SEAPAC 2007
CIGRE Australia Panel B5
Sydney 14 – 15 August

Utility Wide Migration to IEC61850

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Keywords: IEC61850, protection, migration path, implementation strategy, network asset management infrastructure,

Abstract:
Modern power systems are undoubtedly extremely complex systems. Technology has evolved in electric power systems from knife blade switches to the latest in SF_6, vacuum and GIS switchgear. Fault detection systems have evolved from simple fuses and relays to complex wide area protection schemes. Control systems have evolved from operator manned substations to sophisticated SCADA systems operated remotely. Telecommunication services have developed from basic on/off hard wired signalling between substations to low band Power Line Carrier then medium capacity radio and now the virtually limitless capacity of optical fibre.

All these technologies have evolved over many years with the help of a number of generations of engineers thinking about how best to solve a particular problem. At each step in technology there has been much thought and debate about the best way to adopt the technology or indeed in some cases whether not to adopt the technology. At each point the technology change has largely been incremental, limited to that particular item in the substation.

The industry however is faced with one of the most evolutionary and perhaps revolutionary changes in power system design and operation with the introduction of the new standard IEC61850. This technology has wide ranging implications throughout the substations arguably as never seen before. Changes to primary equipment specification, design and functions enabled throughout the substation, the type and capabilities of secondary systems, the expansion of inter and intra substation communication systems and the skills of designers, operators and maintenance crew to name a few.

CIGRE itself has a number of Working Groups working on aspects of IEC61850 and the implications. A new Technical Brochure has been completed by WG B5.11 on the introduction and impact of IEC61850 and is an excellent reference source for utilities embarking into the debate.

Behind all of this is the changing commercial nature of utilities, many now operating under a “return on investment regime” as private entities. In order to satisfy this business model, utilities must approach new technologies such as IEC61850 not only on technical grounds but also on a comparative investment basis in regards to cash flow and available funds. This paper puts forward some of the pros and cons of this debate and the impact on the migration strategy which is likely to affect a “utility wide” implementation strategy, not just a single project

1. Technology To Date

In reviewing the activities of the protection industry in particular, the last 30 years has seen a huge shift in focus.

In the 1970’s most of the activity was centred on the move from electromechanical devices to the first generation electronic devices. This highlighted the need for interference proofing of electronics. In the latter half of the decade some work started on the introduction of microprocessors into substations but mainly in data gathering or control processes. However each box essentially still performed just one primary function, i.e. an over current relay was still largely just an over current relay manufactured using printed circuit boards.

The 1980’s saw electronic relays increase in population and the first microprocessor based protection relay. Digital concepts were borne whether they be simply turning the analogue quantity into binary 1’s and 0’s based on whether the waveform was positive or negative during the cycle, to basic Analogue to Digital (A/D) conversion allowing functions based of basic look up table from memory. Logic based functions were borne on the basis of a digitised representation of the waveform. The emphasis here was to develop innovative electronic or digitised solutions to protection operation. Hardware design also dealt with power supply fluctuation and interference issues, signal isolation techniques, auxiliary supply voltage ranges, component selection and manufacturing techniques.

In the 1990's the numerical relay came into vogue – the analogue waveform was turned into an instantaneous number every millisecond. Calculations were then carried out using a variety of algorithms and the effort was to define the best algorithm for the purpose. At the same time, the concept of communicating to the relay was created both directly in front of the relay and remotely via dial up modems.

The 2000's have marked the work required to satisfy the issues that have developed from all that has preceded – the need for interoperability and standard communication protocols and systems. It is not surprising that a large portion of technical discussion is presented around experiences of implementing a certain substation communication system, or the explanation of certain protocols and their benefit over another. Even casual reading of current industry material will highlight the proliferation of subjects such as TCP/IP, an object oriented model, a GOOSE[1] message, a header frame or the virtues of any of the dozens of communication standards.

Clearly technology is therefore an increasingly important issue in modern substation designs and IEC61850 is arguably one of the most significant. The significance lies in that IEC61850 affects every piece of plant and equipment in the substation as well as the SCADA, telecommunication and business IT domains throughout the entire utility. It is centred on better availability and use of information throughout the entire utility operations.

IEC61850 therefore deserves some broader consideration of what this technology will enable, not just in terms of the substation design and equipment selection, but indeed how the whole utility organisation can benefit, and hence the justification to adopt this technology.

2. Commercialisation of the power industry

Initially utilities were driven by the ever increasing demands of the public to build more power networks. As Government based enterprises, the "public good" was served by more power stations, larger and longer transmission lines and a continual spread of distribution services to cater for sprawling populations.

Of recent times, power utilities have undergone a rapid change in their approach to their capital expenditure. No longer is the "public good" the sole driver for power system developments. The mere fact that many utilities are privately owned has introduced an element of what is good for the shareholders. The "Return On Investment" or "Business Case" to justify an investment for the commercial returns it delivers to the owners has added a new dimension.

Certainly on the major development issues, the regulatory regime operating in many places serves to direct utilities to make sure they respond to market demands. This in itself sometimes leads to alternative supply options to be proposed in a mix of generation, transmission or distribution solutions that would be the least cost to the community. The utility itself is arguably not fussed by whichever option is chosen, provided that if it is their solution, that they receive the appropriate regulated return.

Even minor capital expenditure requests and strategy choices on technology now increasingly incorporate the return on investment analysis within the utility. This is not a bad thing in itself as it brings a measure of perspective and rationale to any particular decision.

On the other hand there is a risk that even the decision to replace a 30 year old relay becomes a decision based on return on investment or some form of business case. Such decisions could be justified to the extreme that a major black out could eventuate due to the failure of an out of date relay to detect and clear a fault. Hence the decision to

[1] Global Object Oriented System Event defined in IEC 61850

replace a relay for a total cost of a few tens of thousands of dollars is a naturally wise investment compared to the direct financial loss of the utility in lost supply, the penalties that may be imposed by the regulatory bodies or even just the loss of public confidence and corporate image that may result. On the other hand, it could be equally argued that few blackouts are actually instigated by the failure of a protection device as the inherent duplication and back up systems and the maintenance and monitoring systems have been designed to prevent or at least minimise such situations.

On this logical basis, a protection system is hard to argue against in any risk/reward analysis. It is the same as an insurance policy that you would hope to never have to claim against for the damages, personal or property, yet is well worth the investment of paying the premiums. There is no real ROI for an insurance policy, it is essentially just a cost. If there is no investment in that cost, when disaster strikes the greater cost would cripple the utility.

Undoubtedly though there is a consideration of “Reasonableness Of Investment”, to define *ROI* in a technical sense, in choosing the right level insurance cover and premium, or equally the type and extent of technology used in the protection system. Whilst the technology is undoubtedly a cost, there are many operational issues as a result of technology choices. In this sense an appropriate choice of technology may yield significantly more accurate and timely data leading to faster response times and reduction in operational costs. In an accounting sense this Return On Investment is hard to prove as there is no specific financial transaction that shows an income stream to the utility. There is only an absence of cost, the amount of which can only be hypothesised by comparing what the costs might have been had the technology not been available.

Even to introduce remote communications, some form of payback analysis has become common place. Most utilities will have already implemented some form of remote communication to a substation and some of the devices in the substation. This will of course vary from simple dial up systems to individual devices, through to more sophisticated engineering LANs and WANs. It is likely that such innovations were supported by a variety of justifications for reduced operating costs and reduced response times.

Undoubtedly the ability to retrieve a fault record – sequence of event or wave form information – will enable more detailed and timely investigation of a fault. Many utilities will suffer the problem of several hours of travel time for technical crews to reach site to extract information from equipment which is obviated through the use of remote interrogation over a telecommunication link. Even the ability to interrogate equipment for equipment failure conditions will enable improved maintenance and corrective actions.

Hence such technology has the potential to significantly reduce real operating costs and times. In terms of investment payback, this affects the life time cost analysis of the substation compared to the capital investment within the substation.

However at the outset of the expenditure approval request for a modem or a communications link, the justification is a bit nebulous. It can only hypothesise that for a particular incident, should it ever happen, that a certain set of costs may be avoided. Even reviewing a real event post technology introduction would rely on a hypothesis of what might have been the costs else wise. As an example it is hard to predict or identify the real cost difference or impact on the utility between reliably extracting an event file from all the devices 400km away in a few seconds versus how many trips to site were necessary to get similar or perhaps more obscure data from a select few devices. Suffice to say there is a significant improvement which can only be quantified by hypothesis and experience of what would have been.

3. Network Asset Management Infrastructure

SCADA has long been an essential tool in power systems operations allowing remote monitoring and operation and the reality of unmanned substations. This has been enabled through the use of telecommunication links connecting the central control system to the Remote Terminal Units in the substations.

Equally there are many examples of operational benefits of faster event response times, less site visits etc as a result of remote engineering and maintenance tools for the Intelligent Electronic Devices (IED) in the substation. These tools operate over the same SCADA telecommunication link or independent, sometimes dial up facilities.

As the number of devices with communication capabilities have increased, and as the SCADA system has become distributed throughout the substation on a communications ring, the concept of a Local Area Network (LAN) in the substation has become reasonably common place. This optimises the number of connections to the outside world from within the substation.

Outside of the substation, the increased data flows has led to utilities introducing Wide Area Networks (WAN) to link their substations to their control centres and engineering departments.

However the concept is rapidly becoming not just establishing a WAN. This is similar in the way that inter and intra-office Information Technology (IT) systems have developed much broader use than just connecting a PC to a printer. The IT network has become the hub of how the company operates and is the repository of its essential knowledge base to allow that to happen.

Utilities are facing many obligations under the commercial and regulated regimes in which they operate. For them, the issue is managing their assets to have a means by which to make profit. It's not just about keeping the lights on. It is not just about having a world class electricity network. It is about profit.

With this in mind, both SCADA and substation WAN infrastructure generally has one purpose – providing a Network Asset Management Infrastructure (NAMI).

NAMI is a concept that says the asset must be properly managed. An asset may be the power system, a substation, a transformer, a circuit breaker, a telecommunications network, a relay or any other element within the utility. It also encompasses the information to enable that to happen efficiently such as the drawings themselves as key assets of as built information and the various databases of setting configurations as an essential asset to the operation of the network. Equally staff and the contractors are an asset to the organisation who need constant and ready access to information at their desk or on site – whether that be emails, the knowledge data bases or suppliers web sites. Some utilities have recognised some of this intuitively with an "any data, any where, any time to any authorised user" concept.

Clearly this opens up the whole realm of complete business and operational systems where in principle information is made available throughout the organisation. The business it, operational SCADA and engineering domains are now co-joined in a seamless system.

4. The Easy Migration Path

With this ultimate NAMI concept in mind as arguably the utopian outcome, we are quickly drawn back to reality that such systems are not going to happen over night. The fact remains that there are limitations in how such a magic wand could be waved, both in the availability of funds and in the time to implement such systems. The utility is therefore left with a hybrid system for many years to come.

We are therefore left with a conundrum that the cost benefits of new technology are justified on the elimination of practices, procedures and costs associated with old technology. However the old technology is still a significant part of the substation. As an example, a partial augmentation of the substation may well be the vehicle to install new technology, but the same substation may well have a number of technology generations preceding the new one. These multiple generations may cover from the initial substation development even up to 40 years old to perhaps just a few years old at the last refurbishment.

As network owners (utilities and industrials alike) face the issue of implementing these new NAMI systems in one form or another, there has been a huge outcry that the cost is high to completely replace the secondary systems in the substation. Undoubtedly there is a cost.

This has led to the development of the “migration path strategy”. This is a plan that allows new technology such as LANs to be established in a substation on a restricted or partial basis as the rest of the substation is not materially affected by the augmentation.

However it is time that this limited approach to justification of spending money needs to be reviewed in as much as the review of what technology is required.

Consider a typical 30-year-old substation. Hard-wired controls, a SCADA RTU, mimic control panels, thousands of slide link isolation points etc.

Now consider where technology will take it even over the next 10 years, a time frame which is not out of the question on the basis of the information being published in papers at every conference around the world. A substation LAN with direct connected IEDs, business LAN functionality, security systems, full device interoperability.

In the meantime what does a partial implementation do?

This effectively islands part of the substation as old technology from the new systems. If nothing else, the old sections of the substation are unlikely to provide the same level of functionality and hence benefits as the new equipment.

As this continues over several years, the new system should gradually grow on a limited and opportunistic expenditure basis. Perhaps in 10 years time, the whole substation will have been converted and seemingly the objective of a painless and low cost change over will have been achieved. But is that really so?

Considering the operation of this hybrid substation evolution, it is evident that there is a conflict in many technical areas.

Two types of local control systems will exist – each probably only controlling part of the sub. The potential for operator error is high, exponentially compounded by the increase trend towards outsourcing of service provision.

The logic operation of the substation is equally at risk. The old section is likely to be hardwired interlocking whilst the new system will be numerically based. Hence significant additional engineering and change to operational procedures will be required which will need to be reconsidered at every subsequent partial augmentation. Isolating a piece of equipment will change from removing a link to entering a command with both systems being used in different parts of the substation.

The initial substation was fully coherent - all secondary equipment of a similar age. The gradual replacement throughout the substation will mean the age profile of the secondary system will spread. As a result, the complexity to integrate the next secondary system partial upgrade will increase and the utility will be locked into upward spiralling integration costs. Even just the effort to scope the next stage of works at the site will escalate as it cannot be simply assumed that the secondary system is of a certain vintage and construction standard – it will need to be checked at the detail level and the scope analysed on a circuit by circuit basis to determine how much work must be done on adjacent bays. Interfaces to interfaces could proliferate.

Furthermore, as a result of the diversity of contractors and their individual design strategies and processes, after even just a few augmentation iterations, the substation will look like a patchwork quilt put together from the left overs of other quilts – quaint in its own way but hardly impressive as a well planned and engineered standard of system.

Of course the most significant driver for all this technology is reduction in wiring and panel space combined with the operational cost reductions of remote interrogation etc.

Inevitably “Murphy’s law” will result in any power system fault occurring on the line or substation section where the old secondary system remains. Site visits will still be necessary; response times will still be days and maintenance programs will still be based on frequent testing. Hence the cost benefits of the new system cannot start to be realised at that substation till the entire substation has been upgraded.

This is clearly not satisfying the commercial drivers in the organisation to actually reduce costs in the short term to pay for the investment.

Hence the easy and gradual migration path must be carefully challenged within each utility to assess whether the costs savings that the new technology should introduce will actually be achieved.

There are 2 significant risks to be explored. the first is that the operating cost and time savings used for the justification of the capital cost won't be realised until the whole substation has been upgraded to the new technology. Secondly, that in trying to operate a hybrid arrangement more costs and most significantly, considerable confusion will be created in the design and daily operation of the substation.

It therefore begs the question as to whether a partial implementation on a very limited extent of the substation is truly an easy migration path. There is a strong case for considering a more substation wide implementation of the new systems with an associated increase in reliability and integrity.

In this respect an earlier CIGRE[2] Technical Brochure[3] is extremely pertinent in its opening remarks

> "*Primary equipment has an average lifetime of approximately 40 years and secondary equipment such as protection, control or communication equipment approximately 20 years. Consequently, the secondary equipment has to be refurbished once during the lifetime of the substation*"

This report was based on the equipment used in substations to that date. Never the less there are many examples of substations where the primary equipment has been replaced at the end of its life whilst the protection systems have remained, as they are essentially still operating correctly, with many examples where a well maintained electromechanical relay will last for several decades.

The contention that there should be (at least) one complete replacement of the secondary systems in the middle of the life of the substation generally over simplifies the issue. Over the life of the substation there are many augmentations and changes of primary plant and layout that lead to partial augmentations.

Equally the 20 year life assumption was based on generally accepted physical end of life criteria of equipment to that date such as reliability and age of components or the availability of staff with the skills to continue maintenance of the equipment of that generation.

However in reality, the definition of "life" has changed dramatically. The operational improvements available with new technology means that Asset Owners are increasingly demanding new equipment with greater capabilities on shorter and shorter cycles simply because they are bound to provide operation cost savings. Simplistically this is similar to a typewriter that would last for many years whilst the life of a PC is now driven by the speed at which it can support new software on a 3 – 5 year cycle, yet the fundamental process of typing is largely at the same speed. Certainly it would be an unusual large company that had half of its staff using typewriters and the others on a networked PC environment.

As a result of this reduction in effective life of substation equipment to perhaps 15 years or less, there is a much higher requirement to obtain the operational cost savings that form the basis of the initial expenditure proposals from the earliest opportunity. This includes a way in which to approach future works with so called forward compatibility of technology with minimum integration costs.

The availability of IEC61850 devices with total interoperability suggests that in order to get the real and maximum benefit of the technology, everything needs to be of a coherent technology standard. Hence even technology of just a few years ago could be considered at the end of its life and the idea of an easy migration path is harder to define even in looking at a single substation augmentation.

As a start, the age profile of all the equipment in the substation must be reviewed along with

[2] CIGRE : International Council on Large Electric Systems http://www.cigre.org/

[3] CIGRE Technical Brochure 246, Study Committee B5, "*The automation of new and existing substations: why and how*" August 2003.

the planned future augmentations and replacement programmes. The objective must be to find ways to minimise ongoing and future costs through the best technology update and harmonisation strategy. This may involve additional investment in these newer enabling technologies such as IEC61850 to a greater degree than just the limited migration path would suggest.

5. The New Substation Design

Ultimately what all this means is that any device can be connected onto a LAN replacing all wires between devices. This includes

- current and voltage transformers,
- circuit breakers, isolators,
- transformers, tap changers,
- Cap Banks, SVCs,
- relays, controllers, RTUs, gateways

and any other electronic device for measuring, monitoring or controlling plant within the substation.

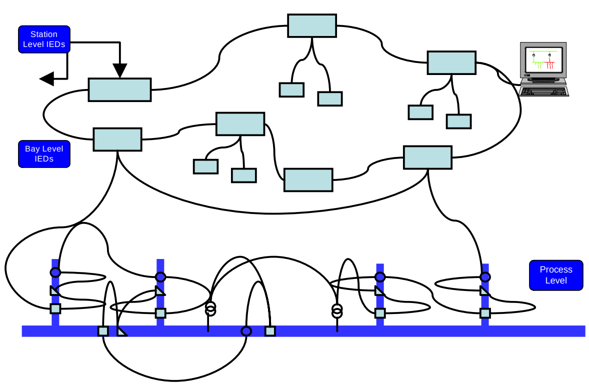
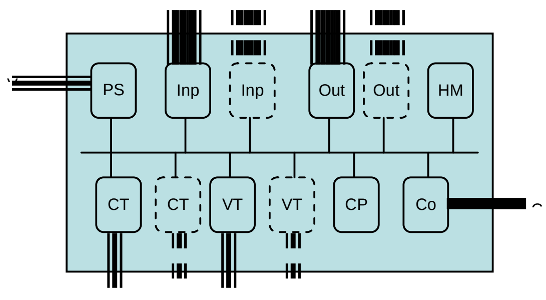


Figure 1 LAN based Substation Connection Diagram

Hence the complete connection diagram for a substation, not just the functional architecture, can almost be shown on one diagram (Fig 1), excluding ac and dc power supply connections to the equipment.

This clearly shows the ability to connect to all devices using an Ethernet cable, most likely fibre optic but equally conventional Cat 5/6 cable as in an office. Of course such a diagram is usually presented in a more structured means showing the 3 levels of substation, bay and process bus communications hierarchy. These structured diagrams with horizontal bus and vertical connections certainly depicts the logic operation of these systems but in reality there is nothing in principle to prevent a single communication loop to be used. The choice of one all embracing single loop, or a number of sub-loops or even just direct connections is all determined by the utilities preference for segregated domains, virtual LAN arrangements and the use of switches and firewalls to direct and control traffic.

The essential point is that there are very few individual wires left in the substation if nothing



else, dramatically reducing the design drafting effort.

This is more evident by looking at an individual relay for example with hundreds of connections to each box (Fig 2):

Figure 2 Conventional Device With Hundreds of Wires

Fig 2 shows that for a conventional device, hundreds of wires would need to be shown on drawings, repeated for every bay with individual wiring numbers. This extends to design and construction quality and verification check systems in place.

An IEC61850 device in the ultimate could reduce to just the communication system(s) connection and the auxiliary supply (Fig3).

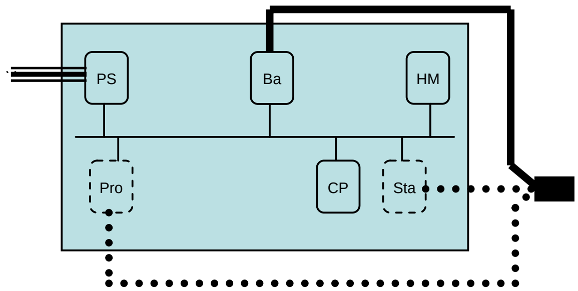


Figure 3 LAN Device With Few Wires

6. Engineering the Design

Whilst the virtual elimination of most of the wires in the substation will simplify the design & documentation process as well as the physical construction installation and commissioning processes, there remains a requirement to engineer the complete substation system. As individual wires no longer carry individual signals, a single Ethernet cable will carry tens of thousands of signals every second.

It is therefore necessary to determine what signals must be sent and the manner in which they will be sent e.g.:

- automatic broadcast one device to all
- automatic one to one device
- polling from all devices
- polling from a specific device
- the priority of each of the above

A typical device configuration file will therefore look something like the following – note the extent of information listing on the right for just one of the 28 nodes shown on the left.

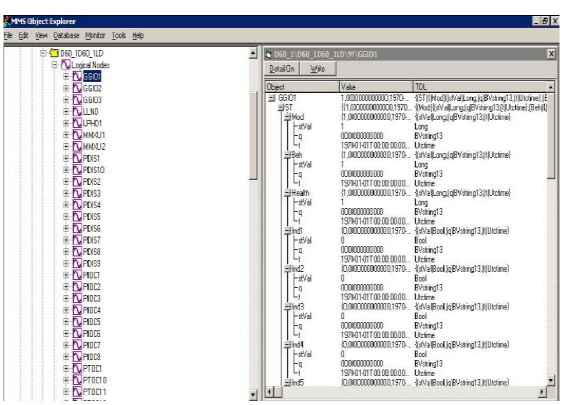


Figure 4 Typical IED Configuration File

The design drafting expertise in determining which terminal to connect a wire to and what to name it, will be replaced by expertise to analyse the available signals in a device or on the LAN and determine how to configure the device to respond to, use or issue that information.

A complexity and opportunity of this is the new freedom with which functions can be provided within the substation from a more diverse source of information. Previously the device manufacturer designed a certain array of fully tested and self contained functions to be available in the device. It was then a process of selecting which devices provided the functions that would satisfy the operational requirements of the substation.

IEC61850 provides the ability for the system integrator to select any signal from any device and combine it with any signal from any other device to create a particular function. Hence in the configuration process it is necessary to carefully consider what is the function, where does it get its data from and where will it send the results. This in itself will need some quality control measures as well as testing and validation methods on the complete system to be applied to avoid bugs. The freedom that the technology presents implies the integrator must develop a close understanding of what each piece of information represents and how frequently it is updated in order to use it appropriately.

7. Operating the substation

At the risk of skipping over several stages of installation and commissioning, another aspect highlighting the impact of IEC61850 is to consider some of the operational changes within the substation. This is by no means trivial as IEC61850 extends to all the primary equipment and interfaces including current transformer signals, trip signals to circuit breakers and a vast array of condition and status monitoring information.

One of the most common tasks in a substation is to isolate equipment before testing. In general this involves removing a fuse or a link of some sort to create physical and observable electrical isolation of a piece of equipment. It is a fundamental step in any work process definition – isolate and confirm. This of course assumes that by looking at a connection diagram of the device, all the isolation points can be individually identified and can be individually and physically verified as isolated at the equipment.

However in a LAN based system with devices providing and receiving information from a host of other devices, it will not be reasonable to simply pull the LAN connection from the device and expect to operate it or the rest of the system to operate in a normal manner. Therefore some alternative means of isolating the device, or perhaps a function within the device must be provided with the same level of security as physically breaking the connection. With such reliance on virtual isolation, it could be argued even higher levels of security to prevent incomplete or incorrect isolation of the device/signal are required.

On the up-side of course is the improvement in reliability with such functions as trip circuit supervision being inherent in devices monitoring the flow of signals on the network continuously.

Whatever systems are provided there will inevitably be a training process for a wide range of staff – from engineers to operators to technicians to response crews.

The mere fact that the protection and control scheme is no longer "electrical" in nature but rather essentially an IT based system, there will be some inevitable organisational interactions to be defined that have not been considered previously. Indeed the effective extension of an IT LAN into the substation brings a raft of corporate IT based services available in the substation and hence a whole raft of issues in allowed applications, access security and even just responsibility for network configuration and maintenance.

As an example, a signal from one relay to another may well pass through a LAN switch, the fibre LAN, a router, a firewall then onto the external telecommunication system and the reverse process at another substation. In a "conventionally" structured utility, this then crosses the domains of protection, IT, telecommunications and of course the different technical staff who respond to failures. Clearly cascaded failure response from one crew to another is unacceptable as each sequentially eliminate their equipment's contribution to the problem. On the other hand IT staff have generally not worked within the substation, nor has the telecom staff necessarily dealt with IT security systems that would allow them to replace a firewall without IT having a vested interest in how it is set up. The same would apply to any other element of replacing a protection relay and establishing a new IP address or the change in a router for the path that a time critical signal is passed through the network.

8. Utility Wide Implementation

Any utility considering the change to IEC61850 will need to consider the impact of this technology not just in the sense of connecting two relays together, but in the total impact in the substation and the utility wide operations.

Naturally such investment in new technology must be considered with some degree of caution as well as with a good sense of strategy. CIGRE Study Committee B5 already has a number of Working Groups that have included either as a specific objective or at least as part of their scope, elements relating to IEC 61850. Of particular interest is the work of WG B5.11 which has recently produced a Technical Brochure titled *"The introduction of IEC61850 and its impact on protection and automation within substations"*. This TB is an excellent start for any utility considering an IEC61850 program.

The TB sets out to give an overview of why IEC61850 has come to be a demand within the industry and essentially paints the scene that over the next decade most utility designs would be well on the path of transition towards the use of IEC61850 as the base technology in the substation.

In the second chapter, the TB sets out to give the Asset Owner a high level understanding of the extent to which the hardware implementation of IEC61850 will dramatically reduce the number of wires in a substation but more importantly how that will translate in operational differences in the substation. Thousands of wires will be replaced by an Ethernet cable carrying hundreds of thousands of signals every second.

Although some degree of IEC61850 jargon is inevitable in such a report, some attempt has been made to give the Asset Manager and senior utility staff a practical insight into what makes IEC61850 work and particularly how the utility would make it work for them.

The TB includes sections on justifying the change, migration strategies, procurement processes, specification development, project execution and complete life cycle opportunities. This therefore forms the starting point of any consideration of a project to implement IEC61850 throughout the utility or even at a single substation.

Even a cursory glance through the TB reveals that IEC61850 is not just about the secondary equipment. It is for this reason that the utility will need to embark on such a project with the understanding that there are many facets of the utility operation that will need to be considered.

Further consideration of the extent of the NAMI is the connection of business IT systems to the substation environment. Previously there protection equipment was physically segregated from the SCADA system and the SCADA system segregated from the business IT systems, all operating in physically isolated domains. NAMI however means that all these systems have some common interfaces or connections at various locations, for example allowing the engineer at his workstation to connect from his PC to a device in the substation.

Thus separate physical domains will no longer exist and much more stringent IT networking and security arrangements will need to be developed.

Indeed the work of the Idaho National Laboratory[4] has demonstrated most graphically in a video demonstration the ease at which a simple SCADA system could be hacked once an IT connection is provided to the world wide web.

Hence security of not just the business systems LAN is important, but the whole co-joined domains to each substation.

9. Conclusion

Utilities face an increasing pressure to operate in a commercial manner. This places some fundamental processes and in some cases constraints in the approach to capital expenditure and in particular to technology choices.

As new technologies are introduced into the substation and power system operation, the engineering departments must approach this choice with the full confidence of the “rightness” and “appropriateness” of the investment choice.

Indeed these new technologies may well have a greater cost impact at the initial implementation stage, but will become the fundamental basis on which all future work will be carried out in the substation. Therefore the repetitive rework and reengineering costs of dealing with multiple generations of technology in the one substation should not be underestimated and in fact should be avoided, if not at least minimised.

Certainly the credibility of the engineer in presenting a cost justification to management for new technology should extend to the conviction that the real cost savings can ONLY be achieved if there is a strategic decision to minimise the existence of older technologies that would other wise circumvent and negate any suggested savings. If it really does save money, then a minimalistic approach as an easy migration path cannot be entertained and certainly not sustained.

This is supported by the understanding that the life of the secondary system is increasingly being dictated and reduced by the increased functionality required in the substation. Hence operational benefits and financial payback cannot be obtained if the substation continues to work with multiple generations of technology which do not support the prime objective of eliminating cost drivers in the substation.

Finally, the move to IEC61850 is not just about the manufacturing technology of a protection relay changing from electromechanical to static to numeric. It affects the whole operation of the substation in all its aspects of primary equipment, purchasing, capital expenditure costs, operation procedures and skills sets of staff. It also extends into the business IT world

[4] Idaho National Laboratories http://www.inl.gov/scada/

at head office and the security of the complete NAMI regime.

Objectives and strategies must be set within the migration path for concept development, architecture consideration, procedures and processes as well as functionality to be obtained.

Hence whilst small augmentations in a substation could boast the use of IEC61850 technology, it is likely that the only real benefit is when a utility wide strategy is identified.

The challenge for asset strategy is therefore to consider the technology benefits more holistically within the substation and throughout the whole organisation and facilities.

10. Biography

Rod Hughes[5] has worked in the electric power industry for over 25 years in engineering and management roles covering applications, R&D, manufacture and marketing of protection products and systems. He has worked for (now) AREVA manufacturing and supplying products and systems to the world market.

Rod also served in ElectraNet for 3 years responsible for the technology and project strategy implementation for the 132 and 275kV network in South Australia covering lines, primary equipment, secondary equipment and telecommunications.

Over the last three years, Rod has been in the engineering consulting industry and is currently Technical Director – Power Advisory Services for Maunsell Australia Pty Ltd[6] based in Adelaide.

As a long serving member of the CIGRE Australia B5 Protection & Automation panel from 1985, Rod is currently serving as Convenor of the Panel being involved in the international Study Committee B5 and a number of the B5 Working Groups including B5.11 Implementation of IEC61850.

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