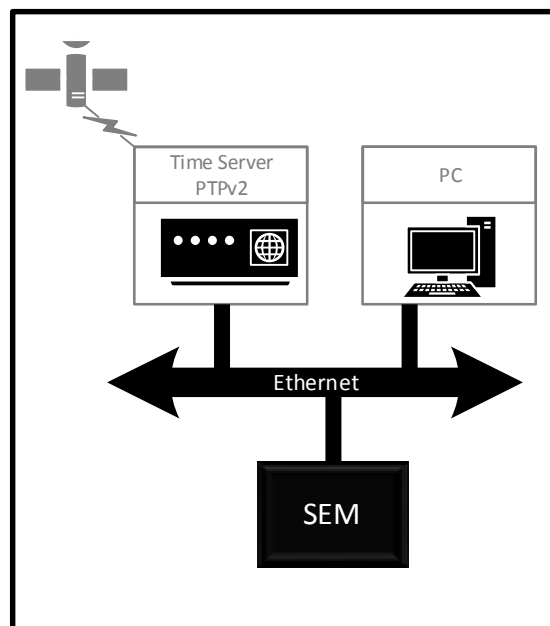


Figure 6.8: PTPv2 synchronisation test setup diagram

-3, which is equivalent of exchanging 8 synchronisation messages per second between the devices. The data from synchronisation start-up phase is shown in Figure 6.9. The result indicated that the SEM took 20 synchronisation messages, which is approximately 2.5 seconds, to be synchronised with the time master clock with the accuracy in the order of ± 100 nanoseconds. The synchronisation accuracy was stabilised and reached ± 50 nanoseconds in 40 synchronisation messages, which is approximately 5 seconds. This result has shown a significant improvement in comparison with PTPv1 as it was expected.

The PTPv2 performance upon the stabilised synchronisation is shown in Figure 6.10. A total number of 28,443 samples were collected and analysed. The test result indicates the synchronisation accuracy was well maintained at ± 50 nanoseconds level with standard deviation of 22.16 nanoseconds. This result further confirmed that the accuracy level and

overall performance has been significantly improved via PTPv2. Due to the difficulty of modifying the set of device drivers for PTPv2 program, the 1PPS signal from SEM was not enabled for testing purpose. This deficiency has been recommended to be rectified as future improvement in Section 8.3.

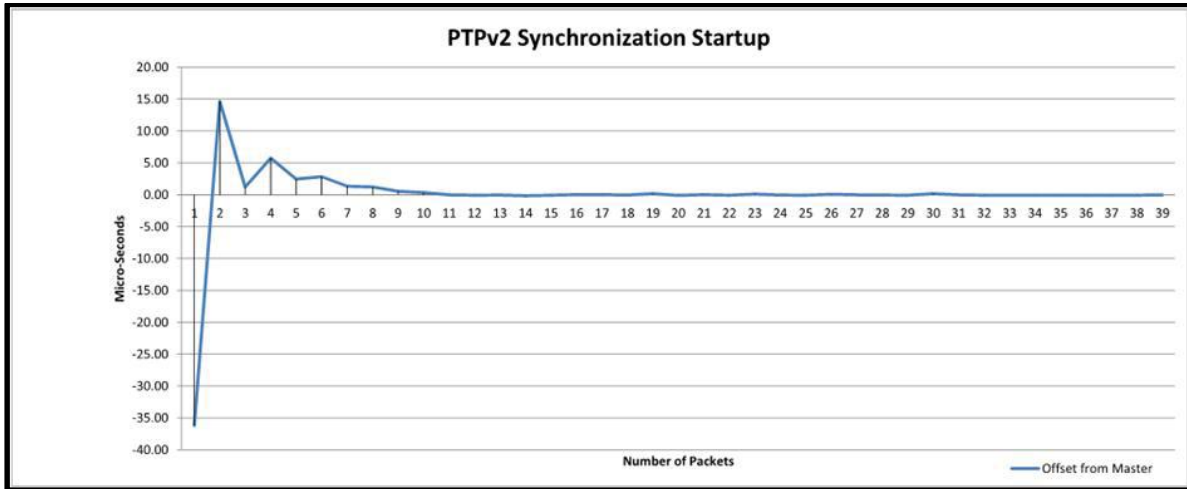


Figure 6.9: PTPv2 performance at synchronisation start-up phase

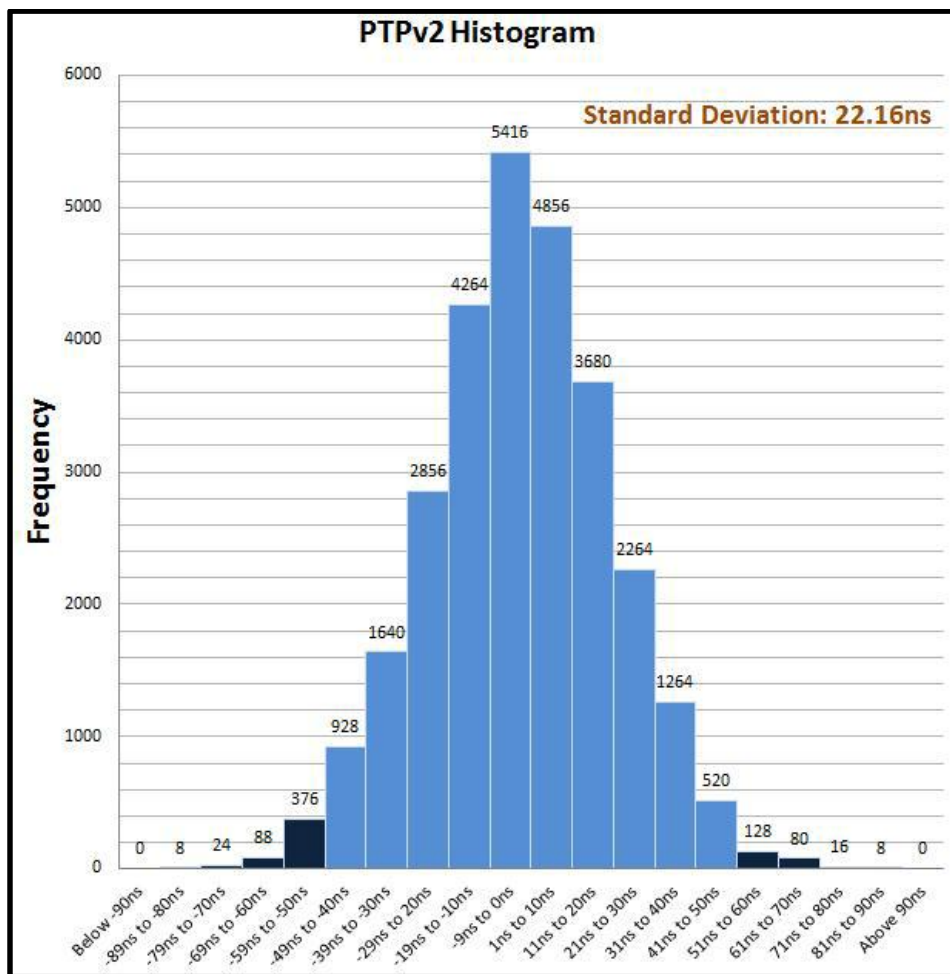


Figure 6.10: PTPv2 performance histogram and standard deviation

6.5 Electronic Circuit Time Compensation

The purpose of this test is to quantify the delay that is caused by the Hall Effect sensor and developed electronics circuitry. The measured delays are then compensated in the timestamp value in order to meet the requirement of achieving ± 1 microsecond overall system timing accuracy.

According to the manufacture datasheet of the Hall Effect sensor, a typical response time of 3 microseconds is specified (Magnesensor Technology, 2015). In order to further prove the response time specification, an additional test report has been provided by the manufacturer. The test report demonstrated the response time of the Hall Effect sensor is less than 3 microsecond under different strength of electromagnetic fields.

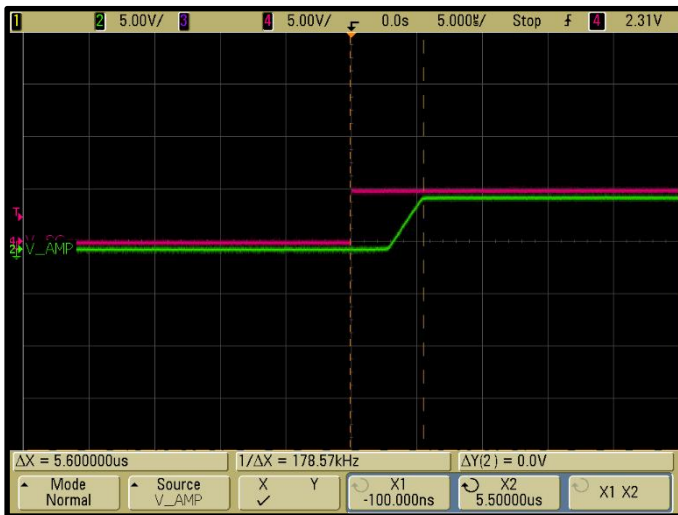


Figure 6.11: Signal amplification delay

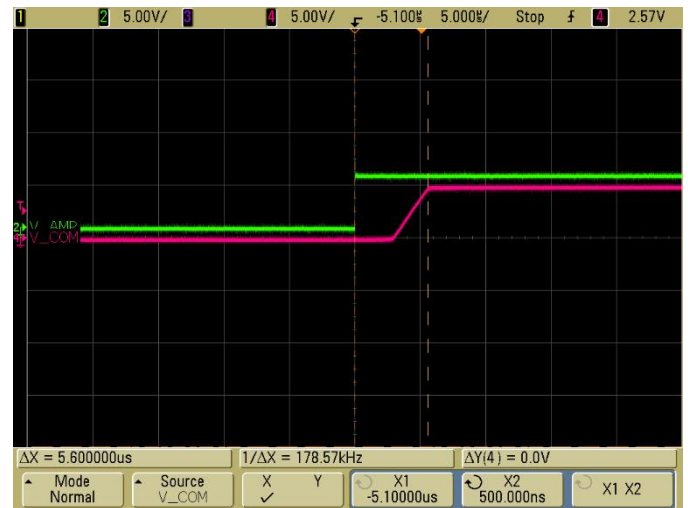


Figure 6.12: Schmitt Trigger rising delay measurement



Figure 6.13: Schmitt Trigger falling delay measurement

The time delay of the designed amplifier is measured through the injection of 5 V Transistor-

Transistor Logic (TTL) square wave from a signal generator. This is due to the difficulty of triggering the oscilloscope from change of Hall Effect sensor output signal. The measured delay of 5.6 microsecond is shown in Figure 6.11. It is worth mentioning that the signal injection is to the same point at which the Hall Effect sensor output is connected such measurement reflects the actual design of the circuit. The same methodology is also applied to the Schmitt Trigger delay measurement. The delay measurements results of both rising and falling edges of Schmitt Trigger are shown in Figure 6.12 and Figure 6.13 respectively. This is to ensure the same delay occurred for any detected switching event and the overall timing accuracy is preserved at ± 1 microsecond level. The results indicated an equal 5.6 microsecond delay is contributed by the Schmitt Trigger. The delay of logic gates was measured using the trigger of oscilloscope from the 5 V Schmitt Trigger output. The delay measurement result of 16.2 nanoseconds is shown in Figure 6.5.

As a result, an overall delay of 13.2162 microseconds has been compensated at the programming level once the synchronised timestamp value is obtained. The time compensation ensures the overall system time information is provided with the accuracy level of ± 1 microsecond which fulfils the requirement as specified in Section 5.1.

6.6 GOOSE Publication Test

The goal of this test is to verify if the PDU information, the monitored event data and the associated timestamp values are correctly encoded in the published GOOSE messages. The test is performed using WireShark and the captured Ethernet packet of GOOSE message is analysed in Figure 6.14.

At the top of Figure 6.14, it is validated that the GOOSE message has been encoded as Type 1/1A message for tripping purpose. It is unfortunate that the expense of renting the dedicated Ethernet traffic analyser device is out of budget. The Ethernet interface card of the utilised computer is not capable of capturing the IEEE 802.1Q tag embedded in the GOOSE message. As a result, the tag information is not shown in Figure 6.14. It is ensured that the native VLAN number 1 and priority 4 are encoded at programming level in the published GOOSE messages. The test result described in Section 6.7 demonstrated the correct VLAN number has been encoded in the GOOSE message for successfully inter-tripping with the independent vender device.

The references of GOOSE control block and data set are verified to be correctly encoded in the captured packet according to the standard. The ASN.1 tags, which is corresponding to

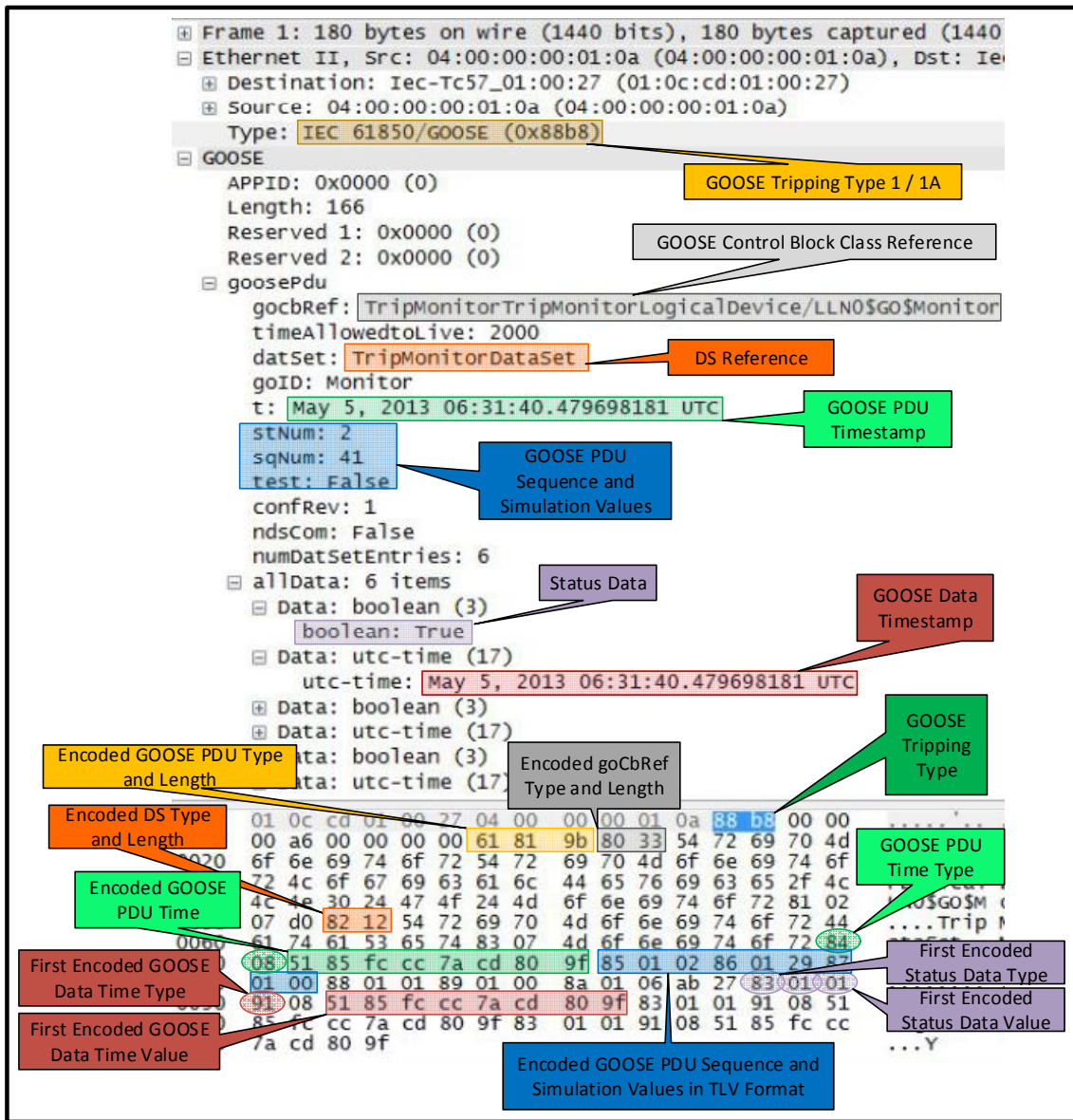


Figure 6.14: Caption of encoded GOOSE message

Table B.1, for the references are also indicated in the data encoding panel at the bottom of Figure 6.14. It is important to emphasise that the standard defined different tag values for the timestamp information in GOOSE PDU and the data attribute associated with the status information. Although both timestamp values are 8 bytes of length, the corresponding tag values are individually defined as shown in Table B.1 and Table B.2. This subtle difference along with the encoding of other PDU data are verified to be correct as shown in Figure 6.14. The encoding of event data is also validated according to the standard as it is shown in the caption. The value of the status data is the true reflection of the detected event from the Hall Effect sensor.

The encoding time verification was also performed to ensure GOOSE data encoding is less than 1.2 millisecond as specified in IEC 61850-10 standard. The test utilised the entry time recorded at the data encoding stage in the software. The result of the test indicated GOOSE

messages have been encoded and delivered in approximately 48 microseconds when a state change was detected in the DC circuit. This is due to the sole function of the embedded system is to perform GOOSE publication which is different from other commercial IEDs. This result demonstrated that the developed software is compliant with the specified time in the standard.

6.7 Interoperability with Different Vendor Device

In order to prove the developed SEM is interoperable with other protection relays from different vendors, a compatibility test has been performed between the SEM platform and a

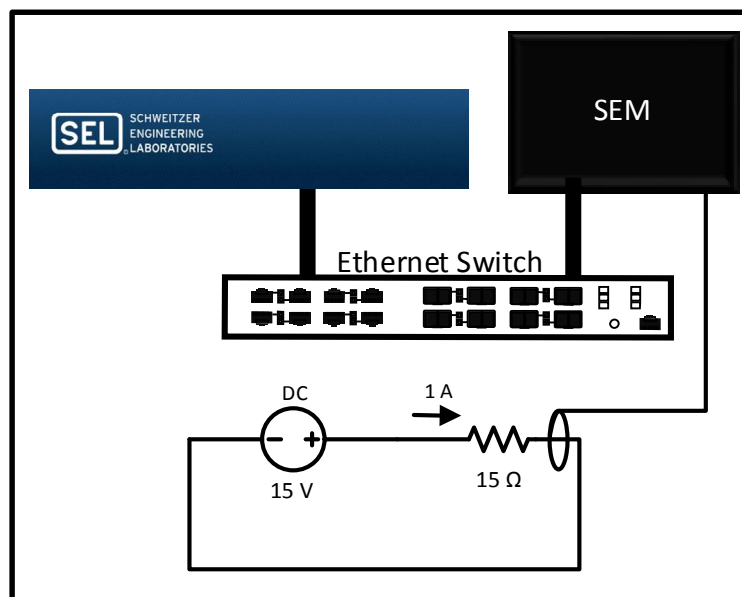


Figure 6.15: Compatibility test setup diagram

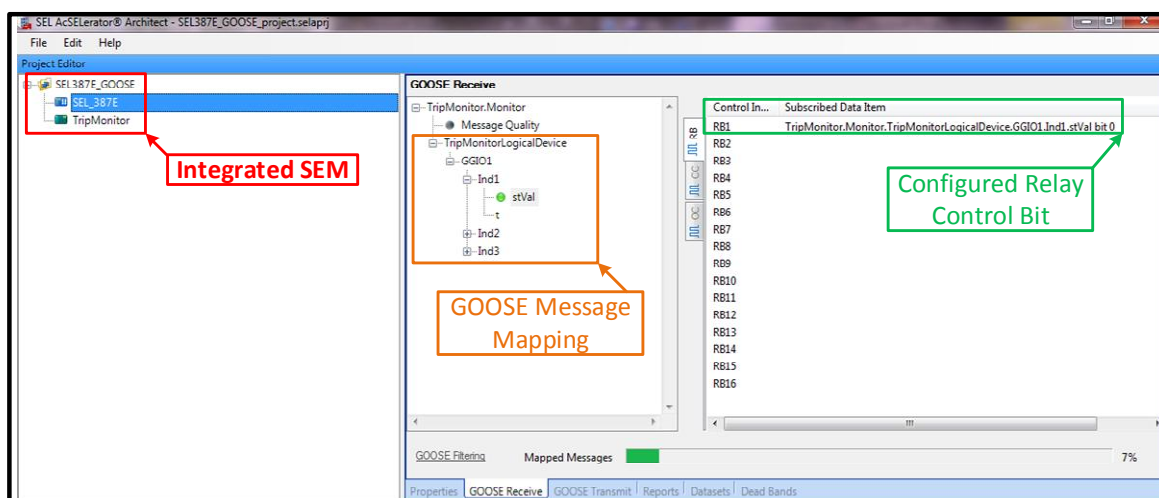


Figure 6.16: SEL-387 relay configuration

transformer current differential relay from Schweitzer Engineering Laboratories (SEL-387). The setup diagram of the test is shown in Figure 6.15. The Hall Effect sensor is clamped to

the DC circuit for monitoring the change of current flow. The 'Remote Bit 1' of the SEL-387 relay was configured to subscribe to the integer status data of the published GOOSE message from SEM platform. The SEL-387 configuration screen using SEL AcSELeator software is shown in Figure 6.16.

The mapped 'Remote Bit 1' of SEL-387 is then configured in the relay trip equation (TR1 or Trip1) in order to drive one of its output contacts. This arrangement is demonstrated in the extracted relay configuration file as follows:

SEL-387 Configuration Summary Data:

```

FID = FID=SEL-387E-R702-V0-Z101003-D20071025
TR1    =50P11T + 51P1T + 51Q1T + OC1 + LB3 + RB1
TR2    =51P2T + 51Q2T + OC2
TR3    =50P31 + 51P3T + OC3
TR4    =87R + 87U
ULTR1  =!50P13
ULTR2  =!50P23
ULTR3  =!50P33
ULTR4  =!(50P13 + 50P23 + 50P33)
CL1    =CC1 + LB4 + /IN104
CL2    =CC2 + /IN105
CL3    =CC3 + /IN106
ULCL1  =TRIP1 + TRIP4
ULCL2  =TRIP2 + TRIP4
ULCL3  =TRIP3 + TRIP4
ER     =/50P11 + /51P1 + /51Q1 + /51P2 + /51Q2 + /51P3
OUT101 =TRIP1
OUT102 =TRIP2
OUT103 =TRIP3
OUT104 =TRIP4
OUT105 =CLS1
OUT106 =CLS2
OUT107 =CLS3

```

It is expected that a trip command is generated by the SEL-387 relay due to the status change in the published GOOSE message from substation event monitor. It is clear that such value

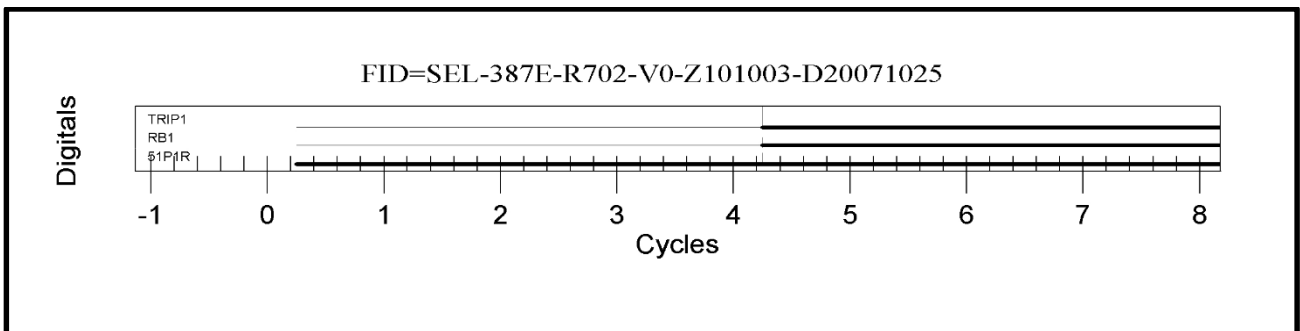


Figure 6.17: SEL-387 relay event log

change in the SEM published GOOSE message is driven from the detection of DC current

flow in the circuit. The event log which is downloaded from the SEL-387 relay is shown in Figure 6.17. This result demonstrated that the SEL-387 relay has been successfully operated by the GOOSE messages from the SEM platform as it was expected.

6.8 Summary

This chapter provided the assessment results on the performance of substation event monitor. The linear response of current sensor provided the foundation of device development. The synchronisation accuracy verification and the time compensation on electronic circuitry enabled ± 1 microsecond timestamp accuracy in the overall system. The GOOSE publication and the interoperability verification with different vendor device demonstrated the compliance with IEC 61850 standard. Therefore, the developed substation event monitor fulfils the requirements that are established in Chapter 5.

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CHAPTER 7 APPLICATIONS

This chapter provides detailed information on two applications of substation event monitor. Section 7.1 describes the application of interfacing with legacy devices based on a practical project in South Australia. Section 7.2 illustrates the need of using substation event monitor for substation topology processing as a part of network state estimation.

7.1 Interfacing with Legacy Devices

ElectraNet, the transmission network service provider in South Australia, has established a new substation named ‘Whyalla Central’ adjacent to the Whyalla township to support the existing power supply demand (Liu, et al., 2013). As a result, both primary and secondary equipment in the old substation named ‘Whyalla Terminal’ will be partly replaced to accommodate such change.

The secondary system of the old Whyalla Terminal substation consists of electromechanical relays. Due to the project implementation constraints on this part of the transmission network, only the protection relays for the 132 kV feeder to Whyalla Central substation and the set ‘Y’ current differential protection relay for the transformer will be replaced with digital relays that are IEC 61850 standard compatible. The rest protection devices, such as overcurrent and restrict earth fault protection on transformer high voltage and low voltage windings, will remain in service as electromechanical relays. Table 7.1 and Table 7.2 list all protection schemes and its associated relay technologies at Whyalla Terminal substation.

Since the modified Whyalla Terminal substation contains mixed relay technologies, the communication among the different generations of protection devices would have to be hardwired as the communication specification of the electromechanical devices is limited to predominantly hardwired interfaces. Hence, the integration of the hardwired system would be very complicated to implement, especially on this brownfield application. The developed SEM could be utilised to implement a modern open communication architecture on the basis of an Ethernet LAN technology for this type of application. The theoretical application of the SEM platform as a communication interface in this brownfield application is illustrated in Figure 7.1. The SEM device could be applied to monitor the DC tripping wires of the installed electromechanical relays by simply clamping the current sensor onto

Table 7.1: Feeder protection scheme and relay technologies at Whyalla Terminal substation

132kV FDR X Protection	Relay Technology	132kV FDR Y Protection	Relay Technology
CDIFF	IED	CDIFF	IED
Backup DIST Protection	IED	Backup DIST Protection	IED
CB Fail	IED	CB Fail	IED
DDR & Fault Location	IED	DDR & Fault Location	IED

Table 7.2: Transformer protection scheme and relay technologies at Whyalla Terminal substation

TF X Protection Scheme	Relay Technology	TF Y Protection Scheme	Relay Technology
CDIFF	EM	CDIFF	IED
HV REF	EM	Tertiary Winding OC	EM
LV REF	EM	HV OC	EM
Pressure Release Device	EM	LV OC	IED
Buchholz Protection	EM	Winding Temperature Y Protection	EM
Winding Temperature X Protection	EM	Oil Temperature Y Protection	EM
		DDR	IED

CDIFF, current differential; DIST, distance; IED, intelligent electronic device; CB, circuit breaker; DDR, digital disturbance recording; HV, high voltage; LV, low voltage; EM, electromechanical; OC, overcurrent.

the wires that require monitoring without disturbing the existing system. If there is any operation of the electromechanical relays, the SEM device would detect the DC current change and publish such information via GOOSE messages on the substation Ethernet LAN. The published GOOSE messages would be subscribed and interoperated by the modern IEDs at Whyalla Terminal substation to enable the communication and cooperation between the protective relays with different technologies. As a result, a completed protection system is established.

In addition, the SEM platform is capable of being synchronised on the same Ethernet LAN via IEEE 1588 standard. This feature will provide an overall system timestamp accuracy at ± 1 microsecond level to the translated tripping signals from electromechanical relays. Therefore, the proposed SEM application could enable a unified communication system in the brownfield application with lowered installation and wiring cost.

Another advantage of applying the SEM platform in brownfield application can be realised during system commissioning. The main purpose of the commissioning is to prove system-

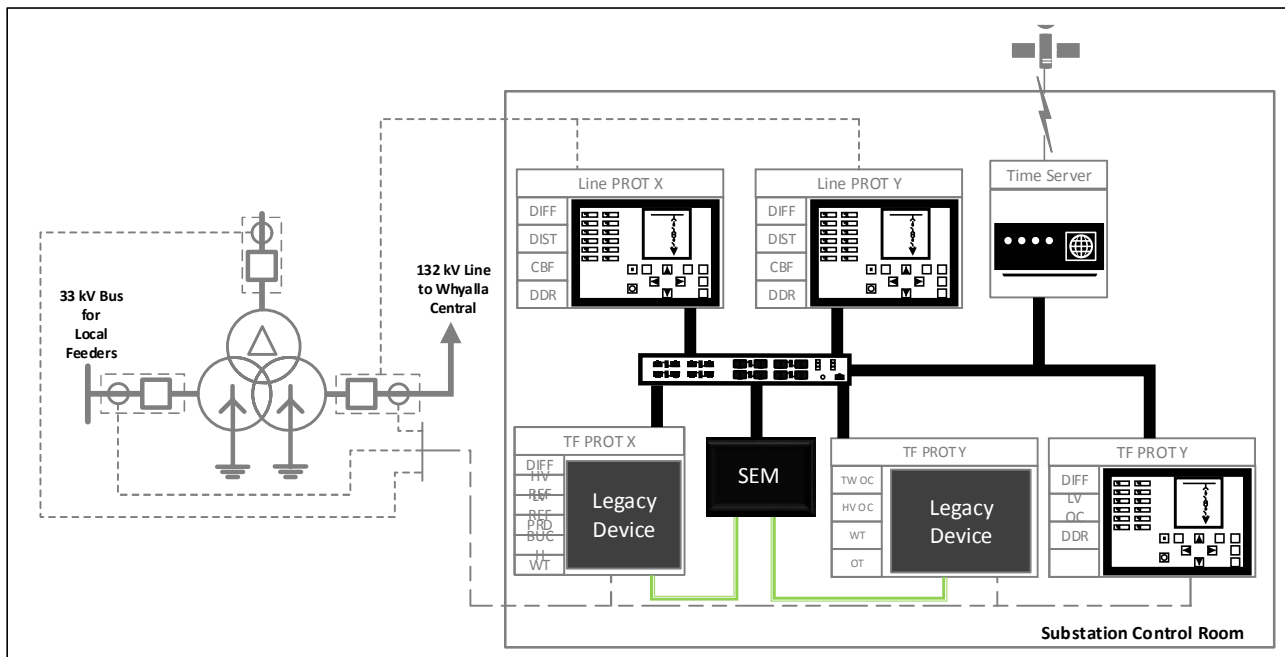


Figure 7.1: Demonstrated SEM application as communication interface

wide protection schemes are functioning as they are designed. As a general practice, the commissioning of SAS is divided into two stages, Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT). The purpose of FAT is to ensure the devices within the substation control building are operated according to the design intent. These tests are generally performed with the simulated analogue signals to the device(s) under the test. The process is from the verification of devices in isolation to the validation of inter-panel protection schemes. The purpose of SAT is to validate the integration of SAS devices and other necessary parties in a complete protection and operation scheme according to design intent, such as primary equipment, remote end substation and control centre. These tests are usually undertaken at substation and network scale.

For greenfield applications, the commissioning process is simply a number of logical procedures. In contrast, the commissioning of brownfield applications, especially with IEC 61850 standard implementations, requires more attention since the in-service devices are more sensitive to modifications. The best practice is to perform FAT testing in a duplicated laboratory environment. This is also critical for brownfield applications with mixed protective relay technologies. The developed SEM platform provides a distinctive advantage for this purpose. The SEM sensor can be applied as an attachment of the intermediate relay signals which are easily simulated in the laboratory environment. The monitored tripping signals are translated to GOOSE messages and acknowledged by other protection IEDs. Therefore, any incorrect tripping or logic mapping could be easily located and diagnosed in the protection system.

In addition, the developed SEM platform can also be applied as an extension of the I/O modules of the test set during commissioning. In a large hardwired protection and control system, it is possible that the number of the equipped I/O ports of the test set is not enough to verify a protection scheme. This will possibly lead to time consuming and complex commissioning procedures. The application of SEM platform translates the hardwired signals into GOOSE format without disturbing the existing wiring is a simple and effective solution for such issue.

7.2 Assistance in Network State Estimation

State estimation is critical in the operation of modern power systems (Zima-Bockarjova, et al., 2011). The centralised state estimation algorithm is executed based on the topology status collected from substations and the most recent analogue measurements. The use of new technologies in substations has enriched the information at substation level. This has enabled the concept of decentralised state estimation (Silva, et al., 2013).

In a decentralised state estimation architecture, the substation level information is processed locally with the advantage of much more detailed modelling of switching devices. The decentralised state estimation that have been proposed in recent literature are generally based on Weighted Least Squares (WLS) algorithm (Muscas, et al., 2014) (Pau, et al., 2013). Muscas *et al* (2014) further analysed the correlation between the traditional measurements and synchrophasor data. This analysis highlighted the importance of including such correlations in the weighting matrix of WLS to improve state estimation accuracy. The implementation of synchrophasor and micro-processor based IEDs in substations also has been proposed by other researchers in the literature in order to achieve the hierarchical state estimation. Although the decentralised architecture eliminates a number of deficiencies in current substation modelling, such proposal requires significant upgrade of existing equipment in substations which is difficult under the current economic environment. This difficulty, which has also been recognised by Yang *et al* (2011a) (2011b), is enlarged for brownfield applications. For this purpose, the implementation of SEM platform is proposed to produce substation level topology detection model based on connectivity analysis. An overview of this proposal for a brownfield application is illustrated in Figure 7.2.

The non-intrusive design of the SEM platform enables the monitoring of substation switching information without disturbing the existing equipment. Any status change event in a substation, which is always associated with a DC current change in the wiring, is

detected by the SEM platform and published on the substation's network. The collected information is fed to the substation model in conjunction with the local analogue analysis based on Kirchhoff's law equations. In the situation of outside measurements, the extra information is added in the analysis such that the current flow through an open switchgear is zero and the voltage difference across a closed switchgear is also zero. This process is similar to the introduced estimation by Yang *et al* (2011a). In the aspects of zero injection on a bus or feeder in a substation, the optimised weight factor in the local state estimation shall be evaluated in the future. By the supplement of this additional analysis, it is believed that the network observability analysis could be improved. As network observability risks are dependent on data redundancy where type and location of measurements in the network are important (Filho, et al., 2013), the application of this approach might also be required at the remote end substation(s) for brownfield projects. Furthermore, the highly accurate timestamps provided by the SEM platform also brings significant benefits for the synchronised sequence of substation events. Finally, the updated substation level state estimation information is transmitted to the utility control centre for further processing.

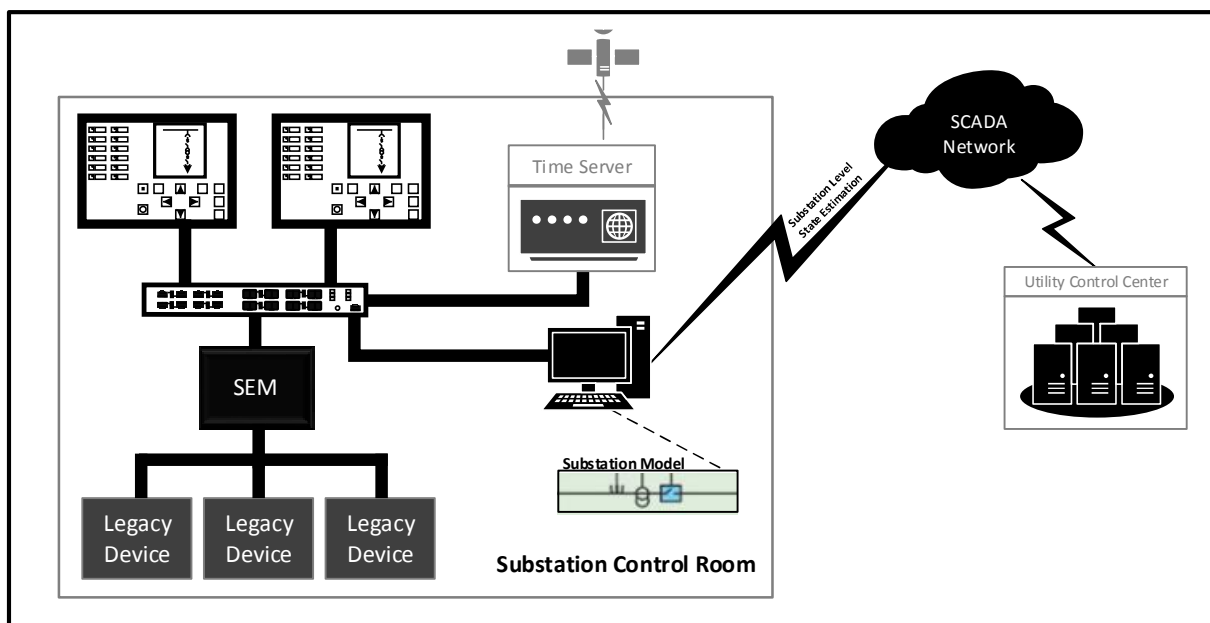


Figure 7.2: Overview of decentralised state estimation with SEM platform

7.3 Summary

This chapter described the possible applications for SEM devices with the emphasis on brownfield projects. Significant improvement can be made by applying the SEM device in partial secondary system replacement projects including non-intrusively event transferring and monitoring, as well as event timestamping with microsecond accuracy. The developed

device is also capable of assisting decentralised state estimation by providing accurate data of switchgear status. Along with additional information processing, the substation level state estimation can be generated and transmitted to utility control for further analysis.

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CHAPTER 8 CONCLUSION

The primary objective of this research is to enable the communication between legacy devices with the up-to-date IEC 61850 standard compatible substation automation system (SAS) devices. This is achieved via the novel development of substation event monitor that fulfils the requirements for typical brownfield applications in electric utilities. The performance of the created substation event monitor has been assessed in a number of aspects that encompass non-intrusive design, real time networking, IEC 61850 standard station level communication, precision timing and power system protection scheme interoperability.

The electricity industry is going through a challenging time period that is mainly due to the slower load growth, higher reliability requirement, tougher regulation policies and stronger present of public pressure for the increasing electricity price. This forces the electric utilities to carefully consider future network expenditure, such as greenfield applications. Conversely, utilities are expected to be much more involved in brownfield applications on its network in the foreseeable future. The fact that there are still a significant amount of legacy devices in service and they are capable of being in service for a long time creates the opportunity of developing the substation event monitor in order to interface the modern technology devices in brownfield applications.

The flexibility of the international standard IEC 61850, which is explained in great detail in Chapter 3, has enabled the creation of the device. The benefit and wide range applications of IEC 61850 standard that are reviewed in Chapter 2 has further confirmed the future trend of implementing the standard in electricity industry. The use of the standardised substation configuration language (SCL) is the foundation of achieving interoperability for the substation event monitor. The created IED capability description (ICD) file for the device is well understood by other vendor's configuration software. This has made the mapping of the desired information much more direct and effective. The comprehensive list of the standardised function descriptive logical nodes (LNs) in IEC 61850 standard provided a strong focus for the function that is translated by the substation event monitor. Although the prototype of substation event monitor has implemented the generic process I/O (GGIO) LN, it can be easily updated in its ICD file to the more suitable LN according to its interfaced

legacy device. Moreover, the direct mapping of the captured data to the underlying communication protocol has enabled fast exchange of information. This is particularly important for the translated tripping information due to its time critical nature. The interoperable generic object oriented substation event (GOOSE) messaging between devices from different vendors at station level also guaranteed the implementation of the developed device in brownfield applications.

Another objective of this research is to improve timing performance in existing electric substations. This is achieved through the implementation of IEEE 1588 standard in the design of substation event monitor. The horizontal comparison of the commonly used time synchronisation techniques, such as Network Timing Protocol (NTP), IRIG-B and 1-pulse-per-second (1PPS), was provided in Chapter 4. The most common technique, NTP, is not capable of achieving high level of synchronisation accuracy even though it is realised through Ethernet network and able to automatically compensate path delay. Both IRIG-B and 1PPS require dedicated cable for time synchronisation though they are able to reach the required time synchronisation accuracy with manually compensated time delay. In comparison with the previous technologies, the IEEE 1588 standard or precision time protocol (PTP) provides distinctive advantages. It is capable of achieving sub-microsecond synchronisation accuracy with the assistance of hardware timestamping feature which has been confirmed in Chapter 6. Another advantage of applying PTP is the fact that it is achieved through Ethernet network. This means no additional cable is required along with the implementation of IEC 61850 standard. The other advantage of the PTP is bi-directional synchronisation technique that leads to the capability of automatic path delay compensation. The application of transparent clock further strengthened this advantage with the requirement of employing PTP-aware devices in substation communication network.

8.1 Applications of the SEM Platform

This thesis presents two particular applications that are focused on brownfield projects in electric utilities. These applications and their implications are summarised with respect to the research questions introduced in Section 1.6.

How to bridge the gap of different communication capabilities between different generations of SAS device to maximise the benefits of implementing IEC 61850 standard in brownfield applications for electric utilities?

The substation event monitor, which is demonstrated in Chapter 5, is developed based on

the flexibility and interoperability of the international standard IEC 61850. The non-intrusive feature that is enabled by the use of Hall Effect sensor has been illustrated with potential applications described in Chapter 7. The evidence of interoperability between the substation event monitor and SEL-387 IED was validated in Chapter 6 provides strong confidence on the interoperability of the device with other vendor IEDs in substation applications. The implementation of both versions of IEEE 1588 synchronisation standards also ensures full compatibility with the standard without any further conversion.

The flexibility of the developed substation event monitor is also capable of being applied during substation commissioning process. This is a distinctive advantage for brownfield applications with mixed protective relay technologies. The use of substation event monitor is also a direct solution for the issue of limited I/O ports in the test set.

How to assist and enhance the network state estimation process for electric utilities by applying the created substation event monitor at substation level?

The critical role of state estimation in modern power system has been highlighted by Zima-Bockarjova *et al.* (2011). Although power system condition is in dynamic nature, the state estimation tool is usually operated based on the static model of the power system. The advent of new technologies enabled extra information at substation level and introduced the concept of decentralised state estimation. The use of substation event monitor for the collection of status information and generation of robust substation topology was proposed in Chapter 7. The non-intrusive feature of the substation event monitor is again a distinctive advantage to be applied in this application. The vendor independent IEC 61850 standard communication provides an easier way of collecting the status data in a substation. The advanced implementation of IEEE 1588 standard with overall ± 1 microsecond timestamp accuracy provides additional benefit on the organisation of substation sequence of events.

8.2 Out of Scope in the Current Study

The substation event monitor developed in this research project is not subjected to the evaluation under international standards. In order to prove the device is fit for the purpose in real applications, a number of tests must be undertaken. The tests might include electromagnetic compatibility emissions (IEC 60255-25), radio frequency immunity (IEC 60255-22-6), electrostatic discharge immunity (IEC 60255-22-2), fast transient immunity (IEC-60255-22-4) and surge withstand capability immunity (IEC 60255-22-1). The device shall be also verified under a set of environmental tests, such as cold temperature, cyclic

heat and dry heat tests under IEC 60068 standard. Vibration, dielectric strength and impulse tests are other important criteria of the substation event monitor.

8.3 Suggestions for Future Work

This research thesis has identified several areas in which further improvements are warranted. The electronic circuitry has been kept simple in the current research project. It is an improvement if the circuit is designed to remove the dependencies of the polarity of the Hall Effect sensor. The closed loop design for the Hall Effect sensor is also a potential improvement of faster response time. Due to the deficiencies of the modified IEEE 1588 device drivers in the embedded system, the synchronisation accuracy verification of the implemented PTPv2 software is limited through sample collection. The improvement of enabling the 1 pulse per second output signal from the IEEE 1588 header of the embedded system was noted in the thesis. This feature will secure the verification of time synchronisation accuracy in an established approach. It is also a significant improvement to fully implement MMS messaging for product monitoring and control functions. The verification of MMS communication shall be conducted using AX-S4 MMS IEC 61850 client software from SISCO (2015). It is also important to enhance user interfacing feature by providing necessary Light Emitting Diode (LED) indications in the final product. The developed substation event monitor is completed as a prototype in this research project. The final product of the device shall be fitted in a metal box with appropriate earthing. The integration and engineering process for brownfield applications shall be conducted in laboratory environment to ensure the correct system-wide functionalities. An end-to-end testing is also warranted for further integration with the SCADA system at utilities control centre. It is also important to further evaluate the optimised weight factor for the measurements in local state estimation in the situation of zero branch in the substation.

As the substation event monitor is considered as an IED, the lifecycle of the device is expected to reach 15-20 years which is similar to other substation automation system devices. Therefore, long term stability assessment including environmental factor verifications of the device subject to maintenance procedures is needed to determine if the device is capable of maintaining the required accuracy under rigours substation environment.

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APPENDIX A NATIONAL ELECTRICITY MARKET

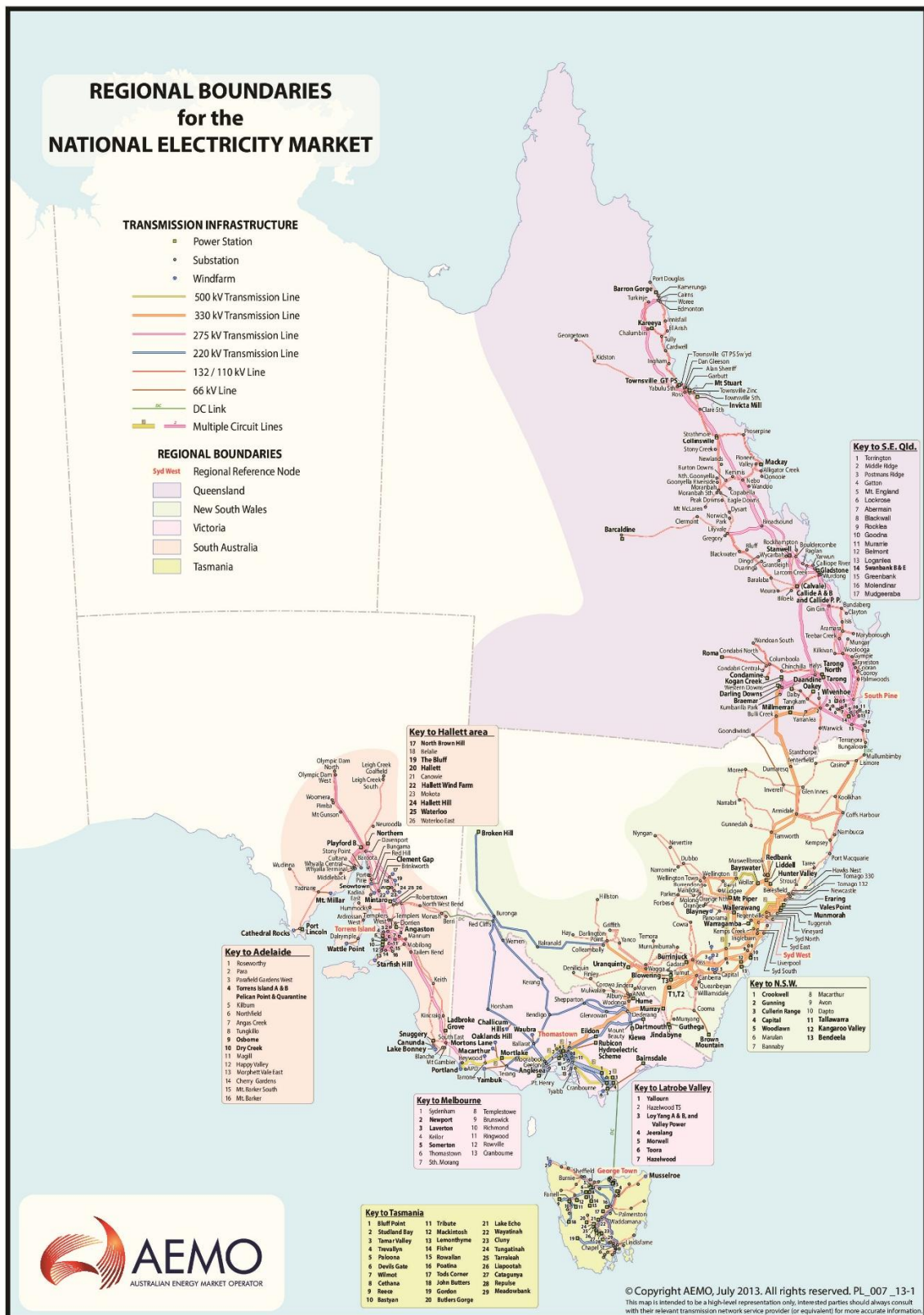


Figure A.1: Map of Australian National Electricity Market (AEMO, 2014)

© Australian Energy Market Operator (AEMO) 2014

APPENDIX B DATA ENCODING RULES FOR FIXED LENGTH GOOSE MESSAGES

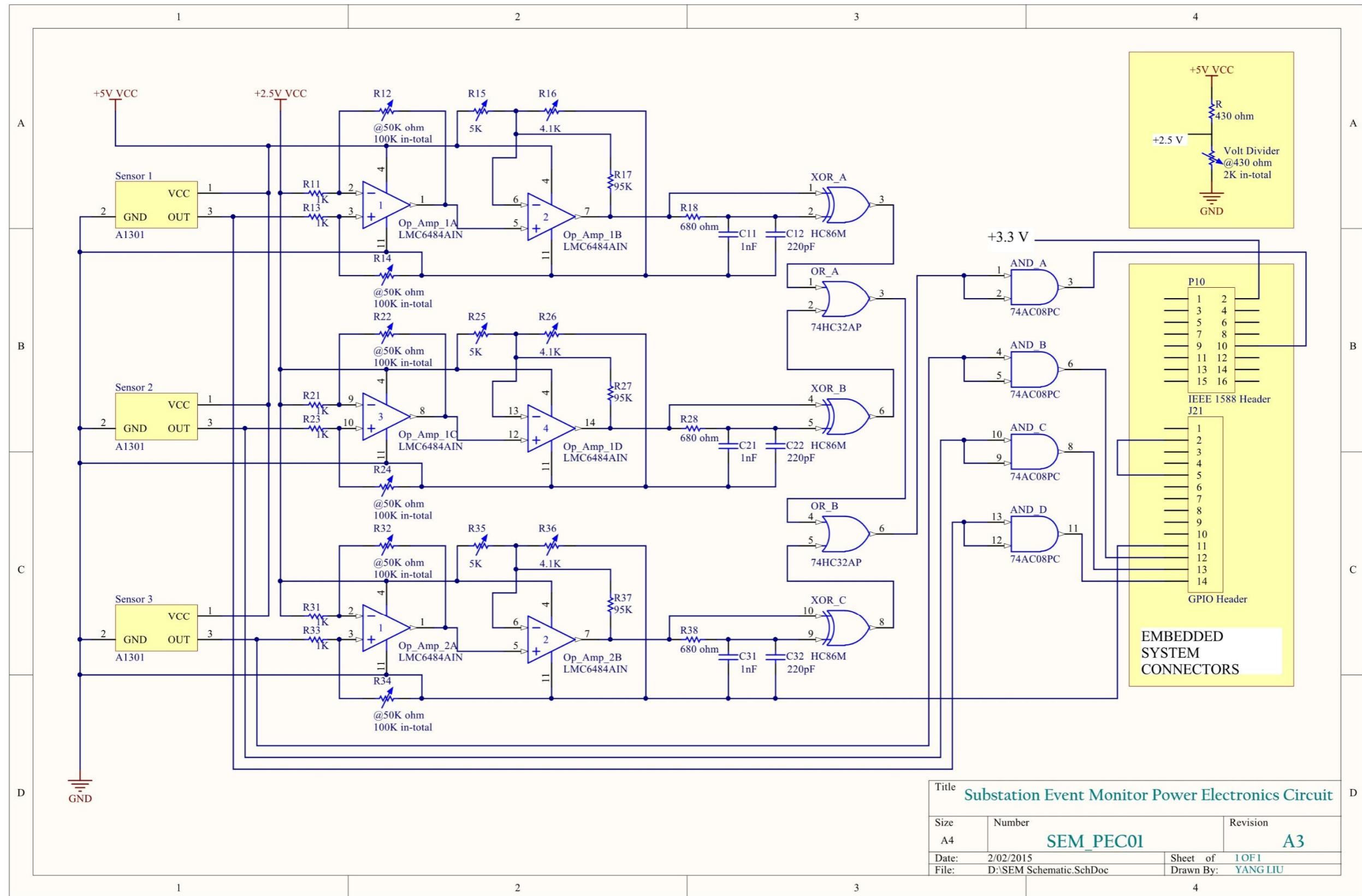
Table B.1: GOOSE PDU data elements encoding rules

GOOSE PDU Elements		ASN.1 Tag	ASN.1 Length (Byte)	Remarks
Attribute Name	Attribute Type			
goCBRef	Visible-	0x80		Length determined by
timeAllowedToLive	INT32U	0x81	5	Fixed size 32 bits unsigned
datSet	Visible-	0x82		Length determined by
goID	Visible-	0x83		Length determined by
T	UtcTime	0x84	8	64 bits timestamp value
stNum	INT32U	0x85	5	Fixed size 32 bits unsigned
sqNum	INT32U	0x86	5	Fixed size 32 bits unsigned
simulation	Boolean	0x87	1	8 bits set to 1 in testing
confRev	INT32U	0x88	5	Fixed size 32 bits unsigned
ndsCom	Boolean	0x89	1	Set to 1 if GoCB needs further
numDatSetEntries	INT32U	0x8a	5	32 bits show member num. in

Table B.2: GOOSE data encoding rules

Data Type	ASN.1 Tag	ASN.1 Length	Remarks
Boolean	0x83	1	8 bits to indicate value TRUE or FALSE
INT8	0x85	2	8 bits signed integer stored in Big Endian
INT16	0x85	3	16 bits signed integer stored in Big Endian
INT32	0x85	5	32 bits signed integer stored in Big Endian
INT64	0x85	9	64 bits signed integer stored in Big Endian
INT8U	0x86	2	8 bits unsigned integer stored in Big Endian
INT16U	0x86	3	16 bits unsigned integer stored in Big Endian
INT32U	0x86	5	32 bits unsigned integer stored in Big Endian
FLOAT32	0x87	4	32 bits floating point according to IEEE 754
ENUMERATED	0x85	2	8 bits signed integer stored as Big Endian
CODED ENUM	0x84	2	2 bytes bit-string determined by definition
OCTET	0x89	20	20 bytes ASCII (character encoded) text
VISIBLE	0x8a	35	35 bytes ASCII (character encoded) text
TimeStamp	0x91	8	64 bits timestamp value
Quality	0x84	3	3 bytes bit-string as defined in Part 7-3

APPENDIX C ELECTRONIC CIRCUIT BOARD SCHEMATICS



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