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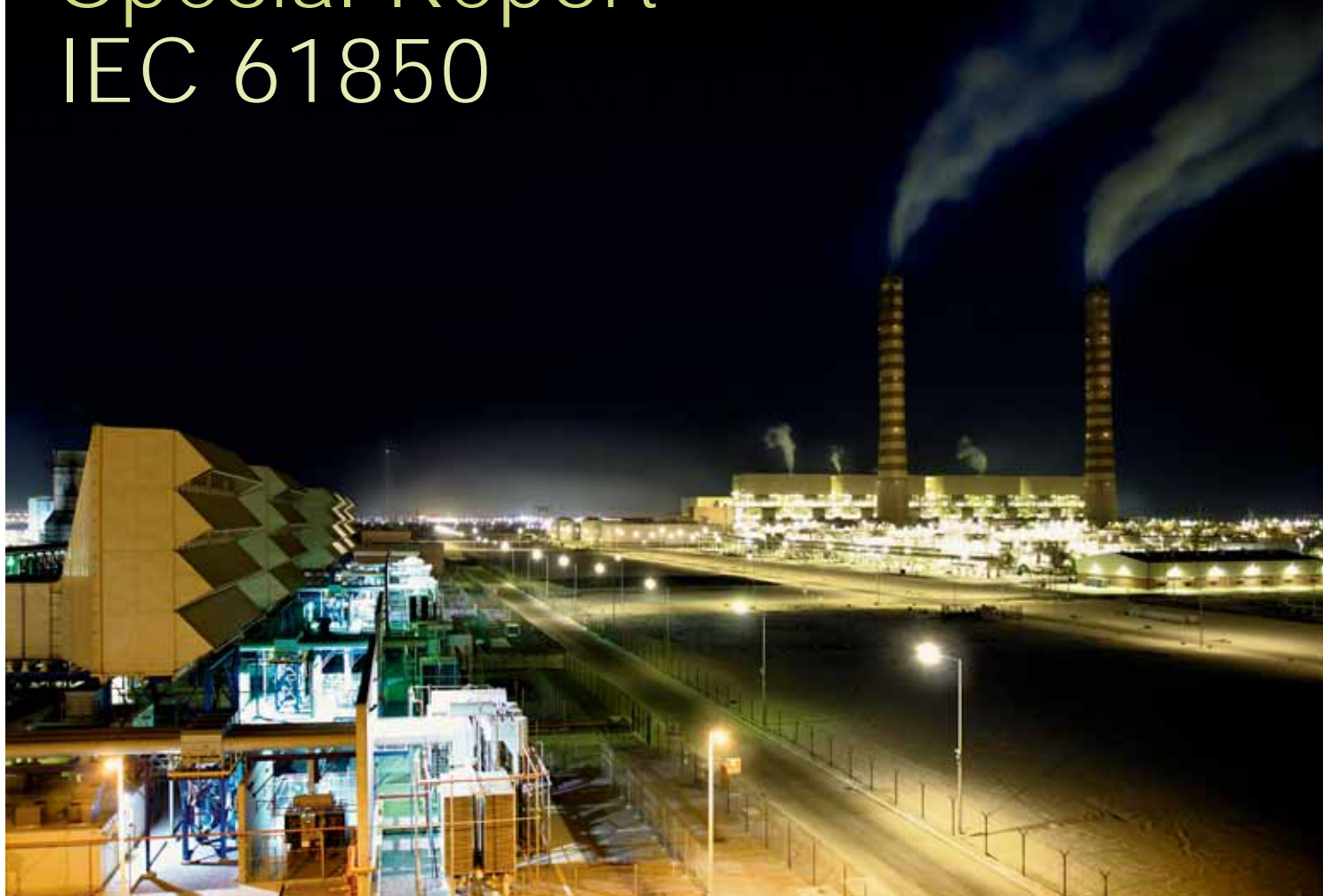
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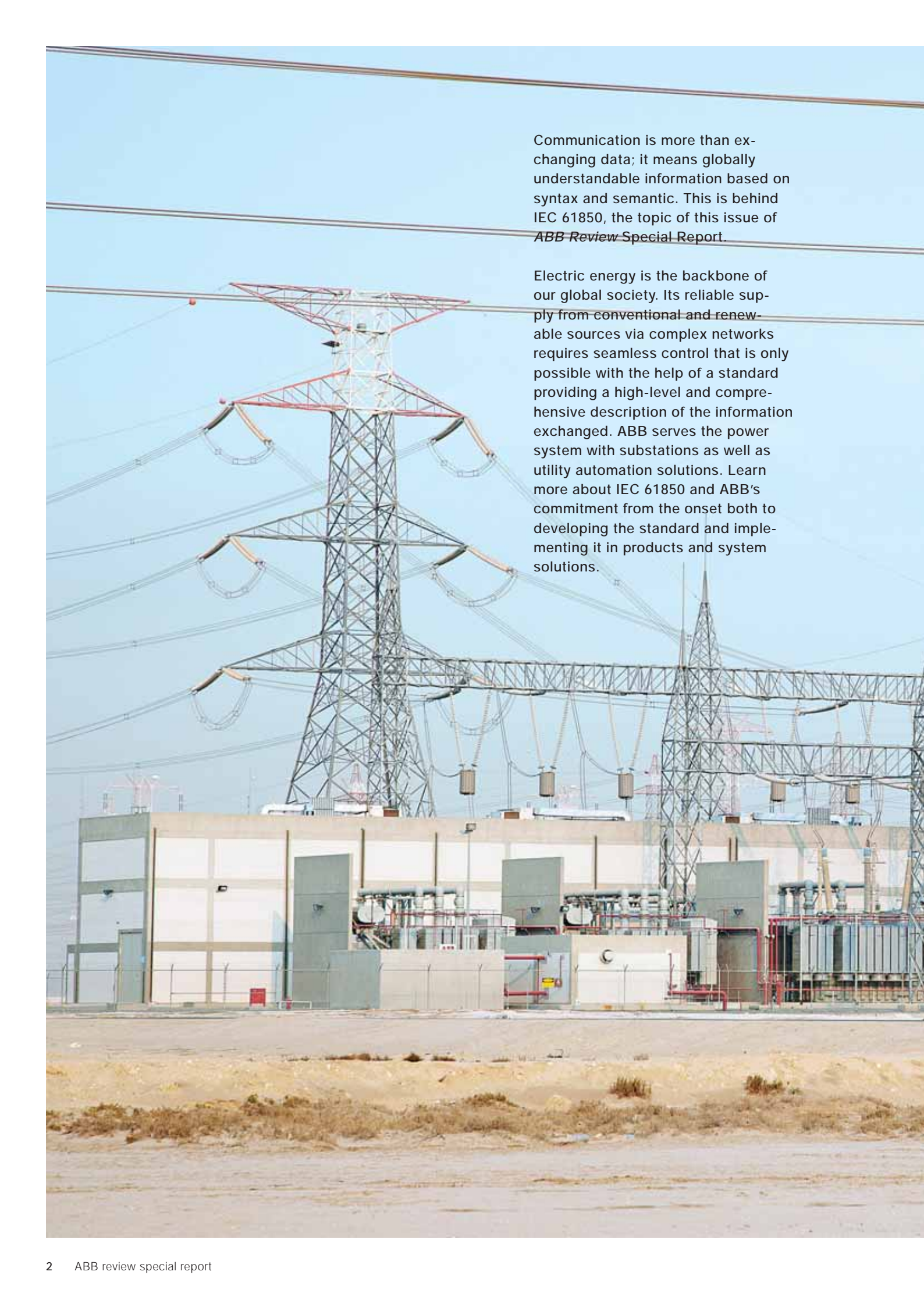
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Special Report IEC 61850



Power and productivity
for a better world™





Communication is more than exchanging data; it means globally understandable information based on syntax and semantic. This is behind IEC 61850, the topic of this issue of *ABB Review Special Report*.

Electric energy is the backbone of our global society. Its reliable supply from conventional and renewable sources via complex networks requires seamless control that is only possible with the help of a standard providing a high-level and comprehensive description of the information exchanged. ABB serves the power system with substations as well as utility automation solutions. Learn more about IEC 61850 and ABB's commitment from the onset both to developing the standard and implementing it in products and system solutions.

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IEC 61850 – A unifying global communication standard



Peter Leupp
Head of Power Systems division
Member ABB Group
Executive Committee



Claes Ryttoft
Head of Technology
Power Systems division

Dear Reader,

Substations are key components of the power grid, facilitating the efficient transmission and distribution of electricity. They play a vital role in terms of monitoring and controlling power flows and provide the interconnection between generating facilities, transmission and distribution networks and end consumers. Substation automation systems make their control and monitoring possible in real time and help maximize availability, efficiency, reliability, safety and data integration.

For decades, the power sector was geographically split between two major standards – IEC (International Electrotechnical Commission) and ANSI (American National Standards Institute). This often proved a deterrent to the development of a global technology offering.

IEC 61850 broke this deadlock. Since its publication in 2004, it has been embraced by both the IEC and ANSI communities. The new standard was designed to:

- Provide a single protocol for a complete substation
- Implement a common format to describe the substation and facilitate object modeling of data required in the substation
- Define the basic services required to transfer data using different communication protocols
- Allow for interoperability between products from different vendors

The standardization work commenced in the mid 1990s and continued for almost a decade, involving more than 60 experts from utility and technology providers across the globe. ABB was very much a part of this process and some of the contributors are represented in this report.

IEC 61850 provides a standardized framework for substation integration that specifies the communications requirements, the functional characteristics, the structure of data in devices, the naming conventions for the data, how applications interact and

control the devices, and how conformity to the standard should be tested.

Following its introduction, the implementation of IEC 61850 has advanced at a remarkable pace. Perhaps never before has an industrial standard been accepted with such speed. Within two years of its release, a majority of the market was demanding IEC 61850 as the preferred communication protocol.

It is increasingly being used for the integration of electrical equipment into distributed control systems in process industries. The fact that new application areas, such as hydro and wind power are being added is yet another indication of its success.

The bottom line is about how technology can lower costs, improve reliability and enhance efficiency. IEC 61850 has a proven track record of deliverable benefits to both small and large utilities. Communication infrastructure costs money to install, configure and maintain. But the savings that IEC 61850 delivers by way of substation design, installation, commissioning, and operation combined with new capabilities that are not practical or cost effective using legacy approaches, makes it a worthwhile investment.

This special edition of *ABB Review* looks at this truly global and unifying standard from different angles and relates many of our experiences based on the vast installed base we have built during the years. We shall also attempt to take a peek into some possible future developments in this area.

We hope you enjoy reading this dedicated special issue.


Peter Leupp


Claes Ryttoft





The concept of IEC 61850

A new approach for communication in substation automation and beyond

KLAUS-PETER BRAND, WOLFGANG WIMMER – The ability to cope with the natural migration of technology combined with the need for interoperability are just some of the reasons the IEC 61850, an international standard that defines communication in and between electrical substation automation systems was developed. Using its object-oriented hierarchical data model approach with high-level standardized semantics, IEC 61850 enables the abstract definition of data items and services to not only specify what data or information needs to be exchanged but also the mechanics of how it is to be exchanged using mainstream communication and networking (mainly Ethernet) technologies. In addition, the cost benefits of implementing IEC 61850 can already be seen in the system design phase and experienced right through to the commissioning and operating phases. All of these factors help to explain the eagerness and speed with which the first edition of the standard has been accepted around the globe.

Substation automation (SA) is commonly used to control, protect and monitor a substation [1]. However, over the years advances in electronics, information and communications technology have brought about sweeping changes in the way substations are operated. The advent of software-based substation automation systems (hereafter referred to as SA systems) connected by serial links rather than rigid parallel copper wiring gradually became the norm rather than the exception. Though successful and widely accepted, these systems were based on either the manufacturers' own proprietary communication solutions or the defined use of communication standards from other application domains, such as DNP3 or IEC 60870-5-104. These solutions made interoperability between devices from different suppliers, and sometimes even between different versions of devices from the same supplier, an engineering nightmare which could only be mitigated by expensive protocol conversion or re-engineering.

The connection of the SA system with the switchgear and instrument transformers was still left to analog standards such as 1A and 3A for current transformers, and 110V and 220V for voltage transformers and contact circuits for switchgear operations.

It took over 20 years before global forces, such as international suppliers and transnational utilities raised their voices to request a solution, in the form of a

Using its object-oriented hierarchical data model approach with high-level standardized semantics, IEC 61850 enables the abstract definition of data items and services.

substation communication standard, to overcome the interoperability problem → 1. While interoperability was a major concern, it wasn't the only one. Only too aware of the dizzying pace at which technologies change, the authors of this new standard, known as IEC 61850, also set about finding a way to create a "future-proof" standard that would be immune

to any future technological developments.

As the IEC 61850 standard evolved, other features, such as the definition of two time-critical services – the fast transmission of trip-type signals and sampled analog current and voltage values – were added. These time-critical services enable the extension of the serial links to be used between any intelligent electronic device (IED) and the electronic interfaces near the switchyard equipment. Demanding market requirements, such as the shortening of transfer times down to 3 ms and time synchronization in the order of 1 μs had also to be considered.

Perhaps the cornerstone of the standard is the innovative extensible markup language or XML-based substation configuration description language (SCL). SCL formally describes the configuration of IEDs in terms of functionality (eg, circuit breaker control, measurements and status values) communication addresses and services (eg, reporting). It also describes the switchyard layout and its relation to the functions implemented in the IEDs.

The emergence of a new standard

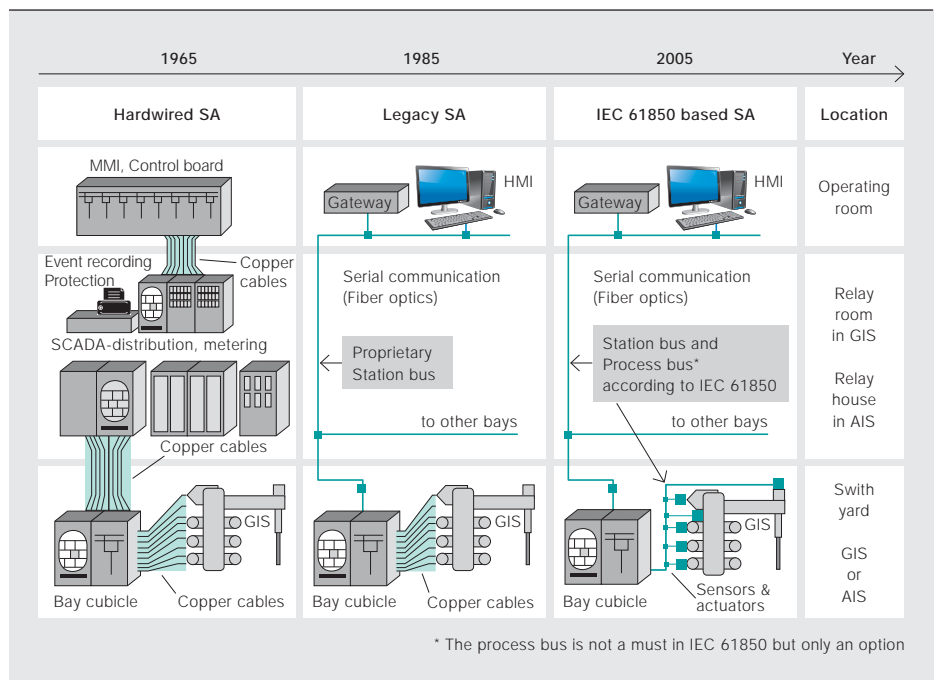
When the authors of the IEC 61850 standard first sat together, they identified a list of market requirements that would influence the form the new standard would take. The most important ones were interoperability, free architecture and long-term stability.

Interoperability

To begin with, the standard must be able to support all functions in its application domain substation. Therefore, in addition to protection, automation, control and monitoring functions, many service functions, such as time synchronization, self supervision and version handling have also to be supported. These functions are executed by software implemented in the IEDs. Interoperability in the SA system means that IEDs from different suppliers or different versions from the same supplier must be able to exchange and use information in real time without any protocol converters and without the need for human interpretation.

It is important to distinguish interoperability from interchangeability. If IEDs were also to be interchangeable, the functions

1 Substation automation (SA) architecture from hardwires over proprietary protocols to IEC 61850



and devices would need to be standardized, thus blocking any technical evolution and functional competition. Nevertheless it must be possible to exchange faulty IEDs within the lifetime of the SA system. Using IEDs that are compliant with the same standard in terms of interoperability will facilitate easy exchangeability.

Free architecture

For a standard to be termed “global,” it must support the operation philosophy of utilities around the world. It has to support an arbitrary allocation of functions to devices and should therefore be capable of supporting centralized and decentralized system architectures.

Long-term stability

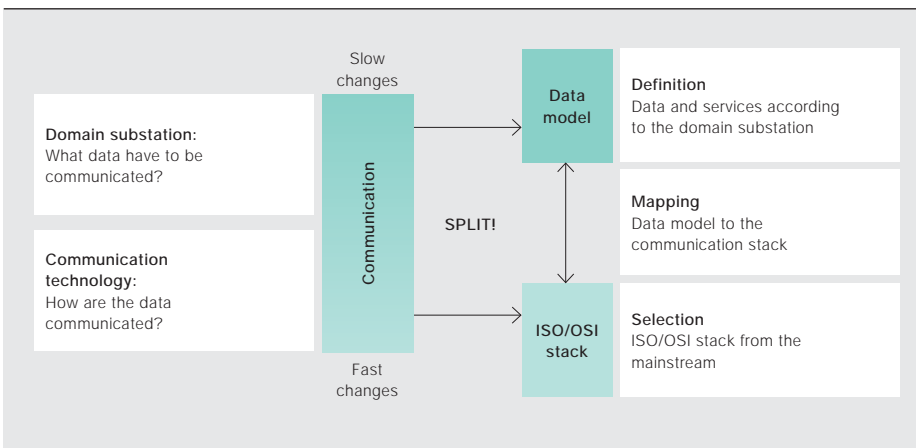
Given that the lifetime of a substation (primary equipment) is between 40 and 60 years, it is anticipated that components of the SA system have to be exchanged, on average, around two to three times during this period; some components may need replacements on a more regular basis. Naturally over time the substation will have to cope with the integration of new components from the same or new suppliers, or it may need to be extended. The point is that irrespective of the changes, interoperability must be maintained indefinitely, or to be more specific, the standard has to be future-proof. This requirement not only applies to substation devices, but also to the

various technologies employed in a typical substation. For example, fast-changing mainstream communication technology will always need to serve the slower-changing requirements of protection and substation automation.

To facilitate the use of the standard for users, the identification of all transmitted data should not be based on a limited number scheme derived from contact terminal rows, but rather on the object-oriented grouping of data and a naming structure that uses standardized acronyms understandable to any substation engineer. In addition, configuration and engineering tools should be used to create systems with minimum effort and with a minimum risk of failure.

The basic approach of IEC 61850

To reach long-term interoperability, ie, to cope with the different time scales of function evolution in the domain substation and with changing communication technology, the approach taken in the IEC 61850 standard separates the domain related model for both data and communication services from the protocols, ie, the ISO/OSI seven-layer stack used to code and decode information into bit strings for communication over a serial link. This approach not only accommodates state-of-the-art communication technology, but it also safeguards investments in applications and engineering (based on the object and com-



munication service model). Therefore, the standard is future-proof. The mapping of the data model to the communication stack is also standardized in IEC 61850 to ensure interoperable communication → 2.

The object-oriented data model

The basic data model structure defined in the IEC 61850 standard is application independent. However, depending on the scope of the standard, the object model classes, as issued in edition 1 of the standard → 3 [2], are related to the domain substation. Object models for wind power [3], hydro power [4] and distributed energy resources [5] were added at a later date. All application functions, including the data interfaces to the primary equipment, are broken down into the smallest feasible pieces, which may communicate with each other and, more importantly, may be implemented separately in dedicated IEDs. In IEC 61850, these basic objects are called logical nodes (LNs). The class name of the LN refers to the function the data objects belong to. The data objects contained in a LN may be mandatory, optional or conditional. The data objects themselves contain attributes¹, which may be seen as values or detailed properties of the data objects. This hierarchical data model is illustrated in → 4.

Since the class names of LNs and the full names of data objects and attributes are standardized, they formally provide the semantics of all exchanged values within the scope of IEC 61850. LNs may be grouped into logical devices (LDs) with non-standardized names, and these LDs are implemented in servers residing in IEDs. The common properties of the

physical device itself are dealt with by an LN class named LPHD.

Only if a LN class for some function is missing it may be substituted by generic LN classes that have restricted semantic meaning. More demanding, however, is the extension of LNs and data according to the strict and restrictive extension rules of the standard, including name spaces as unambiguous references to semantic meaning. These rules preserve interoperability, even in cases where extensions are required.

For the functional identification of each data in the context of the switchyard, a hierarchical plant designation system shall be used for the designation of substation objects and functions preferably according to IEC 61346 [6].

The services of the data model

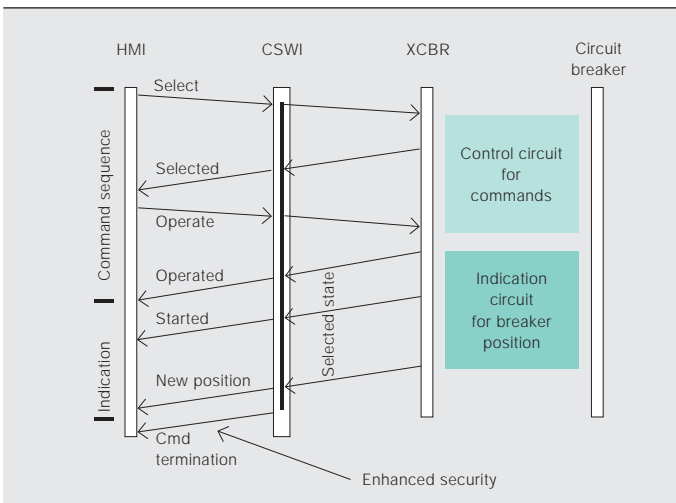
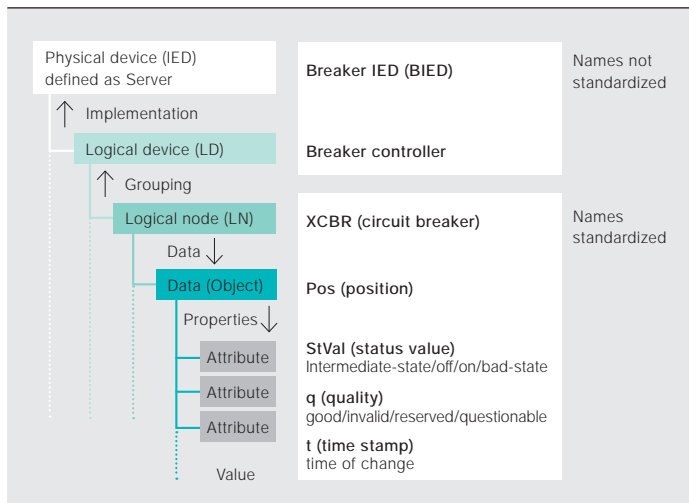
Interoperability requires the standardization of not only the data objects but also the access to them. Therefore, standardized abstract services also belong to IEC 61850. The most common ones include:

- Read: reading data such as the value of an attribute
- Write: for example writing the value of a configuration attribute
- Control: controlling switching devices and other controllable objects using standardized methods such as "select before operate" or "direct operate"
- Reporting: for example, event driven reporting after value changes
- Logging: the local storage of time-stamped events or other historical data
- Get directory: in other words, to read out the data model (important part of self-description)

Communication networks and systems in substations

- Part 1: Introduction and overview
- Part 2: Glossary
- Part 3: General requirements
- Part 4: System and project management
- Part 5: Communication requirements for functions and device models
- Part 6: Configuration description language for communication in electrical substations related IEDs
- Part 7-1: Principles and models
- Part 7-2: Abstract communication service interface
- Part 7-3: Common data classes
- Part 7-4: Compatible logical node (LN) classes and data classes
- Part 8-1: Mapping to MMS and to ISO/IEC 8802-3
- Part 9-1: Sampled values over serial unidirectional multidrop point-to-point link
- Part 9-2: Sampled values over ISO 8802-3
- Part 10: Conformance testing

All application functions, including the data interfaces to the primary equipment, are broken down into the smallest feasible pieces, which may communicate with each other and be implemented separately in dedicated IEDs.



GOOSE is the acronym for generic object oriented system event and is a service used for the speedy transmission of time critical information like status changes, blockings, releases or trips between IEDs.

- File transfer: for configuration, disturbance recording or historical data
- GOOSE: GOOSE is the acronym for generic object oriented system event and is a service used for the speedy transmission of time critical information like status changes, blockings, releases or trips between IEDs
- Sampled value (SV): the SV service quickly transmits a synchronized stream of current and voltage samples for voltages and currents

The control service implementing the “select before operate with enhanced security” mode is illustrated in → 5 in the context of a switch operation: The SELECT command is issued at the operator’s HMI and communicated to the bay control unit represented by the LN CSWI. Depending on the system architecture the SELECT command is confirmed either by the bay controller or the circuit-breaker IED, which is represented by the LN XCBR. When the operator receives a positive acknowledgement (ie, “Selected”) from the CSWI, he then issues an OPERATE command. Once permission has been granted, an operation request is sent via the bay controller to the circuit breaker (XCBR). The execution of the command request is positively acknowledged using the message “Operated.” Additional feedback is provided using the reporting service, which is initiated by the start of the circuit-breaker contact movement (“Started”) and when the end position is reached (“New position”). In cases where a command service with enhanced security is chosen, the end result is confirmed by the command termination message (“Cmd con-

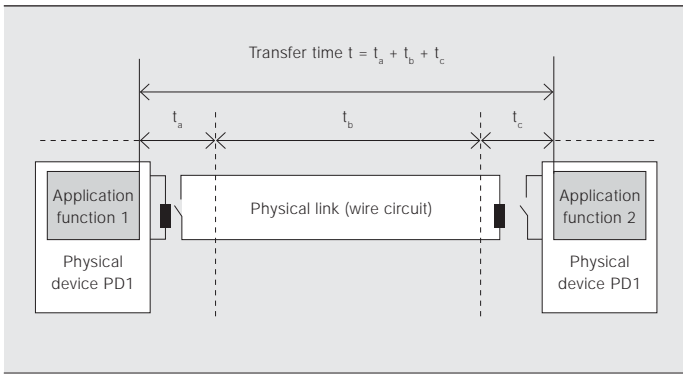
firmation”), which terminates the control service.

Performance requirements

The transfer time of messages between the sending application (eg, protection function issuing the trip) and the receiving application (breaker function performing the breaker operation) is determined by the requirements of functions that depend on this message transfer. As a protection trip is time critical, with a worst case taking around 20ms, it is allocated to the most demanding transfer requirement class, which means 3 ms. The transfer of samples using the SV service is also assigned to this requirement class to avoid, for example, delays in fault detection by protection. The requirements have to be fulfilled not only by the IEDs but also by the SA system design. The transfer time of a GOOSE message over a serial link is compared in → 6 and → 7 with the response time of a hardwired contact circuit.

To properly analyze the sequence of events in the system and for post-event fault analysis, the events need a time stamp with an accuracy against real time of 1 ms; this incidentally is better than any contact change. However, time synchronization for current and voltage samples, which are needed for differential or distance protection or global phasor comparison, requires an accuracy of the order of 1 μs! The 1 ms accuracy level is achieved using the simple network time protocol (SNTP) directly over a serial communication link, while one pulse per second (pps) over a separate wire or fiber achieves the 1 μs time synchronization. In the future, the IEEE 1588 stan-

6 Transfer time definition with hardwired contacts



standard [7] will allow high-precision time synchronization also directly over Ethernet.

The communication stack and mapping

IEC 61850 has selected mainstream technology for the communication stack, ie, a stack structure according to the ISO/OSI layers consisting of Ethernet (layers 1 and 2), TCP/IP (layers 3 and 4) and manufacturing messaging specification, MMS, (layers 5 to 7). The object model and its services are mapped to the MMS application layer (layer 7). Only time-critical services, such as SV and GOOSE are mapped directly to the Ethernet² link layer (layer 2) → 8.

Ethernet bus architectures and dual port redundancy

IEC 61850 uses Ethernet as the basic communication technology, currently with a speed of 100 MBit/s at the IEDs. Support of message priorities by managed switches allows time critical requirements, such as the 3 ms application to application transfer time, to be met. Tree and ring topologies are possible with switches. However, according to the first edition of the standard, the Ethernet ring topology with automatic reconfiguration in case of link or switch failures is the most common architecture for systems. Tree topologies are not used very often because the switch representing the root is a potential single point of failure. It should be noted that in the ring, one switch connection has to be always open – creating in effect a kind of tree topology – to avoid endlessly circulating telegrams. The open switch connection is automatically closed if a failure in any of the ring links or in another switch creates an unwanted second opening (ie, a tree recovery algorithm).

Edition 2 [8] of the standard scheduled for publication in 2010 will define protocols for the connection of IEDs with two ports to two redundant communication systems or the formation of a ring with redundant traffic in both ring directions³.

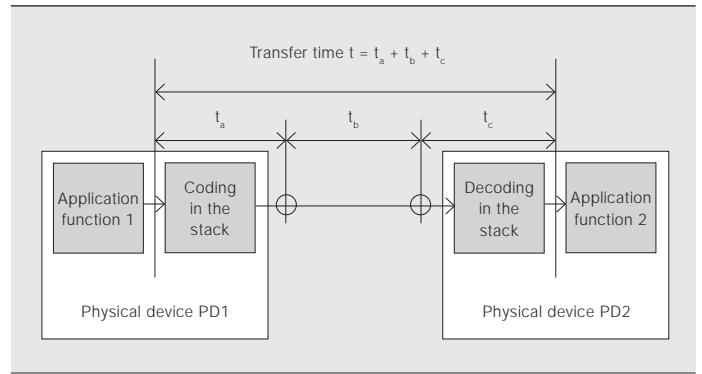
The station and process buses

The station bus connects the IEDs for protection, control and monitoring (ie, bay units) with station level devices (ie, the station computer with HMI and the gateway to the network communication center (NCC)) using whatever services are required by the applications. The process bus connects the bay units with the switchyard devices, and the communication of status information, commands and trips is the same as for the station bus → 9.

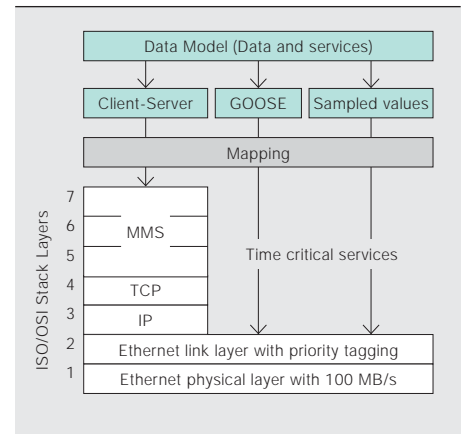
However, getting synchronized samples of current and voltage to the relevant protection IEDs using the SV service is quite challenging.

The conversion of proprietary signals from nonconventional instrument transformers for current and voltage or of the analog values from conventional instrument transformers to IEC 61850 telegrams is done using an IED called a merging unit (MU). An MU merges the 3-phase currents and voltages, including the zero-components of one bay high-precision time-synchronized by definition. The process bus functionality for the switchgear is provided by the so-called breaker or switch IEDs (BIED, SIED). The free allocation of functions allows the creation of IEDs with both BIED and SIED, and MU functionalities.

7 Transfer time definition with communication stacks



8 Mapping to the stack



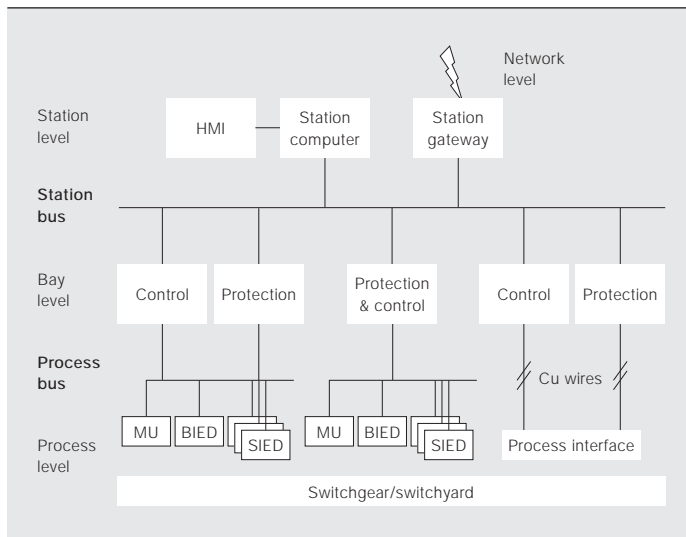
The station bus may be configured in a ring topology with ring redundancy, a redundant star for IEDs with dual port redundancy or any solutions which fulfill

Such is the potential of IEC 61850 that in the future it is hoped it can be applied right across the power system spectrum.

the requested performance and reliability requirements. The process bus may also adopt a ring or even a star topology, but at the very least one or more point-to-point connections.

SCL supported engineering

In order to process data received from IEDs, the receiving IED needs to know how this data has been sent; how it has been coded; what it means in the context of the switchyard; and the functionality of the sender. To be able to transfer this information from one tool to another in a standardized way, the XML-based SCL language has been defined.



To allow the exchange of data between tools from different manufacturers, IEC 61850 introduces a basic engineering process: Based on the system specification and the description of the IEDs, the required device types are selected and their formal description, in the form of an ICD file, is loaded into the system

The station bus connects the IEDs for protection, control and monitoring with station-level devices while the process bus connects the bay units with the switchyard devices.

configuration tool. The system configuration tool then defines the meaning of IED functions in the context of the switchyard by allocating LNs to elements of the switchyard single-line diagram. The data flow between all IEDs is then defined, and all IED names and communication related addresses and parameters are configured. The resulting SCD file is a comprehensive description of the entire system in the context of IEC 61850. This file is then imported into the device tools of the different IEDs to complete their individual configuration in the context of

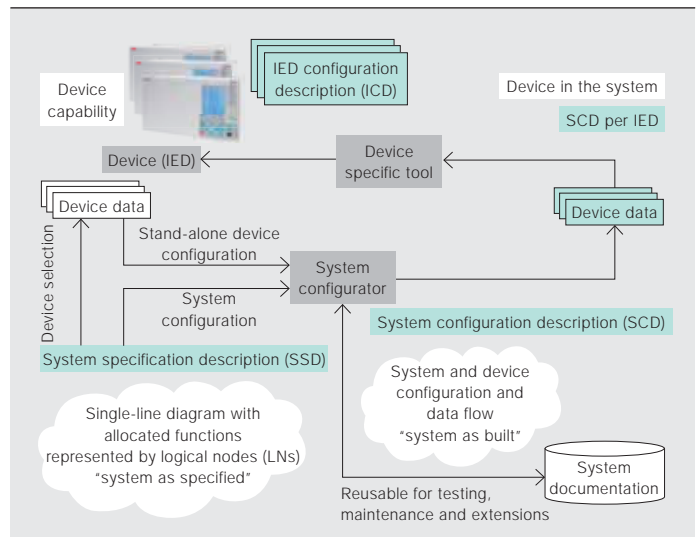
the system. The principles of engineering with SCL files are shown in → 10.

As the entire IED data model is visible via the communication system, including possible configuration and setting parameter values, and all this can be described in SCL, the SCD file is also a medium usable by other applications in the life-cycle of the system [9], such as the archiving of the system configuration in a standardized form and the transfer of protection parameters to protection system configuration tools. It may be used in simulation and testing tools or to check the configuration (version) state of the running system against the intended state. While these applications are outside the scope of IEC 61850 as a communication standard, they are of additional benefit for the user of the standard.

A future-proof outlook

The long-term value of IEC 61850 for users lies in its object-oriented hierarchical data model approach with its high-level standardized semantics and the use of mainstream communication technology, which is dominated by Ethernet. However, IEC 61850 is much more than just a normal communication protocol. Such is its potential that in the future it is hoped IEC 61850 can be applied right across the power system spectrum.

A second edition of the standard is scheduled for publication in 2010. It will contain many additional features, such as the support of dual port redundancy for IEDs.



Klaus-Peter Brand

Wolfgang Wimmer

ABB Substation Automation

Baden, Switzerland

klaus-peter.brand@ch.abb.com

wolfgang.wimmer@ch.abb.com

Footnotes

- 1 The attributes carry the data values.
- 2 Nowadays in communication technology, most efforts and money are invested in Ethernet technology. In fact Ethernet is now successfully competing with the traditional field busses.
- 3 Please refer to "Seamless redundancy" on page 57 of this issue of *ABB Review*.

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Common denominator

Common components have helped ABB adopt the IEC 61850 substation communication standard in record time

MARTIN OSTERTAG – With the advent of the IEC 61850 standard in 2002, and its growing success in substation automation and later in several other industries, ABB was faced with the challenge of adapting a variety of its products to the new technology in a relatively short time. This was successfully accomplished in part due to the development of common components designed for use in a wide variety of ABB products.

1 Interoperability demonstration between major vendors at the IEEE PSRC meeting in Sun Valley in the United States in 2003



2 Use of common components in a variety of ABB products

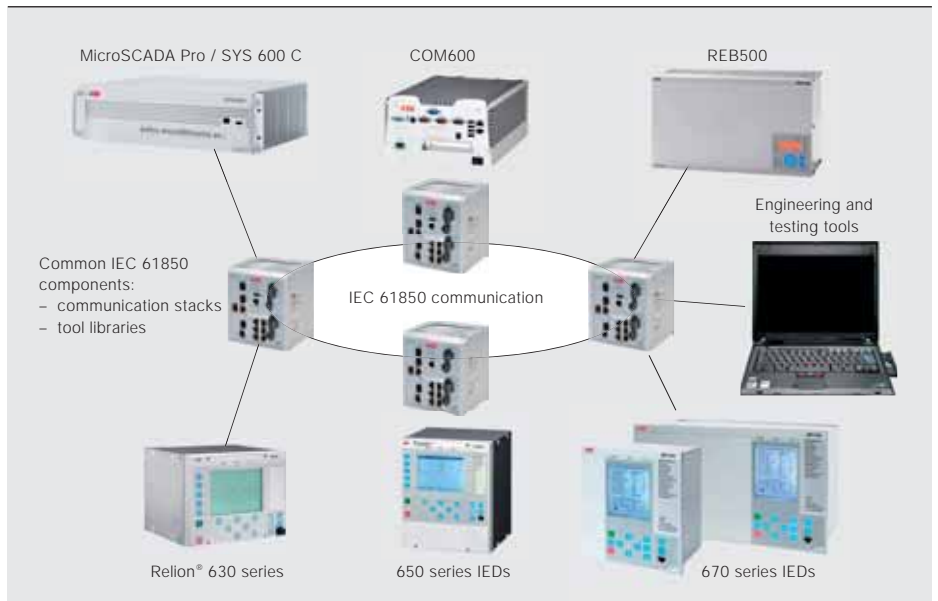


ABB was heavily involved in the process of creating the IEC 61850 standard. As the standardization was in progress, and in order to enable a fast time-to-market, the standard was already being implemented in products in parallel to the standard's finalization between 2002 and 2004. In order to support the standardization, interoperability tests were arranged for these early implementations. As ABB believed that the standard would be a success, it realized that a wide variety of products would need to support it. The company thus decided to implement reusable components right from the beginning. The results of these activities were reported back to the IEC organization that used them to improve the clarity and quality of the standard. In addition, they were presented to the public at the IEEE PSRC meeting in Sun Valley, USA in 2003 → 1 and at the Hannover Fair in April 2004.

At that time, ABB outlined a clear stepwise strategy for the introduction of IEC 61850 into its solutions in its very own internal IEC 61850 application guideline. This guideline defines the mandatory subset of IEC 61850 services that is supported by all ABB devices, it adds additional ABB internal convention, and clarifies and details certain sections where the standard leaves room for interpretation.

Already in its fourth edition, the guideline serves as a good introduction to the soon-to-be-available second edition of the IEC 61850 standard and defines the stepwise transition from the first edition to the second.

Based on the principles defined in the application guideline, ABB started to develop reusable components for a variety of products and tools in its portfolio. Two important components are the communication stack and a set of libraries that handles IEC 61850 object models and configurations → 2.

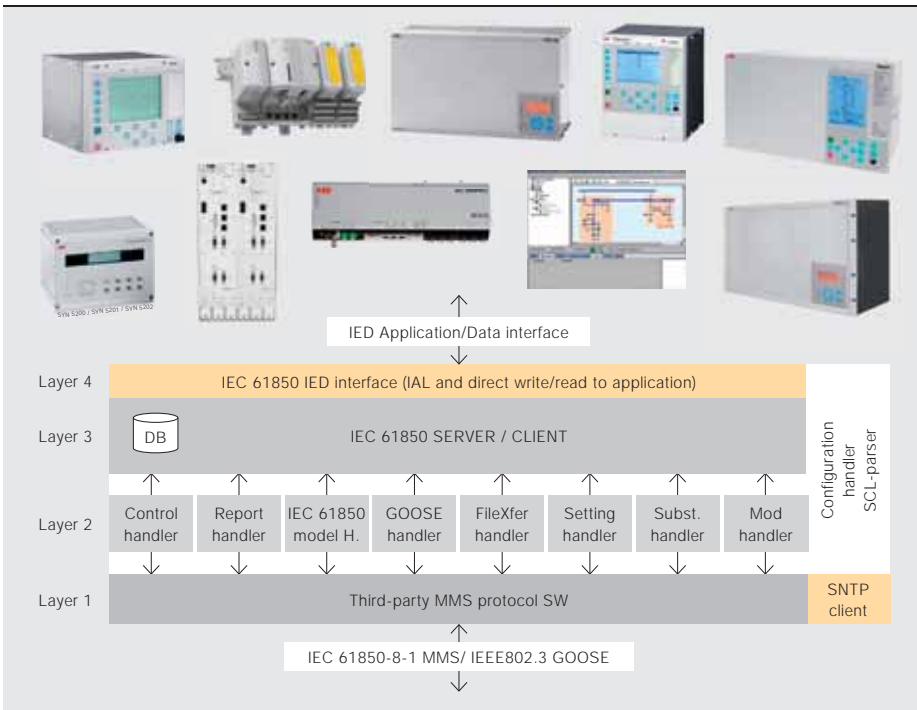
Communication stack

The IEC 61850 communication stack → 3 is effectively a piece of software that implements the communication services for IEC 61850-8-1 manufacturing message

specification (MMS) and generic object oriented substation event (GOOSE) servers and clients. More importantly, it hides the nitty-gritty details from the more application oriented research and development found in ABB's products, thereby allowing developers to concentrate on providing application value to customers. Currently, the communication stack is in-

Currently, the IEC 61850 communication stack is integrated into more than 12 ABB products or product families, with a growing number of host platforms set to follow suit.

tegrated into more than 12 ABB products or product families, with a growing number of host platforms set to follow suit as IEC 61850 continues to be accepted by other industries. The benefits of the IEC 61850 stack include portabili-



ty, and it runs on different real-time operating systems as well as under Windows for PC-based products and tools.

For the upcoming edition 2 of the IEC 61850 communication standard, common components will continue to play an important role in supporting a market-driven, phased upgrade and migration strategy for ABB's product and tool portfolio.

File handling and object modeling

Each product to be integrated into an IEC 61850-based system needs to have its functionality defined in a standardized way that enables it to communicate with, and process information from other products in the system. This is where the

XML-based substation configuration language (SCL) comes into play. In addition, the communication stack, which is a reusable component, needs configuration information to enable such communication to take place.

Configuration tools rely on a software component that interprets and generates both SCL and stack configuration files. This component allows the tools to work on an object-oriented data model rather than parsing and interpreting raw files. In addition, it helps to avoid syntax and semantic errors and contributes to the high quality of ABB's products.

Benefits of ABB's approach

The main benefits of such a component include:

- The ability to carry out maintenance and improvements in one place, allowing all products to benefit
- The uniform implementation of functionality, which is crucial for interoperability between devices from ABB and third-parties
- Detailed testing and experience in the field. Because it is integrated into a variety of products, its functionality is tested way beyond what can be achieved for product-specific implementations.

Success factors for component reuse

ABB's experience in the development of common components for IEC 61850

- Always be a step ahead of the products and tools that will use the components. In other words anticipate upcoming or future IEC 61850 specific communication requirements that component users might not even be aware of at the time they are implemented in the product.
- Fast reaction and premium support during the integration phase of the products research and development. In other words, the component research and development team must have a very "service provider" oriented mindset in that requests and problems from product research and development teams must be dealt with relatively quickly.
- Version traceability. Keep track of the distributed versions and version dependencies, ie, which version of a product contains which version of the component.
- Backward compatibility of the component is very important. If substation primary equipment can have a life expectancy of between 30 and 40 years, it is an absolute certainty that the substation automation system will be extended and upgraded at least once during this time. As a consequence, different versions of products and tools need to co-exist in the same system. This puts certain requirements on the definition of the component's software interfaces and the way functionality is implemented.
- The proper clustering of functionality in a way that keeps the level of detail component users need to know about IEC 61850 at an appropriate level. This in turn allows the product engineers to focus more on application modeling and concept development.

shows several important aspects that need to be observed to successfully capitalize on component development → 4.

For the upcoming edition 2 of the IEC 61850 substation communication standard, common components will continue to play an important role in supporting a market-driven, phased upgrade and migration strategy for ABB's product and tool portfolio. Close links to IEC working groups combined with implementation in parallel to standardization will allow ABB to maintain and strengthen its front-row position in IEC 61850 technology.

Martin Ostertag

ABB Substation Automation Products
Baden, Switzerland
martin.h.ostertag@ch.abb.com



Pushing the limits

ABB product development based on the IEC 61850 standard

JANNE STARCK, STEVEN A. KUNSMAN – Since the publication of the first edition in 2004, the IEC 61850 communication standard has practically become the de-facto standard in the context of substation automation. Almost from the moment of its publication, intelligent electronic devices (IEDs) supporting IEC 61850 started to appear on the market. However, for many of these IEDs, it soon became clear that performance and flexibility were sacrificed in the race to get to the market first. ABB took a somewhat different approach. Experts from within the company

participated in the standardization work from day one, and as it was being developed it was decided to upgrade ABB's Relion® protection and control product family to support the IEC 61850 standard. By the time the standard came into existence, ABB had already adopted a philosophy of "native IEC 61850 implementation" in that the standard is implemented from the start in new product developments. Today, ABB's IEC 61850-based protection and control products are recognized as the number one choice for both utility and industrial power systems.

| PTOC Logical Node Class | | | |
|-------------------------|-----------------------------|--------------------|------------|
| Data Object Name | Explanation | Mandatory/Optional | IED Design |
| Mod | Mode | M | X |
| Beh | Behavior | M | X |
| Health | Health | M | X |
| NamePlt | Name Plate | M | X |
| OpCnt | Operation Counter | O | |
| OpCntRs | Operation Counter Reset | O | |
| Str | Start | M | X |
| Op | Operate | M | X |
| TmASt | Active Curve Characteristic | O | |
| TmACrv | Operating Curve Type | O | X |
| StrVal | Start Value | O | X |
| TmMult | Time Dial Multiplier | O | |
| MinOpTmms | Minimum Operate Time | O | X |
| MaxOpTmms | Maximum Operate Time | O | |
| OpDITmms | Operate Delay Time | O | X |
| TypRsCrv | Type of Reset Curve | O | X |
| RsDITmms | Reset Time Delay | O | X |
| DirMod | Directional mode | O | |

With the introduction of the IEC 61850 standard, the world of substation automation has taken its biggest technology leap since the introduction of microprocessor-based protection and control devices in the early 1980s.

As soon as the standard was published, intelligent electronic devices (IEDs) supporting IEC 61850 started to appear on the market. The speed at which this happened was achieved by upgrading existing IED platforms with an internal or external gateway serving as a proxy to the IEC 61850 Ethernet-based protocol. Because this approach left the IED architecture, internal software and tools unchanged, protocol conversion was required to enable communication between existing IEDs and a modern IEC 61850-based substation. At the time, the IEC 61850 standard was just one of a number of protocols to expose the IED's internal information, which was mapped to the IEC 61850 data models and logical nodes (LNs). The internal architecture did not differ from other point or register-based communication protocols (eg, DNP V3.00 and MODBUS). While these early implementations resulted in a fast time-to-market, performance and flexibility were sacrificed as a result.

As the standard became better known, however, engineers realized the benefits it provided presented them with an opportunity to rethink IED platform and architecture development and introduce

IEC 61850 implementation" philosophy, which stated that from then on the standard would be implemented in new product developments.

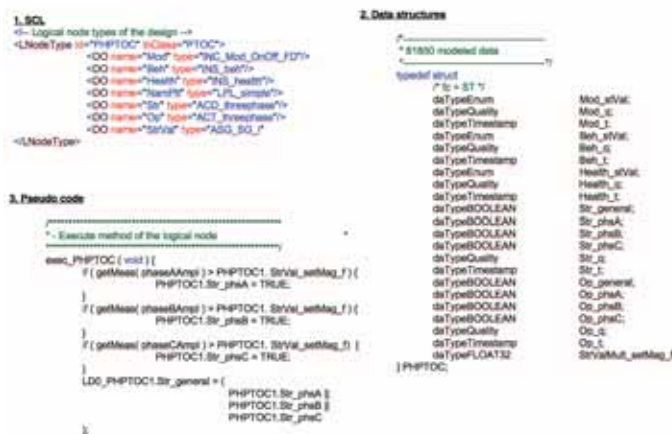
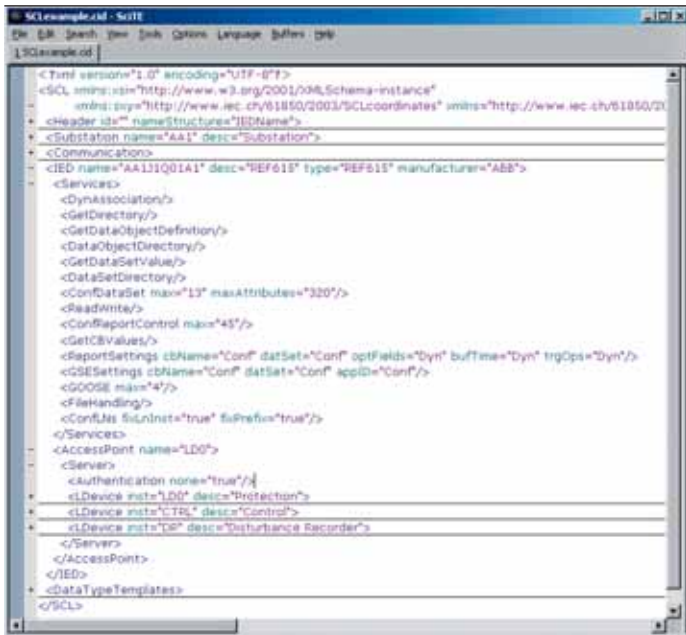
Native IEC 61850 implementation

In a typical IEC 61850 native design, the functionality of the IED must consider the entire process, including specification and evaluation, system and device engineering, system commissioning, and operations and maintenance. An IEC 61850 native IED should provide:

- A full set of protection and control data to SA systems, and to other IEDs and third-party tools in compliance with the defined data models and LNs to achieve a high level of interoperability
- Fast communication and application performance, which is critical when using generic object oriented substation events (GOOSE) peer-to-peer communication for distributed protection algorithms, and complex station and bay control interlocking schemes over Ethernet in the substation station bus
- Adherence to data modeling and substation configuration language (SCL) information available for system engineering, device configuration, diagnostics and commissioning tools

Even before its publication in 2004, ABB was extending the limits of IEC 61850 with its full implementation of the standard in many of its devices, tools and substation automation (SA) systems.

new conceptual ideas for substation automation. ABB was taking this approach even before the standard's publication by fully and genuinely implementing the standard in many of its devices, engineering and commissioning tools, and substation automation (SA) systems. In fact, ABB had already adopted a "native



– Ease of adaptation and be future proof to evolving technologies enabled by Ethernet and IEC 61850, for example, utilizing IEC 61850-9-2 sampled values and microsecond-level time synchronization accuracy via IEEE 1588

ABB's Relion® protection and control product family was one of the first to undergo the IEC 61850 transformation. The products required a completely new platform architecture that would integrate

fully base the IED's functionality on the data model and LNs as defined in the standard. As it now stands, protection and control algorithms, which provide the core IED functionality, are modeled and implemented fully according to the IEC 61850 standard rules. In the new architecture, the data models are supported directly in the protection and control functions, making the LN data directly accessible from the communications services. With this approach the data mapping and conversion process is not required, something that is a key factor in IED performance. IED data are therefore directly available without time-consuming additional processing.

this is dependent on the product and intended application → 1. The supported standard data objects are documented in the mandatory model implementation conformance statement (MICS) document.

In the next stage, the standard LN and its selected functionality are modeled using the SCL, which describes the function structures, data objects and data types of an LN → 2. With the defined function structures according to the SCL, it is possible to automatically generate the skeleton of the application data access functions (read, write) for the IED system software. These functions are inherited and directly linked to the protection algorithm (eg, PTOC) data in the IED architecture's core protection and control subsystem. This direct mapping provides a high-performance interface to the IED's IEC 61850 communication stack, which in turn makes the data accessible to the station bus → 3. No additional conversion of protection and control data is required to support the communication's architecture and protocol. Structures based on LNs can also have a function for settings, which are directly visible to the SA system via the communication stack.

ABB's Relion® protection and control product family was one of the first to undergo the IEC 61850 transformation, a development that was carried out in parallel with the development of the standard.

communication services and data representation into the core protection and control applications. This development was carried out in parallel with the development of the IEC 61850 standard (pre-2004) to ensure that the future ABB Relion family was designed from the beginning to support IEC 61850.

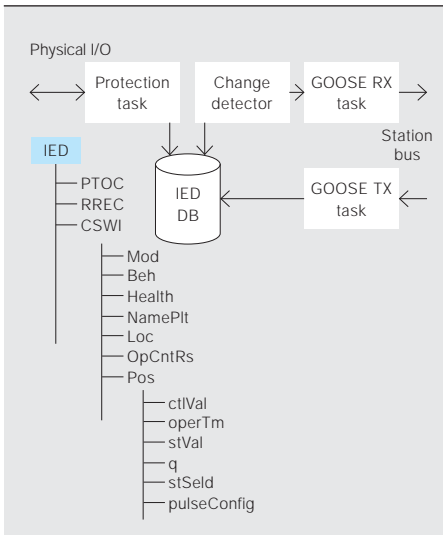
Transforming the Relion IEDs

One of the key factors that led to successful product transformations was to

represent protection, is implemented, the standard phase time overcurrent (PTOC) LN-class definition is the foundation for modeling the protection algorithm. Depending on product and application requirements, all mandatory and selected optional attributes of the LN-class are used in the function design. The IEC 61850 standard requires that the mandatory data objects must exist in the data model of the device. The optional parts are only used when applicable, and

In general, the IEC 61850 standard provides a solid foundation for the design of native IEC 61850 protection and control IEDs due to the fact that data models have been defined by an international working group composed of experts in

4 GOOSE data and message handling



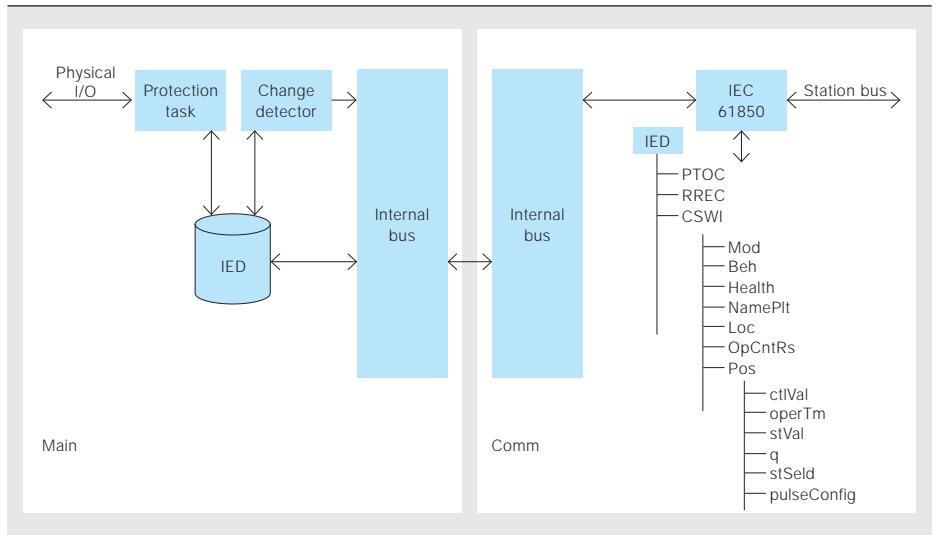
the field. With standard-based data modeling, faster development of IED application functions and communication interfaces can be obtained. The improvements are due to the LN structures, which are inherent in the protection application. This therefore makes data access from the IEC 61850 based SA system to the IED's internal protection and control algorithms very computationally efficient and eliminates the need for time-consuming protocol conversion processing.

The performance of a native Relion IED

IED architectures designed to support IEC 61850 from the start need to ensure that the delay in communicating control signals, analog values and other time critical data between the process and the IEDs is as small as possible. In traditional IEDs, the binary and analog signals were processed by the IED hardware I/O subsystem. In IEC 61850-based architectures, conventional wiring has been eliminated and these signals are transmitted and received via the communications interface. Thus, the communication interface in the new IEC 61850-based IEDs must be very efficient at processing the communication data.

The fast GOOSE performance of a Relion IED is critical in a native IEC 61850 implementation to allow control signal processing as if it were a traditional hardwired IED. During IED algorithm execution or task cycle, the data values of a protection function (eg, the protection start in PTOC) can change if an overcurrent is detected on a feeder, and this in turn updates the database supporting the par-

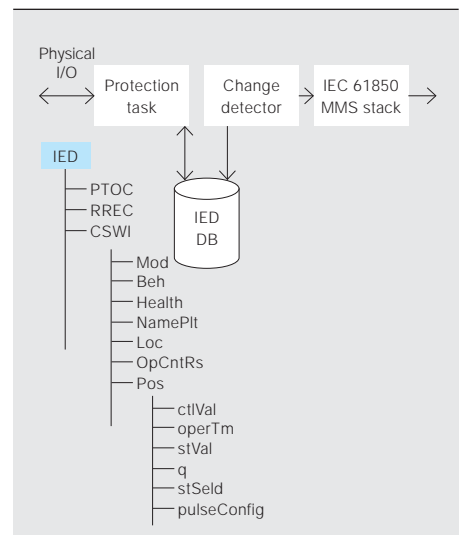
5 IEC 61850 handling in case of a separate communications module



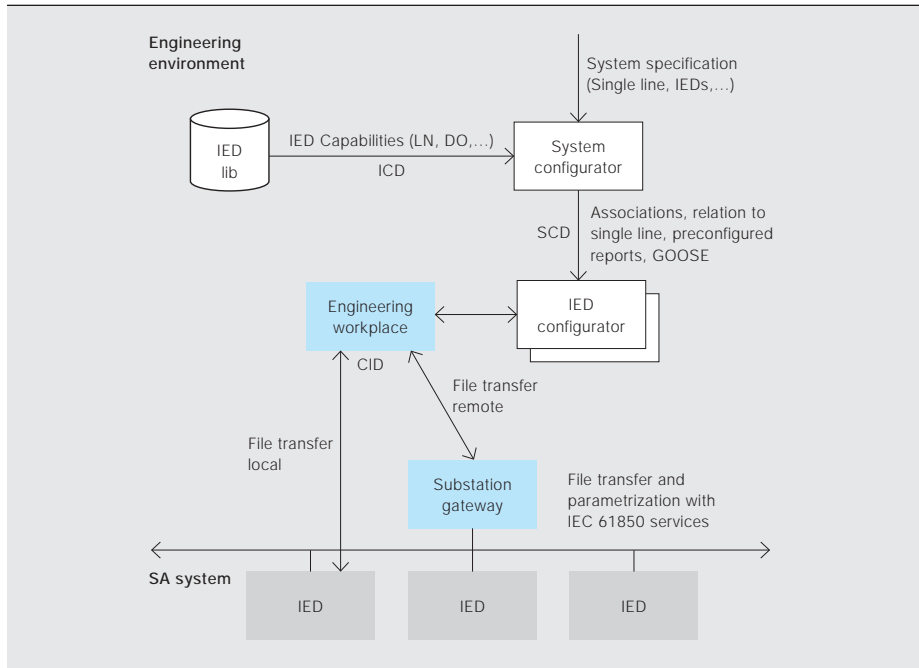
ticular LN structure. After a protection task cycle completes, the IED processing subsystem performs a signal comparison to identify new data in the IEC 61850 connected datasets. In the IEC 61850 data model, most data-change driven activities are based on the datasets, for example, event reporting and GOOSE data publishing. The IED change detector identifies changes in the datasets and if a new value is detected, the dataset and its connected functionality are triggered. In an IED using GOOSE, the internal high-priority subsystem executing the GOOSE function is triggered. Subsequently, the modified data is sent as quickly as possible through the IED communication interface to the SA system station bus using a GOOSE multicast message. GOOSE multicast messages are unsolicited broadcasts which do not require any cyclical data polling mechanism. Data structures used in GOOSE include direct access to the IED internal database, and because the internal data model exactly matches the IEC 61850 standard, no data conversions are required → 4.

In the same way, the IED's IEC 61850 native design yields high-performance subscribing GOOSE datasets from other IEDs in the local sub-network. As GOOSE messages are processed in the data link layer in the Ethernet stack, this does not require additional processing through the TCP and IP layers. This type of Ethernet communication is very fast since the data is retrieved directly from the IED communications hardware interface. The IED's GOOSE processing capabilities can decode the message in less than 1 ms and

6 IEC 61850 event handling



In IEC 61850-based architectures, conventional wiring has been eliminated and binary and analog signals are transmitted and received via the communications interface.



deliver only the modified subscribed GOOSE data to the IED's internal database, which makes it immediately accessible to the next execution of the protection and control algorithms. A "put" operation is a single data value copy from a GOOSE frame to the internal LN structure database → 4. No conversion is required as the data in both the IED database and incoming GOOSE message comply with IEC 61850 data types. The next application execution checks for new input values and processes them accordingly.

If GOOSE was based on a non-native IEC 61850 implementation, a conversion from an internal data model to an IEC 61850 data model would be needed. It would therefore be difficult to achieve the performance classes for protection communication as stated in the IEC 61850 standard. In some architectures, the processing of horizontal communication utilizes a different processor on a separate IED communication card or an external gateway, which would make the performance and configuration even more challenging → 5.

Reporting events to SCADA systems using standard buffered or unbuffered reporting services is based on the same mechanism that is implemented to detect GOOSE data changes. When a change of data is activated by an application, for example, a protection start signal in PTOC, the new data value and

its associated timestamp and quality attributes are stored in an internal event queue by the IED's change detector. At the same time, the IED's communication interface is triggered and starts sending queued events to clients (eg, the gateway or station HMI) on the station bus → 6. As internal data models and stack data structures are based on the same IEC 61850 data model, there is no need to carry out any additional data processing.

ABB has created an internal IEC 61850 application guideline that defines the appropriate default dataset names and

The configuration of IEDs belonging to the Relion product family is based on ICD files available in the IED connectivity packages.

uses; for example, StatNrm1 for protection events and StatUrg for primary equipment value changes. In this way, different IEDs in the Relion family have similar properties and are easier to configure in the SA system. Default values

are defined and used in the IED tool and connectivity packages, and are available for the user when an IEC 61850 configuration (SCL) is exported using the IED tool.

In the new IED architecture, traditional communication protocols, such as Modbus, IEC 60870-5-103 and DNP 3.0 are mapped from the IEC 61850-based data model and event datasets. The convenience of protocol mapping stems from the fact that IEC 61850 includes most of the different data and service types required for legacy protocols. A comparison of legacy protocols and IEC 61850 typically shows that legacy protocols have a subset of services and data types available. Many customers prefer to use legacy protocols and the internal architecture of an IED must be ready to support multiple protocols. IEC 61850, however, is the preferred superset in terms of functionality and services.

System engineering

IEDs belonging to the Relion product family are configured according to the rules defined in the IEC 61850 standard. The configuration is based on library installable client driver (ICD) files available in the IED connectivity packages where these library files include the IED's data model. In the top-down engineering process, the system integrator selects the appropriate library ICD files representing the Relion IED types and builds the system configuration description (SCD) according to the substation design. In this phase, the substation configuration already includes all IEDs, the single-line diagram, the GOOSE links between the devices and the event definitions. The SCD file is imported to the IED tool where the IEDs are parameterized and configured according to the application/power system specifications → 7.

In small and simple IEC 61850 based substations, the system engineering of the substation automation system can be done using a bottom-up process. The workflow starts from the IED tool, which creates the set of IEDs and exports the initial SCD file to the system configuration tool. Using connectivity packages, the IED tool exports the SCD file, including a default single-line diagram and datasets for event reporting. In many cases, these values, as such, fit customer specifications. In the system configu-



ration tool, the system engineer can add GOOSE links and if required, customize the details of the single-line diagram and event datasets. The system engineer exports the completed SCD file back to the relay setting tool where the IED's application configuration is finalized.

In both top-down and bottom-up system engineering processes, the final result is an SCD file which is needed for the configuration of substation SCADA systems and gateways. The substation section of the SCD file can be used as an information source to create the substation single-line diagram, which in turn minimizes any additional work needed for the design of the substation's graphical diagram. In this way, the SA system greatly benefits from the self-descriptive feature of the IEC 61850 defined SCL.

Testing and using Relion IEDs

The capability of the native IEC 61850 implementation and the IED design have been thoroughly tested as part of the development validation – as have products already on the market – at the ABB UCA level B certified System Verification test Center (SVC)¹. The most important test is the basic IEC 61850 conformance test. All Relion IEDs have been tested and certified according to the procedures defined in part 10 of the IEC 61850 standard. For end users and manufacturers, the certificate states that no nonconformities to the standard have been found in the behavior of the IEDs. The IEDs are



therefore capable of interoperating with other systems offering IED protocol services and which have SCL files exported from the IED tool. A typical IEC 61850 certificate from KEMA is shown in → 8.

To date the IEC 61850 standard conformance test does not test IED performance. However, part 5 of the standard defines, for example, a performance class P1, type 1A "Trip" for protection purposes using horizontal GOOSE communication. According to this definition, data exchange times between IEDs must not exceed 10 ms in distribution automation applications.

Two IEDs, the REF630 and REF615, both members of the Relion family, were installed in ABB's UniGear medium-voltage switchgear cubicles and tested according to the procedures stated in the IEC 62271-3 standard² → 9. This standard, applicable to switchgear and control gear, specifies equipment for digital communication with other parts of the substation and its impact on testing. Specifically, the standard defines performance test procedures with reference to the IEC 61850 performance classes and the requirements which the IED must fulfill for these applications. ↗

The test results more than proved the concept. In fact the functional and performance test results have been nothing short of impressive. The Relion IEDs fulfilled the performance class defined by

All Relion IEDs have been tested and certified according to the IEC 61850 standard; for end users and manufacturers, this means that no non-conformities to the standard have been found in the behavior of the IEDs.

| | |
|---|-------|
| Protection blocking data exchange time between Relion® IEDs using hard wired signals (max) including protection activation time | 32 ms |
| Protection blocking data exchange time between Relion® IEDs using IEC 61850 GOOSE (max) including protection activation time | 16 ms |
| Signal transfer time between Relion® IEDs using hard wired signals (max) | 24 ms |
| Signal transfer time between Relion® IEDs using IEC 61850 GOOSE (max) | 8 ms |

IEC 61850-5 for protection applications using GOOSE. In addition, they showed that the signaling between devices using GOOSE was faster than with traditional hardwired signals → 10.

The performance capability of the Relion product family allows the customer to fully exploit the benefits of the IEC 61850 standard in SA systems and smart grid solutions. Based on a native implementation, the Relion product technology is well prepared for tomorrow's challenges. This surely puts ABB's solution in a pre-eminent position among competitors worldwide.

SA application perspectives for IEC 61850 transmission applications

The benefits of IEC 61850 over traditional communication protocols are not strictly limited to IEDs, open infrastructures and device interoperability in multi-vendor systems.

ABB continues to explore advanced applications and engineering improvements and the goal is to continue to push the benefits of IEC 61850 well beyond what is now possible.

To explain further, major features of the standard that are used include the self-describing IEDs and the standardized

SCL. The complete topology of both the primary and secondary network of a substation is described in the SCD file. This information source can be used to automatically generate graphical diagrams on the station HMI, such as the communication network overview including supervision data and the station single-line diagram. While this reduces the engineering work needed, it also improves quality with respect to consistency because of the single information source being used. Furthermore, maintenance and extension work becomes more efficient and the efforts needed for testing can be automated or reduced. Moreover, based on the static information available in the SCD file together with the online status information from the substation IEDs, new types of applications can be developed.

One example of a new application already implemented in today's products, and which is very beneficial to operators, is dynamic busbar coloring. The primary network layout (ie, conducting equipment, objects) is known from the SCD file. Together with the actual positions and measurements reported from the IEDs, all information is available to perform this task.

A more complex function or application is station interlocking. Algorithms can be implemented to dynamically adapt the interlocking rules based on the current substation network topology. Again, the required information to perform this topology-based interlocking can be retrieved from the SCD file and the online data provided by the IEDs.

And last but not least, the IEC 61850 LNs allow the implementation of distributed functions, which will no doubt lead to new applications in the not too distant future.

Keep pushing the limits

The introduction of the IEC 61850 standard and its achievement in enabling device level interoperability is considered a major advancement over legacy and proprietary protocols. ABB's native IEC 61850 Relion product family implementation demonstrates that interoperability is only one goal that can be realized by this standard. The product architectures provide increased value and high performance, and are capable of meeting the most demanding application requirements. Another main goal of IEC 61850 is that it future proof's a company's investment. This can only be done when the products meet tomorrow's anticipated performance requirement and engineering tools, and processes can be easily extended in future station expansion. ABB continues to explore advanced applications and engineering improvements. Its GOOSE performance is best in its class and the goal is to continue to push the benefits of IEC 61850 well beyond what is now possible.

Janne Starck
 ABB Distribution Automation
 Vaasa, Finland
 janne.starck@fi.abb.com

Steven A. Kunsman
 ABB Substation Automation
 Raleigh, United States
 steven.a.kunsman@us.abb.com

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Footnotes

- 1 The UCA users group maintains the IEC 61850 standard and defines different levels of certified IEC 61850 test centers. Independent labs are generally classed as level A test centers while manufacturer test labs, like ABB SVC, are certified as level B test centers. For more information on SVC, please also read "Verified and validated" on pages 23–28 of this *ABB Review* Special Report
- 2 The tests were witnessed and reported by KEMA.



Verified and validated

ABB has its own system verification and validation center

STEPHAN GERSPACH, PETER WEBER – When the IEC 61850 standard was introduced, ABB not only implemented it in its product portfolio, but also established a system verification and validation center (SVC), to verify correct implementation. In this test center, each and every product, system component, application and tool is tested in a real-life system environment to demonstrate its specified functionality and performance. Complete systems are verified to ensure that they fully meet the requirements in terms of communication, integration, functionality, security and performance.

Validation means:

- Is the right product being built?
- Is it meeting the operational need in the designated environment?

Tests performed as part of SVC validation focus on the behavior of the product in the specified system environment.

Both verification and validation are necessary throughout the product-development cycle → 2.

UCAlug

The UCA¹ International Users Group (UCAlug) is a not-for-profit consortium of leading utilities and their supplier companies. UCAlug is dedicated to promoting the integration and interoperability of electric/gas/water utility systems through technology based on international standards. The group is an international organization and strongly supports open standards and the free exchange of information. One activity of UCAlug is the provision of a forum in which members coordinate their efforts in relation to the various technical committees. Although the group does not write standards as such, its activities affect the definition of standards as well as the implementation of testing and product certification programs. One focus has been on the "Communication Networks and Systems in Substations" section of IEC 61850.

Each and every product, system component, application and tool is tested in a real-life system environment to demonstrate its specified functionality and performance.

UCAlug complements the activities of international standards organizations. For example, UCAlug works closely with IEC. The convener of IEC TC57/WG10 (IEC 61850) is on several UCAlug committees and is an advisor to their board.

1 ABB's system verification and validation center (SVC)

All actions of the SVC are focused on the following targets:

- Ensure a common understanding for the system integration of products
- Ensure a common understanding for the engineering process.
- Aim at a consistent philosophy within ABB systems and products
- Identify and initiate the closing of gaps between system requirements and product features
- Improve the quality of the system solution in architecture, integration and performance
- Decrease demand for specialized expertise within a customer system project
- Build up integral know how in testing and system integration of third party products
- Reduce cost and execution time of customer projects

The SVC's purpose is to ensure the high quality of ABB's system automation system solutions and provide a platform for the exchange of experience between IEC 61850 experts within ABB.

The purpose and scope of SVC is summarized in → 1. The center does not only test individual devices, but also tests their integration into larger systems and furthermore provides support and understanding of the standard, leading to its improved integration and implementation.

Verification versus validation

The relative concepts of verification and validation are sometimes a cause of confusion.

Verification means:

- Is the product being built according to the original specification?
- Are the specified requirements being met?

Verification testing should thus be about the product's conformance to the original specification.

In SVC verification, all tests performed assure the product accords with the defined substation automation requirements. These requirements are defined and reviewed by a group of experts approximately once per year and have to be implemented in each ABB product.

The editor of the Testing Quality Assurance Program (QAP) was also the editor of Part 10, "Testing Requirements", of the IEC 61850 document. Furthermore, many members of TC57/WG10 are on UCAlug's Technical Subcommittee for the Resolution of 61850 Issues (Tissues). The group works closely with standards organizations to support technology transfer, resolution of issues and assists users in the testing and implementation of products. One major focus of UCAlug's charter is the Testing Quality Assurance Program (QAP).

A recognized IEC 61850 conformance test center

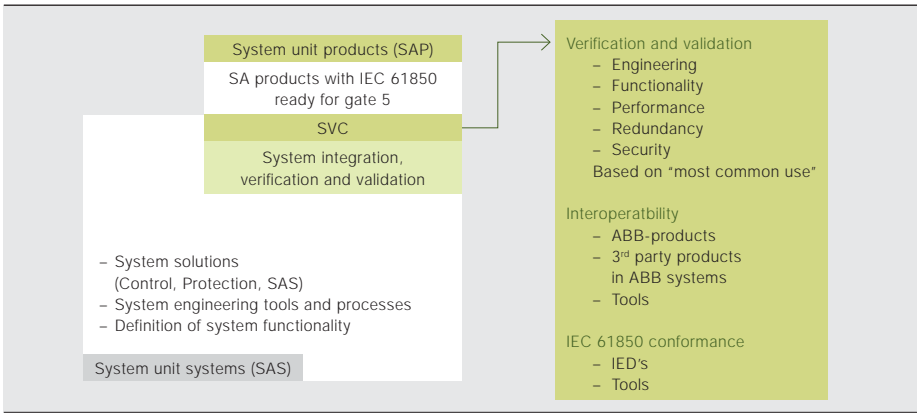
UCAlug has qualified SVC as an IEC 61850 test facility and competence centre. SVC is thereby officially qualified to test and certify the IEC 61850 conformity of products and confer the users' group label to them.

SVC is represented on UCA's IEC 61850 testing subcommittee. This strengthens the center's ability to support upcoming IEC 61850 test procedures and keeps it informed about UCA- and IEC-driven changes regarding IEC 61850 testing.

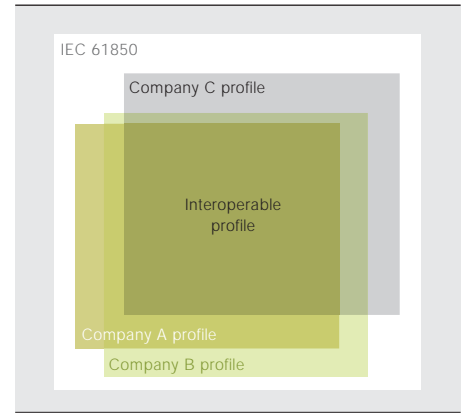
Footnotes

1 UCA: Utility Communications Architecture

2 Both verification and validation are part of the product-development cycle.



3 The fact that products conform to the standard does not guarantee interoperability.



Various profiles from different products may conform to the standard but may still not be totally interoperable.

Beyond conformance testing: system verification and validation

Once a product has passed conformance testing, it can be accepted for formal system verification and validation.

Interoperability

Interoperability testing is neither part of the scope of the standard nor is it tested by all UCALug accredited test centers or

The fact that standard products from different suppliers or different products from the same supplier conform to the standard is in itself no guarantee for their interoperability. The reason for this is that communication profiles can differ.

A communication profile defines the mandatory subset of a standard consisting of the selected options that are implemented.

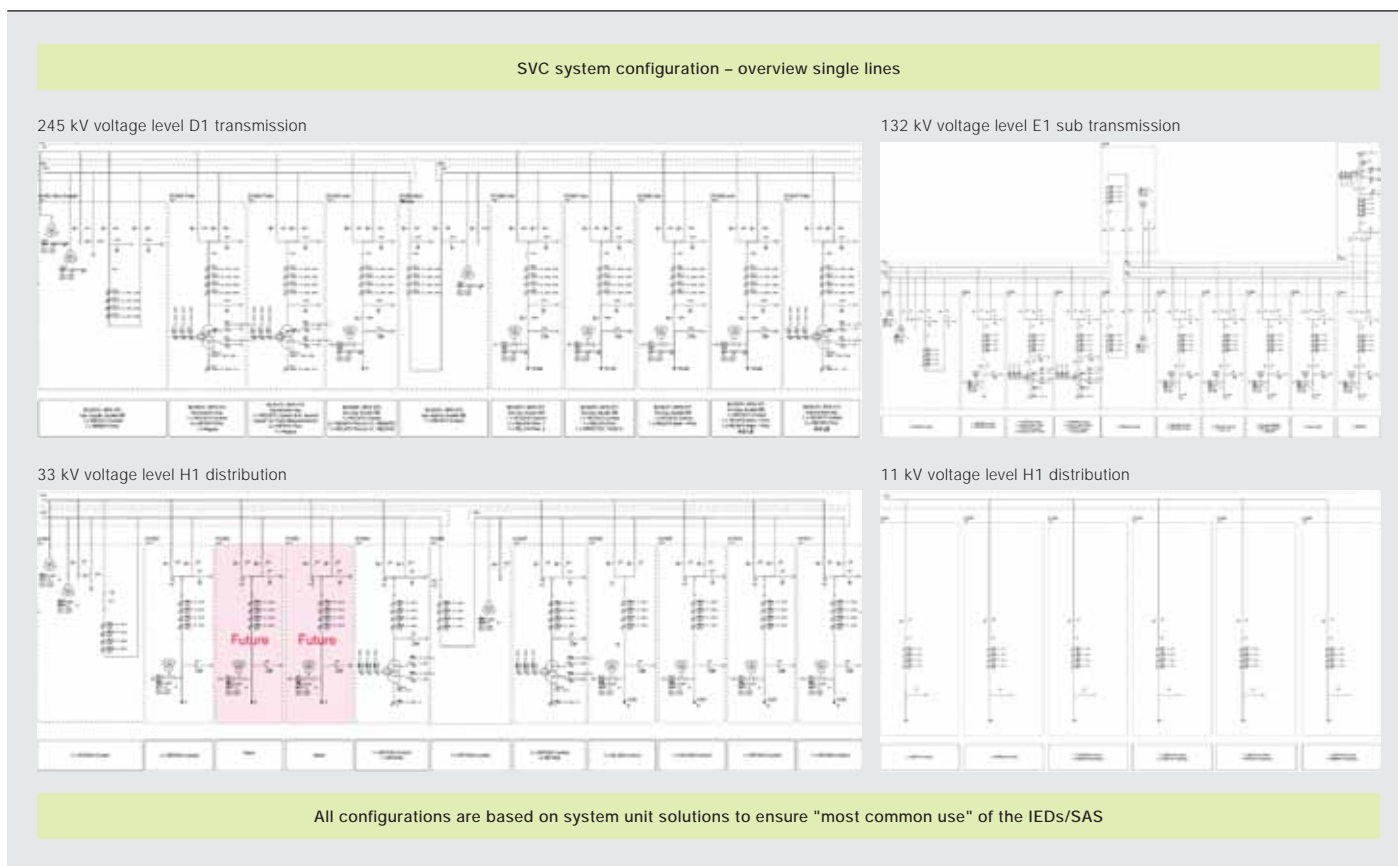
Thus various profiles from different products may conform to the standard but may still not be totally interoperable → 3.

It is the responsibility of the system integrator to check the interoperability

of two or more products. The requirements for this are based on the conformance statements of the different products and the system functionality

An interoperability test looks at the dynamic interaction of at least two IEDs in a substation automation system covering (as far as possible) all potential configurations.

in all procedures. However, the verification of conformance is a very important milestone.



The goal of IEC 61850 is the interoperability of IEDs in SASs. The system test should therefore be part of R&D and conformance testing.

required. For example, one vendor might implement only GOOSE² and a second vendor might implement only GSSE³. Both devices would pass conformance tests but would not be able to interoperate.

An interoperability test looks at the dynamic interaction of at least two IEDs in a substation automation system (SAS) covering (as far as possible) all potential configurations. This is especially important for their interaction in executing distributed functions. Furthermore, it permits the verification of the performance of services provided by communication equipment such as switches (including delays caused). This test must be performed independently of specific projects as a kind of type test for the system. Such testing will reduce the risks for customer projects considerably. The interoperability of the different configuration and engineering tools (based on SCL

and XML) is also important here. As a side effect, this testing also permits the system configuration tool and its interface with the product tools to be verified.

Test setup, SVC environment

The SVC installation represents all areas of ABB's system-automation activities from distribution to transmission applications (245 kV, 132 kV, 33 kV, 11 kV). All configurations are based on system-unit solutions to ensure "most common use" of the IEDs/SAS.

The primary process is completely simulated by process-simulation equipment. The related single-line diagrams are shown in → 4.

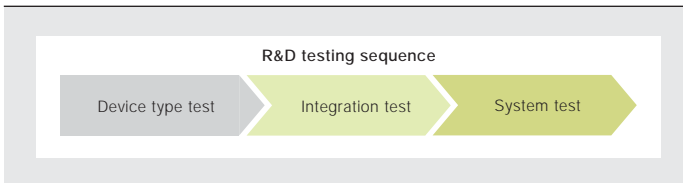
From product to lifecycle testing of SA systems

It is not possible to consider the lifecycle of any SAS without taking into account the lifecycles of all integrated products. The process of creating a substation automation system involves numerous tests, from the development and production of an individual IED to the completion of the system. Testing improves the quality and reduces costly risks both for the supplier and the users.

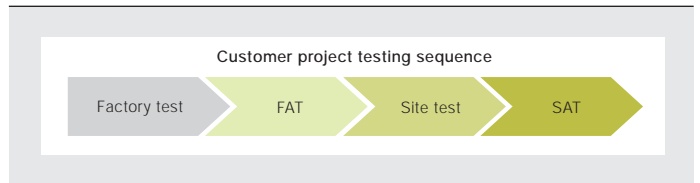
Footnotes

- 2 GOOSE: Generic Object Oriented Substation Event, A data-set format permitting the exchange of a wide range of possible common data.
- 3 GSSE: Generic Substation Status Event. In contrast to GOOSE this supports only a fixed data structure.

5 Testing sequence for product testing by R&D, performed independently of customer project



7 Testing sequence for customer project



6 Overview of R&D testing sequence

| | Test related to | Pre-condition | Executed tests | Result |
|--------------------|-----------------|---|---|---|
| Device Type Test | Product | Specification and development of new functions based on an existing platform or ... based on a new platform | Function and type tests are performed continuously by the R&D of the manufacturer The product with its functions is tested as stand-alone unit ("white box") IEC 61850 conformance tests | Clearance for Integration Test |
| Integration test | Product | Device type tests are finalized successfully | Tests are performed in a small, well-defined and normally fixed IEC 61850 test system Test of IEC 61850 communications and verification of tools including commissioning and application engineering aspects Focus on the products and its interfaces to the rest of the system ("Black box") IED configuration tool will be tested also regarding IEC 61850 aspects like generation and exchange of SCL Files | Clearance for System Test |
| System test | System | Integration tests are finalized successfully | <ul style="list-style-type: none"> - Verification of products with a clear focus on IEC 61850 system aspects - Tools and their interaction in the engineering process (exchange IEC 61850 SCL files) - Verification of the system under normal operation, avalanche and fault conditions (evaluation IEC 61850 system performance) - System-security testing. | Release for use in customer projects |
| Manufacturing Test | Product | All tests up to system test finalized successfully | SW has dedicated manufacturing test | Product available for customer projects |

The base for reliable in-house testing is the quality system of the manufacturer and supplier according to ISO 9001/9002 (as far as applicable). The life-cycle testing sequence can be divided into two parts:

- Testing independent of the customer-specific project, handled entirely by the R&D organization.
- Testing of configurations specific to the customer project, completely handled by the system supplier or system integrator in cooperation with the end-user.

Testing independent of the customer-specific project

The test sequence for the standalone product (which can be the device or the IED) starts with the device's type test and

Several hundred IEDs can be simulated in the SVC, helping identify the limitations of SA Systems.

ends with its integration test → 5. The conformance test is the type test relating to standards such as IEC 61850. The successful passing of type tests is the prerequisite to begin integration testing. Integration testing involves testing the new product in a small and fixed test system. Type tests and integration tests are performed (as a minimum) by the product supplier and (if applicable and requested) by an independent test authority. Normally, the conformance of the IED is confirmed by the issuing of a certificate. In addition, routine tests or manufacturing tests performed in the production chain ensure a constant quality of delivered devices.

The goal of IEC 61850 is the interoperability of IEDs in SASs. Therefore, the sys-

8 Overview of testing sequence for customer project

| | Test related to | Pre-condition | Executed tests | Result |
|-------------------------------|------------------|--|--|---|
| Factory test | Customer project | All tests up to system test finalized successfully and products available for projects | Configuration of the full system Project assembled and pre-tested especially regarding project specific parts; parts not available in the factory are simulated on IEC 61850 network. Tests performed according to the agreed test plan. | The substation automation system is running as specified |
| Factory acceptance test (FAT) | Customer project | All factory tests are finalized successfully | System test witnessed by the customer | Clearance for shipping, commissioning and SAT |
| Site test | Customer project | FAT finalized successfully. All system components are installed. | Complete system goes into operation, fully functional including all connections to switchgear and remote systems and work places Last adaptations if needed | The complete substation automation system is running as specified |
| Site acceptance test (SAT) | Customer project | System commissioned on-site | Complete system will be witnessed by the customer. | System handed over to the customer, incl final SCD file! |



tem test should also be part of the R&D testing sequence and conformance testing. However, as explained above, both the content of IEC 61850-10 and the detailed test procedures defined by the UCAlug only focus on IED (single product) testing. Today's conformance certificates are thus no guarantee for interoperability from a system perspective → 6.

In summary: SVC takes care of that part of system testing not covered by the previous quality assurance steps.

Testing of configurations specific to customer-projects

The customer-project testing sequence → 7 starts with the factory test. This is a project-related test that prepares the customized system for the factory acceptance test (FAT). Following the installation,

site tests are carried out to prepare the system for the site acceptance test (SAT). The testing sequence for customer projects consists of project-related tests, based on the specification for the system ordered. Such tests are performed by the system supplier or system integrator and witnessed by the customer. These tests confirm that the delivered individual SAS is running as specified → 8.

Successful operation of the test center

Following the planning and build-up phase, by mid 2005, SVC was ready for operation. In 2006, the center was qualified by the UCAlug for use as an IEC 61850 test facility and competence centre. SVC was the first manufacturer's test lab in the world to earn this level of qualification. It meets the high quality levels set out for common test proce-

dures for all labs in accordance with IEC 61850-10 and the UCA Quality Assurance Program (Level A independent lab, Level B manufacturer's lab).

The SVC is an active member of UCA international users group and the IEC 61850 testing subcommittee. In 2007, SVC extended the test centre to fulfill new upcoming requirements. Besides the verification and validation of ABB products against IEC 61850-8-1, activities were extended to third party IED's, redundancy concepts, and IEC 61850-9-2.

Today the SVC test system comprises a considerable quantity of relays from ABB as well as from several other manufacturers. In addition, several hundred IEDs can be simulated, helping identify the limitations of SA Systems in terms of architecture, engineering processes, engineering tools, system functionality, system security and performance.

SVC helps ensure the high quality of ABB's IEC 61850 offerings through its verification and validation capabilities and provide a platform for the exchange of experience between IEC 61850 experts within ABB. SVC actively influences further IEC 61850 developments both within and outside ABB.

Stephan Gerspach

Peter Weber

ABB Substation Automation Systems
Baden, Switzerland
stephan.gerspach@ch.abb.com
peter.weber@ch.abb.com

A testing environment

ABB's comprehensive suite of software testing and commissioning tools for substation automation systems

TETSUJI MAEDA – The testing and commissioning of IEC 61850-based substation automation systems introduce new challenges and demands for advanced software applications. ABB recognized this at a very early stage of the introduction of IEC 61850 and redesigned the engineering and testing tool landscape to serve these purposes.

The IEC 61850 standard is built mainly on known technologies such as extensible markup language (XML), Ethernet, manufacturing messaging specification (MMS) and transmission control protocol/Internet protocol (TCP/IP), each of which have a number of well established software tools to handle them. Why then was it initially quite challenging to deal with IEC 61850-based systems?

The crux of the matter lies in the approach taken. IEC 61850 seamlessly combines the underlying technology components and application aspects from an integral system point of view. Existing tools, however, were designed to focus on specialized single tasks, for example communication analysis, and leave out any substation automation appli-

cation aspects, and are therefore no longer capable of addressing today's challenges. To overcome this problem, it was evident a new generation of software tools to efficiently manage and support

the IEC 61850 system integration process was needed.

ABB's approach, taken during the initial phase of the introduction of IEC 61850, was to take the existing expert tools and identify clear functional gaps in them. This information was then used to develop (and afterwards continuously improve) a comprehensive suite of software testing tools for communication, and protection and control application specialists in the field of substation automation.

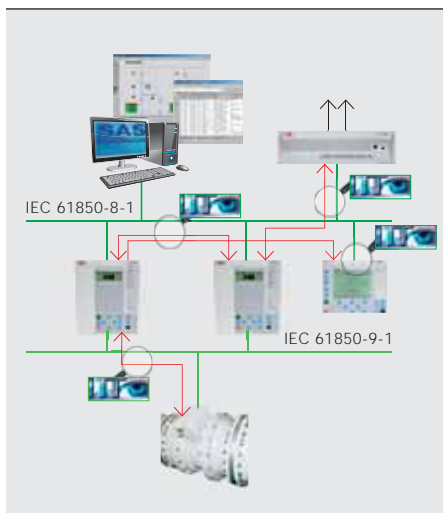
ABB developed the Integrated Testing Toolbox, a software tool suite used to manage and support the IEC 61850 system integration process and which has proven invaluable in many turnkey SA projects.

With the benefit of active participation in the IEC 61850 standardization group on its side combined with its in-depth knowledge and experience in designing and building substation automation (SA) sys-

1 Typical contents of a system configuration description (SCD) file

- Description of complete substation topology and primary equipment
- All protection and control devices (servers), and station level automation system (clients) including the standardized data models of their functionality
- All communication addresses
- Complete horizontal and vertical data-flow within the system
- Relationship between SA functionality and the primary equipment

2 Application areas for analytical and diagnostic tools



3 Typical features of a diagnosis and analysis tool

- The use of project specific data (SCD file) for configuration
- Establishing an online communication connection to the IEDs using either static or dynamic configured data sets and control blocks for reports
- Visualizing the health of the running system
- Checking data consistencies and configuration revisions against the SCD file
- Analyzing and verifying running applications
- Decoding Ethernet traffic to the substation automation (SA) domain language based on the SCD file
- Showing functional (system-oriented) or product-oriented addressing of logged data

tems, ABB developed the Integrated Testing Toolbox (ITT), a tool suite which has proven invaluable in over 900 turnkey SA projects delivered by the company.

From the very beginning, ABB's approach was to build a tool suite that would hide the complexity of the technology components IEC 61850 is built on and focus on displaying application relevant data only. While having an in-depth knowledge of the technologies was necessary to achieve this, the complexity lay in creating the interfaces that would enable the application and display layer of the testing tool to be tailored to project specific configuration data.

Substation configuration language (SCL)

One of the greatest achievements of the IEC 61850 standard and one of the things that differentiates it from other communication standards was the introduction of the substation configuration language (SCL). SCL makes it possible to create files that are used for the exchange of configuration data (eg, standardized object models and data flow configurations of devices in a system) between engineering tools. Several file types have been defined in IEC 61850, and the content of each type depends on the role of a specific tool (e.g., system configuration tool or device configuration tool) that it is created for and the different evolution phases of the system integration process.

The system configuration description (SCD) file is one such file type, and is defined as the master document of a com-

plete SA system → 1. For creation and maintenance, an IEC 61850 system configuration tool is required.

From the system point of view, the interfaces for each device (client or server) connected to the system are described in this file. This makes the complete SCD file the central part of the IEC 61850 system documentation, which makes it interesting to be used for all future activities performed on the SA system, such as testing, maintenance and extensions. The engineer no longer needs to worry about error-prone manual configuration of the testing and analysis tool environ-

ABB'S approach was to build a tool suite that would hide the complexity of the technology components IEC 61850 is built on and focus on displaying application relevant data only.

ment; all he has to do is simply import the project-specific SCD file into the testing tool. This in turn focuses the effort to where it is most needed, on functional

diagnosis and analysis of the running applications.

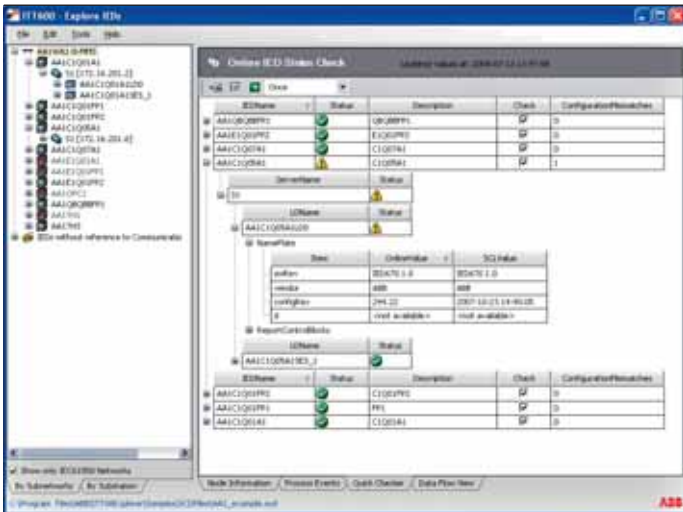
Conformance testing

One very important aspect of IEC 61850 system integration is the selection of standard compliant intelligent electronic devices (IEDs). Compliant in the sense that all selected IEDs have been tested to ensure that they conform to the IEC 61850 standard and are officially certified by a test center which itself is accredited by the UCA international users group. This certification covers the verification of the data model, the standardized documentation and a black-box test of all the communication services the IED supports. The conformance test gives a minimum guarantee that the selected IEDs will interoperate with other certified devices if they are configured and loaded correctly within the system. This prerequisite relieves the testing tools from research and development related bits and bytes analysis even more.

Revealing inconsistencies

There are often situations, specifically during the testing and commissioning phase of an IEC 61850 based system, where temporary inconsistencies due to stepwise integration, the configuration of systems parts or simply human error result in a situation where distributed functions do not interoperate. Debugging can be very time consuming and often requires expert know-how, which is not always available. To handle such situations ABB has developed a tool called the ITT600 SA Explorer. It simplifies the diagnosis and troubleshooting of IEC 61850-based SA systems by combining a set of

4 Consistency check – comparison of an SCD file with online data using ITT600



powerful online diagnostic tools with built-in intelligence to interpret IEC 61850 data. Typical application areas within an SA system where the ITT600 SA Explorer can be of great value is shown in → 2, while typical features of a diagnostic and analytical tool are listed in → 3.

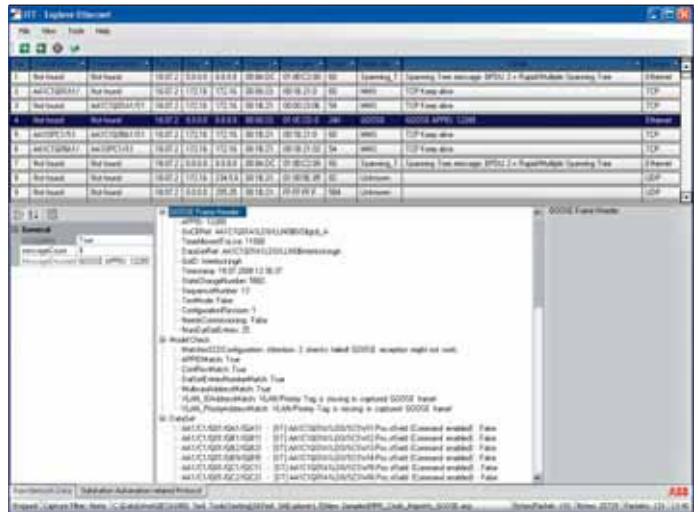
Narrowing down a problem source basically requires some quick consistency checks → 4. One such check that can immediately reveal inconsistencies involves comparing the correct offline configuration with the online communication – as it actually is – world.

The comprehensive decoding by ABB's ITT600 SA Explorer of an IEC 61850 generic object oriented substation event (GOOSE) message, which is used for horizontal real-time communication between multiple IEDs, is illustrated in → 5. The on-screen display of clear text protocol and application information, with the mapping of it to the IEC 61850 SCD file in the background, gives an excellent view of the corresponding online Ethernet traffic. Additional checks on the IEC 61850 object model reveal potential sources of interoperability problems.

Tools visualize applications

Another way of supporting the testing of distributed functions is shown in → 6. Here the GOOSE messages from multiple IEDs can be displayed along a common timeline, making it easy to follow the interaction of various applications, such as interlocking or double command blocking.

5 Decoding the horizontal Ethernet traffic with an IEC 61850 analyzer (ITT600)



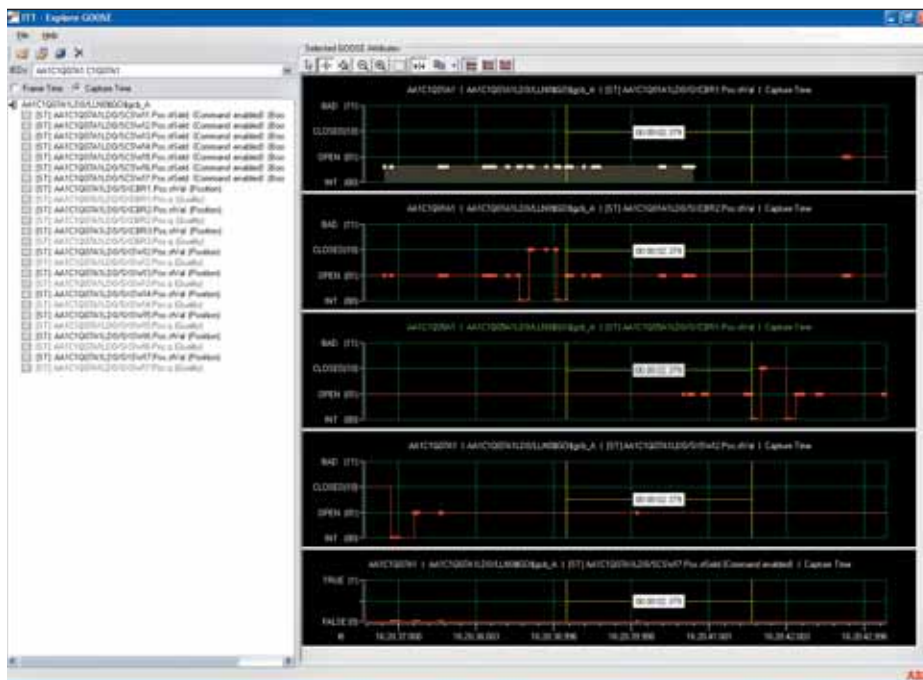
Tools support processes

To support the ABB project execution process the IEC 61850 simulation tool out of the ITT tool suite has proven to be very useful. Specifically during engineering phases or factory acceptance tests when not all system components are physically available but nevertheless application tests must proceed, simulation of non-existing devices is essential for efficient workflows.

The IEC 61850 simulation tool can be connected either to the system bus or directly to an IED → 7. The SCD file that has been created and used during the engineering process of the specific SA system, and which is now part of the common system documentation any engineer should have available when he goes on site, is then loaded into the tool. In both cases the tool could simulate one or more user selected clients/servers based on the interface description extracted from the SCD file. If the SCD file is missing or incomplete, then the engineering and configuration work has to be completed first. Based on this simulation, application tests on real system components can be performed. If the process bus or additional injection hardware is used, then closed loop testing of an IED is possible. Typical features of a simulation tool are summarized in → 8.

Various substation automation projects have shown that the most obvious and common application for using GOOSE messages is interlocking. The horizontal GOOSE service uses publisher-subscriber communication, which corresponds to

The ITT600 SA Explorer simplifies the diagnosis and troubleshooting of IEC 61850-based SA systems by combining a set of powerful online diagnostic tools with built-in intelligence to interpret IEC 61850 data.



vertical server-client communication. In a situation when a specific IED “publishes” data for interlocking, eg, switch positions have failed (and therefore the IED must be taken out of service or disconnected from the communication bus), the sub-

neering and reloading of the configuration.

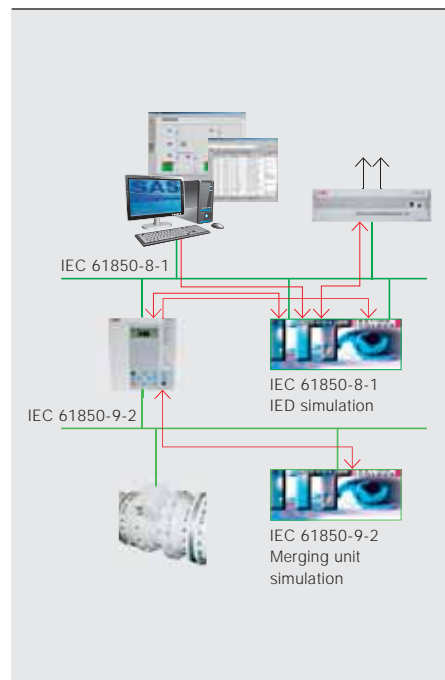
A growing trend

The IEC 61850 standard is complex and cannot be applied without any significant software support. The degrees of freedom and new possibilities that it offers, combined with varying levels of IEC 61850 integration, both in the configuration tools and IEDs from different suppliers, emphasize the challenge even the more.

There is a strong trend toward the use of more modern communication technology to distribute critical data and this demands more advanced integration and verification processes.

scribers of the now missing data on the bus must be operated in an interlock-override mode. This is because applications running on the IEDs usually refuse operations with obsolete data that have not been refreshed in time by the publisher. Maintenance concepts for such situations must be considered in order to ensure that the remaining healthy or unaffected parts of the system continue to work undisturbed. This type of situation can typically occur during the testing and commissioning phase where the sequential adding of bays – including their control and protection IEDs – to an energized system should not lead to major re-engi-

Evidently, the strong trend toward the use of more modern communication technology to distribute mission critical data demands very advanced integration and verification processes. To manage these challenges, engineering, testing and commissioning tools have been developed which incorporate all the possibilities offered by the IEC 61850 standard. They have been proven to facilitate and ensure the high standards of ABB’s project execution.



8 Typical features of a simulation tool

- Uses project specific data (SCD file) for configuration
- An IED specific configuration can be extracted from the SCD file
- The consistent simulation of selected IEDs
- Real life simulation of communication services
- Horizontal communication – repeated sending of GOOSE messages and cyclic sending of sampled values
- Vertical communication – spontaneous sending of reports
- Setting any data configured in the IEDs selected for simulation
- Tailored scripts for the simulation of simple applications, such as control applications double command blocking

Note: Receiving IEDs and clients cannot see any difference between simulated and real data on the bus

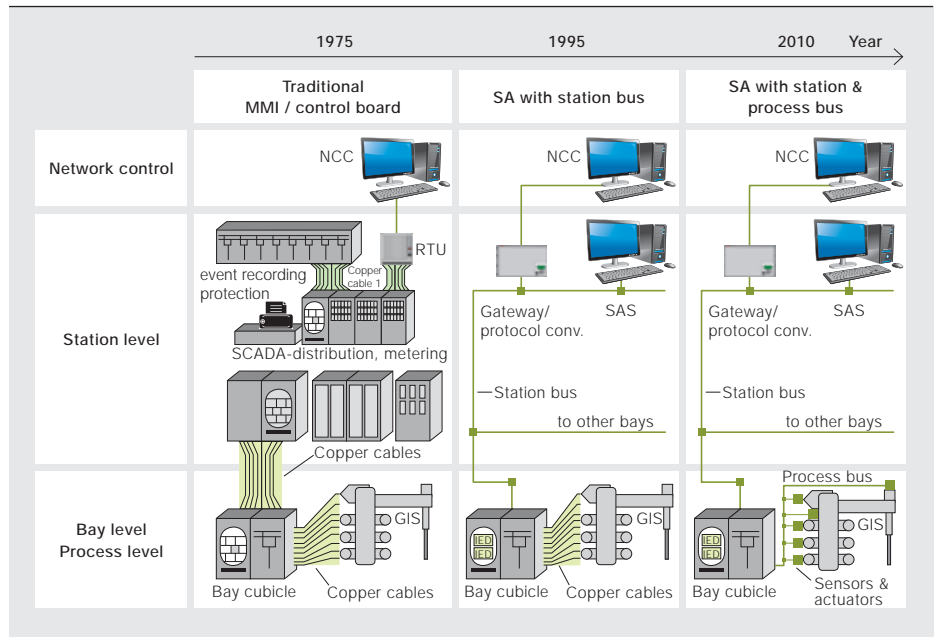
Tetsuji Maeda
 ABB Substation Automation Systems
 Baden, Switzerland
 tetsuji.maeda@ch.abb.com



Next generation substations

Impact of the process bus

HANS-ERIK OLOVSSON, THOMAS WERNER, PETER RIETMANN – Substations are a crucial element for the transmission and distribution of electrical energy. Their primary role is to transfer and transform electrical energy (stepping-up or down the voltage). This is done with high voltage switching equipment and power transformers. In order to protect and control, instrument transformers supply the status of the primary system to secondary equipment. ABB has the expertise, experience and technology to design and build substations of any size.



Since the first substations were built more than 100 years ago, there has been tremendous development of both the primary equipment (switchgear, power transformers, etc.) and the secondary equipment (protection, control and metering, etc).

ABB has been engineering and constructing substations from their very beginning and has delivered more substations than any other supplier. The first substations deployed had air-insulated switchgear (AIS). The development focus for AIS was on circuit breaker (CB) technology that would increase reliability and reduce maintenance. In 1965 ABB delivered the world's first substation with gas-insulated switchgear (GIS). With GIS the footprint of substations can be reduced by about 60 percent, by housing all primary conductors within earthed SF₆ gas-insulated aluminum tubes. Over the years new generations of GIS have been developed, providing today's GIS with, among other things, a considerably smaller footprint (for more detail see "Compact and reliable" on pages 92-98 of *ABB Review* issue 1/2009).

Due to the reduced maintenance of CBs, new substation design principles emerged for AIS in the late 1990s. The

disconnecting function was still required but more for maintenance of overhead lines and power transformers. This led to the development of two types of solutions with disconnect switches (DSs) integrated with the CB function. One was a hybrid (PASS™), which has a separate DS design in the same gas compartment as the CB. Another one was the disconnecting CB (DCB), which uses the same contact for both breaking and disconnecting functions. Due to the reduced maintenance of CBs and the protection by SF₆ gas of the DSs' primary contacts from external pollution, the availability and reliability of AIS substations using hybrid or DCB has increased. Furthermore the footprint of AIS substations using this technique can now be reduced to about 50 percent.

The latest step in substation development comes with the introduction of the standard IEC 61850-9-2 for the process bus interface. For primary equipment, this means conventional instrument transformers (CIT) that use copper, iron and insulation material providing analogue values (1 A, 110 V) can be exchanged for fiber-optic sensors that send a process bus digital signal via fiber optic cables to metering, protection and control equipment. As the use of sensors in-

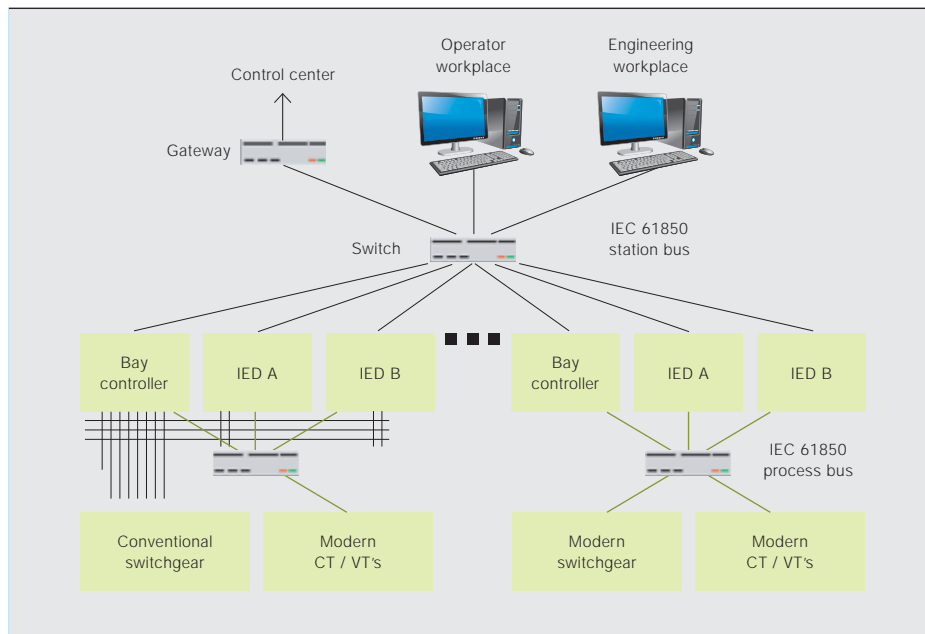
creases gradually over time the requirement for a secondary system to support both CIT and non-conventional instrument transformers (NCIT) during this transition period will become apparent. This requirement is obvious when extending substations, since the new bays will contain NCITs and existing bays will contain CITs.

The greatest physical impact of process bus will be on AIS with live tank CBs or DCBs, where the measuring transformers can be integrated in the CB or DCB, allowing the substation's footprint to be reduced substantially. For hybrid and GIS solutions, the footprint reduction will be less significant as the insulation distance between primary and secondary equipment is already reduced by the use of SF₆ gas. However, the process bus will enable the use of non conventional voltage transformers (VTs) making equipment much lighter (a traditional VT is

The latest step in substation development comes with the introduction of the standard IEC 61850-9-2 for the process bus interface.

quite heavy). Further, the manufacturing time can be reduced since all adaptations can be done with software and the hardware can be standardized.

2 Topology of substation secondary systems



The introduction of the process bus will also mean changes regarding interfaces for CBs and DSs. All signals, digital and analogue, to and from the control room can now be run via process bus in a few optical fibers instead of tons of copper cables. The CBs and DSs will include I/O electronics for signal transfer from optical to electrical and vice versa.

Secondary side developments

The digital (r)evolution has provided technical solutions for substations. Digital technology was first implemented in substations in the 1970s, providing communication channels from the substations to control centers → 1.

During the early 1990s, with the increased capacity and speed of computing and communications technology, digital protection and control devices, the so called IEDs (intelligent electronic devices) were installed in substations. Digital communication between the IEDs was introduced using station bus with protocols that differed between manufacturers → 1.

With the introduction of the IEC 61850 standard, substations are moving into a new era regarding communications. All manufacturers can adapt their products to the same communication model and protocol, making it possible for different manufacturers IEDs to "talk with each other" and thus interoperate on the same station bus, replacing all previous proprietary protocols.

IEC 61850 also includes a new standard for the communication between the high-voltage apparatus and IEDs, the so called process bus using the 9-2 profile and communications architecture. The process bus has high requirements on bandwidth since it will be used to transfer continuous sampled values from the primary process.

On the secondary equipment side the most obvious physical change will be from copper cables to fiber optic cables. The massive reduction of secondary cabling will mean reduced cost for cables

The widely accepted IEC 61850 standard defines the complete communications architecture for station and process bus to ensure a high level of device interoperability.

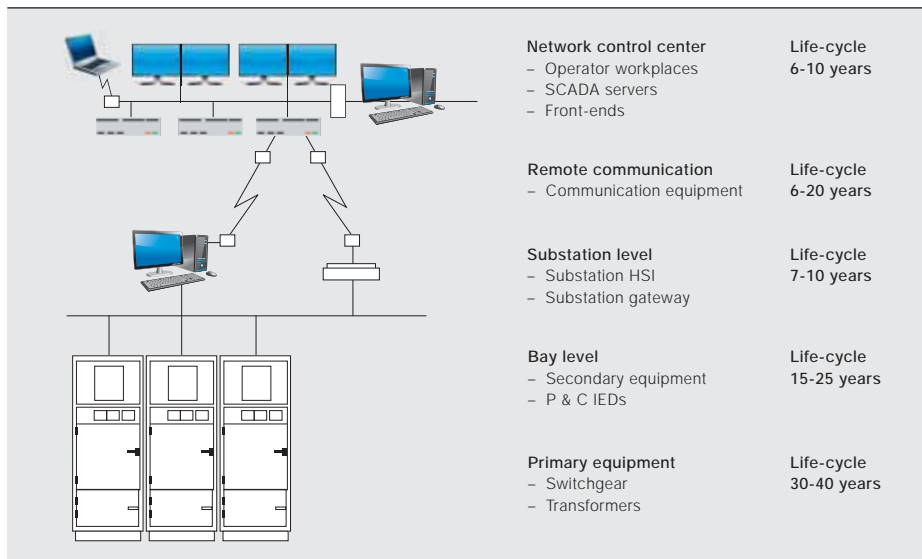
and associated equipment such as cable trenches and installation material. Man hours for installation and testing on-site will be reduced and more thorough test-

ing can be made at the factory before delivery to site, leading to a secondary system of higher overall quality. Also the architecture of the secondary systems will change compared with today's substations. The bay house principle, in which the relay and control equipment are decentralized in the switchyard, will disappear since there will be no copper connections between the switchgear apparatus and metering, protection and control devices, as the process devices can now be mounted directly onto the primary apparatus. The central control room of the substation will become the natural location for relay and control equipment connected by fiber optics to marshalling cubicles close to the primary equipment. Interface equipment, such as merging units will be located in the marshalling cubicle.

Process Bus – connecting the last mile

The widely accepted standard IEC 61850 defines the complete communications architecture for station and process bus to ensure a high level of device interoperability. The standard's data models and communication services are the key to interoperability between multi-vendor substation protection, control devices (IEDs), and station computers (gateways) via Ethernet. A substation's secondary system with station and bay level devices communicating over the so-called station bus has been widely adopted by utilities and vendors → 2.

The cyclic exchange of sampled values, ie, between NCIT and IED devices for protection functions and other purposes is also defined in the standard (part 9-2). The interconnection between sensors, actuators, protection and control devices, is referred to as "process bus" (lower part → 3). This means that not only analog data, but also status information from primary switchgear to IEDs, as well as command signals from IEDs to the primary switchgear can be exchanged. This interconnection between sensors, actuators, protection and control devices, is referred to as the "process bus" (lower part → 2). A vendor-agreed subset under the umbrella of the utility communication architecture (UCA) foundation has been in place since 2004. This subset specifies the exchange of sampled values and is called IEC 61850-9-2LE (light edition). Today, pilot projects utilizing the process



Both new installations as well as the increasing number of secondary retrofit or extension installations will see both sensor and conventional instrument transformer technologies side-by-side.

bus for sampled values are in operation already and the execution of the first commercial project for Powerlink Queensland's Loganlea 275kV substation is well underway.

Modern substations, both new installations as well as the increasing number of secondary retrofit or extensions installations will see both sensor and conventional instrument transformer technologies side-by-side. The same applies for handling signaling commands and position indications to and from primary switchgear.

Realizing the process bus

With the process bus, new devices such as merging units (MU) for the optical sensors, as well interface units for conventional instrument transformers, are needed. In addition switchgear controllers for circuit breakers and disconnectors ("Breaker IEDs") will be introduced. Those devices can be seen as conversion "endpoints" to and from the primary process to the secondary equipment.

A merging unit, as the name implies, merges various input signals into one digital output signal, eg, three phase sensors can have one common electronic unit, which transform the optical signals from the sensors into digital sampled values and make them available on the process bus.

A switchgear controller contains electronics for handling binary input and output signals (signal and power contacts). The device will communicate status in-

formation and commands through the process bus.

The location of the electronics depends on a number of criteria. Primary apparatus with electronics integrated in the drive cubicles is one possibility. On the other hand, it must be possible to handle cases where the primary equipment does not yet contain communication interfaces. Here, system integrators need to mount the process electronics as near as possible to the primary equipment, eg, to locate them within the marshalling kiosks.

Interoperability and architecture on the process bus

Field experience with sensors has been gathered for more than ten years now, mostly in conjunction with protection and control equipment from the same vendor. For the process bus, utilities are executing an increasing number of pilot installations in order to gain experience. Widespread commercial adoption has not yet taken place.

Interoperability

Both the communication architectures (9-2, 9-2LE) and the steady-state behavior of sensors are defined (IEC 60044). The transient signal response of merging units has not yet been standardized. The latter defines the extent (in terms of angle and amplitude) to which a merging unit output signal is allowed to differ from its corresponding input signal. This is essential since protection algorithms and the corresponding data acquisition hardware and filtering has so far been "interconnected" within one device, the IED. Now those parts are split up into different physical devices that can be supplied from different vendors, and therefore a transient signal response standard is essential for correct functioning. A newly formed working group with Cigré (B5.24) is addressing signal interoperability and results are expected during 2011.

Process bus communication architectures

Several different process bus architectures exist. In fact, depending on factors such as distance (location of MUs and IEDs), communication capabilities (single port, multiple ports), available network bandwidth, availability considerations or communication topologies, such as point-to-point, star or ring configurations the process bus architecture can vary considerably. Both utilities and vendors

are working on guidelines for reference topologies for such architectures.

Refurbishment and extension of existing SA systems

The typical life cycle of the primary and secondary equipment of a substation is illustrated in → 3. During the life time of the primary equipment the entire secondary equipment or parts of the secondary equipment are replaced between one to four times.

The most interesting and future proof migration scenarios will be the ones in which IEC 61850-based equipment is introduced in steps to already installed systems. There are two main driving factors for this: Retrofit and extension of substations or of system functionality. With the long life of primary equipment compared to secondary equipment, there will be a continuous need for secondary equipment replacement, while retaining the existing primary equipment.

By introducing the process bus it will be possible to make a very efficient retrofit of protection and control systems with minimum outage. While keeping the substation in service using the old equipment, the new IEC 61850-9-2-based equipment can be installed and tested using new fiber optic cables laid in parallel to existing copper cables. A short outage is necessary to connect the new protection and control equipment to the existing primary equipment. When the substation is taken into service again the old protection and control equipment together with all copper cabling can be removed or can remain.

Refurbishment drivers

There are different reasons for refurbishing a substation or parts thereof. These can depend on the starting point (eg, whether starting from a conventional remote terminal unit, RTU, solution or from a proprietary numerical control system). All of the below drivers may be applicable or only a selection of them.

Increase system availability

Exchanging of electromechanical, static or old fashioned digital secondary equipment with modern numerical devices bundled to a real-time communication network and connected to a higher level system such as a substation automation

system or SCADA, allows continuous monitoring of all connected secondary equipment.

Increased system and personnel safety

Remote control combined with authority and rule-based access and remote testing, allows increased system safety and security. Personnel safety is increased since more tests can be done without putting the test personnel close to primary equipment or without the risk of inadvertently opening current transformer (CT) circuits.

Increased functionality

Fully distributed system architecture coupled with un-restricted communication and process capability enables the system to add new functions easily with zero or minimal outage time, giving the user additional benefit with respect to safe and secure system operation.

Interoperability

By deploying the IEC 61850 compliant solution¹, interoperability with regard to communications with other manufacturer's equipment can be achieved. The benefit to customers is that IEDs from different suppliers can be mixed on the same bus without concern for communication incompatibilities.

Prospects

The introduction of the IEC 61850-9-2 process bus standard in substations will give the following main advantages:

The footprint of primary switchgear can be reduced since fiber optic sensors (NCIT) can replace conventional measuring transformers. This will be most pronounced for air-insulated substations, especially when using live tank CBs.

Traditional VTs are quite a heavy part of GIS and by using new sensor technology for voltage measurement the equipment can be made much lighter. Further, the manufacturing time can be reduced since all adaptations of NCIT can be done with software and their hardware can be standardized leading to an overall shorter delivery time.

On the secondary side the massive reduction of secondary cabling by going from a lot of copper cables to a few fiber optic communication cables will mean reduced costs for cables and associated

equipment such as cable trenches and installation material. Testing at site will be very much reduced and more thorough testing can be made at the factory. This will lead to higher quality overall and a reduced time at site.

Changing to optical sensors (NCIT) will increase personnel safety since there will be no risk of injuries due to the inadvertent opening of current transformer secondary electrical circuits.

For retrofit, the possibility of installing the new 9-2 process bus system in parallel with the existing system will allow the substation to remain in service during the main part of the work. This will be a big advantage, reducing outages to a minimum, during the retrofit process.

Hans-Erik Olovsson

ABB Substations

Västerås, Sweden

hans-erik.olvsson@se.abb.com

Thomas Werner

Peter Rietmann

ABB Substation Automation Systems

Baden, Switzerland

thomas.werner@ch.abb.com

peter.rietmann@ch.abb.com

Footnote

¹ There are a number of solutions slightly different in architecture etc. that will be compliant with IEC 61850.

Case studies

IEC 61850 at work

The goal of IEC 61850 is to facilitate interoperability of substation devices while simplifying engineering and maintenance. The examples described in this section present some of the standard's successes.

Retrofitting for the future

It is inevitable that as substations age, their parts will need to be replaced. The 380/220kV air-insulated substation (AIS) located in the Alps in Sils, Switzerland was one such case. Its secondary infrastructure – ie, protection, control and metering – and parts of its primary equipment at the 380kV level – ie, switchgear, power transformers and circuit breakers – had reached the end of their life cycles. The operator KHR (Kraftwerke Hinterrhein) thus turned to ABB for an economically feasible, standardized and forward-looking solution for one of the most important nodes of the Swiss transmission network. The answer: a substation automation retrofit using IEC 61850 technology.

Implementing the IEC 61850 standard enables availability of all necessary information – which supports extensions, replacements or upgrades of all or part of the substation automation system – and enables integration of products from different suppliers. It also ensures data consistency within the complete system and defines the



engineering processes, helping to keep data and data flow consistent for the whole substation. In this project, the horizontal bay-to-bay communication model GOOSE was used to considerably reduce the copper wiring between the bays. All information for interlocking between bays is now exchanged between the ABB Relion® 670 series IEDs on the IEC 61850 bus via GOOSE messages.

Although testing was a major part of the retrofit, the greater challenge was to avoid a shutdown during commissioning. Outage time of individual feeders had to be minimized and coordinated with the grid operator months in advance. The complete system was manufactured and delivered to the site where, except for the connection to the AIS interfaces, it was installed. Once the dedicated bay

was commissioned, the new IEDs were connected to the primary equipment. The substation was configured to enable concurrent operation of the existing and new equipment during this transition phase.

After successfully retrofitting the 380kV substation, the 220kV part was integrated into the new control system. The existing IEDs were equipped with a new IEC 61850 communication interface, allowing communication with the new MicroSCADA control system and ensuring that both the 380kV and 220kV switchyards could be operated and monitored from the central control system. A hot standby system was put in place to provide backup should a failure occur.

Marcel Lenzin
ABB Substation Automation Systems
Baden, Switzerland
marcel.lenzin@ch.abb.com

Challenges build partnerships

In 2006, ABB supplied a pioneering substation-automation project to the Brazilian government power transmission utility, Eletrosul. This utility is responsible for electrical transmission in the south of Brazil. The projects delivered were based on the IEC 61850 standard, with applications using messages between IEDs, GOOSE¹, redundant control units and featuring interoperability between systems from different vendors.

The first project consisted of three substations, "Atlântida 2", "Gravataí 3" and "Osório 2". These are 230 kV and 138 kV transmission substations. "Atlântida 2" uses 60 IEDs (14 with redundancy and 32 without) for protection, acquisition and control. These are mapped to 13,683 dynamic objects from a total of 28,786 objects available in the IED. About 3,300 of these were distributed to centers of higher hierarchy.

Redundant control

Redundant control was one of the special challenges of this project. This philosophy, used by Eletrosul for many years, uses two control terminals (for ABB's projects this meant two REC670s). These have exactly the same functionality in terms of control logic, interlocking and automatism for controlling a certain number of bays. Both units are active, but just one is monitored by the supervisory system. In case of unavailability of a terminal, the SCADA system switches to the other IED.

Based on this philosophy, Eletrosul clearly defines how a system should react, for example, in contingency situations. Briefly, the terminal managed by the supervisory system is monitored and executes remote commands. In case of interlocks, the two redundant terminals send signals to external bays. This affects the philosophy of treatment of these



redundant signals by the receiving logic.

In this project, GOOSE was widely used both for monitoring the active terminal and for interlocks and automatic logics. This permitted a considerable saving of cables, as twice as many signals are generated and received in this philosophy versus a philosophy of simple control.

Interoperability

Eletrosul uses SAGE (an open-source energy-management system) as SCADA software. SAGE was developed by CEPEL, a Brazilian government research center. The MMS protocol defined in IEC 61850 was implemented in SAGE in 2006. The ABB project was thus a test of the standard's interoperability. This test was passed successfully.

Results

Another request from Eletrosul was to minimize the number of hours required for the preparation of texts in the system database. For this, it encouraged the use of generic signs (GGIOs) to be minimized. Even so, in the control terminals that use many

monitoring aspects not defined in the standard (mostly complex interlocks and automatic logic) the use of GGIOs is still very high. It is hoped that as the IEC 61850 standard evolves, more standard signs will be provided. In IED protection, it was found that the use of GGIOs was reduced because of the standard, and because ABB IEDs use standards for all protection functions.

The three substation projects fostered a spirit of partnership between Eletrosul and ABB, resulting in new projects being carried out together delivering the benefits of IEC 61850.

Maurício Pereira

ABB Power Systems
Guarulhos, São Paulo, Brazil
mauricio.pereira@br.abb.com

Gonzalo Humeres Flores

Eletrosul

Footnote

1 GOOSE: Generic Object Oriented Substation Event

Portuguese transmission substations

REN is the main Portuguese utility for electrical energy transmission. ABB supplied the utility's first IEC 61850 system, installing it at the 400/220kV Lagoaça substation. The installation is responsible for some of the most important interconnection points with the Spanish grid on the 400kV voltage level.

Of all the benefits of migrating substation automation systems to the new standard, the customer was especially focused on one in particular: standardizing the system architecture, ie, using the same network topology and overall arrangement independently of the supplier.

ABB brought much experience into this project that it had built up in previous deliveries to the customer. The previous platform may have been different, but marked an excellent

starting point and permitted ABB to quickly identify the required solution.

The Lagoaça substation uses a system based on a decentralized Ethernet ring. The main products from ABB are:

- MicroSCADA Pro for local HMI, and automated sequences
- COM500i as Gateway, for communication with network control center
- IED's 670 for control and protection units
- REB 500 Systems for busbar protection

Third party products used were:

- Switches and routers from RUGGEDCOM
- Meinberg GPS servers for SNTP time synchronization
- Computers with no-moving parts running Windows XP Embedded platform
- KVM switches and fallback switches from Black-Box
- Industrial computers from Advantech, for remote access and engineering stations.
- RTU servers and local-event printing system from SYCOMP Germany (REN mandatory).



- Remote access via RX1000 routers from RUGGEDCOM

The adoption of IEC 61850 was clearly beneficial. It allows both customers and vendors to retain extensive functional freedom in their definitions and philosophies. It also assures independence from single suppliers as well as cost savings in both engineering and maintenance.

Carlos Caetano

ABB Substation Automation Systems
Paço de Arcos, Portugal
carlos.caetano@pt.abb.com

Wuskwatim transmission system

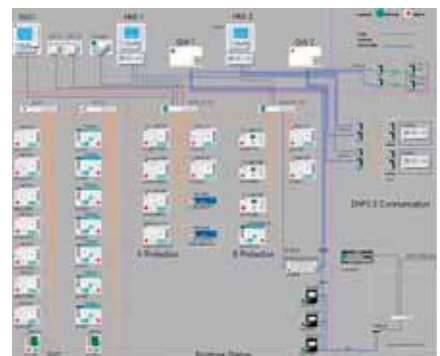
In order to strengthen the existing 230kV network, Manitoba Hydro main utility in Manitoba contracted with ABB for the design, engineering, supply and commissioning of Wuskwatim Transmission System Complex, comprising three new stations and expansion of four existing ones. The new stations featured distributed control, bay protection and a bay controller concept. The entire control and communication process used the IEC 61850 standard.

Protection devices were sourced from three different manufacturers. In fact the use of different suppliers was a requirement of the protection redun-

dancy concept. Prior to IEC 61850 such integration would have been challenging if not impossible, especially for large systems due to inconsistency of data and engineering.

The IEC 61850 engineering approach and data structure using SCL language significantly facilitated the engineering of interfaces between different units. The descriptive power of the SCL language enabled part of the integration to occur without having access to all devices or bay level information.

Because design, manufacturing and testing of the two SA systems was completed in close collaboration between ABB and Manitoba Hydro, an attuned and future-proof system was delivered. The IEC 61850 standard made it possible to combine and integrate ABB, Siemens and Areva Protection IEDs within the SA and thus to fulfill safety requirements. The use of GOOSE



messages for bay-to-bay interlocking and intertrip reduced the amount of copper wiring required. The complete communication of the substations are now described and documented in SCD-files, which is of advantage for the future maintenance and extension of the stations that are now in service.

Mansour Jalali

ABB Substation Automation Systems
Burlington, Canada
mansour.j.jalali@ca.abb.com

The Star of Laufenburg shines

The 380kV Laufenburg substation – one of the largest and most important in Europe – boosts several world premieres. Staying abreast of the development and extension of IEC 61850, its owners, the Swiss utility EGL AG, were the first to equip a high-voltage substation with an IEC 61850 automation system, doing so shortly after the release of the standard in 2004, and even opting for a multi-vendor solution. Two years on, the utility issued the very first open tender based on a SCD (substation configuration description) file, and most recently implemented the 9-2 process bus.



When built in 1967 at the inception of the European grid, the Laufenburg substation, with its key position in terms of interconnection and metering, was dubbed the “Star of Laufenburg”. It was extended and upgraded from 1979 to 1981. From 2004 to 2009, EGL undertook the following refurbishment work:

- Step 1: retrofit of primary and secondary equipment
- Step 2: replacement of old station HMI
- Step 3: pilot project for IEC 61850-9-2

Step 1: Bay retrofit

Both primary and secondary equipment of the 17 feeders was replaced in a bay-by-bay manner, warranting an almost interruption-free retrofit. The migration was supported by a compact hybrid solution that connects the new gas-insulated switchgear (GIS) modules to the existing air-insulated switchgear (AIS) busbar using silicon bushings. The GIS modules comprising circuit breaker, disconnecter, earthing switch and instrument transformers were pre-tested to enable short installation times. They offer maximum operational safety and high immunity to environmental conditions. They also require less

space and simplify maintenance as replacement of a complete pole can be performed in less than 24 hours.

The future-proof secondary retrofit concept addressed the varying lifecycles of bay and station-level equipment. With the latter equipment being retained, ABB integrated its new IEC 61850 compliant bay control and protection IEDs (Intelligent Electronic Devices) to the third-party control system using a gateway converting IEC 61850 to IEC 60870-5-101. ABB also successfully integrated a third-party main protection device with an IEC 61850 interface. Consistency of bay data during the stepwise upgrade was supported by pre-configuring and pre-testing using an SCL-based tool.

Step 2: Station-level replacement

In 2007, ABB won an open tender for the replacement of the old station HMI (human-machine-interface). ABB installed a new IEC 61850 HMI fully re-using the engineering data from the SCD file generated for the bay retrofit.

Step 3: Introduction of process bus

The pilot installation contains a selection of products and systems ready for the IEC 61850 process bus.

On the primary side, there is a combined and fully redundant CP-3 current and voltage sensor with merging units for protection and metering. On the secondary side, a REL670 line distance protection IED and a REB500 busbar protection system with three bay units are in operation. Metering is performed by an L+G energy meter. For supervision and easy access, a SAS using IEC 61850 station bus completes the pilot installation.

The pilot is running in parallel to the conventional control and protection system and enables collection of long-term real-life experience as well as comparison of behavior. Since its commissioning in 2009, the system has been in continuous operation.

Petra Reinhardt
ABB Substations
Baden, Switzerland
petra.reinhardt@ch.abb.com

Stefan Meier
ABB Substation Automation Systems
Baden, Switzerland
stefan.meier@ch.abb.com



When two become one

IEC 61850 in combination with ABB's award-winning Extended Automation System 800xA is opening doors to new and cost-effective solutions.

JOHAN HANSSON, STEFAN BOLLMEYER – The successful introduction of the IEC 61850 standard some six years ago has already brought huge benefits to power distribution and substation automation in terms of scalability, interoperability, safety and data management. Even though it was drafted by substation automation domain experts, it is by no means exclusively reserved for that domain alone. In fact, IEC 61850 is more than capable of operating in other areas, such as in

process and power generation plant automation. These plants are controlled and monitored from a central control room in which there are typically two different systems deployed; one for process control and the other for monitoring and controlling the electrical system. Plant operators, in their quest to reduce complexity and optimize efficiency have been actively seeking solutions that overcome the separation of the systems and the extra costs associated with it.



Even though it was drafted by substation automation domain experts, the IEC 61850 standard is capable of operating in process and power generation plant automation.

The integration of field instruments into process control applications is based on a limited set of industry standards that provide harmonized access to process data and diagnostics. For electrical equipment, however, a multitude of different, often proprietary communication protocols is deployed. Therefore electrical systems, especially those composed of equipment from different vendors, are often characterized by multiple different interfaces, a broad variety of engineering tools, protocol converters and gateways.

Process control systems typically do not offer built-in support for those communication protocols and data models. And because of this significant engineering and adaptation efforts need to be made on a project-by-project basis to make the increasing amount of information, which modern intelligent electronic devices (IEDs) provide, available to a monitoring and control system. Nowadays to mitigate the impact on the process con-

trol system, IED monitoring and control is usually implemented by a separate substation automation (SA) system while connectivity between the electrical system and process control is limited to the most essential data, eg, for interlocking purposes. Although only a limited set of signals is selected for data exchange, today's practice for this type of electrical and control system interfacing, such as hardwiring or Modbus connectivity, still requires significant hardware and engineering efforts. The presence of two different systems also increases costs because, for example, different spare parts and a duplicated effort to ensure integration with enterprise level systems are required → 1.

To help plant operators overcome these expensive complexities, IEC 61850, with its standardized communication protocols and data model, in combination with ABB's award-winning Extended Automation System 800xA is opening doors to new and cost-effective solutions.

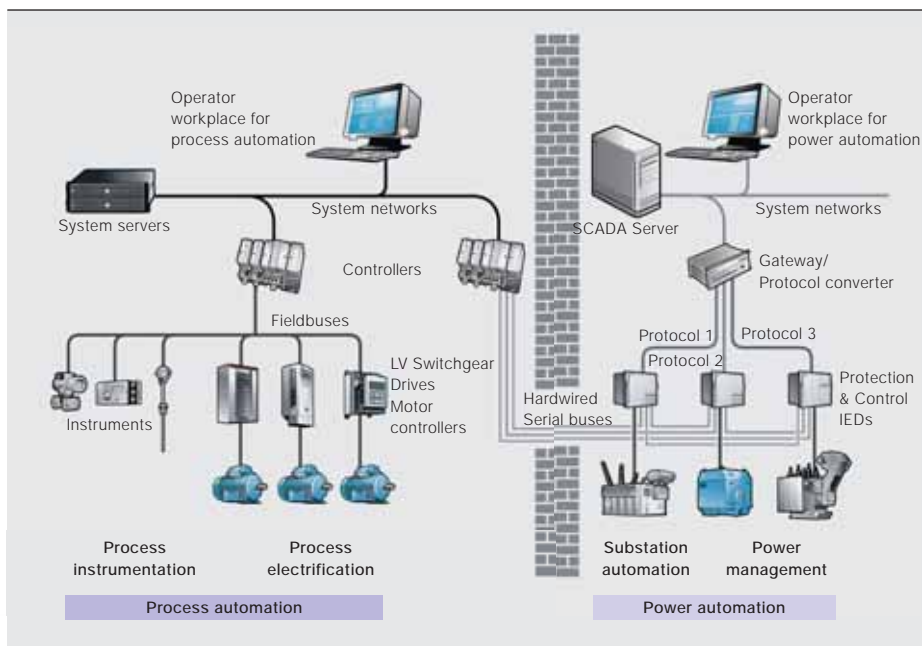
IEC 61850 integration in System 800xA

The combination of ABB's Extended Automation System 800xA with IEC 61850 not only addresses the above-mentioned end-user demands, but it also gives greater synergy and flexibility to fully integrated plant operations.

Introduced in December 2003, System 800xA provides a scalable solution that extends traditional process control by incorporating: safety; discrete logic and sequence control; production management; information management; smart instrumentation; asset management; and document management. Based on Aspect Object technology, System 800xA is capable of adopting data models from different disciplines and making them available in a harmonized way through a singular virtual database environment.

The integration of IEC 61850 into System 800xA supports both generic object oriented substation events (GOOSE) and manufacturing message specification (MMS) protocol options described in the

1 Traditional process control systems do not offer built-in support for proprietary communication protocols and data models



standard. GOOSE communication is directly connected to the AC 800M controller (one of many from the System 800xA family of controllers) via a communication interface so that the data becomes available in the controller application. This so-called horizontal integration¹ enables the AC 800M controller to communicate with all other IEDs on the same IEC 61850 network in real time → 2. Moreover, the AC 800M controller acts like an IED on the IEC 61850 network, and can therefore be involved in load shedding or other power management applications.

MMS communication is used for the vertical integration of IEC 61850. Via an OPC² interface, System 800xA has direct access to all IED data such as current and voltage measurements, status, interlocking, time-stamped alarms and events. The system can also send open and close commands to IEDs. Logical nodes (LNs) of IEDs are modeled as Aspect Objects in System 800xA and therefore all system features, such as freely configurable graphics, faceplates, alarms and event lists, and historian capabilities are available for IED data.

To engineer IEC 61850 integration, System 800xA uses the information contained in the substation configuration description (SCD) file, which describes the complete substation configuration. System 800xA processes the extensible markup language (XML) based substa-

tion configuration file to create all data items for vertical integration as well as the connections for horizontal communication. Separate gateway configuration or additional project-specific software interfaces become obsolete.

To be more specific, System 800xA seamlessly integrates IEC 61850, delivering the features and benefits requested by end users, such as:

- Reduced cost of ownership through fewer components and spare parts, and less system administration.
- Greater flexibility as integration is much less complicated than before and the interfaces adapt easier to changes.
- Centralized data recording, including the plant-wide sequence of events and a harmonized interface to enterprise level systems.
- A complete view of electrical system data, especially to process operators so they can make educated decisions.
- Improved operator effectiveness with one user interface that can consistently present plant-wide data, enable data access and display operating procedures.

Because of its flexibility, System 800xA allows the configuration of individual workplaces for both electrical and process operators so that they can retain the graphical displays and workflows familiar to them while operating in a single environment. Maintenance and asset optimi-

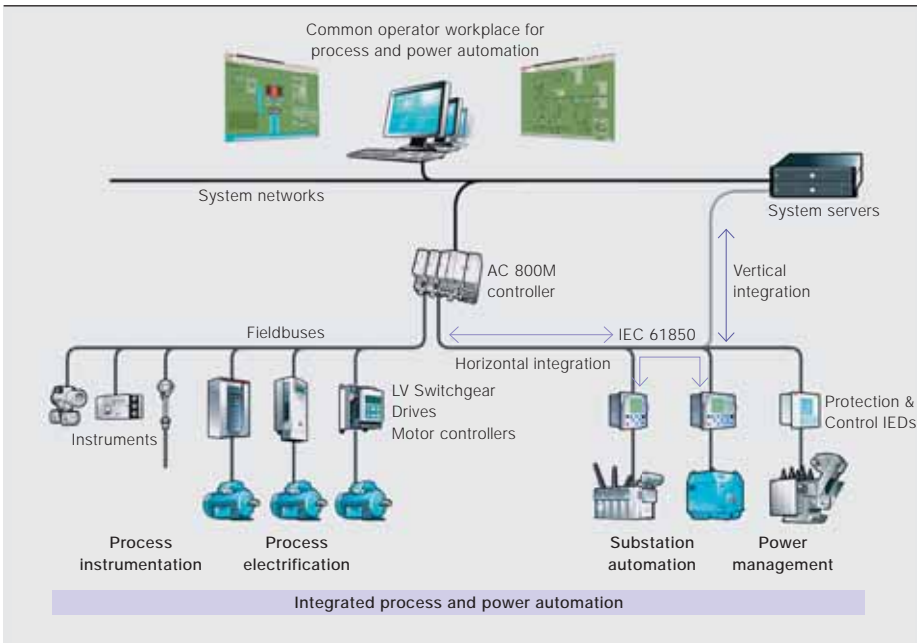
zation workflows can be harmonized once IED data is available in System 800xA, allowing instrument maintenance engineers and those servicing electrical devices to work from the system's common maintenance workplace. System 800xA's maintenance structure gives an overview of all plant assets in a single display. Conditions can be monitored, and diagnostics and maintenance related alarms for electrical devices and process instruments are presented in practically the same fashion. For further in-depth analysis, additional IED data points can be subscribed to or disturbance records can be uploaded. Access-right settings ensure that only authorized people are allowed to perform such detailed analysis.

As the ultimate step, System 800xA's Asset Optimization functionality can be integrated with a computerized maintenance management system (CMMS) so that work order handling is automatically treated the same for both electrical and process equipment. This eliminates the need for separate working procedures or the adaption of different systems to the CMMS.

The Flåsjö facility is one of the first hydro power plants to utilize a combination of IEC 61850 and System 800xA for process and substation automation.

The possibility of electrical integration presented by ABB's System 800xA in combination with IEC 61850 has been keenly observed by industries other than power distribution. The Oil & Gas and Power Generation industries in particular have been evaluating these new opportunities and some have even taken the first steps toward the implementation of such a system.

2 Communication with all other IEDs on the same IEC 61850 network is possible in real time



3 The Flåsjö hydro power plant

Upstream, Flåsjö is the first of E.ON's hydropower plants on the 350-kilometer long river Ljungan. The Ljungan runs to the northeast of Helagsfjället and flows into the Gulf of Bothnia just south of Sundsvall. The power plant was built in 1975 and has a maximum waterfall of 46 meters and a flow through the turbine of 60 m³ per second. The Flåsjö plant produces about 73 GWh with an installed capacity of 24 MW. The plant is unmanned, and controlled and monitored from E.ON Vattenkraft's control center in Sundsvall. Communications between the power plant in Flåsjö and the control center in Sundsvall is via satellite transmission.

E.ON integrates substation and process automation

E.ON Vattenkraft, a subsidiary of E.ON Sverige, is the third largest hydroelectric power producer in Sweden. In a typical year it produces about 8 TWh from 77 hydro power plants, from Kristianstad in the south to Lycksele in the north. Most of these plants were built between the 1950s and 1970s using what is now considered legacy technology. Up to 2015, E.ON plans to invest SEK 6 billion (\$763 million) in safety, renewal and productivity improvements in installed power plants. All of E.ON's hydro power plants are usually operated remotely from the central control center in Sundsvall, and are visited only for maintenance reasons.

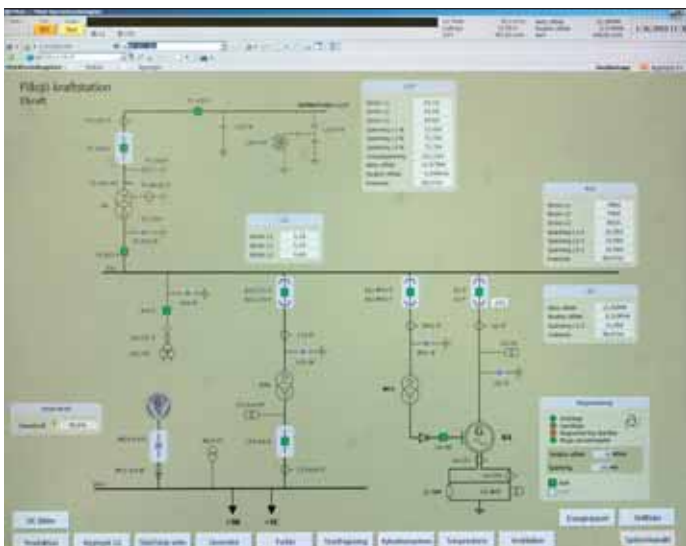
One of these, the Flåsjö hydro power plant, was the first upstream plant installed on the river Ljungan in northern Sweden → 3. Since 2009, it holds the distinction of being one of the first hydro power plants in the world to utilize a combination of IEC 61850 and System 800xA for both process and substation automation.

In the installation at Flåsjö, the original relay-based system was replaced by one System 800xA together with an AC 800M controller. Process control handles applications such as turbine control, vibration protection and synchronization. Process electrification and control of auxiliaries and pumps are done using Profibus communication with ABB's modular low-voltage switchgear MNS.

For substation automation, the IEDs are the most critical devices in the plant in that they provide protection, control and monitoring of generators and lines from the outgoing high-voltage substation. Three native IEC 61850 compliant ABB Relion® IEDs are integrated with System 800xA, two redundant REG670 IEDs are used for generator protection and one REL670 for protection of the outgoing 130kV line. All the IEDs are integrated with the AC 800M controller using IEC 61850-defined GOOSE. This enables the AC 800M controller to function not only as the process controller, but also to act as an IED on the IEC 61850 network, communicating horizontally with all other IEDs as well as with the control center via satellite communication. Important data from the IEDs include measurements such as power, reactive power, voltages and currents, together with breaker and disconnecter statuses → 4. This data is displayed at the local System 800xA operator workplace and the control center in Sundsvall some 260 km away from where the system is usually monitored and controlled → 5. In addition, alarms and events from the combined process and substation automation system are also transmitted to Sundsvall, providing operators with valuable information about the plant. At the control center, the operators monitor and control the plant using an ABB Network Management System. They also have remote access to the System 800xA operator workplace, providing a redundant connection to the control system.

The use of IEC 61850 with a single control system provided E.ON with the means to investigate the benefits of using the standard for standardized system integration, application building, installation and testing.

4 IED data include power, reactive power, voltage and current measurements



5 The control center in Sundsvall from which all of E.ON's hydropower plants in Sweden are controlled and monitored



Main benefits

The use of IEC 61850 with a single control system in the Flåsjö hydro power plant was a pilot installation for E.ON. It provided the means from which the company could investigate the benefits of using the renowned global standard for substation automation not only as a communication protocol for devices, but also for standardized system integration, application building, installation and testing. The success of this pilot project is very important to E.ON because it will influence the upgrade of the substation and process control systems in other hydro power plants.

Assar Svensson worked on technology assessment and plant design for the power plant in Flåsjö and is now involved in the majority of E.ON Vattenkraft's upgrades and modernizations → 6. Of the renewal plans for the hydropower plants, he says, "this is an extensive conversion job we have ahead of us. We're therefore looking for standardized solutions in accordance with IEC 61850. Thus far, it only concerns relay protection." For E.ON, IEC 61850 will provide new opportunities to increase availability and simplify engineering. Several standardized components provide the capability to build plants in a more structured manner. "We want to be able to receive deliveries in which all components can be tested together prior to initiating operations." Another important reason for a more standardized structure for the control systems is that all E.ON Vattenkraft facilities in Sweden are controlled from a single control center. Svensson says that

when so many power plants are controlled from one location, it's very important that there is a standard on which everything is based.

From an E.ON point of view, there are many benefits of using IEC 61850 and System 800xA:

- Complete system configuration is more efficient and safer because standardized solutions for IED configuration, substation automation design and control system programming are used.
- The testing of protection, control and monitoring functions can be carried out before installation begins, and this helps to minimize the downtime needed for installation and commissioning.
- IEC 61850 is standard for Ethernet-based communication solutions and that means reduced wiring, which in turn leads to shorter installation time and reduced sources of errors during operations.
- With improved access to electrical and process data from the entire plant, the focus is shifted from troubleshooting to more preventive maintenance. The system itself can indicate when a component needs servicing or replacing.
- A common event list for both the process and electrical monitoring makes it easier to monitor errors and draft maintenance plans.

These benefits are such that according to Assar Svensson, E.ON will continue to ask for IEC 61850 in its specifications:

6 Assar Svensson is involved in many of E.ON Vattenkraft's upgrades and modernizations



"I now have major expectations regarding our supplier's ability to give us additional capabilities to standardize and simplify construction of electrical and control systems for hydropower plants. With the installation in Flåsjö, we have hopefully just opened the door to the future."

Johan Hansson
ABB AB
Västerås, Sweden
johan.hansson@se.abb.com

Stefan Bollmeyer
ABB Automation GmbH
Minden, Germany
stefan.bollmeyer@de.abb.com

Footnotes

- 1 Horizontal integration can also replace the hardwiring traditionally used for interlocking signals.
- 2 Object linking and embedding (OLE) for process control



IEC 61850 Edition 2

From substation automation to power utility automation

KLAUS-PETER BRAND, WOLFGANG WIMMER – The final part of IEC 61850 Edition 1 “Communication Networks and Systems in Substation Automation” [1] was published in June 2005. Among the standard’s greatest achievements and benefits are the use of standardized semantics and a formal system description (the latter being the key to efficient engineering of substation automation systems) as well as it being embedded into the broader scope of power-system management. Since its introduction, IEC 61850 has established itself as global standard for substation automation. An example from Switzerland is the system installed in Sils → 1 [2]. This is, however, far from the conclusion of its development. Additional application areas are being considered by IEC. The standard is thus being extended.

changes. In many cases, only a subset of them is needed.

- The basic substation-automation related data model has to be extended only by additional logical node classes needed for functions from these other domains.
- The communication stack used is very common (especially TCP/IP and Ethernet).

The standard extends beyond the switch yard

There is a significant advantage for utilities if data from substation IEDs can be used directly on higher system levels for control and monitoring purposes, without there being a need for protocol converters or having to handle numerous different protocols. Therefore two working groups of IEC TC57 have looked at the use of IEC 61850 for real-time applications such as line protection and also other applications that involve communication between substations as well as monitoring and control applications involving communication between substations and network control centers. The results will be published as technical reports.

The report that handles communication between substations is published as IEC TR 61850 90 1 [8]. Its results are being integrated into the second edition of the base standard. Besides discussing direct tunneling of Ethernet-level messages on high-bandwidth links, it also looks at the usage of proxy gateways with low-bandwidth links → 2.

The report handling communications between substations and network control centers will be published as IEC TR 61850-90-2 [9] and any resulting additions to the base standard will be integrated into an amendment to Edition 2, or at the latest in Edition 3 of the base standard.

Work on a third report handling the automated transformation and mapping between the IEC 61850 data model and the IEC 61970 Common Information Model (CIM, [10]) has just begun.

These extensions do not only concern the application-data model itself, but also the capabilities of the SCL (substation configuration language) to support new data models and enhanced engineering processes.

Remaining challenges from Edition 1

61850-9-2 defines the standardized communication of current and voltage samples across an Ethernet-based serial link. Besides transmitting such analog samples, the link also transmits switch positions, commands and protection trips. According to IEC 61850-8-1, this combination results in a complete process bus between primary and secondary equipment → 3.

The response time and throughput requirements on this bus are determined mainly by the samples. The advantages of such a process bus are:

- It permits the replacement of many copper cables by a few optical cables (lower cabling costs)
- Optical cables achieve the galvanic decoupling of primary and secondary equipment (makes maintenance and replacement easier).
- The serial interface makes the applications independent of the physical principle of the instrument transformer (electromagnetic, capacitive, optical, others) allowing more flexibility on the primary equipment side.

Edition 1 of the standard did not define a solution for the time synchronization required for the communication of samples at rates in the region of microseconds. Therefore, and to achieve the acceptance of a faster process bus, the user organization, UCA International [11], developed an application recommendation

The development of the IEC 61850 standard is continuing. This work is primarily aimed at remedying various shortcomings that were identified during the first installations, but it also seeks to enhance its application range – as is reflected in its changed title “Communication Networks and Systems for Power Utilities” [3]. This work is resulting in Edition 2 of the standard, which is being published in 15 parts during 2010.

Expanding into new application areas

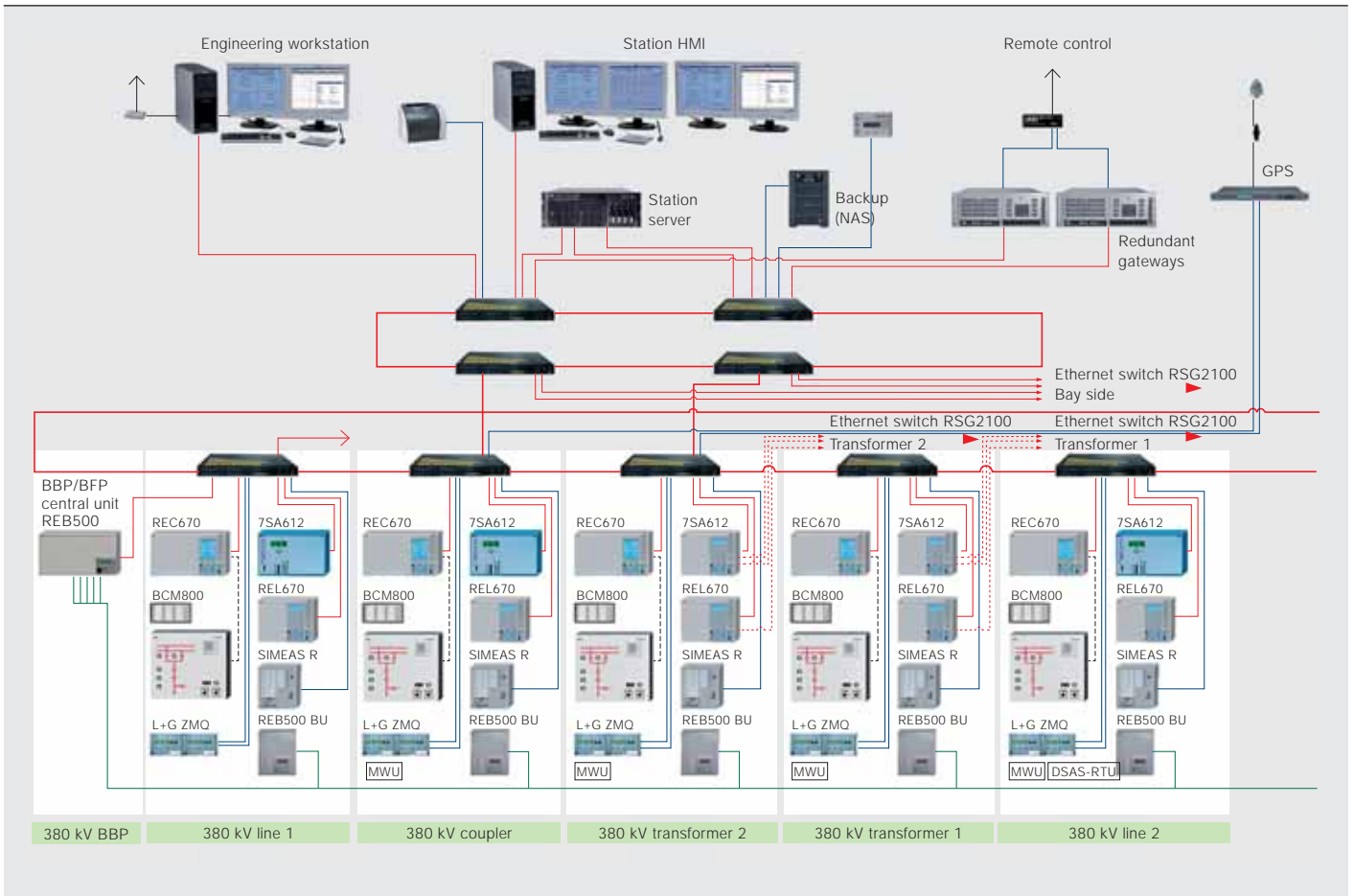
IEC 61850 was originally defined exclusively for substation automation systems (including protection applications). It has since been extended to other application areas. These are automation of wind power systems [4], hydro power systems [5], and distributed energy resources such as combined heat and power systems or photovoltaic plants [6]. The fact that the standard is being applied in the domain of distributed energy resources indicates the significance of IEC 61850 for smart grids.

Aspects of the extension of IEC 61850 to these domains include the following:

- The services of IEC 61850 have been proven to fulfill the known requirements of these other domains and may hence be applied without

IEC 61850 was originally defined exclusively for substation automation systems, but has since been extended to other application areas.

known as IEC 61850-9-2LE (Light Edition). This recommendation is based on the concept of a merging unit (MU) that delivers all current and voltage samples



from a given bay in a time-synchronized manner. It defines a telegram format containing voltages and currents from the three phases and the zero components. It specifies two sample rates (80 and 256 samples per period) and a time synchronization by a pulse per second (1 pps) with a synchronization accuracy class of T4 ($\pm 4 \mu\text{s}$). Meanwhile, a profile of the standard IEEE 1588 [12] is being worked on, which will support high-precision time synchronization across switch-based Ethernet.

The numerous features and benefits that the process bus offers are considered in a discussion on optimal processes in connection with communication architecture. The interoperable application has been delayed, however, because the dynamic behavior (step and frequency response) of the samples has not been sufficiently defined to guarantee application-level interoperability. The behavior of conventional instrument transformers is defined in the standard IEC 60044 [13] as is the behavior of electronic current and voltage transformers, thus summarizing all NCITs. It is stated, eg, that the electronic current transformer behaves as

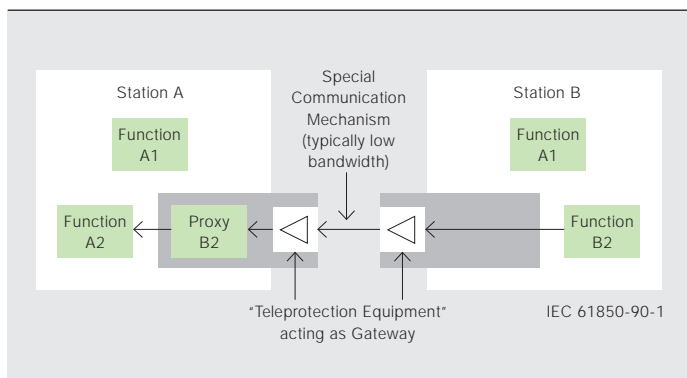
the conventional current transformer of type TPY for protection. This allows the type testing of the combined set of NCIT and MU. This has been done successfully for ABB's NCIT CP, (combined current and voltage sensors for GIS) which are now ready for use.

Some questions remain unresolved, especially how the signal from a conventional transformer (CIT) is changed due to digitalization in the MU. These questions are addressed by the IEC TC38 (Instrument Transformers) that has started replacing IEC 60444 by new standard IEC 61869 [14] in a step by step manner. It will define in its part 9 the "digital interface" covering the whole issue of MUs. The result will not be available in time to be referenced in Edition 2 of IEC 61850.

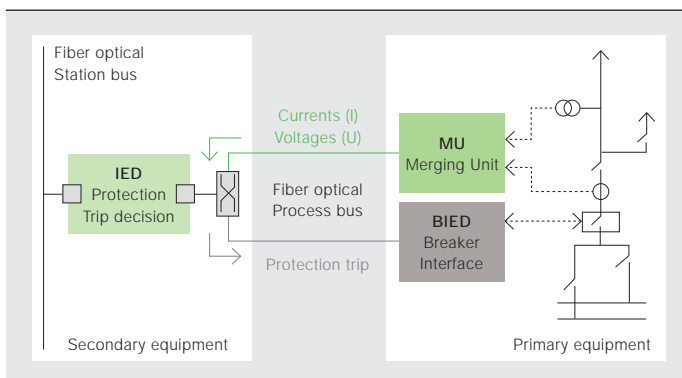
Several manufacturers are already offering MUs as pilot products. However, the electronic interface to a switch (often called a breaker IED or BIED) is rare even as a pilot product. Sometimes "normal" controllers are used in a similar way to BIEDs, eg, by receiving GOOSE (Generic Object Oriented Substation Event) trips from protection devices. This can for ex-

More components will facilitate the adoption of the architecture of the SA system and permit the better physical distribution of the primary equipment, providing the full advantage of the process bus.

2 Communication principles between substations based on IEC 61850



3 Process bus with merging unit (MU), switch interface (BIED) and external Ethernet switch



It is possible to use Edition 2 engineering and SCL descriptions with IEDs still having an Edition 1 data model.

ample be used for the two affected breakers of a 1 ½ breaker switchyard diameter, or for breaker failure protection.

There are also ideas to combine a MU and a BIED into one product. However, this is not a matter for IEC 61850 but for the optimized application of the process bus. The benefits of process bus applications can already be reaped today. More components will facilitate the adoption of the architecture of the SA system and permit the better physical distribution of the primary equipment, providing the full advantage of the process bus.

IEC 61850 Edition 2

Besides the correction of errors and many small details, Edition 2 will contain the add-ons laid out in → 5.

It is planned to publish all parts of Edition 2 with the exception of 7-5xy as an international standard during the course of 2010. The question of when corresponding tools and products will appear on the market depends on the manufacturers and appropriate requirements from customers and is difficult to predict. All error corrections, clarifications and restrictions contained in Edition 2 with respect to Edition 1, however, should already be followed by the next releases of Edition 1 devices. In this context it should also be mentioned that it is possible to use Edition 2 engineering and SCL descriptions with IEDs still having an Edition 1 data model. Edition 2 and all following editions will be backwards compatible to Edition 1 (with the exception of error corrections). A customer or supplier today deciding to apply IEC 61850 Edition 1 will thus benefit from all present advantages and future benefits of this standard. To assure as much compatibility to future editions as possible, it should be

verified that the Edition 1 devices used already implement resolutions of all technical problems identified up to Edition 2. This can be done by means of the so called TICS document, which should be available from the manufacturer for each certified IED type.

Beyond Edition 2

IEC standards are being developed in a time-consuming procedure involving commenting and voting by the national committees in several steps and via different drafts as they work towards the final international standard (IS). Therefore, some task forces have already started work on topics for amendments or for a future Edition 3, which will fulfill further user requirements. Some of the topics being considered are:

- Ethernet network architectures within substations including redundancy and Ethernet switch configuration.
- A setup for the supervision and diagnosis of primary equipment, called CMD (condition monitoring and diagnosis).

To provide an overview of the standard's fast-growing data model for both present and future application domains, and to be able to realize extensions more quickly than is possible in the normal standardization process, the introduction of an IEC database for model definitions is under discussion. This would be accessible via Internet. A standardized formal description of the model definitions defined in Edition 2 will help with the rapid integration of new models into the tools.

IEC 61850 and Smart Grids

The discussion around the future of the power grid with more and more decentralized power generation, flexible power buying and high grid reliability often labels this objective as "smart grid". An as-

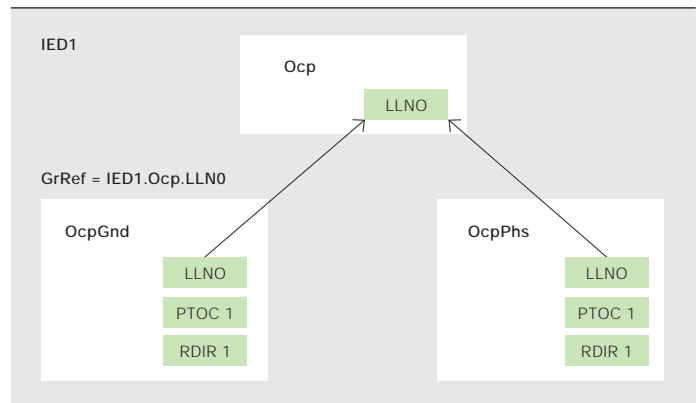
Besides the correction of errors and many small details, Edition 2 of IEC 61850 will contain the following add-ons:

- **Clarifications of unclear parts** such as:
 - buffered reporting
 - mode switch (test mode)
 - control access hierarchy (local / remote)
- **Data model and SCL extensions for communication between substations:** discussed above and outlined in → 2
- **Support for redundant IED interfaces:** discussed in "Seamless redundancy" on pages 57-61 of this *ABB Review* Special Report.
- **Data model extensions for new application functions:** supervision of non electrical quantities, etc. (These new logical nodes have been mainly introduced by other application domains such as hydro-power plants)
- **Statistical evaluations of measurements as contained in the logical nodes MMXU and MMXN:** Triggered by power-quality discussions and other application domains such as wind power → 5a.
- **Support for tracking and logging of services and service responses:** This feature makes service parameters and service handling visible without the use of protocol analyzers by the standard's existing reporting and logging facilities and allows, eg, the logging of negative answers on service requests (negative acknowledgements). This feature is useful both for commissioning and security supervision.
- **Management hierarchies of logical devices:** Especially complex multifunctional protection IEDs require more functional levels for the management of common parameters. For an example see → 5b: The logical device Ocp controls the mode of the lower level logical devices OcpPhs and OcpGnd by group reference (GrRef) which additionally could be controlled individually.
- **New data objects and concepts for testing of function parts in the running system:** This feature allows now a standardized application of the test and test-blocked mode which was already introduced in Edition 1 and is now clarified in Edition 2. It supports the handling of test messages in parallel to the real messages.
- **SCL extensions to describe new IED properties and better support of engineering processes and retrofit:** The data exchange between different projects in a controlled way allows coordinated engineering in parallel running subprojects.
- **SCL implementation conformance statement (SICS):** stating mandatory and optional features of IED tools and system tools. This feature allows judging the degree of interoperability between different engineering tools, system tools as well as IED tools.
- **An informative part 7-5x with examples of modeling important application functions in the system:** This part is intended to support common understanding of modeling and to move towards broadly accepted modeling solutions

5a Example for statistical methods (ClcMth) applied on MMXU

| MMXU 1 | Clc Mth | MMXU 2 |
|-----------------------------|------------------|-----------------------------|
| TotW Total Active Power | PRES | TotW Total Active Power |
| TotVAr Total Reactive Power | TRUE_RMS | TotVAr Total Reactive Power |
| TotVA Total Apparent Power | PEAK_FUNDAMENTAL | TotVA Total Apparent Power |
| TotPF Average Power Factor | RMS_FUNDAMENTAL | TotPF Average Power Factor |
| PPV Phase to phase Voltages | MIN | PPV Phase to phase Voltages |
| V Phase to ground Voltages | MAX | V Phase to ground Voltages |
| A Phase Currents | AVG | A Phase Currents |
| | SDV | |
| | PREDICTION RATE | |
| | | |

5b Management hierarchy for logical devices



summed prerequisite to the functioning of such a grid is that more information can be made available in a reliable and timely manner to more and more distributed applications and users, permitting control to be optimized. This will assure the grid's stability, make electrical energy available where needed, and permit interactive communication with consumers. This requires the needed data to be made available within a common information network and according to standardized data semantics. This is precisely where IEC 61850 fits in. Therefore IEC 61850 has been taken up alongside IEC 61970 in a smart-grid related report from EPRI [15] and adopted by NIST as a key interest.

Klaus-Peter Brand

Wolfgang Wimmer

ABB Substation Automation

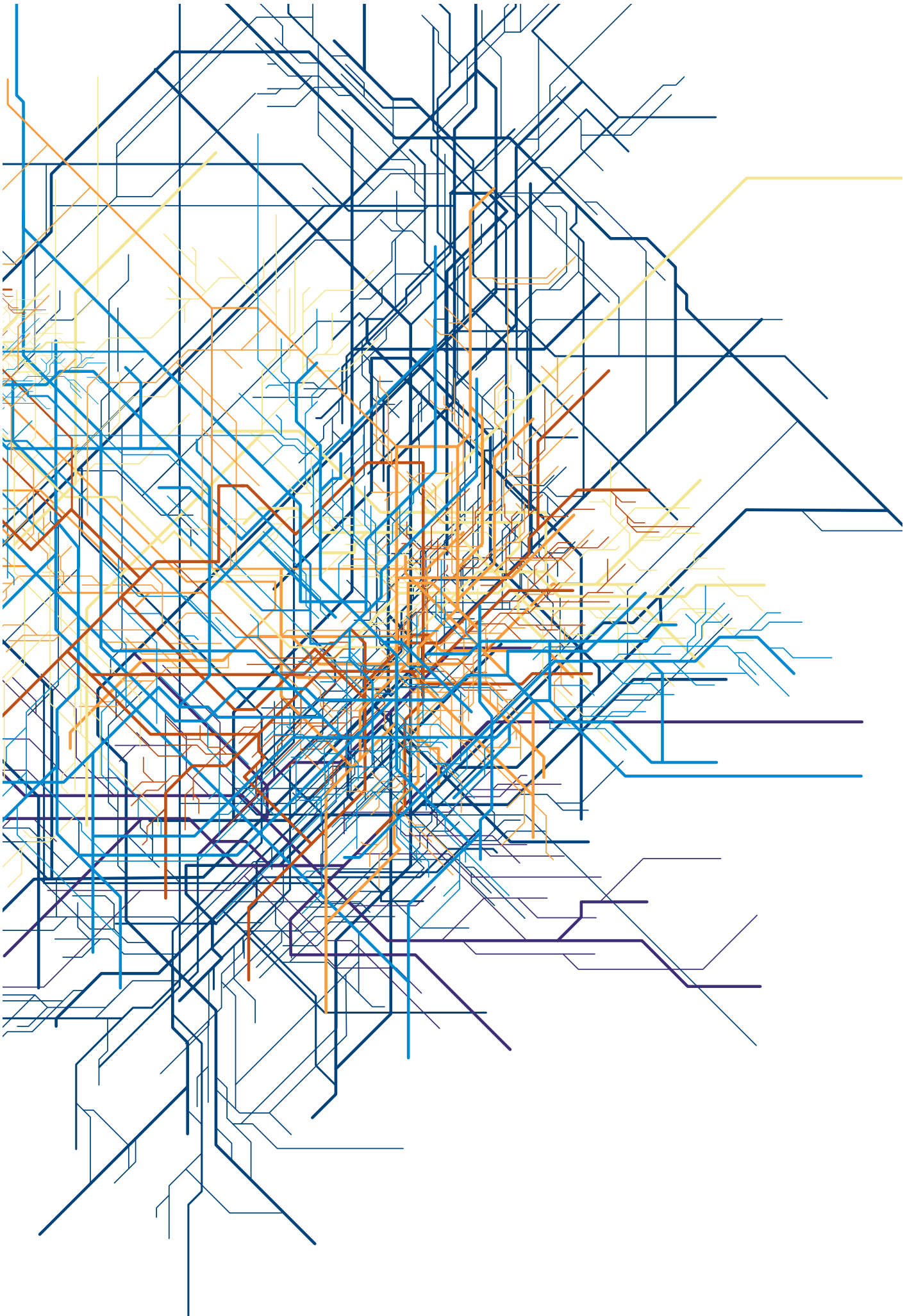
Baden, Switzerland

klaus-peter.brand@ch.abb.com

wolfgang.wimmer@ch.abb.com

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Reliable networking

Impact of modern communication technology on system reliability

KLAUS-PETER BRAND, WOLFGANG WIMMER – The communication standard IEC 61850 was introduced to standardize the communication for substation automation so that all devices, no matter their origin, could communicate using a standard protocol replacing wires with serial communication. Based on mainstream communication technology, like that of the Ethernet, IEC 61850 benefits from a high degree of flexibility with regard to communication architecture. Any solution, however, has to fulfill stringent reliability requirements to ensure a constant power supply in transmission and distribution grids to accomplish the safety-critical mission of substation automation. Mainstream Ethernet connections do not necessarily provide the required reliability. The IEC 61850 reaches the required level of communication reliability for substation automation by configuring appropriate message filtering and checking the load for worst case application scenarios for time critical communication traffic.

Substation automation (SA) is commonly used to control, protect and monitor substations [1]. Up to now, the communication for SA has used proprietary serial communication systems complemented by conventional parallel copper wiring, especially from the bay level to the switchgear. With the advent of IEC 61850 [2], a comprehensive global standard for all communication needs in the substation is available.

The reliability of SA communication architectures is of great importance for the reliability of the power supply from the power transmission and distribution grid. Up until now a dedicated communication system has been used, however the IEC 61850 uses a standard mainstream communication means like Ethernet, which provides a high degree of flexibility, but does it bring reliability?

Reliability according to IEC 60870-4 [3] is defined as a measure of the equipment or a system to perform its intended function, under specified conditions, for a specified period of time. Often investigations concentrate on reliability with regard to hardware faults. In the case of time-critical functions, like protection or load shedding based on serial communication, the "specified conditions" also

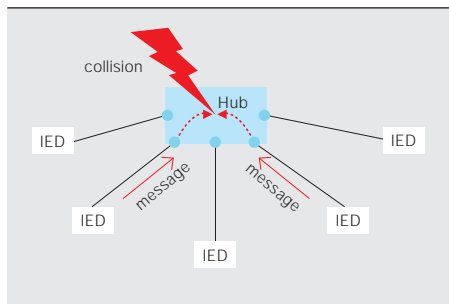
include the maximum allowed response time for an action. Ethernet was originally designed to be tolerant of failures, but not to guarantee response times. Therefore for this purpose special rules must be applied so that the Ethernet can be used for time critical application functions.

Failure modes and services

A failure means that some component in the SA system is not working as intended, which impacts the functionality of the SA system. Failures can be permanent or temporary. Failures produce errors in the intended system functionality. The result of a permanent failure may be the loss of power supply, loss of processing electronics, or loss of communication ports, like failing diodes for fiber optic links. These kinds of errors can be accommodated by appropriate redundancy strategies as discussed in the context of communication in the previous article (see "Seamless redundancy" on page 57 of this issue of the *ABB Review* Special Report).

Often, especially in the context of communication, temporary errors can occur as a result of electromagnetic disturbances or the intermittent failure of components. These may be caused by temperature fluctuations, the distortion of

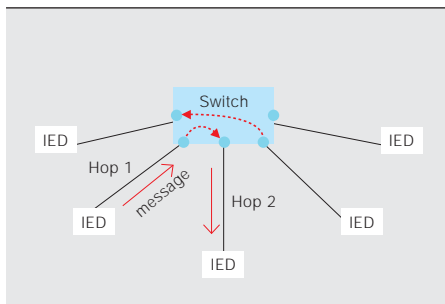
1 Collision on a bus with hubs



optical cables that have been bent too much or similar, leading to temporarily disturbed or missed messages in the communication system. These kinds of failures are typically detected by high-level protocols like transmission control protocol (TCP), and are handled by telling the sender about a missed message and then repeating its dispatch. For this reason all IEC 61850-based communications, which are not time critical, are built on the TCP protocol. To allow additional routing in arbitrary communication networks, TCP runs on top of the Internet networking protocol (IP).

Unfortunately, the handling of message errors through repetition results in further message delays. The detection of a failed message and its repeated dispatch in TCP is based on an acknowledgement mechanism with timeouts that may lead to delays in the order of seconds. However, the acceptable maximum delay for a time critical application function is in the order of 10 ms to 100 ms. TCP-based services, therefore, are not suitable for many automation and protection functions. For this reason IEC 61850 introduces the GOOSE (generic object oriented system event) and SV (sampled value) services for functions needing real-time performance. Both services are directly mapped onto the Ethernet link layer. Both periodically send sequentially numbered messages, which allow a receiver to detect missing messages as well as permanent failures. Sampled values are transmitted with a high rate corresponding to the sampling rate of currents and voltages, eg, 80 messages per cycle being 4,000 messages/s for a 50Hz system, thus replacing a missed sample by the next one very quickly. It is up to the receiving application to handle single lost values, eg, by interpolating the received well-known ones already from any A/D conversion.

2 Switches with "store-and-forward"



The GOOSE service is meant for fast sending of process state changes (events). Therefore, to overcome temporary errors on single messages, the message is repeated in case a value in the GOOSE message changes a few times very quickly (eg, within 4 ms intervals). After this, a fall back to the periodic background period occurs in the order of a second (see "The concept of IEC 61850" on page 7 of this issue of the *ABB Review Special Report*). The time span between three or four fast sendings is a configuration parameter, which typically depends on the maximum tolerable delay. These services can be used for protection and other safety related functions [4].

Ethernet specific challenges

Ethernet was originally developed as a bus system, in which several devices are coupled to a common communication medium. This mechanism leads to collisions if two devices try to send data at the same time → 1. Due to such collisions, the response times during burst situations are unpredictable, and the maximum throughput is less than 10 to 20 percent of the raw bit rate of the bus. This is overcome by using Ethernet switches with duplex connections between them and to the end devices.

Switches work with a "store-and-forward" principle like IP level routers → 2. They receive a message completely, and then forward it to the known output port, thereby avoiding message collisions completely by prioritizing messages within the switches. The disadvantage of switched Ethernet is, that each hop from one respective switch to another adds to

the delay, which for a 1,000 Byte (8 kBit) message and 100 MBit/s Ethernet, equates to about 100 μs. This is typically much more than the routing time within a switch. Assuming a ring with 20 switches, for example, an additional delay of 2 ms can occur between sender and receiver.

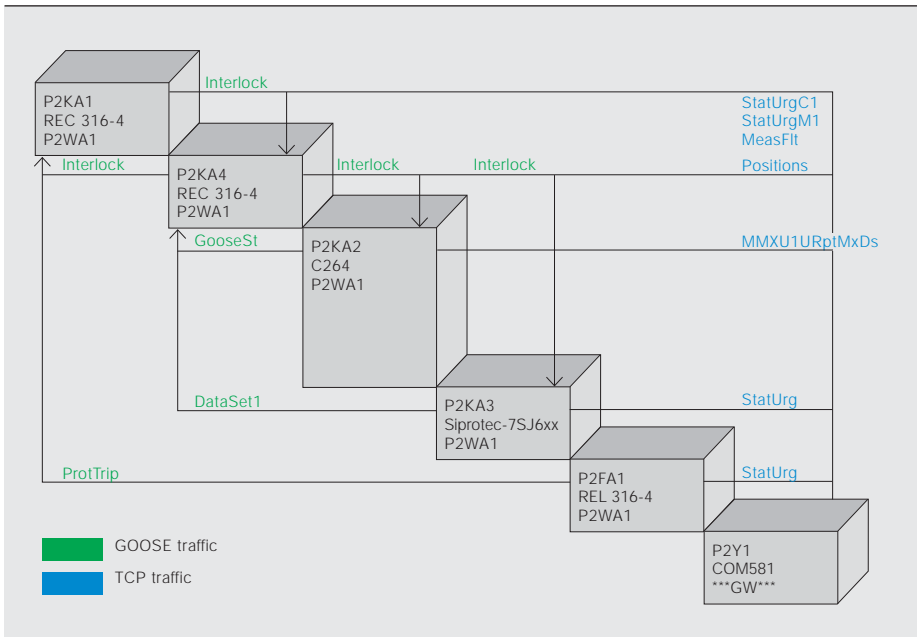
IP-based traffic normally has a determined destination. Thus a switch can learn to route a corresponding Ethernet message to a particular port, as shown in → 2. The disadvantage of this point to point traffic is that the sender has to send separate messages to each intended receiver. For real-time messages there is often more than one receiver of the same message. The interlocking function, for example, needs the state (switch positions) of the bus coupler at all bay controllers of all bays at the same voltage level. Therefore, the GOOSE and SV services use Ethernet-level multicast addresses. These configurable, hardware-independent link level addresses also make maintenance easier. As a switch does not know where the receivers of multicast messages are, it typically forwards the messages to all devices connected to it, thus producing a lot of possibly unwanted load for the receivers. Considering the interlocking function for 30 bays, where each bay sends the state of its busbar related primary switches to

The reliability of SA communication architectures is of great importance for the reliability of the power supply from the power transmission and distribution grid.

all other bays in the same voltage level with a background period of 1 s, this results in a background load of 30 messages per second. This load is needed at the controllers, however not at the protection devices, which instead might need other GOOSE messages eg, for the breaker failure function.

To separate wanted load from unwanted load, Ethernet switches support the concept of multicast message filtering. This can be based on multicast addresses as

3 Logical data flow in a small system



are lost due to insufficient buffer space.

These challenges can be tackled with appropriate tools. The IEC 61850 data flow allows the intended destinations for all kinds of messages to be described, thus defining the required data flow at the application level. An example for GOOSE (green) and TCP based (blue) data flow is shown in → 3. The load situation based on the presumed data flow can be determined easily at each receiver in normal and burst situations → 4. Comparing this with the input capacity of the devices gives a quick check as to whether the intended function distribution and data flow at application level is reasonable and will work from a communication point of view.

well as on the introduction of virtual LANs (VLAN). Therefore, IEC 61850 introduces a separately configurable multicast address as well as a separate VLAN identification for each GOOSE or SV message source. This leads to additional engineering effort to identify the flow of multicast messages from the source to all intended destinations through the switch network and to configure the concerned switches accordingly.

Another challenge, with the store-and-forward principle of switches, is the related intermediate buffering (storing) of messages in case of bursts. In such a situation, a lot of messages from different input ports arrive at a switch, which typically has to be forwarded through a single output port eg, to the station level. If the inputs of 10 ports are routed to one output port with the same bit rate, then nine messages have to be buffered in between. This leads to additional message delays, and in extreme cases may result also in message losses due to insufficient buffer capacity.

It should be kept in mind that the reliability of GOOSE messages depends on the prerequisite that not more than two consecutive messages are lost. This prerequisite has been validated by a lot of tests based on physical disturbance scenarios. However, if in a busbar trip situation, GOOSE messages are lost in the switches due to insufficient buffer size, delayed GOOSE-based actions may result.

To a certain extent this can be handled by the Ethernet priority feature. TCP-based time uncritical traffic has no priority and can also be delayed by appropriate configuration at the sender by 50 to 200 ms. GOOSE and SV traffic gets priority in the switches and is put first into the output message queues. Thus it is not delayed by TCP traffic, just by other GOOSE and SV messages.

To sum up:

- The IEC 61850 usage of switched Ethernet for time critical applications can guarantee maximum response times down to a few milliseconds.
- To reach this performance and also to restrict unwanted load on the end devices, the Ethernet must be built with duplex connections to and between managed switches, ie, switches supporting priorities and VLAN or multicast address-based filtering.
- It is necessary to configure priorities, VLAN IDs and multicast addresses at the GOOSE and SV sources as well as appropriate message filtering at the switches for the intended high-performance multicast data flow.

Solutions to remaining problems

Two main challenges remain:

- Configuring VLAN or Multicast filtering into the switches
- Assuring that for big systems the maximum delay in the switch network fits within the required maximum response time, and that no messages

The boxes in → 3 represent intelligent electronic devices (IEDs), whose names are written in the first line, and which all communicate within the SubNetwork P2WA1 (third line in each box). The IEDs P2KA1, P2KA2, P2KA3 and P2KA4 are controllers sending GOOSE messages for interlocking to each other. The IED P2FA1 is a protection device, which sends a trip with GOOSE to the controller P2KA1 to trigger a disturbance recorder. The IED P2Y1 is a gateway to a network control center, which receives reports from all other devices.

→ 4 shows the load calculated from a substation configuration language (SCL) description of this system for all receivers based on the configured data flow. This results in the required load for a switch network that is correctly configured. If the allowed message input rate to an application IED is known, it can be checked if the application would really work. → 5 now contains the calculated load based on the configured virtual local area network (VLAN) identifications. By comparison with → 4 it can be easily seen that this configuration using mainly VLAN 000, ie, no VLAN, leads to a suboptimal situation. Even the gateway P2Y1, which should only receive reports and does not belong to any VLAN, is loaded with GOOSE messages, and the protection device P2FA1, which should receive nothing, gets 3 GOOSE messages/s. For this small system the resulting load, even during a burst, is no problem at all. However, for a bigger system a better VLAN configuration should be used to

4 Expected load at receivers due to configured data flow

| Received load per IED based on client allocation | | | |
|--|--------|--------|------------|
| IED name | kBit/s | Msgs/s | Burst msgs |
| P2KA1 | 11 | 2 | 6 |
| P2KA4 | 16 | 2 | 9 |
| P2KA2 | 10 | 1 | 3 |
| P2KA3 | 10 | 1 | 3 |
| P2Y1 | 5 | 5 | 25 |

get closer to the minimum message rate needed for the application level engineering as shown → 4.

In a ring network, the filtering configuration at the switches can be derived from the logical data flow. To avoid filter reconfiguration in case of switch ring reconfiguration, the filtering should only be configured for the receiving devices or between different rings, while all ports between switches should allow all used VLANs. The filter to the receiving devices can be automatically calculated together with the receiver load. As an example → 5 contains the VLAN identifications, which should be configured at the switches to be sent to the port where the corresponding device is connected. As VLAN 000 just means “ignore the VLAN and send everywhere”, here the only thing to be configured is the VLAN 001 as output to the device P2KA4. In a similar way a related configuration for filtering based on multicast addressing can be generated.

For tree networks a similar strategy could be used. However, if within the tree network appropriate filtering is also needed, an additional formal description of the physical network, as defined in IEC 61850-6 Ed2 [5], also permits the switch filter configuration to be automatically derived from the logical data flow.

Finally the configuration data must be manually loaded into the switches (differently per switch manufacturer). This should change in the future, since IEC TC57 WG10 is working on a standardized switch configuration description in SCL, which should then be used as input to switch engineering tools.

The formal description of the physical structure also supports handling of the last problem: probable message loss due to insufficient buffer size and additional

delays in worst case situations. The main problem here is to know what are the worst case situations seen from the process point of view, and how do they manifest themselves in message load for the devices hosting application functions. One typical scenario is a busbar trip, resulting in a change of all measurements and the tripping of all circuit breakers within a very short time span, with the addition of 10 alarms from the switchyard or protection system. Other scenarios depend on the switch yard configuration and its place in the power network and must be defined by the utilities. If these scenarios and the resulting message load are known, the system description as IEC 61850 SCL file allows for a tool to determine the resulting messages and their flow to the end devices as illustrated above. With a description of the physical structure, the flow through the switch network may be calculated also; this includes the required maximum buffer size to ensure that no message is lost, as well as the maximum delay in the output queues. This allows the maximum GOOSE and SV message delay to be determined in advance, and the buffer size of the switches to be checked against their required size. If this is not consistent, then redesigning the communication architecture might be a solution. More buffer space in the switches might be required, or in the worst case the application implementation itself may need to be changed to reduce the communication load required.

However, these kinds of problems only arise in very big systems or systems where SV messages are used between several bays. It is common today in big systems without process bus and only a few GOOSE-based functions to find bottlenecks typically at the station level devices, may be at the human machine interface (HMI), or may be at the gateway.

5 Actual load in normal situation due to configured VLANs

| Received SV/GOOSE load per IED due to VLAN config, and VLAN list | | | | |
|--|--------|--------|------------|----------|
| IED name | kBit/s | Msgs/s | Burst msgs | VLAN IDs |
| P2KA1 | 12 | 2 | 9 | 000 |
| P2KA4 | 17 | 2 | 12 | 001 000 |
| P2KA2 | 21 | 3 | 9 | 000 |
| P2KA3 | 22 | 3 | 12 | 000 |
| P2FA1 | 21 | 3 | 9 | |
| P2Y1 | 22 | 3 | 12 | |

This bottleneck can be easily found by just analyzing the receiver load for normal data flow based on the SCD file → 4. This kind of analysis is recommended for a system without process bus, if it handles more than 30 bays. The trend to put more and more devices to 100 MBit/s Ethernet will make this analysis more and more urgent, since it is the receiving end devices that have the bottlenecks and not the communication system itself.

To conclude, networking can be highly reliable for substations and utility automation is possible using modern main stream communication technology, such as Ethernet, in accordance with IEC 61850.

Klaus-Peter Brand
Wolfgang Wimmer

ABB Substation Automation
Baden, Switzerland
klaus-peter.brand@ch.abb.com
wolfgang.wimmer@ch.abb.com

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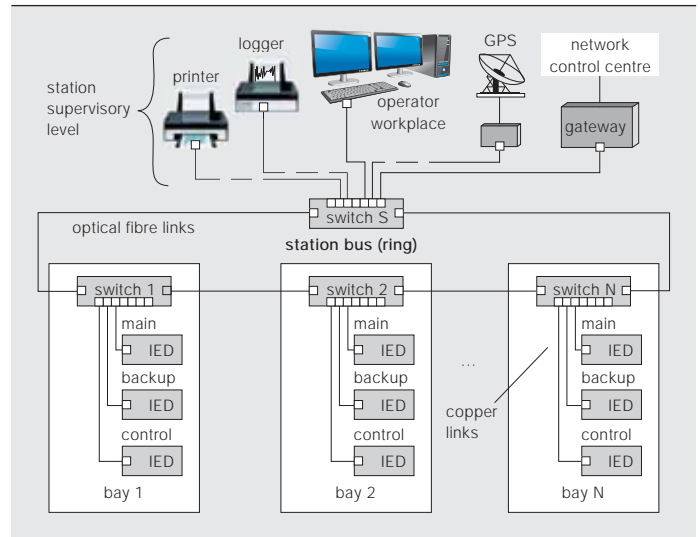
Seamless redundancy

Bumpless Ethernet redundancy for substations with IEC 61850

HUBERT KIRRMANN – The IEC 61850 standard has become the backbone of substation automation, allowing for the first time interoperation between protection, measurement and control devices from different manufacturers on the same Ethernet local area network, station or process bus. This network is duplicated in substations that require a very high availability. Interoperability requires that all devices use the same redundancy concept. IEC 61850 now specifies a network redundancy that fulfills the requirements of substation automation, for

the station bus as well as for the process bus. It is based on two complementary protocols defined in the IEC 62439-3 standard: parallel redundancy protocol (PRP) and high-availability seamless redundancy (HSR) protocol. Both are able to overcome the failure of a link or switch with zero switchover time, while allowing clock synchronization according to IEEE 1588 to operate reliably. Developed by ABB in collaboration with other companies, both PRP and HSR will be part of the second edition of the IEC 61850 standard.

1 A non-redundant station bus



all transmitted information and provide zero-switchover time if links or switches fail, thus fulfilling all the difficult real-time requirements of substation automation.

PRP (IEC 62439-3 Clause 4) specifies that each device is connected in parallel to two local area networks of similar topology. HSR (IEC 62439-3 Clause 5) applies the PRP principle to rings and to rings of rings to achieve cost-effective redundancy. To this effect, each device incorporates a switch element that forwards frames from port to port.

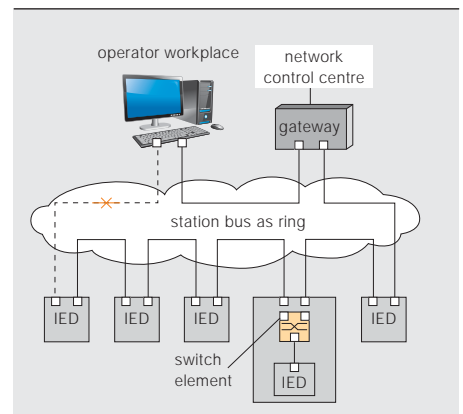
IEC 61850 network topology

IEC 61850 encompasses two busses based on switched Ethernet technology [4]:

- The station bus [5] interconnects all bays and the station supervisory level; it mainly carries control information, such as measurements, interlocking and select-before-operate. Typically the manufacturing messaging specification (MMS) protocol is used to transfer data between station level and bay level intelligent electronic devices (IEDs) while generic object oriented substation events (GOOSE) looks after bay IED to bay IED data transfer.
- The process bus [6] interconnects the IEDs within a bay and mainly carries measurements, known as sampled values (SV), for protection. The SV are sampled at a nominal value of 4 kHz in 50 Hz grids (4.8 kHz in 60 Hz grids).

IEC 61850 does not prescribe a topology, tree, star or ring. Indeed, the same

2 A ring with switching end nodes



physical Ethernet network could carry both the station and the process bus traffic.

For the station bus, the network topology generally adopted in large substations is that each voltage level uses a ring of switches, which connect the main protection, backup protection and control IEDs → 1. In smaller medium-voltage substations, a cost-effective arrangement uses IEDs that include a switch element, which can be chained into a ring topology, making the network resilient to the loss of one link → 2.

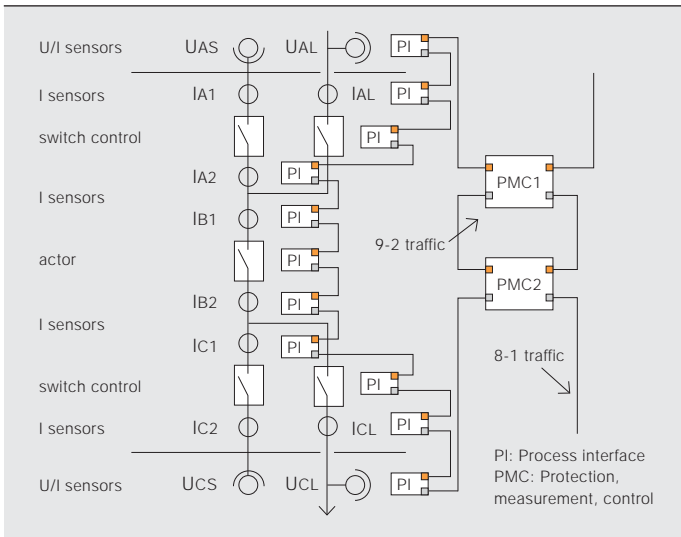
In large substations, the different voltage level rings are connected to the station level in a tree formation, allowing the station bus to exhibit a mixed ring and tree topology. Alternatively, a ring of rings formation can also be used.

At the process bus level, IEDs are typically simple measurement and control devices connected to the protection and control

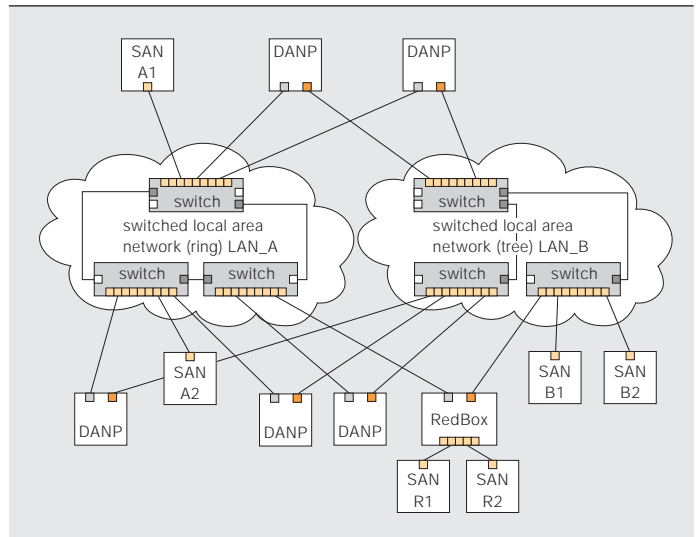
The IEC 61850 standard replaces the numerous busses and links in use today by a hierarchy of well specified switched Ethernet networks, namely the station bus between the bays and the process bus within a bay. To achieve interoperability, IEC 61850 Edition 2 specifies in greater detail the underlying protocols of these busses. Two indispensable network features for a real-time system are given particular attention: time synchronization and network redundancy. Time synchronization is solved by the simple network time protocol (SNTP) [1], with stricter requirements taken care of by the IEEE standard 1588 [2]. Redundancy was a major hurdle, since the lack of a commonly accepted redundancy protocol prompted manufacturers to market incompatible proprietary solutions.

IEC 61850 edition 2 now includes two redundancy protocols, which are defined in the IEC standard 62439-3 [3] and applicable to substations of any size and topology for the station bus as well as for the process bus: parallel redundancy protocol (PRP) and high-availability seamless redundancy (HSR). In both protocols, each node has two identical Ethernet ports for one network connection. They rely on the duplication of

3 A process bus topology



5 Redundancy in the nodes



4 Recovery times compiled by the IEC TC57 WG10

| Communicating partners | Communicating partners | Recovery Time |
|-----------------------------|------------------------|---------------|
| SCADA to IED client-server | station bus | 100 ms |
| IED to IED interlocking | station bus | 4 ms |
| IED to IED reverse blocking | station bus | 4 ms |
| bus bar protection | station bus | 0 ms |
| sampled values | process bus | 0 ms |

units, which interface to the station bus → 3. A ring topology at this level also offers a cost-effective wiring solution.

Timing requirements in substation networks

The timing requirements for the station and process buses are distinct; they dictate how redundancy is used.

The time during which the substation tolerates an outage of the automation system is called the “grace” time, and the network recovery time must be lower than the grace time. As well as applying in cases of failure, the recovery time also applies to the reinsertion of repaired components.

When the station bus carries only command information, delays of some 100 ms are tolerated. However, a delay of only 4 ms is tolerated when interlocking, trip and reverse blocking signals are carried, although it is unlikely that a failure will take place exactly when an (infrequent)

control sequence is issued. The process bus, which carries time-critical data from the measuring units, requires a deterministic mode of operation, with maximum delays in the order of 4 ms. The recovery times compiled by IEC technical committee 57 (TC57) working group 10 (WG10) are summarized in → 4.

Redundancy will be regularly checked at intervals of less than one minute for the complete network. Only one device, station operator or gateway to the network communication center (NCC) is needed to monitor the network. Configuration errors are reported to the station operator or the NCC gateway.

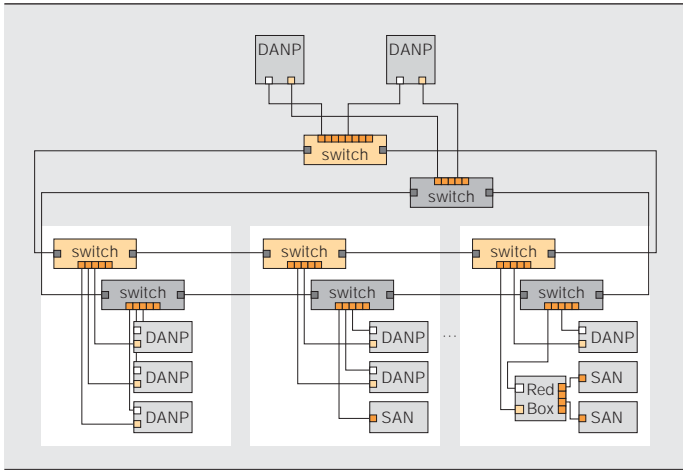
Highly available network topology

IEC 62439 [3] is applicable to all industrial Ethernet networks [7], since it considers only protocol-independent methods. It contemplates two basic methods to increase the availability of automation networks through redundancy:

- Redundancy in the network. The network offers redundant links and switches, but nodes are individually attached to the switches through non-redundant links. The gain in availability is small since only part of the network is redundant. Redundancy is normally not active, and its insertion costs a recovery delay. A typical example of such a method is the rapid spanning tree protocol (RSTP IEEE 802.1D [8]). However, RSTP can only guarantee a recovery time of less than a second in a restricted topology. Nevertheless, RSTP is a good choice for the station bus in non-redundant systems, such as that shown in → 1.

In a redundant network, the most important parameter is the recovery time needed to restore error-free operation after a failure. Both PRP and HSR offer zero recovery time.

6 A duplicated station bus with parallel redundancy protocol (PRP)



– Redundancy in the nodes. A node is attached to two different redundant networks of arbitrary topology by two ports → 5. Each node independently chooses the network to use. This scheme supports any network topology; the redundant networks can even exhibit a different structure. The cost of implementing this redundancy method is about twice that of the redundancy method discussed in the previous bullet, but the gain in availability is large. The only non-redundant parts are the nodes themselves.

With regard to PRP, IEC 62439-3 Clause 4 specifies redundancy in devices in which the nodes use the two networks simultaneously. This offers zero recovery time, making PRP suited for all difficult real-time applications.

IEC 62439-3 Clause 5 defines another redundancy-in-the-nodes solution with HSR, in which a switch element is integrated in each device. The operating mode is the same as for PRP.

PRP operating principle

Each PRP node, called a doubly attached node with PRP (DANP) is attached to two independent local area networks (LANs) operated in parallel. The networks are completely separated to ensure failure independence and can have different topologies. Both networks operate in parallel, thus providing zero-time recovery and the continuous checking of redundancy to avoid lurking failures → 5.

Non-PRP Nodes, called singly attached nodes (SAN) are either attached to one network only (and can therefore commu-

nicate only with DANPs and SANs attached to the same network), or are attached through what is known as a red box, a device that behaves like a DANP → 6.

The nodes detect the duplicates with a sequence number inserted in the frames after the payload. This allows full transparency of PRP (DANP) and non-PRP (SANP) nodes. The complete PRP protocol can be executed in software. Node failures are not covered by PRP, but duplicated nodes may be connected via a PRP network.

HSR

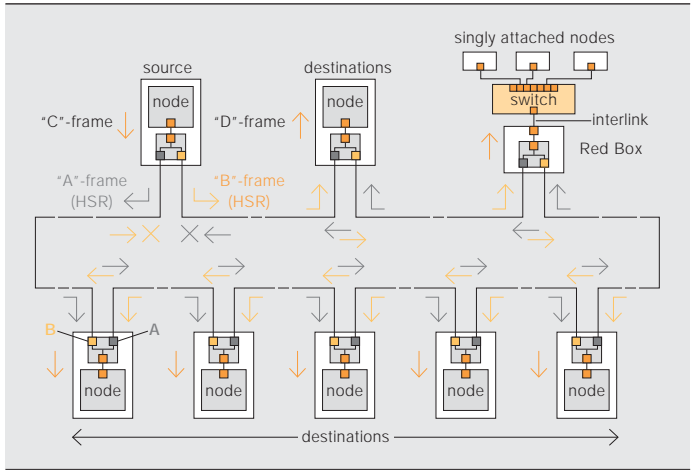
HSR applies the PRP principle of parallel operation to a single ring, treating the two directions as two virtual LANs. This allows a significant reduction in hardware costs because no switches are used and only one link is added. However, all

PRP offers easy integration of non-redundant devices, while HSR offers cost-effective ring topologies.

nodes of the ring must be switching nodes, ie, they have two ports and integrate a switch element, preferably implemented in hardware, as shown in → 7.

For each frame sent, a node sends two frames – one over each port. Both frames circulate in opposite directions over the

7 A high-availability seamless redundancy (HSR) protocol ring



ring and every node forwards the frames it receives from one port to the other. When the originating node receives a frame it sent itself, it discards it to avoid loops; therefore, no special ring protocol is needed.

To detect duplicates, the Ethernet frames include a sequence number incremented by the source for each sent frame. Contrary to PRP, the sequence number is not inserted after the payload, but in the header so the switch element can recognize the duplicates before they are received entirely. Therefore, cut-through operation with less than 5 μs per node is possible.

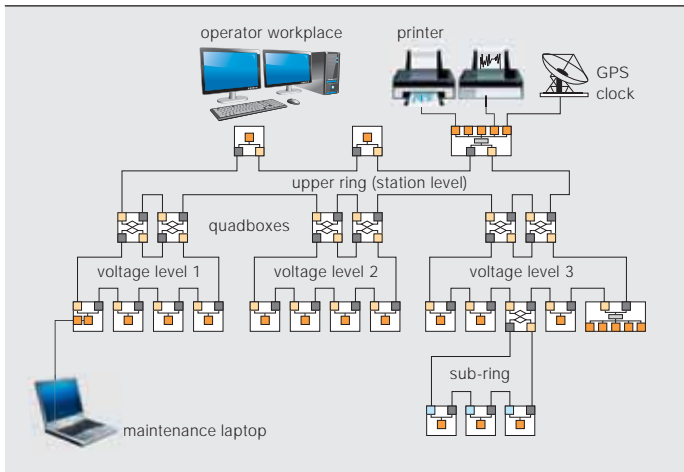
With respect to a single ring, the bus traffic is roughly doubled, but the average propagation time is reduced, allowing the ring to support a similar number of devices. Individually attached nodes, such as laptops and printers are attached through a “redundancy box” that acts as a ring element.

A pair of redundancy boxes can be used to attach a seamless ring to a duplicated PRP network. In this case, each red box sends the frames in one direction only. This overcomes the basic limitation of a ring, and enables the construction of a hierarchical or peer network → 8.

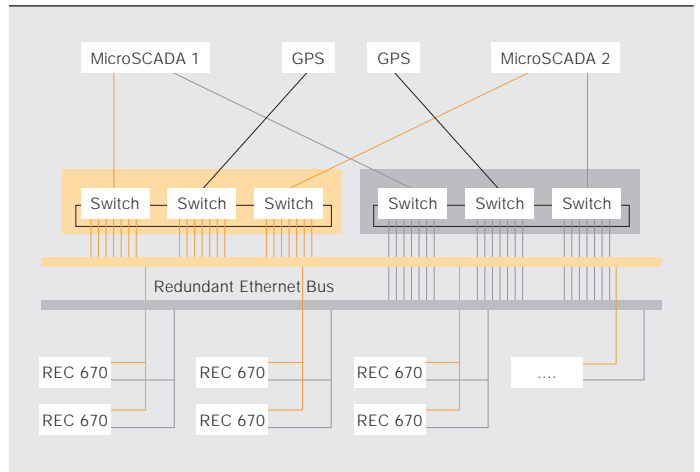
Precision clock synchronization

The PRP/HSR scheme presents a challenge for time synchronization as defined in IEEE 1588 because the delays over the two redundant networks are different. Here, some restriction to IEEE 1588 actually enabled the robustness and precision of the clock system to be increased.

8 HSR ring of rings



9 A system overview using PRP



10 PRP and HSR features

PRP and HSR provide ideal redundancy schemes for IEC 61850-based substations in that they:

- Fulfill all requirements of substation automation according to IEC 61850
- Can be used in a variety of topologies, eg, rings, trees.
- Are transparent to the application
- Tolerate any single network component failure
- Achieve zero recovery time, making it suitable for the most time-critical processes
- Do not rely on higher layer protocols
- Are compatible with RSTP
- PRP allows nodes not equipped for redundancy to operate on the same network
- Use off-the-shelf network components (tools, controllers, switches and links)
- Support precision time synchronization according to IEEE 1588
- Have been proven in the field in high-voltage substations

Field experience

The first substation automation (SA) system for a high-voltage substation with control devices operating under PRP is now ready for installation. The tests have proven that the technology is mature for substation automation devices and it performs as expected. One of the major requirements for this project was to have fully redundant communication down to the bay level IEDs to remove any single point of failure in the substation control. This called for full duplication, with redundant station computers (MicroSCADA 1 and MicroSCADA 2 in hot stand-by configuration for control and monitoring at the substation level as well as redundant gateway functionality for telecontrol. For bay level control, ABB's latest control device for high-voltage applications, the REC670, is used → 9.

The bay control units (REC670) are connected by two completely separated network rings. The entire system is synchronized using SNTP sent in parallel to both networks using two independent GPS receivers with integrated SNTP time servers. The communication system is supervised using SNMP and the failure of the redundant connection of any device is immediately reported to the system.

Ideal redundancy schemes

PRP and HSR make an important contribution in achieving interoperability – with respect to redundant communication – between protection, measurement and control devices from different manufacturers → 10. Their success relies on the ability of ABB to team up with competitors and suppliers to ensure device interoperability in the customer's interest.

Hubert Kirmann

ABB Switzerland
Corporate Research
Baden, Switzerland
hubert.kirmann@ch.abb.com

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Further reading

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IEC 61850 – a success story around the world

Substation automation systems pave the way to a smarter grid

PETRA REINHARDT – Since the publication of the IEC 61850 standard and the commissioning of the world's first multi-vendor project in Laufenburg in 2004, ABB has supported numerous customers in accomplishing the paradigm change associated with introducing IEC 61850 substation automation systems. Meanwhile, more than a thousand systems and a vast number of products have been delivered to around 70 countries resulting in comprehensive experience with new installations, retrofit and migration projects.

The development of powerful tools and efficient processes simplifies the implementation of IEC 61850 across the portfolio of products, applications and systems. Full compliance to the standard is verified by an in-house system verification center, the world's first vendor-owned test laboratory to earn qualification by the UCA International Users Group.

The state-of-the-art product portfolio along with proven system integration capabilities enables ABB to realize the standard's full potential in substation automation systems. This is equally ensured in systems with centralized and decentralized architectures, GOOSE-based and distributed functions as well as multi-vendor integration and latest

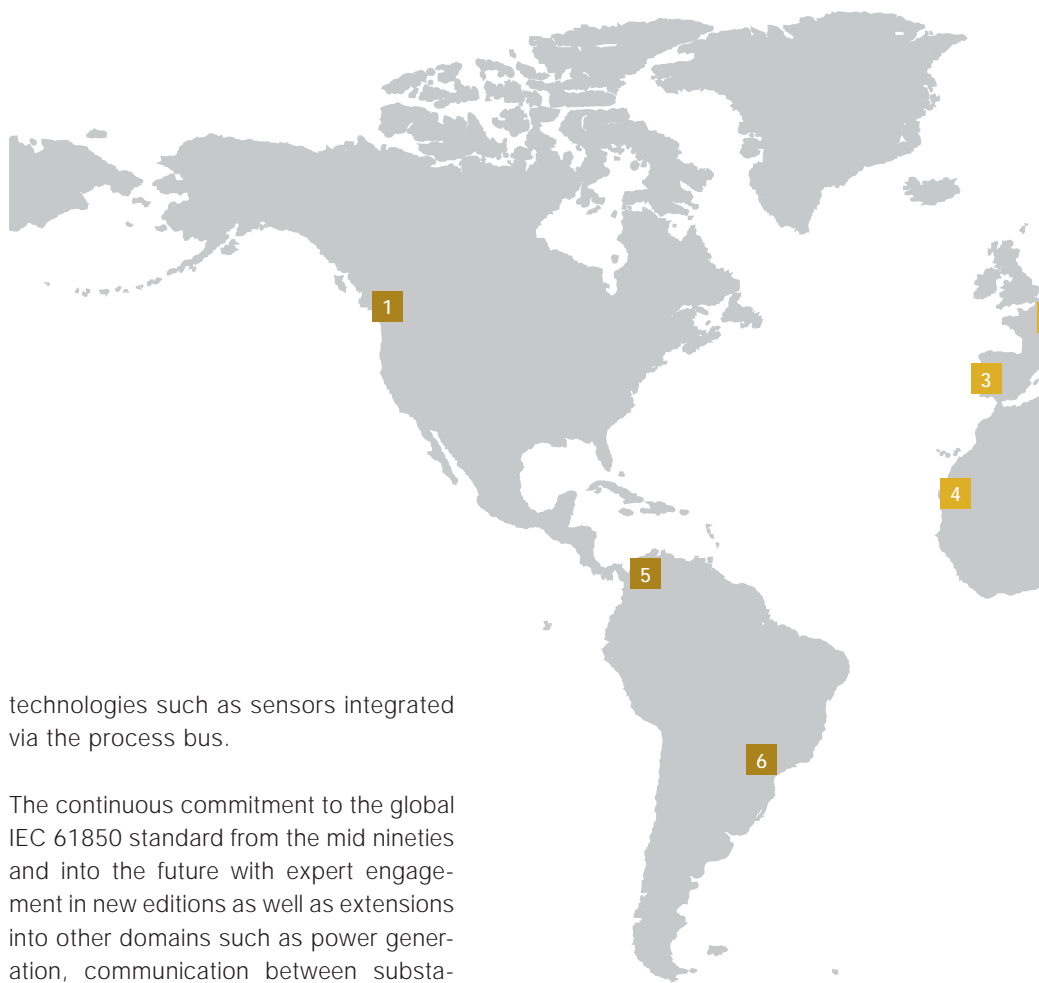
technologies such as sensors integrated via the process bus.

The continuous commitment to the global IEC 61850 standard from the mid nineties and into the future with expert engagement in new editions as well as extensions into other domains such as power generation, communication between substations and to network control centers allows ABB to support customers wanting to benefit from these developments.

Offering its comprehensive domain knowledge both of the power value chain and industrial processes, ABB provides utility and industry customers with SA systems leveraging both current and future perspectives and benefits of the standard. Facilitating enterprise-wide data integration, the IEC 61850 automation systems

enable efficient power system management and integrate substations that are reliably supplying energy from conventional and renewable resources to millions of people or are powering industrial productivity, into the smart grid.

This map shows a selection of IEC 61850 implementations around the world with ABB participation.



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- 14 NGCP's Pitogo S/S and Meralco's Amadeo S/S, Philippines
- 15 Rio Tinto/Hamersley Iron's 220 kV Juna Downs S/S, Australia



Power under control?

Absolutely.

The IEC 61850 open communication standard provides a common framework for substation automation and facilitates interoperability across devices and systems. ABB's IEC 61850 compliant systems enable real-time control and monitoring and help maximize availability, efficiency, reliability and safety. They enable flexibility for multi-vendor integration and extension, in addition to supporting enterprise-wide data integration for efficient power system management. With an unparalleled installed base and a proven track record of technology and innovation, ABB is a substation partner you can depend on.

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