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Movement to the full digital substation

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SUMMARY

Digital devices such as numerical protection relays and digital systems such as substation control are prevalent as the technology of choice in substations today, in most countries worldwide. This article looks at other substation areas into which digital technology can permeate, such that progressively, transmission substations can become fully digital in their implementation.

Digital technology has penetrated further into the substation environment over the past two decades. Firstly, vendor-specific implementations in the SCADA domain were followed by eventual standardization on IEC 61850 for station-bus based digital control systems (DCS). Correct application of the standards has allowed a lot more of the substation engineering and construction activity to be undertook in the controlled environment of the factory, rather than on the substation site – where outage times and site labor are at a premium. The paper builds on the advantages realized using IEC 61850-8-1 for the DCS, including the full protection and control scheme, extending the implementation to include the process bus too. Process bus deployments replace the traditional hardwiring to the circuit breaker with an Ethernet link, and also convert the primary current and voltage measurement channels into protection relays and other IEDs (intelligent electronic devices) to fiber-optic too. Achieving a full station and process bus digital implementation helps to reduce the substation physical size, move as much configuration and testing to the FAT stage (factory acceptance testing), and also decouples the dissimilar renewal cycles of the primary and secondary equipment. Specific attention is paid to the common benefits and applicable use cases where initial full digital substations were applied in transmission stations, but are now penetrating lower in voltage, through subtransmission and primary distribution. Particular focus is made on solution continuity from conventional to non-conventional substations, including those with digital instrument transformers instead of conventional wound instrument transformers. The paper briefly discusses how such transformers employing optical, rogowski and capacitive technologies are accommodated within the substation topology, and some practicalities and advantages for each.

KEYWORDS

GOOSE, Process bus and Sampled values.

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Introduction

Firstly, one might ask "what is a digital substation?", and this will yield a variety of possible replies, as there is no standard definition. Clearly as most substations today are switching and routing AC power at high/extra high voltage, it is not the primary flow which is digital. This means that we are talking about the secondary systems, and all the protection, control, measurement, condition monitoring, recording and supervisory systems associated with that primary "process".

In general terms, a full digital substation is one in which as much as possible of the data related to the primary process is digitised immediately, at the point where it is measured. Thereafter, the exchange of that measured data between devices which may need to subscribe to it is via Ethernet, as opposed to the many kilometres of copper hardwiring which may exist in a conventional substation.

In reality, many utilities will wish to move fully digital at a pace which suits their engineering capabilities and technology aspirations. This article suggests some of the steps which could be taken, and how adherence to international standards to ensure interoperability can be built-in. From the point of view of the authors and their company, the technology is now mature, and far beyond the point where it might be deemed prototype. Fifteen years of prototyping, site trials and perfection have passed, such that our company is confident to offer this technology as a real commercial proposition. A number of contracts in execution are included later in this article.

Digital substations imply a solution and architecture in which the substation's functionality is predominantly now achieved in the software, with lesser reliance on hardware implementations such as hardwiring.

Drivers towards digital substations

Some of the areas in which digital technology brings real benefits are now highlighted:

<u>Increased reliability and availability</u>
The extensive self-diagnosis capability of digital devices ensures maximised up-time of the substation. Any degradation in the performance of an asset is pinpointed in real-time. Inherent redundancy in the system may be employed to self-heal the operation, which permits troubleshooting without the need for any primary system outage.

<u>Optimised operation of assets</u>
The intelligence within digital substation schemes allows close monitoring of the loadflow capacity of plant equipment, compared to its design ratings. This dynamic load analysis permits operation of lines, cables, transformers and other grid equipment closer to their limits.

<u>Improved safety</u>
The removal of wired cross-site current transformer circuits reduces the risk of lethal injury due to inadvertent opening of the circuit by personnel. The avoidance of oil in instrument transformers reduces explosion risks too.

<u>Reduced maintenance costs</u>
The digital substation closely monitors all substation assets in terms of operational conditions, effective load capacity and asset health indicators. Intelligent systems analyse the data and provide recommendations on maintenance and repair actions to conduct. This allows a shift to predictive maintenance, avoiding unplanned outages and emergency repair costs. It is in this regard that ongoing operational cost savings may be made, such that the lifetime total cost of ownership of the substation will be reduced. Additionally, asset optimisation and loss-of-life monitoring tools facilitate the identification of weak areas on the primary system which need to be reinforced.

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Easier renovation and extension of existing substations
Interoperable solutions and the use of fibre optics instead of copper wires reduce the duration and cost of on-site work for the refurbishment of secondary equipment. Prudent design of the substation plans ahead for the mid-life refurbishment of secondary schemes, when often the primary equipment is left as-is, given that decades of years of serviceable life may still remain. This permits the refurbishment activity to take place with the absolute minimum of primary system outage.

Improved communications capabilities
Data exchange between intelligent devices, intra and inter-substation, is optimised through Ethernet communications. Smart local and wide area control units (WACU) can allow data exchange between voltage levels in substations, and between substations. Direct inter-substation communication without the need to transit via a control centre reduces the response times, for fast, real-time applications.

IEC 61850: a crucial technology enabler

Modern sensors and other Intelligent Electronic Devices (IEDs) must be connected to communicate within the substation and with the greater grid system at large. In the past, there were many different protocols and a lot of effort went into making them communicate. For many years, insufficient standardisation, fear of degraded reliability and lack of return on investment slowed down the emergence of a fully digital substation. But today, the IEC 61850 standard makes it possible to facilitate interoperability between different equipment and suppliers

IEC 61850 is the international standard for Ethernet-based communication in substations. It is more than just a protocol, it is a comprehensive standard designed for utilities, to deliver functionality that is not supported in legacy communication protocols. Introduced in 2004, the standard is increasingly accepted across the world, as its main objective is to ensure interoperability between equipment coming from various suppliers. IEC 61850 continues to grow and encompass the needs identified by the industry's user group (UCA UG), to ensure that it caters for all substation needs.

IEC 61850 allows for the full digitising of the signals in a substation and is necessary for the large amount of data to be managed and communicated for the real-time management
of a smarter, modern power grid. IEC 61850 is designed for interoperability and longevity, in order to be independent from one supplier and one generation of equipment.

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The architecture of digital substations

The digital substation architecture may be divided into three levels:

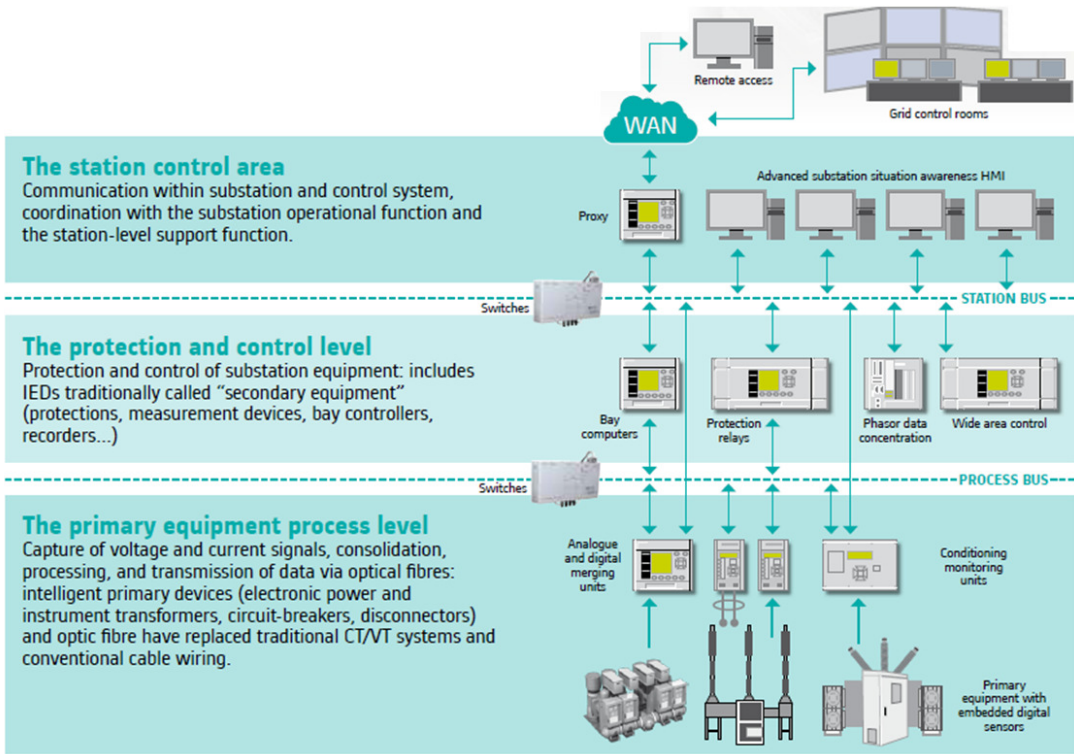

Fig 1 : Architecture levels in a digital substation

A typical digital substation solution incorporates many components all designed for optimal inter-operability, data retrieval, protection and control capability and remote settings. Its architecture can be divided into three levels:

<u>The process level</u>

A digital substation is based on a communicating architecture, whereby real-time operational measurements and other data are polled from the primary system. This data is obtained using sensors, embedded within the primary system, which is termed as the electrical process. It is communicated to devices which must act on those measurements by means of a "process bus". Most important is that smart devices and systems within the substation, (protection relays, recorders, phasor measurement units, bay controllers, wide area controllers or asset managers), can immediately process this operational data. By subscribing as clients to this data flow over an Ethernet process bus, the information from the "eyes and ears" of the power system is distributed and communicated much more efficiently to the bay level than in conventional hardwired schemes.

The process bus is also the link by which the primary equipment information from out in the yard travels back to the substation control house – it links the field back to the substation. In a fully digital architecture, control commands (switchgear operator commands, protection trips) also are routed to the primary devices via the process bus, in the opposite direction.

It will be described later how IEC 61850-9-2 brings non-conventional instrument transformer technology into play, breaking the constraints of conventional CTs and VTs. It is particularly

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important for the process bus, as it describes how analogue signals such as phase currents and voltages can be exchanged as sampled values.

The protection and control level

Between the process bus and the station bus are devices historically identified as the "secondary equipment". In the digital substation, these devices are IEDs (intelligent electronic devices), interacting with the field via the process bus, and with other peer devices in the bay, to other bays, and the digital control system via the station bus.

The station control area

The digital substation station bus is much more than a traditional SCADA bus, as it permits multiple clients to exchange data, supports peer-to-peer device communication, and links to gateways for inter-substation wide-area communication.

IEC 61850-8-1 is the relevant standard for the station bus. It describes the means to generate and present reports which may be subscribed to by other devices and HMIs (Human Machine Interfaces), and the way to communicate peer-to-peer. The latter is achieved by the exchange of GOOSE messages between devices on the LAN (Local Area Network). GOOSE is more often than not used as high-speed exchange of binary status information/commands.

In addition to the need for distributed intelligence between IEDs at the station level, there is the need to distribute the information to local or remotely-stationed control operators to visualise the operational status of the substation. This requires substation HMIs (human-machine interfaces) and proxy server links to remote HMIs and control servers, to communicate pertinent data in real-time. One or several workstations apply the instructions assigned by regional dispatchers, or can be used as an engineering workstation for IED configuration, or for local concentration and archiving of power system data. On-line condition monitoring may have specific workstations for alerts, and to manage the database history of each primary device.

Digital Instrument Transformers

The root of many of the limitations of conventional instrument transformers is the reliance upon an iron core. The core is a source of inaccuracy, due to the need to magnetise it, but not to overflux it. In the case of conventional CTs, achieving the low-level accuracy and dynamic range to satisfy both measurement and protection duties is a challenge. Conventional VTs similarly may experience ferroresonance phenomena and thermal overstressing can result.

Instead of an iron core, the translation from primary to secondary measurement may use optical, Rogowski or capacitive technology, with the optimum choice for AIS (Air-Insulated Substation) and GIS (Gas-Insulated Substation) driven by the respective digital device size, which in turn permits size optimisation of the switchgear. Some examples of the non-conventional principles are as follows, considering just the CT function here for brevity:

• **Optical sensors** (AIS) use the Faraday effect, whereby a fibre optic loop sensor carrying a polarised light beam encircles the power conductor. This light will experience an angular deflection due to the magnetic field, generated by the primary current flow.
• **Rogowski sensors** (GIS) dispense with the conventional CT core and instead implement windings as tracks on a multi-layer printed circuit board. Four quadrants of the board are clamped together to form a toroid around the primary conductor. The sensor output becomes a low-level voltage measurement, which can be accurately correlated to the primary current.

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Fig 2: Example optical CT showing freedom to mount in different orientations
(Shown horizontally-mounted here)

Fig 3 : Example flexible optical CT wrapped-around a bushing

Analogue Signal Conversion, Merging and Switchgear Control

Primary converters associated with each CT and VT convert analogue signals from the primary equipment into digital signals. The primary converters interface with merging units to perform all the digital data processing necessary to produce a precise output data stream of sampled values according to the IEC 61850-9-2 standard.

For retrofitting, or where the client has a preference to retain traditional instrument transformers, analogue merging units are available, digitising the CT and VT outputs at any convenient kiosk out in the yard.

Digital controllers (SCU - switch control units) are the fast, real-time interface to switchgear, mounted close to the plant which they command. They replace hardwiring of inputs/outputs by an Ethernet interface to the yard.

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Fig 4: Example merging unit

Numerical Protection Relays

In a fully-digital architecture, protection relays receive currents and voltages as IEC 61850-9-2 sampled values, and issue trip or alarm signals using IEC 61850-8-1 GOOSE.

The authors' company's IEDs extend their supervision facilities to include comprehensive addressing and plausibility checking of the incoming sampled values from the process bus. This addresses the fact that the traditional task of current and voltage sampling is now external to the device, and is connected via Ethernet. The supervision compensates for any latency or mismatch in the network, provides ride-through intelligent compensation in the event of several missing samples or jitter, and blocks/alarms if the quality of incoming data would compromise the secure and reliable protection operation of the IED. This ensures maximum security, dependability and speed of the protection scheme.

Fig 5: Example process bus protection relay

Digital Control System (DCS)

Any digital substation will need a system by which operation and control data can be obtained and communicated to operational personnel by an intuitive interface (typically termed as an "HMI" – human machine interface). These personnel may be local to the substation, or at a remote control centre. This information flow from the substation to the HMI might be deemed the "monitor" direction, and the DCS supplements this in the "control" direction by allowing the operator to interact with the primary plant.

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The DCS is the intelligence which binds together the digital substation. It is central to the flow, management and presentation of all components in the digital substation. In the authors' company, specific focus has been paid to the way that operational and plant condition monitoring data has been networked, for the first time, within what would have traditionally been exclusively a protection and control system. This avoids the need to overlay multiple Ethernet networks, as the system is deployed as a generic whole. In addition, attention has been paid to how data can be presented as simple dashboards, such that operational staff can clearly see what is happening on the network, easing subsequent decision-making on actions to take.

All digital substation architectures can be set up as an IEC 62439 standards-compliant self-healing ring (HSR protocol) or dual-homing star (PRP protocol); both of which are "bumpless" redundant. This means that data is exchanged between devices via two diverse paths, and should one of these paths fail, data is instantly available hot from the other, with zero delay. Fibre optic networks link all the system's components, together and with the operator interface (HMI), through a full range of Ethernet switches.

Wide area control units (WACU) offer the possibility to exchange IEC 61850 GOOSE data between voltage levels within a substation and also between neighbouring substations.

Fig 6: Digital Control Systems: the marriage of state-of-the-art software and intelligent electronic devices

Cyber security

Intrusion protection and protection against virus attacks is recommended to be integrated in all switches and IEDs. Cyber security provides protection against unauthorised access to equipment and unauthorised transfer, modification or destruction of data – whether deliberate or accidental. Particularly when wide area networks extend beyond the traditional substation fence, cyber-security measures are essential. Security procedures, controls, firewalls and role-based access are all examples of such measures.

On-line condition monitoring and asset management

On-line condition monitoring functions are mainly delivered for power transformers, circuit breakers, disconnectors and gas insulated switchgear. Physical parameters are continuously monitored and real-

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time measurements are combined and compared to models in order to generate specific recommendations regarding operation and maintenance, as well as alarms when necessary. An interface with an asset management system yields additional features such as remaining lifetime or dynamic rating capabilities.

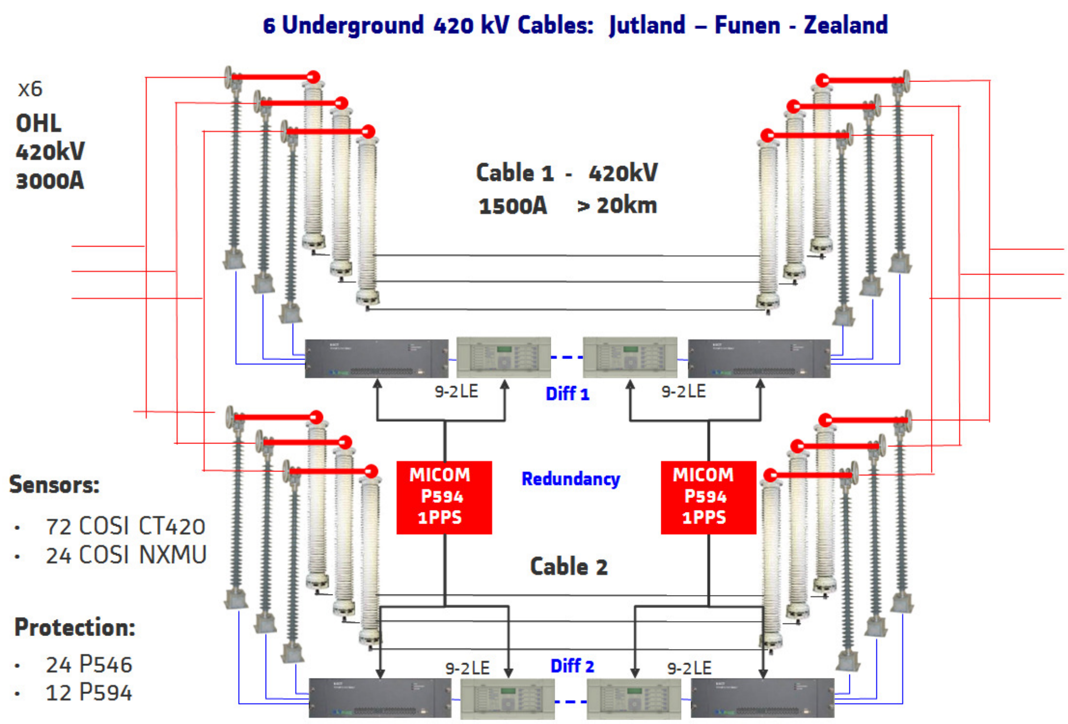
The new architecture enables operational and maintenance teams to have an overview of the condition of all substations in real time, and take appropriate and strategic asset management decisions.

Conclusion - Example Commercial Projects

1) Energinet, Denmark – Digital Current Measurement and Protection

One current application is on Energinet's transmission system, in a differential protection application. The protected circuits are hybrid lines, consisting of 400kV lines, and cabled portions laid sub-sea. The cables are over 20km in length, and the operational demands are such that autoreclosing is required for faults on the overhead lines, but not for faults within the underground cable sections. The differential protection is thus used for fast and precise detection of faults within the cables. The undersea cables run from stations on the Jutland mainland, on to Funen island and then onwards to Zealand.

The equipment supply includes 72 optical CT units, 24 merging units and 24 line differential relays which subscribe to the sampled values in a process bus protection scheme. The principal reason for selecting to use non-conventional instrument transformers was due to their low mass and slimline construction. In the Energinet substations, the optical CTs are mounted on the same support structures as the cable bushings themselves. A single structure and foundation per phase carries the larger mass of the cable, plus the optical CT support on a cantilever frame.



The scheme has been fully tested and verified for performance in June 2012 at a special FAT laboratory in Lyon, France.

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2) FSK, Russia – Conventional Analogue Instrument Transformers Interfacing to Full Digital Protection and Control

In the 110kV and 220kV substation contracts for Nadezhda in Russia, the primary GIS equipment is supplied by a 3rd party vendor, equipped with conventional instrument transformers (wound CTs and VTs). This analogue data is digitised at source using analogue merging units, and connected cross-site to relays and bay controllers by an IEC 61850-9-2 process bus.
A full range of transmission relays protect the substations, interfacing with the digital control system. The architecture of the substation incorporates PRP redundancy. Trip and operational control of switchgear is secured using SCU switchgear control units, completing the full digital acquisition and command chain.
These two contract examples demonstrate the maturity of the technology, the faith placed in our company by two important customers, and hence the readiness for other customers to adopt. The authors believe that we are in the ramp-up phase of digital substation technology, and that the market will continue to grow, worldwide.

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