DIGITAL SUBSTATION…DREAM OR NIGHTMARE

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ABSTRACT

The Process bus and digital substations have dominated most of our recent technical discussions in the electrical substation industry. The majority of technical papers based on digital substations tend to focus on the benefits of using IEC61850 and how it is changing the substation environment. There has also been a focus on continuous refinement of the standard and, consequently, on striving for better ways of working with and deploying the technology.

In short, the traditional focus of engineers naturally veers towards the technical side of things and the resultant challenges.

Sometimes it's necessary to take a step back and ask oneself some different questions that revolve more around what the output of the deployment of new technologies is supposed to be (particularly in the context of developing economies such as South Africa).

Maybe we should also be asking questions like "What are the real benefits of building and operating a digital substation?", "How can we measure these benefits?", "What new tasks are involved?", "What new resources are required?", "What skills are required?", "What systems and processes are required?" and mostly "Can we adapt and will it all be worth it in the end?".

The purpose of this paper is to explore these questions as seen from the end user's point of view.

In broad terms, three scenarios will be considered when deploying digital substation technologies: new substation construction, substation refurbishment/upgrade and substation emergencies or breakdowns.

This paper will attempt to provide answers to the critical questions above and, in so doing, analyse the impact these new technologies will have (both positive and negative) on the end user's ability to execute daily tasks.

It will therefore not only focus on the technical challenges experienced through the deployment of digital substation technologies, but also consider the impact they will have on time and money.

INTRODUCTION

In order to understand whether building and operating a digital substation is indeed advantageous for an electrical utility or the electrical department of a municipality, it is essential to understand what it is they are really selling.

For ease of reference, electrical utilities and the electrical departments of municipalities will be referred to as utilities throughout this paper.

To answer the question posed above, if electrical utilities are selling the latest technology, then building a digital substation is the way to go. As we all know, however, utilities are in the business of selling affordable electric power of a good quality, continuously and preferably for a profit. If the installation and operation of a digital substation negatively affects customer service, continuity of supply and profits, the digital substation becomes a nightmare.

One should understand what challenges utilities face on a daily basis in order to assess whether the various elements of digital substation implementations to date have been a success. Phrased differently: how should a digital substation be designed, built and operated to ensure continued success in the future?

CHALLENGES FACED BY UTILITIES

Utilities experience technical and commercial challenges on a daily basis. Some of these challenges are discussed below to contextualize the potential impacts of the introduction of new technologies.

The life expectancy of primary plant equipment like transformers and switchgear is typically 60 years if operated and maintained correctly. As we know, life expectancy depends on the climatic conditions to which the equipment is exposed and on how much the equipment has been stressed throughout its working life. To complicate matters further, it is expected that microprocessor-based relays will be replaced every 20 years. This will result in replacing the secondary plant three times before the primary plant equipment needs to be replaced [1].

Due to the fact that electrical substations have been around for more than 100 years, the technology available to control and protect the primary plant equipment has changed with time. As a result utilities have many different generations of secondary control and protection equipment technologies installed. The bulk of protection and control equipment installed at utilities prior to the 1960's was predominantly electromechanical.

Solid state equipment was installed in the late 1960's when researchers ventured into the use of computers for power system protection and control. These ventures coupled with the advancements in Very Large Scale Integrated (VLSI) technology and software techniques in the 1970's lead to the first microprocessor-based equipment being offered commercially in 1979 [2].

It is important to note that the different generations of control and protection equipment will require different maintenance and replacement plans. This affects how utilities schedule maintenance on this equipment and how they formulate a strategy to phase out older technologies.

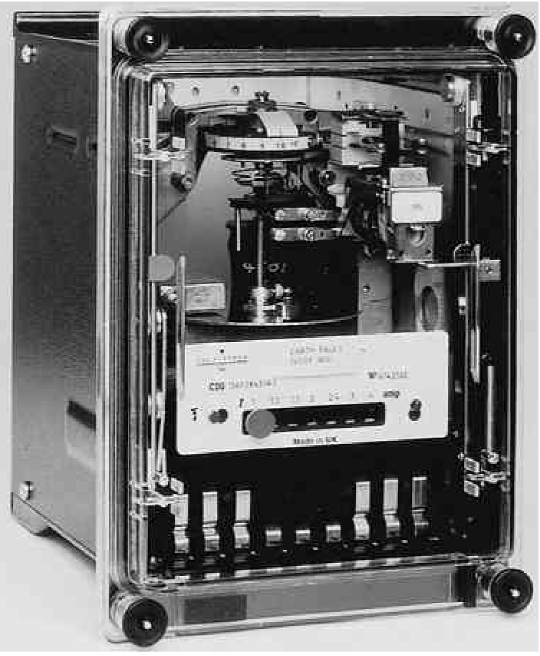

FIGURE 1: Electromechanical Protection Relay.

By having the mix of different secondary plant technologies installed, spares are kept to replace equipment when failures occur. Spares handling for microprocessor-basedd equipment like protection relays has proved to be a problem given the fact that there are so many different Original Equipment Manufacturers (OEMs) supporting different functionality and communication protocols. A storeroom has to be kept and maintained on a continual basis, which bears an operational expense of its own.

When deploying microprocessor-basedd equipment, the utility must have updated software available to interrogate and make changes to configurations of each type of device when required. As a result, a Personal Computer (PC) or laptop is required to perform settings or configuration updates, which have an additional financial impact on the utility.

The devices from the different OEMs may even require their own, unique communication cables supporting proprietary protocols and software packages. The settings and maintenance personnel must be trained to use these packages. Attending training courses further encroaches on the time personnel have available to perform their daily tasks. Attending training courses naturally also carries its own financial burden.

Adding to the technical challenges utilities face on a daily basis, consider maintaining substation schematics and relay configurations and settings. This problem is by no means new or as a result of installing new secondary plant equipment but has always existed where a change to the substation or secondary plant equipment was made. The challenge experienced by utilities is configuration and change management following the occurrence of a particular event.

With the advancement in secondary plant equipment technology from electromechanical relays to solid-state relays and now to microprocessor-based relays, the amount of settings parameters available has increased and the complexity of configuring newer generation technologies has also increased.

Designing, populating and maintaining a configuration management system remains a key challenge in modern electricity utilities worldwide. Ideally, any configuration and document management database should be easily updated and vendor agnostic to as greater extent as possible.

As if technical challenges are not enough, utilities face many other (commercial) challenges, some of which have only surfaced in recent times. Consider extended outages caused by theft of copper cable, incorrect operation of protection relays and sabotage of power system protection equipment by disgruntled employees or cyber-attack from hackers.

As can be seen from the technical and commercial challenges outlined above, utilities are facing an increasingly difficult task in their quest to sell affordable electric power of a good quality, continuously and at a profit while operating and maintaining the electrical network.

All these challenges raise a number of burning questions that must be considered in the deployment of new technologies.

THE BURNING QUESTIONS

i) What is the desired output of deploying newer relay technologies?

Differently phrased, surely the deployment of newer technologies should better enable a utility to sell affordable power of a better quality, more readily at greater profits?

With the advancement in microprocessor-based technology, hardware is clocked at higher speeds resulting in secondary equipment operating faster due to analogue measurements being sampled at higher rates. Consequently, relays will process this information faster, trip faster and clear the fault condition faster.

The improvement in speed decreases the amount of energy to which the primary plant equipment is exposed. As a result the life span of the primary plant equipment is extended. We can even prove this from first principles!

The energy dissipated by the primary plant is governed by the following equation:

$E = I^2 t$ ……………………………………………[1]

E = Energy (Joule)
I = Current (Ampere)
t = Time (seconds)

As can be seen from the energy equation, reducing tripping times reduces the energy the primary plant dissipates under fault conditions.

Here are some of the many benefits realised through the application of microprocessor-based relays [2]:

- Microprocessor-based relays have more information available to enable the user to create custom configurations.
- Multiple functions are supported by one device. The cost per function implemented in microprocessor-based relays is therefore cheaper relative to electromechanical relays.
- Microprocessor-based relays provide users with the capability of customizing logic in software.
- There is a reduction in required panel space when installing microprocessor-based relays as compared to electromechanical relays.
- Modern relays also place less burden on Current Transformers (CTs) and Voltage Transformers (VTs) relative to electromechanical relays.
- Sequence of events and oscillography data used during fault investigations were never available with electromechanical relays.
- Self-monitoring and testing functions to report in the event of component or relay failure are also available.

There are, however, some shortcomings related to microprocessor-based relays [2]:

- They have a shorter life span relative to their electromechanical counterparts
- They are susceptible to transients such as Electro Magnetic Interference (EMI) and Radio Frequency Interference (RFI)
- They are more complex to configure and maintain.

Ultimately, industry has concluded that the benefits of using microprocessor-based relays far outweigh their shortcomings. This has led to their widespread acceptance over the last twenty years.

ii) What are the *real* benefits of building and operating a digital substation?

To answer the question one probably first needs to define what a digital substation is.

Most substations today switch and route AC power at high or very high voltages - it is not the primary flow of power which is digital.

A digital substation typically refers to its secondary plant, including all the protection, control, measurement, condition monitoring, recording and supervisory systems associated with that primary power flow, being digital.

In general terms, a full digital substation is one in which most of the available data related to the primary power flow is digitized immediately, at the point where it is measured. Thereafter, the exchange of that data between devices occurs via Ethernet, as opposed to via the many kilometres of copper hardwiring which may exist in a conventional substation.

Digital substations imply a solution and architecture in which the substation's functionality is predominantly achieved in software with less reliance on hardware implementations such as hardwiring [3].

The success of a digital substation relies on the effectiveness of the digital communications system within the substation to connect all protection, control and monitoring devices. Until recently, all OEMs supported proprietary protocols when building a digital substation. Solutions such as these typically require protocol converters to communicate to equipment from other OEMs.

As a result, IEC workgroup TC57 published the IEC61850 standard in 2003 [4]. This standard did not only cover ***what*** information the equipment within a substation should communicate, but also ***how*** to communicate. IEC61850 provides interoperability between vendors by defining the communication protocol, data format and configuration language.

The functional hierarchy of IEC61850 is show in Figure 2.

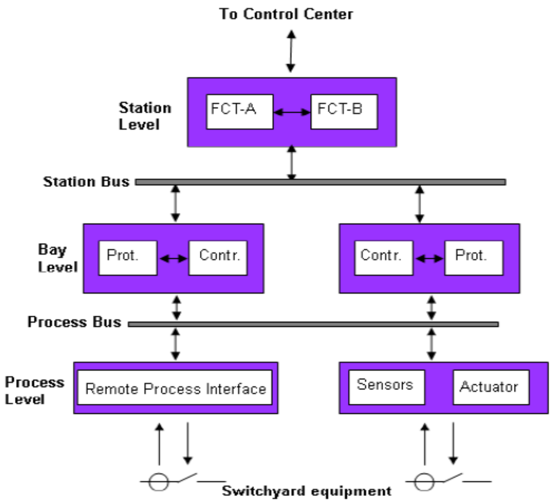

FIGURE 2: Functional hierarchy of IEC61850 [5].

Process level: This includes switchyard equipment such as CTs, VTs, Remote I/O and actuators.
Bay level: This includes Intelligent Electronic Devices (IEDs) such as protection, control and metering devices of different bays.
Station level: The functions and equipment requiring data from more than one bay such as Human Machine Interfaces (HMIs) and communications gateways are implemented at this level.
Process bus: This facilitates the time critical communication between protection and control IEDs to the process (the primary equipment in the substation) such as sampled values, binary status signals or binary control signals.
Station bus: This facilitates communication between station level and bay level. It also allows communication among different bays.

In practical terms the information from the primary plant equipment is made available via an IED in a digital format. This IED is installed in the yard either in the primary plant equipment or in a junction box. A fibre optic Ethernet connection is made between the IED and a Process Bus Ethernet Switch to establish the Process Bus. The protection, control and metering IEDs are also connected to the Process Bus Ethernet Switch to enable IEDs to obtain process level information.

The protection, control and metering IEDs also connect to the Station level equipment (HMI and Gateway) via an Ethernet connection between the IEDs and the station bus switch to form the station bus.

Because of the technology advances, the digital substation offers the following benefits:

- **Interoperability between different vendors**. Using IEC61850, different vendors' IEDs can communicate with each other to exchange information. This places the customer in the position of being able to choose the best IED for the application based on functionality and price. Due to the open model structure of IEC61850, an IED can be replaced with and IED from another vendor if required.
- **Substation wide, high-speed peer-to-peer communication.** Substation control and protection functions can be integrated at bay level using Generic Object Orientated Substation Event (GOOSE) messaging.
- **Reduction in required CT cores.** The use of Sample Measured Value (SMV) reduces the required cores per CT because the SMV published from one CT core can be used by many different IEDs for different functions.
- **Reduction in control cable.** A reduction in cabling between the primary plant equipment and the protection, control and metering IEDs results in significant cost savings.
- **Reduction in restoration times caused by cable theft.** A significant saving is realised if the need arises to replace fibre optic cable(s) installed between the primary plant equipment and the process bus Ethernet switch. No re-commissioning of the protection schemes is required as would be the case with conventional copper cable. This results from the inherent behaviour of the IEC61850 protocol allowing self-testing functionality to be configured within the IEDs.

While discussing the benefits it is also necessary to address the shortcomings of a digital substation so that we can objectively assess the benefits of building and operating a digital substation.

One of the major problems with the implementation of IEC61850 is that utilities do not necessarily have the relevant experience and expertise to work with Process Bus.

The lack of tools to assess problems while fault-finding and the ease-of-use of such tools are some of the biggest hurdles utilities experience. Process Bus is typically used for time critical messages such as GOOSE and SMV that require high-speed performance. It is essential for all components forming part of the Process Bus and Station Bus to operate as quickly, reliably and efficiently as possible.

The major issues experienced by utilities when it comes to Process Bus level communication are [5]:

- **Incorrect network topology implemented between IEDs**. Slow communication network performance due to LAN configuration not meeting the IEC61850-5 message transmission delay requirements [6].
- **Not all relays and switches support priority tagging**
- **Time synchronization accuracy.** IEC61850 specifies Simple Network Time Protocol (SNTP) as the synchronization standard. SNTP provides a 1 millisecond (ms) timing accuracy. This has proved to be too inaccurate for certain applications. The IEEE1588 standard provides a better timing accuracy but not all vendors support IEEE1588.
- **Proprietary implementations**. Vendors have also released products that provide a point-to-point connection between Process Bus IEDs and the protection relay which implements a propriety protocol used for time stamping of the events on a process level.
- **Conformance to IEC standards.** Not all IEDs installed in IEC61850 networks comply with the IEC standards with respect to EMI and environmental specifications. This often leads to interference causing loss of information between IEDs on the network.

On the station bus, the following implementation problems have been experienced [5]:

- **Not all relays and switches support priority tagging**
- **Peer-to-peer communications between different vendors.** Not all IEC61850 IEDs available, communicate effectively with IEDs from other vendors.
- **Specifications for intra-substation communications.** Control data exchange between station levels (i.e. between substations) is beyond the scope of IEC61850 [5]. IEC61850-90-1 *discusses* the different aspects of IEC61850 used for communication between substations.
- **Specifications for control centre to substation communications**. Control data exchange between substations and control centres is beyond the scope of IEC61850 [5]. IEC61850-90-2 *discusses* the communication between substations and control centres [7].

After evaluating both the benefits and shortcomings for building, operating and maintaining a digital substation, one needs to ask how these benefits and shortcomings can be measured and whether deploying digital substation technologies is really in the utility's best interest.

Before measuring and quantifying if building a digital substation is in the best interest of the utility, the new equipment and related tasks required to build, operate and maintain a digital substation must be identified and understood.

iii) What new equipment and related tasks are involved in building, operating and maintaining a digital substation?

In the previous section of this paper digital substations and conventional substations were compared, the benefits and shortcomings identified and new tasks highlighted when building, operating and maintaining a digital substation.

Hardware considerations will be analysed starting at the primary plant equipment level and moving up towards the station level.

New IEDs are introduced at the primary plant level (whether installed as a separate device or integrated as part of the primary plant itself). These IEDs are required in addition to conventional substation IEDs and effectively digitize measurements and other data related to the primary plant. They then publish this information to all other interested parties.

These new yard devices come with the disadvantage of requiring some form of power source whether AC or DC. Other primary plant devices such as circuit breaker motors, however, also require auxiliary power. The IEDs installed in the yard can simply be powered from sources that are required in any event.

With the introduction of the digital substation, the copper cable installed between the substation yard and substation control room will reduce significantly (due to the yard IED making all this information available digitally as mentioned above).

FIGURE 3: Merging Unit Installed in substation yard.

The CT test blocks, traditionally installed on the protection and control panels, will move to the yard as can be seen from figure 3.

By moving the test blocks to the yard, the testing and commissioning procedures will need to change. The process of CT testing will be simplified with all equipment involved being in close proximity in the yard. This raises a few pertinent questions:

How will the location of the test blocks impact secondary injection tests? Will test sets used to perform secondary injections even have current probes? Will a test set not simply be a software program residing on a PC or laptop leisurely simulating digital currents, voltages and trips over an Ethernet connection?

FIGURE 4: Fibre optic cable installed in substation yard.

The various physical connections and inter-connections between the yard IEDs and Ethernet switches will all be using fibre optic cable.

The fibre cable is a new addition to the conventional substation. It possesses different challenges that raise different questions when operating and maintaining this cable:

How will the cable be replaced when damaged? Will the utility keep standard lengths cable in a store and replace the cable when required, or will the utility have splicing kits and tools used to repair damaged cables?

The bigger utilities will likely find it more economical to own the equipment to install, test and repair fibre optic cable as compared to the smaller utilities who might outsource this function.

The Ethernet switch is another new addition to the conventional substation. It is one of the most important components of the digital substation and has proved to be the downfall of digital substations if incorrect hardware was selected or incorrectly configured.

iv) What new resources, systems and processes are required when building, operating and maintaining a digital substation?

Once the equipment and tasks required for building, operating and maintaining a digital substation are identified, a few new questions come to mind:

Who will be responsible for performing new tasks that previously did not exist? Consider the dilemma of the Ethernet switch. Is the protection department responsible? Is it rather the control/SCADA or Telecommunication department? Should there perhaps be a new department formed who takes on this responsibility? If so, what do we call this department?

Traditionally the organizational structure of utilities was guided by the *function* personnel performed within a substation. As a simple example, the Protection Department is responsible for all protection related tasks within the substation and the Control/SCADA Department is responsible for all tasks related to the communication of data to various users for SCADA purposes. Telecommunication department is responsible for communication infrastructure to and from the substation.

The advent of the digital substation has, however introduced a new function within the substation that relates to the communications network itself (as opposed to the data it carries). Is a new department required within the utility responsible for substation communications networks?

The general consensus in the industry today is that a group of networking specialists is held responsible for communications networks in substations. There can be no doubt that inappropriate or ill-informed designs and decisions relating to this important function will become the utilities nightmare.

It is therefore the author's opinion that a department dedicated to substation communications networks is critical in order for utilities to reap the benefits of the digital substation.

The answer to the challenges posed above will clearly be different for each utility, as their requirements will vary according to their size, budget and installed base.

These challenges will force utilities to rethink their organizational structures when it comes to operating and maintaining digital substations.

v) How can we measure the benefits of a digital substation?

From a technical point of view, the digital substation with all the benefits and shortcomings as discussed has been accepted by the industry to be the only way forward.

As engineers we tend to focus only on the technical aspects and forget the financial impact of a technology decision. This section will focus on a cost calculation performed from the utilities point of view for the following conditions:

i. Capital and operational cost comparison between building a digital substation vs. conventional substation.
ii. Capital and operational cost calculation when upgrading a conventional substation to a digital substation.
iii. Capital and operational cost calculation when upgrading a conventional substation to a digital substation during an emergency condition or breakdown.

With respect to capital cost comparisons for new substation construction, a South African utility performed an exercise to determine the financial impact of building a digital substation versus a conventional substation [8]. The exercise was performed on a 132/11kV substation with four transformers and twenty 11kV feeders. No yard IEDs were installed with primary plant signals wired from junction boxes in the yard to the control and protection panels. IEC61850 was used to make the information available within the substation between the IEDs at both bay and station level.

The tendered prices for the digital substation equipment were compared to prices of existing contracts at the time that were using legacy control and protection equipment. The value of "take-out" and "add-in" items were as follows:

TABLE 1: Equipment not required in the digital substation

Take-Out Items	
Secondary cabling	R 200 000
Remote Control Panels	R 160 000
Tap Change Control Panels	R 500 000
11kV Bus-Zone Scheme	R 20 000
Supervisory Junction Board	R 15 000
Supervisory Outstanding	R 115 000
Reduction in Control Room size	R 220 000
Total	R 1 230 000

TABLE 2: Additional equipment required in the digital substation

Add-In Items	
11kV Bus-Zone Scheme with bay processing for bussection and coupler	R 55 000
SCADA Gateway	R 80 000
HMI	R 130 000
Communications Network	R 165 000
Total	R 430 000

TABLE 3: Digital substation capital saving

Savings are thus	
Take-Out Items	(R 1 230 000)
Add-In Items	R 430 000
Total	R 800 000

A capital saving of R 800 000 was realized by building a digital substation as compared to a conventional substation.

It should be noted, however, that no process bus equipment was used in this specific case. Tables 4 and 5 below show the additional cost for process bus equipment for this substation and the savings for legacy equipment not required.

TABLE 4: Equipment not required when using Process Bus

Take-Out Items for Process Bus	
Secondary cabling	R 143 200
Saving in Protection IED (CT,VT,IO reduction)	R 42 000
Saving in Protection panel cost (panel wiring)	R 49 000
Commission time	R 49 000
Reduction in CT and VT price	R 28 000
Total	R 311 200

TABLE 5: Additional equipment required when using Process Bus

Add-In Items for Process Bus	
Yard IED and marshalling kiosk including installation	R 196 800
Fiber optic cable including installation	R 89 600
Patch panel	R 4 200
Patch leads	R 2 100
Upgrade network swtich to Process bus compliant	R 14 000
Total	R 306 700

From tables 4 and 5 only a relatively small saving of R4 500 would have been realized by installing a process bus solution. Note that the cost calculation of the utility [8] was performed in 2007 and therefore the costs in tables 4 and 5 have been adjusted by inflation to reflect 2007 pricing for comparative purposes.

In a separate exercise performed by the same utility for a 132 kV Switchyard with nine feeders and a bus section, indicated little difference in price between the legacy and new philosophy protection and control equipment [8].

In the case of this switchyard, the reduction in costs of the secondary cabling and the omission of the legacy supervisory equipment is cancelled out by the additional costs of the communications network and HMI. The improved functionality achieved through substation automation is therefore achieved for no extra cost in this case.

Shifting the focus to assessing cost differentials from an operational and maintenance point of view, spares holding and new tools required for maintenance and repair must be considered.

The process bus installation requires spares to be kept for the yard IEDs. Table 5 indicates the price of four units. Depending on the utility's spares holding philosophy, one spare would typically be kept for four installed units. Tools required to repair the fibre optic installation are also required.

The conventional substation using copper cable between the primary plant equipment and substation will require no additional spares to be kept.

In addition to the capital savings outlined above, additional operational savings become apparent when one considers certain network events. Consider, for example, the control cable in a conventional substation being stolen or damaged and requires replacing.

In such a case, the new cable installation needs to be tested and the scheme re-commissioned. At the same time, the conventional substation is at risk due to the inability of a protection trip signal reaching the circuit breaker and clearing the fault. This can lead to substation equipment damage resulting in prolonged outages. This has a negative impact on the goal of utilities to sell affordable electric power of a good quality, continuously and at a profit.

In the example discussed above one of the transformers has a 30 MVA rating. If we conservatively assume a 30 % loading for an industrial customer with a constant load, the loss of revenue would be 108 MWh of electrical power sales for a 12 hour outage.

The process bus installation reduces the risk of cable theft in the substation due to the reduction in the copper cable installed. In the event of any of the process bus equipment becoming faulty, the control personnel will be notified immediately using the built-in mechanisms of IEC61850.

It is apparent from the above that real capital and operational cost savings can be realised through the application of digital substation technologies.

The next scenario will focus on the upgrading of a conventional substation to a digital substation. The calculations are based on upgrading four 132/11kV, 30 MVA transformers and twenty 11kV feeders to IEC61850. The additional equipment and labour is shown in table 6.

TABLE 6: Upgrading legacy substation to digital substation

Add-In Items for upgrade legacy substation to Digital Substation	
Yard IED and marshalling kiosk including installaiton	R 196 800
Fiber optic cable including installation	R 89 600
Patch panel	R 4 200
Patch leads	R 2 100
Main, Back-up and Tap Change control IEDs process bus enabled for four transformer schemes	R 341 600
11kV Bus-Zone Scheme with bay processing for bussection and coupler	R 55 000
11kV IEDs IEC61850 enabled, no modification to Switchgear, No process bus	R 518 000
Labour to install, modify and recommission 11kV protection scheme	R 630 000
SCADA Gateway	R 80 000
HMI	R 130 000
Communications Network	R 179 000
Total	R 2 226 300

When upgrading an existing substation it is assumed no "Take-Out" costs exist, the primary plant and all other equipment already purchased and not used will become redundant. It should be noted that the costs reflected in Table 6 could be significantly reduced for scenarios where existing substation equipment already supports certain elements of IEC61850.

Similar to the first scenario, one cannot lose sight of the direct revenue losses associated with prolonged outages not to mention potential claims for consequential damages against the utility for such outages.

An important, additional scenario to consider with respect to substation upgrades is when cases exist where portions of a conventional substation are damaged to such an extent that significant refurbishment is required. In such cases, utilities should consider the advantages of deploying digital substation technologies for the partial upgrade.

In addition to all the benefits described in the previous scenarios, considering digital substation upgrades when emergency repairs are undertaken can drastically reduce the repair time and therefore reduce the revenue losses due to the outage.

vi) Will we as South Africans in an emerging market be able to adapt and will it be worth it?

As South African's we have proven that we are able to adapt to changing technologies and use these technologies to drive our economy. Due to globalisation we as South Africans have started to compete with countries around to world to provide products and services as effectively and economically as possible.

To stay relevant in this competitive world, new technologies should be embraced, but they should also be driven by purpose. In the case of this paper, that ultimate purpose is defined as the supplying of affordable electrical power of a good quality, continuously and at a profit.

The digital substation should be viewed as an opportunity to advance our country to produce electrical power of a good quality continuously at a profit. It will result in economic growth which will reduce unemployment and improve our quality of life.

CONCLUSION

This paper has attempted to view the construction, operation and maintenance of a digital substation from a utility's point of view. It raised critical questions to be answered in order to determine whether it is in a utility's best interests to build, operate and maintain a digital substation.
Utilities face technical and commercial challenges on a daily basis due to different secondary plant technologies installed within substations. Each technology discussed brings its own challenges with respect to configuration, maintenance and spares handling.

Digital substation technologies provide utilities with a means of standardising secondary plant solutions across different OEMs. At the same time, utilities reap the benefits of capital, operational and maintenance cost reduction for substation construction, refurbishment.

There is no doubt that the digital substation brings with it new technical, operational and potential structural challenges to which utilities will need to adapt. This should not detract utilities from embracing the digital substation as the benefits far outweigh the challenges.

As South Africans, we have proven through generations that we are not only willing and able to adapt to newer technologies but also to adapt newer technologies to suit our (sometimes) unique requirements.

We use these new technologies not only to showcase our engineering ingenuity but to drive our economy.

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