23rd April, 2012

Mr Simon Bartlett
Chairperson
E. S. Cornwall Scholarship Advisory Committee
PO Box 1193
Virginia QLD 4014

Dear Simon

Second Quarterly Report - E. S. Cornwall Memorial Scholarship – Sarah Hiley

Please find enclosed my second quarterly E. S. Cornwall Scholarship report outlining my period of employment from the 10th of January 2012 to the 10th of April 2012.

During the past three months with ABB, I have continued to work as the substation automation system engineer on two of the Powerlink iPASS upgrade projects – Millmerran and Bulli Creek. I am currently working in ABB's test field, undertaking system integration and testing for the Millmerran substation. In addition to this, I have undertaken system configuration work for four IEC 61850 substations being installed in the Middle East. I have also had the opportunity to witness on site commissioning testing for an IEC 61850 retrofit project and have visited the Laufenburg substation in northern Switzerland, which is the world's first high voltage substation to have been equipped with an IEC 61850 system.

It should be noted that due to the confidential nature of the work I have undertaken I am not able to include any technical information relating to ABB specific tools and processes or customer projects.

I welcome the committee's feedback on this report and my goals for the next quarter.

Yours faithfully,

Sarah Hiley

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1 Introduction

My program of work under the E. S. Cornwall Memorial Scholarship is aimed at gaining international experience in substation automation systems using the IEC 61850 standard. More specifically, the program focuses on gaining technical experience with the design, integration and testing of such systems whilst working for an international manufacturer, utility and consultancy firm. The program will also provide exposure to the challenges and issues that face organisations when adopting a new technology.

My tenure of the E. S. Cornwall Memorial Scholarship is from the 10th of October, 2011 to the 10th of April, 2013. My first nine month placement is with ABB Switzerland in Baden, where I am working as part of the Substation Automation System (SAS) Engineering and Test Team. During my time with ABB, my primary responsibility has been to undertake the system level detailed design, system integration and testing of two of Powerlink's iPASS IEC 61850 secondary system upgrade projects – Millmerran and Bulli Creek. I undertook the detailed design in my first quarter and I am now based in the ABB test field, having recently undertaken the system level configuration and testing for the Millmerran substation. In addition to this, I have also been involved with the system integration work for four new IEC 61850 substations being installed in the Middle East and have been able to witness the on-site commissioning testing for a IEC 61850 retrofit project at a European substation. I have also had the opportunity to visit the Laufenburg substation located in the north of Switzerland. This substation was the first high voltage substation in the world to be retrofitted with an IEC 61850 compliant system.

This report is the second of six reports and outlines the work that I have undertaken from the 10th of January, 2012 to the 10th of April, 2012. I have also included an appendix to give some background into the IEC 61850 standard, its advantages and areas of application.

2 Work Experience

My main responsibility this quarter has been working as the SAS engineer on the Powerlink iPASS upgrade projects. However, in addition to this work, I have also had the opportunity to work on and gain exposure to the IEC 61850 systems being installed by various power utilities in the Middle East and Europe. I will provide a high level overview of this experience in the following sections.

2.1 Powerlink Millmerran and Bulli Creek iPASS Upgrade Projects

The work that I have undertaken for the Powerlink iPASS projects this quarter has included finalising the detailed design (as discussed in my first report), attending numerous meetings, updating the systems based on feedback from the customer design reviews and simulating and testing the MicroSCADA for both Millmerran and Bulli Creek substations.

Manufacturing of the Millmerran system was completed in March and the system was delivered to ABB's test field. Since this time, I have been based in the test field and have undertaken the system integration, testing and ABB internal Factory Acceptance Testing (FAT) for the Millmerran system. I will discuss the system integration, testing and ABB FAT for both of the Powerlink projects together in my next quarterly report.

2.2 System Configuration Work for Middle East Utilities

I have been involved with the system configuration for four new IEC 61850 substations being installed in the Middle East for two different utilities. The work that I have carried out in ABB's test field for these projects consists of the set up and configuration of the IEC 61850-8-1 station bus network, which includes the following station level components:

- SYS600 Gateway devices (Windows 7)
- MicroSCADA front end station computers (Windows 2008)
- Engineering Workstation computers (Windows 7)
- Operator Workstation computers (Windows 7)
- Ruggedcom RSG2100 Managed Ethernet Switches
- Meinberg NTP Servers

This work has enabled me to gain a much better understanding of network concepts and protocols, which is critical when engineering and configuring IEC 61850 systems. I have also gained more insight into IEC 61850-8-1, the part of the standard that specifies the communication over the station bus. In this section, I will briefly discuss the IEC 61850-8-1 standard and the communication model that the standard uses. I will then describe the network configuration work that I have carried out for these projects and how it relates to this standard.

2.2.1 IEC 61850-8-1 and the OSI Model

The basic philosophy behind the IEC 61850 standard was to develop a domain related model for the data and communication services required for an application (e.g. for a substation automation system) that is independent of the communication protocols or stack used. This separation means that the standard can incorporate advances in communication technologies without affecting the domain data model. As communication technologies change at a much faster rate than the requirements for data exchange within a substation, this separation was critical to ‘future proof’ the standard. However, to ensure interoperable communication the standard must also specify the mapping between the data model and the communication stack. IEC 61850-8-1 is the part of the standard that handles this mapping. The data model and its services (i.e. standard methods to access the data) are defined in IEC 61850-7-x.

IEC 61850 uses mainstream technology for the communication stack. The structure of the stack is in accordance with the International Standardisation Organisation (ISO) Open Systems Interconnection (OSI) layers consisting of Ethernet (layers 1 and 2), TCP/IP, Transport Control Protocol / Internet Protocol (layers 3 and 4) and MMS, Manufacturing Messaging Specification (layers 5 to 7). (Refer to Figure 1)

IEC 61850-8-1 specifies how the objects and services defined in IEC 61850-7-x are to be mapped to MMS (layer 7). This mapping allows for the interoperable exchange of data between all kinds of utility devices over a Local Area Network (LAN). It should be noted that IEC 61850-7-x defines some services that are not mapped to MMS. For example, time critical services such as Sample Values (SV) and GOOSE are mapped directly to the Ethernet link layer (layer 2) and time synchronisation uses Simple Network Time Protocol (SNTP) for the upper layers and User Datagram Protocol (UDP) / IP for the lower layers.

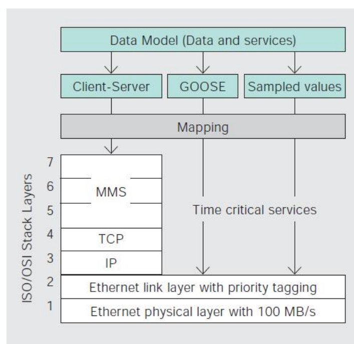

Figure 1 – IEC 61850 Mapping to the ISO/OSI Stack [1]

The OSI reference model is based on the concept of layering of communication functionality. It includes seven layers that each play a specific role when applications are communicating over a network. The following table describes the seven layers and gives examples:

OSI Layer	Description	Examples
Layer 7 - Application	Contains the applications which are used by the end-user such as MS Word, MicroSCADA etc.	Telnet, HTTP
Layer 6 - Presentation	Defines the format of the data transmitted to the applications including encryption, data compression/decompression etc.	JPEG, ASCII
Layer 5 - Session	Manages the access to the network; creates, maintains and manages end-to-end bidirectional data flows between endpoints	Operating Systems e.g. Windows
Layer 4 – Transport	In charge of the *delivery* of data; provides end-to-end error detection and correction	TCP, UDP
Layer 3 – Network	In charge of the *transmission* of data; handles the connection of the higher layers to the network	IP
Layer 2 – Data Link	Facilitates safe communication of data over the physical network. It combines bits into bytes and bytes into frames and provides error detection and error recovery. Access to media is through a MAC (Media Access Control) address.	ISO/IEC 8802.3 & 8802.2
Layer 1 - Physical	Defines the physical characteristics of the network; responsible for moving bits between devices	IEC 60874-10-1,2,3

The seven layers of the OSI model can be divided into two categories: application (upper layers) and transport (lower layers). The application layers deal with application issues and are generally only implemented in software. The transport layers handle data transport issues and are implemented in hardware and software. The lowest layer, the physical layer, is closest to the physical network medium and is responsible for actually placing information on the medium. Each layer on the OSI model generally communicates with three different layers: the layers directly above and below it and its peer layer in another device on the network. For data to be transmitted from an application in one device to an application in another device, it must travel down, step by step, through the layers of its own stack, travel across the network connecting the devices and then up the layers of the receiver's stack. Figure 2 below illustrates these concepts.

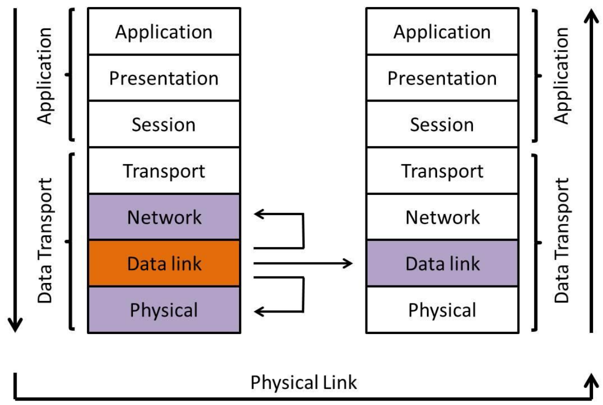

Figure 2 – OSI Reference Model

2.2.2 Network Configuration

With the uptake of the IEC 61850 standard, networks are now an integral part of a substation automation system. For example, the substations that I have been working on utilise a number of separate networks with different communication protocols as follows: (Refer to Figure 3)

- **IEC 61850-8-1 Fibre Optic Station Bus** – used for the exchange of data between different bay level IEDs and also between bay level IEDs and station level IEDs. Communication is conformant to IEC 61850 and based on the OSI 7 layer model. Typically, separate station bus networks are implemented for each voltage level.
- **Station Level Electrical LANs** – used to interconnect the subsystems at the station level including devices such as station computers, workstations, routers and printers. Communication is based on the TCP/IP 4 layer model and SNMP (Simple Network Management Protocol).
- **Network Level Communication System –** used to exchange data to and from a remote control authority. Communication is based on protocols such as IEC 60870-5-101, IEC 60870-5-104 or DNP3 (depending on the preference of the utility).
- **Time Synchronisation** – Required to ensure time synchronisation of IEDs. Communication is based on UDP/IP and SNTP.

The main network components are shown in Figure 3 below. When configuring these networks it is important to understand the function of each network device, the protocols used and which level/s of the communication stack the device operates on. The following provides a high level overview of the configuration work that I undertook for the main network devices.

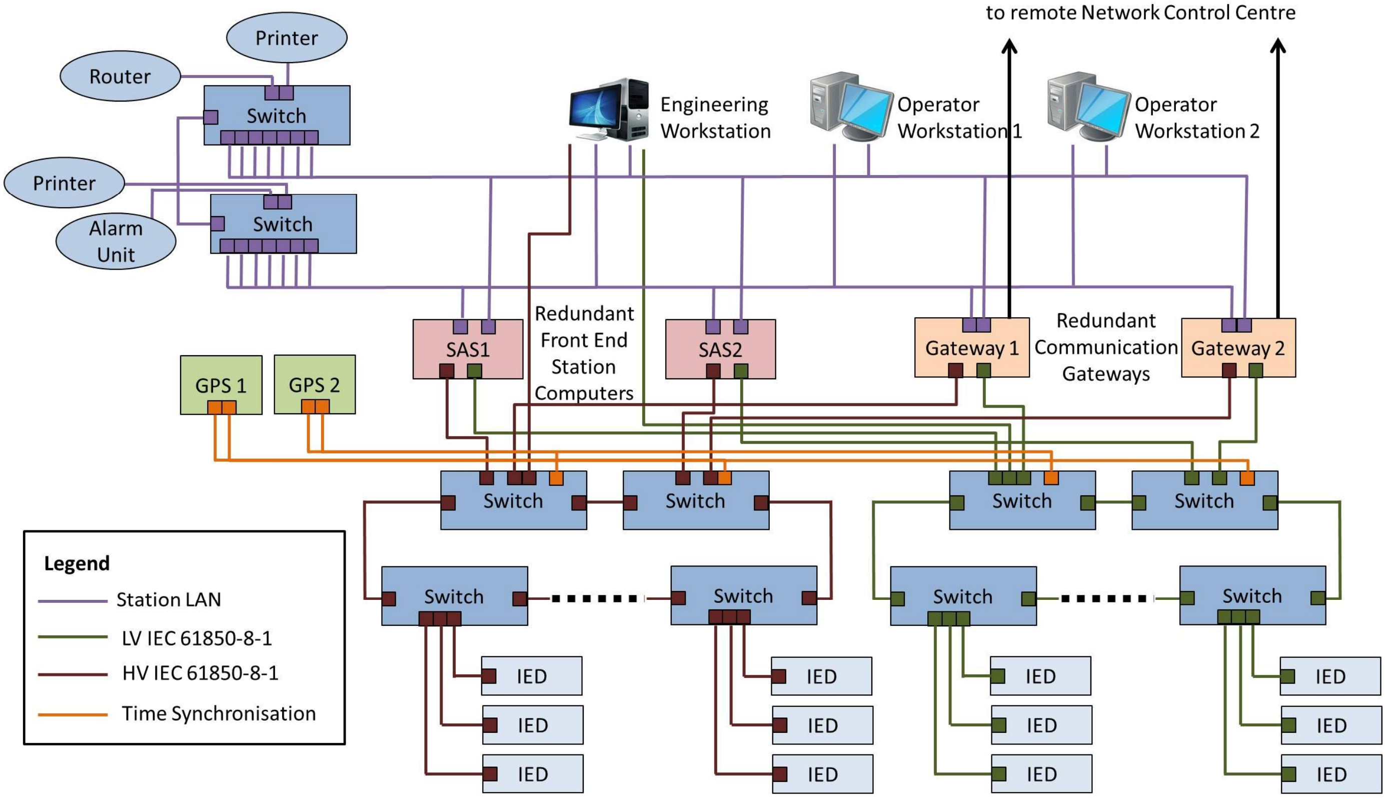

Figure 3 – Example of an IEC 61850-8-1 Substation Automation System

<u>Computers & Gateways</u>

The substations that I worked on contained seven computers: two MicroSCADA front end computers, two operator workstations, two SYS600 gateways (for communication to the remote network control centre) and one engineering workstation. Although these computers serve different functions and are therefore set up with different operating systems and applications, the initial configuration work that I carried out is similar and will be discussed together in this section.

Computers operate on all seven layers of the OSI model and require the most time to configure. Once the hardware has been set up, the first step is to configure the Basic Input Output System (BIOS) settings and check the Redundant Array of Independent Disks (RAID) settings. The BIOS defines the firmware interface. The BIOS software is built into the PC and is the first code run when the computer is powered up. Firstly it conducts a Power On Self-Test which identifies and initiates system devices e.g. Central Processing Unit, Hard Disk Drive, keyboard etc. and then searches for the Operating System and starts it. (In other words, the computer is running through the first five layers of the OSI model.) The BIOS has a user interface (accessible during start up) that allows the user to configure hardware, enable/disable system components, set boot device priority order, set the system clock etc. RAID is a data storage scheme that manages the division or replication of data among multiple physical drives. In this case, the RAID 1 mirroring method is used where two disks are written with the same data simultaneously. The advantage of this method is that in the case of a disk failure, the data remains online and available at all times.

Once the BIOS and RAID configuration has been done, the next step is to install and configure the operating system. This includes creating user accounts, setting up all required services such as Terminal Services and SNMP, security settings, installing / updating hardware drivers etc. For these projects, Windows 2008 was used for the MicroSCADA front end machines and Windows7 was installed on all other machines. Once the operating system is set up, all other required applications e.g. MicroSCADA, SNMP and IEC 61850 OPC servers, backup software, adobe, WinZip etc. need to be installed and configured.

In order for a computer to communicate over an Ethernet network it must be equipped with a Network Interface Card (NIC). A NIC runs on OSI layer 2 and therefore has a hardware decoded Media Access Control (MAC) address. (A MAC address is a unique number that is assigned to each Ethernet interface at the time of manufacturing. This number uniquely defines a device in a network e.g. a NIC or a switch.) Configuration of the network cards involves installing the appropriate hardware drivers, setting IP addresses and subnet masks, teaming or bridging ports where required and setting network properties such as speed, duplex, name, location etc. For example, the majority of the computers that I configured had two on board ports and three additional single port NICs. The on board ports were connected to the two separate redundant station LANs and teamed together. Teaming is required when two ports are connected to the same sub network. It is used to handle the redundant connection and port switchover if one of the networks fails. The three additional NICs were used to connect to the IEC 61850 networks. One card was connected to the low voltage IEC 61850 station bus and the other two cards were used to connect to the two high voltage IEC 61850 networks.

Switches

For the projects that I have worked on, the communication infrastructure of the IEC 61850-8-1 station bus consisted of a fibre optic, managed switched Ethernet LAN in a fault tolerant ring configuration. This configuration utilised IEEE 802.3 compliant Ruggedcom RSG2100 Managed Ethernet Switches. In this type of communication network the Ethernet switch plays an important role and dominates the performance of the system. Therefore, the correct configuration of these switches is critical in order to satisfy performance and redundancy requirements.

All switches in a substation automation system are of the managed type, meaning that they require a combination of global and local parameters to be set for their configuration. These switches are required to operate on the transport layers of the OSI model and require both a MAC address and an IP address. All IEC 61850 client-server traffic that is mapped to MMS is based on point to point TCP/IP i.e. not IP multicast. In other words, the switch is required to read the destination IP address of the data frame and only forward the data frame to the port where the device with the destination IP address is connected. IEC 61850 GOOSE and Sample Value (SV) services on the other hand use MAC multicast addresses where a switch, by default, forwards data to all ports. It is possible, however, to implement multicast filtering, where data frames can be forwarded to specific ports, thereby reducing unwanted traffic through other devices. The switches are set up to give priority to GOOSE and SV traffic to ensure that these time critical services are not delayed by TCP traffic. These switches also support SNMP for network management and SNTP for time synchronisation.

The easiest way to configure these switches initially (i.e. before an IP address has been set) is to connect a computer directly to the switch (through the serial COM Port) and use a terminal emulator such as Hyperterm. Once an IP address has been set, the switch configuration can be easily changed remotely using applications such as a web browser or Telnet. The main areas to configure include:

- IP addressing
- Port configuration e.g. speed, duplex etc.
- Traffic priority configuration
- Virtual LAN configuration for traffic segregation
- Redundancy protocol configuration e.g. Rapid Spanning Tree RSTP
- Time synchronisation
- SNMP
- General parameters such as user accounts etc.

It should be noted that although the fundamental switch functionality and configuration issues are similar for switches from different manufactures, the individual parameters and the configuration technique varies greatly between different vendors.

Time Synchronisation

Time synchronisation is a critical part of substation automation systems. For time synchronisation, IEC 61850 uses Simple Network Time Protocol (SNTP) for the application layers of the OSI stack and UDP/IP for the transport layers. Unlike TCP, UDP does not implement error detection or verification and is therefore very fast, making it ideal for sending time synchronisation data.

The IEC 61850 systems that I have been working on use GPS timeservers from Meinberg to achieve time synchronisation. These timeservers have direct LAN connections which are used to synchronise several clients with SNTP. Configuration of the GPS timeserver is relatively straightforward. Firstly, the IP address for each port must be configured from the front panel. Once this is done the GPS can be configured remotely using a web browser application. It should be noted that NTP is based on Coordinated Universal Time (UTC) and therefore the time zone and daylight saving must be configured for each network device or client.

2.3 IEC 61850 Commissioning Testing for European Utility

I have also had the opportunity to be involved in the IEC 61850 commissioning testing of a bus section bay for a European utility. This work was one stage of a large scale project to retrofit the entire substation automation system with IEC 61850 technology. The system consisted of an IEC 61850-8-1 station bus in a fault tolerant ring configuration. ABB devices were installed for control and Main1 protection and third party devices were installed for Main2 protection. The station bus was used to transmit reporting and monitoring data using MMS protocol. GOOSE messaging was not implemented in this case due to difficulties interfacing with the existing system throughout the staged retrofit.

I was able to accompany the lead engineer on site and observe the various commissioning procedures and testing that took place. In particular, I was involved with the SCADA testing from the remote network control centre. Through this experience I was able to gain a good understanding of the overall IEC 61850 system being implemented for this utility and a better appreciation of the different testing methods and commissioning procedures used. All testing ran smoothly with no significant issues or problems arising and the bus section bay was successfully commissioned on time.

3 Observations

Working on and observing the projects being implemented by ABB for different utilities has enabled me to gain a better insight into IEC 61850 development and implementation across the international power community. Most of the systems being implemented by ABB are now IEC 61850-8-1 compliant, showing worldwide acceptance of this part of the standard. The majority of these systems use third party devices demonstrating the success of the standard in terms of interoperability. It is clear from these projects that the IEC 61850 standard has already brought significant benefits to power utilities in terms of interoperability and ease of engineering and maintenance; however, there is still a long way to go in this development with many potential benefits still to be realised. The following sections discuss some technical observations in terms of system architecture and interoperability.

3.1 IEC 61850 System Architectures and Redundancy

The majority of the IEC 61850 systems that I have been exposed to, including the Powerlink projects, utilise a separate station bus for each voltage level that consists of a fibre optic, managed, switched Ethernet LAN in a fault tolerant ring configuration. Each control and protection IED is connected to an Ethernet switch in a star topology (refer Figure 4). Usually, there is an Ethernet switch for each bay. To connect the IEC 61850-8-1 station bus to the station level devices (i.e. station computers and Network Control Centre (NCC) gateways) a root switch and a backup root switch are installed in the station panels to facilitate dual connections between these devices for increased availability.

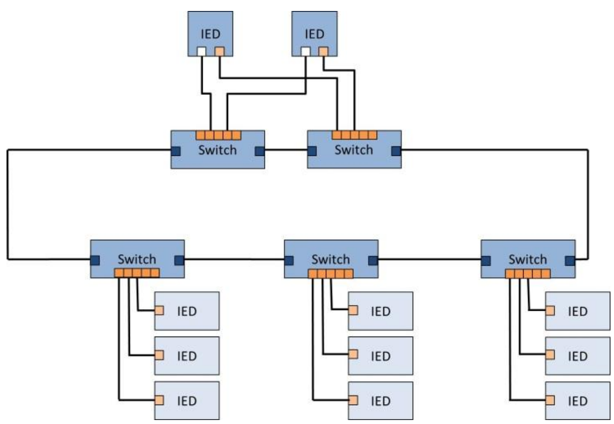

Figure 4 – Fault Tolerant Ring Configuration

Although the ring topology has been widely accepted throughout the world it does present limitations in terms of redundancy. Firstly, in this configuration only part of the network is redundant. The network offers redundant links and switches; however, the control and protection IEDs are individually connected to the switches through non-redundant links. Secondly, one switch connection within the ring must always remain open to prevent endlessly circulating telegrams. If a failure in any of the ring links or in a switch is detected, the normally open switch connection is closed. The most common method to manage this automatic reconfiguration (that I have observed) is the rapid spanning tree protocol (RSTP). The downside of this arrangement is that it results in a significant recovery time (possibly up to one second depending on the size of the network and the devices used). This recovery time has proven to be too slow for the most demanding applications.

I have been fortunate to gain exposure to some IEC 61850 systems that trialled a relatively new IEC 61850 redundancy protocol (introduced in IEC 61850 edition 2) called Parallel Redundancy Protocol (PRP). In this protocol, each IED has two identical Ethernet ports for the one network connection. All transmitted information and data is duplicated and sent over two independent, physically separated networks (refer Figure 5). These networks are powered by separate supplies and no direct connection is made between them. Unlike RSTP, PRP does not change the active network topology and therefore, it can ensure a zero-switchover time when a link or switch fails. The key difference is that PRP implements redundancy functions in the end nodes rather than in the network elements. PRP offers an effective solution that can meet the demanding, real-time requirements of substation automation.

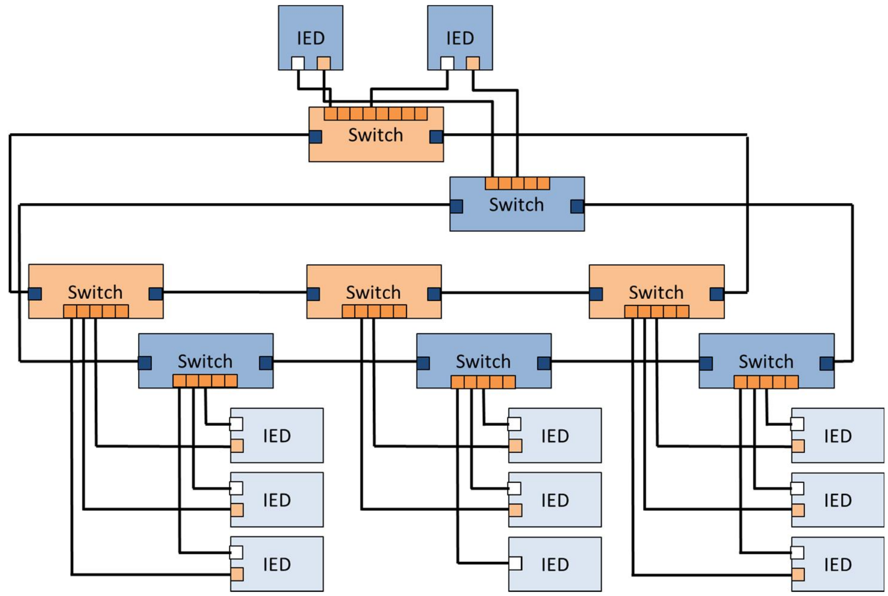

Figure 5 – Parallel Redundancy Protocol (PRP) Configuration

3.2 Interoperability

Interoperability was one of the most important goals of the IEC 61850 standard identified at its inception. In the context of a substation automation system, interoperability means that IEDs from different suppliers or different versions from the same supplier must be able to exchange and use information in real time without any protocol converters and without the need for human interpretation. This simplifies engineering and results in significant cost savings as there is no longer the need for protocol conversions. The majority of the systems that I have worked on successfully incorporated third party devices with no communication incompatibilities. It has been interesting to see this interoperability first hand and also the benefits in terms of ease of engineering.

IEC 61850-6 specifies a Substation Configuration description Language (SCL) that allows for the data exchange between tools from different manufacturers. This means that if a third party IED is specified according to IEC 61850, its ICD file (IED Capability Description) can be exported from a third party tool and imported directly into ABB’s system configuration tool where the IEC 61850 dataflow engineering can be carried out. This significantly simplifies system engineering and allows for more comprehensive data access to the third party devices. Although this process currently works effectively, manufactures are continually developing and improving their IED and system configuration tools to remove limitations and ensure that the engineering process is as straightforward as possible.

4 Laufenburg Substation Visit

This quarter, I was very fortunate to have the opportunity to visit the Laufenburg 380/220 kV substation, the first high voltage substation in the world to be equipped with IEC 61850 technology. It also boasts the world's first IEC 61850 multivendor implementation. Laufenburg substation is located in the north of Switzerland and is a very significant grid node in the European connected system (Refer Figure 6). It was built in 1967 with the inception of the European grid and was named 'Star of Laufenburg' as it forms the interconnection between the French, German and Swiss 380 kV networks. It is a triple busbar configuration with transfer bus. After almost forty years of operation, both the primary and secondary equipment needed to be replaced prompting its owner, the Swiss utility EGL, to commission ABB to commence a staged retrofit of primary and secondary equipment starting in 2004. Since 2004, the following refurbishment work in three main stages has been undertaken:

Stage 1 – retrofit of primary and secondary equipment

Stage 2 – replacement of old station HMI

Stage 3 – pilot project for IEC 61850-9-2

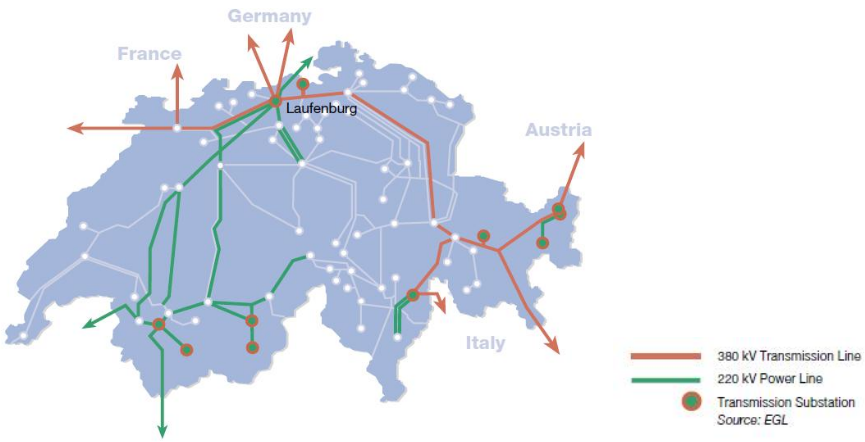

Figure 6 – Swiss High Voltage Network

The site visit provided an excellent opportunity to see the new IEC 61850 system in operation and gain an appreciation for both the primary and secondary system refurbishment work that has been carried out over the past eight years. I also had the opportunity to talk to one of the lead engineers from the customer company (originally EGL now Axpo) who has been involved with this project since its inception. He was able to offer a great deal of insight into the new system, the project implementation process, problems encountered and the final outcome.

Stage 1 – Bay Retrofit

The primary and secondary equipment of all seventeen feeders at Laufenburg have now been replaced. This work was done by ABB over several years, in a number of separate portions and in a bay-by-bay manner to minimise interruptions to the network. The primary equipment was replaced with a compact, hybrid gas insulated switchgear (GIS) module, incorporating the circuit breaker, line isolator, earth switch and current and voltage transformers. For the secondary system refurbishment, EGL required a future proof concept that would meet current and future requirements in terms of efficient operation, high functionality and open integration. For this reason, the utility chose to implement an IEC 61850 compliant system.

The first portion of this work involved the refurbishment of five line bays, one transformer bay and one bus coupler and the associated secondary systems, over a two year period, from 2004 to 2006. At this point, the existing third party station level equipment needed to be retained and therefore had to be interfaced to the new

IEC 61850 control and protection system. In addition to this, EGL required integration of third party Main2 protection.

The substation automation solution implemented by ABB to meet these requirements consisted of an IEC 61850 compliant Ethernet ring for serial communication between the bays and to the existing third party station bus (via a gateway for protocol conversion) (Refer to Figure 7 below). A single GPS receiver was connected to the Ethernet ring for the time synchronisation of all connected IEDs. IEC 61850 compliant ABB devices were implemented for control and Main1 protection with IEC 61850 compliant Siemens devices for Main2 protection.

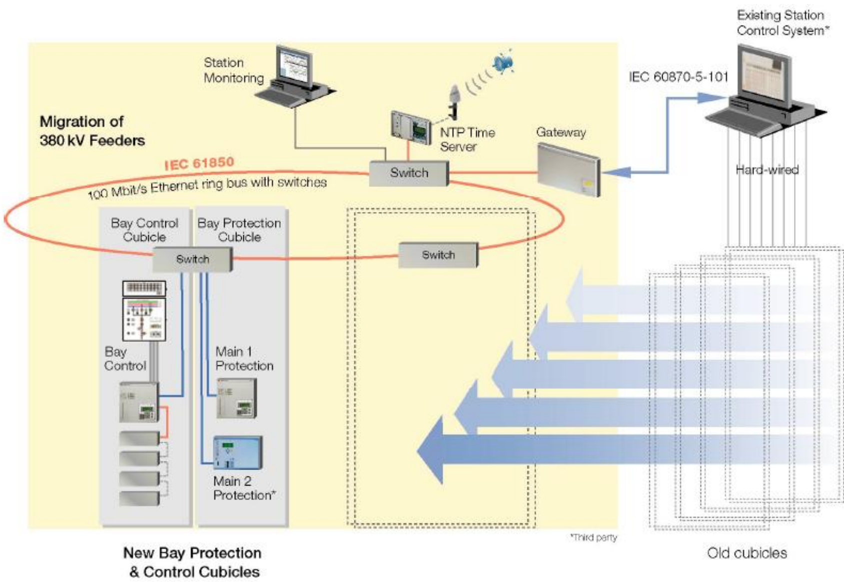

Figure 7 – Overview of the new staged IEC 61850 substation automation system configuration [5]

Due to the nature of IEC 61850, the remaining bays were easily upgraded and integrated into the new system. This solution also facilitated a trouble free integration of a new IEC 61850 station level in the future. IEC 61850 also simplified the integration of the third party devices and resulted in more comprehensive data access. The third party devices were specified and provided with an interface according to IEC 61850. This means that their data model and services were specified in an IED Capability Description (ICD) file as per IEC 61850. To integrate these devices, the ICD files could be simply imported into the system configurator tool to create the overall Substation Configuration Description (SCD) file. This eliminates costly protocol conversions and overcomes the data access restrictions imposed by proprietary standard protocols.

The first stage of the Laufenburg retrofit was successful and the project goals were fully achieved. Since this time, the system has been stable and operating with high performance. This initial installation proved to be a very valuable experience for both ABB and EGL, as well as the international power community in general. The lessons learnt from the initial installation provided a solid foundation to undertake the upgrade of the remaining bays. All remaining 380kV substation bays have now been successfully upgraded.

<u>Stage 2 – Station Level Replacement</u>

In 2007, EGL commissioned ABB to replace the old station HMI with a new IEC 61850 compliant HMI. The works for this stage were greatly aided by the use of the SCD file generated for the bay retrofit.

Stage 3 – Introduction of the Process Bus

In 2009, ABB commissioned a pilot process bus installation at Laufenburg. On the primary side, the installation consists of a combined and fully redundant CP-3 current and voltage sensor with merging units for protection and metering. On the secondary side, a REL670 line distance protection IED and a REB500 busbar protection system with three bay units was installed. The pilot has been running in parallel to the conventional system and has been in continuous operation since 2009 providing valuable field experience.

Advantages Gained from IEC 61850

The IEC 61850 installation at Laufenburg has proven to be very successful and a number of advantages over a conventional proprietary system were realised by EGL. These advantages include:

1. Ease of engineering and integration of third party devices and existing equipment. The integration of third party Main2 protection devices with ABB control and Main1 protection devices posed no problems and did not require any costly protocol conversion.

2. The complete substation is now documented in a SCD file in a standardised way, which is an advantage for future maintenance and extension projects. Due to this, EGL was able to put out an open tender for the station level / HMI upgrade instead of being restricted to the original manufacturer.

3. IEC 61850 provides a 'future proof' solution that can manage the differing lifecycles of bay level, station level and communication technology.

4. IEC 61850 was found to simplify FAT as formal checks and testing against the SCD file could be carried out during the design phase. SAT testing was also simplified as once the external interfaces have been correctly connected, the data consistency and the logical behaviour of the functions cannot deviate from the known FAT state. (Only the overall performance of a small number of functions can be impacted by the connection to the external equipment.)

5 Planned Future Experience

Throughout my second quarter with ABB I have been predominantly based in the test field, undertaking system integration and testing for a number of substations in the Middle East and also for Powerlink's Millmerran substation. In my final three months with ABB, my main responsibility will be to carry out the system level configuration, testing and ABB internal FAT for Powerlink's Bulli Creek Substation. This will provide further insight into the setup of IEC 61850 systems and the different testing methodologies. I am also hoping to have the opportunity to be involved with bay level testing, in addition to doing the system level testing, which should afford a better insight into the protection and control devices and the communications across the station and process buses. Once testing is complete for the Powerlink projects, I will be responsible for preparing the system level test reports and finalising all system level design documentation.

Appendix A – Background of the IEC 61850 standard

(This section was taken from my scholarship proposal document and was written before I commenced work with ABB.)

Substation automation systems are continually changing and advancing with the development of new electronics and communication technologies. The adoption of software based substation automation systems connected by serial links rather than rigid parallel copper wiring have become common practise worldwide. Although very successful, these systems were based on either the manufacturers' own proprietary communication solutions or communication standards such as DNP3 or IEC 60870-5-104. These solutions have made interoperability between devices from different suppliers extremely difficult and costly, if not impossible.

In 2004, international suppliers and utilities came together and developed a solution to this problem in the form of IEC 61850, an international standard that defines communication in and between electrical substation automation systems. The goal of the standard is to facilitate interoperability of substation devices while simplifying engineering and maintenance. This means that utilities can install IEDs from different suppliers on the same network without concern for communication incompatibilities and the digital system can easily facilitate system expansion without major hardware changes.

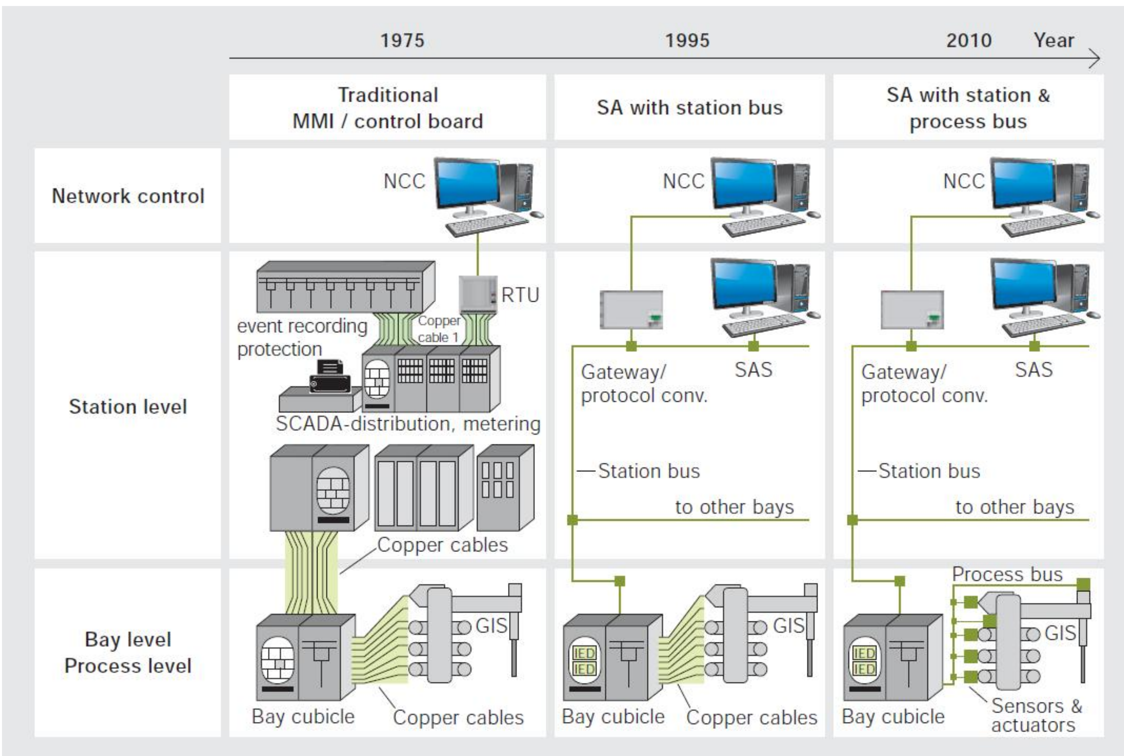

Figure 1: Development of Substation Automation Systems [1]

IEC 61850-8-1 defines the communications service over the station bus. The station bus connects the IEDs for protection, control and monitoring with station level devices such as the station computer with HMI (refer Figure 1). Since the publication of the standard in 2004, the implementation of IEC 61850-8-1 has advanced at a remarkable pace with hundreds of installations in operation worldwide proving the standard's success. IEC 61850 has received widespread acceptance and has become a standard requirement in specifications of high voltage substations [2].

The latest step in substation development comes with the introduction of IEC 61850-9-2 ("9-2"), the standard that defines the communications service over the process bus. The process bus connects the high voltage plant with the station level IEDs (refer Figure 1). IEC 61850-9-2 is the part of the standard that brings NCITs into play, eliminating the constraints of conventional iron core CTs and VTs and allowing the full benefits of IEC 61850 to be realised. NCITs have been successfully field tested for decades but have never gained widespread acceptance for protection applications as they provide sensor specific signals instead of the standardised 1/5A and 110V/220V for current and voltage respectively [1]. IEC 61850-9-2 overcomes this issue by providing a standard, cost effective, digital interface. Process bus is a very promising technology that has the potential to bring extensive benefits and cost savings to utilities, including:

1. Massive reductions in secondary cabling as hundreds of copper cables can be replaced with a few fibre optic communication cables, simplifying design and resulting in considerable cost savings in terms of cables, trenches and installation material.
2. Substation footprints can be reduced substantially, since NCITs can replace conventional measuring transformers. This will have the greatest impact on substations with Air Insulated Switchgear (AIS) as the measuring transformers can now be integrated in the CB or DCB. This also decreases costs associated with foundations and support structures.
3. Improved system performance, as NCITs eliminate the problems associated with conventional CTs and VTs such as saturation, Ferro resonances and magnetising losses.
4. On site testing will be greatly reduced and more thorough testing can be done at the factory.
5. Changing to NCITs will increase personnel safety since there will be no risk of injuries caused by CT secondary circuits and no risk of NCIT explosion.
6. For retrofit, the possibility of installing the new 9-2 process bus system in parallel with the existing system will allow the substation to remain in service while the majority of work is carried out. This is a big advantage as outages can be reduced to a minimum.

Today, pilot projects utilising the process bus are already in operation throughout the world and the execution of the world's first commercial project based on IEC 61850-9-2 LE[1] (light edition) by ABB for Powerlink Queensland has been successfully commissioned.

Industry Wide Applications

As discussed above, the IEC 61850 standard was originally defined exclusively for substation automation systems (including protection applications) however, this is far from the conclusion of its development. The standard has been extended to meet the requirements for almost the whole electrical energy supply chain including control and monitoring of wind power systems, hydro power systems and distributed energy resources [1]. The application of IEC 61850 to distributed energy resources indicates the significance of the standard to smart grids. Thus, in the future, IEC 61850 will extend far beyond substation automation applications and will have the potential to bring significant benefits to almost every sector of the Queensland power industry.

International Experience with IEC 61850

Since the publication of IEC 61850 in 2004, hundreds of substations worldwide have been installed or retrofitted with IEC 61850-8-1 station bus systems demonstrating the huge success of the standard in terms of interoperability and simplification of design and maintenance. The Swiss utility Elektrizitats-Gesellschaft Laufenburg AG (EGL) with ABB as system integrator, were the first to equip a high voltage substation with an IEC 61850 automation system, doing so shortly after the release of the standard and even opting for a multi-vendor solution integrating Siemens protection in the ABB system [3]. Since the premier of Laufenburg in 2004, more than a thousand systems and a vast number of products have been delivered to around 70 countries, resulting in international manufacturers and utilities gaining comprehensive experience with IEC 61850-8-1 through new installations, retrofit and migration projects [1].

Manufacturers such as ABB, Siemens and Alstom (previously Areva T & D) are leading the way with IEC 61850 development and a number of utilities have been very progressive in implementing multi-vendor IEC

[1] IEC 61850-9-2 LE (light edition) refers to a vendor agreed subset under the umbrella of the utility communication architecture (UCA) foundation.

61850-8-1 systems and developing comprehensive design solutions for the implementation of 9-2 process bus systems. The Middle East has been a rapid adopter of IEC 61850-8-1 systems with a large number of installations in a number of countries including the United Arab Emirates (UAE), Saudi Arabia and Bahrain. To meet continuous demand growth, the Dubai Electricity and Water Authority (DEWA) alone has been building approximately 10-12 new GIS substations based on IEC 61850-8-1 each year for 5 years [4].

As well as gaining extensive technical experience with IEC 61850, utilities and manufacturers across these regions have faced the organisational and managerial challenges that have accompanied this paradigm shift and have implemented structural changes, training and management procedures that have allowed the successful implementation of a large number of IEC 61850 projects. Widespread commercial adoption of the process bus has not yet taken place, however utilities are executing an increasing number of pilot installations in order to gain experience.

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