University of Southern Queensland

Faculty of Engineering and Surveying

The Skid Mounted Substation

A dissertation submitted by

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Courses ENG4111 and ENG4112 Research project

towards the degree of

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Abstract

The research undertaken has collated a broad range of technologies and provided a guide to assist the development of a new improved 66/11 kV skid mounted substation. This dissertation investigated the impact of modern secondary systems in substations to utilities and, takes a look at different approaches used by electricity services providers, for migrating from today's system to the future ones, typically using Supervisory Control and Data Acquisition (SCADA) communication systems incorporated with IEC 61850 protocols. This report covered most of the technical constraints associated with IEC 61850 standards and also explained the impact it might have on 66/11 kV skid mounted substation design, construction and operation. The implementation of IEC 61850 standards is possible if it meets the various challenges facing the current distribution network systems.

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ENG4111 Research Project Part 1 &
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Signature

___________27/10/2011_______________

Date

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Table of content

List of figures

List of table

Dissertation layout

Chapter 1: Introduction to general overview about existing 66/11 kV Skid Mounted Substation

Chapter 2: Described the development of Gas insulated switchgear (GIS) technology and the types of circuit breaker.

Chapter 3: Concerns with new improved 66/11 kV skid mounted substation design based on the concept specifications and changes recommended for switchgear, interfacing of the SCADA control and communication into the control centre and complying with the general intent of the specification for substations requirements.

Chapter 4: Provides details of a modern communication technology, the IEC 61850 standards and its impact on substation design, construction and operation.

Chapter 5: Discuss the outcomes and recommendation in both chapter 3 and chapter 4.

Chapter 6: Overall conclusion and future research.

Chapter 7: Appendixes

Chapter 8: References used.

Chapter 1

This chapter introduced background information about the existing 66/11 kV skid mounted substation in terms of structure, fundamental, component, interface, function and communication.

1. Introduction

The aim of this research is to develop a new improved 66/11 kV Skid Mounted Substation a re-locatable small scale Distribution Substation with a capacity of 10 MVA. The design is based on the concept specifications and changes recommended for switchgear interfacing with the SCADA control and communication systems.

This dissertation cover challenges facing the current 66/11 kV skid mounted substations such as dismantling of outdoor circuit breaker. It will analyse and investigate the advantages and disadvantages of both the use and impact of available communication technologies inside and outside the skid mounted substation. The improved design will incorporate features such as Gas Insulated Switchgear (GIS) and Supervisory Control and Data Acquisition (SCADA) and Communications that align with the new IEC 61850 standards protocols.

The main objectives of the project are:

1. Review 66/11 kV Skid Mounted Substation design process
2. Introduce the new IEC 61850 protocol to the existing Network
3. Changing the type of circuit breaker
4. Design a new improved 66/11 kV 10 MVA Skid Mounted Substation

The document provides background information about the current 66/11 kV skid mounted substation and the layout of the design. It explains the design methodology of the new improved 66/11 kV skid mounted substation design and the implications of using different communications technologies in protection and control systems design.

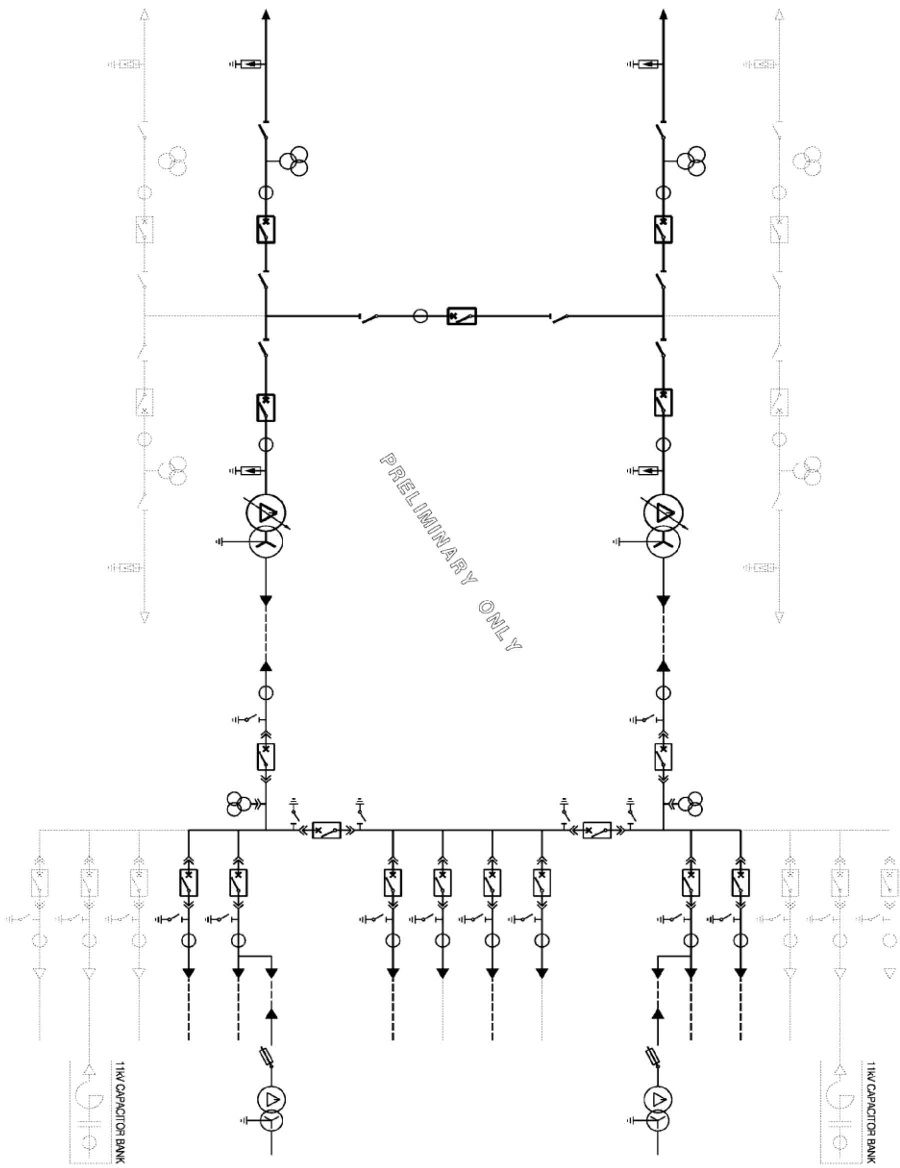

Figure 1: A typical single line diagram for SMS (Ergon Energy, 2011)

Figure 1 shows a typical single line diagram of Skid Mounted Substation.

Background

1.1The 66/11 kV Skid Mounted Substation

A skid mounted substation is a fully assembled single transformer substation with an ultimate firm capacity of typically 10 MVA and is mounted on a fabricated structural skid base for outdoors use. They are manufactured in a workshop and lifted onto a heavy transport vehicle for relocating between sites. They are generally used for temporary supply during lengthy maintenance periods, substation re-builds, other special substation project work, or temporary demand augmentation needs.

The Skid Mounted Substation (SMS) is based on a modular concept that is designed to be self-contained and easily transportable. The substation skid is pre-assembled for simplification of installation and to minimize on-site works, testing, cost and construction lead time. As shown in figure 2, the skid mounted substation provides the utility with a flexible method of response for emergency applications such as equipment failure, rapid load increases and weather related disruptions such as cyclones.

Figure 2: Skid Mounted Substation (Ergon Energy, 2011)

1.2 Skid Mounted Substation structure and fundamentals

The existing Skid Mounted Substation (SMS) design consists of a given set of devices that protect, supervise and operate a part of the system, e.g., 66/11 kV power transformer, 66 kV circuit breaker and three 11 kV feeder reclosers. The protection and control for the circuit breaker, reclosers, transformer and Remote Terminal Unit (RTU) are included in the design and all are reviewed and considered in this project for change to suit the new design.

The 66 kV outdoor switchgear is connected to the outdoor power transformer. The secondary side 11 kV distribution switchgear includes outdoor reclosers whilst the, protection, SCADA, metering, communications, DC supplies and other equipment are housed within the substation outdoor control cubicles. The connection to the local primary distribution network is done with overhead connections. But an underground cable connection option is available. The base model includes a SCADA connection system that provides full remote control and monitoring.

Figure 3: A typical 66/11kV zone substation (Ergon Energy, 2011)

1.2.1 Mathematical methodology for Skid Mounted Substation

Transformer rating given S_{bt} = 10 MVA

High Voltage side V_{bl} = 66 kV

Low voltage side V_{bl} = 11 kV

Base phase voltage V_b = ?

Base impedance Z_b = ?

Base impedance on HV = ?

Base impedance on LV = ?

Base load current = ?

Solution

Assume star connection

I_b = S_{bt}/(sqrt3 x V_{bl}) (1)

= 10000000/(sqrt3 x 66000) = 87.477 A

V_b = 38.105 kV

Z_b = 38105/87.477

= 435.601Ω

HV impedance Z = V_b / I_b = 435.6 Ω

LV impedance Z = 12.1Ω

The base value for impedance is given by the value for line to line voltage square divided by the base MVA (transformer rating). The maximum rated apparent power is typically selected in this case 10 MVA. In order to achieve magnitude current compensation, individual phase current is normalized on power transformer side by dividing the base current. The base current in primary amperes is calculated using equation (1).

1.3.0 66/11 kV Skid Mounted Substation Major Components

1.3.1 The 66 kV Circuit Breaker

Circuit breakers and protective relays are used in combination to detect and isolate faults. Circuit breakers (CB) are the main making and breaking devices in an electrical circuit that allow or prevents the flow of power from source to the load. The 66 kV circuit breaker is capable of supplying a maximum fixed load at a given security level. Under fault conditions, a monitoring relays send a signal to a breakers to change status. A protective relay detects, evaluates the fault and determines when the circuit breaker should be open. Closed CB has sufficient energy to open its contacts stored generally in charged springs. When a protective relay signals to open the circuit, the stored energy is release causing the circuit breaker to open with the exception where protective relays are mounted on the CB. The connection between the relay and the CB is by hard wiring. As shown in figure 4, the important parts of the circuit breaker are the trip coil, latching mechanism, main and auxiliary contacts.

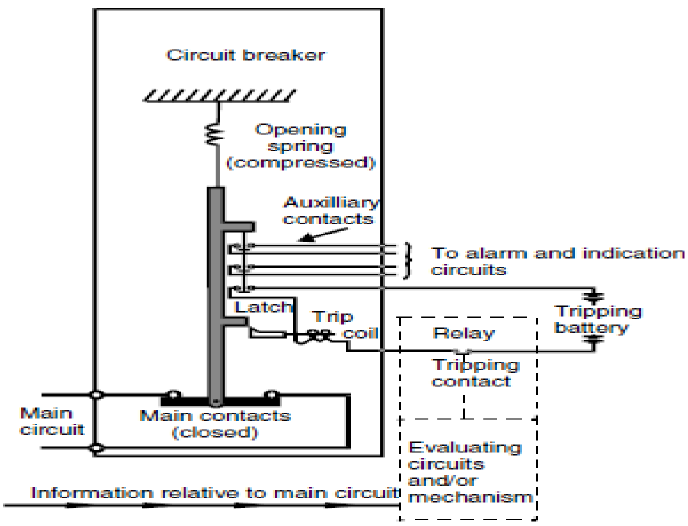

Figure 4: Schematic typical relay-circuit breaker combination

During fault isolation, the time interval between each event is in an order of a few milliseconds through the following procedures:

- ❖ Relay receives information, analyses and determines that the circuit breaker should be opened.
- ❖ Relay closes its contacts energizing the trip coil of the circuit breaker.
- ❖ Circuit breaker is unlatch and opens its main contact under the control of the tripping spring.

The trip coil is de-energized by opening of the circuit breaker auxiliary contacts.

The main important characteristic in term of protection is the speed in which the main current is opened after a tripping impulse is received and the capacity of the circuit that the main contacts are capable of interrupting. Figure 5 shows a typical fault clearing time.

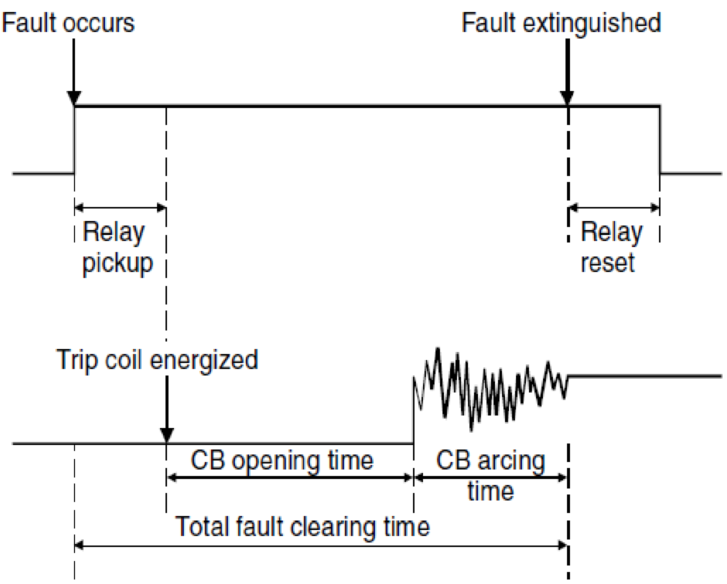

Figure 5: Total fault clearing time

The CB opening time is the time between instant of application of tripping power to the instant of separation of the main contacts. The arcing timed shows the time between the instant of separation of the main circuit breaker contacts to the instant of arc extinction of short circuit current. The combination of both opening and arcing time as a result gives total fault clearing time.

The circuit breaker has a minimum short time fault current rating of 31.5 kA for one second. The circuit breaker must be transported separately from the skid mounted substation, due to it "live head" design. Figure 6 shows an example of a typical outdoor "live head" circuit breaker.

Figure 6: A typical outdoor 66kV "live head" circuit breaker (Ergon Energy, 2011)

This project addresses the issue of dismantling the outdoor circuit breaker during relocation and finds room within the SMS to accommodate the gas insulated (G)IS switchgear. More will be covered in details in next chapter under new improved design. The existing live head circuit breaker (CB) assembly, SF_6 gas filling, wiring and testing work is performed on site prior to commissioning.

This additional work has created problems with the deployment time and resources and does not fit within the intended purpose or scope for the substations. Therefore, solution needed to be found to overcome this problem.

1.3.2 The 66 kV Current Transformer

The current transformer (CT) is used for monitoring current or transforming primary current into a reduced secondary current of 1 amp or 5 amps for metering, protection relays and control equipment. Figure 7 below shows a typical current transformer.

Figure 7: A typical outdoor HV Current Transformer (Ergon Energy, 2011)

Fundamentally all current transformers follow the same basic principles of dividing the measured current in the primary by the primary to secondary turns-ratio. A current transformer utilizes the strength of the magnetic field around the conductor to induce a current on its secondary side. Current transformers (CTs) provide a means of scaling large primary input currents into smaller, manageable secondary currents for measurement, control and protection.

In the case of the SMS, a set of 11 kV current transformers is installed inside of the power transformer along with a set on the neutral.

The Current Transformer will be used in the new improved design project to measure the actual current in the substation and produce proportional currents in their secondary windings which are isolated from the main power system.

These replica currents are used as inputs to protection relays which automatically isolate part of the power circuit under fault conditions, yet permit other parts of the plant to continue operation.

1.3.3 66/11 kV Power Transformer

A power transformer is a device that transfers electric energy in any part of the circuit between the generator and the distribution network. General issues such as, typical operation for the transformer, grounding of transformer neutrals, tap changers, types of transformer faults, technology of transformer protective relays, backup protection and the overall protection of the network transformers are discussed briefly in this section. Figure 8 shows a typical operation of the transformer.

1.3.3.1 Method of grounding transformer neutral

Three phase transformers winding are generally connected in star or delta configuration. The windings of star connected transformer are joined at one end to form neutral which is generally grounded to an earth point but other methods such as resistance and reactance grounding can be used in special circumstances. Figure 9 show a typical earthing of the neutral

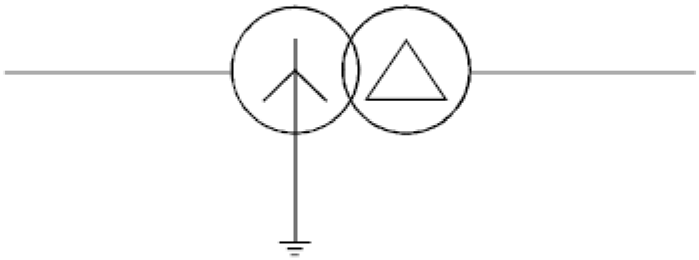

Figure 8: A typical earthing of the neutral

By connecting the neutral to earth and monitoring the current flowing in the neutral via a current transformer any fault or out of balance current can be detected and operate a relay to protect the transformer or other equipment from damage.

1.3.3.2 Tap changer

Network power transformers and large voltage regulators are equipped with manual or automatic tap changers so that the voltage ratio and hence the secondary voltage can be varied as the load supplied by the transformer changes.

The de-energized or off circuit tap changer is used for regulating the voltage after the transformer has been completely de-energised for safety operation.

It allows the voltage ratio of the transformer to be adjusted to suite voltage requirements for the transformer. The linear selector with bridge contact, shown below in figure 10 is typically used for small tap selectors with up to seven positions.

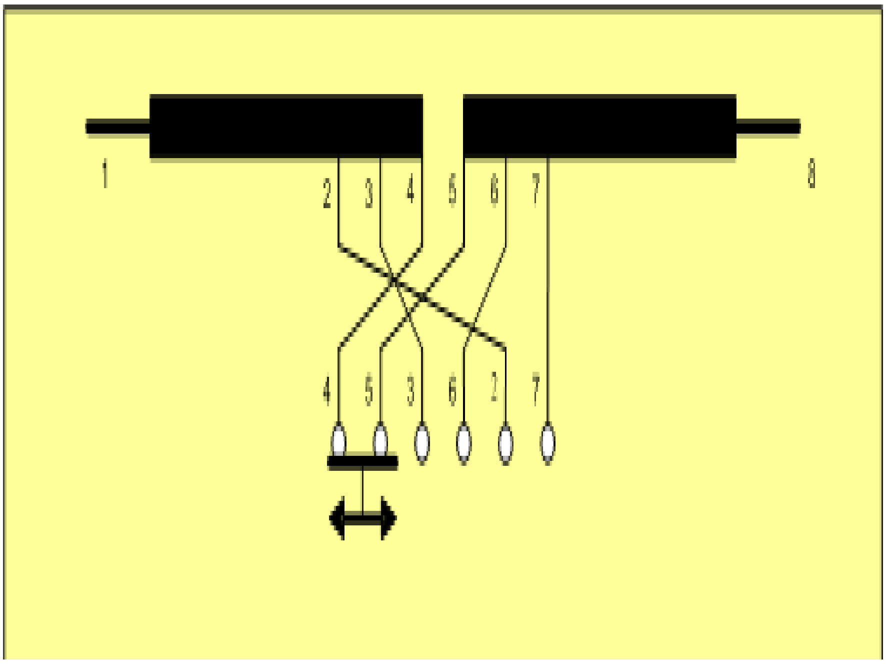

Figure 9: A typical de-energized tap changer

In figure 10, the bridging contact 4 and 5 connects all the turns of the winding in the circuit. If the bridging contacts turn to move across, it will take out one additional for each position until, at the other end of the range, it bridges contacts 2 and 7 leaving the minimum number of turns in the circuit.

1.3.3.3 Two types of On-load tap changer (OLTC)

There are two types of OLTC which includes diverter with selector switch and transition resistor type. On-load tap changers are used to enable transformation ratio to be varied while the transformation is energised and may be supplying power to the loads connected to it.

OLTC is located at the top of the range and fitted with separate tap selector and a diverter switch for each phase. The diverter-switch is only capable of switching the rated load current at the step voltage that is the voltage between the taps.

It doesn't switch fault current, hence overcurrent blocking is require to inhibit tap changing when the current coming through exceeded the maximum rated current. Figure 11 shows on load tap changer with diverter switch and tap selector.

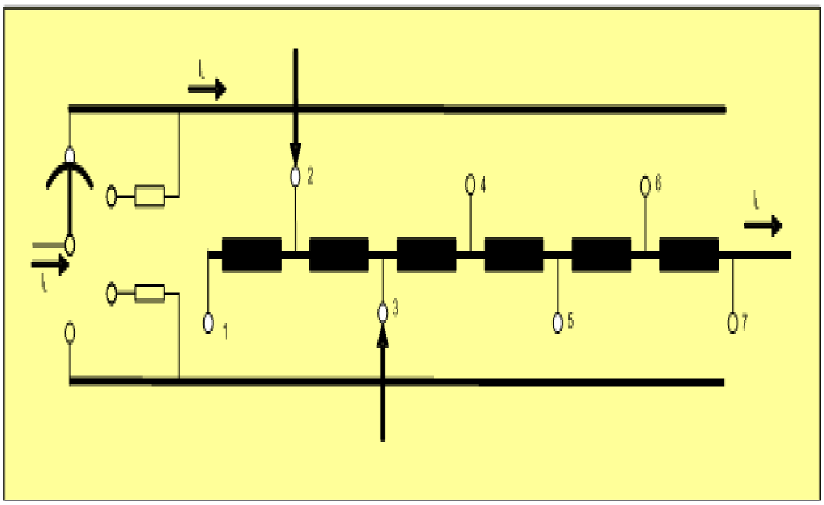

Figure 10: OLTC with transition resistors type

The tap changers are known as "resistor type" because they use short time rated transition resistors to carry the load during the switching operation. During operation sequence, a transition contact moves to the next fixed contact, resulting in circulating current flowing through it transition resistor. At the midpoint through the switching sequence, the trailing transition contact moved across to the previous fixed contact and the main moving contact is midway between fixed contacts. The circulating current dropped to half because there are now two resistors in series across the tap.

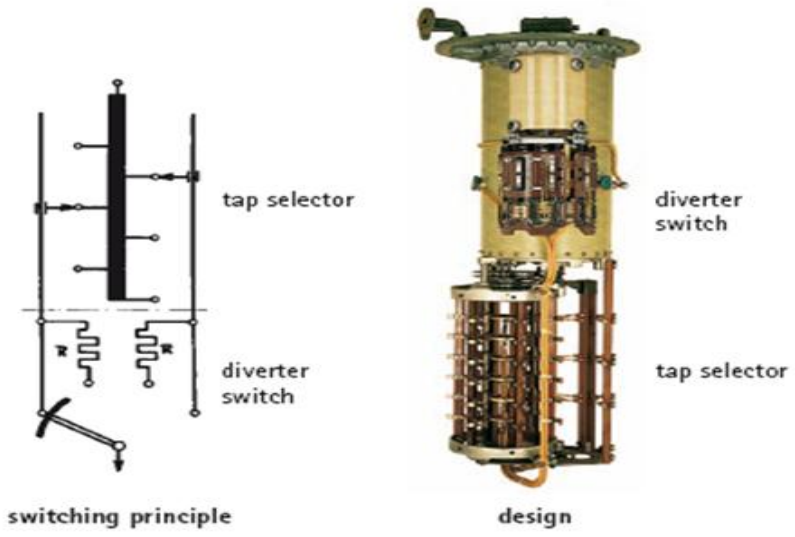

Figure 11: OLTC with both diverter and tap selector

In each phase, there are two moving contacts within the tap selector, one is capable to select the odds numbers and the other for selecting the even taps numbers as shown above. Since the tap position numbers must be either odd or even, only one of the moving contacts carries current at a time, except during tap changer.

Table 1: Transformer data specification

Rated Voltage Ratio	66,000/11,000 V
Rated KVA (ONAN)	10,000 kVA
Insulation Level HV	325 kV
Insulation Level LV	95 kV
Number of phases	3
Frequency (Hz)	50
Vector Symbols	Dyn11 or Dyn1*
Winding Terminations – HV & LV	Bushing
Earthing on all windings	Effectively earthed
Tap changing device	On load – in tank type vacuum switch

Protective devices	Buchholz – main tank and tap-changer Oil and winding temperature pressure relief HV, LV and LV Neutral
Tapping range (% of rated input voltage)	-15% (boost), +5% (buck)
With OLTC Taping steps voltage	1.25% of 66kV
Impedance	10 % on 10 MVA base

The transformer vector group can be converted between DYn1 and DYn11 by adjusting links on the transformer as per requirements.

1.3.4 The 11 kV Plant

1.3.4.1 The 11 kV Reclosers

Reclosers are non-air insulated pole mounted switch installed outside of a substation that trip automatically to clear faults, and then reclose after a predetermined time interval. An 11 kV recloser is installed on each of the three phase outgoing 11 kV feeders.

Reclosers have current transformers, capacitive voltage transformers (CVT), circuit breaker mechanisms and lightning arresters/mountings all contained within a fully welded and sealed stainless steel enclosure. These reclosers have a minimum rated primary current of 800 Amperes and a maximum rated short time current of 12.5 kA. They have the ability to be connected to the SCADA system for remote operation and integration.

1.4.0 Skid Mounted Substation ancillary components

The 66/11 kV SMS's components include the following systems: protection, metering, earthing, control, AC/DC supply and communication. These components play an important role in substation design operation. There are other components which are not critical to the performance of the system but are primarily used for measurement or maintenance functions. These include monitoring operation of device, switching tools and oil containment apparatus.

1.4.1 Protection system

Protection performance requirements specify the balance between the conflicting goals of reliability and security. Reliability goals require maximum sensitivity and fast response time to detect and clear all faults quickly with very low probability of a failure to trip. While security goals require maximum selectivity and slow response time to minimize the probability of spurious operation leading to an unwanted trip on a faultless circuit. Security is very important during normal, fault and faultless conditions. Power system equipment assets such as generators, busbars, transformers and power lines are monitored by protective relays designed to detect faults and operate isolating devices designed to interrupt damaging fault current.

Protective relays analyse the output currents and voltages measured by instrument transformer on the high-voltage apparatus. For instance, the power transformer is equipped with differential protection scheme as the main form of protection with instantaneous over-current and earth fault detection as backup.

The earth fault protection (EFP) function protects mostly the line or any other electrical node by local zero current measurement or calculation against rapid increasing short circuit current to ground. The protection earth fault trips if the current flowing in the neutral exceeds some predetermined level.

Current and voltage signals are monitored to decide whether the protection has to act to eliminate a fault. The operation of a protection relay is mainly by issuing a trip command to the breaker. However, each level of substation involves several protection relays of different types and each relay is assigned to manage a specific type of fault.

1.4.2 Communication systems

SCADA communication provides periodic exchange of short data messages between a central platform in the control centre and the remote terminal units (RTU) in substations. The messages contain status indications, measurements, commands, set point and synchronizing signals that can be transmitted in real time and requiring high data integrity, accuracy and short transfer time. The communication system provides interfacing between the local substation programmable remote terminal units (RTU) local SCADA and the Network Control Centre SCADA system. The goal of SCADA communication systems is to control and monitor the operation of the network.

1.4.3 Skid Mounted Substation control

The skid mounted substation (SMS) has integrated control systems that optimise the operation of the substation within the electricity distribution network. This is the case for any control with SCADA point both internal and external to the substation interface that provides access to substation real time operational data and operational metering data.

1.4.4 Skid Mounted Substation Earthing systems

The earthing system is used to accommodate a skid mounted substation and provide an earthing system connection to which transformer neutrals or earthing impedances connected in order to pass the maximum fault current. The earthing system ensured that no thermal or mechanical damage occurs on the equipment within the substation, thereby resulting in safety to operation and maintenance personnel. Substation earthing provides a safe return path for the fault currents and facilitates protection operation by providing return path.

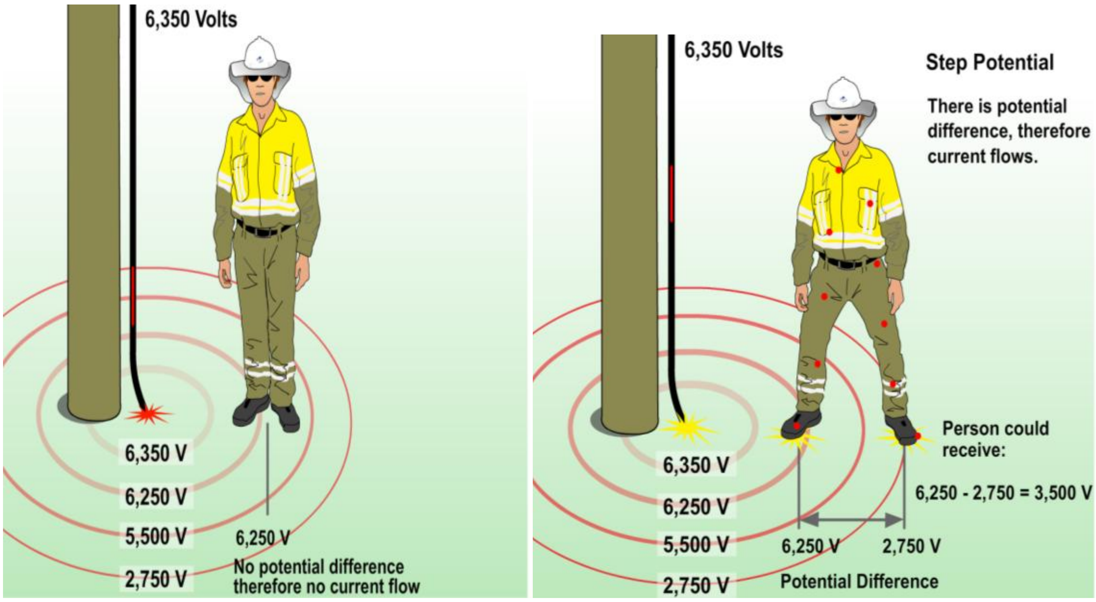

Figure 12: Earth potential (Ergon Energy, 2011)

Substation earthing control earth potential fluctuation step, touch voltages and provide lightning protection. Touch voltage is the difference in potential between the surface potential and the potential at earthed equipment whilst a man is standing and touching the earth structure as shown in figure 13. Step voltage is the potential difference developed when a man bridges a certain distance with his feet whilst not touching any other earthed equipment. Refer to figure 12.

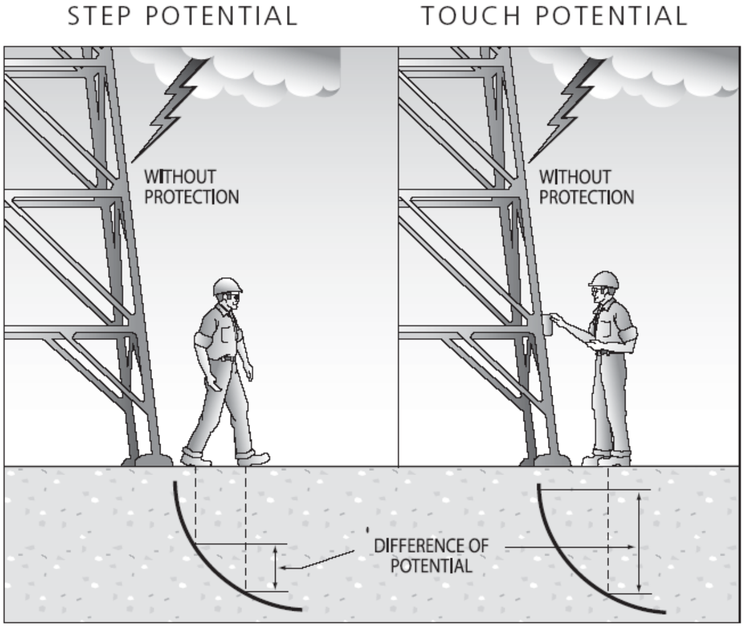

Figure 13: A typical earth potential variation (Ergon Energy, 2011)

Line arresters are used to reduce the risk of having dangerous touch or step voltages due to power frequency earth potential rise. If the skid mounted substation is to be deployed on a green field site, an adequate earth grid must be provided on site prior to installation. The earth system is designed to ensure that it complies with the standards and safety requirement.

1.4.5 AC/DC Supplies Systems

The SMS has a very reliable three phase four-wire, 415V AC power supply. This supply is sourced either directly from an 11 kV/433V station service transformer or a 25 kVA auxiliary winding built into the main power transformer.

The skid mounted substation is equipped with a highly reliable 48 V DC supply for auxiliary critical systems within the substation. This supply is able to power the critical systems of the skid mounted substation for a minimum of 10 hours during and after an emergency situation.

1.4.6 Skid Mounted Substation lightning protection systems

The lightning protection system provides adequate lightning protection for the safety of plant, equipment and personnel. Typical methods such as the rolling sphere method are used to calculate the level of protection for a substation. This along with the equipment basic impulse levels (BIL) and the earth system design form an integral part of the insulation co-ordination system design of the substation.

Surge diverters are installed on the power transformer primary side of 66 kV circuit breaker, the 11 kV bus, and the 11 kV reclosers. If the skid mounted substation is to be deployed on a green field site, adequate lightning protection is provided on site prior to installation s shown in figure 14.

Figure 14: A typical substation lightning protection (Ergon Energy, 2011)

An appropriate lightning protection of substation networks is required to minimize damage to equipment, power plant and public.

1.4.7 Metering functions

The metering system is installed on 66/11 kV Skid Mounted Substation to provide statistical or revenue metering information where available. There are two types of energy metering which include external and internal metering. The external metering represents either the conventional energy meters external to the substation digital system but feeding it with energy information through contact pulses or other devices with serial communication. The internal energy meter calculates the energy from the voltage and current. Metering in this context includes both measuring for operation purposes and metering for billing.

1.4.8 Skid Mounted Substation Safety

Why do we need to be extra conscious in considering substation safety? Staffs are expected to visit substation sites for maintenance and other services design requirement. There is a range of safety policies. The detailed application of these policies to major substation construction, operation and maintenance is checked as part of the detailed design process. In particular, all new sites will meet regulatory and Australian Standard requirements for electrical clearances. Space will be allowed in the substation to carry out maintenance, replacement of plant and extension of the facility without the need to remove adjacent equipment from service where ever practicable. Auxiliary systems will be designed with the safety of operating and maintenance control in mind. Figure 15 shows a burning substation possibly caused by equipment failures.

Figure 15: Burning substation

To maintain reasonable safety procedures, the following are put into consideration to ensure the safety for plant equipment, environment and the public.

- ❖ Earth potential rise (step and touch potential)
- ❖ Electromagnetic fields (EMF)
- ❖ Access – public members must not gain access to substation
- ❖ Clearance
- ❖ Fire
- ❖ Equipment failures – some pieces of plant can fail explosively which may causing injury from shrapnel

Figure 16: A typical substation clearance and equipment failure (Ergon Energy, 2011)

1.4.8.1 Risk associated with Skid Mounted Substation

There are several risk associated with SMS which include but not limited to:

- Transformer oil leak
- Transformer tank rupture causing possible fire
- Major components e.g. CT fail with porcelain rupture, surge arrestors fail with porcelain rupture

1.4.8.2 Control measure

- ❖ Major component need to be correctly tightened to support frames otherwise looseness causing conductors to be stressed and made loose.
- ❖ All connection must be correctly tightened otherwise risk of looseness causing hot spots
- ❖ Transformers protection devices e.g. Oil level and winding temperature indicators and Buchholz relays need to be checked regularly to ensure correct set up and operation to avoid risk of system failures to operate when required.

1.4.9 Environmental safety

Environmental safety is very important. Therefore, the substation is laid out to allow the noise and EMF levels to be within acceptable levels at the substation boundary. Oil containment is provided for all transformers with a capacity and the storm water drainage system is designed to allow monitoring of discharges from site.

To reduce the use of the Greenhouse gases, vacuum-switching technology is used wherever possible. At voltages above 33 kV where vacuum circuit breakers are not available, the use of SF_6 gas is minimized. In general, SF_6 is used when no other economic alternative is available.

1.5.0 Summary

The project is mainly focusing on changes to SCADA communication system that aligned with IEC 61850 communication standards protocols. The existing 66/11 kV SMS design has outdoor 66 kV Circuit Breaker that need to be dismantled to relocate. Therefore, the primary focus of the new design project is to eliminate this and find room within the SMS to accommodate the Gas Insulated Switchgear (GIS). In doing this, the system will be connected to the network much quicker and more readily transportable as a fully assemble SMS.

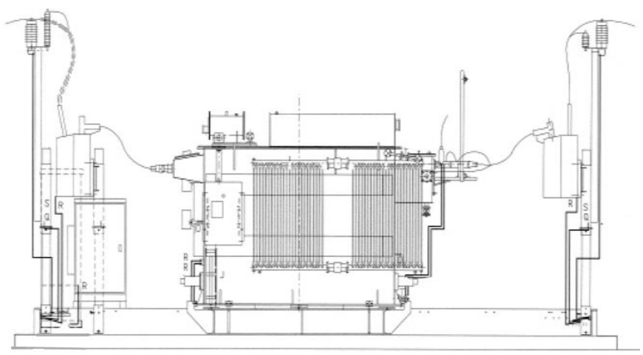

Figure 17: SMS diagram (Ergon Energy, 2011)

Chapter 2

New Improved 66/11 kV Skid Mounted Substation

2.1. Introduction

Industry Standards which govern the design, testing and application of power devices and communication interfaces have undergone significance changes since their original publication. This revolution of standards follows changes in both advancing technology of equipment and increasing demands imposed on them due to the complex environment which they are applied. This ever-ending technology development makes it critical for engineers to be aware of the current status of, and recent changes to these standards in order to properly specify and applied the equipment.

This section will begin with a theory of circuit breakers, describing method used and any significant changes made or used currently. Described and show the method of operation of various technologies of interrupters that have been and currently being used in medium and high voltage circuit breakers. Provides comparative information to help understand the GIS switchgear and how it can be incorporated into the new improved design.

2.1.1 Circuit breaker theory

Circuit breakers (CB) are breaking devices designed to open and close a circuit by non-automatic means and to open the circuit automatically on a predetermined overcurrent without damage to itself when properly applied within it rating.

A circuit breaker must be able to be switched open and closed manually and to protect a circuit from overcurrent by opening automatically. This allows a breaker to be used repeatedly without replacement.

The switching function of CB provides easy isolation for the circuit or circuits protected by the circuit breaker from the rest of the electrical system, allowing safe modification or maintenance of the equipment in the circuit. All CBs are intended to switch load and some are specifically rated for switching load such as lighting in commercial and in industrial buildings on a regular basis.

2.1.2 Gas Insulated Switchgear (GIS)

Gas Insulated Switchgear is metal-enclosed switchgear in which the insulating medium is SF_6 at higher than atmospheric pressure. GIS technology is typically of modular design and filled with a minimum quantity of SF_6. It has low life cycle cost compare to air insulating switchgear and can be used for both indoor and outdoor application.

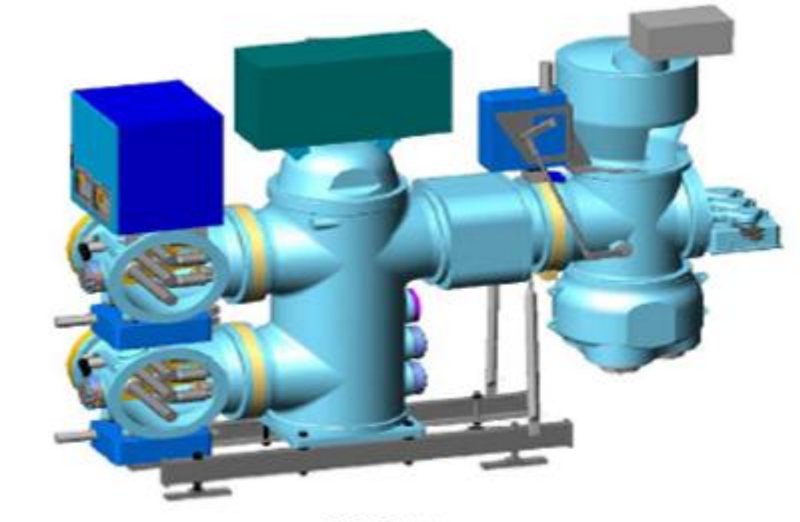

Figure 18: A typical GIS switchgear

2.1.3 Circuit breaker technology

The SF6 circuit breakers are based on SF6 puffer principle used in Gas Insulated Switchgear (GIS) applications. SF6 puffer circuit breakers have good interruption capabilities and are particularly well suited to application in a GIS environment that also uses SF6 for the main dielectric medium.

The downside with SF6 puffer circuit breakers is the relatively high driven energy requirement. The flow of high pressure gas necessary to travel along over the length of the arc drawn between the contacts is generated by the mechanical compression of SF6 gas in the puffer interrupter cylinder. The energy requirement for this operation can be considerable and additionally a high energy mechanism leads to high reaction forces on the GIS support framework and foundations.

The advantage is using the interruption methods such as thermal, auto-expansion or self-blast interrupters that requires less energy. These methods can overcome high operational energy requirements of conventional puffer devices.

The existing 66kV outdoor circuit breaker requires dismantling for relocation. This is to be eliminated by changing the type of CB and making a room to accommodate it. The more compact the switchgear is, the less space it occupies, there is a chance that the installation will fit within the available space and be more readily transportable. Figure 19 shows typical containerized indoor gas insulated switchgear (GIS).

Figure 19: 66kV (GIS) Gas Insulated Switchgear (Ergon Energy, 2011)

2.1.4 Gas insulated switchgear transport design

The best scenario is the installation of the switchgear module within a container for easy transportation regardless of whether it is used as a moveable or stationary on the Skid Mounted Substation. GIS is disassembled for packing and shipment. The equipment is designed to minimize the number of disassembled parts, while considering performance, maintenance, ease of installation and transportation. The disassembled parts are packed as a complete unit whenever possible to reduce the construction cost at the site.

2.1.5 Indoor Gas Insulated Switchgear (GIS)

The main role of buildings indoor GIS switchgear installations is to house all primary and secondary equipment. Indoor GIS design in particular, requires specials measures against dust penetration GIS room, SF_6 ventilation system and direct connection of switchgear earthing grid with the building reinforcement.

As the volume of the container is limited it can be used for full GIS only for rated voltages up to 245kV or very small switchgear. Relocatable equipment is considered as GIS of variable layout which can be moved to new locations of use and service with little dismantling, assembly and commissioning effort.

Figure 20: A typical GIS switchgear (Ergon Energy, 2011)

Moveable GIS are needed for temporary distribution of energy in cases when the planning and execution of substations is not able to follow the need for local energy supply, as a temporary means of supply during network upgrading, for rebuilding of substations or increasing load demand.

2.1.6 GIS hazards and safety

Like most fire protection systems, which are based on minimizing the hazards for the operators, public, environment protection and assets by limiting damage to power transformers and to adjacent apparatus, equipment, buildings and other single elements and minimizing the outage of power to the customer.

Sulphur Hexafluoride (SF_6) is a relatively non-toxic gas but is a greenhouse gas. The good dielectric and other physical properties have led to the extensive use of SF_6 as an insulating medium in switching equipment such as circuit breakers. While SF_6 is inert during normal use, toxic by-products can be produced that pose a threat to health of workers who come into contact with them. The side-effect includes long term respiratory damage, skin irritations and acidic burn damage.

An indoor GIS installation does not require any specific fire precautions except for special interface applications such as oil or cable terminations. No pressurised porcelain or other potential risk of explosion due to failure of insulation is involved.

With the use of SF6 insulation risk of oil or fire can be eliminated. In general and independently, indoor installation requires more considerations than outdoor installations. The following has been considered in the design:

1. Appropriate material for walls
2. Ceilings
3. Fire barriers
4. Escape routes
5. Rescue routes

6. Emergency exits

2.1.7 Security of GIS

Gas Insulated Switchgear (GIS) is inherently suited to provide high levels of security due to increased reliability and availability compared to other technologies such as Air Insulated Switchgear (AIS) and other solutions which result in increased levels of availability of power supplies. All conductors in GIS are enclosed in earthed metal enclosures which make it impossible for casual intruders to accidentally come into contact with high voltage connections. This means that the risk of accidental electric shock during sites visit is eliminated compared to conventional switchgear design.

2.1.8 GIS impact on environment

Transports are considered as a big contributor to the negative environmental influence. The disconnecting circuit breaker system will off course reduce that part as the less use of material and the decreased number of apparatus implies less transports. Sulphur hexafluoride gas (SF6) is a gas with outstanding isolating and extinguishing qualities and is for the time being the only technical and commercial alternative for high voltage (HV) circuit breakers (CBs). However, SF6 has the drawback that it contributes to the greenhouse effect and must therefore be handled with caution. For this reason, the used amount must be kept as low as possible and that is the case of Skid Mounted Substation design.

Containerized switchgear solutions used special indoor applications but are protected from some of the environmental factors such as rain, wind, strong solar radiation and extreme pollution. The type shown in figure 21 is solidly constructed for transportation and this helps reduce gas leakage from the equipment and eliminate gas handling procedures.

Although the total length of SF_6 seals is the greatest within GIS, consideration should be given to the fact that GIS equipment can be installed indoor, thus minimizing exposure to environment and extending the life of the sealing systems.

GIS produce lower levels of noise due to the fact that equipment is completely enclosed, and the SF_6 gas in the enclosures is a very efficient sound absorber.

Figure 21: A relocatable GIS switchgear (Ergon Energy, 2011)

However, every action should be taken to keep the level of SF6 emission to minimum, since the amount of SF6 within the substation become larger as a result of gas insulated technology developed.

2.1.9 Future possibilities

Sulphur hexafluoride gas SF6 circuit breakers have better maintenance and failure performance than disconnected switches. That means that the traditional way of (isolating circuit breaker in the system for maintenance or repair) building substation with many busbar systems and disconnected switches rather decrease the availability than increase it. In this case, the best way to increase the availability is to avoid using disconnected switches and use circuit breakers (CBs). However, due to safety aspects a disconnected function is necessary. In a disconnecting circuit breaker, disconnection function is integrated in the circuit breaker and it is then possible to design disconnected switches free substation solutions.

2.2 Conclusion

The requirement to change type of circuit breaker has been reflected in the associated gas insulated switchgear (GIS) equipment. As mentioned earlier, the 66kV outdoor type circuit breaker will be replaced by modern SF6 circuit breaker. This will eliminate the dismantling of 66kV type outdoor circuit breaker and allow quick connection for the system.

Chapter 3

3.1. Introduction

This section will look at current situation and outline the development of communication in SCADA systems between control centres and Remote Terminal Units (RTU). Investigate the possibility of integrating SCADA communication with IEC standards protocols.

This has been achieved by presenting a series of real service providers which explained the future and transition from today's situation to the future one. The outcomes will determine the recommendation for future improvement for the systems design.

3.1.1 Supervisory Control and Data Acquisition (SCADA)

Supervisory Control and Data Acquisition (SCADA) is the central system that provides full remote control and monitoring of the system. It has been in service for many years in power utilities for operation and control of electrical systems. SCADA systems typically use low speed (200 to 1200 bits per second), Point to point, point to multipoint or ring simple and dedicated network structures. It provides support interfacing between the local substation programmable remote terminal unit (RTU) and the network control centre SCADA system.

A SCADA system covers most functions necessary to monitor and control the operation of the power network.

Control Centres are required to exchange information with generating stations, substations and other Control Centres. The information to be exchanged comprise real time and historical power system monitoring data including control and accounting data. Figure 21 shows typical control centre transported using router network.

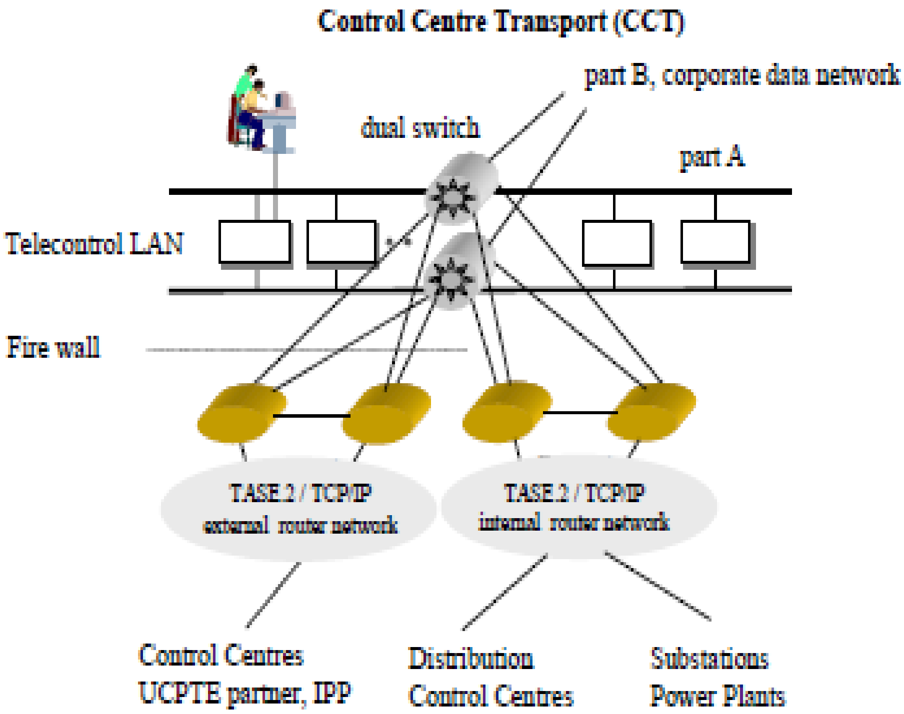

Figure 22: Typical control centre transport using router network (CIGRE, 2000)

Most power system architecture and their operational organization often include different hierarchical levels of Control Centres as well as geographically distinct back-up facilities.

3.1.2 Data Type

There are three sets of standards that are more applicable in different contexts of telecommunication control. These include:

1. Semi-static Data
2. Real Time Data
3. Historical Data

The Semi-static data is suited to communication between control centres. It describes the physical processes such as power system topology, functions such as asset parameters and displays.

Real time data from the physical process involve features such as alarm, event, and status, analogue measures of energy generation, load flow, voltage and current. In addition, real time data may be imported from other information system such as SCADA nodes from external SCADA systems.

Historical data has long term storage of selective real time data for trending, analysis and planning purposes.

This dissertation describes the alternatives, takes a look at different approaches used or planned by power utilities and highlights the number of difficulties using three aforementioned sets of standards and draws a conclusion depending on the outcomes of the investigation.

3.1.3 Data communication

Due to ever changing world of communication technologies, the need for higher availability and faster information for data communication requirement is rapidly changing. Mostly digital network communication systems are being installed for internal and external use by communication services providers. This section focuses on data communication network used:

1. Power network control and monitoring (SCADA, LFC)

2. Centre-Centre and information exchange with other companies
3. Information access to mailboxes, info centres (Meteorology, Energy Stock Exchange)
4. Utility-wide office information (mail, maintenance, service, data exchange with corporate database, video)
5. Telephone and facsimile services

The abovementioned types of data communication have different requirements when it comes to:

1. Communication path
2. Speed transmission
3. Data volume
4. Quality (security, availability, reliability)
5. Transmission protocols
6. Interfaces to the network
7. EMC compatibility (especially within substations)
8. Integrity of data and mobility

In addition, the data communication requirements are affected by the Internet technology strategies and IT development for electricity service providers. This widespread availability of the internet technology may possibly affect future requirements of data communications if appropriate control measures are not implemented. Table 2 gives an overview of the different requirements for different types of utility data communication network.

Table 2: Service provider data communication requirements

	Requirement							
Type of data communication	**Interface**	**Com path**	**Transmission speed kbit/s**	**Data volume**	**Quality availability**	**Transmission protocol**	**Application protocol**	**Special remarks**
A Power network control and monitoring								
A1 SCADA (supervisory control and data acquisition)	G.703, X.21, V.11, V.24	PDH	0.3-64	Small, sporadic or cyclic	High 99.95–99.9%	IEC 60870-5-101	IEC60870-5-101	
A2 LFC (load and frequency control)	G.703 ,X.21, V.11, V.24	PDH	0.3-64	Cyclic, permanent	High, 99.99%	IEC60870-5-101	IEC60870-5-101	
A3 Energy metering	G.703, X.21, V.11, V.24	PDH	0.3-64	0.5-10Kb periodic	High, 99.00%	IEC60870-5-102	IEC60870-5-102	
A4 Video for plant supervision	G.703	PDH	2 x 64	Medium, permanent	Low. 99.99-99.5%	Proprietary		
A5 Remote access for control and monitoring	Modem, 33.36kbit/s or 64kbit/s ISDN	Switched network	1.2-64	Small, as needed for services purpose	High, 99.95%	Often proprietary		
A6 Meteorological data acquisition	G.703, X.21, V.11, V.24	PDH or Switched network	1.2-64	Small, permanent	High, 99.00%	n/a		
A7 Line protection equipment	G.703, X.21, V.11, V.24	PDH	0.3–64	Small, sporadic	High, 99.99%	IEC60870-5-103	IEC60870-5-103	
B Centre to centre and information with other utilities	Router LAN Ethernet, TCP/IP to Frame – Relay G.703 or later ATM/SDH	PDH, or later ATM/SDH ISDN as a backup	2 x 64, may be increase if necessary	Medium, burst some kB to MB	High, 99.9 – 99.99% depending on the application	TCP-IP Frame-Relay encapsulation	TASE.2 ELCOM 90	
C Information access to mailboxes and information centre through Internet								

C1 Access to data bases of general interest	Router LAN Ethernet, TCP-IP to ISDN	ISDN or analogue modem	64 or 33.6/56	Medium to very high: some kB to many hundreds MB	Medium to high, 99.0-99.90%	TCP-IP		
C2 Access to manufacturer's data base								
C3 Access to external e-mail services								
C4 Access to utility's home page								
C5 Access to meteo services								
D Utility wide office information								
D1 Access to utility's internet e-mail	Router LAN, Ethernet, TCP-IP to Frame Relay or eventually PC communication over modem	PDH or ISDN backup	64	Some kB	High, 99.90%	TCP-IP alone or with Frame-Relay		
D2 Access to utility's services (WAN, LAN) computer-computer link			PC: 1 to 2 x 64 other: n x 64	kB to MB	Depend on the application			
D3 Video for plant supervision		PDH	2 x 64	~12kBytes/s	High, 99.95%	Proprietary		
D4 Access to utility's meteo service		PDH	2 x 64	~12kBytes/s	High, 99.90%	Replaced by F2		
D5 Access to energy exchange planning		PDH or ISDN backup	1 to 2 x 64	Some kB	High, 99.95%	Frame-Relay		
E Telephone and facsimile services								

E1 Red line phone (***)	Analogue 3.1 kHz	PDH	64	n/a	Low, 99.99%	A-law		
E2 Utility's phone (***)					Low, 99.90%			
E3 Normal phone (***)	Analogue 3.1 kHz or ISDN	Analogue or ISDN	Analogue or 64			Analogue or A-law		
E4 Transmission network's service phone (***)		PDH	64		Low, 99.95%	a-law		
E5 Facsimile		Analogue or ISDN	Analogue 14.4; ISDN 64	Some hundred kB	High, 99.90%	ITU…		
F **Videoconferencing/videophone**						ITU…	n/a	

F1 Videoconferencing	G.703, X.21, ISDN	ISDN or PDH	n x 64	Some hundred MB	High, 99.90%	ITU H.320 H.323 Frame structure H.261, H.263, data transmission T.120	PABX own	

F2 Videophone over internet (****)	Modem analogue or ISDN	Analogue or ISDN	33.6/56 /64	Some ten MB	High, 99.90 %	H.323/ TCP-IP	PABX and Internet provider				
	H.323 supporting following voice compression algorithms: G.711/G.723.1/G.728/G.729/G.729A for respectively 64/6.3/16/8/8kbit/s										
G Data (or phone) over satellite VSAT (propagation delay =~253ms***	V.24, x.25	Satellite	Mainly up to 9.6 seldom 32 or 64	Small to medium	Medium, 99.0% or higher	Veterby FEC ½, BPSK	Proprietary				

As shown above in table 2, it is clear that the type of data communication used by power network for control and monitoring is the plesiochronous digital hierarchy (PDH).

3.1.4 Communication network

The communication used by most utilities today typically consists of:

1. Mesh microwave radio link
2. Copper cable (4-wire and coax)
3. Power line carrier Digital or analogue
4. Integrated Service Digital Network (ISDN) connection for backup transmission
5. Meshed optical fibre network

3.1.5 Impact of deregulation

The current deregulation in telecommunications as well as in the electricity power industries and distribution sectors exerts a massive influence on the internal communications between the electricity supply undertakings. In some cases it brings forth absolutely contradictory trends and requirements.

3.1.6 Competition

Deregulation of the utilities has resulted in increased competition. The margins on energy prices is more likely to drop as a result, the utilities are more likely to consider the cost more carefully and built their network to be more affordable and reliable. This may lead the transmission network to be used for the power generation and the commercial services which may be reliable. Basically, the same data can be declared important or less important depending on the utilisation by the user. The risk of a utility being bought by another one still exists. The use of open systems and equipment complying with international standards guarantees the protection of the investments.

3.1.7 Technical development and influence on the data transfer

In order to reduce the load both in the transmission network and at the control centre, more local intelligence may be delegated to remote stations. For example the plausibility of the meter values may be checked locally instead of sending the values of both the main and the check meter to a control centre. This may reduce the quantity of data, but the use of standard transfer protocol IEC 60870-5-101 for SCADA applications, which are often less efficient than the previous optimised proprietary protocols, will increase the number of bits to be transmitted, so that the need for transmission capacity will increase rather than decline.

Low speed data transmission between the control centres and remote stations may be replaced by a transmission produced by remote database access at higher bit rates either at control centre or at remote stations. For the database access between control centres, frame-relay or similar protocols providing similar functionality are recommended to enable sharing the available transmission capacity with many users.

3.1.8 New technologies

Internet brings access to databases of general interest, gives the opportunity to download new software updates and offers an efficient e-mail service. However, the transmission of data over the internet is not very secure, the data can be read and modified by unknown third parties and the effective data through bit rate depends on the network load. Anti-viruses software or fire wall is recommended to prevent hackers and other potential threats.

3.1.9 Satellite (VSAT)

Satellite transmission is usable for sites not easily accessible with traditional transmission lines. Very small aperture terminals (VSAT) transmit at low bit rates of 300 to 9600bit/s at low cost. A link availability of 99.0 % or higher (refer to table 2) can be guaranteed. If some information is needed at many sites in a secure way, a broadcast transmission procedure is not suitable. The best suggestion way is to consider sending the information first to hub. This hub forward the information to one remote station after the other in such a way the transmission quality can be individually checked.

3.2. Synchronous digital hierarchy (SDH)

The very high transmission capacity offered by Synchronous Digital Hierarchy (SDH) systems is not strictly necessary for the stand-alone utilities in the near future. SDH is already replacing plesiochronous digital hierarchy (PDH) for bit rates higher than 34 Mbit/s and is no longer more expensive than PDH. It is also predicted that the availability of PDH equipment will be phased out by the major manufacturers in the short term as the demand decreases. Very few public telecommunications operators are ordering PDH equipment currently and manufacturers tend to concentrate on the requirements of the public operators. Due to large quantity of data transmitted, it is not possible to buffer them into the transmission equipment as is commonly done when using the PDH technique. This means every switching operation between the main transmission path and the auxiliary transmission path may lead to an interruption of the link for some milliseconds depending on the reaction time of the equipment and data will be lost. Data integrity should be ensured by using an appropriate transmission protocol.

3.2.1 Integrated services digital network (ISDN) for backup

The integrated services digital network is a low-cost solution for backup lines. Due to the dial-in time of up to 2 seconds it is not usable for the transmission of line protection signals. It is also subject to congestion at peak traffic hours after a disruption or when the telecommunication service providers' interruption.

3.2.2 Future development

It becomes more and more necessary to guarantee the interoperability of the systems used in the private network with those used in the shared sectors. The equipment used must be compatible with a system many neighbouring utilities can agree upon. The control centre systems must enable remote database access, using relational databases.

3.2.2.1 Communication

The availability of transmission of communication data over optical fibre can possibly replace the existing analogue transmission systems over private copper cables, rented lines and also some analogue Power Line Carrier.

The network structure used for communication between control centres and remote stations will still remain in many places as a logical star network for economic reasons, and as far as possible, a physical ring or a meshed network.

3.2.2.2 Network hierarchy

There are two options available:

1. The plesiochronous digital hierarchy (PDH) may be used provided the transmission does not need to be over some 2 Mbit/s.

2. The synchronous digital hierarchy (SDH) network with PDH access. There is additional cost for the requirement as compared to a low capacity PDH network. But the installation cost is not significantly higher than that for the pure PDH network. To build a SDH/PDH network is cheaper than to upgrade the PDH network later. Some SDH nodes today no more expensive than 34 Mbit/s PDH nodes.

3.2.2.3 Interoperability

The interoperability of the systems is very desirable. For this reason it is important that the systems meet the international standards and widely used transmission protocols. The transmission systems must be upgradable to meet future requirement.

The interface to and from the network management system will preferably fulfil the requirements of most standards.

3.3 Summary and conclusion

This summary is about general development for the modernization of SCADA systems.

3.3.1 Architecture

Most utilities currently have a hierarchy structured SCADA network with information from remote terminal units (RTUs) being passed by at low speed to control centres. This information is concentrated and passed on to regional control centres.

With technology development, utilities are moving toward reducing the number of layers of control to a few networked regional centres, optionally with a central control to provide co-ordination. In one case the national grid company (NGC) in United Kingdom has been reduced to a single control centre handling the entire HV grid network.

So there is a clear development towards a reduction in the number of control centres and systems, which are getting larger and more centralised, basically due to cost reduction needs and technology improvements. This development is driven by technology evolution of computers and the deregulation of the electricity market.

3.3.2 Standardisation

Of significance is the trend across the utilities towards standardisation based on the need of the utilities for flexible and, therefore, open systems to meet the organisational changes of today. The increase in data exchanges, the integration of functions, and to become less dependent on single manufacturer.

3.3.3 Protocols

In most cases, utilities plan to phase out the proprietary communication protocols used today such as IEC standards for control centre to control centre communications IEC 60870-6 telecommunication control application service element (TASE.1 and TASE 2) are competing (refer to table 2). More modern TASE.2 is getting wider acceptance as the future standard due an open object model decoupled from the protocol allowing easier exchange of different type of information such as SCADA information.

The case is less clear for remote terminal units (RTU) to control centre communication. Emphasis is made on IEC 60870-5-101, while IEC 60870-5-104 is emerging and

IEC 60870-6 TASE.2 is also a contender for large installations.

The emergence of protocols like distribution network protocol (DNP) based on early drafts of IEC protocols. Nevertheless, standard such as distribution network protocol (DNP) is quite open and allow different functionality within the standard, being necessary to define profiles or subsets for specific applications.

3.3.4 Data Rates

Following results from introduction of new control applications, the amount of information being transmitted is increasing, alarm information in particular. Similarly, as the quality of the communications has improved the use of remote control has increased significantly. Moreover, the advent of the electricity market is producing a need to share control centre data with other applications in commercial and trading systems.

3.3.5 Networks

In general the development of networking allows predicting an increase in the use of wide area network for telecommunication control. For security and confidentiality reason, dedicated networks may be separated from internal telecommunication control networks and used for communication with control centres or between control centres, especially when several utilities share the same network.

3.3.6 Managing network

In general, the ownership of the network is held by the power utility, while the transmission media can be either owned or leased. In any of these cases, emphasis is more on the network management and control than in the ownership. The recognition of the importance, necessity of well organised and structured communication network management systems especially when using wide area network. Another reason for the emphasis in network management is also influenced by the deregulation of the electricity market, which as a result creates a growing need for using wireless networks that, although the scenarios in general keep separate from the ones dedicated to information system traffic, sometime must mixed other traffics like for instance customer information data, resulting in a need for an improved management systems able to differentiate and protect the telecommunication control traffic.

3.3.7 Integration strategies

Remote Terminal Units (RTUs) tend to be replaced smoothly and less frequently than control systems. Many of the utilities in most cases plan for a successive replacement of old RTUs with modern RTUs or integrated substation control systems over a longer time period. The result is that when a master station is replaced it is still required to use the legacy communications protocols provided by the RTUs.

This conditions the integration strategies from the old protocols and networks to the new ones by imposing a long coexistence period. During which translation from one protocol to another is a must. New equipment must, where possible, be able to handle both old and new protocols for integration into communication networks and for easy change over to new standards as appropriate.

The handling of old remote terminal units (RTUs) can be done in several different ways but one preferred method is to set up getaways or concentrators for protocol and data conversion from proprietary protocols to standard protocols to allow the updating to new equipment over a period of time.

These concentrators can be more or less integrated with the communication network. This allows for little or no change on the remote terminal units side and the use of new standard protocols between the getaway and the control centre.

3.3.8 Conclusion

The major development in terms of architecture seems to be relaying on distribution, which aim at reaching availability and modularity. In term of distribution, there is no substation master controller, but only one bay level controller and protection units.

Chapter 4

4.1 The IEC 61850 Standards

Researchers have put in a considerable effort in the development of the new standard IEC 61850, which focuses on reaching interoperability and improvement to substation design operations and maintenance. This section will cover the concepts contained in IEC 61850 and background leading to the development of communication standards.

4.1.1 Introduction to IEC 61850

The standard IEC 61850 communication networks and systems in substations is based on the need expressed by the industry to have devices which are interoperable through communication link at least to the same degree as hardwired devices. It has unique feature rich with support for functions and supports of standardized device models using names instead of registered numbers and indexes.

The development of IEC 61850 standard communication and networks systems in substations is set not only to reach interoperability but also makes wide ranging changes to the way in which substations and power systems are designed, build, commissioned, operated and maintained. The reason behind this is the request for the lower costs and increased flexibility of substation automation.

4.1.2 The need for IEC 61850

The objective of incorporating IEC 61850 standards is to provide a communication that meets performance and cost requirements which supports current and future technology developments. The need for the standard is the free exchange of information between intelligence electronic devices (IEDs). IEC 61850 standard supports any types of substations automation functions and therefore, the standard considers all operational requirements.

4.1.3 The Purpose for IEC 61850

The purpose of the standard however is neither to standardize nor limit in any way the functions involved in substation operation nor their allocation within the substation automation systems. The operational functions are identified and described in order to define their impact on the communication protocol requirements.

Technically, the standard is not a protocol in a communication sense however; rather a structured definition of data within devices such that information can be exchanged correctly between functions within devices over whatever communication media and protocol is used.

To get interoperability for real IEDs, all layers of the protocol stack including media definitions have been standardised by a well-defined selection of a main stream communication technology. IEC 61850 enable IEDs (Intelligent Electronic Devices) get digitalized power grid condition data via process bus and merge units.

IEDs communicate with each other using substation buses as shown in figure 23.

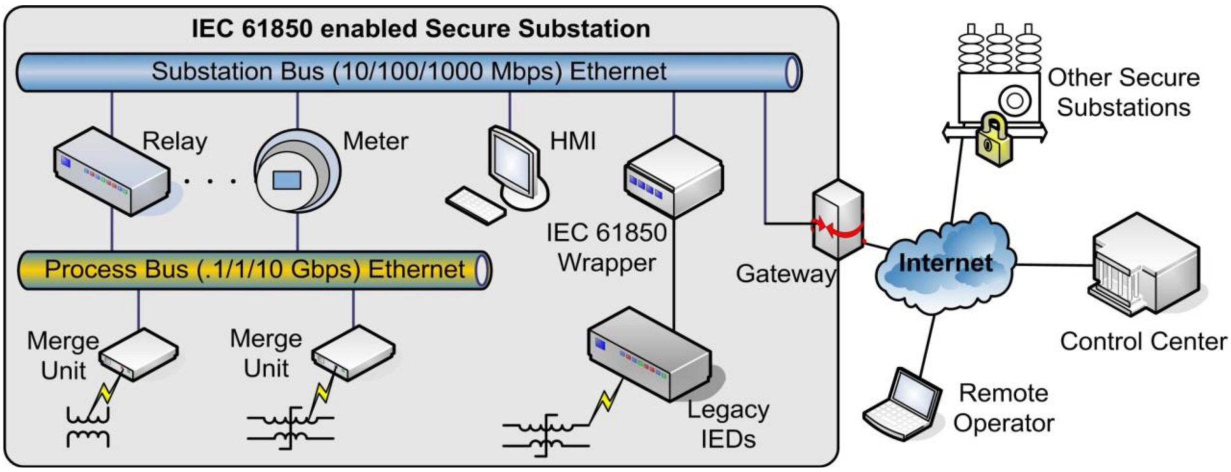

Figure 23: A typical IEC 61850 enable secure substation

4.1.4 Advantages of IEC 61850

Based on an object oriented approach and the use of main stream communication technology, IEC 61850 provide significant benefits to users. The most significantly important ones are listed below:

1. Lower installation and maintenance costs through self-describing devices that reduce manual configuration
2. Reduction in engineering and commissioning with standardised object models and naming conventions for all devices that eliminates configuration and mapping of I/O signals to power system variables
3. Less time needed to configure and deploy new and updated devices through standardised configuration files
4. Lower wiring costs while enabling more advanced protection capabilities via the use of peer to peer messaging for direct exchange of data between devices and high speed process bus that enable sharing of instrumentation signal between devices
5. Lower communication infrastructure costs using readily available TCP/IP and Ethernet technology
6. A complete set of services for reporting, data access, event logging, and control sufficient for most applications
7. Maximum flexibility for users to choose among an increasing number of compliant products to be used as interoperable components

4.1.5 Goal of IEC 61850

The primary goal of IEC 61850 is the interoperability of IEDs. Interoperability within IEC 61850 is defined as the ability of two or more IEDs from the same or different manufacturers to exchange information and use that information for their own functions. From the utility point of view there is also a desire for IED inter-changeability, or in other words, the ability to replace a device supplied by one manufacturer with a device supplied by another manufacturer without making changes to the other elements in the system. Hence interoperability is a prerequisite for inter-changeability but, in addition, inter-changeability would require the standardisation of functions available within each device which is specifically not defined in IEC 61850 to avoid any limitations. If however, the end user considers and compares all performance and functional requirements then by carefully selecting the appropriate IEDs an acceptable level of inter-changeability may be achieved at least on a functional level.

4.1.6 The logical interfaces in substation automation

Substation automation systems normally incorporate functions for control, supervision, protection and monitoring of the high voltage equipment and of the grid. Three different functions in a substation are listed below:

1. **Station** – relating to substation in general
2. **Bay** – relating to one feeder, circuit breaker or piece of plant
3. **Process** – related to high voltage power system or primary equipment and sensors.

The communication between these levels consists of physical mapping of logical interfaces. Figure 24 shows applicable logical interfaces in a substation and forms the basis for the IEC 61850 standard.

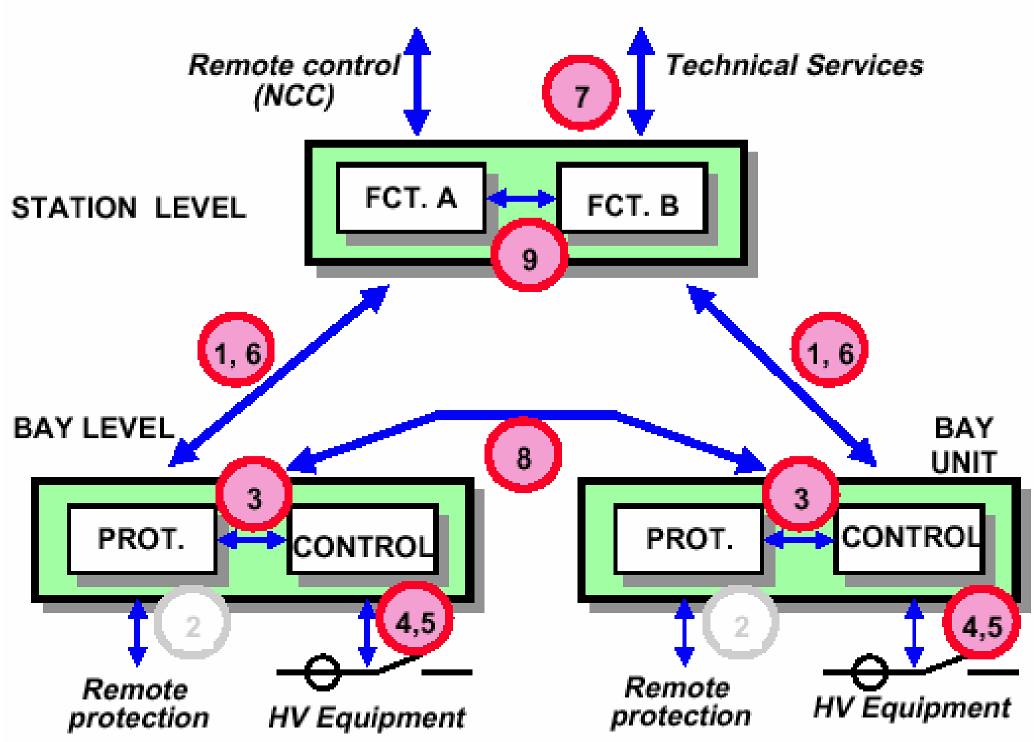

Figure 24: Logical interfaces in Substation automation (CIGRE, 2007)

At each level there are a number of physical nodes which are simply individual devices whether a circuit breaker, a sensor, a transformer, a relay, a SCADA RTU or any other IED. Within each physical node, there is one or more logical node as individual function related data group which form the basis of the IEC 61850 standard definitions. As these physical nodes are connected via the communication system, it is no longer significant or relevant as to which physical node supports the function. The logical interfaces handle the linking of the functions to other ones at the basis of the data contained in the logical nodes.

4.1.7 Logical Nodes (LN)

To create a meaning overview, all logical nodes are grouped according to their most common application area, a short textual description of the functionality, a device function number if applicable and the relationship between function and logical nodes. Each logical node has definition of the data associated with a particular function including its naming convention, the type and format of the data and it is to interpreted and used. From the communication point of view, a logical node is the smallest logical entity, which exchanges data with other separate logical entities. Therefore, a logical node is a complete, self contains function that can be addressed and whose data has to be standardised to reach interoperability.

There are two main applications of logical nodes:

1. Logical nodes representing primary equipment such as circuit breaker
2. Logical nodes related to substation functions such protection function

4.1.8 Physical Interfaces

Within an IEC 61850 based substation automation system, a local area network (LAN) is used as a communication system between the physical nodes. Hence there is a physical interface between two devices and there is a logical interface between the logical nodes within the devices. This meant that it is necessary to map the logical interfaces through the physical interface in order for the system to operate. On the other hand, logical network interface may be mapped to physical interfaces in several different ways.

4.1.9 Communication Independent Interface

Any standard may not represent the state of the art at the date of publication due to the time need for standardisation. Newer manufacturer specific solutions may have a better performance than standardised protocols and thus may be considered as emerging standards. Therefore manufacturers and utilities have to focusing on maintaining applications functions that are optimized to meet specific requirements and that have reached a high degree of quality.

4.1.10 Engineering for IEC 61850 standard

The engineering of substation automation system is a very complex process with many specific topics in view of the specific requirements of a physical switchyard and the intended operating philosophy. Questions such as the position of any intelligence electronic device (IED) within the system structure, their relation to the switchyard, the function to be performed, how and with which quality information shall be transmitted to the other IEDs in the system have to be explained in detail in this section.

The IEC 61850 offers standardised formal means to describe the answer so that they can be exchanged in an interoperable way between IED tools and system tools. For this purpose a strict and formal system configuration description language (SCL) has been defined. SCL is based on the eXtensible Markup Language (XML), which is broadly used in information technology, also in connection with web technology. During the engineering process appropriate types of engineering tools create and modify configuration files, which must be built according to the SCL rules. To support the overall engineering process three basic steps have been defined during which specific SCL files are used for different purposes.

1. Systems specification and general IED configuration
2. Configuration of applied IED and system specification is defined.

The system specification can be described in SCL using the system specification description (SSD) files. This file contains the single line topology, the basic substation automation functions and their allocation to the bays and devices of the switchyard. Due to the standard format appropriate engineering tools can read this formal specification directly.

The IED configuration of IEDs selected for substation automation system implementation is done with the manufacturer and possibly IED type specific IED configuration tool outside the standard. The result is an ICD (IED capability description) file for each IED type, which describes the capabilities in terms of functions, communication services and configurability of the selected IED type. This process is shows in figure 25.

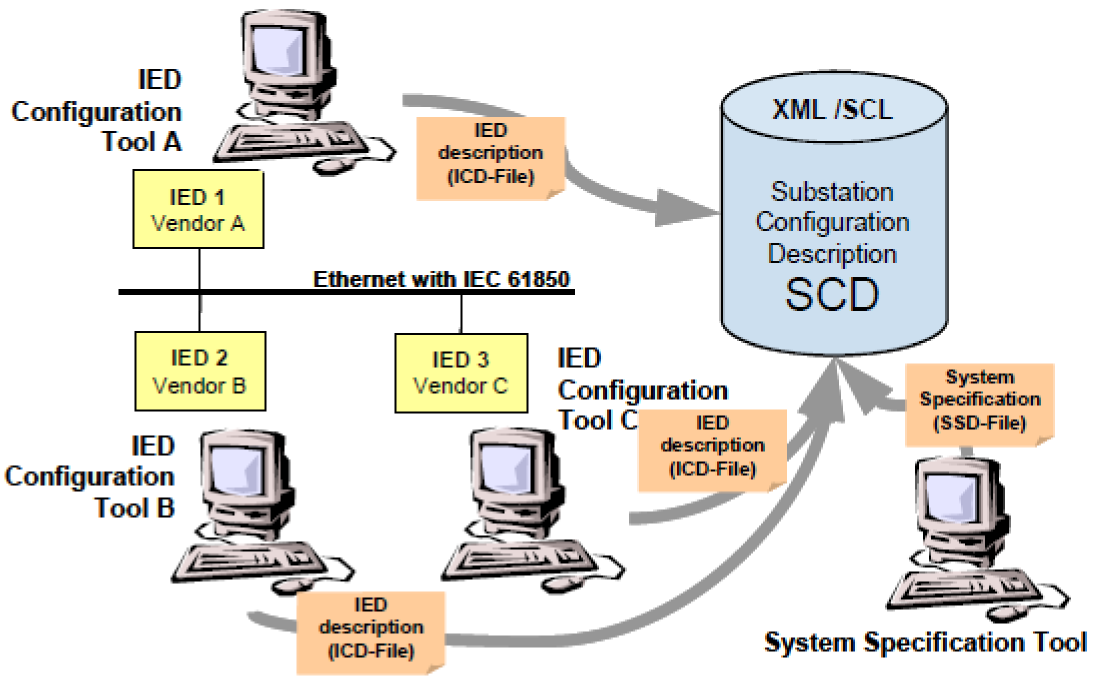

Figure 25: A typical basic IED configuration (left) and system specification (right) (CIGRE 2007)

1. System configuration

In this section, the Intelligence Electronic Device Configuration Description (ICD) files are imported into a system configuration tool. By means of this tool the functional specification such as an SSD file is mapped to the functional capabilities of the IEDs. The result in this engineering step is a system configuration description (SCD) file, which can be exported from the system configurator in the SCL standardised format as shown in figure 26.

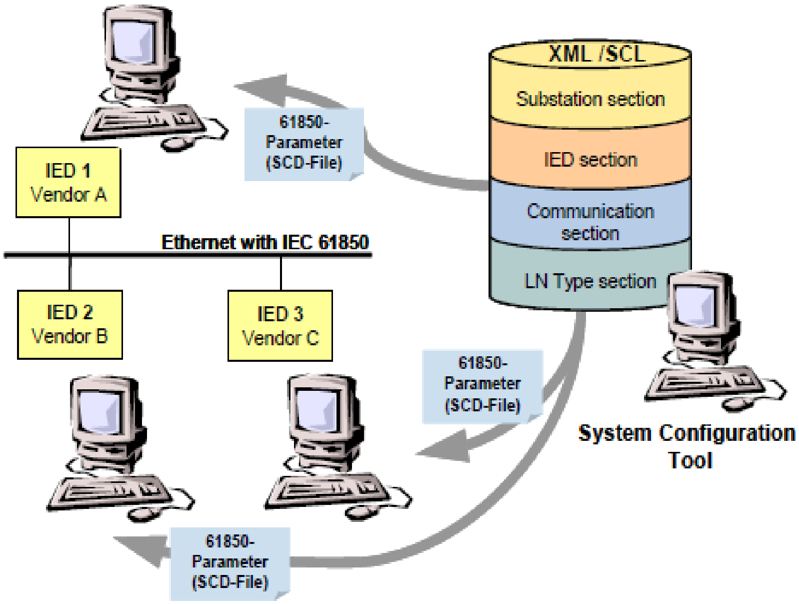

Figure 26: System configuration and the use of SCD file (CIGRE 2007)

2. Specific IED configuration

As shown in figure 26, each IED configuration tool uses the IED specific and system independent parameters that are or not defined in IEC 61850 from the SCD file to generate the IED type respective manufacturer specific IED parameter and configuration files. Through IEC 61850 standard, the engineering process is supported by a standardised system description model for substation automation applications. By the possibility to associate this model to the process and store the result in the standardised form as SCL file. Figure 27 shows specific IED configuration.

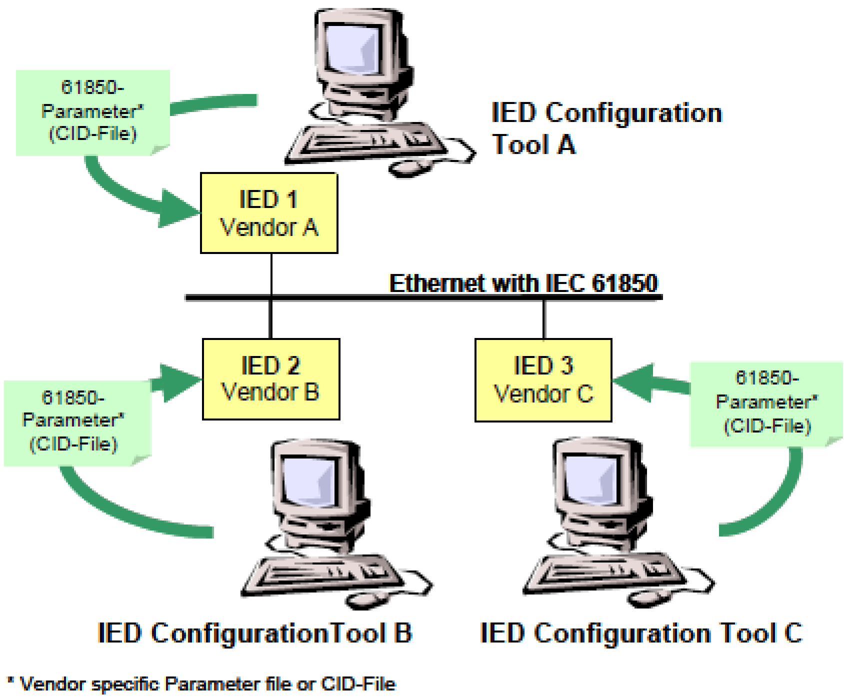

Figure 27: Specification for IED configuration (CIGRE 2007)

4.1.11 Interoperability features

The major barrier to be able to use IEDs to their full extent is the proprietary nature of the communication interfaces. Especially the use of multiple of IEDs from multiple suppliers in a single network is impossible without the use of special gateways and converters. These gateways and converters tend to limit the functionality and performance of the overall systems. However, the concept of logical nodes together with a standardisation of the data contained within a logical node allows interoperability between IEDs in order to share information and commands in a single network. With the help of the substation communication language (SCL), a formal standardised description of the engineering process is supported including performance requirements and common functions. The relationship between the process and the communication interface is shown in figure 28.

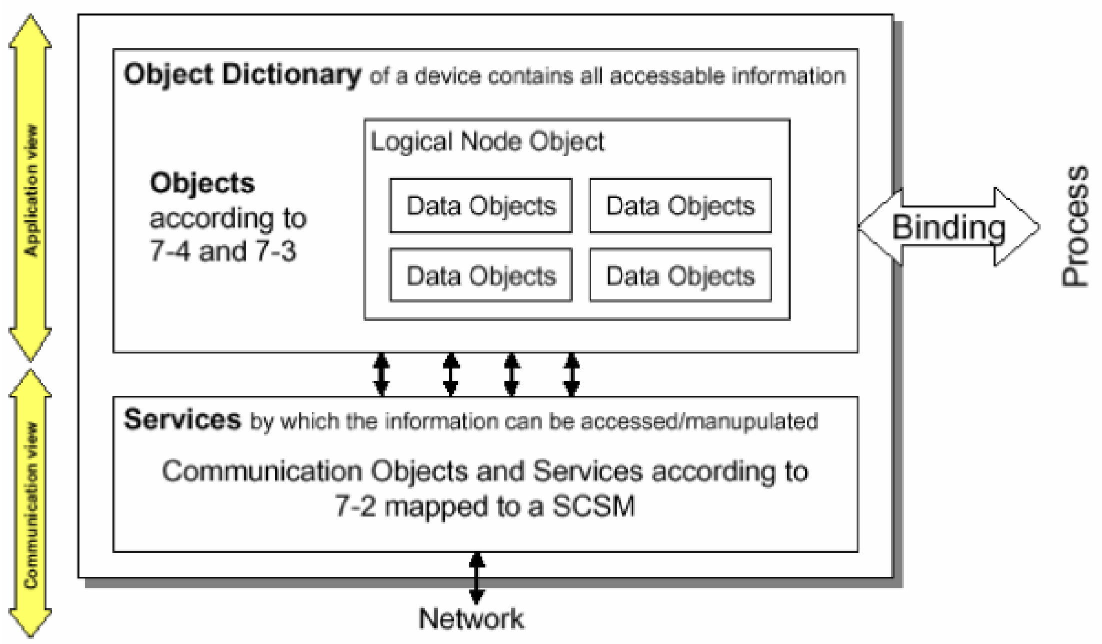

Figure 28: Configuration interface process (CIGRE 2007)

Since the naming of the data is independent of the actual device used, applications can be defined using the standardised data without knowledge about the actual device. However, for physical engineering and maintenance purposes, of course, the physical structure has to be known.

4.1.12 The IEC 61850 security capability

Research shows that IEC 61850 is a well-defined standard for the definition of protection, automation functions and the associated communication process, but currently it does not include security standard specifications needed to control access to and use privileges of IEC61850 data objects. For this reason, strong security for both local as well as remote access and used control is most important. The complex issue of communication security against hostile unauthorized access has different aspects. For example, the communication system might be wire-bound and confined to the substation, intrusion may come only over the gateways for the remote links. Therefore, intrusion protection has to be done at that point. For substation however, there will be a number of access points within substation specifically set up for security purpose that must be considered. The operator console, or human machine interface (HMI) itself is a potential access point threat through both personal computer and by plugging in another device to network. Given the important of the communication to and within a substation, vulnerabilities of communication system have to be eliminated. With regards to IEC protocols, this issue have been addressed but not yet fully resolved. The reliability of the electricity supply depends ultimately on the security and reliability of the managing system and its ability to exchange information at this point. The Control Centre and its communications need therefore to be highly secure and reliable. This is a great challenge for power utilities as new technologies emerge such as internet communication.

4.1.13 Advantages and disadvantages

The higher degree of integration of functions in a substation automation system reduced the number of equipment, devices, simplification in wiring and reduced number of cubicles. All these factors contribute to an overall cost reduction of the control system. The downside is caused by higher functional integration implies on the reliability and the performance of the overall system compared to a less integrated system using same technology equipment.

4.1.14 Summary

The main objective of IEC 61850 is to design a communication system that provides interoperability between the functions to be performed in a substation, but residing in equipment from different suppliers, meeting the same functional and operational requirements conditions. This supports the optimization substation automation systems regarding functionality and cost. In order to achieve interoperability, the user is required to have a detailed specification of the data models and communication services.

4.1.15 Conclusion

The IEC 61850 defines a comprehensive communication standard for substations. This includes a consistent data and service model at all communication level. Operational information such as indications, commands and measurement values are coded and transmitted in the same way on a possible process and station bus. The use of the same application interfaces and protocol stacks at the station and process bus levels ensures that gateway free communication links are established within the station.

Chapter 5

5.1 Analysis and recommendation for communication standards

In this section, recommendation of incorporating SCADA communication systems with IEC 61850 standard and future research are outlined.

5.1.1 Substation Automation System (SAS)

Based on the research undertaken, the efforts to automate existing substations focus on two aspects that influence the optimum control of power distribution management systems. These aspects are:

1. Economical
2. Technical

Technical solutions for energy distribution supply are important factors for long term success for energy distribution network. A major contribution is provided by substation control system. The technical requirements for this system are constantly increasing the demands on its communication capacity.

5.1.2 Incorporating SCADA RTU with IEC 61850 communication Standard

The existing SCADA master station uses the distribution network protocol (DNP3.0) for communication with substation SCADA remote terminal unit (RTU). With the introduction of IEC 61850 standards protocol, there are several devices from different manufactures that are capable of populating a DNP3.0 database by communicating with protection relays using IEC 61850 protocol over Ethernet physical layer. This functionality is specified for SCADA gateway. All relays that are compliant with IEC 61850 are supplied with an IED capability description (ICD) file. The work flow of substation configuration language (SCL) manager is shown in figure 28.

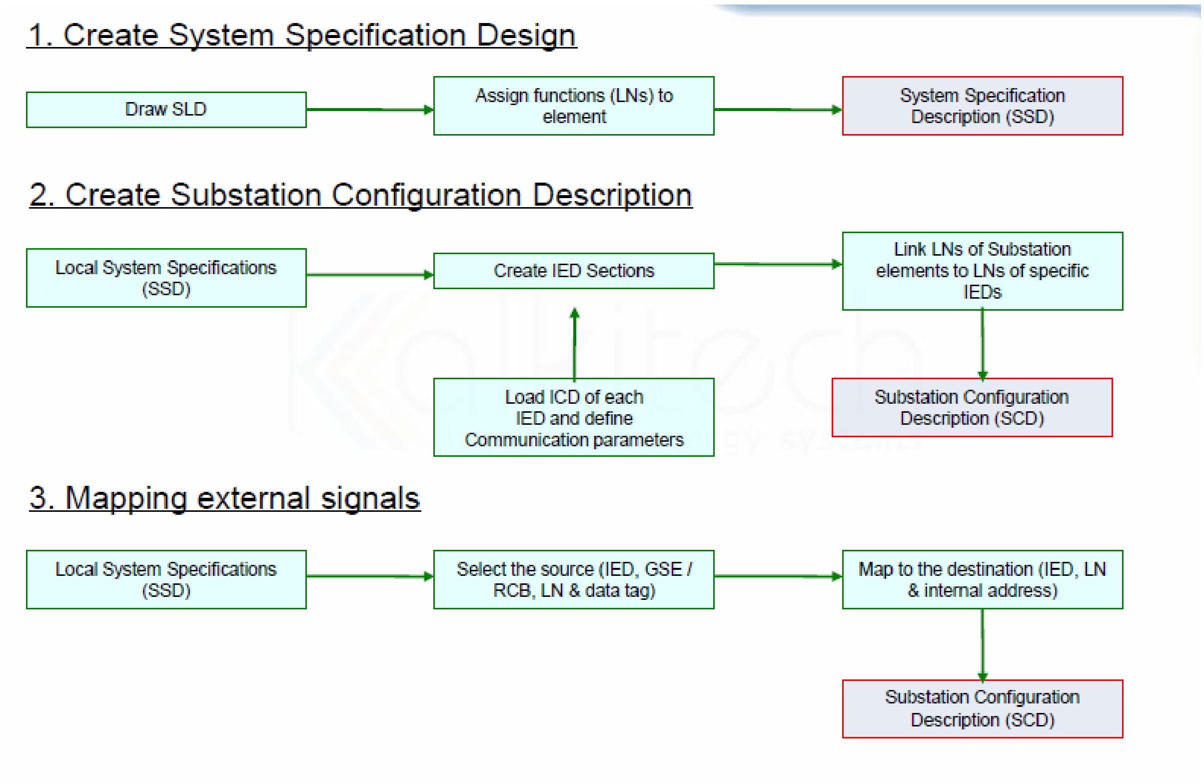

Figure 29: Typical substation configuration language

The IEC 61850 defines a formal description of substation automation configuration using substation configuration description language (SCL) (refer to figure 29) based on universal Extended Mark-up Language (XML). The SCL file is be provided by any party, comprises software that imports the capability data of protection relays in a standard format, carry out substation communication configuration and produces configuration files that are sent to the relays or devices to fully configure them for the required communication arrangement.

5.1.3 Recommendation

Given the need for remote access to IEC 61850 substation automation and protection system, there is no question that a high level security should be highly considered. On the other hand, special attention should be drawn to the problems of interoperability among intelligence electronic devices (IEDs) supply by different manufacturers for substation automation systems. Research shows an attempt has been made to build a universal standard to eliminate the problem of interoperability. In this context, the IEC 61850 standard is getting approval for flexible data communication across the IEDs in electricity distribution substations. Thus standardisation is the key for the advancement of the connectivity and interoperability of substation automation systems. Through standardisation both users and manufacturers arrive at economically suitable and reliable solution.

5.1.4 IEC 61850 network and SCADA legacy architecture

When comparing both Supervisory Control and Data Acquisition (SCADA) legacy and IEC 61850 network architecture, the following conclusion can be underlined.

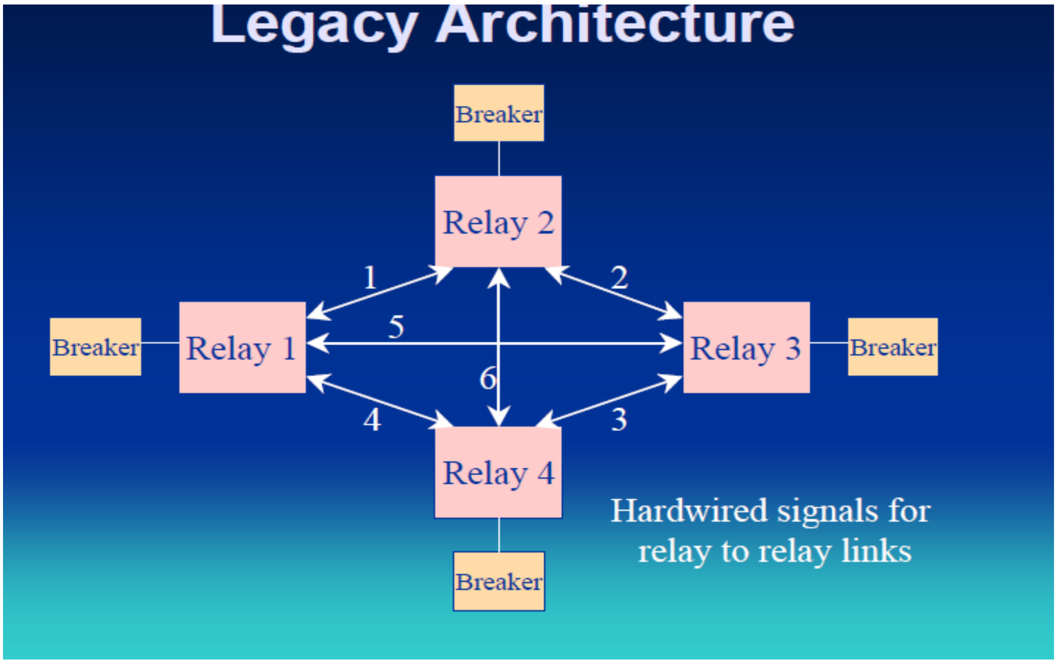

Figure 30: Typical relay to relay application for legacy architecture

Legacy architecture:

- ❖ Required N*(N-1)/2 links for N relays

- ❖ Required Filtering on links to prevent false trips.
- ❖ Reprograming can require rewiring.
- ❖ Don't know if links are working until you use them

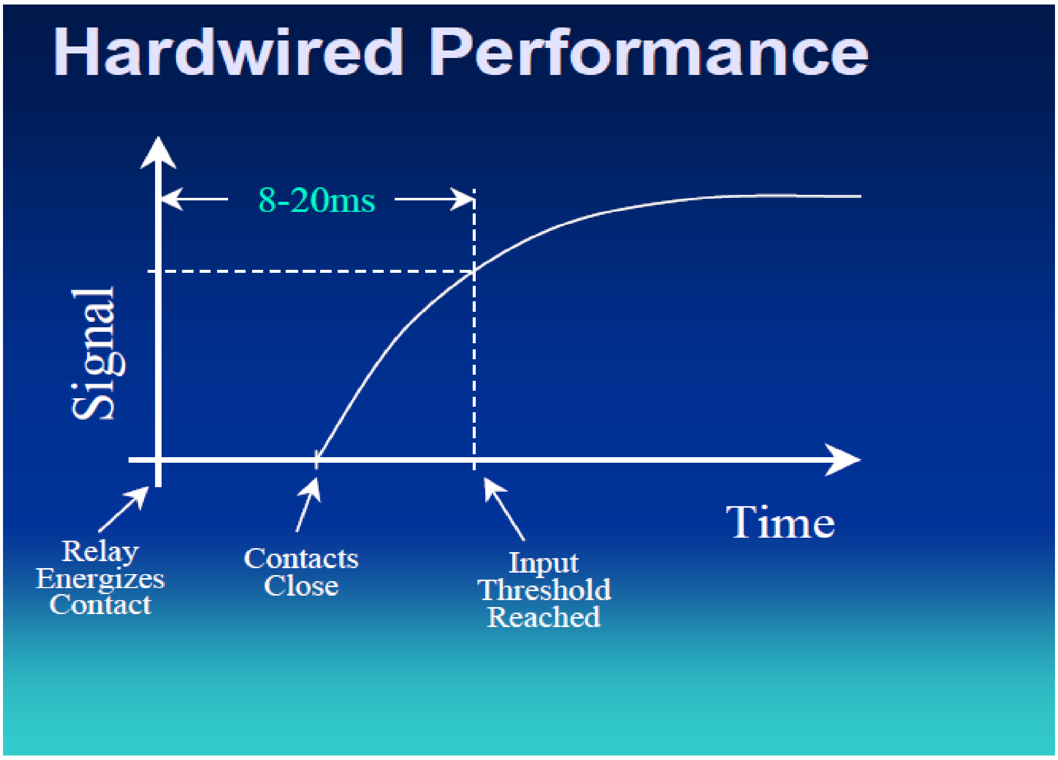

Figure 31: A typical hardwired performance (UCA, 2011)

Figure 31 shows that hardwired performance is slower compared with network architecture performance shown in figure 33.

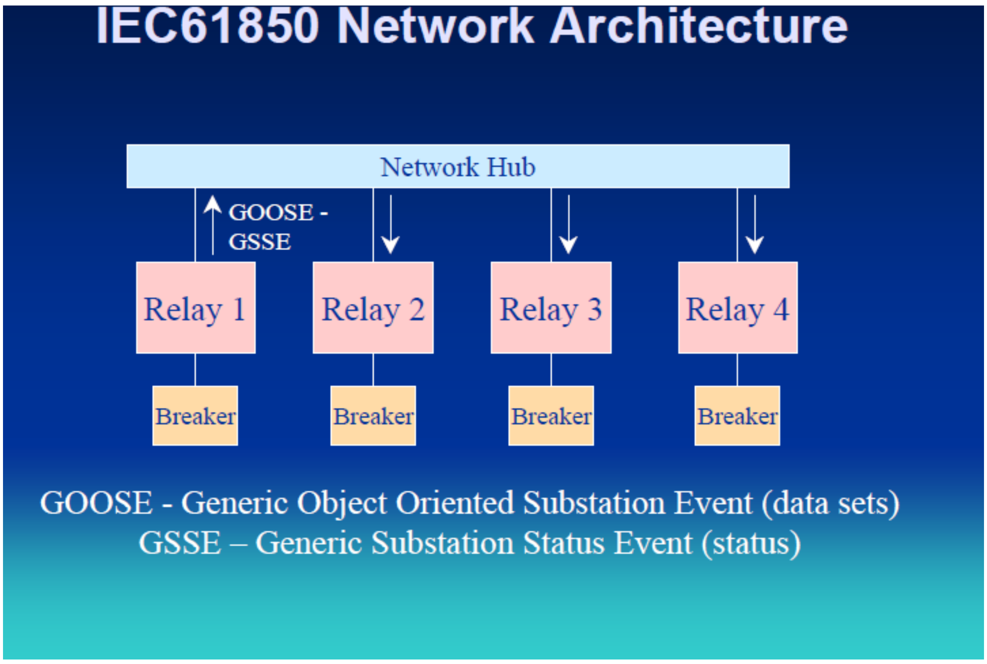

Figure 32: Typical network architecture for IEC 61850 (UCA, 2011)

For IEC 61850 network architecture:

- Relays share a common network making sophisticated protection schemes possible.
- Number of links for N relays is N and shared with SCADA.
- Relays and their status to all other relays at once using Generic Object oriented Substation Event (GOOSE).
- Status exchanged continuously
- High performance

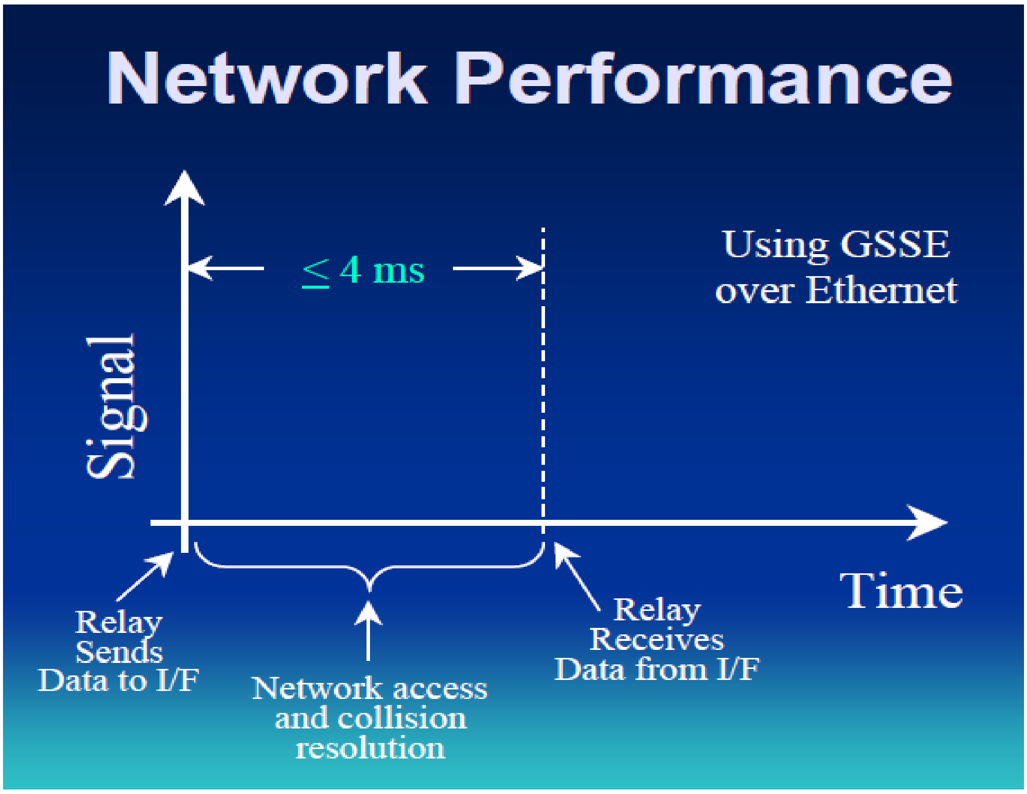

Figure 33: A typical IEC network performance (UCA 2011)

According to figure 31, IEC 61850 provide significant benefits to the users these include but not limited to:

- ❖ Reduction of wiring costs.
- ❖ More flexible programing is independent of wiring.
- ❖ Reliability: Link status known before use.
- ❖ New capabilities not cost-effective with hardwired systems.
- ❖ Higher performance with more data.
- ❖ Network access resolves very fast even with collisions
- ❖ Data is transmitted multiple times to avoid missing data.
- ❖ Digital error checking instead of analogue filtering.

In contrasts, the new concept introduced by IEC 61850 of modelling any device or function in substation as a component of complex system with a functional hierarchy, regardless of the location of an individual functional element within a specific physical device will have significant impact on the levels of functional integration in substation secondary equipment.

6. Conclusion

The aim of this dissertation was to develop new improved 66/11 kV Skid Mounted Substations that incorporate features such as Gas Insulated switchgear (GIS), SCADA (Supervisory Control and Data Acquisition) and communications that aligned with new IEC 61850 standard protocols.

6.1 Skid Mounted Substation

Skid Mounted Substation is a complete stand-alone substation (SMS) based on a modular concept that is designed to be self-contained and easily transportable. SMS provide contingencies, solutions for long term primary plant failures and additional options for the use of strategic assets for system support and augmentation.

6.2 Gas Insulated Switchgear (GIS)

Research shows that many of the developments that have taken place in the area of GIS are driven not by GIS technology itself but by general economic, environmental and business drivers. Therefore, the attributes of gas insulated switchgear (GIS) are ideally placed to respond to these challenges. Generally GIS solution minimized environmental impacts giving the preferred solution for an increasing number of customers despite concerns regarding the use of Sulphur hexafluoride (SF6) gas.

6.3 The IEC 61850 standard

It is evident from this report that Interoperability is one of the major concerns for utilities. An IEC 61850 communication standard protocol is reaching the goal of interoperability through distribution of logical nodes in various intelligence electronic devices (IEDs). This standard is incorporating data communication protocol that is suitable for several applications.

One of the key advantages of IEC 61850 standards based system is the availability of the Substation Configuration Language (SCL) that allows interoperability and seamless integration process.

6.4 Supervisory Control and Data Acquisition (SCADA)

The legacy architecture systems used by SCADA is heavily depend on hardwired secondary cabling with associated advantages and disadvantages. This will be eliminated by new IEC 61850 standard protocols which provide connection via communication networks with minimum secondary cabling.

Overall, from the discussion and evidences shows in this dissertation, Skid Mounted Substation remains an alternative solution for substation rebuilds or significant plant replacement due to its flexibility. However, due to challenges that emerged as a result of technology development, utilities have the opportunity to avoid being locked into proprietary communication standards by allowing interoperability of devices from different manufactures. This will result in cost reduction and improved quality and reliability of distribution substation automation systems. Although the objectives have been achieved to a certain extent, it can be argued that the full potential of the project is not effectively targeted. Current network distribution (SCADA) systems will still be used until full implementation of new IEC 61850 standards protocol is successfully investigated and tested.

6.5 Future improvement

In the future projects it is plan to research effect that an increase in load will have beyond the current 10 MVA maximum load on the 66 kV/ 11 kV Skid Mounted Substations. Analyse IEC 61850 especially part of engineering distribution substation automation system that related to the architecture and configuration of the primary and secondary equipment in the distribution substation. To fully understand the development of a formalised format that allows the description of all different elements and their relationships. Investigate Extended Mark-up language (XML) that provide a standard way of describing the complex structure of distribution substation protection and control systems and a format for exchange of data between different tools that are used in engineering process.

7. Appendices

Appendix A: PROJECT SPECIFICATION

University of Southern Queensland

FACULTY OF ENGINEERING AND SURVEYING

ENG4111 Research Project

PROJECT SPECIFICATION

FOR:	**THIEW ATEM**
TOPIC:	NEW 66 kV /11 kV SKID MOUNTED SUBSTATION DESIGN
SUPERVISORS:	Dr. Fouad Kamel
	Darryl Sanders, Kerry Williams, Ergon Energy
ENROLMENT:	ENG4111 – S1, D, 2011;
	ENG4112 – S2, D, 2011;
PROJECT AIM:	This project seeks to develop an improved 66 kV/ 11 kV Skid Mounted Substation by assessing the risks, operational constraints, transport restraints and design issues. The improved design will incorporate features such as GIS switchgear and SCADA and Communications that align with the new IEC 61850 protocols.
SPONSORSHIP:	Ergon Energy Corporation Limited
PROGRAMME:	**Issue 22 March 2011**

1. Research the background information relating to the design, construction and operations of the existing Skid - Mounted Substations and their design.
2. Identify, assess the risks and operational constraints, then make recommendations for the improved design
3. Create a scope or specification and design brief for a new Skid Substation.
4. Analyse and compare the variations between the old and new Skid Substations based on the results obtained.

5. Evaluate the differences to conventional substations and detail operational constraints.
6. Research the effect that an increase in load will have beyond the current 10 MVA maximum on the 66 kV/ 11 kV Skid Substations.

As time permits:

7. Design an improved 66 kV /11 kV Skid Mounted Substations based on the learning experience from the Nomad Mobile Substation.
8. Design practical methods that may improve the wiring and main electrical connections and thereby improve transportation of a Skid Mounted Substation.

AGREED: -------------- (Student) ---------- (Supervisor)

------/---------/----- 22/03/2011 ----/-----/----

7.1 Appendix B: Timeline

Topic	Starting Date	Finishing Date	Duration
Chapter 1 introduction	26/6/2011	3/07/2011	7
Chapter 2 Lit' Discussion ' Requirement etc" Writing instruction	3/07/2011	10/07/2011	7
Methodology Implement	10/07/2011	17/07/2011	7
Discussion	17/07/2011	24/07/2011	7
Correction	24/07/2011	31/07/2011	7
Writing evaluation	31/07/2011	07/08/2011	7
Testing	7/08/2011	14/08/2011	7
Writing evaluation	14/08/2011	21/08/2011	7
Result Writing evaluation	21/08/2011	28/08/2011	7
Conclusion	28/08/2011	09/09/2011	7
Presentation Preparation	09/09/2011	21/09/2011	7
Dissertation draft due	16/09/2011	17/09/2011	7

Prove reading	21/09/2011	23/09/2011	3
Print, collation, Binding	25/09/2011	30/09/2011	5
Second initial draft for supervisor	4/10/2011	17/10/2011	5
Final draft	26/10/2011	27/10/2011	7

Appendix C- Glossary

Word	Description
RTU – Remote Terminal Units	Typically an outstation in a SCADA system. Remote Terminal Units act as an interface between the communication network and the substation equipment.
SCADA	Supervisory control and data acquisition
SAS	Substation automation system
CID	Configured IED description
HMI	Human machine Interface
IED	Intelligent Electronic Device
IP	Internet protocol
Switch	Network device that cross connect stations or local area network segments.
Backup protection	Protection which is intended to operate when a system fault is not cleared or abnormal condition not detected in the requirement time due to failure of circuit breaker.
Interoperability (IEC 61850)	The ability of two or more IEDs from the same vendor or different vendors to exchanged information and used that information for correct execution.
Interface	A shared boundary between two functional

	units, defined by functional characteristics such as signal.
Interchangeability	The ability to replace a device from the same or different vendor, utilizing the same communication interface and as a minimum, with the same functionality and with no impact on the rest of the system.
IEC 61850	International communication standard for communication in substations.
GIS	Gas Insulated Switchgear
SMS	Skid Mounted Substation
CB	Circuit breaker
LN	Logical Nodes
SCL	Substation Configuration Language
IEC	International Electrical Commission's (IEC) technical committee.
CT	Current Transformer
VT	Voltage Transformer
OLTC	On Load Tap Changer
PT	Power Transformer
CIGRE	International Council on Large Electric Systems
UCA	International User group

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