Preferential Subject: IEC 61850, applications and benefits.

From wires to datasets
Case studies on Australian utilities organisation migration to IEC 61850

Paper P102

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Australia

The Australian power system context

Australia has seven transmission utilities and 13 distribution utilities and a much more diverse mix of coal, gas, hydro and wind and other emerging 'renewable' based generators. This power system supports consumers for a population of 22million through to some of the world's most remote and sizable mining investments across a country some 3000km x 3000km.

It can be said that much of the MV/HV/EHV electricity infrastructure equipment and technology in use in Australia has, to a large degree, its origins in overseas based vendors. That is not to dismiss the very strong local industry, which in many respects is world class and highly innovative in its own right. This has generally led to a general expectation that technology will be brought to Australia by the vendors when the technology has matured and they are prepared to support it "on the other side of the world" from the manufacturing facilities. The Australian drive to use good world class practice and technology is evident in the extremely strong participation in the CIGRE organisation by membership and working group activity being one of the top few of the many countries.

Within this context Australia represents a interesting arena for the deployment of IEC 61850 solutions. This article presents a summary of some of these implementations and deployment strategies that are seeing a rapid turn in the industry over the last 2-3 years.

Where have we got to?

Some have observed that as a remote country to the more significant major development centres for IEC 61850 technology in North America and Europe, Australia has largely remained, not ignorant of the Standard, but at least somewhat slow to the take up of IEC 61850 since its first release in 2004.

However where Australia may have been a lesser player in the raw development of the Standard, Australia has a tradition of rapidly adopting new technology as it becomes available. The period since the beginning of 2008 has seen a dramatic upsurge in activity as the industry develops the skill base and confidence along with the essential understanding of what IEC 61850 achieves.

A quick summary of some of the notable deployments to date include those listed in Table 1 Selection of IEC 61850 Deployments in Australia-New Zealand.

Naturally each of the projects highlighted, and others in development phases currently, have a wide range of experiences which could not be detailed within this report. There are however a number of key areas which have been identified as important issues for the industry across these projects which are discussed in this report covering:

- Rationale and Justification of making the change – "why should we bother?"
- Changing the engineering process
- Interoperability testing vs. skill development The role of laboratory test systems
- Procurement strategies and specification requirements
- Network architectures

Figure 1 IEC 61850 Panel

Table 1 Selection of IEC 61850 Deployments in Australia-New Zealand
• More than six wind farms that already boast IEC 61850 for their 11 kV system from nacelle to collector substations to the grid substation.
• Distribution utility: over 25 x 33 kV substations specifically because they needed a better solution for their SCADA deployment
• Gold mine: 143 IEDs connected using IEC 61850 in order to provide a site wide under frequency load shedding scheme – try to do that with copper wires!
• Mine site in a remote desert area boasts a 220 kV substation based on IEC 61850
• Transmission utility is currently commissioning its first 132 kV substation control room with IEC 61850 panels
• Transmission utility is deploying process bus solutions incorporating optical non conventional instrument CTs and IEC 61850 Merging Units
• First Australian distribution utility full implementation including process bus trial to be commissioned in 2012
• Several industrial MV switchgear based projects

Why should we bother?

The supply of electric power is an essential commodity which has to have ultimate reliability and security – reliability it will work when it should, and security that it won't work when it shouldn't – it is about confidence and trust in how substations are designed and built. There is much to be said for the tried and proven practices that have evolved over many decades.

Such conservatism naturally evokes many views and discussions about protection and automation of substations. This 'new' Standard for technology in the secondary systems providing protection, automation, control and monitoring of the substation is clearly 'fancy stuff' with some discussions along the following lines:

- "I don't understand it".
- "it is only for really complex extra high voltage installations".
- "it uses Ethernet which I don't trust for ultimate reliability in my office so why would I trust it for my generation, transmission, distribution or industrial consumer power system".
- "I can't afford to use it on my project"
- "it is just that special protection stuff"
- "it doesn't affect my protection procurement"
- "its not mature"
- "I'll buy one when I really need it"
- "why should I invest so heavily to change from DNP3?"
- "I'll learn all about it when we have to do a project with it"

Clearly much of these opinions tend to be based on a lack of awareness of what the technology is, let alone a sufficient understanding of the maturity of the technology and existing experience on the world scene, and certainly a lack of understanding of the implications and benefits of deployment.

There are on the other hand, an increasing many of the 'enlightened' who are already saying at the outset

- **"so fancy, how can I get the benefits in my project now?"**

These are the people who are grabbing every opportunity to proactively make IEC 61850 their engineering platform as evidenced in the rapid uptake in real project deployment and focused teams on developing the first deployments for their organisation.

Some organisations have realised that IEC 61850 could save 10-20% of the project cost and 6-12 months engineering time and are pressing to get on with it.

If that is not enough reason, the visionaries have realised that one of the most significant aspects of the technology is in the engineering process such that whatever they do today affects what will be easier (or harder) to do in the future. **Reusable Engineering** is the key to the future in consideration of the lifetime of modern secondary systems[1].

For any electrical substation asset owner they will need a solution which they can easily replace in 15 years time without having to be constrained by their vendor choice of today. They also want to be able to reuse all the engineering they do today without starting all over again on a blank piece of paper drawing wiring connections between the new boxes of the future. The hidden risk and cost of this wire based engineering is in re thinking how the same functions will be connected using different boxes and then multiple and extensive testing and validation to prove that it has been done correctly, …. again!

Application at higher voltages is generally seen as an obvious benefit, especially considering the deployment of Merging Units in the process bus to eliminate long CT cables out to the yard and several cores of CTs on each circuit. This also brings the further opportunity for the deployment of Non Conventional Instrument Transformers to eliminate the possibility of CT explosions and limited dynamic range. There is also the complexity of the control and interlocking schemes and large numbers of complex tripping and reclose schemes that are much easier using IEC 61850. Thousands of long wires and multiples of that in terminations and wire numbers on drawings can easily be saved.

Medium voltage applications have different justification. One distribution utility has feeder count of 96 CBs in one substation feeding a capital city business district. The conventional SCADA mapping and interlocking for that system alone is a huge effort. 11kV metal-clad switchgear has limited justification to replace the very short CT wires, although the number and size of CT cores for bus bar protection, double bus arrangements and the need for zone switching of the CTs is a significant basis for consideration.

Implementation Program

Of course all of the above sounds like the decision to implement IEC 61850 is a simple decision and all will fall into place. However the utilities are quickly identifying various core components that need to be addressed for an effective implementation along the lines as quoted by the IEC[2]. In various forms, detail and sequences, the utilities are addressing these seven elements:

1. Business Case, Technical Strategy, Project Management & Selection
2. SAS Definition
3. Hardware specification and procurement
4. Tool specification and procurement
5. Engineering process development
6. Scheme development & standardisation
7. Staff development

In some cases the utilities are attempting to develop their requirements and solutions using in-house expertise. Where there is spare engineering capacity this can be an effective approach with utilities considering that only they can identify and solve their internal engineering needs.

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[1] CIGRE Technical Brochure 246 (2004): *"secondary equipment such as protection, control or communication equipment has a lifetime of approximately 20 years."*

[2] *"Technology is not the barrier to adoption. The fundamental issue is organization and prioritization to focus on those first aspects that provide the greatest customer benefit toward the goal of achieving an interoperable and secure Smart Grid."* http://www.iec.ch/zone/smartgrid/grid_needstandards.htm

In other cases there is reliance on vendors to interactively develop their preferred off-the-shelf solution to meet the emerging requirements of the utility. This provides an expeditious implementation with learning opportunities for the utility based on what the particular vendor has proposed.

The third approach is the engagement of specialist consultants with the aim of broader consideration of both the user needs and practical implementations that can be specified to the ultimate system integrator. This gives the opportunity for learning and policy development within the utility whilst opening up opportunities for consideration of the best that multiple vendors have to offer.

The engineering focus

Some of the early Australian implementations have essentially used the communications aspects of IEC 61850, the protocol part if you use that term, to enable the replacement of wires in the substation and between substations. The communication element allows this signal to be output as a communication message to a particular address IP address and the network handles the rest. Such an approach is still the fundamental device level engineering on a signal-by-signal level. This has allowed various systems to be installed which are classed as IEC 61850 at various wind farms for applications such as transfer tripping between the nacelle, the collector substation and the main grid connection substation.

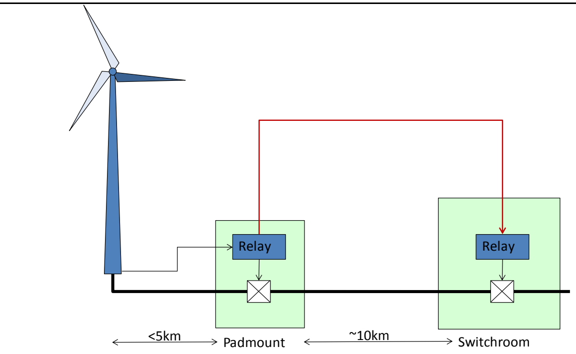

Figure 2 Wind farm application of transfer tripping

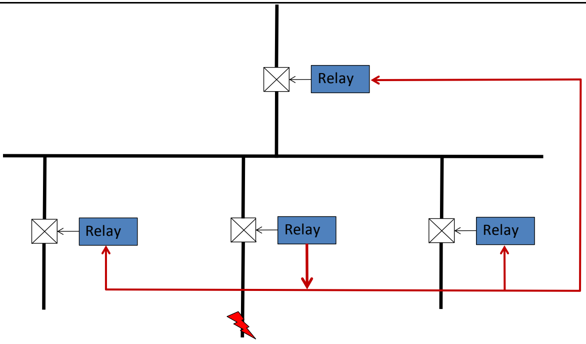

Figure 3 Typical CB Fail implementation

At the next level of engineering is the use of GOOSE and defining datasets. The first transmission utility implementation of station bus was simply specified as to provide all bay to bay and bay to SCADA signalling using IEC 61850.

The first implementations referenced above have essentially been delivered as vendor-led solutions. In most cases these implementations have provided the Configured IED Description files as the ultimate implementation of the scheme. These implementations have not as yet addressed the system level engineering of the System Specification Description file and the System Configuration Description file requirements. Whilst these implementations therefore can wear a badge of IEC 612850 technology, they cannot be considered as fully compliant to IEC 61850 having avoided the Reusable Engineering process implied in Part 4 and Part 6 of the Standard. Despite some claims by vendors that it is only necessary to use their device configuration tool, this is just another form of the individual device engineering process of previous technology and proprietary software. Utilities are now actively seeking the use of true System Integration tools to provide the upfront specifications, reusable files and documentation requirements.

As utilities look to using more holistic system integration tools, there is also a reconsideration of where the IEC 61850 tools themselves fit into the larger engineering process and life cycle of the substation. This encompasses the process and tools for power system planning, plant layout, cable schedules, SCADA master station configuration, in-service protection setting management, test procedures, isolations etc.

Laboratory learning

Engineers like to learn without interference from others and we like to test the limits to the extent of being very disappointed if we can't "break" the latest device offering from a vendor!

Hands-on-learning is essential to be effective and competent engineers in the implementation of the technology. In order to achieve this, as IEC 61850 is about the implementation of a System, it is no longer testing a single device. This means the engineer needs a system representative of the required SAS. Herein lies the chicken and the egg – knowing enough to specify what you want to play with vs. playing enough to specify how you will use what you know.

It is not necessarily true that it is the fault of the technology or the vendor if these test systems find things that do not work. If you ask for a bridge you will get it but you may only get that vendors version of a bridge. A little more effort will get you world class bridge of the right length for the right traffic with the right opening mechanism when a ship comes along the river, a solution that suits your operational objectives, but the specification of your needs has to be done up front.

The investment in these laboratories, playgrounds or sand pits is therefore an expensive exercise. Utilities can usually fund this through their general equipment procurement but must staff the process with people understanding the complete secondary system operation and the necessary networking and system configuration skills. Other organisations have more difficulty in such technology research and skill development. It is not uncommon that a couple of panels of IEDs, switches and test equipment is an investment of some $200K, and even then is a very select set of manufacturers and a very select set of device functionality. It is very hard therefore for organisations such as consultants and contractors to establish these facilities that will provide the essential learning environment for a multitude of client needs and applications. Even the vendors as system integrators and panel constructors have a significant requirement when taking responsibility to assure a proper functioning system when particular third party vendor selections are imposed by the client.

Beyond the laboratory with a few devices in a simulated system, there are also moves to establish "substation university" environments where full bays are implemented as part of a live substation in order to evaluate performance of process bus applications for NCIT, Merging Units and intelligent field devices as shown in Figure 4 and Figure 5.

Figure 4 Optical CT Retrofit

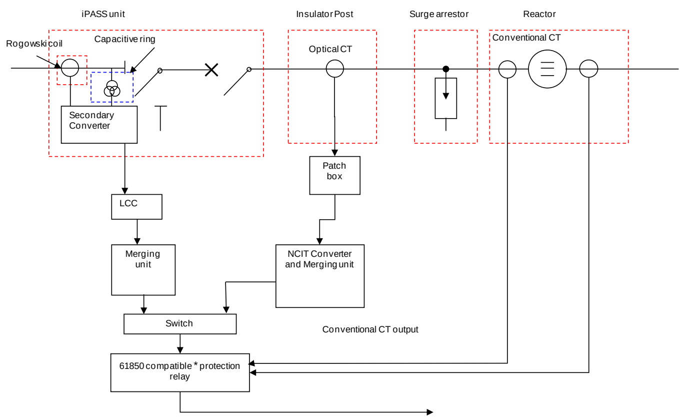

Figure 5 Optical CT performance evaluation system

Figure 4 Optical CT Retrofit shows the installation of a new optical CT to an existing substation. The Australian developed optical CT sensor can be seen at the top of the stanchion and the insulator string carrying the optical fibre is seen running down to the left at 45degrees.

Figure 5 Optical CT performance evaluation system shows the system for evaluating the performance of the both the optical CT and a Rogowski coil against a conventional CT.

Procurement implementation strategies

The vast array of utility organisations, vendors, contractors and end users naturally means there are many approaches to implementation depending on business models and drivers as well as the propensity and capability of the organisations and people skills to invest in the process.

Applications in the industrial sector are driven by significantly different requirements to the utility sector. In principle this is related to the core nature of the business.

As an example, a mining group is driven by having reliable and fast access to power to be able to carry out their core business of digging dirt. They generally aren't specifically interested in the engineering process their contractor uses to design and build the substation. However even this is a changing environment as the mine operator sees benefits in having visibility of key information about the power system and some form of control system integrated to their overall mine or processing plant management system. Moreover, the industrial clients are realising that they also face the issue of refurbishments, upgrades and augmentations so the substation is not a 'build and forget' asset.

The utility sector is driven by the long term process of generating transmitting and distributing power. Their core business is the power itself and the infrastructure asset over long periods of time, generally more than 50 years. This sector is seeing its wave of change in accommodating renewable sources, micro grids and the ubiquitous Smart Grid. At the core, the requirement is about a safe and reliable asset.

It is not surprising that some organisations took an approach of simply adding a line in their procurement specification for the protection equipment as "all devices shall be IEC 61850 compliant" or at least some words to the effect that they should "have an upgrade path to compliance in the future". However one utility reported finding a device that has claimed use of the Standard based on the only function as LLN0 – the name plate, it has no other functional Logical Node!.

Equally the upgrade path is a strange requirement ranging from presumed firmware upgrade or card replacement to a full relay replacement. These paths may or may not be achievable in service or on site or may necessitate return of the equipment to the factory which may not suit the immediacy needs of the future project. The upgrade path requirement also presumes that having engineered and commissioned this wire based substation, there is a desire and justification to subsequently rip out all that engineering and wires to be replaced with an IEC 61850 system, just because you can.

Perhaps there will be future projects in the conventional substation which will start an IEC 61850 implementation that will benefit from having devices that are upgradable to IEC 61850. However, this effectively means that the new project is essentially a whole new concept of the SAS for the substation which presumably you would not want necessarily constrained by the (potentially now inappropriate) choice of a relay made five years earlier simply because it had an upgrade path. The upgrade path presumes that the future requirement is known in terms of Logical Nodes and ACSI communications services to be supported in detail of the nuances of mandatory and optional implementation defined in the Standard.

Broader multi-discipline teams

A growing realisation is that the protection engineer alone cannot develop the complete concept and implementation of a substation automation system.

The SAS is now an Ethernet environment with IP and MAC addresses at its base and requirements for configuration of network switches. Naturally this has caused some initial reluctance to involve people from pure information technology areas that run the corporate head office LANs. On the other hand these groups understand the configuration issues associated with network environments and have added to the skill level of the team developing the SAS. Of course selecting the right team members who understand the difference between real time signals needing guaranteed sub-millisecond performance as a critical infrastructure in a substation applied using the network configuration options of IEC 62439 vs the less onerous performance of the corporate data network may involve some training on the overall application requirements.

Along with the general IT network and hardware involvement is the realisation of Cyber Security issues. This generally evokes a range of responses including:

- "Is anyone really interested in hacking into a substation? Opening a circuit breaker isn't really much fun"

- "They can do more damage by jumping the substation fence and removing trip links or blowing up a tower down the line (have you watched the original Ocean's 11 movie?)"

Certainly no-one wants to be the first person responsible for a substantial power system event as a result of a cyber intrusion. Whilst this perhaps is based on the justification of FUD (Fear, Uncertainty and Doubt), the normal risk analysis reviews are increasingly including the cyber issues. These are supported by increasingly relevant information such as being produced by CIGRE in the D2 and B5 Study Committees specifically on cyber security. The involvement of true cyber security specialists in developing the SAS is helping to make sure the industry doesn't reinvent the wheel and the wheel has all the necessary elements to be an effective solution.

As an example, in the 'old days' when the LAN network supported highly proprietary protocols and generally only talked to devices to poll data which was restricted to physical connectivity in the substation rather than have real time interaction. In these circumstances, utilities used a spare open port on the network switches for anyone to connect PCs and test equipment. In the cyber risk analysis these ports must be closed and measures implemented to enable control of access to the LAN by contractors and even the utility staff with utility PCs complying to the utility security policy - the staff may have stopped off at the internet hot spot to check their bank balance on the way to the substation and picked up a new virus. This adds some complexity to the process but the potential for denial of service, spoofing, network performance degradation and many other threats must be eliminated to sustain the reliability and performance of the system. This involves both procedural controls of authority to do certain tasks, physical facilities to do the tasks. Devices are now being proposed as test and operation interfaces which manage the requirements for operation of the SAS and in particular testing mechanisms.

Network Architectures

Deciding on a network architecture is a complicated exercise. References such as IEC 62349 "High Reliability Networks" provide help in respect of defining the characteristics of the many generic possibilities. The utilities still need to determine which suits their requirement. Several systems have been deployed, not surprisingly all of them working to provide an operational SAS – these include

- Ring
- Star
- Rings with stars
- Stars with rings
- Duplicated, fully segregated rings
- Duplicated, linked rings (Figure 6)
- Duplicated, dual connection IEDs to both networks with failover (IED only talking to one network until fail over) (Figure 7)
- Hierarchical (multilevel) star (Figure 8)

One industry body with transmission utility membership has attempted to give guidance to the industry on at least the starting point of these considerations with the arrangement shown in Figure 6 Duplicated, Linked Rings referred to as the "Reference Architecture" as one arrangement (of several) providing the necessary protection redundancy through duplication to satisfy the requirements of the National Electricity Rules (NER)[3]. Whilst this Reference Architecture is shown as duplicated rings, the NER requirements could as well be met by duplicated star networks.

[3] **Extract of NER Clause S5.1.9**

(c) ……. The Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected…..

(d) …… the primary protection system must have sufficient redundancy to ensure that it can clear short circuit faults of any fault type within the relevant fault clearance time with any single protection element (including any communications facility upon which the protection system depends) out of service.

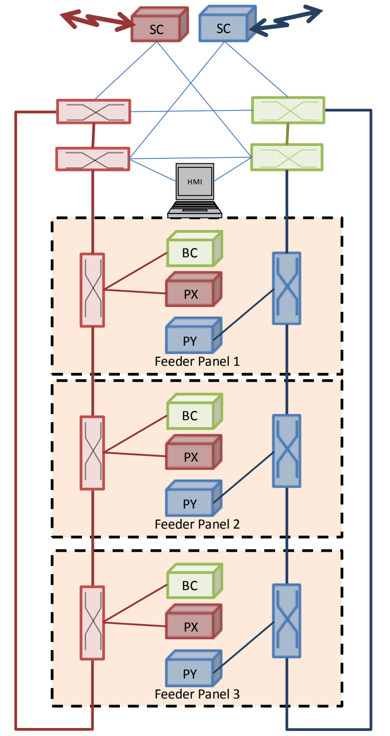

Figure 6 Duplicated, Linked Rings

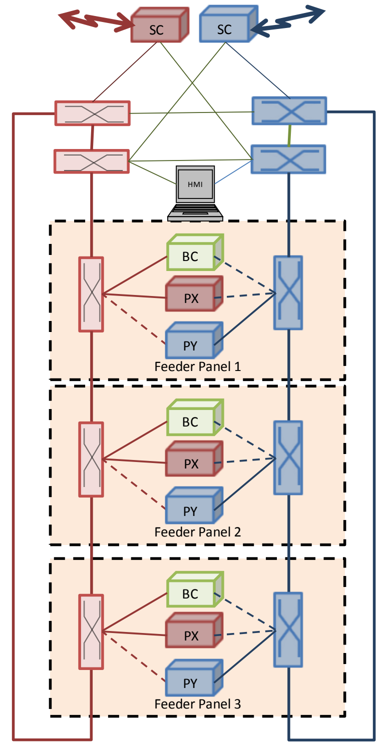

Figure 7 Duplicated Rings, Dual Connection IEDs

The arrangement in Figure 7 Duplicated Rings, Dual Connection IEDs is clearly a highly advanced level of security involving special fail over mechanisms within the IEDs to detect failure of the preferred left or right network as appropriate to each IED and switch to the healthy alternative network on the other side. This level of automatic network switching is significantly higher reliability and availability than the NER requirements which accept one of the redundant protection systems to be out of service for up to eight hours.

Figure 8 Duplicated Hierarchical Star shows an arrangement for a single diameter of one and half breaker and the two halves of a split low voltage busbar for both X and Y systems. This system has been determined in order to maximise the independence and continued operation of the network when one section or bay is taken out of service for maintenance and ensure that a single LAN failure affects no more than one diameter on one system, noting that the duplicate system continues to function correctly.

Redundancy considerations have also been introduced by the Standard for Power System Data Communications[4] requirements down to the point where the real world is translated into digital form. This implies all the SCADA related equipment shown in Figure 9 Zone of Redundancy Requirements for the SPSDC must be sufficiently redundant as to always provide correct operation of the national grid.

[4] **Extract of NEMMCO SPSDC:**
"Data communications facilities must be arranged to have sufficient redundant elements to be reasonably expected to satisfy the reliability standards :
(a) the likely failure rate of their elements;
(b) the likely time to repair of their elements; and
(c) the likely need for planned outages of their elements."

"data communication facility": that part of remote monitoring equipment and remote control equipment that provides the analogue to digital conversion function; …."

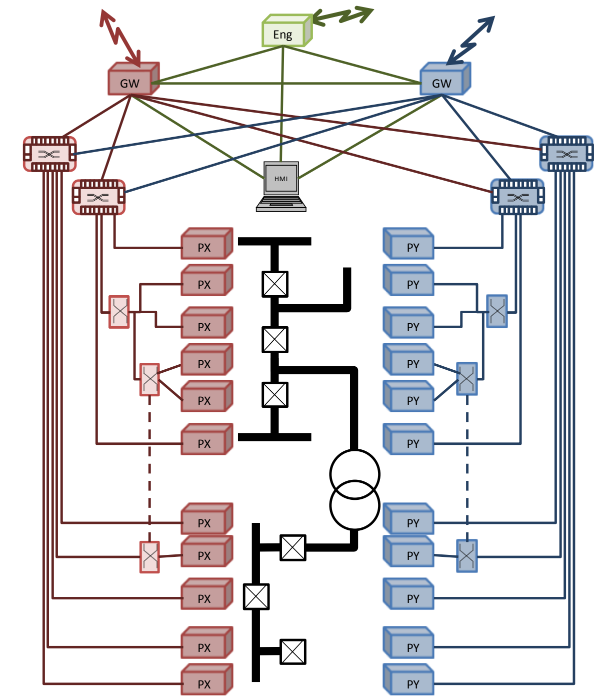

Figure 8 Duplicated Hierarchical Star

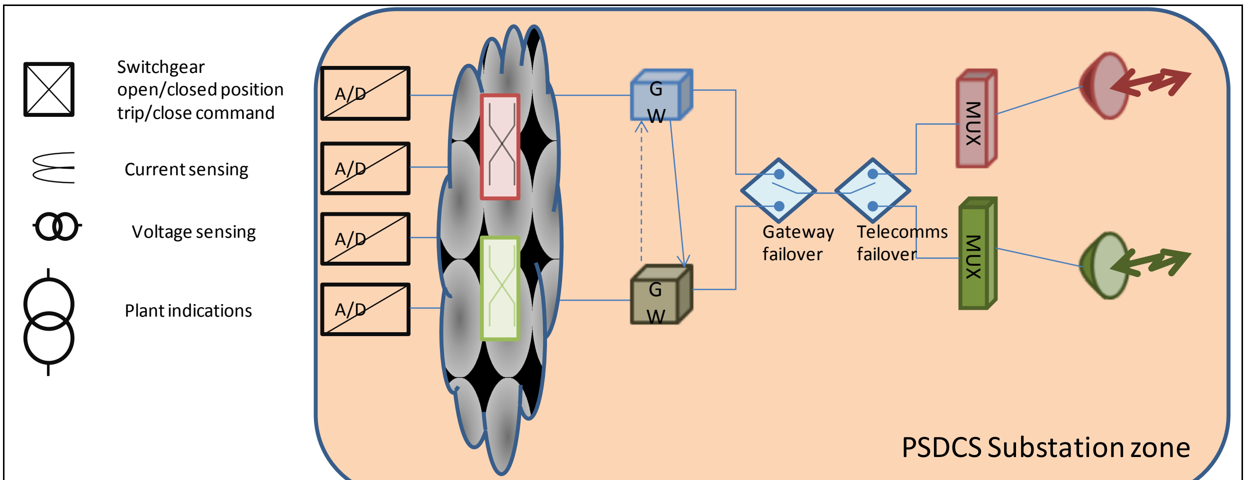

Figure 9 Zone of Redundancy Requirements for the SPSDC

Operational Facilities

The facilities for operating, maintaining and testing the Substation Automation System are a vital element of the SAS design. Fundamentally these facilities must provide an interface for humans and equipment to the SAS. Any operator visiting a substation will readily recognise the location of these facilities as they are familiar in a generic sense as switches, lights and isolating links as shown in Figure 10 Conventional Operation, Isolation and Test Facilities.

Notably these facilities have not changed significantly in concept over the decades of substation design for two reasons – they are simple in concept and operators prefer the familiarity of these facilities. In most utilities, the types of test blocks, the types of switches and the types of indicator lamps are standardised across all substation projects so as not to introduce operator confusion and reduce operator training costs. Notably these facilities remain in place regardless of whether the individual devices are energised or are being replaced. These principles should and must not change simply because the means to pass information and signals between devices as non-human beings now changes to Ethernet technologies.

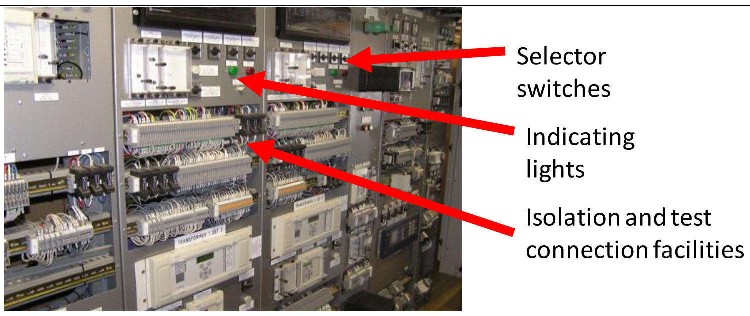

Figure 10 Conventional Operation, Isolation and Test Facilities

The fundamental principles for operating and maintaining the substation shown in Figure 11 Generic Operation, Isolation and Test Mechanisms include

- Blocking or enabling a signal between two functions – e.g. disabling an autoreclose initiate whilst lineman are working on a the second circuit of a double circuit line
- Changing the parameters or operating modes of a function e.g. changing settings of the relay trip setting to match summer/winter line rating
- Isolating a function or device inputs &/or outputs in order that certain tests can be carried out or even the device replaced

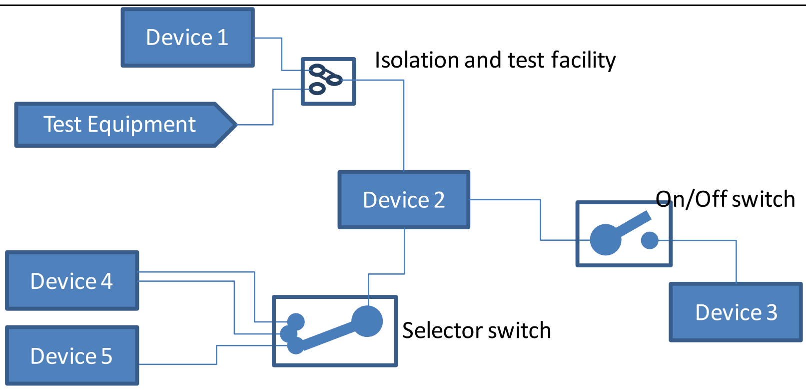

Figure 11 Generic Operation, Isolation and Test Mechanisms

In the digital SAS, these operational considerations remain exactly the same. They are however more complex in that where such facilities were provided by a physical break in the wire connecting the signals to or from the device, this is not so easily achieved when hundreds of individual signals are all operating over a single fibre connection between devices which are sending and receiving millions of messages every second.

Naturally an easy solution to these operational procedures is to provide a mechanism on the IED itself which replicates the process of enabling/disabling a function, changing a parameter or creating a virtual isolation of the device, noting that in the latter arrangement the IED still receives and sends messages, but the messages are now being ignored. Alternatively a system can be implemented on the substation HMI to manage the isolations of the equipment, subject to the HMI not having been stolen or corrupted itself.

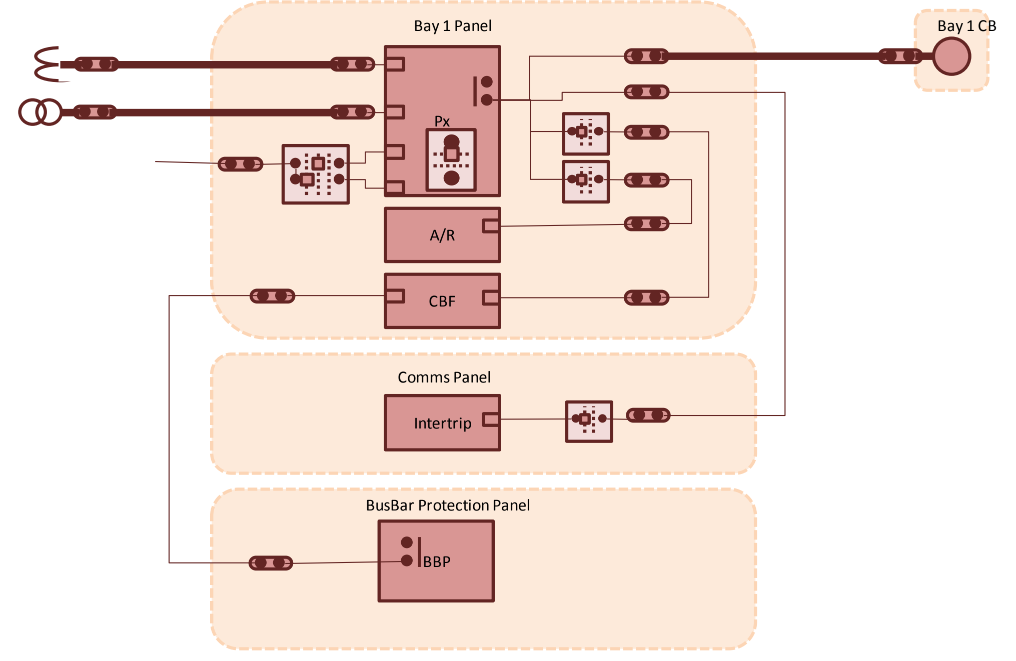

Figure 12 Conventional Wired Systems

However whilst simplistic this does not meet the essential requirements of operational facilities of

- Being recognisable by operators in every substation regardless of the choice of vendors' IEDs, now and in the future.
- Being independent of the types of functions and degree of functional integration now and in the future
- Being independent of the IED such that any interaction with other IEDs is maintained when the IED is powered down or physically disconnected from the SAS network

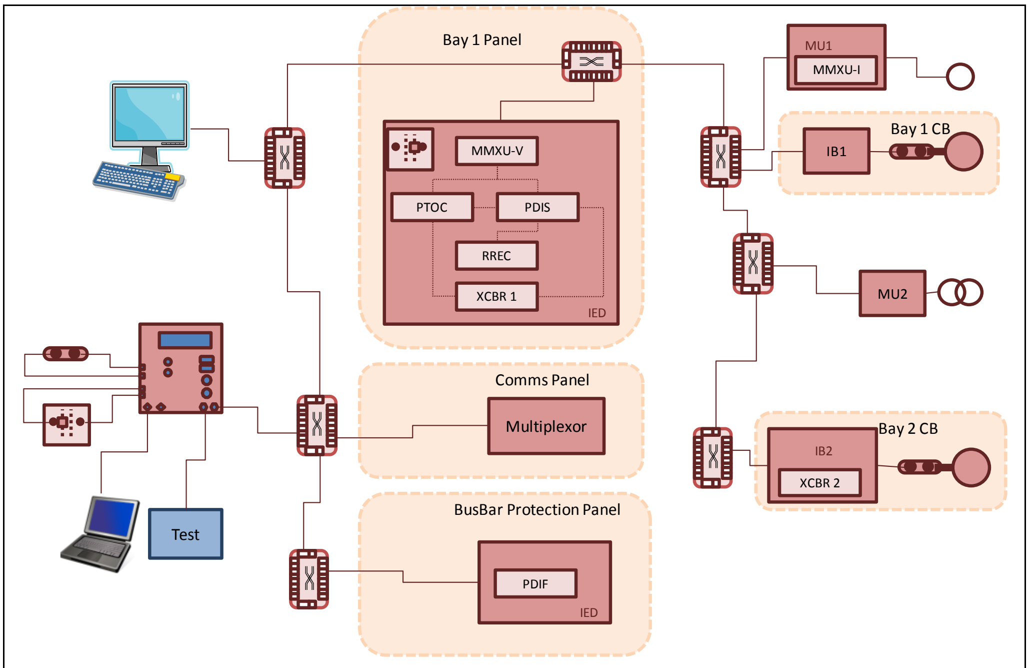

Figure 13 Virtual System Interface

Figure 13 Virtual System Interface shows a system using a specific device as the Operator, Isolation and Test interface which manages the commands to the various IEDs to implement the isolation, manages the security aspects of connecting equipment to the LAN and provides the familiar operation point for the operators regardless of IED or HMI vendor, wither via the physical links and switches on the panel or via its own integrated facilities.

Digital SAS must still provide the essential facilities operating the substation in a virtual environment. The utility must remain free to choose the particular vendors and IEDs to suit the functions and performance of the SAS under its automated design. However under human control, specific facilities are required. In particular during transitional stages, there will be some reluctance to change the physical process of operating the substation in order to control the impact of implementing new technologies. Hence there may in fact be a requirement to retain the same isolating links, switches and indicators as conventional SAS but connected to the Operational Interface (Patent lodged) which then converts the requirement to the virtual messages to control the IEDs and functions.

Conclusion

Australia has recognised the importance of adopting IEC 61850 as being an essential element to securing the ability of utilities to deliver an increased capital works program and enable future projects to be delivered more efficiently.

There is already a significant underlying belief that the technology essentially works, although some areas such as Merging Units are yet to reach commercial maturity.

The issues that concern the industry are more towards:

- the organisational change and the implementation process,
- the specification of needs,
- the new engineering process,
- the implementation of appropriate solutions for automation and operation,
- staff development.

All these factors must be considered in the context of a critical infrastructure that must operate "24 hours a day, 7 days a week", including during operation maintenance and test, else blackouts happen and people die.

Sound engineering practices must be used that build on the wisdom of decades of 'conventional' wired solutions and must be tailored to the diversity of different organisations needs and business models.

Abstract

Australian utilities and major industrial sites are starting to embrace IEC 61850 within their substation design solutions taking a pragmatic approach based on business drivers that demand new technology based solutions rather than just technology for its own sake.

The experiences gained already indicate there are many issues to be managed beyond the technology itself. These are being addressed in practical and innovative solutions that will embed IEC 61850 as the engineering platform for substation development.

Biography

Rod has 30 years experience as a protection engineer with an equipment supplier, a utility and consultancy organisations, with the past 25 years as General Manager and business leader roles.

He now runs his own niche consulting business focused on supporting the industry in learning and applying IEC 61850 technologies to substation engineering. He is a strong participant in international industry associations, is a highly experienced technology trainer and educator.