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THE INTRODUCTION OF IEC 61850 AND ITS IMPACT ON PROTECTION AND AUTOMATION WITHIN SUBSTATIONS

Working Group
B5.11

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1. Introduction

1.1 Purpose

Over the last few years considerable work has been carried out in the development of the new standard IEC 61850, “Communication Networks and Systems in Substations” which is set to reach interoperability but makes also wide ranging changes to the way substations and power systems are designed, built, commissioned, operated, maintained and extended. This standard is unique in technology respects in that whilst it is implemented in individual devices, it is directed at system wide benefits. The standard comprises of 14 parts with more than 1000 pages. The last part was issued by IEC in June 2005.

The power industry has seen many individual components of the power system under go various technology improvements but these have generally had minor impact to the rest of the substation. The individual steps in technology have effectively therefore been incremental allowing the utilities to adopt technologies without major change to the rest of their systems and philosophies. This is evident in the types of switchgear that have become available, improvements in instrument transformer technology, changes in substation layout and arrangements, improved telecommunication systems from power line carrier to radio to optical fiber, and indeed the change in secondary systems from electromechanical devices to electronic to digital and microprocessor technologies. These changes have tended to affect only the particular technology, the manufacturing techniques and the direct operational issues associated with them. In other words, the current state of the art in substation design is the result of decades of incremental changes, technology improvements and operational experience.

This standard however will require a broader understanding of more than just the standard itself. The standard will provide utilities an opportunity to improve their complete systems from initial project concept to the end of life of the substation. It will directly lead to review of strategies and technologies employed in the primary equipment as well as the secondary systems, including protection, control, SCADA and communications.

The purpose of this report is therefore to provide utility management and their technical support staff an overview on the impact of IEC 61850 on protection and automation. The document is intended to take care to the different views on the standard within utilities. The scope and use of this report is given in section 1.3.

<u>Note</u>: The scope of IEC 61850 is Substation Automation of any type, size and voltage level. The scalability of the standard and of the used mainstream communication technology allows the application from transmission to distribution level. The high investments in Ethernet technology and the strong move of Ethernet into all areas of industrial processes will allow using IEC 61850 competitively also on the low end of this application range in the near future.

1.2 The Problem and the Solution

Of recent times new substations have been built with increasing levels of state-of-the-art secondary equipment. It is of great importance to know what their overall purpose is during the whole lifetime of the substation as these systems are no longer individual devices operating in isolation of the complete substation philosophy. This can influence the chosen concept, architecture and equipment. Already considerable expertise exists on an international scale and its related subjects [41] .

Since the 1980s electric utilities throughout the world have implemented substation automation systems (SAS) in their transmission and distribution substations. Utilities decided to invest in new technologies for the control of their substations based upon promises that, for example, engineering would become easier and operation and maintenance costs would be lower. The acceptance and success of this strategy is evident with well over 4000 Substation Automation systems in operation today. This evolution was triggered by the advent of microprocessor based Intelligent Electronic Devices (IEDs) providing the utility engineer with the ability to meet substation requirements in new ways not previously envisioned. The application of microprocessor relays provides significant cost savings[1] over the previous generations of static and electromagnetic relays. The key elements for this development have been increased processing capability for complex tasks, large storage capacities for parameters and events, and the introduction of communication means to enable highly interactive systems.

However, based upon the first experiences with substation automation systems, both utilities and manufacturers have found that not all of the initial promises could be fulfilled. It proved that especially the “learning curve” for both manufacturers and utilities was in many cases longer than expected. Furthermore, the lack of international standards in certain areas, such as for serial communication, resulted in many different proprietary solutions offered by the manufacturers, which in turn led to many debates regarding the viability of full exploitation of automation systems in substations.

With the advent of open and deregulated markets, the utilities strive to be competitive and therefore wish to improve their efficiency and reduce costs. At the same time the manufacturers can no longer afford to invest in the support of proprietary solutions used by their competitors. The industry is therefore are at the point of no return where the "old ways of doing business" must change. All of these factors have led to a situation where the overall life cycle costs of the high voltage infrastructure and its components must be considered in the selection of a substation automation system. Consideration of the life cycle costs can be challenging over the 20 years or more of the SAS life and over 40 years for the substation, but this consideration has to include the systems for protection and control, the initial investment, time to build, operation and maintenance processes, subsequent refurbishment, expansion and upgrade and the inherent systems flexibility.

In the new corporate culture, utility engineers are faced with fundamental changes to the traditional approach to engineering to meet the competitive challenges of today. Protection and control cannot be seen anymore as totally independent technologies since they are now generally integrated in some way, or at least interact, using powerful communication links. Functions that were at one time installed in a central location may now be provided in a highly distributed arrangement using the communication system. A typical example for a distributed function is the station-wide Interlocking in decentralized devices interconnected with serials links which in the past required a large number of wires and signals to operate from a central location.

The integration of IEDs in Local Area Network (LAN) architecture has been a goal only recently achievable. However, due to the proprietary nature of the applied protocols, only communications between like devices was possible, without the use of protocol conversion. The IED protocols were also limited in capability including speed, functionality and services. The capability of these devices to provide necessary throughput of data and fast response times was limiting substation applications. This profusion of protocols required the substation engineer to understand the use of a variety of protocols depending on the selected IEDs and suppliers for the substation protection and control schemes. It is apparent that a non-proprietary standard providing a high speed protocol and offering sufficient services was required. This would enable a robust, integrated substation communications network, without protocol conversion.

[1] Example is the integration of the function of many devices into a single device reducing total device costs and the space needed for the cubicles.

The answer to this request came from the development and introduction of IEC 61850, "Communication Networks and Systems in Substations". The standardized high-speed communication between IEDs allows the utility engineer to eliminate many expensive stand-alone devices and complex copper wiring. The engineer is now able to use the sophisticated functionality of interconnected IEDs and exploit all the benefits of Substation Automation.

1.3 Scope and use of this report

This report describes the new concepts contained in IEC 61850 and the practical approach regarding migration strategies, utility procurement process, system specification, project execution and life-cycle management. Each chapter gives another view on the standard to be useful for a dedicated user group within utilities.

The titles of the different chapters clearly indicate the subjects discussed. The intention of WG B5.11 is to provide useful information to these many different subjects, and being able to understand them without having to read the report as a whole. It is, for example, not a prerequisite to read the whole report in order to understand the chapter "Impact on life-cycle management". This approach implies some intended redundancy of information between the chapters.

Figure 1 refers to the paragraphs in this document and their order with IEC 61850. Implementation of IEC 61850 does require consideration by the utility from different perspectives (levels).

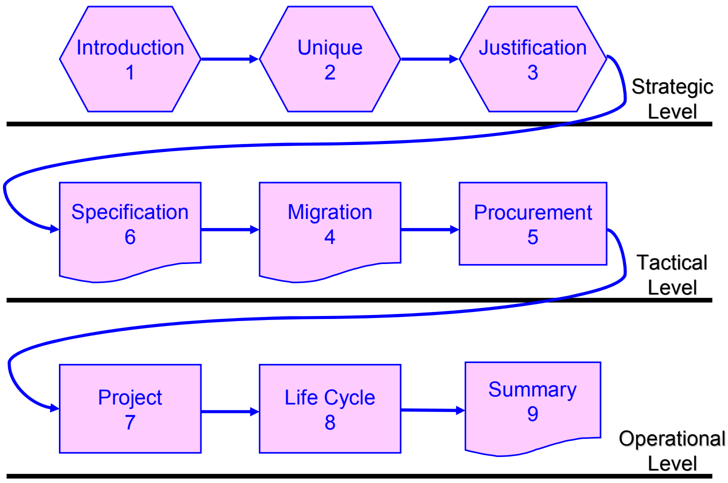


Figure 1 - Overview of chapters

Table 1 below provides some guidance to the content of each chapter in this report.

Table 1 - Roadmap to use this report

Chapter	Topic of discussion	Specific points and issues addressed
1	Introduction describing background, purpose, scope and recommendation on how to use this report.	• Background leading to the need of IEC 61850. • The scope and the audience for this report • Use of this report
2	What is IEC 61850 and what makes it unique.	• Goal interoperability • More than communication • System wide design impacts • Object model with semantic meanings • Services based on standard technology • Quality and maintenance process
3	Practical views justifying IEC 61850	• Reducing number of protocols • Future proof approach of the standard • Flexibility • Exchanges and upgrades
4	Migration strategies	• Definition of "migration"? • Reasons for migration • Different scenarios and perspectives
5	Impact on utility procurement process	• The procurement process • Impact of different project types • Specification aspects • Purchasing and maintenance • The role of system integrator
6	Specification	• Different levels of specification possible • Specify functionality and not solutions • Specification to get optimized solutions • Specifying too much detail restricts the solutions • Specification of the different roles in the system integration and maintenance process
7	Project execution	• Steps in the project execution process • Engineering • Manufacturing and assembling • Test steps • Installation and commissioning
8	Impact on life cycle management	• System-wide maintenance • Training • Technical support

Chapter	Topic of discussion	Specific points and issues addressed
		• Different kinds of maintenance • Change and version control • Responsibilities
9	Findings summarizing this report	• Functions are not changed, and therefore neither does the basis for future specifications • Approach of IEC 61850 fulfils the requirements of interoperability, free allocation and being future-proof • Multi-vendor systems are possible but require clear definition of role responsibilities and have a strong impact on the procurement process. A system integrator is needed • Tools play a key role in system realization • The interaction of functions over a common LAN allows to interconnect single functions and to distribute complex ones. Exploiting the benefits needs sometimes new concepts
10	Definition of terms and acronyms	• Special terms and abbreviations
11	Bibliography of documents used for this study	• Cited references

2. What is IEC 61850 and what makes it unique

2.1 Standardization of communication within a substation - IEC 61850

The standard IEC 61850 “Communication Networks and Systems in Substations" is based on the need expressed by the industry to have devices which are **interoperable** via a communication link at least to the same degree as hardwired devices. Behind this is the request for lower costs and increased flexibility of substation automation. The objective of IEC 61850 is therefore to provide a communication standard that meets performance and cost requirements, and which supports future technological developments. Key to the usefulness of the standard is the free exchange of information between IEDs. The communication standard supports any type of substation automation functions and therefore, the standard considers all operational requirements.

The purpose of the standard however is neither to standardize (nor limit in any way) the functions involved in substation operation nor their allocation within the substation automation systems. The operational functions are identified and described in order to define their impact on the communication protocol requirements (e.g. amount of data to be exchanged, exchange time constraints, etc.).

<u>Note</u>: The scope of IEC 61850 is Substation Automation of any type, size and voltage level. The scalability of the standard and of the used mainstream communication technology allows the application from transmission to distribution level. The high investments in the Ethernet technology and the strong move of Ethernet into all areas of industrial processes will allow using IEC 61850 competitively also on the low end of this application range in the near future. The standard will be used also outside Substation Automation as indicated in section 2.14.

The communication standard IEC 61850, to the maximum extent possible, makes use of existing standards and commonly accepted communication principles. Fundamentally, the standard is not a protocol in a communications sense, but rather a structured definition of data within devices such that information can be exchanged correctly between functions within devices over whatever communication media and protocol is used. To get interoperability for real IEDs, also all layers of the protocol stack including media definitions have been standardized by a well-defined selection out of main stream communication technology.

Based on an object-oriented approach and the use of main stream communication technology, IEC 61850 provides significant benefits to users which are uniquely at least in this combination. The most important ones are listed in the following:

- Lower installation and maintenance costs through self-describing devices that reduce manual configuration
- Reduction in engineering and commissioning with standardized object models and naming conventions for all devices that eliminates manual configuration and mapping of I/O signals to power system variables
- Less time needed to configure and deploy new and updated devices through standardized configuration files
- Lower wiring costs while enabling more advanced protection capabilities via the use of peer-to-peer messaging for direct exchange of data between devices and a high speed process bus that enables sharing of instrumentation signals between devices
- Lower communication infrastructure costs by using readily available TCP/IP and Ethernet technology
- A complete set of services for reporting, data access, event logging, and control sufficient for most applications

- Maximum flexibility for users to choose among an increasing number of compliant products to be used as interoperable system components

The primary goal of IEC 61850 is the **interoperability** of IEDs. Interoperability within IEC 61850 is defined as the ability of two or more IEDs from the same or different vendors to exchange information and use that information for their own functions.

From a utility point of view there is also a desire for IED **interchangeability** or, in other words, the ability to replace a device supplied by one manufacturer with a device supplied by another manufacturer without making changes to the other elements in the system. Interoperability is a prerequisite for interchangeability but, in addition, interchangeability would require the standardization of functions available within each device which is specifically not defined in IEC 61850 to avoid any limitations. If however the end user considers and compares all performance and functional requirements then by carefully selecting the appropriate IEDs an acceptable level of interchangeability may be achieved at least on a functional level.

2.2 Fundamental design and operation changes using IEC 61850

In attempting to describe or explain what IEC 61850 is, there is an inevitable use of specific jargon related to the standard. These jargons serve to describe the various elements of the standard and hence describe how the standard works to achieve its objectives. The jargons are the result from the fact that knowledge from different areas e.g. from control, protection, monitoring, object modeling, and communication had to be combined in the standard. The above overview describes the creation and evolution of the standard and its objectives. In addition there are fundamental changes that IEC 61850 will bring to the utility and system integrators. This must be noted as one of the driving forces for a particular utility as well as the challenges the utility must deal with in the migration. These changes are diverse across both design and operational areas which each utility must consider in some depth.

This report cannot cover all aspects of these changes for any particular utility, but it is sufficiently to say that there are some examples as a catalyst for the utility to start this process of fundamental re-engineering of their design, construction, operation, maintenance and staff training processes that must be worked through for obtaining the benefits of IEC 61850.

Indeed the introduction of IEC 61850 into a substation automation system design is significantly different to the previous evolution of technologies in the substation. It is a new holistic substation automation approach necessitating a much bigger shift in traditional design considerations than ever before. The change from electromechanical to electronic relays was essentially a device for device change - the technology improvement was essentially a manufacturing issue with the introduction of electronic components. The next change to digital technologies within the relays converted analogue signals into binary data of some sort, which allowed improving in the number of functions and the way in which those functions performed within the device. The next stage moving to numerical devices using algorithms opened up a new regime of multifunctional devices and the ability of the device to communicate via a serial link. Each of these changes however has generally been device centered changes in that very little changed in the substation system design and operation.

Currently a substation consists of many thousands of individual copper wires connecting various pieces of equipment. In simple terms, the use of IEC 61850 may replace almost all these wires, those excepted being device power supplies, with a copper cable based or optical fiber based Ethernet communication network. If this significant concept is understood, the implications for the utility become more apparent.

Consider the large numbers of drawings used to record each and every connection in the substation secondary system, regardless of whether it has evolved into an automation system, and the associated wire numbering regime, all being replaced by essentially a generic diagram with connections from each device and around the network shown as one Ethernet copper or optical fiber connection. All these details are not lost but comprehensively described by a formal modeling language which implies the use of appropriate computer based tools. The cost savings in engineering and in construction are by no means subtle in themselves. However at the operational level it is now not possible to trace an individual wire or a specific signal between each and every device as has been common practice during commissioning, maintenance or event investigation. But the specific signals may be traced back in the formal description and verified by monitoring messages running over the communication links.

Even the simple concept of auxiliary relays either for contact multiplication for sending signals to other devices or as physical latching relays to provide a mechanical prevention against closing the circuit breaker until the operator has manually reset the relay, will no longer exist.

Many other improvements in design and equipment costs are realized through the ability of IEC 61850 to enable the measurement or collection of information at one point and making it available to all other devices. Traditional designs have required even up to eight expensive and often very large current transformer cores with knee point voltages to cater for the burden and performance requirements of a few thousand volts to be installed on each phase of each feeder. This has been necessary for the operational requirements of distance protection segregated from the bus bar protection, the duplication of each of these, separate circuit breaker fail current sensors and of course metering. Hence there could be 48 wires in total from the CTs for the measurement of current in the feeder. The ability of new so called non-conventional sensors with wide dynamic ranges and high accuracy plus the interoperability concepts providing information sharing over the process bus and the network will eliminate the need for multiple measurement of the same value in multiple devices, replacing the wires with just a few optical fiber connections. Note that also the reading of conventional instrument transformers may be converted to messages over the fiber optic link.

Similarly monitoring of circuit breaker open/closed status need only be carried out in one device and shared with all others rather than wiring multiple individual circuit breaker auxiliary switch signals to multiple devices in a daisy chain connection. Indeed the trip signals themselves will no longer be copper wires with trip circuit supervision and individual trip isolation links, but rather an optical or electrical serial link connecting the relay room to the primary plant.

In another sense consider the common practice of physical isolating links throughout the substation for physical disconnection of individual functions. These links are fundamental operational security and safety measures such as for example isolating a circuit breaker trip output from a relay or at the circuit breaker and using the current transformer shorting links during maintenance testing. In a full IEC 61850 based system, both trip signals and current measurement signals operate over the Ethernet LAN so the Ethernet cable cannot be simply unplugged from the IED to “isolate” it without consideration of what other IEDs may be relying on data from the disconnected unit. To the operator seeking to undertake some maintenance or operational procedure, new skills and confidence in the security and safety levels need to be established to use and rely on screen based controls to affect such isolations.

Over the life time of the substation there will also be a number of changes to the substation for a variety of power system needs or just equipment end of life replacement requirements. Traditionally this would require considerable reengineering and reconnection of hundreds if not thousands of wires in the substation. Once again IEC 61850 will simplify the process of both the engineering and physical device installation which will bring significant time, cost and supply disruption minimization benefits to the utility. On the other hand, future integrators will need to rely on different types of documentation to understand the operational philosophy of the substation, for example which devices initiate the auto-reclose function, or indeed in which device, or devices, the auto-reclose function is established. The present practice of tracing an individual wire from a distance relay to an autorecloser relay will no longer apply and is replaced by the information in the formal system description file

Amongst all of these changes in substation design and operation implementation, there is an implied subtlety that substation designs will transform from hardwired electrical connections between devices to essentially computer based technologies operating over a Local Area Network or Wide Area Network in virtually the same way as the computer network and systems in an office environment. But note: despite of the use of main stream IT and communication technology the requirement to be substation proof remains.

Indeed the substation LAN may ultimately be seamlessly integrated into the complete system wide and business wide communication network. Note that there may be some integration limits regarding security, privacy and performance. This change in itself will bring significant challenges to the substation engineer's skill set, having to understand the purpose, configuration, performance and operation of switches, routers, firewalls and gateways and indeed security measures that are common place in the Information Technology world. Nevertheless, the substation engineer has to master the control and protection skills as in the past. These skills will get more important since more advanced control and protection schemes are possible.

This change in skill set will also apply to operation and maintenance staff, which will need a whole raft of IT type skills in order to operate or test individual IEDs or the system in part or whole. These skills do not replace but extend the existing functional skill sets.

Indeed the designs will need to incorporate thinking on access to the system for the utility staff, maintenance staff and third party organizations which will need to encompass issues such as password control and intrusion prevention.

As a result of this technology, redefinition of support and maintenance staff functions with respect to call out and corrective actions will be required, including such aspects as IT Help Desk support and indeed the training of IT staff in safe work practices within a substation. Alternatively the existing substation automation, the teleprotection and telecontrol staff will need training in IT technologies and maintenance for such issues as configuring a replacement router or switch.

Hence whilst attempting to describe IEC 61850, there are many design, construction, operation, maintenance, training, documentation and responsibility issues that must be thought through in respect of the particular utility practices based on the issues dealt with in this report.

Indeed, throughout this transition period, it is useful in the utility approach to adopting IEC 61850, to avoid referring to non-IEC 61850 systems as "conventional" or "traditional" and in contrast, IEC 61850 as "non-conventional", as IEC 61850 systems will quickly become the standard design and basis of equipment selection within a few years.

The following sections provide some guidance on the technology itself although there is considerable detail contained within the original documents of the standard IEC 61850 which should be reviewed at least partly and understood.

2.3 Logical interfaces in Substation Automation

Substation automation systems normally incorporate functions for control, supervision, protection and monitoring of the high voltage equipment and of the grid. Other functions are related to the system itself, e.g. supervision of the automation system itself including communication. Functions in a substation can be assigned to three levels:

- the station – relating to the substation as a whole
- the bay – relating to one feeder/circuit breaker or piece of plant

- the process – the high voltage power system or primary equipment and sensors

Communication between these levels consists of physical mappings of logical interfaces. Figure 2 shows the applicable logical interfaces in a substation and forms the basis for the IEC 61850 standard series [1] .

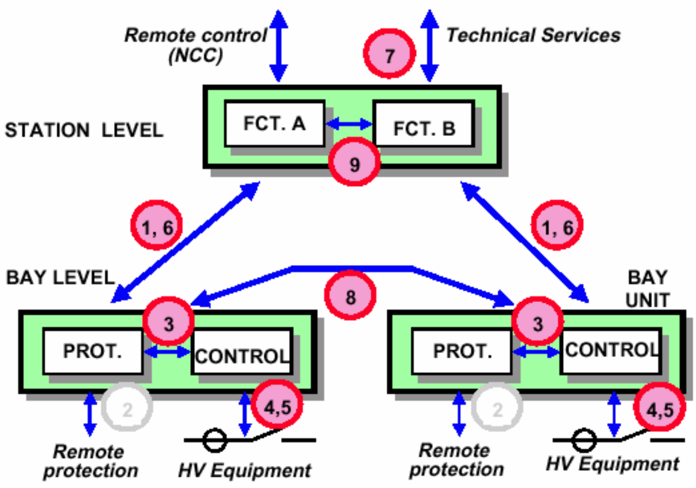


Figure 2 - Logical Interfaces in Substation Automation

At each level there will be a number of Physical Nodes which are simply individual devices whether that is a circuit breaker, a sensor, a transformer, a relay, a SCADA RTU or any other IED.

Within each Physical Node, there will be one or more Logical Nodes (described in the next section) as individual function related data groups or unique pieces of information or data of the device which form the basis of the IEC 61850 standard definitions. As these physical nodes are connected via the communication system, it is no longer significant or relevant as to which Physical Node supports the function. The Logical Interfaces handle the linking of functions to other ones at the basis of the data contained in the Logical Nodes.

2.3.1 Logical Nodes (LN)

IEC 61850 identifies currently known functions in a substation automation system, split these into the core functionality with data represented by the so-called Logical Nodes. Furthermore, rules have been defined to facilitate the definition of new logical nodes and the extension of existing ones. The rules are very strict to maintain the interoperability also in such cases.

Each Logical Node has a definition of the data associated with a particular function including its naming convention, the type and format of the data and how it is to be interpreted and used. From the communication point of view, a logical node is the smallest logical entity, which exchanges data with other separate logical entities. Therefore, a logical node is a complete, self contained function that can be addressed and whose data has to be standardized to reach interoperability. More precisely, Logical Nodes are function related data containers. They contain all data of a function which is written on the container i.e. the Logical Node name. Logical nodes may reside in different devices and at different levels.

To create a meaningful overview, all logical nodes have been grouped according to their most common application area, a short textual description of the functionality, a device function number if applicable [20] and the relationship between functions and logical nodes.

Logical nodes fall in two main applications:

- logical nodes representing primary equipment (e.g. a circuit breaker)
- logical nodes related to substation functions (e.g. protection function)

All Logical Node groups defined in the standard [10] are listed in Table 2 below.

Table 2 - Logical node groups

Group Indicator	Logical Node Groups	LNs defined
A	Automatic Control	4
C	Supervisory control	5
G	Generic Function References	3
I	Interfacing and Archiving	3
L	System Logical Nodes	3
M	Metering and Measurement	8
P	Protection Functions	28
R	Protection Related Functions	10
S[a)]	Sensors, Monitoring	4
T[a)]	Instrument Transformer	2
X[a)]	Switchgear	2
Y[a)]	Power Transformer and Related Functions	4
Z[a)]	Further (power system) Equipment	15
[a)] LNs of this group exist in dedicated IEDs if a process bus is used. Without a process bus, LNs of this group represent the I/Os in the hardwired IED one level higher (for example in a bay unit) representing the external device by its input and output data.		

Within each of these groups, each generic Logical Node definition is referred to as the Logical Node *Class.* When a Logical Node Class is implemented within an IED it is referred to as a Logical Node *Instance*. There may be multiple instances of LNs if needed by IED functionality.

As an example the Logical Node Class (LN) that can be used for the modeling of an instantaneous overcurrent protection function **PIOC** is given in Table 3. For a detailed description of this LN, please see IEC 61850 part 5 [5] and part 7-4 [10] .

Table 3 - Logical Node Class definition for PIOC as defined in IEC 61850-7-4

PIOC Class				
Attribute Name	**Attribute Type**	**Explanation**	**T**	**M/O**
LNName		Shall be inherited from Logical-Node Class (see IEC 61850-7-2)		
DATA				
Common Logical Node Information				
Mod	INC			M
Beh	INS			M
Health	INS			M
NamPlt	LPL			M
OpCntRs	INC	Resetable Operation Counter		O
Status Information				
Str	ACD	Start		O
Op	ACT	Operate	T	M
Settings				
StrVal	ASG	Start Value		O

In this table the "Attribute Name" is the actual name of the Data or, more precisely, the Data Object.

The "Attribute Type" refers to the so-called Common Data Class (CDC) that defines the attribute structure of the data. The CDCs are defined in IEC 61850-7-3 [9] .

The "T" indicates whether the Data is so-called *transient* Data meaning that the status of the data with this designation is momentary and must be logged or reported to provide evidence of this only transient existing state.

Finally the "M/O" column defines whether data is mandatory (M), or optional (O) for each instance of a specific Logical Node. In the CDC tables exist also columns with “M/O/C” column where C means the attribute is conditional i.e. mandatory (M) only under given, well defined conditions.
Note: The attributes for data that is instantiated may also be mandatory, optional, or conditional based on the CDC (Attribute Type) definition in IEC 61850-7-3 [9] .

To show the comprehensive nature of the data model, an example of one Common Data Class - the directional protection activation information or ACD Class is shown in Table 4.

Table 4 - Common Data Class directional protection activation information (ACD)

ACD Class					
Attribute Name	**Attribute Type**	**FC**	**TrgOp**	**Value / Value Range**	**M/O/C**
DataName	Inherited from Data Class (see IEC 61850-7-2				
DataAttribute					
Status					
General	BOOLEAN	ST	dchg		M
dirGeneral	ENUMERATED	ST	dchg	unknown | forward | backward | both	M
phsA	BOOLEAN	ST	dchg		GC_2 (1)
dirPhsA	ENUMERATED	ST	dchg	unknown | forward | backward	GC_2 (1)
phsB	BOOLEAN	ST	dchg		GC_2 (2)
dirPhsB	ENUMERATED	ST	dchg	unknown | forward | backward	GC_2 (2)
phsC	BOOLEAN	ST	dchg		GC_2 (3)
dirPhsC	ENUMERATED	ST	dchg	unknown | forward | backward	GC_2 (3)
Neut	BOOLEAN	ST	dchg		GC_2 (4)
dirNeut	ENUMERATED	ST	dchg	unknown | forward | backward	GC_2 (4)
Q	Quality	ST	qchg		M
T	Timestamp	ST			M
Configuration, description and extension					
D	VISIBLE STRING255	DC		Text	O
dU	UNICODE STRING255	DC			O
cdcNs	VISIBLE STRING255	EX			AC_DLNDA_M
cdcName	VISIBLE STRING255	EX			AC_DLNDA_M
dataNs	VISIBLE STRING255	EX			AC_DLN_M
Services					
The following services are inherited from IEC 61850-7-2. They are specialized by restricting the service to attributes with a functional constraint as specified below.					

Service Model of IEC 61850-7-2	**Service**	**Service applies to Attributes with FC**	**Remark**
Data Model	SetDataValues GetDataValues GetDataDefinition	DC, CF, SV ALL ALL	
Data set model	GetDataSetValues SetDataSetValues	ALL DC, CF, SV	
Reporting model	Report	ALL	as specified within the data set that is used to define the report content

2.4 Services

For interoperability, not only the data but also the access methods to the data have to be standardized. These access methods are called Services. There are very common services like write and read but also substation specific ones such as the control services for switches (circuit breaker, isolator, and earthing switch) with select-before-operate (SBO). The services are listed in Table 5.

Table 5 –Services defined in IEC 61850

Service	**Purpose (examples)**
Read	read a value / attribute
Write	write e.g. configuration attributes
Operate	control a device (direct operate, select before operate, etc.)
Report	reports about changes send out automatically
Log	local storage of time-stamped events in a log
Get directory	get directory information
File transfer	parameter and software download or upload, file-structured data from monitoring information like travel curves, history of gas density values, disturbances
GOOSE	Transfer of generic object oriented system events (GOOSE)
SV	Transfer of sampled (analogue) values (SV)

Since services may include the transmission of groups of data and spontaneous transmission also, some services (Report, GOOSE, SV) require the definition of data sets and control blocks. This is indicated at the bottom of the CDC as shown in Table 4 under the header "*Services"* with all the details provided in the Standard. Because spontaneous transmissions have to be defined explicitly with data sets and control blocks, no data avalanches will happen if the services are context sensitively designed.

2.5 Dynamic requirements

The free exchange of data to perform certain functions must meet several dynamic requirements. These "dynamic" requirements on transmission of explicit pieces of information, including their attributes such as the required data integrity, have been elaborated by WG 03 of the CIGRÉ Study Committee B5 and the result has been published in a report ([33] , [34]) and used in IEC 61850 part 5 [5] .

2.6 Physical interfaces

Within an IEC 61850 based substation automation system, a Local Area Network or LAN is used as the communication system between Physical Nodes. Hence there is a physical interface between two devices and there is a Logical interface between the Logical Nodes within the devices. It is therefore necessary to "map" the logical interfaces through the physical interfaces in order for the system to operate. Logical interfaces on this network may be mapped to physical interfaces in several different ways.

A common hierarchical station or bay oriented communication network normally covers the logical interfaces 1, 3, 6, and 9 (see Figure 3).

A process oriented communication network may cover the logical interfaces 4 and 5.

The logical interface 8 ("inter-bay-communication") may be mapped to either or to both.

The choice of mapping will have a major impact on the requirements on the overall performance (throughput), the reliability and the functionality. Mapping of all logical interfaces to one single communication network is therefore not excluded but shall be considered only when such a flat structure satisfies all the functional, reliability and performance requirements.

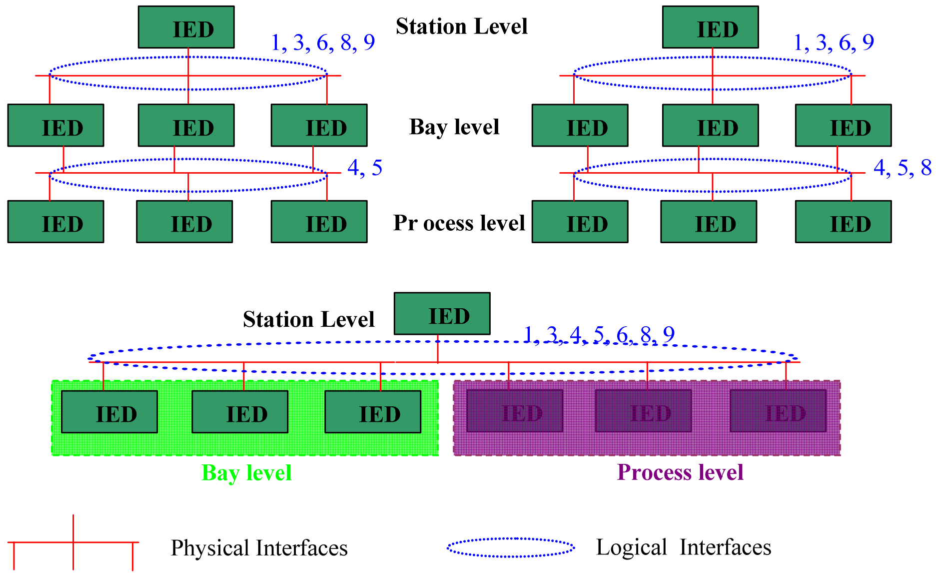


Figure 3 - Mapping of Logical Interfaces to Physical Interfaces

2.7 Communication independent interface

It is often debated that any standard may not represent the state-of-the-art at the date of publication, because of the time needed for standardization. Newer proprietary, vendor specific solutions may have a better performance than standardized protocols and thus may be considered as emerging or "de-facto" standards. Vendors and utilities have increasingly focused on maintaining application functions that are optimized to meet specific requirements and that have reached a high degree of maturity and quality.

Therefore IEC 61850 specifically decouples applications from the communication system, i.e. the design of applications independently from the implementation of the communication so they are able to communicate by use of different communication interfaces, referred to as "stacks" (hierarchical rules for coding data in bit strings and reverse) under the ISO/OSI definitions. However based on the performance and functional requirements, it is expected that only one type of communication system will normally be selected to maintain interoperability also at this level and make implementation easier. This approach gives the future proof aspect for new stacks by a new mapping within the Standard. In Figure 4 the mapping on the communication of the different services as defined by the stack selection in IEC 61850 part 7-2 [8] , part 8-1 [11] and parts 9-1 [12] and 9-2 [13] is given.

The abbreviations in Figure 4 have the following meaning:

- SV: sampled value service
- GOOSE: GOOSE service according to IEC; GSSE: GOOSE service according to UCA2
- SNTP: Simple Network Time Protocol
- MSS: Manufacturing Message Specification
- UDP: User Datagram Protocol (used for time synchronization)
- TCP: Transport Control Protocol
- IP: Internet Protocol
- T-Profile: Transport Profile

- LLC: Logical Link Control

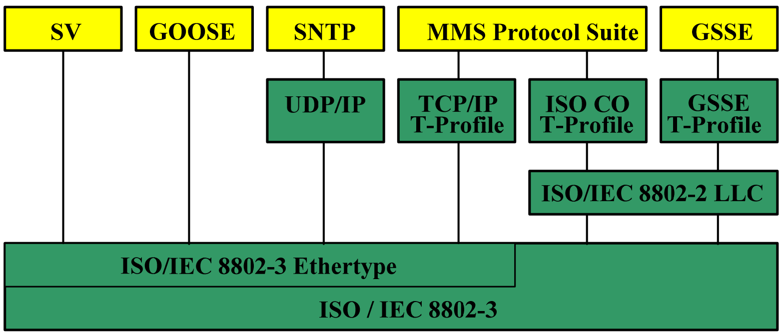


Figure 4 - Mapping of services on the communication (in principle)

The approach of decoupling the applications from the communication profiles in IEC 61850 allows using the state of the art communication stack available without in principle affecting the applications and functions. This has lead to the definition of an interface between application and communication and "application objects" and the related "application services", allowing a compatible exchange of data among components of a substation automation system have been standardized. Figure 5 shows the basic reference model.

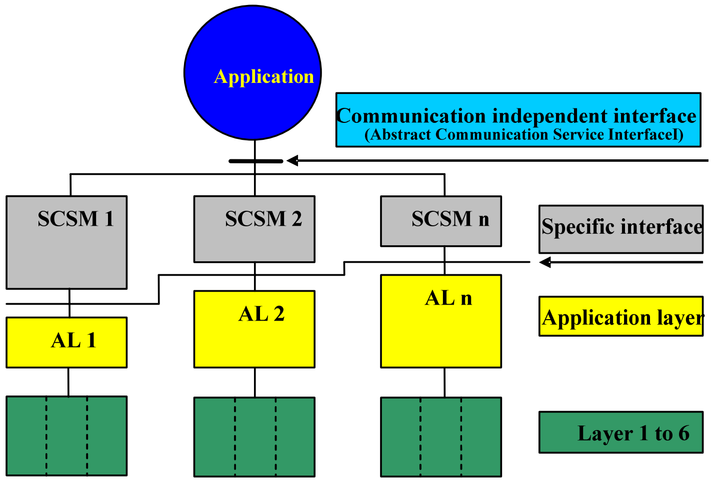


Figure 5 - Basic reference model

At the Abstract Communication Service Interface (ACSI), data is presented to the application layer of the communication stack using abstract communication services. Since the application layer of the stack not always provides all the needed services, a mapping to available services has to be done and the data objects have to be mapped according to the protocol's facilities. Services not provided by the application layer have to be emulated by an appropriate combination of the provided ones, in minimum with simple read and write services. This mapping is shown as the Specific Communication Service Mapping (SCSM). According to the property of the related application layer, the mapping process can be different. This means that if a new specific interface is selected by a new stack, a new specific mapping is required to define the connection between the ACSI and specific interface.

Functions represented by the Logical nodes can only interoperate with each other if they are able to interpret and to process the data received (syntax and semantics), and if the communication services used are harmonized. Thus it is necessary to standardize data objects assigned to logical nodes and their logical addresses as well as the communication services to access the logical nodes and the data. Data and services of an application can be modeled in three levels. The first level describes the communication services used to access the logical nodes, data objects and data attributes, levels 2 and 3 define the logical nodes, the data objects and their attributes.

2.7.1 Level 1: Abstract Communication Service Interface (ACSI)

The ACSI specifies the communication services used for access to these objects independently from the used stack implementation but which have to be mapped by the SCSM to this stack. Communication services provide mechanisms not only for reading and writing of object values, but also for other operations such as controlling primary equipment in a dedicated way e.g. Select Before Operate (SBO) with / without enhanced security.

2.7.2 Level 2: Common data classes

The second level defines all attributes to be applied to data objects. The attributes are specified with type definitions, and values or ranges of values. Finally, changing or fixed attribute values are transmitted. Therefore, the Common Data Classes are closely tied to the services.

2.7.3 Level 3: Compatible addressing of logical nodes and data objects

This level defines compatible objects, which do not need any additional specification, as their identity and meaning (semantics) are defined. They are strongly assigned to a logical node. Data objects of this level are similar to objects defined in e.g. the IEC 60870-5 or DNP 3.0 series. An example for a data object is “current phase L1 with quality and time stamp”. The difference is that IEC 61850 communicates the semantics of the data and not a number representing the semantics of the data as is done in e.g. the IEC 60870-5 series. This describes in clear text the meaning of the data transmitted and therefore "self describes" the data. It also eliminates the need for intermediate lookup tables or specific interpretation. Last but not least it avoids problems that existed when additional numbers had to be added to the predefined number ranges to identify a specific function or data element. This was made possible due to the increase of the bandwidth of the communication channels between the IEDs since this allows that a greater number of characters are transmitted in the maximum allowed transfer or response time [BR1].

2.8 Engineering

The engineering of a substation automation system is a complex process with many specific topics in view of the specific requirements of a physical switchyard and the intended operating philosophy. Questions such as the position of any IED within the system structure, their relation to the switchyard, the functions to be performed, how and with which quality information shall be transmitted to the other IEDs in the system have to be answered in the engineering process.

IEC 61850 part 6 [6] offers standardized formal means to describe the answers so that they can be exchanged in an interoperable way between IED tools and System tools. For this purpose a strict and formal System Configuration description Language (SCL) has been defined. SCL is based on the eXtensible Markup Language XML, which is broadly used in information technology, also in connection with Web technology. During the engineering process appropriate types of engineering tools create and modify configuration files, which must be built according to the SCL rules.

To support the overall engineering process three basic engineering steps have been defined during which specific SCL files are used for different purposes.

2.8.1 Step 1: System specification and general IED configuration

During step 1 the system specification and the configuration of the applied IEDs are defined.

The system specification can be described in SCL using the SSD (System Specification Description) file. This file contains the single line topology, the basic SA functions and their allocation to the bays and devices of the switchyard. Due to the standard format appropriate engineering tools can read this formal specification directly. This functional specification uses the Substation Section defined in IEC 61850-6 and the Data model defined in IEC 61850-7-3/4 and the Services defined in IEC 61850-7-2. The parts can be taken from a project library of the user, or be generated with special engineering tools (System Specification Tool).

Such a System Specification Tool may be supplier specific tool, due to functionality of the applied IEDs and/or functions, which may also be outside the standard, or be a generic one.

The IED configuration of IEDs selected for the SA system implementation is done with a vendor and possibly even IED type specific IED Configuration Tool outside the standard. The result is an ICD (IED Capability Description) file for each IED type, which describes the capabilities in terms of functions, communication services and configurability of the selected IED type. The ICD file may be also provided on a data storage mean like a CD. The principle of this process is shown in Figure 6.

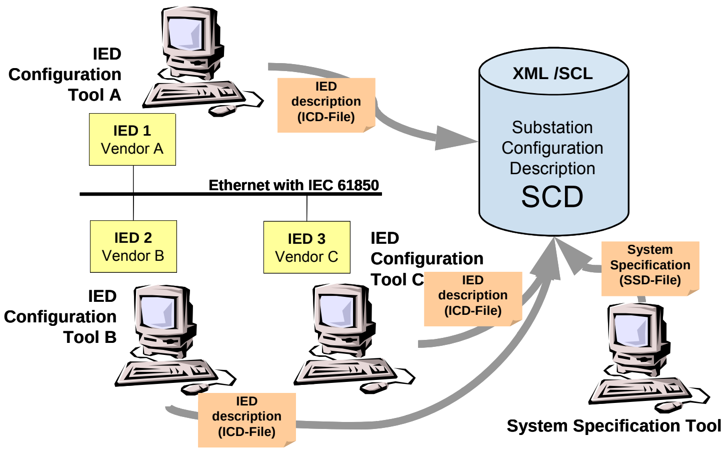


Figure 6 - Basic IED configuration (left) and System specification (right)

2.8.2 Step 2: System Configuration

In the second step the ICD files are imported into a System Configuration Tool or system configurator. By means of this tool the functional specification e.g. From an SSD file is mapped to the functional capabilities of the IEDs. Further the communication relations between the IEDs and their connection in communication subnetworks are configured. The result of this engineering step is a **System Configuration Description** (SCD) file, which can be exported from the system configurator in the standardized SCL format. This process is shown in Figure 7.

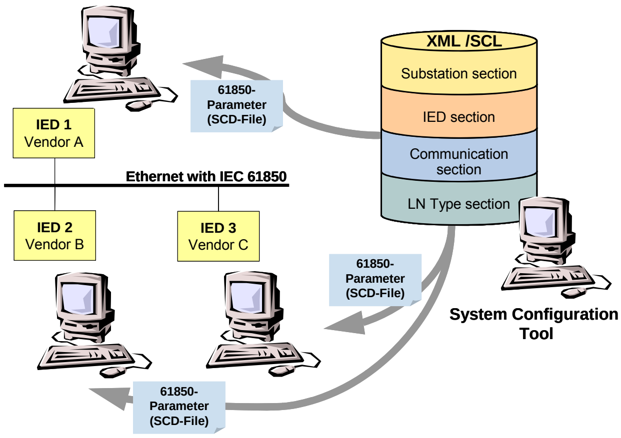


Figure 7 - System configuration and the use of the SCD file

2.8.3 Step 3: Specific IED configuration

Each IED Configuration Tool uses the IED specific and system independent parameters (not defined in IEC 61850) as well as system parameters (defined in IEC 61850) from the SCD file to generate the IED type respective vendor specific IED parameter files and configuration files. These can then be loaded by this tool into the IEDs. This process is shown in Figure 7.

IEC 61850-6 [6] defines for parts of this an optional, SCL based file format, the CID (Configured IED Description) file (see Figure 8). This means however, that alternatively or additionally to the optional CID file a vendor specific file format can be used for downloading configuration data to the IED.

Through IEC 61850 part 6 [6] the engineering process is supported by a standardized system description model for substation automation applications. By the possibility to associate this model to the process (switchyard) and store the result in standardized form as SCL file, it is possible to effectively engineer an IEC 61850 based substation automation system.

In addition, the object oriented approach rationalizes the data engineering within the system as each function related object (Logical Node) incorporates and handles all related signals. Therefore, the introduction of SCL as core description, which can be extended with standardized methods, will in the future lead to additional synergies for individual users as well as for further standardization activities in the context of IEC 61850.

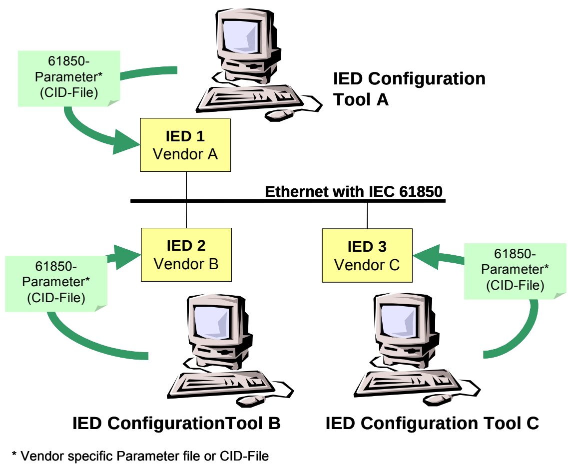


Figure 8 - Specific IED configuration

2.9 Other topics addressed by the standard

If any utility is planning to build a substation automation system, and is intending to combine IEDs from different vendors, it expects not only interoperability of functions and devices, but also a homogeneous system handling. This is the reason why IEC 61850 covers not only the communication, but also the language of the configuration description files [6] to be used by the engineering tools, measures for quality management, and configuration management.

IEC 61850 covers quality assurance for system life cycles, with definition of utilities' and vendors' responsibilities [4] . It also deals with guidelines for environmental conditions and auxiliary services, with recommendations of the relevance of specific requirements from other standards and specifications [3] . Quality requirements are defined in detail, such as reliability, availability, maintainability, security, data integrity and others that apply to the communication system that is used for all functions to be performed within the substation. Other "general" requirements are geographic requirements.

2.10 Additional features for interoperability

Over the years one of the major barriers to be able to use IEDs to their full extent was the proprietary nature of the communication interfaces. Especially the use of multiple IEDs from multiple vendors in a single network was impossible without the use of special gateways and converters and associated specialized engineering. These gateways and converters furthermore tend to limit the functionality and performance of the overall systems.

The concept of Logical Nodes together with a standardization of the data contained within a Logical Node as so called Data Objects allows interoperability between IEDs in order to share information and commands in a single network. Through strongly standardized descriptions, a comprehensive engineering support is defined and, in the long term, plug and play may be possible. With help of the Substation Communication Language (SCL) as defined in the part 6 of IEC 61850 [6] , a formal standardized description of the engineering process is supported including performance requirements, common functions, etc. Therefore, if a standardized approach is defined by utility, IEC 61850 supports minimum effort scenarios. The relationship between the process and the communication interface is shown Figure 9.

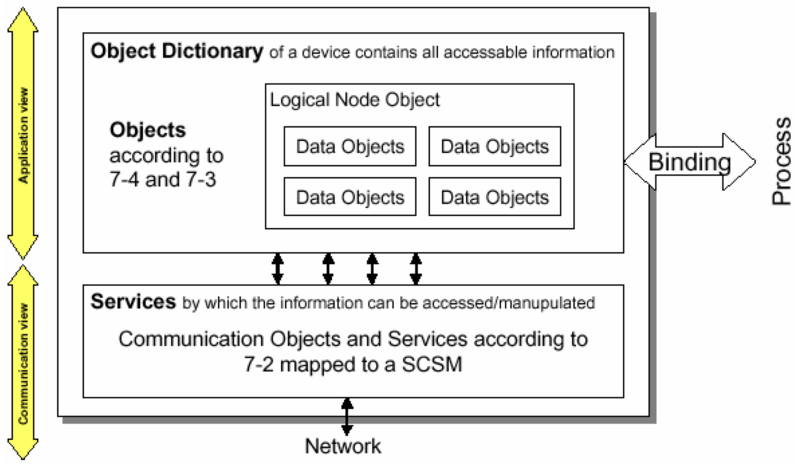


Figure 9 - Relation process and configuration interface

Since the addressing is based on the naming conventions given in the standard the addressing of data elements becomes independent of the telecommunication technology used. With the use of standardized objects the data contained in a device, and available on the network for further use, this is known up front. Since furthermore the naming of the data is independent of the actual device used, applications can be defined using the standardized data without knowledge about the actual device. But for physical engineering and maintenance purposes, of course, the physical structure has to be known. This is, however, also addressed in part 6 [6] and 7 of IEC 61850.

As long as the manufacturers implement the logical nodes, data classes, data object and data elements as specified in the standard we know up front which data will be present from the communication point of view. If we now add the capability of self-description of logical nodes and therefore of devices in which the logical nodes reside and it becomes clear that plug and play is possible in principle but meaning an embedding of all engineering tool features and an internal understanding of SCL by any device. But this is a feature for the more distant future.

There are three items essential for vendors to provide to the users relative to authenticating device compatibility with the interoperability objective of IEC 61850. These are:

- Protocol Implementation Conformance Statement (PICS)
- Protocol Implementation Extra Information for Testing (PIXIT)
- Model Implementation Conformance Statement (MICS)

These elements clearly do not represent any basis for device selection in order to satisfy a particular application in a substation but purely the ability to use these devices in an IEC 61850 environment with full compatibility. Equally the tests necessary to establish these credentials for a device can not be undertaken using every other possible device that could be connected to the IEC 61850 network. Therefore devices that act as servers are tested with simulated client devices. Similarly client based devices are tested with simulated server devices. These tests are able to verify that they perform the required messaging functions in that role.

It is apparent that manufacturers will provide devices that contain extension of functions and/or functions that are not (yet) modeled in IEC 61850. To assure interoperability with these specific extensions the standard contains rules how to model extensions so that the data contained in these specific extensions are understandable for any party either by referring to existing data or to a public available document defining these. This feature keeps interoperability for any extension.

2.11 Security

Given the importance of the communication to and within a substation, vulnerabilities of the communication system have to be eliminated as far as reasonably possible. With regard to the TC57 protocols including IEC 61850, this issue is being addressed by IEC TC 57 WG 15 ([28] , [29] , [30] , [31]).

The security of communication systems comprises four main functional areas:

- Confidentiality: The ability to protect information from disclosure
- Authentication: The ability to unambiguously identify co-operating entities
- Access Control: The ability to provide different privilege access based upon the identity established by Authentication
- Message Integrity: The ability to ensure that a message has not been tampered with

2.11.1 Confidentiality

Confidentiality needs to be provided through appropriate communication path selection or the use of encryption technology. Within the IEC 61850 set of profiles, there is a mixture of approaches. For the MMS based profile, IEC 62351-3 [28] and IEC 62351-4 [29] (all currently drafts) specify the use of Transport Layer Security (TLS).

Within IEC 61850 the services GOOSE and Sampled Values (SV) use the LAN or Virtual LAN (VLAN) high speed profiles. The issue is that the performance requirements (e.g. 4 ms or less) for these services prohibit the use of full encryption. For these profiles confidentiality is to be provided via appropriate communication path selection (e.g. internal to the substation network or a controlled network topology only).

2.11.2 Authentication

The MMS based profile in IEC 61850 directly aligns with the IEC 60870-6 [18] TASE.2 profile and it has been recommended in IEC TC57 WG15 that this profile and TASE.2 implement security in a similar way using the Transport Layer Security or TLS. Important is that the related standard IEC 62351-6 [31] references IEC 62351-3 [28] (security for profiles including TCP) and IEC 62351-4 [29] (security for profiles including MMS) with regard to the IEC 61850 MMS based profile. The authentication mechanism is based upon signed and sealed digital certificates.

Within IEC 61850 the GOOSE and Sampled Values (SV) use the LAN or Virtual LAN (VLAN) high speed profiles and these will provide authentication based upon address-based credentials.

2.11.3 Access Control

The control of access is not standardized. This is considered to be a utility policy issue for the actual implementation. This means that the system integrator has to provide the necessary measures to assure access control within the substation automation system. A collection of measures is found in IEC TR 62210 [25] .

2.11.4 Message Integrity

The issue with message integrity is to detect whether a message has been altered between the source and the destination. Current thoughts within IEC TC57 WG15 are to use a CRC based Message Authentication Code (MAC)/Seal to provide the means to assure message integrity.

For the MMS profile, TLS already provides this capability. For other IEC 61850 communication profiles work is ongoing to follow the same procedures as TLS but to recast the Authentication Code mechanism to fit the capabilities and message structure of these alternate profiles. The associated Message Authentication Code or MAC mechanism is addressed in IEC 62351-6 [31] (Security for IEC 61850 profiles).

2.11.5 Intrusion Detection (a side benefit)

There is also a need to provide an intrusion detection capability for IEC 61850 implementations. The issue here is the lack of definition of standardized security related Management Information Base (MIB) objects. Therefore these security MIB objects have been defined facilitating intrusion detection. Furthermore it is recommended that the recommendations of IEC 62351-7 [32] (Objects for Network Management) be reviewed carefully.

2.12 Maintenance of the IEC 61850 standard

Technologies and views change thus forcing changes to be made in standards. Also problems, mistakes or ambiguities can lead to the necessity to update existing standards. In the case of IEC 61850 there are two mechanisms in place:

- the procedures for the developments of Standards from the IEC
- the procedure for the resolution of Technical Issues by a joint Group of Experts both from the WG10 of IEC TC57 and from the UCA International Users Group

The IEC procedures include arrangements to make amendments and changes of the standard. Amendments have to follow the same procedure as the base standard i.e. from NWIP to IS with all voting in between. Only two amendments per standard part are allowed; then a new version of the standard has to be issued. This process is however relatively slow and therefore not suitable for fast fixes or resolution of issues

The UCA International Users Group and the WG10 of IEC TC 57 have therefore jointly established a process for the relatively fast resolution of Technical Issues (Tissues) with the IEC 61850 standard. This so-called tissue process involves a common Group of Experts (GoE) where most of the contributors to the standard are included.

The tissue process has the following steps: New Tissues are placed into a Tissue Database which automatically informs all experts about the new item. The responsible GoE members prepare a 1st proposal and submit it via the database to the other GoE members. After a short discussion period a final proposal is then distributed to the GoE group for voting. After voting, the status of all proposals that receive 100% approval are set to “green”. The status of final proposals that are not 100% approved are set to “yellow”. All green tissues are then taken by the WG10 of IEC TC 57 for Amendments or a New Edition. Because the members of the GoE are also the members of IEC TC 57 WG 10 and, in most cases, also the editors of the respective parts of the standard, the “green” proposals are very likely to be approved by the National Committees of IEC as well.

These proposals are therefore reasonably reliable and used as if they were already part of the IEC 61850 standard. The proposals, that were not 100% approved, may of course change but still they can be used very well as harmonized quick fixes that are very likely to be accepted and that allows project design to continue. Schematically the whole process is shown in Figure 10.

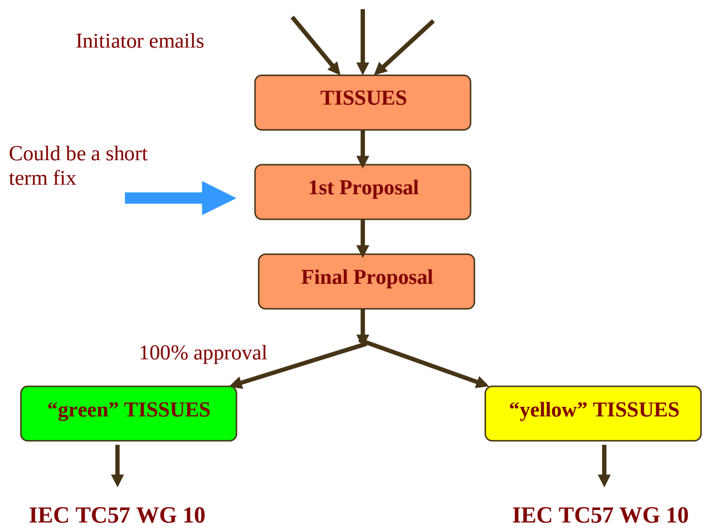


Figure 10 - The tissue resolution process

2.13 Amendments and new editions

2.13.1 Amendments for Power Quality and Statistical Data – IEC 61850

During the preparation of the data model in IEC 61850 it became clear that the Logical Nodes defined were not 100% suitable for application in the Power Quality domain. It therefore has been proposed to extend the current data model to reflect the functionality required for Power Quality incorporating e.g.:

- Under and Overvoltage
- Voltage Sag and Swell
- Voltage Dip
- Flicker
- Frequency
- Short and Long Interruption
- Permanent Interruption
- Transient Overvoltage
- Asymmetry
- Harmonics
- Statistics

Power Quality measurements are based on standardized statistical models. The statistical models include standard definitions on how values are to be calculated in principle. Important is also that the calculations for Power Quality is done at or very close to the data source. The resulting values can be read by any IED. This process eliminates the necessity that every IED requiring statistical data has to perform its own calculations and does it possibly in a different way.

Devices performing Power Quality related functions require large amounts of data in order to reach the required accuracy of the end result. This implies that data or measurements have to be read frequently or they have to be stored in a server and are afterwards transmitted as a file. The latter process is not suitable for real time calculation while the first process requires high speed and preferably synchronous data transfer.

By combining the statistical data with the reporting concepts defined in IEC 61850 part 7-2 [8] , it is possible to decrease the loading on the communication.

For part IEC 61850-7-4 [10] two Amendments have been created as drafts, one focused on Power Quality [22] and one focused on Statistical Data [23] .

2.13.2 Edition 2 of IEC 61850

Because amendments list only the changes, they have to be read in parallel with the related base part of the standard. In addition, the number of tissues for nearly all parts is increasing based on the feedback of the first implementations and the first commercial substations. For both reasons, it was decided by IEC to bring both amendments not to the IS status but to go as fast as possible to an Edition 2 of IEC 61850. This process was started in the second half of 2006.

2.14 Use and Extensions of IEC 61850 in other areas

Already before the publication of the final parts of IEC 61850 this standard has led to discussions in other areas than in Substation Automation for which IEC 61850 was originally designed. Main topic was the feasibility of using the IEC 61850 concepts in other technical domains with similar device interoperability requirements.

It was quickly recognized that the concepts and content of IEC 61850 allows for their re-use in other areas which led to international standardization activities in the following areas:

- Power Quality – Extension to IEC 61850
- Wind Turbine Systems – Domain specific standard IEC 61400-25 [21]
- Hydro Power Plants – Domain specific standard IEC 62344 [24]
- Distributed Energy Resources – Domain specific standard IEC 62350 [27] → IEC 61850-7-420 [21]

It is however expected that it will not stop there. It can be foreseen that areas such as the oil industry, the gas industry, the water industry, as well as industries dealing with for example solar energy and fuel cells and others will also embrace the IEC 61850 concepts. This would provide the potential to define one power system concept using a "Utility Communication Language" (UCL) that is based on the definitions in IEC 61850 (which can be considered as the language grammar rules) and uses domain specific definitions (the dictionaries) for different application domains. As main impact, the different domains may have domain specific data models, i.e. Logical Nodes. The mitigating factor however is the specific operational constraints that may exist for each specific domain. The ACSI is not affected since it provides an abstract interface between the application and the communication stack. The domain specific mapping may be affected by these constraints since it has to provide the link between the actual application and the communication stack used taking into account any constraints that may exist.

2.14.1 Communication between substations and for wide area applications

The New Work Item Proposal (NWIP) "57/759/NP Use of IEC 61850 for the communication between substations" was accepted in 2005 and work started in 2006. The goal is to provide a standardized communication according to IEC 61850 between substations e.g. for automatics and line protection. Besides modeling and communication issues this new work will also define interfaces and state requirements for external communication systems (WAN).

Being outside the basic scope of the NWIP the resulting extensions will allow the use of IEC 61850 also for wide area applications like wide area monitoring, regulation and protection.

2.14.2 Communication between substation and network control centre

The New Work Item Proposal (NWIP) "57/760/NP Use of IEC 61850 for the communication between control centers and substations" was accepted in 2005 and the work started in 2006. The goal is to provide a standardized communication according to IEC 61850 between the substations and the network control centre (NCC) e.g. for Telecontrol replacing IEC 60870-5-101 [15] and IEC 60870-5-104 [17] . In the NCC, the Common Information Model (CIM) is used [53] . It has been shown already that the data model of IEC 61850 is compatible with CIM in principle.

2.14.3 Wind Turbine Systems - IEC 61400-25

The Project Team 25 of IEC TC 88 "Wind Turbine Systems" is responsible for the definition of IEC 61400-25: “Communications for monitoring and control of wind power plants" [21] . This standard defines the domain specific extensions of the IEC 61850 object models to represent the specific functions for wind energy installations.

Since other communication stacks are used for wind turbine systems today additional and specific mappings of the communication services are defined. For example a mapping of the client-server services on web services (XML Based) and mappings for IEC 60870-5-101/104 and DNP3.0 have been defined so far. But is should be noted that these multiple definitions are reducing the interoperability in general requiring protocol converters in case of connecting devices with different mappings.

2.14.4 Hydroelectric Power Plants – IEC 62344

The New Work Item Proposal (NWIP) "57/661/NP: Hydroelectric power plants – Communication for monitoring and control" was accepted. The idea is to extend the IEC 61850 object models for Hydroelectric Power Plants.

IEC TC 57 WG 18 is responsible for the definition of this standard and the resulting IEC 62344 [26] will extend IEC 61850 by object models representing the domain specific functions for hydroelectric power plants. The standard will be released presumable in 2007 and renumbered as part of IEC 61850.

The use of IEC 61850 in wind power plants and in hydro power plants results in the definition of data models for power generating entities and may open the door for the use of IEC 61850 also in other power plants.

2.14.5 Distributed Energy Resources – IEC 61850-7-420

Based on initiatives from EPRI and its affiliate the Electricity Innovation Institute (E2I) a New Work Item Proposal (NWIP) "57/660/NP: Communication Systems for Distributed Energy Resources (DER)" was proposed and accepted.

IEC TC 57 WG 17 is responsible for the definition of the standard IEC 62350 [27] extending the IEC 61850 object models to represent the domain specific functions for distributed energy resources. In 2006 the standard number was changed to IEC 61850-7-420 [21] . This standard will be harmonized with the base standard and the hydroelectric power plant standard IEC 62344 [24] . This standardization work is complicated and time consuming because of the many very different types of DER like diesel generators, fuel cells and combined power and heat producing units (CPH). The second CDV is 2007 in progress

2.15 Conclusions

IEC 61850 covers all requirements for communication in substations. It is more than a common communication standard since it provides also a domain specific data model including all related services, and the substation configuration language (SCL) for engineering systems.

The benefits of adopting an IEC 61850 based SAS are wide ranging in all aspects of substation design and equipment selection. This also extends to training and skills for staff as well as changes to operational procedures, and responsibilities.

The basics goals of the standard are met, i.e. interoperability and free allocations of functions. The standard is future proof by splitting the domain specific model from the selection of a stack interface from the mainstream communication technology.

This means for the user that IEDs compatible with IEC 61850 from different suppliers may be integrated in a common system. Plug-and-play is some issue for the future but by using SCL in powerful tools, the engineering process is substantially simplified. Despite the restriction of free allocation by actual implementations this approach allows to fulfill different design and operation philosophies of the utilities world-wide and to optimize solutions according the state-of-the-art. Also investments done today in substation automation systems based on IEC 61850 are safe-guarded by its approach.

Strong extensions rules guarantee that extensions within the framework of the standard are possible, i.e. interoperability is conserved. This means that also future applications may be included without destroying interoperability. This extendibility is proven already today by the migration of IEC 61850 in domains outside the substation as mentioned above.

All domain specific data models may be used in other domains also if needed. For this, a strong co-ordination of all the data models is necessary. It has to be avoided e.g. that for nearly the same application different LNs are defined. This is one important task of IEC TC57 WG10 which has been renamed from “Functional architecture, communication structure and the general requirements” (referring to substation automation) to “Power system IED communication and associated data models”.

. LNs common to nearly all application domains will be already listed in part 7-4 of Edition 2 of the base standard IEC 61850.

The user benefits for *today* are all features mentioned above, the benefits for *tomorrow* are provided by the fast spread out of the standard in more and more applications within the power system.

3. Practical views justifying IEC 61850

3.1 Introduction

As substation automation systems have developed throughout the world, different regions have adopted one protocol or another as the more dominant preference for various reasons particular to their use or which ever range of equipment and equipment supplier is chosen initially. Hence there a large variety of regionally standardized and proprietary protocols have been created for substation communication. However even within a region, it has not been practical or possible to standardize on equipment from a single supplier which might be thought to achieve interoperability more easily with the restrictions of protocols and hardware platforms. If for no other reason, a significant principle in protection systems is the use of different manufacturers' equipment for the two independent protection systems in order to eliminate common mode failures or mal-operations. Equally no single manufacturer is likely to have equipment to satisfy all the design requirements of the particular utility.

Hence, substantial time and expenditure on engineering and maintenance would be needed both by the suppliers and utilities, to achieve interoperability between products of different manufacturers. Because of the globalization and deregulation of electricity markets, manufacturers, as well as large utilities, are operating more and more internationally, and the wide variety of incompatible protocols is hindering their business activities.

Utilities also face high equipment-replacement costs because communication equipment of the new devices may be incompatible with that of the old devices, despite being from the same supplier; necessitating the use of migration strategies with protocol conversion (see Chapter 4).

3.1.1 Standardization efforts

The IEC working groups, consisting of international experts, responded to all these requirements and created the single, global standard with the extendibility needed to accept new technologies and functions, and this is IEC 61850. The standard is divided into an object-oriented data model for applications in the substation domain and the mapping to a selected mainstream communication stack based on Ethernet (Layer 1 and Layer 2 in the ISO/OSI model). This allows updating of the mapping, in order to follow the state-of-the-art in the communication technology, without changing the data model or the substation automation functions, thus safeguarding the investments of the utilities.

3.1.2 Enhancements

Compared with the previous generations of communication standards, e.g. IEC 60870-5-103 [16] , IEC 61850 supports a true distributed automation system, traditionally achieved by hardwires between the distributed intelligent devices in the system or by using a centralized controller with remote non-intelligent I/Os. These true distributed automation systems minimize maintenance and encourage innovative designs for further reductions in operational costs within or between substations.

IEC 61850 defines a formal description of the substation automation configuration using the Substation Configuration description Language (SCL) based on the universal Extended Mark-up Language (XML). This is one of the key features for interoperability among equipment from different suppliers in a substation [45] .

3.2 Challenges

3.2.1 Too many protocols

The present substation automation market is characterized by real and de-facto standards, manufacturer-specific and hardware-oriented solutions. A large number of protocols for communication exist; giving rise to the problem that equipment from different manufacturers cannot communicate effectively with each other, or only with disproportionate expenditure and still with some limitations.

Furthermore, fuelled by the advancement in communication technology, modern information systems are increasing in number and the volume of data being handled is becoming larger. The innovation cycle-time of hardware and software is also constantly shortening. IEC 61850 replaces a number of incompatible protocols, leading to an improvement of the situation.

Manufacturers have experience with the constantly changing technological environment in which substation automation systems are developed, produced and maintained. If all the equipment of the SAS was able to be sourced from a single manufacturer, the system could be optimally configured to avoid problems on protocols. However, if the system comprises equipment from different manufacturers, the utility and system integrators could encounter incompatible protocols and would need additional equipment and resources to deal with them from specification to maintenance and subsequent augmentation.

Today a substation automation system comprises mostly three hierarchical levels, i.e. the station level, the bay level, the process level, as shown in Figure 11.

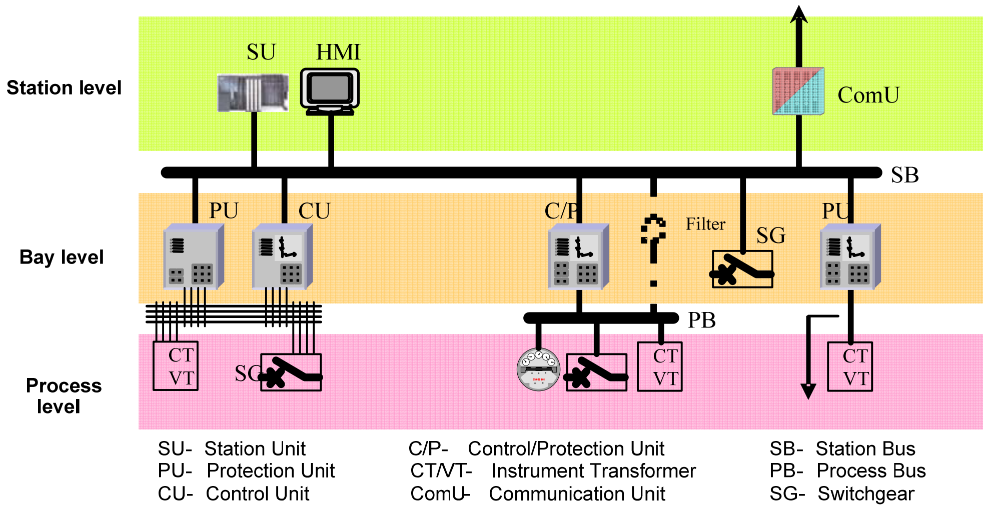
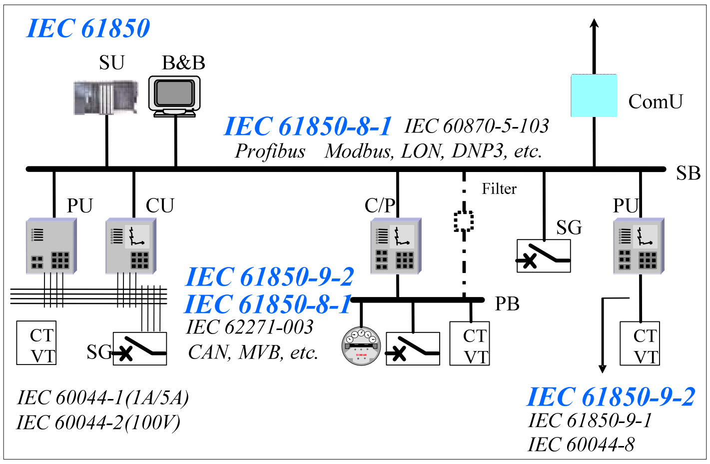


Figure 11 - Three levels of communications in substations in Europe

The communication between station level and bay level (Station Bus, SB) was realized before the advent of IEC 61850 by means of different incompatible protocols such as IEC 60870, Profibus, DNP, LON, Modbus and many of other proprietary and non-proprietary ones. Parallel wiring is mostly used for the communication between the bay level and the process level. If a Process Bus (PB) is used instead of individual wiring, further incompatible proprietary protocols have been used in pilot installations.



SU	Station Unit	C/P	Control/Protection Unit	SB	Station Bus
PU	Protection Unit	CT,VT	Instrument Transform	PB	Process Bus
CU	Control Unit	ComU	Communication Unit	SG	Switchgear

Figure 12 - Protocols in substations

Figure 12 illustrates some of the protocols and the parts of the substation communication for which they are responsible.

In most installations up to now, only the two upper levels, i.e. station and bay level, have been implemented in IEDs. In this case, the components of a substation control system are connected via a station bus and the process is connected to the bay level IEDs via parallel wiring.

Gateways, or other protocol conversions, largely solve the problem of incompatibility between protocols, but they could add extra equipment to the system. They also introduce delays and possibly errors in the communication paths. Even in situations where gateways are not used, the large number of protocols is undesirable from the point of view of both the users and the manufacturers. In a utility, personnel need to be trained to handle and to maintain all these protocols. Over the life of the substation, it is also quite likely that different system integrators will be involved for different augmentations of the system and hence multiple legacy protocols will be an exponential increase in difficulty and cost to add to the system, as well as being a limiting factor in what functionality is achieved.

Utilities also engage themselves more and more internationally nowadays, often acting as owners and consultants to utilities overseas. To them, fewer protocols would be desirable everywhere. For manufacturers, tremendous sales, marketing and development efforts are also required to deal with a wide variety of protocols. Such efforts would eventually take the form of costs passed on to the utilities. Therefore, a reduction in the number of protocols is extremely beneficial for both the manufacturers and the users. Standardization is the key for the advancement of the connectivity and interoperability of systems. Through standardization both the users and the suppliers can achieve economical and reliable solutions.

3.2.2 Equipment Replacement Costs

In a substation, the service-life of primary equipment e.g. circuit breaker is about 40 years or more while the service-life of secondary equipment e.g. substation automation system is typically 15 to 20 years, generally limited as result of technological changes. General purpose computers as used for operator's work place have even less life-time e.g. just a few years. Communication is playing an increasingly important role in any SAS, and has it been experiencing technological changes in the last few decades. Devices of different generations are often incompatible because the protocols are not the same. As a result, the replacement costs at the end of service life become high. These are asset management issues which utilities now face.

3.2.3 Short Summary

As explained above, interoperability lies in two dimensions:

- Interoperability among different manufacturers
- Interoperability among different generations

The challenges are detailed in the document of working group WG B5.07 [35] .

3.3 Goals

3.3.1 Reduction in Costs

Power transmission and distribution are becoming an open market. Network operators need to run the power systems reliably and efficiently at minimum cost. There is a world-wide incentive to achieve these operation objectives by taking advantage of the capability of substation automation systems. It becomes important that there is only one standard protocol moving to the future so as to allow the elimination of the diversity of protocols that exist today. The standard must be for an open communication system which permits equipment from different manufacturers to operate together. The reduction of the life cycle costs is detailed in the document of working group WG B5.18 [37] and, focused on IEC 61850, in a conference paper [51] .

3.3.2 Safeguarding Investments

Digital electronics have made a great impact as it has helped realize substation automation and has made communications largely an explicit part of the automation system. In parallel, communication technology itself has recently been evolving particularly fast because of the rising capability of processors and the advancement in fiber optics. Applications and communication equipment have different technology lifetimes. Applications within substations are generally stable over a long time, but in view of the trend in the last twenty years, the communication technology may change reasonable during the lifetime of the substation automation system.

When the communication technology is changing, only the communication part of the automation system should be changed. Compatibility between the old and the new technology is definitely desirable because it would make the transition from the old to new much smoother and less costly. The present communication technology, such as IP-based networks and Ethernet, is considered to provide the best compatibility to future evolutions in communication technology [45] .

3.3.3 Simplifying Engineering

The lifespan of a substation is longer than that of the substation automation system. The standard must provide means to support updating, extending, testing and maintaining the substation automation system and its communication system, over the lifetime of the substation at least.

3.3.4 Flexibility

The standard must be flexible and can survive:

- Changes in user's preferences and requirements like extensions
- Changes due to the manufacturers' innovations e.g. there will be functions tomorrow which are not thought of today

3.4 IEC 61850 in practice

IEC 61850 offers solutions to the aforementioned requirements and achieves the set goals. It provides interoperability of equipment from different manufacturers, and leads to minimum-change solutions for interoperability of equipment from different generations. It covers all the automation functions in substations. A communication can exist within the Station Level or the Bay Level, and can also exist between two levels, for example between the Bay Level and the Process Level.

3.4.1 Benefits for the users

3.4.1.1 Reduction in Costs

IEC 61850 specifies the use of an open and common protocol stack containing for example TCP/IP facilitating the access to public and private data networks. It opens the possibilities of remote interrogation of substation equipment, alleviating maintenance and reducing the number of site visits.

The use of a common standard also opens up the substation automation market to more competition – potentially giving the user a larger selection of IEDs, suppliers and system integrators.

3.4.1.2 Safeguarding Investments

The investment of the utility is safeguarded because the development of the communication network is independent of the development of the applications. The utility may also benefit from the latest communication technologies to enhance the performance of the substation automation system or to have the possibility of a common communication infrastructure for the utility.

Ethernet is highly backward and forward compatible. For example, a 10Mbit/s network can easily be integrated into a 100Mbit/s network, and a 100Mbit/s network can be integrated into a 1Gbit/s network in the same manner. Thus, the investment of the utility is safeguarded at least on this level. But note that an increase in communication speed may need an increase of all input buffers in the system not to loose messages by unchanged processing speeds in the IEDs.

The use of IEC 61850 implies that a substation automation system based on this standard may be refurbished for enhanced functionality and/or performance without a full-scale replacement of all components / subsystems. The user is free to upgrade subsystems or components in line with evolving technology and organizational / operational requirements.

3.4.1.3 Higher Performance

The major advantage of IEC 61850 is the interoperability of IEDs' of different manufacturers and the elimination of gateways. The absence of gateways means less equipment, no unnecessary delays and no additional errors caused by protocol conversions. The use of Ethernet communications for all the substation automation functions means standardized and simpler cabling in comparison with the use of parallel communications. This is an advantage in project execution, equipment installation and equipment testing.

The capability of Ethernet components is expected to increase every year, and it will be possible in a few years' time for the utility to have one single communication infrastructure, making the flow of data more streamline in the organization. Nevertheless, an intelligent structure and the positioning of appropriate firewalls are needed.

3.4.1.4 Simplifying Engineering

IEC 61850 defines also the Substation Configuration description Language (SCL) which allows the configuration of an automation system to be defined and the settings of IEDs from different manufacturers to be fixed by the user or any of the manufacturers involved, at least in the data model context of IEC 61850

It will reduce project time, simplifies system integration with all related engineering and will reduce maintenance and also training efforts.

3.4.1.5 Flexibility

IEC 61850 does not make the use of the station bus or the process bus mandatory.

The number of buses is flexible. It is unnecessary to adopt the rigid three-level structure namely, station level, bay level and process level. The utility may specify the system configuration in a flexible way. Nevertheless, following the structure of the primary equipment looks also promising for the future.

3.4.1.6 Summary

So the utility will find that operation is more streamlined, investment better safeguarded against technological changes and staff can run the automation system more efficiently as they have fewer variations.

3.5 General advantages of IEC 61850 compared with other standards

IEC 61850 is the only standard which covers the communications at all the three levels of equipment in a substation, namely at Station Level, Bay Level and Process Level. Other standards cover the communications at only one or two of these three levels because most standards were developed for specific purposes.

IEC 61850 specifies high speed event driven communication rather than polling as used in master-slave communication. The applied client-server architecture allows also to have instead of a single master many clients e.g. for redundancy purposes.

The advantages are:

- Ethernet allows a device to send a message whenever it needs (event driven communication), and there is no master device governing which device can talk at any given time. A master-slave communication system can create a bottleneck because when the master fails other devices cannot communicate, which is resolved by the now used client-server architecture
- Multicasting (i.e. one device sending a message simultaneously to several devices inside one logical LAN-segment) is simple in Ethernet and improves the performance of time-critical messages. This reduces network message traffic and communication time by eliminating the need to repeat messages to individual devices sequentially

TCP/IP is the transmission control protocol of the Internet. IEC 61850 facilitates data transfer through public or private data networks by using TCP/IP also. Data of other protocols based on Ethernet and TCP/IP, such as web-services data for remote maintenance, can be transmitted in parallel via the same communication infrastructure.

IEC 61850 is future-oriented, but other standards are not. Any changes in communication technology in the future will cause minimum changes only in the substation automation systems compliant with IEC 61850.

In IEC 61850, the data model is clearly defined. Thus, they are easy to extend but strict extension rules take care for maintaining interoperability.

Last not least the maintenance process defined for IEC 61850 as described in 2.12 provides a unique quality assurance process.

3.6 Conclusions

Most of the topics described above have a direct impact on cost:

Interoperability optimizes the choice of the IEDs based on functionality and cost. The replacement of outdated IEDs from the same or different suppliers is facilitated.

One protocol which covers all communication requirements in the substation facilitates the data exchange and the maintenance of the communication system and communication know-how.

The number of gateways needed is minimized i.e. only the one connecting to the network control centre is left until IEC 61850 is used also for this communication link.

The investments of today in SAS are safeguarded for the future through the long-term stability of the application data and the selection of the stack from the main stream communication technology.

4. Migration strategies

4.1 Defining Migration to IEC 61850

4.1.1 Migration, semantically

Dictionaries define ‘migration’ as “the movement from one place to another of a large group of people, birds, animals etc: the great migration to North America of the 19th century”.

Migration to IEC 61850 constitutes not only a change from the current techniques used to convey information pertaining to the protection, supervision and control of a substation but also to the essential design of the substation and the way substations are operated., Hence in a similar fashion as the “great migration of the 19th century” affecting the cultural environment at the time, the utilities will face a large effort in establishing IEC 61850 as the natural *modus operandi* for Utilities such that it becomes a normal, but more importantly integrated part of the operation of substation as important as the techniques of the past.

4.1.2 The reason for migration

The main reason of the migration to IEC 61850 can be condensed into one word: **interoperability**.

Interoperability is defined (in IEC 61850-2 [2] Section 2.64) as:

> “the ability for IEDs from one or several manufacturer to exchange information and use the information for their own functions”.

The need for interoperability between products from the same or different vendors has been the foremost driving factor in the development of the IEC 61850 standard.

The interoperability itself is a significant element of the standard covering the ability to share information between devices with total confidence. With this confidence, the various functions within the substation can be optimized and enhanced through process such as integration of protection and local control or IED to IED communication for busbar protection rather than using a complete stand alone bus bar protection system.

IEC 61850 will not give an individual IED higher or better functionality just because of their ability to interoperate - any improvements in the capabilities of the IED will come from the normal evolution of the IED. The functions are not standardized and hence manufacturers will still be driven in a competitive manner to develop IEDs that have the ability to provide functions to satisfy the client’s needs. However, some system features might possibly see some improvement if the combination of interoperable superior IEDs from different vendors that could give features not readily achievable within a single IED from any one vendor. The most important system features are the comprehensive Data Model including all Services needed and the Substation Configuration description Language (SCL) describing the interconnectivity of all system components and functions.

The migration of the communication functions in a substation to IEC 61850 is a possible secondary effect of the need for replacement of smaller or larger parts of an existing substation or through the need for an extension of it. IEC 61850 is not in itself a factor that motivates the migration, i.e. it is unlikely that a decision would be taken to convert an existing substation to IEC 61850 based communication infrastructure and then subsequently try to design what connects to it. It will be driven by what functions are needed in the substation and what technologies are needed to implement those functions. A completely new substation on the other hand will provide the opportunity to define the basic operation of the substation as IEC 61850 in order to ensure the ongoing ease of operation, maintenance, refurbishment and augmentation of the substation.

Migration means always that existing non-IEC 61850 parts of the SAS have to continue to be operated **in parallel** with new parts compliant with IEC 61850 at least for a transition period. This may mean the continued use of gateways, protocol converters or interfaces in order to maintain the essential operation of the substation. As the extent of use of IEC 61850 increases throughout the substation an increasing justification to convert the remainder of the substation in order to eliminate this patchwork type engineering which by definition will be unique to each substation and each stage of migration.

4.2 Migration to IEC 61850

Due to the long lifetime of primary and secondary equipment in a substation the current status of substation protection and control varies considerably. The status varies from electromechanical protection relays and manual control to (almost) fully automated stations with digital protection and control system.

In the latter case, the IEDs communicate with each other using more or less proprietary communication protocols, protocols that not are interoperable with the IED protocols of other vendors, or do this only with support of protocol converters.

The migration is most likely to occur initially as the gradual exchange and replacement of the secondary equipment in a substation i.e. of the Substation Automation System. In some cases the primary equipment will also need to be gradually replaced whilst minimizing the interruption of power supply, this replacement will set the pace for the steps of the migration (see e.g. in [52]). If the complete substation automation system is exchanged in one step the situation is the same as for a completely new system. The design and construction of a completely new substation automation system based on IEC 61850 is not discussed in this chapter. It is not considered a migration except for staff training and documentation as already mentioned above.

The migration to IEC 61850 will likely follow the rate of modernization and extension of substations. The longevity of the primary equipment, often much more than 25 years, and the lifetime of 15 years or more of the secondary equipment indicate that the migration phase may take a decade or more.

There are two main migration strategies:

- The IEC 61850 compliant equipment interfaces to the existing, non-compliant equipment. The non-compliant equipment then needs to be upgraded
- The IEC 61850 compliant equipment is operated in island-mode separated from the existing, non-compliant equipment. This can be a viable interim case until the existing, non-compliant equipment is replaced or upgraded but may introduce operational limitations

The prerequisite for migration under the first strategy is that the current SAS can be modified to interface to the new IEC 61850 compatible SAS equipment. This implies either that the considered IEC 61850 equipment has or can be equipped with interface(s) to the current SAS <u>or</u> that the current SAS can be extended with interface(s) that are IEC 61850 compliant. It should be noted that an upgrade of devices not designed for IEC 61850 may result in restrictions regarding the data available for communication or regarding the performance.

For the second strategy of course operational constraints need to be considered as well as the succeeding equipment replacement or upgrading.

The engineering and configuration tools are just as much an important consideration for the choice of strategies as the devices themselves: The tools currently used may not be able to properly coordinate with the tools of the IEC 61850 equipment and vice versa.

4.3 Reasons worthwhile for migration

A migration from the current substation status to a more or less IEC 61850 compatible substation is only worthwhile if the substation needs rework for reason(s) including:

- Replacement of station level devices
- Total or partial replacement bay level devices
- Total or partial replacement process level devices and introducing the process bus
- Extension with one or more bays
- Improved information flow from the IEDs to higher level clients
- Documentation system upgrade

Upgrading of the communication system to achieve interoperability and communication between IEDs in a well running substation is by itself not a reason for migration.

4.4 Substation terminology

IEC 61850 uses the terminology 'station level', 'bay level', and 'process level' for the equipment on the different functional levels of a substation. The 'station bus' ties devices on the 'station level' and 'bay level' together. The 'process bus' ties devices on the 'bay level' and 'process level' together.

However these buses are not mandated as being in any case separate networks, and in fact they could conceivably be just one single substation wide LAN or may be several different LANs with connection between the LANs. Equally these LANs could operate as a homogenous entity or be segregated within the one LAN as totally independent virtual LANs operating over the same communication system. Hence whilst these levels are referred to extensively in IEC 61850 substations, they may not be implemented in the same physical way as they are described pictorially.

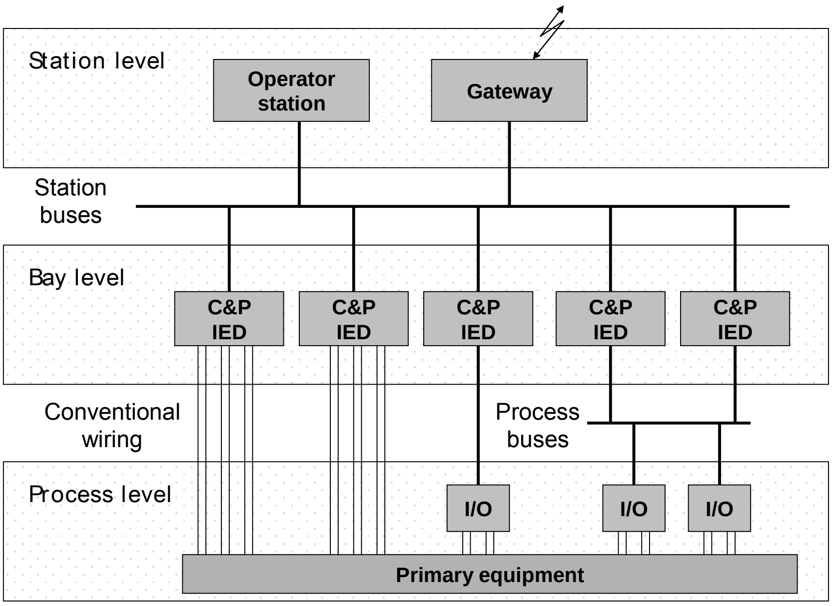


Figure 13 - Substation terminology

These levels and buses are present, more or less explicit, also in non-IEC 61850 substations.

4.5 IEC 61850 station and process buses

The station and process buses comprise of electrical or optical connections with communication network switches as the active communication elements. Switches and hubs are devices that are connected by the communication LAN to which the IEDs can be connected. Their role is to direct the LAN traffic to and from the respective devices. Hence in the same way a personal computer or printer is connected by a single cable, the other end of the cable connects to the switch in the LAN. The existence of these devices is largely unknown and irrelevant to the user establishing a connection to the network, but it is another example of how the physical system is implemented differently to the operational description provided pictorially such as in Figure 13.

The buses have to be considered as substation entities with defined characteristics. The topology of a bus may vary from a single point-to-point connection between two IEDs to a complex network with multiple switches in a redundant or backed up configuration. It has to be considered that not only the IEDs for protection and control but also the switches have to be substation proof i.e. to withstand the environmental conditions like temperature (e.g. -40° C to +85° C) and substation level electromagnetic interference, and to have power supplies for direct connection to the station battery i.e. to 110 V DC or 200 V DC. In this respect the communication system devices must comply with the requirements of IEC 60255 in as much as the IEDs themselves.

The buses therefore have properties such as reliability and performance that are reflected on the interface and switch characteristics. These properties will be included and considered in the substation specification/design/integration, e.g. in reliability and performance calculations, as any other substation entity. The station and process buses need to be supervised and any performance degradation or failure has to be included in the event and alarm handling of the substation.

The migration from the current station bus (or corresponding) certainly needs to consider these aspects. The IEC 61850 station and process buses are based on commercially available network switches and routers but have to be substation environment proof as mentioned above. These are prepared for supervision and control using SNMP (Simple Network Management Protocol). A suitable network manager and network management applications that supervise and control the IEC 61850 network should be included. Events and alarms originating in the IEC 61850 station and process buses should be treated in the same way as events and alarms from the rest of the substation or substation automation system.

The switches have to be managed switches. It means that they have to support the definition of virtual private LANs (VLAN), priority tagging and time synchronization, i.e. today SNTP (Simple Network Time Protocol) for 1 ms time tagging and in future the coming standardized synchronization down to µs level for samples and phasors, especially for the process bus if applicable. In addition they have to allow network management with SNMP (Simple Network Management Protocol) also.

4.6 Migration scenarios

4.6.1 Migration at station level

The station level devices like HMI and central controllers have, as general purpose computer hardware, typically the shortest lifespan in a substation and are, therefore, are the first candidates for an update. Upgrading of these substation parts could be the starting point for the migration of the substation automation system to IEC 61850.

The new station level devices need, of course, to be compatible function-wise with those they replace to retain the current station functionality.

Also in the case where the rest of the substation is left as it is, the new station level devices should be IEC 61850 compatible. They should have, as a minimum, the required software and hardware available for an upgrade option so that, when further upgrading or extension of the substation is considered, modern IEC 61850 compatible IEDs can be used.

The software technology used must be integrate well with the current station level applications and may be realized as a (integrated) gateway or an OPC server for the IEC 61850 station bus. The hardware should cause no problem, since the station bus is generally based on standard Ethernet with TCP/IP and both electrical and optical interfaces for the station bus are available.

The engineering and configuration tools for the new station level devices need to fulfill all relevant requirements of the IEC 61850-6 [6] to ensure that, when the IEC 61850 station bus is taken into use, the station level devices can be properly configured for the IEC 61850 compliant IEDs connected to the station bus.

4.6.2 Migration on bay level

Migration to IEC 61850 on bay level has impact on the station bus as well as the process bus where used.

4.6.2.1 Replacement of single IED

If an IED needs to be replaced no matter what the reason, it must be considered if a replacement by an equivalent spare part or a replacement with a different IEC 61850 compliant IED is the better choice. A spare part replacement is the simplest way but if a new IED needs to be purchased and the vendor has an upgraded version having both a legacy interface and an IEC 61850 compliant one, then this approach should be considered as a possible starting point for the migration of the station to IEC 61850. The new IED is then connected with its legacy interface to the existing bus and station level and the IEC 61850 compliant interface is left open until the station level of the substation is upgraded providing an IEC 61850 compliant bus.

4.6.2.2 Retrofit of bay

If the secondary equipment of a bay is retrofitted, i.e. if more or less all IEDs of the bay are replaced, there is a strong justification to consider IEC 61850 compliant IEDs even if all features provided by IEC 61850 are not used. IEC 61850 compliant IEDs having hardwired interfaces to the primary equipment and legacy interfaces to the station level equipment will still be available for many years.

The IEC 61850-8-1 [11] station bus interface of the retrofitted bay may be connected to the existing station bus either via a gateway to the existing non-compliant communication system or in parallel via IEC 61850 directly to the upgraded station level. It has also to be recognized that some performance problems may arise if non-compliant and compliant IEDs have to communicate which each other as e.g. for interlocking.

4.6.2.3 Extension with new bay

Extension of a new bay(s) is similar to the retrofit case above but in this case one should also consider the full use of the process bus within the new bay, i.e. serial communication according to IEC 61850 with the primary equipment using IEC 61850-9-2 [13] interfaces.

4.6.2.4 Migration on process level

The migration on the process level is closely connected to that at the bay level.

In the case of extending the substation with a new bay, it will be common that the new primary equipment is equipped with intelligent CTs and VTs that use process bus interfaces according to IEC 61850-9-2 [13] . The new secondary equipment has to provide for such a process bus interface, noting that the process bus may or may not be implemented over the same or different LANs to the station bus.

Retrofitting the primary equipment of an existing bay implies the retrofit of the secondary equipment of that bay also if the new primary equipment has an IEC 61850-9-2 interface. Partial retrofitting, e.g. replacement of conventional sensors with intelligent CTs and VTs, requires data conversion between the process and bay level.

If a process bus is used between the bay units and the primary equipment, there will be in most cases a merging unit (MU) in between. The MU is a device which combines the information from each phase of the sensors into a time correlated set of digital data pertaining to the measurements of the power system. Depending on implementation, the MU may have optionally both hardwired inputs for conventional CTs (1or 5A secondary) and VTs (110V secondary) and dedicated inputs for non-conventional instrument transformers (NCIT: Rogowksi coils, optical sensors etc) which are converted to data on the process bus compliant with IEC 61850. This provides a high degree of flexibility for a wide range and combination of migration scenarios.

4.7 Migration impact on the interfaces between substation parts

The migration from the current substation arrangement to the use of IEC 61850 to enable communication between the various IEDs requires data conversion between the new and old parts of the substation automation system.

Until IEC 61850 is the only communication protocol used between the IEDs, data or protocol conversion is necessary using separate devices or by modernization/upgrading of the IEDs. It is reasonable to assume that IEC 61850 provides all features of the legacy protocols as all major station bus protocols, e.g. MVB, LON, SPA, DNP, and Profibus had been considered in its definition. In this sense, IEC 61850 is a superset of all relevant substation protocols. Therefore, in principle, protocol conversion from all current protocols to IEC 61850 is possible although some services may not have an exact one-to-one mapping.

Protocol converters and gateways to convert from standardized or de-facto standard protocols, such as IEC 60870-5-103 or DNP, are likely to be available from third party vendors. Gateways from proprietary protocols like SPA, LON or Profibus should be readily available from the original vendor as no doubt they will have need for such interfaces in order to provide ongoing support to their existing installations.

Systems and schemes based on conventional wiring, as for example interlocking, can be converted to IEC 61850. The related information is distributed to all relevant IEDs using the GOOSE (Generic Object Oriented Substation Event) service of IEC 61850. The GOOSE messages are transmitted over the station bus and process bus if applicable, and received simultaneously by all so configured IEDs. Similarly instantaneously sampled primary equipment status indications and power system analogue values, or values calculated from them, are transmitted from the transducer to all the IEDs requiring this data. This capability allows distributed station wide protection and control and including trip signals and interlocking over the network. Each design must always consider that with the defined Ethernet speed of 100 Mbit/s, not all samples from the complete substation may be transmitted over the same bus segment whilst retaining acceptable traffic levels and delays over the network. Hence separate process station and process bus may be required, even creating separate sub-bus networks if there are a large number of signals in that section. In one physical LAN, the separation of bus traffic may be also done by the use of some or many VLAN.

4.8 Engineering, configuration and documentation

IEC 61850 provides in Part 6 [6] the standardized Substation Configuration description Language (SCL). It allows the integrator to define the relations between the switchyard topology (single line diagram) and the functions needed, the data exchanged between the functions and the allocation of the data model and services to the IEDs, and the structure of the communication system.

The SCL is used to exchange engineering and configuration data by standardized files between the IED tool(s) and the system configuration tool even if they are from different vendors. IEC 61850 compatible devices have their related features and capabilities as stand-alone devices – may first after pre-configuration - formally documented in the mandatory ICD file and this formal description is by the system engineering tool for engineering of the complete substation automation system resulting in the SCD file..

Migration to IEC 61850 implies also that the current system description, at least for the migrated parts, shall be converted to SCL. Most convenient is to represent the part not compliant with IEC 61850 in a proxy server according to the IEC 61850 data structure.

4.9 Examples of migration

Figure 14 sketches possible bay topologies as starting point for the migration scenario.

Bays A and B are modern systems connected to a proprietary station bus. The protection and control IEDs are connected to the remote I/O via a proprietary process bus. Bay C is connected via a marshalling rack and via the neighboring IED to the station controller. Bay B and C have hardwired interlocking. Bay D is connected to the station controller via a link according to IEC 60870-5-103 [16] .

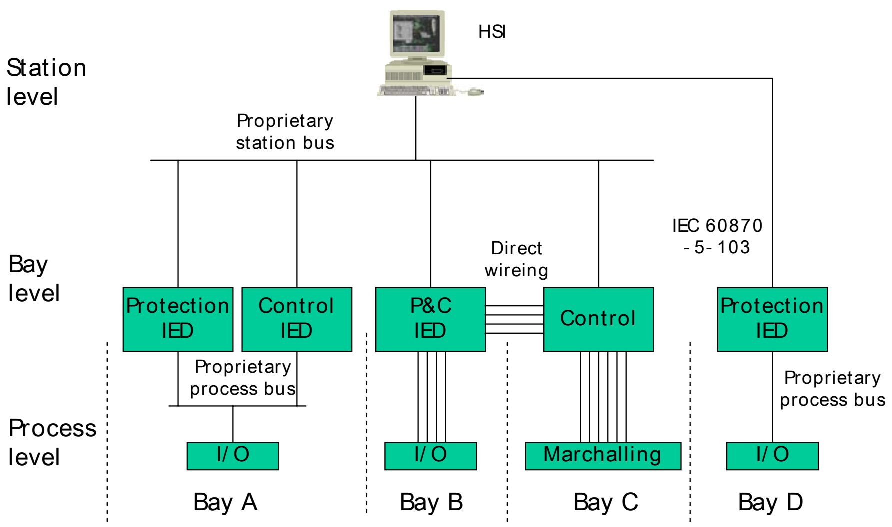
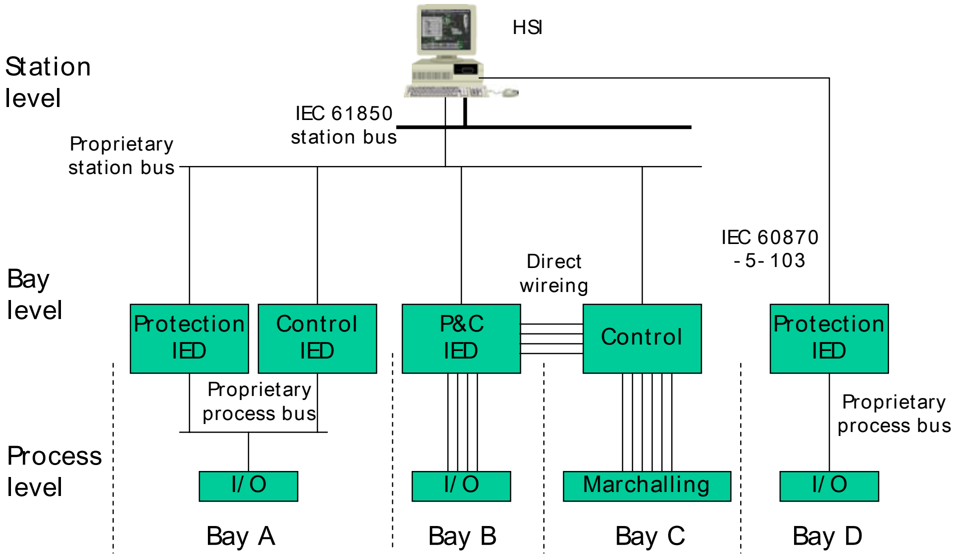


Figure 14 - Possible starting points for migration

4.9.1 Station level migration

All devices on station level are replaced. The rest of the substation is left untouched. This



scenario is shown in

Figure 15.

The only externally visible difference is that the new device(s) on the substation level have an unused IEC 61850 station bus interface.

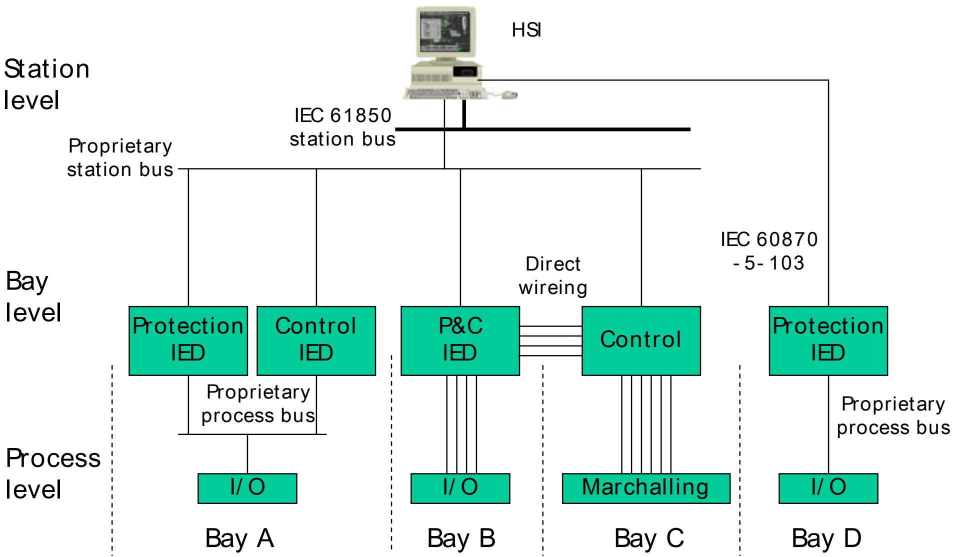


Figure 15 - Refurbishing station level

Internally the new equipment should be fully ready to interface IEC 61850 compliant IEDs. To facilitate this also, the new system engineering and configuration tool(s) should be IEC 61850 compliant. The tools should be integrated in the tools for the old system or exist in a well-ordered parallel form. This tool set shall be capable to engineer the legacy IEDs, the future IEC 61850 compliant IEDs, and the system itself resulting in a well functioning system.

4.9.2 Extension of bays

In this scenario, the substation is extended with a new bay E for a new line. The IED for bay D is replaced with the same type of IED as in bay E. An interlocking scheme is required for bays D and E. The rest of the substation shall be modernized later. This scenario is sketched in Figure 16.

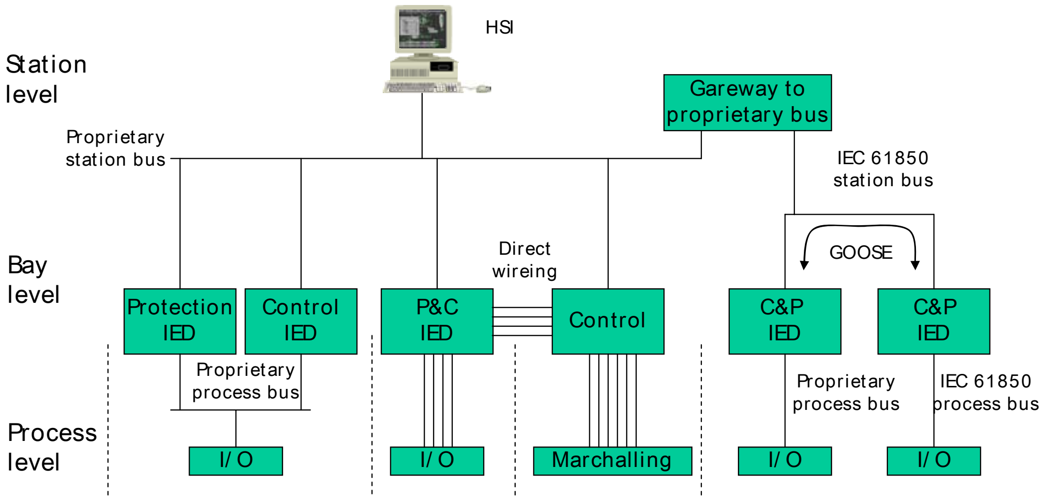


Figure 16 - Extension with new bay (bays from left to right: A, B, C, D, and E)

The new bay E and the old bay D are protected and controlled by IEDs combining these functions including the interlocking. The IEDs in bay E connected via the IEC 61850-9-2 [13] process bus to the new primary equipment having an integrated IEC 61850-9-2 interface. The IEDs in bay A are connected by the proprietary bus to the existing primary equipment having and integrated proprietary interface.

4.9.3 Migration from the process bus perspective

The process bus is an entity for which the same considerations are needed as for the station bus regarding reliability etc. The structure of the process bus commonly depends on a number of factors: substation size, operational constraints, utility strategies and other constraints.

A few alternative logical structures are depicted in Figure 17 (Figure and text from draft IEC 61850-9-2 [13]). These are based, however, on a station completely built with an IEC 61850 process bus and may be seen as indicator for the ultimate target of migration.

The process bus migration alternatives will in reality be associated with the station bus migration alternatives, depending on the boundary conditions of each utility, resulting in an optimized substation topology for the user.

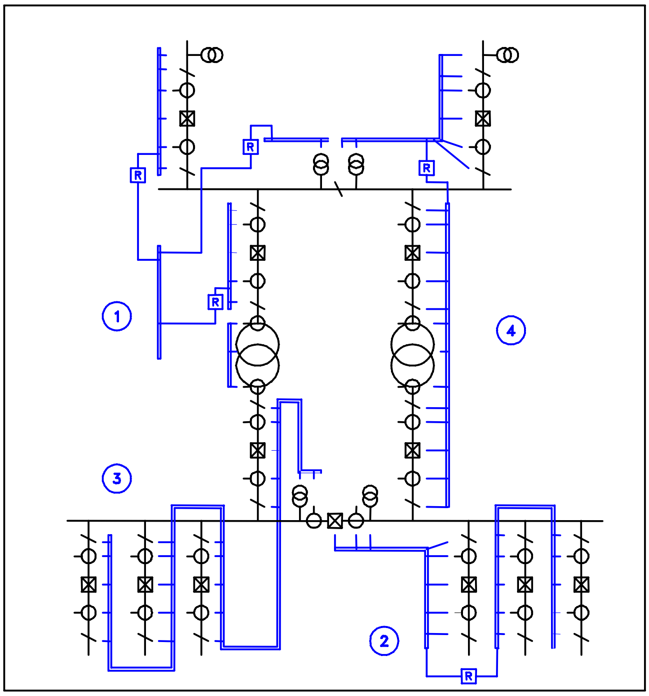


Figure 17 - Alternative bus strategies

<u>Alternative 1</u> indicates a communication bus structure where each bay (installation unit) has its own process bus segment. To allow for protection and control equipment that requires data from more than one segment, a separate station-wide communication bus is installed, with switches or routers (R) to each bay segment to transmit the required data streams.

<u>Alternative 2</u> indicates a similar structure but each bay segment covers more than one bay. Data streams required by more than one segment are transferred by switches or routers (R). The example shows data from the busbar voltage transformer being used by directional earth-fault relays on all bays.

<u>Alternative 3</u> indicates a single station-wide communications bus, to which all devices are connected. This requires a very high data rate on the bus not possible with the actual 100 Mbit/s, but eliminates the need for routers.

<u>Alternative 4</u> indicates a function oriented bus structure. In this case the bus segments are set up to correspond to protection zones. Although routers are required, the segments can be arranged to minimize the data to be transferred between segments.

The process bus has to be considered as a substation entity with defined interfaces. The process bus may therefore have properties such as reliability and performance that are reflected on the interface characteristics. The properties will be included in the substation design/integration, e.g. in reliability and performance calculations, as any other entity. The process bus entity may, and will comprise several parts that vary by vendor and implementation.

As a consequence of this model, the process bus implementation may be a single 'entity' or divided into several 'entities' that may be interconnected or chained. The characteristics of the process bus 'entity' will depend on the realization (one or many process busses, etc.). But by no means is the process bus allowed to jeopardize the independence between main 1 and main 2 protections where this is applied.

4.10 Migration from the configuration and engineering tools perspective

IEC 61850 is a new communication protocol by its combination of the domain specific data model including services and the selection of a seven layer stack. The communication stack, as selected in IEC 61850-8-1 [11] , consists of layers being de-facto (TCP/IP) or real standards (Ethernet) in the communication world. The abstract data model of IEC 61850 provides a consistent information-modeling concept focused on the information exchange needs of a substation (domain substation or substation automation).

The information transfer is not only related to the real time data flowing between the various parts of the substation but also to the engineering and configuration data of the substation, its operation, and documentation.

Thus the migration to IEC 61850 will have an impact on the utility's work *modus operandi* for the corresponding areas.

The engineering and configuration of the new IEC 61850 compliant devices and their interaction will require that the tools from one or many suppliers used can import and export SCL files as defined in IEC 61850-6 [6] and that the tools interact properly with the tools for the non-migrated parts or specifically take them into account.

The SCL files being provided with the IEDs, by the system specification, or resulting from the engineering/configuration are as follows:

- IED Capability Description (ICD) file describing the communication capability of the IED
- Substation System Description (SSD) file describing the single line diagram and the function allocation
- Substation Configuration Description (SCD) describing the configured automation system

These files are an essential part of the substation documentation and hence the documentation structure and systems of the utility may need adaptation to handle the new documentation format.

4.11 Migration from the user's perspective

In principle, the migration to IEC 61850 of certain substation parts or devices should not be visible in the daily work. IEC 61850 is intentionally defined so that the <u>functions</u> are <u>not</u> standardized but only the <u>information</u> and the ways it is exchanged. The applications in the IEDs and in the operators' workstations are not part of the standard; they are vendor specific as before.

The migration to IEC 61850 has hence no impact on the user in his or hers daily work in supervising and controlling the substation.

4.12 Conclusions

After the release of the final part of IEC 61850 in June 2005, the demand for installation of IEC 61850 compliant systems has rapidly and significantly increased. Therefore, there is no doubt that the standard will have a tremendous impact in the coming years. This is not only because of the technical solutions chosen but because of the well structured information modeling and the handling of it in the engineering, configuration, and operational phases. Furthermore all major vendors support IEC 61850 as seen since the exhibitions at the Cigre 2006 plenary convention in Paris.

The users, i.e. mostly the utilities, will benefit from the interoperability between IEDs from different vendors and from the price pressure that will come out of that.

The substation equipment vendors and the system integrators will benefit from the simplified engineering and configuration of a substation that in turn will be beneficial for the utilities.

The technical approach as defined in IEC 61850 such as Ethernet and the free allocation of application functions and last not least the SCL will allow optimized solutions and reduce the total life-cycle cost of substations automation systems.

5. The impact of IEC 61850 on the procurement process of a substation automation system

5.1 Introduction

The goal of this chapter is to describe how the procurement process in utilities may be affected by the introduction of IEC 61850 in Substation Automation systems.

Most importantly in considering this chapter it must be recognized that such terms as ***procurement process, substation automation systems*** *and* ***utilities*** are mentioned without any additional explanation,

- …as if there exists only one "procurement process" for all utilities,
- …as if all present and future substation automation systems were quite similar, and, of course,
- …as if all utilities all over the world could be referred as equivalent business companies.

Clearly such notions are far from reality and hence this chapter addresses the issues and intent behind the procurement process.

There are three general types of companies operating under the general description of a utility but their expectations, technical position, and personnel dedication to Substation Automation Systems (SAS) are very much different.

Large companies perhaps have more than 10000 employees in the workforce with high level well trained technical staff, cover a huge variety of services internally, and have a high number of installations within their assets.

Medium size energy companies may have elements of the larger companies but may also be more focused on financial business outcomes, partnering or outsourcing many services and subcontracting work from the erection to the maintenance of installations.

Small size companies, managing only a few installations, usually low cost oriented, are also part of the industry.

Compact black-box SAS systems, normally provided by the whole substation manufacturer (primary and secondary equipment) are purchased by some utilities as turn-key projects, where time-schedule for construction and commissioning is the main issue. In such cases, the technical documents referring to control and protection systems can be summarized as "*The protection and control system must be of digital type and based on the modern state-of-the-art practices*". These types of specifications are ideal for companies seeking to minimize the effort and detail in preparing the specifications.

Nevertheless, in some cases, full specification of each IED (type and manufacturer) can also be listed in technical specifications of more than a few hundred pages specifying every aspect the utility is concerned about if the utility has gained enough knowledge based on their own experience.

All big utilities are also confronted with the problem of future maintenance of the large list of their installations with the increased risk of having a wide diversity of equipment types necessitating special tools and training which may lead to more things being pre-scribed according to the accepted utility practice.

Clearly no two companies will have the same procurement process referring to turnkey projects, open book philosophy, individual components stock policy, acting with/without third party system integrator, with/without external consultancy, etc.

The above mentioned examples do not mean we are facing an unsolvable issue. They just serve to clarify the "IEC 61850 impact" has to be observed from different standpoints to cover the present and future situation of everyone.

5.2 Main features of the IEC 61850 standard

At the very beginning, IEC 61850 was the first attempt from manufacturers and users of protection and control IEDs to reach an agreement about a common protocol to be used for modern SAS. Today, the complete set of IEC 61850 documents represents indeed much more than just a protocol. A global view of a Substation Automation System, its functions and associated data, communication capabilities and requirements are fully present within the standard. First, there is a "logical level" normally called "data model" including the abstract services for data exchange. The specific mapping to existing main stream protocols layers of the selected communication standard is finally defined in a standardized way to communicate and interchange data between IEDs. This approach provides the opportunity to define future mapping as new communication technologies evolve.

Some features of IEC 61850, relevant to be taken into account, are listed below:

- Main goal is the Interoperability between products of different manufacturers
- Full standardized data exchange between protection and control functions. Detailed rules to add local data from each party (manufacturer as well as user) are also provided
- Conceptual separation between "application functions" and real devices defined by the implementation of data model and services, and the communication stack
- Substation Configuration description Language (SCL) is also provided to standardize engineering and configuring data exchange between tools and IEDs
- The whole communication process from centralized station units (HMI, gateway, etc.) to the bay units for protection and control, to the process apparatus (VTs, CTs, CB etc…) is covered within the standard. The implementation level depends on the state of the art technology, from the suppliers capabilities and from the user's needs

All these features clearly differentiate IEC 61850 from other possible solutions for communication in a new SAS. The most important feature is that IEC 61850 is the only globally accepted standard for this purpose.

5.3 SAS Procurement Process

Let us consider all the steps to be followed when purchasing new SAS, independently if it is IEC 61850 based or not (see Figure 18). By this approach the impact on the procurement process can be shown.

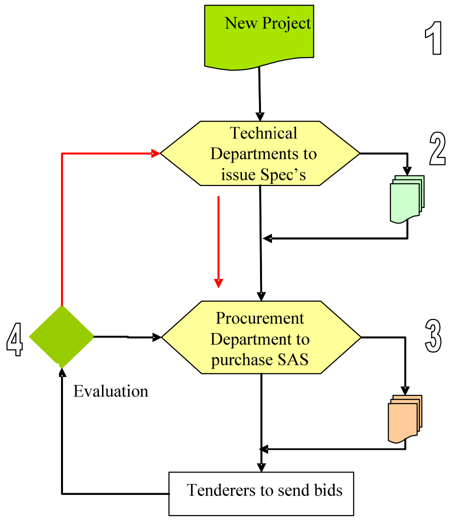


Figure 18 - Procurement process

5.3.1 New project

The first thing to be considered is an internal assessment of the power system development projects a utility will undertake over at least over the next five years. The results of this study can modify dramatically what should be the policy of the utility regarding IEC 61850.

After looking through the aspects to be considered, one can see that the impact on utilities differ a lot if projects to be built consist of completely new installations, or require refurbishment, or are extensions of existing ones, etc.

Table 6 - New and modified installations

Completely New Installations	When a new substation has to be erected, it is assumed that full benefits from IEC 61850 are to be used. This may be as completely new installations as well as full refurbishment of existing ones with full replacement of protection and control devices in one step.
Adding to existing installations, old fashion SAS equipped	Existing substations may need new bays to be added Or new and more modern protection relays and control units installed which may provide some benefits in their own right. Therefore, utilities must think about an integration of the new IEDs into the existing substation automation system if there is no plan for a complete replacement.
Adding to traditional wired installations	If new IEDs provide only IEC 61850 communication capability, the implication to integrate these ones in traditionally wired installation has to be considered.

Table 7 - Impact on project types

	Impact on Project Types		
Aspects	**Completely new installations**	**Some extensions to existing installations old fashion SAS equipped**	**Some extensions to traditional wired installations**
Knowledge of IEC 61850	High level	Functional level	Basic level

	Impact on Project Types		
Aspects	**Completely new installations**	**Some extensions to existing installations old fashion SAS equipped**	**Some extensions to traditional wired installations**
Purchasing policy	High	High	Low
Maintenance	High	Medium	Low
Migration Strategy	No	Yes	Partly
Impact on utilities organization	High	Medium	Low
SAS Tools	Utility statement	Manufacturer approach	Manufacturer approach
Process Bus	High	High	Not recommended
Other Aspects	Remote communication	Remote communication Existing SAS configuration skills	Remote communication Existing SAS configuration skills

The relevant aspects that have been mentioned could be explained in detail as follows:

Table 8 - Relevant aspects

Aspect	Considerations
Knowledge of IEC 61850:	IEC 61850 comprises a functional approach for modern substations, a complete logical data model including abstract communication services, mapping to a selected main stream communication stack, and the Substation Configuration description Language. The requested knowledge level depends on the user needs. • **High Level**: It would be necessary to have comprehensive knowledge about the IEC 61850 concept, the data model and the related communication services, and the Substation Configuration description Language (SCL). Full knowledge of MMS communication services is not needed for this level since stack implementation is provided always by the manufacturer. • **Functional Level**: It would be necessary to have basic knowledge about the IEC 61850 concept, the data model focused especially to the list of LNs and CDCs, basic features of the communication services, and an overview about the use of SCL. • **Basic Level**: The concept of LNs, GOOSE and SV service if applicable, some client-server services. No knowledge is needed about the communication stack. When listing these levels of knowledge, these do not refer directly to the “utility required knowledge level”. It means the knowledge level needed for a responsible handling of IEC 61850 for the project types under consideration. It has to include the related knowledge about the specification and information given to the manufacturers, as well as knowledge of the

Aspect	Considerations
	responsibility for acceptance tests to be carried out, independently by the utility staff itself, by the manufacturer or an external consultant. Essential to all levels is knowledge about the role of compliance tests and of the system integrator.
Purchasing policy	Depending on the type of projects as well as repetitiveness of these projects, some philosophies on equipment purchase may be more appropriate than others: • Turn Key projects: Big projects where the utility wants to allocate the whole responsibility for system integration, performance, completion time, and total cost control to external EPC companies. Depending on utility experience, available technical staff, repetitiveness of projects etc. different approaches to the standard handling will be required. • Integration: When utility is concerned about a technical selection of best products for each protection and control function, equipment acceptance testing or about cost effective solutions, as well as having relationships with several manufacturers in parallel, the utility will arrange procurement and provide delivery of equipment to the integrator. • Stock Policy: Individual products are purchased for maintaining specific stocks. These products can be applied to different projects. Selecting which of these approaches should be used is not within the scope of this document. The utility will however need to consider each of these aspects. Therefore, regarding “purchasing policy” three different impact levels have been established: • **High:** The preparation of the technical specification by the utility staff, the repetitiveness of the projects, the maintenance policy of the company and the number of present and future installations, as well as the internal organization of the company will directly affect the way to purchase SAS systems and elements. Any of the purchasing methodologies may be chosen for the particular project after an appropriate assessment by the utility, with the possibility of a complete change to their processes in the future. • **Medium:** Only turnkey projects or external integration could be possible, not so much to be discussed. • **Low:** Traditional way to purchase is possible, whenever an IED is IEC 61850 based or not.
Maintenance	Maintenance aspects are one of the most important things to have in mind when moving to the new generation of IEC 61850 based equipment. Not only capabilities for communication but quality of associated maintenance tools, user function adaptability capacity, etc. is of interest. The different impact levels to be considered are: • **High:** Maintenance and future support requires a lot of training on engineering, configuration, and maintenance skills. Decisions must be made if this issue can be solved best by the utility itself or by outsourcing. Replacement and future addition should also be considered when considering the present purchasing approach. This may be affected by the number of different installations within the utility, or the location of the manufacturers support facilities and staff with respect to the utility. • **Medium:** Actual maintenance procedures will not change when

Aspect	Considerations
	introducing the new IEDs compliant with IEC 61850. • **Low:** Maintenance issues are outside of the utilities direct responsibility. Setting up a Maintenance Contract (Post Delivery Service Agreement) is a very popular option among users of Substation Automation. Given the criticality of system availability, such contracts would define the response time in case of a contingency (e.g. reach site within two hours, provide a diagnosis within X hours / days etc.). This would relieve the user of the need for high level training for their own staff, particularly in the early stages of experience with automation systems. Typically, the maintenance contract also transfers the responsibility for spares to the contractor.
Migration Strategy	• **Yes**: It has to be considered as discussed in chapter 4 • **No**: There is nothing to be considered out of the migration discussion • **Partly**: Dedicated aspects of the migration strategy may have to be considered depending on the kind of extensions
Impact on utility organization	Modern SAS as well as communication facilities for protection devices have already had an impact on most utility organizations. The introduction of IEC 61850 may be even more significant. • **High:** Telecontrol, protection and control sections are merged as an integrated unit and potentially at least greater cooperation and interface with general business IT systems. Traditional purchasing evaluation methods could be not effective regarding this equipment. The process bus will affect the traditional work assignment to the engineering organization. SAT test methods have to be revised. • **Medium:** Some internal organizations and methods have to be revised. It refers especially to purchasing policies and SAT methods but without having big impact on the utility organization. • **Low:** Not important to look at. Soft changes only may be necessary.
SAS Tools	When preparing engineering and maintenance policies within a company, several ways to proceed are possible: • **Utility statement:** Tools developed independently of any manufacturer able to be used with all IEDs and by all integrators or the utility itself. The utility must consider how to integrate these tools in the overall company procedures for the configuration and engineering of new IEC 61850 devices. Solutions could differ a lot and different approaches are of course valid: - Manufacturer independent tools - Manufacturer based tool - Homogeneous / versus local process • **Manufacturer approach:** The manufacturer or integrator may have a range of tools which can be offered. .
Process Bus	It is commonly accepted than for introducing IEC 61850 at least the new station bus according part 8-1 is used. The introduction of the process bus according to part 9-2 means an additional step forward. • **High**: The impact on the procurement process has to be considered carefully from the beginning. It requires a proper interface for the switchgear itself, and perhaps complete replacement. Section 5.6 will explain this impact in more detail.

Aspect	Considerations
	• **Not recommended**: For the system under consideration the primary equipment replacement and hence the process bus is not within the scope of the project and, therefore, no impact is expected
Other Aspects	Many other things to be considered may be listed. Two examples are used in the table: **Remote communication**: Since Substation Automation Systems communicate always at least with the Network control centre (NCC), remote communication is always impacted. **Existing SAS configuration skills**: In completely new installations, equipment configuration and the related skills are homogeneous under the IEC 61850 process and, therefore, have no special impact. In case of extensions, the parallel operation of old and new parts including the allocated tools may have a high impact for the integrator in being able to undertake reconfiguration of existing systems using the tools associated with the old system.

5.3.2 Technical Department to deliver Specifications

Technical specifications are the basic documents which define the full requirements on the client side and which have to be accomplished by the equipment to be purchased. Therefore, the documentation to be included in the specification will depend on the level of specific information the purchaser must provide in order to properly transmit all of the clients needs and wishes.

- The more general the specification is, the less expensive the specification process is for the client. More manufacturers or contractors are available to bid. But in this case the client will have less technical control regarding the resulting solution
- The more precise and detailed the specification is, the more expensive the specification process for the client will be. Fewer manufacturers or contractors may probably fit to the specification and are able to bid. But in this case the client will have more control regarding the resulting solution

The technical departments must asses which process they think will better suit their organization, necessities and internal capabilities.

It is a challenging task to specify in detail totally new technology, especially as protection, control, IT and telecommunication systems merge; these having separate specialists divided possibly even in separate departments in the utility. Therefore, it is essential that the utilities make efforts to understand and learn the new concepts before making too many implementation projects based on bid competition, in which the solution offered does not fulfill the expectations that it hadn't the know-how to specify accurately enough.

The types of documents that form the specification will vary considerably depending on the project types. Importantly, the aspects listed below do not mean that they have to be accomplished by the utility itself or being provided by an external consultant or manufacturer purposely contracted by the client. Responsibility depends on the role of each party which has to be defined from the beginning.

Moreover, some of the aspects or documents presented would be the same when introducing IEC 61850 as that of other SAS design types, but collating them leads to a more complete picture of the pertinent issues to be addressed.

It is important to point out that some minimum requirements shall be included in the specification, as for instance, the need for each IED to have a certification issued by a test organization qualified by the Users Group of IEC 61850 i.e. by UCA International. This certification will guarantee that the equipment is going to perform according to the IEC 61850 standard. In addition, it shall be demonstrated that this IED will be interoperable with other IEDs, even when supplied by different manufacturers.

Table 9 - Impact of project types

	Impact of Project Types		
Documents from client side	**Repetitive new substation design using several manufacturers**	**Single new substation Only one manufacturer**	**Extensions of existing SAS**
I/O List	Required if SAS procurement differs from principal equipment		
Signal List to telecontrol incl. protocol type	Always required		Refer to Chapter 4 Migration strategies
Functional naming or product naming definition	Relevant in order to have consistency within the company	Not relevant. Use manufacturer's choice	Not relevant
List of functions and their allocation to the substation (Single line)	Detail the most, specific function control in such a way that coherence between substations is achieved Function blocks and parameters	Basic functional requirements to come from the client. Detailed functional description of system may be created by manufacturers or the system integrator	
System architecture	Required in detail	Functional requirements and manufacturer's choice based on availability and performance	
Engineering and configuration requirements	Very high relevancy	Not Relevant. Manufacturer's proposal evaluation	
GOOSE application	Always relevant. Define internal policy and strategy. Same coherent use.	Maybe relevant. Manufacturer's proposal	Maybe relevant. Manufacturer's proposal
Redundancy levels required	Always relevant. Define internal policy and strategy. Same coherent use.	Not Relevant. Manufacturer's proposal	Not Relevant. Manufacturer's proposal
Process Bus	Very highly relevant. Define internal policy and have big impact. See section 5.6 about process bus.		

	Impact of Project Types		
Documents from client side	**Repetitive new substation design using several manufacturers**	**Single new substation Only one manufacturer**	**Extensions of existing SAS**
Protection requirements	Always relevant. Define internal policy and strategy. Also define allocation of protection functions to IEDs.	Function definition and manufacturer's proposal	
Control Mode Definition, Communication services specification	Always relevant. Define internal policy and strategy. Also define allocation of protection functions to IEDs.	Functional definition by the client and manufacturer's proposal	

For specification refer also to chapter 6. "Specification of IEC 61850 based Substation Automation Systems".

5.3.3 Purchasing SAS

As in the past with any kind of highly technical equipment, all related technical documentation and specification for Substation Automation Systems must be prepared by the technical staff, because the complexity of the technology involved and the necessity for correct operation of the power system.

A major impact on this process is an expected reduction in prices because of the competition between manufacturers due to the new interoperability facilities of IEC 61850.

The potential for reduction of prices does not necessarily mean that the new devices compliant to IEC 61850 will be cheaper on an individual basis than non-IEC based devices. In the short-term there will be additional costs due to the implementation of more powerful Ethernet communication systems, offset by a reduction in auxiliary relaying and extensive copper wire based signals being replaced by GOOSE messages and SV messages if applicable. In the mid-term the cost of the IEDs will stabilize due to competitive pressures and increased production volumes.

The new competitive environment may lead some manufacturers to specialize on a specific product range more tailored to the utility implementations which will benefit the utility. It will not be necessary for a manufacturer to have the complete range of products to participate in a tender process, so a new specialization and skills focus is beginning to happen in the industry.

It is also expected that a reduction in engineering, construction and commissioning takes place due to the support by the SCL based SA configuration description. This will also affect ongoing support service costs and project completion times.

On the other hand, new investments in specification, training or outsourcing consultancy will also be needed for utilities at least in the beginning. For the manufacturer, major investments in developing engineering and configuring tools will be required which may initially negate some of the reduction in hours provided by the tools. These investments may take a few years to provide real reductions in total costs and requirements for services.

Finally, protection and control equipment should therefore not be the bottleneck of a SA project when talking about erecting new installations, both for procurement and engineering as well as for commissioning tasks.

5.3.4 Evaluation procedure for IEC 61850 solutions compared to traditional SAS

The new data model and communication features combined with the greater flexibility supported by IEC 61850 lead to a more complex evaluation for protection and control devices. It means that it is not possible to make evaluation of cost/effective solution when looking at a new IED as one isolated device only; the evaluation has to be done within the full system and life-cycle context considering the

- Cost reduction by more competition resulting from the interoperability of IEC 61850 compliant devices
- Advantages in all maintenance actions over the full life cycle from the first implementation as a result of the formal SCL description to be used an reused by all kind of tools
- Simplification of future configuration maintenance by use of the revision indices in the data model and SCL
- Additional savings by the reduction or replacement of wires by using GOOSE services over the serial communication system

The life-cycle costs under the influence of the first two points are increasingly being reported as systems gain operational experience e.g. [51] .

5.4 The role of System Integrator

Traditionally, a system integrator is a highly skilled staff person that can “integrate” systems from different manufacturers to provide better solutions to clients. Therefore, the origin of System Integrator comes from the necessity to integrate different solutions from different vendors in order to build a complete system. Very often, existing systems have been supplied by one, or a selected set of suppliers who have taken over the system integrator role for convenience.

This role definition and the skills to deal with multiple vendors unique equipment and tools is no longer applicable for IEC 61850 based systems because of the interoperability between devices and between manufacturers. This does not mean that the System Integrator will disappear, but instead take on the skills associated with a more efficient process and may be undertaken by a totally separate company, or indeed the utility itself.

IEC 61850 does not provide for the so called “plug-and-play” approach to equipment integration as the data consistency has to be checked. This incorporates verifying that all data is defined and allocated in a unique way, and that all data needed by each IED is supplied by the other IEDs. This is not inherently guaranteed by the IEC 61850 compliance of IEDs as the choice of use of data and functions within the capability of the IED is the responsibility of the Integrator. In addition, not all data is mandatory within a particular IED. Another issue is to design a multi-vendor system in such a way that the specified overall functionality and performance is fulfilled. All this is the task of the System Integrator.

The System Integrator may be seen as one additional party in the project, which will use IEDs from several manufacturers to design cost effective solutions according to the specification of the utilities. This role may be taken over by a manufacturer, the utility or a third party. It must be considered in the budget for the SAS and negotiated early so that all related responsibilities are clear.

5.5 Consulting

As commented in the previous paragraphs, a lot of investment in dedicated knowledge about the standard may be necessary depending on the type of project and the role of the project participants. This knowledge could be provided by internal training of utility technical people or being allocated to external consultancy.

Activities that may be requested from external consultancy:

- Training services for a minimum level of IEC 61850 knowledge.
- Training services for full education of technical and operational staff making them self-sufficient.
- Preparing the system specification for the utility.
- Assessment on procurement evaluation.
- Review of operational procedures, policies and facilities.
- Strategic and detailed review of communication systems type, capacity and security.
- FAT and SAT test assessment
- FAT and SAT protocols preparation. Today testing protocols is already crucial for the consistent operation of any system. With IEC 61850, this role will be even more important, because this standard goes beyond communication and includes the data model, the services and the system description. The testing has to prove that also a multi-vendor SA system is running as specified.
- Quality program review and audit. IEC 61850-4 states all recommendations and requirements that a SAS project handling has to fulfill, especially from a management and quality assurance point of view. It will be the responsibility of the System Integrator to follow these recommendations or to control compliance. Namely, a quality system based on the standard ISO 9001 has to be followed in all steps of the project. The System Integrator should make all necessary test equipment available for any audit or testing of the system to the quality control requirements.

5.6 Primary Equipment and the Process bus

When talking about the impact of IEC 61850 on procurement process, the process bus part of the standard requires a specific and extensive analysis. This is due to the fact that the complete system concept and indeed operation within the substation and across the power system as a whole may depend on this selection.

Acquiring SAS including process bus means that switching devices (circuit breakers and isolators) and instrument transformers (CTs and VTs) shall have process bus compliant interfaces with or without the merging unit (MU) providing data according to IEC 61850. With other words, primary equipment or at least the process interface becomes part of the overall system. Therefore, many new issues have to be considered in the procurement process.

Sampled values available on the process bus system may be used by many different IEDs. Nevertheless the process bus architecture has to maintain the independence of “main 1” and “main 2” protection functions if both exist.

Certainly the extent to which a process bus is implemented will have an affect on the specification of new primary equipment (circuit breakers, isolators, power and earthing transformers, capacitor banks, SVC, CTs, VTs, etc.) but may also require modification to existing equipment. The addition of IEC 61850 interfaces to the primary equipment will provide opportunities to reduce some of the hard wired features such as the number of CT cores, number of CB auxiliary position indication switches, isolating links and fuses etc.

5.7 Conclusion

Both positive and negative impacts on the procurement process will be experienced by the utilities summarized as:

- The utilities will have to invest in the knowledge of the IEC 61850 standard to be prepared for the procurement process. A minimum knowledge about the standard is required to be given to utility staff
- Depending on the utility situation, full knowledge could be afforded by utilities itself or outsourced to external consultancy
- Decreases in system engineering as well as in the delivery time for new projects and extensions of SAS are to be expected over time
- Process bus will have a tremendous impact on traditional ways to proceed in procurement process since it allows not only the use on non-conventional sensors but also new allocations of functions as far as these options are available on the market
- Since there may be more parties involved in the SA system than presently, the standard features have to be used to safeguard that situation. The allocation of responsibilities including the definition of the **System Integrator** role has to be done from the beginning of the project
- The project of interlocking and logic circuits shall be completely redesigned, using GOOSE messages and eliminating auxiliary relays and hardwiring. This new project philosophy will provide considerable cost reduction, as well as reduction on design, installation and factory/ field tests."

It is very important to include these cost savings on the project viability calculation, since if only the equipment price is considered the difference in price may not be attractive. However, if all advantages of the new technology are taken into account, the investment will be more easily justified in favor of this new technology.

6. Specification of IEC 61850 based Systems

6.1 Introduction

6.1.1 Goal and approach

This section aims to give some guidance on the proper specification, the purpose and the functional requirements of an IEC6150 based SAS. These systems are commonly used in controlling, protecting and monitoring of substations. They consist of components acquiring data from the switchgear including instrument transformers and issuing actions towards the switchgear (actuators) like commands and trips (process level). They have dedicated or combined devices (IEDs) for protection, control and monitoring (bay level). They allow the operation the substation from a local (station level) HMI or from the remote HMI in the Network Control Centre via an appropriate gateway. Also a lot of supporting automatic functions may be contained. All these functions with the allocated IEDs exist whether or not the three levels of the SAS architecture are clearly defined or named explicitly [41] .

In order to prepare a specification incorporating the impact of IEC 61850, it is important to understand the basic features of IEC 61850.

This chapter of the report wills not only list new specification issues as a result of IEC 61850 but also gives a comprehensive overview of the complete specification process for SA systems.

It is not recommended to include the requirements of use of, or conformance with IEC 61850 as a simple add-on only to an existing non-IEC 61850 specification. This procedure would risk dismissing some benefits of IEC 61850 since this combined set of specifications is not tailored to IEC 61850. Of course, the functional part of the existing specification can be reused but should be extended by an IEC 61850 specific part.

If the structure of a non-IEC 61850 specification is used and only complemented by an add-on for IEC 61850, the non-IEC 61850 components will severely limit the optimization of the solution. This also applies to adding too many details in a new specification as explained in the approach to the specification given below.

The challenge is to reconsider not only the system concepts (see section 6.2) but also the comprehensive hierarchical specification approach as proposed in this chapter. Pro and cons are mentioned if applicable.

The process of specifying IEC 61850 based systems has been sketch already in [49] , the basic steps from a basic specification to an appropriate architecture of an IEC 61850 based system in [48] .

6.1.2 Basic features of IEC 61850

In order to prepare a specification, it is important to understand that IEC 61850:

- covers *all communication* needs in the substation, i.e. both the station bus and process bus, although does not specify the actual system components or performance
- specifies no functions but a *data model* for the functions and their related communication *services*, i.e. it does not block the future development of functions
- supports the *free allocation* of functions to devices, i.e. it is open for different system philosophies and system optimization
- defines *Ethernet* as layer 1 and 2 of the ISO/OSI reference model, i.e. provides the broad range of features of mainstream communication

- provides the *Substation Configuration description Language (SCL)*, i.e. it supports comprehensive consistency in system definition and engineering

6.1.3 Basic consequences

According to the basic features, the *functions* have to be specified in the same manner as before, i.e. independent of the use of IEC 61850. It has to be decided by the specifying party, e.g. by the utility using the system, if the selection of devices is left to the supplier's discretion or limited by some pre-selection of devices standardized (homologated) by the utility. Availability figures or failure scenarios have to be provided in the specification to get the proper communication architecture. The environmental (electrical, physical, geographical) conditions have to be specified just the same as previously but some of these conditions may heavily influence the selection of the communication hardware, architecture and, especially, for the communication media selection, e.g. to use copper cable or optical fiber links.

If the switchgear, including the CTs and VTs, already exist, the type of process interface must be included in the specification. If the process interface can be selected (conventionally hardwired or serially linked) it may have some important impact on the optimization process for the solution to be offered.

6.2 Reconsideration of SA concepts

Since IEC 61850 is a new approach with a lot of new features and capabilities (see chapter 2) it is worthwhile for the asset owner to reconsider the design and operation principles of the substation and the substation automation system. A one-to-one migration of the existing principles is always possible but may not fully exploit the benefits of IEC 61850.

The key question is what *functionality* is *really needed* to reach an optimized operation of the power system operation by the user.

One approach is to specify the needs of the utility with no, or a minimum of implementation constraints and invite suppliers to offer their optimized solutions. In proceeding to build the chosen solution, the utility will gain considerable experience in a system with total confidence of the solution proposed by the supplier. The user can then re-evaluate his needs and consider continuing with this as his new design principle. On the other hand as a first solution, there would need to be a careful review of the architecture for future substations in order to cater for new requirements and technological advances either as part of the standard solution or for specific substations.

This chapter of the report can therefore only provide conceptual guidance on the interaction between various principles and the range of IEC 61850 solutions. The utility must embark at the outset with a full review of their principles as there are a multitude of solutions and capabilities of IEC 61850 combined with the various compliant IEDs that may or may not suit the individual utility.

6.3 The substation

6.3.1 Single line diagram

The basis of any substation automation system is the *single line diagram* of the substation. The switchgear included in the substation

- determines the process related part of the data model, i.e. the use of process near logical nodes modeling switchgear data (mainly the *Logical Nodes* of type X, T, Y , S, and G (see chapter 2)
- predefines, together with the philosophy of the utility, the control and protection functions to be applied and, therefore, the use of the logical nodes for protection, control, and automation other (mainly *Logical Nodes* of the type P, R, C, and A – see chapter 2).

- allocates functions and devices to bays or busbars
- provides the high level part of the data identification structure by a plant designation system like IEC 61346 [19] (see chapter 2)

Therefore, for a comprehensive SA system specification the single line diagram has to include *all* switching devices including earthing switches as well as power and earthing transformers, instrument transformers, capacitor banks, SVCs, etc. It has to indicate the type of bays (overhead line bay, cable bay, transformer bay etc) which are all formally described by an SSD (System Specification Description) file using SCL as defined in part 6 of IEC 61850 [6] .

6.3.2 Process interface

IEC 61850 provides also a standardized serial communication between the bay level and the process level often called *process bus* (physical allocation). Client-server services (e.g. commands and reports) and GOOSE messages (e.g. position indications for interlocking or trips) according to IEC 61850-8-1 may be used if applicable as on the *station bus* between the bay and station levels (physical allocation). IEC 61850 supports the use of intelligent switchgear incorporating electronics with integrated serial communication interface as well as conventional equipment connected by parallel copper wires. In addition, the sampled data service (SV) may be used for samples of current and voltage according to IEC 61850-9-x both for so called non-conventional instrument transformers (NCIT)[2] and conventional instrument transformers with A/D conversion near to the sensor.

The key point for the specification is to define for each item of equipment which type of process interface is used.

6.3.3 Remote interfaces

Besides the process interface the specification has to include all interfaces for external links from and to the substation, i.e. the links to

- network control centers
- maintenance centers
- expert centers for protection, asset management, etc.

Not only the communication protocols of these links have to be specified but also the data to be exchanged and the required communication services (if applicable). Dedicated performance requirements should also be stated.

Within the substation, the individual IEDs for protection, control, etc are referred to as servers. Remote interfaces compliant with IEC 61850, and the gateways for non-compliant ones, are referred to as *clients*. Since an individual association has to be established between each of the servers (IEDs) and all connected clients, the IEDs have to support a reasonable number of clients with the necessary computation and storage capacity per association. The number of clients per IED will be limited but as a recommended minimum there should be at least 5 clients supported (2 x station HMI, 2 x NCC gateway, and 1 x maintenance client). Careful review of the proposed architecture should be undertaken and the number of required clients to be supported has to be stated in the SA specification for the IEDs.

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[2] Non-conventional instrument transformers (NCIT) are current and voltage transformers not based on the classical transformer principle with an iron core. NCITs may be Rogowksi coils, capacitive dividers, fibre optic based current sensors and solid state optical voltage transducers providing signals not compatible with the common 1 or 5 A, 110VAC and 110/220 V DC systems.

Note that the implementation of these requirements, especially the communication system performance, may be outside the scope of the substation automation system and be dependent on the link and the remote application on the other end of the link. This may necessitate the utility establishing an appropriate strategic development plan for their wide area communications network capacity as existing systems may be limited to just a few Megabytes/sec (Mb/s) over radio networks or even as low as 64 kilobytes/sec (kB/s) over digital power line carrier systems. It is likely that the WAN system would need to provide well in excess of 100Mb/s as done e.g. by SDH to provide effective performance for communication between substations if that is required.

6.4 The substation automation system

6.4.1 Introduction to IEC 61850 based substation automation systems

The substation automation system comprises all functions which are needed to control supervise, monitor and protect the substation and the power lines between the substations. All functions are implemented in physical devices (Intelligent Electronic Devices, IEDs), which are connected by the communication system. IEC 61850 supports the free allocation of functions to devices, i.e. it provides no rules or recommendations of what functions should be implemented, nor in which device or location.

Therefore, specifications have to include the functional requirements but may have different levels of details regarding the devices needed. This is discussed in the following sections.

As general rule for all devices, the specification must include the requirement for standard documentation according to IEC 61850 including per device the

- MICS document (model implementation conformance statement)
- PICS (protocol implementation conformance statement)
- Conformance Test Certificate
- ICD file (IED capability description file)

and for the complete system the

- SCD file (substation configuration description)

6.4.2 Minimum specification

The minimum specification has to define the functions like control, protection, monitoring, etc. (see below) including both performance (response times, availability, etc.) and physical constraints (switchyard site layout, building structures, environmental conditions, etc.). As explained in section 6.3.3 the number of HMI and other clients like gateways has to be defined to ensure correct operation of the system.

In avoiding the detailed specification of individual devices, the suppliers will be able to provide their optimized solution and IED selection and therefore is the recommended approach if none of the following constraints apply.

The utility must include in the specification details of any constraints on the solution in the following areas:

- pre-qualified devices for which the utility has determined there is some operational benefit in standardization
- pre-defined degree of functional integration or segregation to provide a certain degree of security and availability to suit the utilities operational and regulatory requirements

- pre-defined architecture to satisfy the organizational structure, network capacity as well as network security regimes
- re-use of existing system parts for the above reasons and to benefit from previous utility expenditure

Another constraint for any solution is the *availability* of suitable IEDs *on the market*. This cannot be stated in advance but will be evident from the response of the suppliers to the specification and what functions they are able to satisfy or not satisfy with their chosen IEDs.

Normally, all constraints listed above can be considered in the solution to be offered but may *restrict offering an optimized solution* based on functional requirements only. Suppliers should be encouraged in addition to provide solutions incorporating the constraints of the utility, to describe the benefits of alternative systems where these constraints have been relaxed or modified.

In all specifications, the device documentation according section 6.4.1 and one comprehensive SCD file according to IEC 61850 for the complete SA system has to be requested.

Finally, if applicable to the particular contract and assigned responsibilities, the specification must require a copy of the test plan to be provided for FAT and SAT. These plans cover all aspects of functional and system performance testing and should be provided initially at the concept approval stage to ensure appropriate facilities and methodologies are incorporated in the design, as well as prior to commencement of testing to identify all aspects are appropriately tested.

6.4.3 Pre-qualified devices

If there are pre-qualified devices requested by the user, these devices have to be listed in the specification. The request for pre-qualified devices implies a defined allocation of functions according to the implemented capabilities of the IEDs.

It always has to be stated and documented for the system integrator that these devices are compliant with IEC 61850. For this purpose the device documentation (especially the ICD file) as stated in section 6.4.1 has to be provided to the system integrator. Such devices may be then integrated in an IEC 61850 based system without basic problems. Deviations from compliance with IEC 61850 or functional problems outside the scope of the standard will cause problems during the integration and testing phases which may require specialized solutions or a change in specification at considerable additional cost.

If the pre-qualified devices are not compliant, the issues discussed in chapter 4 regarding migration strategy need to be considered.

6.4.4 Degree of integration

The degree of integration refers to the number of functions integrated in one device, i.e. the number of function related Logical Nodes allocated to one IED. There will be a variety of reasons that a user may limit or define the degree or manner of integration within the devices. This may be for function segregation purposes to facilitate maintenance or operational activities or it may be related to the communication system architecture to manage peak demand on bandwidth of the network. The integrator must evaluate all the requirements regarding performance, availability, etc. and provide a response regarding their recommended degree of integration.

If the degree of integration is given already in the specification it has to be added to the constraints on the integrator's chosen solution. Such degree may be kept without any problem as long as there are suitable devices on the market.

6.4.5 Pre-defined architecture

If is the user has a requirement for a pre-defined communication or system architecture this must be described fully in the specification. In particular the integrator must be advised if the architecture is compliant with IEC 61850. If it is not compliant, the issues identified in chapter 4 regarding migration strategies have to be considered either by the user or a strategy developed by the integrator.

Note that the request for a pre-defined architecture implies that the availability or performance may be limited as a direct consequence of the requirement and hence the user should remain open to consider improvements to the architecture.

6.4.6 Re-use of existing system parts

There may be some existing substation automation structures (subsystems), which have to be retained. This may be due to a number of factors within the utility and the nature of the project itself. These situations will only occur in projects involving a partial implementation in the substation. This may be driven by the need to maximize the benefit from previous investments in SAS or operational differences between old and new equipments. In this case the requirements of chapter 4 regarding migration strategies have to be taken into account.

6.5 Specification of functions and the related data model

6.5.1 Functions

As the inherent nature of IEC 61850 Is not to standardize or limit any functions in the substation, these must continue to be specified as in the past. The utility may have already established its own functionally based specification and there are reference sources to assist in development of such specifications [41] . The specification of functions refers especially to the *behavior of the functions* like response times, protection characteristics, interlocking conditions, sequences, operator interfaces, etc. In addition to the behavior aspect, some functions require specific data as input to perform the specified function, e.g. station-wide interlocking requires the position indications of all switches in the substation. Some functions may have dedicated rules or criteria unique to the user which have to be fully specified e.g. if the voltage reading of the instrument transformers has to be included in the interlocking arrangement.

Note that compliancy with IEC 61850 does not imply compliancy with the functional requirements of the user since it refers to the data model including the services for the data exchange only. The Abstract Communications Services Interface level ensures the data model and the communication services requested for this data are independent from the stack implementation. At function implementation level, the behavior of the functions distributed over the communication network is summarized as performance requirements. The specification must also include besides the general function specification also the performance requirements of any specific data exchange for the distributed functions to be nominated. How, and from which IEDs these data are communicated should not be included in the specification but should be included in the suppliers and system integrators description of the proposed solution.

6.5.2 Data model

If the *functions* are fixed, the data model of IEC 61850 automatically specifies *all mandatory data* and, therefore the *minimum signal list*, which may be checked via the specification of the Logical Nodes. This is specified in IEC 61850-7-4 [10] or may be undertaken with support of the supplier or system integrator.

In addition, any *optional* data and data attributes declared as part of IEC 61850 must be specified by the user for the substation automation system under consideration. If both the mandatory and optional data do not cover all needs determined from the strategies for operation, protection and maintenance and requirements of the existing overall EMS/SCADA system, the missing data have to be listed to be provided as *extensions* to be offered by the device (IED) provider if possible. The complete data model including the extension rules is given in IEC 61850-7-3 [9] and IEC 61850-7-4 [10]

It may be helpful, but it is not necessary, that the user understands the standard in respect of the data model and extensions. The data may be specified by the user in a conventional signal list. In this case the mapping to the data objects of IEC 61850 has to be done by the provider or the system integrator. Independent of whether the devices are pre-defined or selected in an optimization process, some data may not be available in the system, whilst other signals may not be needed in the solution offered. If the devices provide all requested functions, at least the minimum of data needed for the functionality is provided. As user or system specific extensions may not be readily available, these should be avoided if at all possible.

6.5.3 Services

The data model provides the complete set of standardized data available for communication. All data may be accessed by the basic *read* and *write services* but for the user the domain specific services are of interest because they are related to the system operation. Therefore, all switchgear has to exist in the data model to be operated by the *command services, such as* "*select-before-operate"*. The related data are transmitted by definition from the standard. Event driven data exchange as used e.g. for updating information across the system, is provided by the *report service*. Time critical event data are exchanged by the *GOOSE service* and samples being always time critical by the SV service. Details of these services are not part of the specification but comparing the data model with a conventional signal list, it has to be considered that the transmitted data have to be in the appropriate *Data Sets*; otherwise they are not transmitted automatically at all. The conditions for event driven or spontaneous transmission are defined in the *Control Blocks*.

If there are choices or options in the standard, individual services may be specified explicitly. However, such an explicit specification may impose constraints against system optimization.

Performance figures, availability figures or failure scenarios, and the synchronization requirements (dedicated service) determine all services (defined in IEC 61850-7-2 [8]) not otherwise pre-defined by the data to be transmitted according to the data model.

A key feature of IEC 61850 is the dedicated GOOSE service for time critical information and SV service.

6.5.4 Naming convention

All data in the substation have to be identified, i.e. named in an unambiguous way. This has to be done in the naming convention of the data.

The standard IEC 61850 defines the names of Logical Nodes, Data and Attributes (refer to the data model in IEC 61850-7-4 and IEC 61850-7-3 or to chapter 2). These names cannot be changed.

The names of some prefixes and postfixes and the Logical Devices may be predefined by the provider of the related device.

The customer has to specify his plant and device designation scheme. It is recommended to use for this definition a standard with a hierarchical designation scheme such as provided in IEC 61346 [19] .

All these naming parts contribute to the naming convention of the project under consideration and are needed for a unique identification of all data in the system. All parts which are not fixed by IEC 61850 itself have to be agreed and confirmed between the user (e.g. utility) and the System Integrator for use by the system engineering tool based on the substation configuration language (SCL). They appear also in the final SA configuration file (Substation Configuration Description, SCD) and complementary documentation of the substation automation system.

6.6 Specification of communication

The basic requirement in the specification for interoperable systems based on IEC 61850 is that all devices have to be compliant with IEC 61850. Because of the flexibility of the standard and the scalability of the resulting communication system some performance criteria have to be specified.

The services defined in IEC 61850-7-2 [8] are the standard processes to access the data within the IEDs. The type of data to be transmitted predefines a lot of services but there are some options. Ethernet as defined for IEC 61850 allows scaling the communication system by different communication architectures. The accuracy requested for the time synchronization may have also an impact on the communication solution.

To resolve these issues, the following figures important for the user and the integrator have to be specified.

- Performance
- Availability
- Time synchronization accuracy

Details about these figures are given in the following sections.

6.6.1 Performance

The response times of local functions may be given with the function specification above. For distributed functions i.e. functions comprising more than one IED, the response time has to be specified also.

Performance requirements may be stated qualitatively in words, or formally defined by the requirement classes according to IEC 61850-5 [5] . These classes should be used for uniformity reasons. The system provider or integrator has to support these requirements by a proper device selection and by the system architecture.

6.6.2 Environmental conditions

The environmental conditions like EMI, temperature, humidity, and power supply (110/220 V DC) in substations are very well known. Details may be different from substation to substation, but the common standards classifying these conditions are listed in IEC 61850-3 [3] . Generally IEDs both for protection and control meet these requirements although with the potential for non-traditional IEDs and suppliers to be used, all IEDs should be confirmed for compliance. In addition to the IEDs, as IEC 61850 and the supporting communication network is the base operating technology, the Ethernet switches, routers, gateways, time synchronization systems and any other device in the communications system must also comply with these requirements to be considered suitable for use in a substation automation system and not to degrade the reliability and security requirements.

6.6.3 Availability and failure scenarios

Using Ethernet in IEC 61850 provides a high flexibility regarding the communication architecture which will allow the system to evolve as newer technology becomes available and performance needs or the system size increases. This allows a high scalability of solutions but the customer's initial performance criteria for these solutions must be specified.

The customer is interested in the *availability* of certain *functions* in the system. Availability figures are needed to determine the optimized architecture. The availability of IEDs and its functions implemented is a matter of the devices selected or to be selected. Availability for distributed functions is not a result of a single IED but of the complete system including the logical communication structure and the physical communication architecture including switches.

Very often, meaningful figures for *availability* are not easily defined by the user. More realistic and comparable with the operational needs of the user may be *failure scenarios*.

Failure scenarios have to consider all possible losses both of IEDs and communication links caused by system component failures and their impact on any function. These scenarios answer the question what functions have to be still alive in case of a single failure. These scenarios are driven by the impact both on operational cost, network stability, power delivery targets and endangered assets and human lives. The failure scenarios should also include steps for *graceful degradation* if applicable, meaning a non-catastrophic shut down of facilities and services in a gradual method which may allow some remedial actions against more widespread disruption.

An important underlying philosophy in protection systems is to ensure that at least a transmission level there are two independent, functions capable of clearing a fault (main 1 and main 2, X and Y, main and back up). This has generally been implemented as independent CT cores or current sensors, segregated VT signals or voltage sensors, duplicated protection devices and independent trip signals to duplicated trip coils or breaker IEDs. Such requirements result also in two fully segregated process bus communication networks.

All these requirements have a direct impact both on logical system structure and physical architecture of the communication system and answer also the question what parts of the system have to be *redundant*. Finally, they will influence the price level of the system. Therefore, availability figures or failure scenarios have to be given in the specification.

6.6.4 Time synchronization

The time synchronization requirements have to be specified if not already provided in the function specification above. Time synchronization requirements may be stated qualitatively in words or formally defined by the synchronization classes according to IEC 61850-5 [5] . Normally, two basic levels for time synchronization requirements exist:

- Typically 1 ms for the events reported (e.g. for event lists)
- Typically 1 µs for sample values and phasors (current, voltage)

The classes regarding time synchronization are defined in IEC 61850-5 [5] and should be used for uniformity reasons.

The system provider or integrator has to support these synchronization requirements by proper device selection and clock integration. Time synchronization accuracy belongs to the type test of any IED if applicable. Time synchronization accuracy of the devices in the system is important for the system performance and may be confirmed in the factory or site acceptance test and, therefore, has to be specified in the related test plans (see chapter 7 and section 6.1.2).

6.6.5 Architecture

Performance figures, availability figures or failure scenarios, and the synchronization requirements determine the communication architecture based on the capabilities of the Ethernet and its communication devices (mainly switches).

The physical architecture including IEDs hosting the request functions, cubicles, communication links, and dedicated communication IEDs (mainly with SA proof *Ethernet switches*) is the implementation of functional structure with all the performance and availability requirements. Recommended SA-proof switches will be normally part of the system offer. The system supplier or System Integrator has to take over the guarantee for the performance of the LAN.

If there is no predefined architecture by the utility, no architecture of the substation automation system should be specified. The architecture will be the result of the optimized system design provided in the offer.

The request for a predefined architecture always implies a predetermined availability or performance. It may restrict offering an optimized solution based on functional requirements only.

6.7 Constraints

6.7.1 Basic constraints

In section 6.6., the functional requirements to be stated in the specification have been listed and described. This information is necessary and sufficient to build an optimized system, which allows operating, protecting and monitoring the substation as requested. However in most cases any of the following constraints for the system – if applicable - has to be stated in the specification in order to achieve the desired result.

In the specification, the switchyard with all switchgear has to be defined so that the *location and type of process interfaces* are clear. Drawings and description by text is needed. The switchyard is also a source of electromagnetic interferences, which has to be considered in the design of the substation automation system layout.

The site of the switchyard including cable ducts has to be defined precisely as a constraint regarding the length and number of *communication links* needed. Its definition has to include all buildings regarding the substation automation system if applicable.

The site definition in the specification has to provide also all grounding means, especially for high frequency disturbances. This helps to identify sensitive areas, where special measures for electromagnetic compatibility have to be taken.

Other constraints of the site are the *environmental conditions* (refer to IEC 61850-3 [3]) including temperature range, humidity, corrosive environment, etc.

All these criteria are needed to be specified even for non-IEC 61850 systems. However as the standard allows the free allocation of functions and comprises the flexibility of Ethernet, the IEC 61850 based SA systems must designed and selected to maintain the level of security against mal-operation and not introduce elements that may be more sensitive or susceptible to these basic constraints.

6.7.2 Additional constraints

The additional constraints listed below have been mentioned already in different sections above.

- Pre-defined devices
- Pre-qualified degree of functional integration
- Pre-defined architecture
- Re-use of existing system parts
- Pre-defined process interface
- Requirements from the remote interface

6.7.3 Access and communication security

The specification has to include the requested levels of access control. This access control is supported by IEC 61850.

The complex issue of communication security against hostile intrusion or unauthorized access has different aspects. As long as the communication system is wire-bound and confined to the substation, intrusion may come only over the gateways for the remote links. Therefore, intrusion protection has to be done at this point.

In most implementations however there will be a number of *access points* within the substation specifically set up for this purpose which must be considered. The operator console, or HMI, itself is a potential access point threat both through the PC and by plugging in another device to the network. In some cases, specific connection points are provided for lap top and other equipment to be connected for the purpose of operation or maintenance within the substation by the utility staff or vendor support staff.

The security means depend also from the type of the communication network connected to the substation (dedicated, private, public, etc.). Therefore, the specification has to describe the types of the external communication networks to be connected.

In many cases these networks are running according to some utility communication standard (e.g. IEC 60870-5-101, -104, etc.), which is generally based on utility owned private communication systems. Although it is not in the scope of this report to assess the suitability of commercially provided communications systems, it is generally considered that such systems are not likely to offer the availability and event response times across a geographically dispersed network necessary to guarantee the power system performance and availability requirements which utilities are increasingly obligated to provide.

Many security problems have already been solved outside of the IEC 61850 environment. In order to provide security guidance for more open interfaces or environments, IEC TC57 has set up Working Group 15 to strengthen the existing standardized protocols including IEC 61850 for these issues. The results are being published in the standard series IEC 62351-x (refer to [28] - [31]).

Typically the security performance will be specified through the description of various scenarios, although there may be quantitative measures available in the future.

6.8 Migration

The specification has to state if there exist devices or system parts *not* compliant with IEC 61850 which have to be re-used or which have to be migrated to an IEC 61850 compliant system. If a migration is needed all related boundary conditions including time schedule have to be specified.

The response of the system supplier will be to provide a migration strategy. Note that any system incorporating a migration requirement with temporarily or permanent co-existence of compliant and non-compliant parts has to be treated on a case by case basis, given the starting configuration and the intended final configuration. Migration needs a close interaction of the user and the supplier in the specification phase.

The issue of migration is discussed in detail in chapter 4 of this report.

6.9 Formal description of the SA system

Both the single line diagram and the communication view (data model, links) of the allocated functions can be specified together with help of the *Substation Configuration description Language* (SCL). The result is the *Substation System Description* (SSD) file. If the customer specification is not written already in SCL, the System Integrator has to translate the conventional description into the SSD file to be used in the System Integration Tool (see part IEC 61850-6 [6]).

This formal description of the single line diagram may be used also for creating its graphical representation on the screen or the local HMI, but this is outside the scope of IEC 61850. The graphic representation has to be specified like any other function, e.g. in a set of screen views for the operator.

6.10 System integration

The specification under consideration requests a system compliant to IEC 61850 and has defined the functions, fixed the data model and stated all constraints. Therefore, all components offered have to be compliant also. The *supplier* has the responsibility to fulfill all requirements for his supply of system parts as given in the specification and stated (confirmed or modified) in the offer.

The standard IEC 61850 allows combining devices from different suppliers. Each supplier has the responsibility for his part. The responsibility for the complete system regarding integration, functionality, performance and quality has to be fully taken over by the *System Integrator*. The system integrator may be one of the suppliers, the customer or a third party. The system integration was also part of proprietary SAS solutions in the past, but the system integrator was hidden behind the proprietary system supplier.

The specification has to clearly define the *responsibilities* of the different parties, especially the very important role of the *System Integrator*.

6.11 Project management

The requirements for the project management are the same as in any other substation automation system. Recommendations for system and project management are given in IEC 61850-4 [4] . For the highly standardized systems based on IEC 61850 and consisting of components from different vendors, the *system integrator* is a new role that must be considered in project management also.

The project management is heavily influenced by the migration to be done over time or a complete replacement of the existing system. The extent of primary equipment replacement associated with or without the implementation of the process bus will have a significant bearing on the project management tasks. Every step in the project plan has to keep the downtime of the substation at a minimum. The project time schedule has to be defined also.

6.12 Maintenance

The customer of a substation automation system has to define or request a maintenance concept depending on acceptable down times or failure response time he needs, the accessibility of the substation, as well as the utility capability and philosophy. Depending on this, the specification must include a *maintenance contract* and/or a *maintenance tool*.

If the customer prefers to undertake maintenance activities by himself, the extent of maintenance responsibilities including the tools needed has to be specified. Maintenance levels are:

1. Localization of failures
2. Replacement of devices by spare parts
3. Extension of the system by data
4. Update of the system by functions
5. Extensions of the system by new bays

It is recommended for systems compliant to IEC 61850 that the maintenance is done tool-based using the substation configuration description (SCD) file. This has to be stated in the specification.

Software maintenance i.e. software version control is relevant for any changes and updates. The standard provides in the data model a number of places for software information and revision indices.

The software both for functions, data model and communication is installed in decentralized IEDs. Some kind of a centralized backup storage is useful to be specified.

If different parties are involved the *maintenance responsibilities* of all parties have to be specified very clearly. For the overall maintenance the counterpart of a system integrator is needed. This role may be called system maintainer.

6.13 Testing

6.13.1 Goal

The goal of the customer for testing is to get a system running perfectly as specified, offered and ordered. This has to be considered in the three types of tests described below. The scope of testing refers to devices and systems compliant with IEC 61850.

Since the customer requires a proper running system, testing requirements may be left to the *system integrator* independently who takes this role. The test specification for the system is an add-on to the customer specification.

6.13.2 Types of test

The conformance of devices regarding IEC 61850 is proven by a project independent *conformance test* according to IEC 61850-10 [14] . The conformance may be documented by a supplier's certificate declaration, statement in the data sheet, or a test certificate by a qualified test facility.

The operation of the system according to the specification has to be proven in the project both by the *factory acceptance test* (FAT) and the *site acceptance test* (SAT). Either the customer or the system integrator has to provide appropriate *test plans*, as negotiated between the customer and the system integrator. These *test plans* need also an approval by the customer.

6.13.3 IED conformance test

All suppliers have to be able to offer IEDs with functionality implemented and compliant with IEC 61850 as an international standard. To minimize problems in system integration, there has to be an accepted proof of this compliancy. IEC 61850 supports consistent self-testing and testing worldwide by its part 10 “Conformance Testing” (IEC 61850-10). This part makes no comment about “compliance authorities” but these authorities are qualified by the UCA International Users Group. There are some ways to the performance proof.

- Any IED supplier has to prove during device development and production that the IED is compliant with the standard. It is part of his Quality Assurance process as defined in IEC 61850-4 [4] and IEC 61850-10 [10] . Self-certification may be indicated by a label and/or a certificate if applicable. In any case, the self-certifying supplier is fully responsible for any deviation from the standard although this may not be detected until actual system integration is attempted.
- Conformance test centers are qualified by the UCA International Users Group. Label A is foreseen for qualified supplier independent test centers, level B for qualified test centers allocated to suppliers. The test procedures and qualities are identical.
- Conformance certificates can be obtained from these test centers. .

The customer has to consider what type of compliance certification is requested in the specification. Some flexibility may be required as some IEDs or some suppliers may have provided this in different ways and hence the chosen method may not be available for all IEDs or from all suppliers.

The *end-customer* or *system integrator* has to specify his certification requirements or may choose to take over responsibility for independent certification.

Project specific conformance tests of IEDs is of no value since the overall conformity including all project specific requirements is tested in the factory acceptance test (FAT) and site acceptance test (SAT) – see below.

6.13.4 System test

In the standard part IEC 61850-10, there are no system tests defined but suppliers may have a general system testing facility to minimize the risk in projects for the FAT and SAT. The utility may request information about such a test facility and methodology supporting the quality assurance process of the supplier.

6.13.5 Factory acceptance test

The comprehensive factory acceptance test (FAT) of a system is a well proven process to minimize the problems on site. The FAT for an IEC 61850 based system has to also prove that the data model, the communication services and the performance defined in the standard are in accordance with the project specification. There may be limitations to the extent of this real performance testing due to the availability of some system components in the factory, such as the primary switchgear and remote control centre links. These can be subsequently tested in the site acceptance test (SAT), if not simulated already in the FAT.

The customer has to request and negotiate as in the past the FAT plan as part of the specification. Since IEC 61850 supports testing, the time and effort for the test may be reduced by appropriate tools.

6.13.6 Site acceptance test

The comprehensive site acceptance test (SAT) of a system is also a well established process to verify the specified properties of the substation automation system on site. An SAT for an IEC 61850 based system has to also prove that the data model, the communication services and the performance defined in the standard is in accordance with the project specification. The difference to the FAT is that now all components of the system including the link to remote control centers and the related switchgear are available and tested together.

The customer has to request and negotiate a SAT plan as done today as part of the specification. Since IEC 61850 supports testing, the time and effort for the test may be reduced by appropriate tools.

6.14 Conclusion

To a large extent the specification of an IEC 61850 based substation automation system is the same as has been done in the past. The most important points to be made clear in the specification regarding IEC 61850 are:

- Functions should be specified without allocation to devices (IEDs)
- All boundary conditions have to be stated
- If more than the mandatory data are needed, optional data have to be identified. If more requirements for data exist extensions have to be listed in the specification.
- Figures for system performance and availability or – more recommended – failures scenarios should be specified.
- The type of the requested process interface according to the related switchgear has to be given.

6.15 Check list for SA specification

- ❑ Single line diagram
- ❑ Process interface
- ❑ Remote control/maintenance interfaces (type, number)
- ❑ Station level HMI (type, number)
- ❑ System functions including performance
- ❑ Site restrictions
- ❑ Pre-qualified devices (if applicable)
- ❑ Degree of function integration accepted (if applicable)
- ❑ Pre-defined architecture (if applicable)
- ❑ Re-use of existing parts (if applicable)
- ❑ Functions and function behavior
- ❑ Data model (refer to mandatory, optional, extensions in IEC 61850) or signal list
- ❑ Naming convention (if applicable)
- ❑ Communication performance
- ❑ Availability requirements for functions (figures or failure scenarios)
- ❑ Time synchronization requirements for the IEDs based on functionality included
- ❑ Pre-defined services (if applicable)
- ❑ Pre-defined architecture (if applicable)

- Access levels and communication security requirements
- Requirements for migration scenarios
- Allocation of responsibilities in multi-vendor environment incl. the system integrator role
- Milestones for project management (time schedule)
- Maintenance requirements and spare parts incl. responsibilities
- Request for maintenance contract if applicable
- Requirements for conformance tests, FAT and SAT
- Request for deliverables (1) system with all components
- Request for deliverables (2)product documentation on paper and file for any IED including drawings, MICS, PICS, and ICD file, compliance test certificate
- Request for deliverables (3) system documentation on paper and file for the complete system including drawings and the SCD file

7. Project execution

7.1 Introduction

In this chapter, the report identifies the differences that IEC 61850 will bring to the execution process although the details of what would be considered as the essential elements of a more traditional project have not been presented. A 'normal project' means here a system delivery philosophy consisting of components, functions and responsibilities proven by past experiences as effective and appropriate in non-IEC 61850 based projects..

7.1.1 The start

The operation stages required for the execution of a control system project applying the communication protocol IEC 61850 will not change compared to now.

Figure 19 refers to the chapters in this document and their order with IEC 61850. Whilst any project execution strategy will need to consider a large range of issues they can be considered by the utility from different perspectives identified in each of these chapters of the report. To set-up a new structure for the project execution system at the company's strategic level, there has to be an understanding and support from the business goals point of view.

This chapter tries to cover the project execution process that starts after the order contract for the SA system has been signed. The content of this is based on the chosen migration path, specifications of the ordering party, the offer of the supplier (or suppliers if more than one), the documentation from the offer negotiation stage and on the supply contract or supply order made up of these documents. During the negotiation process it has been defined in detail which components the SA system consists of and which functions are included as well as the boundaries of the delivery regarding the connection of the SA system to external systems.

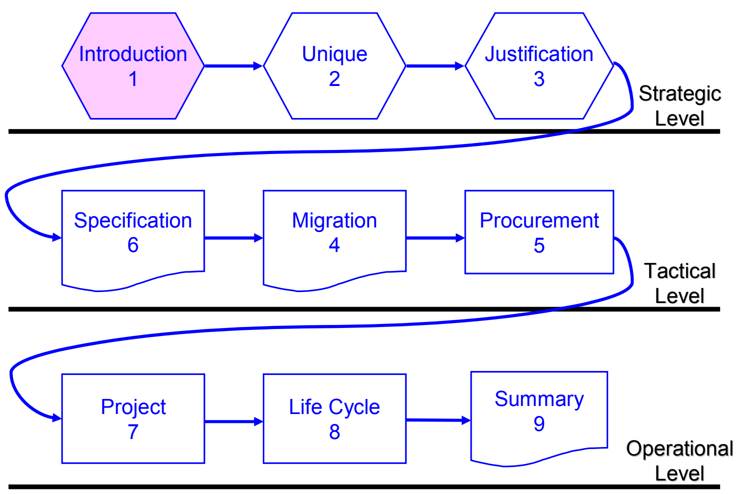

Figure 19 - Overview of chapters

7.1.2 Move of responsibility & impact

The use of standard protocols is beneficial, but it has transferred more responsibility for the interoperability of the communication environment from the supplier to the *System Integrator,* these entities no longer necessarily being the same company. The standard gives the utility the opportunity to specify to a certain extent its own requirements based on standards. This may require a more pro-active role of the utility compared to projects and/or systems with proprietary solutions.

This has impact on all stages in Figure 19. The execution process consists of various parts, which possibly will be carried out by different parties. The transparency brought in by the standard IEC 61850 enables the utilization of several different execution models. Regardless of the execution model, the quality, compatibility and functionality of the different execution stages must be clearly defined, accepted and visible. An execution organization has to be defined in the negotiation and supply phase showing which organizational unit is responsible for the overall functionality and the compatibility of the system, i.e. who is the *System Integrator*. The responsibilities of the customer (user), provider and system integrator in project execution are also mentioned in IEC 61850-4 [4] paragraph 7 “Quality assurance”.

The responsibility referred in this section is the responsibility for defining functional specifications and the boundaries of how to use IEC 61850 as the user. These points are discussed in the chapter 6 “Specification”.

7.1.3 Goal of the project process

The challenge is to transfer written definitions into a real operational system in an effective way within budget, time and the requested quality. Those written definitions are defined in previous stages and mostly in different departments. The impact on costs of IEC 61850 will come to surface in the project phase, which can be divided in two parts:

One-time costs

- Introduction 61850 ↑

Repetitive costs

- Engineering ↓
- FAT & Commissioning ↓
- Replacement of equipment “proof of principle” ↓
- Devices ↓↑
- Infrastructure for substation automation ↑

One-time costs are costs that must be invested because this new technology has to be introduced in the user’s company, which needs training about IEC 61850, i.e. the approach and the used technologies as Ethernet and TCP/IP. The utility project team has to learn the dedicated specification procedure, to read the documentation supplied with IEC 61850 compliant devices and systems including the related SCL files and become accomplished with user’s tools and all other operational aspects affected by the implementation of IEC 61850.

The initial mental shift needed when using IEC 61850 is easily underestimated, because the power industry has limited experience in using combined functions in one device, reduced or even no hard wiring for trip signals, etc. Also real multi-vendors systems are not common up to now.

Repetitive costs are the costs you also have in each project such as engineering, testing, devices, infrastructure, etc.

7.2 Quality Assurance

Quality Assurance is the combination of Quality (what do you need) and Assurance (you get what you need). As seen in Figure 20 it may seem from a cursory assessment that a system satisfies the general specification and intent, but it must also be assured as fit for the purpose.

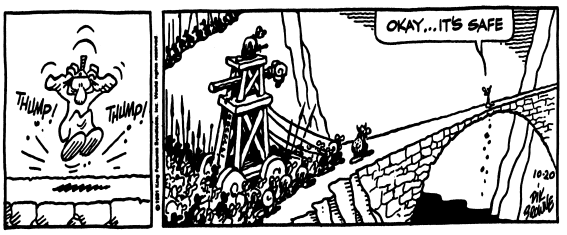

Figure 20 - Quality Assurance

Open standards give users the opportunity to increase the level of quality assurance, namely having better control on the outcome of a project by better control of each part and step (see Figure 21), and detect deviations from the specification in an early stage.

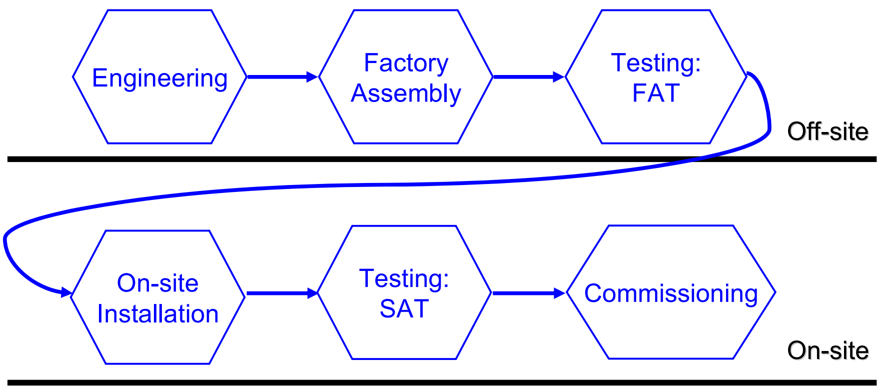

Figure 21 - A project phase chain

Solving deviations from the specifications on-site has a huge impact on the three project aspects as being money, time and quality. It is proven that solving detected deviations on-site cost a multiple factor both for both user and vendor compared to solving these off-site. Reference is made to IEC 61850-4 [4] paragraph 7 “Quality assurance”.

7.2.1 Engineering

The goal of engineering is to translate the specification into a detailed technical solution to be able to start production i.e. factory assembly mainly. The starting condition for the engineering process is a complete specification as discussed in chapter 6 and listed in section 6.15. Especially important are

- Specifications from previous projects (experience, not formally described)
- Single line diagram of the substation and/or bay to be controlled by the system
- The functionality requested for the SA system
- The capabilities of the IEDs’ to be used in the project, called ‘IEC capability description file’ (ICD)

- All boundary conditions applicable

The differences with the traditional systems are:

- The formal description of the IED capabilities and the complete SA system with help of the SA Configuration description Language (SCL) according to IEC 61850-6 [6]

7.2.2 Factory assembling

The goal of factory assembly is to assemble and built the system according to the specification, which is formally described in the results of the engineering process. The starting conditions for the Factory assembly are:

- The SCL files
    - 'substation description file' *.sad describing the single line diagram of the substation with the associated functions represented by logical nodes
    - 'substation configuration description file', *.scd describing the complete substation configuration with single line diagram, communication network, IED configurations, binding information (e.g. trip matrix)
    - 'configured IED description file', *.cid for each IED describing all configuration parameters relevant for that IED

- IEDs that comply to
    - Communication according to the *.cid file, which means conformant with the applicable PICS, MICS and PIXIT
    - Performance and additional requirements for testing according to and PIXIT

The differences with the traditional systems are:

- the support of the factory assembling process by the SCD file

7.2.3 FAT

The goal of the factory acceptance test is to test the functionality of the system to be installed on-site.

The starting condition for this phase is:

- The complete assembling of the system
- The complete documentation of the system on paper and files if applicable
- Simulator(s) for missing parts
- Test plan negotiated between the system integrator and the user

The differences compared to traditional systems are:

- Support of automatic or semi-automatic testing by the SCD file
- Easy simulation of missing parts with help of the SCD file
- Object oriented tests compared to conventional signal tests my reduce the test effort

7.2.4 On-site installation

The goal of on-site installation is to install the SA system approved in the FAT in the final operative environment. The starting condition for this phase is:

- The complete material of the SA system on-site
- The complete documentation on paper and files if applicable on-site

The differences compared to traditional systems are:

- Depending on the actual system design, a lot of wires may be replaced by serial connections

7.2.5 Commissioning

The goal of commissioning is to set the SA system installed on-site into operation

The starting condition for this phase is:

- Finalization of in-site installations with first tests like power supply, correct cabling and provision of all serial links

The differences compared to traditional systems are:

- The use of different tools and processes to prove correct connection and operation

7.2.6 SAT

The goal of the factory acceptance test is to test the functionality of the system under on-site conditions.

The starting condition for this phase is:

- Finalization of the commissioning
- Updated as-built documentation available on paper and files if applicable
- Test plan negotiated between the system integrator and the user

The differences to traditional systems are:

- Support of automatic or semi-automatic testing by the SCD file
- Object oriented tests compared to conventional signal tests my reduce the test effort

7.3 Engineering

7.3.1 Introduction

One of the key benefits is the re-use of engineering efforts. The re-use factor for engineering of the communication inside the substation is today low in most cases due to the lack of

- Standard modeling of substations equipment
- Formal system description of all communication links
- Generic engineering tools
- Open method for configuring IEDs

7.3.2 Standard modeling of substations equipment

Instead of mapping the signals of every component to an address in a protocol, the object oriented data model of IEC 61850 means:

- Engineers don't have to think about what signals have to be mapped, but only have to choose what is in the model and define their event driven sending by data sets and control blocks
- No explicit address list necessary because IEC 61850 is using object names resulting in
  - no address configuration necessary on the client (master station) and server (slave station)
  - no addressing mismatches in case of gateways
- The signals don't have to be defined for every device of different manufacturers or even different types of devices of the same manufacturers, but can be done once for typical substations or per bay independently of the manufacturer
- Information to be sent to the Control Centre only has to be defined once and mapped only once to a telecontrol protocol such as DNP3 or IEC 60870-101/104
- The modeling is also supported by the SCL

7.3.3 Generic engineering tools

There have been no engineering tools capable to engineer the communication of the used IEDs from multiple vendors in a substation. IEC 61850 opens the road to

- Exchange information of the whole substation configuration up to the IED configuration (see also 7.2.1, page 77) without manual configuration
- Use the Substation Configuration description Language files (SCL files) to import or export configurations to and from tools of different manufacturers
- The IED capabilities can be imported in the system engineering tool, resulting in
  - Up-to-date information of IED capabilities
  - Storage of the capabilities of the engineered IED in case of replacement
- Exchange of detailed engineering data in a formal, open and standardized way between the different parties in a project, such as system integrator, IED manufacturers, communication equipment suppliers, etc.
- Definition on how to make data extensions, which can be interpreted by every manufacturer. This results in an open communication infrastructure with generic method of describing data extensions. Data extensions with no meanings are allowed to be implemented by the manufacturer only if using the name space feature. Generally, such private data extensions should be minimized but, if of general importance, forwarded to the joint Group of Experts of the IEC TC57 and the user organization UCA International to add these data into amendments and future versions of the standard (see Section 2.11).

7.3.4 Open method for electronic configuration of IEDs

IEC 61850-6 describes the file format for exchanging SA configurations with the following data:

- System configuration (e.g. single line diagram) in the SSD file
- IED capabilities (what are the technical capabilities of the IED) in the ICD file
- System and IED configuration in the SCD file
- IED configuration data after system configuration in the CID (configured IED description) file

This means:

- Final configuration of the IED without manual configuration, but with the IED configuration tool / file (*.cid) resulting in:
  - Significant reduction of configuration time per IED is a real expectation
  - Configuration of new device in case of replacement in less than a few hours is achievable
  - Easy and simple re-configuration, if the same IED is replaced by the same type, by using the same *.cid file
- Easy and simple re-use of the engineering effort by using the system configuration description file (*.scd) and importing new IED capabilities by loading the relevant (*.icd) file. Any re-engineering is based on those capabilities generating a new IED configuration file (*.cid) file
- Reduce the boundaries using different manufacturers implementation, because the files are standardized and accessible for everyone

7.4 Testing

7.4.1 Introduction

The testing phase is the key in a system integration project in order to ensure that the specification is met. The aim of this section is <u>not</u> to describe once again some traditional tests definitions (such as FAT, Factory Acceptance Test, SAT; Site acceptance Test, etc.) nor well established principles (device qualification, end-to-end test, QA role, etc) <u>but</u> to focus on what differs with the use of IEC 61850. Guidelines for conformance testing of devices and for interoperability testing in standardized SA communication systems as IEC 61850 are described in [39] .

This communication standard offers tremendous new opportunities discussed in the previous sections but may also imply additional tests depending on what is requested: mixing any devices of any suppliers, adding new automation or redefining the functional mapping between devices has a cost that will be explained here.

Use of methodologies and tools will be discussed. Clearly the need is to go beyond the often seen “demo” that only covers a part of the job to be done.

7.4.2 IEC 61850 Specific testing requirements

Compared to traditional communication protocols, such as IEC 60870-5-103, DNP3, MODBUS, etc., the IEC 61850 offers the following testing challenges:

- Use of Ethernet: Ethernet is extremely open and a lot of devices are available on the market to build a *communication infrastructure*. Ethernet is now very common in offices and is by no means trivial to use the right specialist to configure it properly. This infrastructure represented by managed switches must actually meet the substation environmental conditions (EMC, battery supply, etc.), the dependability requirements (partial or full redundancy management for instance) and the performance needs (respect of the peer-to-peer reconfiguration delays when breaking one of the link for instance).
- Use of a *client-server* paradigm instead of a master-slave one. The server (typically a protection relay) must manage one context per client, such as the list of reports required by the client including the criteria to be checked to send the report and the data contained in the report. The performance of the server might be dependant on the number of clients connected and complexity of the reports required. Since there is a virtually unlimited combination of configurations here it is unlikely that all tests results will be provided by the IED suppliers. In reality, the number of clients per server should be a minimum of 5 and, therefore, the complexity of testing is limited.

- Use of an additional publisher/subscriber paradigm (used by the GOOSE service) in order to facilitate the design of fast distributed automation. The GOOSE message is repeated - initially quite fast after a change of state of any information belonging to the GOOSE data set – then with a slow period to supervise the sender and the link. The performance of the receivers may depend of the number of GOOSE messages to process and the complexity of their data structure. The input buffer size is mainly responsibly not loosing messages.
- Fast communication between IEDs is enabled by the GOOSE service. It is used for example for interlocking, reverse blocking schemes, local trips, breaker failure trips and fast automation, replacing hundreds of copper wires in the medium term. Besides this time critical data exchange there may also be project specific applications realized with help of GOOSE resulting in function specific tests. The tests shall not only check the interoperability but the performance and endurance in nominal but also degraded cases (see next section).
- Data mapping is another improvement provided by the new standard. Making sure that the interpretation of the few words describing each data is consistent between the suppliers is the key. This implies checking the communication in relation with the detailed application processing. Therefore, it needs both communication and application specialists to test this.

7.4.3 Test categories

The tests can be classified into the following categories:

Single device:

- Conformance tests as per IEC 61850-10. Such tests are mandatory and may be done internally by each manufacturer or by an external center. Test institutions are qualified by UCA International for performing such conformance tests and issuing the related test certificates.

System:

- Further tests are not defined in the above standard in order to facilitate the project execution. This includes: specific performance tests (cf. above section), data mapping test (idem), regression check (see below), etc.
- Tests of multiple devices from different suppliers in a system to prove interoperability are not defined in the standard. Such tests have to be done in a given context of a generic configuration, which is not specific to a particular project. Missing devices are easily simulated with support of the SCD file. Also the performance and the engineering of the tested components and of the resulting system are checked. Such tests are necessary, but not sufficient in their own right for the project. But they will heavily reduce the risk for integrating of the tested devices in a system including different interpretations and implementations of the standard. Therefore, they also heavily reduce the probability of problems during FAT and SAT.

Project specific tests

- These tests (FAT and SAT) include the comprehensive verification of the complete specification i.e. not only of the communication infrastructure but also the behavior and performance of functions, especially of the distributed functions, and more.

Regression tests

- These tests are needed when there is a change of the software in any component which may likely be happen in any project for bug fixing or extensions of SA features. Their definition is clearly specialized skill to be able to confirm a level of confidence that the changes have been correctly implemented with no adverse affects on other elements, especially when ignoring how the changes may affect the communication. The risk is minimized if all changes are entered in an appropriate system engineering tool updating the SCD file. The resulting new CID files have to be downloaded to all affected IEDs. The IEDS affected may be easily identified automatically with help of the SCD file.

Extension tests

- This is needed when making extensions in the substation already energized. This might affect the distributed functions and the performances of the system. The performance tests shall normally have been anticipated and therefore tested during the initial design but this is not always the case. As for software changes above, the update of the SCD file and the following update of the CID files of the affected IEDs will minimize the risk.

7.4.4 Test methodology

This section only discusses the tests to be done in a *system* environment (see also Test category 'System' in the section 7.4.3 above).

It is recommended to have first a general interoperability tests session before proceeding to the project specific tests (and then regression and extension tests).

Each test session shall be managed by a *test plan* and *tests sheets*. The test plan and tests sheets are documents that shall be reviewed and accepted by the different parties, i.e. by the suppliers, system integrator and end customer.

The test plan shall contain:

- The configuration under test.
- The list of tools needed to make and verify the tests (see below).
- The list of test objectives. This shall be organized in nominal, degraded, performance and endurance tests.
- Degraded: this shall test the various combinations where some data are missing or invalid, when time out has elapsed, etc. due to missing devices, result of self-check, etc.
- Performance: this shall test the behavior of the system under maximal stress conditions, i.e. avalanches of input changes or GOOSE.
- Endurance: this shall test the long term stability of the network, making sure that for example data losses do not occur or do not endanger the system.
- The philosophy and classification of test acceptance/rejection: minor, major, and blocking.
- The process to manage the tests: actors, management of fault report and release, etc.
- The planning and actual resources.
- The test form and fault report form. This shall clearly identify the version of the test, the versions of the devices, etc.

Important is that the test system is fully engineered in the same manner as any project but using the SCL. In addition, the test should be performed with *test tools* using test scripts based on the SCD file of the test system. This option facilitates testing and is one of the benefits using IEC 61850.

7.4.5 Test tools

Test tools include:

- *Process simulator* being used to create external stimuli to the devices: binary or analogue inputs. What is specific to IEC 61850 is that there might be the need to synchronize the various inputs in order to validate distributed functions not existing before.
- *Network analyzer* being used to understand what messages are circulating on the network. For the most cases it is very beneficial if the network analyzer is not displaying the traffic on Ethernet of MMS level but on the Data Model level of IEC 61850.

- *Equipment simulator* being used to supply messages of missing equipment e.g. for creating the real traffic on the network using dedicated scenarios. The use of the substituted ICD file of the simulated IED for creating the SCD file specific for IEC 61850 based systems.
- *Test monitor* being used to display the result of the tests. This might be the standard station level HMI (Human Machine Interface). If applicable, test results may be also given by supervised output relays, etc. If the device evaluating tests is a very specific one then it should have at least an IEC 61850 based feedback link to the SA system under test e.g. to the station level HMI.
- *Test database* being used to manage the various tests script for all simulators and testing sequences and the related results.

7.4.6 Tests costs

- Interoperability may have a cost tag and the flexibility brought by the IEC 61850 shall be used carefully with respect to delay and costs constraints.
- Re-use of proven SA schemes is a clear way to reduce such costs in term of tests definition. Therefore, first a detailed library of SA schemes has to be created and then a list of appropriate interoperability tests which shall certainly be pursued in the future.
- Re-use of proven IEDs associations is another one. This is a similar concept than a device qualification but involving several suppliers. Note that it does not cover GOOSE and SV messages.
- Insulating logical flow of data and associated function is another one. As such the concept of "standard bay" can contribute to such optimization see **Error! Reference source not found.**.
- The worst case: Such tests may involve the different parties, at least the System Integrator and the end user but may be also additional suppliers. The associated cost must be clearly specified and understood at the beginning of the project in order to avoid blocking it for financial reasons. Everything will not be resolved overnight so it is recommended to have a progressive approach in the complexity of such projects, make prototype for new features and be prepared for compromises.
- The best case:
  - For the IED all test steps have been done from internal tests in IED development over the conformance tests specified in IEC 61850-10 [14] and the non standardized system tests mentioned above. The IED should work properly in an IEC 61850 based system.
  - The system design is made using IEDs certified for IEC 61850 conformance and by using a fully fledged system engineering tool creating a comprehensive SCD file.
  - The CID files are automatically derived from the SCD file.

  In this best case the project specific SA system will have no more problems in the FAT and SAT than a legacy one. The higher degree of automation in testing facilitated by SCL support may reduce also the test costs.

7.5 On-site activities

7.5.1 Introduction

The impact on the on-site activities can be optimized and reduced by controlled Quality Assurance, Testing Strategies and Engineering as in the previous paragraphs.

7.5.2 Reduction of planned outage time

7.5.2.1 In the installation phase of the SA system

Installation of IEC 61850 based systems takes less time because nearly all the problems have already been solved in the IED conformance test, the system test as mentioned above, and in the FAT. The problem left open is the completeness of the FAT regarding system components and the process interface to the switchgear.

If for the process interface predefined standardized plugs are used the interface problem is negligible. The process interface may be based on process level IEDs using the process bus according to IEC 61850. In this case the use of the related ICD and CID files in the engineering process cover the interface problems totally.

7.5.2.2 By maintenance of switchgear on demand only

The IEC 61850 supports Circuit Breaker Monitoring (CBM) information e.g. the circuit breaker may indicate if 90 % of its allowed number of switching actions is reached.

7.5.3 Reduction of unplanned outage time

7.5.3.1 By self-supervision of the SA system

The implementation of the Health feature is mandatory for IEDs compliant to IEC 61850. Therefore, an appropriate self-supervision as existing in modern IEDs may report selectively any failure. In case of replacing a faulted IED by a spare IED, the old configuration file may be used directly for the new one. Depending on details in the implementation, the integration of this spare IED into the system may be easy also without real ‘plug and play’ today neither supported by the standard nor by any device in SA systems.

7.5.3.2 In case of switchgear failures

IEC 61850 has introduced the concept of External Health referring to switchgear outside the processors of the SA system. This feature and all the Circuit Breaker Monitoring (CBM) information provides all means for a quick detection and maintenance of a faulted breaker or any other components in the switchyard.

7.6 Conclusion

Implementation of an IEC 61850 system in essence follows the same project methodologies as have been tried and well proven in the past.

Some additional processes are needed to cater for the specifics of IEC 61850 but the benefits of the standard in both the old processes and additional steps should result in a more effective project execution.

8. The impact of IEC 61850 on life-cycle management

8.1 Introduction

The lifetime of a conventional SA system (electromechanical or electronic generation) is typically 25 to 35 years due to refurbishment constraints. The goal is to avoid frequent substation refurbishments that result in huge costs of non-transported energy and re-testing. The cost of de-energizing feeder lines and transformers is much greater than the acquisition cost of the SA system itself. Calculation of the return on investments of the SA system is not appropriate or practical as a basis to define the correct point in time for refurbishment and must be correlated with the grid operation constraints.

Consequently, the utility is interested in extending the life span of the secondary equipments to minimize the impact on the primary equipments and, therefore, on the power system and power delivery.

The key issue is to reach an acceptable life span with a digital technology that has a traditional commercial duration of 10 to 15 years. A reasonable goal is to have maintenance services during 15 to 20 years. A lower value would mean that the technology is not mature enough for realistic and feasible use within the substation environment. These figures are matched by the legacy SA systems and are also valid for IEC 61850 based ones.

The following maintenance activities are inescapable to achieve proper lifecycle management:

- Training
- Technical support
- Preventive maintenance
- Spare parts supply
- Corrective maintenance
- Obsolescence management
- Software evolution
- System extension
- Version control
- Performance measurements

According to the Transmission System Operator's (TSO) industrial strategy, these activities can be entrusted partially or totally to the suppliers.

With the growing complexity of substation automation in digital technology and the previous lack of any comprehensive standard, the utilities have reduced the technical expertise they may have had.

Until the advent of IEC 61850, the utilities have had to cope with proprietary technologies or standards limited to dedicated purposes. The necessary degree of expertise to combine these varied protocols and achieve global functionality is high. A very common approach to overcome these difficulties was to purchase the digital SA system as a "black box".

The TSO as a customer defines its requirements in terms of

- Functional behavior
- Performances and maximum capacity
- Reliability and availability

- External interfaces

The customer purchased the digital SA system as some kind of turn-key product ready for installation and commissioning.

The provider was responsible for an all-inclusive package including the product and the attached support services so as to control the overall ownership cost. These services were commonly

- Engineering and data configuration
- Factory and Site acceptance tests
- Long-term maintenance (spare parts provision and extension services during the product lifetime, software debugging, training …)

With proprietary technologies, the SA system maintenance was entrusted compulsorily to the provider during the whole lifecycle. It was complex to ensure interoperability and some level of device interchangeability. The forward compatibility of successive system generations has to be guaranteed by the supplier but was not granted.

The use of the IEC 61850 makes it possible to choose between several industrial strategies and procurement procedures for truly multi-vendor SA systems. The modern features of the IEC 61850 such as interoperability and free allocation of functions enable the definition of standard interfaces within the SAS for example at bay level or IED level.

In a multi-vendor scheme, the role of the System Integrator is essential in the procurement process and also for the lifecycle management.

This chapter assesses the impact of the procurement of a multi-vendor SAS on maintenance activities.

Generally, it is important that all roles needed in the different phases of the life cycle are clearly defined and negotiated from the beginning.

8.2 System-wide maintenance

8.2.1 Objectives

The basic need is to provide system-wide maintenance even though the SAS is composed of multiple vendor IEDs. The substation owner’s requirement is that the internal interfaces should be as transparent as possible and should not disrupt the lifecycle management. This is the reason why the role of the *System Integrator* is not limited solely to the procurement process but is extended throughout the SA system lifespan. After the commissioning and Factory Acceptance Test, the system integrator’s role becomes that of a *System Maintainer*. This would be a good choice but sometimes this role has to be taken over by another party. Therefore, the roles of the System Integrator and the System Maintainer have to be defined separately and negotiated from the beginning.

As a corollary, the same level of maintenance and device management should be provided for all the IEDs otherwise the poorly maintained IEDs may endanger the performance and life-expectancy of the entire system.

The requirements defined for the aforementioned services are thus applicable to all the equipments whether they are at substation level, at bay level or part of the communication infrastructure.

8.2.2 Coverage

The maintenance services cover the whole spectrum of the SAS:

- Substation level: station computer, HMI, telecontrol gateway, remote access gateway, etc.
- Bay level: bay controller, protection relays, monitoring devices, etc.
- Process level: sensor and actuator IEDs, merging units (MU) if applicable, etc.
- Communication infrastructure: switches, fibers, etc.

The bay cubicles and the on-site stock of spare parts are included as well in the SAS maintenance.

The services encompass the hardware and software, function and data configuration aspects, independently from the supplier.

The *system maintainer* is a role to be defined and negotiated same as all others in the SA project. The utility may take over this task or outsource it to any competent (third) party. It should be noted that this party needs in addition to competence also all relevant tools.

8.3 Training

The training sessions for the utility and their content vary according to the services the utility has outsourced:

- On-site cabling, fiber termination, installation (along with Site Acceptance Test) or/and commissioning,
- Data configuration and version upgrade (on-site loading of the new version),
- Remote and on-site operation/maintenance.

Consequently, the following table should be interpreted and adapted with regard to each TSO industrial strategy.

Table 10 TSO industrial strategy

Profile	Description of know-how and tasks
Operation	Basic knowledge of the SAS architecture, its interfaces and the role of each IED Allocation of functions within the system Local control (HMI: overview picture, event list, alarm handling, issuing commands, local/remote operation modes) First level of maintenance (diagnostic of anomalies, assessment of the impact on SAS functions) using the event recorder, the system supervision, the IED logs Upload of disturbance records, fault location records, settings and sequence of events
Maintenance	Expert knowledge of the SAS architecture, its interfaces and the role of each IED Allocation of functions within the system Behavior and settings of each function Preventive maintenance Replacement by spare parts

Profile	Description of know-how and tasks
	Modification of settings Functional testing using secondary injection tester if applicable and the local HMI Expert access to remote maintenance tools (system supervision, data configuration, disturbance records)
Configuration and version management	At least basic knowledge of the SAS architecture, its interfaces and the role of each IED Expert knowledge of SCL and the role of the associated configuration files (SSD, ICD, SCD, CID) Expert knowledge of the SAS architecture, its interfaces and the role of each IED Allocation of functions within the system Settings of each function Configuration process in a system-wide perspective Database administration (upload / download, import / export archiving / restoring) Version control (compatibility of hardware/software/data configuration versions) On-site version upgrade (data configuration or/and software) Modification of settings
Installation and commissioning	Expert knowledge of the SAS architecture and its interfaces Allocation of functions within the system Behavior and settings of each function Installation precautions and guidelines SAT procedure Functional testing using secondary injection tester if applicable and the local HMI Dedicated testing tools if applicable

At the end of any training session, an assessment of the new skills of the personnel should be conducted to ensure they have the necessary competencies to operate, manage and modify the SA system without risk to its performance and operation.

8.4 Technical support

The objective is to provide assistance to the operation and maintenance crews in order to bring the system back to normal status when the normal maintenance procedures do not solve the problem. The technical support can be supplied through several media:

- Hotline
- Fax
- E-mail
- On-line web assistance

- Remote access to the system supervision
- On-site assistance if all the other alternatives have failed

The technical support is critical for major anomalies and the corresponding service has to meet the following requirements:

- Direct access to the system integrator (no re-routing)
- Direct access to the supplier experts (no re-routing)
- Sufficiently staffed to handle simultaneous calls
- Suitably trained experts
- Proper level of performance (answer and response time)

The technical support can also be extended to less urgent matters such as data configuration or installation. In that case, a separate level of support has to be defined.

8.5 Preventive maintenance

The digital technology minimizes the need to perform preventive maintenance thanks to the self-supervision of IEDs and system functions. Some system parts may have ageing or consumable components to be exchanged periodically. The System Integrator or Maintainer has to issue the guidelines for the preventive maintenance for each IED and to state

- The periodicity: if the recommended period is exceeded, the supplier can disclaim all responsibility
- The content: the preventive maintenance should not require a high degree of expertise or specialized tools. It can be performed within the substation without any external help. Typically, the preventive maintenance consists in cleaning the filters, replacing the batteries, the capacitors, the consumables or aged parts

8.6 Spare parts

The requested stock of spare parts depends on the maintenance philosophy of the utility or supplier. But it is depending also from the availability of spares from the supplier and the transport time to the site.

Maintenance contracts may be negotiated with or without spare parts.

8.7 Corrective maintenance

8.7.1 Data configuration maintenance

Updates if applicable and necessary

8.7.2 Software maintenance

Updates if applicable and necessary

8.7.3 Hardware maintenance

Updates if applicable (see also section 8.8) and necessary

If not possible anymore, IEDs including functions/software have to be replaced with functional equivalents. This is facilitated by IEC 61850 under the assumption that both the old and the new IED are complaint to the standard.

8.8 Obsolescence management

The System Maintainer's responsibility is to provide spare parts from the suppliers throughout the SAS lifespan and monitor the technological development. He should periodically produce a comprehensive obsolescence report analyzing the remaining lifespan of each component of the SAS architecture and monitoring the supplier strategy to prevent any supply disruption. That report should anticipate any software or hardware obsolescence two years ahead to ensure SAS durability. Recommendations for suppliers in regards to the announcement of hardware and software updates, and of discontinuation of production or maintenance are found in the standard [4] .

Due to the fact that the SAS life expectancy is greater than the commercial lifetime, the spare parts can not be strictly identical over the years. The requirement is thus to provide a functional equivalent (see above).

For the bay level IEDs, it is recommended that the functional equivalent is supplied at the module level (binary I/O board, CT and VT board, analogue input board, communication module, DC-supply module …). More compact devices in the future may request replacement at IED level. Bay level IEDs have a typical commercial lifetime i.e. maintainability of 10 to 15 years disregarding factors such as new processor chips, etc.

At substation level, the station computer and HMI are either PC based or come from the standard computer science industry and have an average commercial lifetime of 5 years including the operation system and drivers. Therefore, the replacement of this station level equipment as a whole may be the most reasonable solution.

It should be noted that there are gateways with the same life time as a bay IED.

The life time of substation environment proof Ethernet switches is generally better than the life time of the station level PC and is moving towards that of the bay level IEDs.

The version evolutions have to meet the following requirements (see also IEC 61850-4 [4]) under the assumption of the same functionality:

- Software/hardware compatibility : a previous project-specific software can be ported to the new hardware generation
- Backward/forward compatibility : a recent bay controller interoperates with the previous system generation
- No negative impact on the behavior of the functions and their performances
- No negative impact on the reliability and availability
- Minimization of the influence on operation
- Significant gain in SAS durability
- Control of the maintenance cost

An alternative solution to the re-conception of functional equivalents is to set up a strategic stock. That solution has significant drawbacks and should only be considered as last resort when the supplier has no longer any capacity to provide maintenance. That solution involves freezing the hardware and software versions and hindering any evolution. A key issue is to estimate the proper content and size of that stock based on reliability statistics and estimates of system extension.

In case of a supplier no longer being in business, some users have considered a requirement to be able to transfer the production of spare parts to a third-party according to a backup plan. This plan has to include all the relevant information needed to redesign from scratch the appropriate modules and equipments. Since the interoperability provided by IEC 61850 allows, with careful evaluation of functional differences, replacement of IEDs with ones of other suppliers, this approach is neither cost efficient nor needed.

8.9 Software evolution

The software of bay level IEDs is evolving but generally does not need to be changed if no bugs have to be corrected nor if new functions have not been requested. However the software of general computer equipment is also evolving and is more likely to require updates to keep maintainability, e.g. for new applications that need to be run, new hardware components such as hard disks, display adaptors, network interface cards etc for which the old software may not be compatible or not provide appropriate drivers.

8.10 System extension

The extensions of the system with new software functions may be very limited by the capability of the existing hardwired I/Os or by the performance of the microprocessor, which may lead to additional hardware changes to the existing system as part of the migration strategy. This may be mitigated to some extent by initial purchasing strategies which provide for additional hardware power or performance in anticipation of the increased demands of new applications in both areas, given such technologies are said to double in performance every few years.

The addition of new IEDs or a complete new bay is supported by IEC 61850 but it needs a reengineering to update the SCD file and downloading CID files to all affected IEDs.

8.11 Version control

A global SAS version control is essential at the project start and throughout the SAS lifespan.

The integration of a multi-vendor SAS requires a careful check of compatibility and interoperability between the varied IEDs assembled in the architecture. The System Integrator is responsible for the global functionality of the system. In that context, the System Integrator has to map the functional specifications of the utility by selecting the proper IEDs and the adequate allocation of function.

The hardware/software version of the IED clearly states unambiguously:

- The compliance with the IEC 618505 (according to part 10 – conformance testing)
- The implemented functions
- The implemented communication services
- The data model

The version number provides all the necessary information for a safe and seamless integration of the IED. IEC 61850 also provides different *version indices* which allow the user to identify changes in the SA system.

All these facilities support the system maintainability and device interoperability but not device interchangeability.

The *interoperability* is a prerequisite for the interchangeability but is not sufficient. The functionality and functional performance of devices are stated already in the specification. If a new device is compliant with the specification, interchangeability is possible, noting what functions are provided in the new IED. The physical aspects of installing the device may still be different or there may be different conventional I/O arrangements. An identical set of incoming and outgoing data will raise no problems for system integrations, but an update of the SCD file and of all impacted CID files is needed.

The System Maintainer has to examine the ICD file of the new device to check whether this IED implements compatible functions along with the associated logical nodes and compatible communication services. The ICD file is the “business card” summary of the IED capabilities and provides all the necessary information for integration in the early stage of the project and later for device interchangeability when the time has come to replace it.

8.12 Performance measurements

The System Maintainer should periodically produce performance measurements of the system and of the subcontracted services.

The data compiled by the system integrator shall cover for the technical aspects:

- Reliability and availability figures
- Major anomalies with impact on operation
- Performance of the protection and automation functions

The utility monitors the service quality via sets of Key Performance Indicators (KPI) such as:

Table 11 Service quality KPI

Service	KPI
Training	Ratio of satisfied trainees Ratio of suitably trained staff (control of the knowledge acquisition at the end of the session)
Technical support	Yearly ratio of satisfactory answer and response times Quality of the technical answers and solutions proposed by the supplier
Preventive maintenance	Reports of routine maintenance
Spare parts supply	Average delay of spare parts supply Probability of unavailable spare part Number of supplied spare parts for each type of module and equipment Ratio of supplied spare parts that have proved faulty
Corrective maintenance (software / hardware / data configuration)	Data configuration corrective maintenance • Ratio of data configuration errors after the SAS commissioning • FAT or/and SAT reports if necessary Software / Hardware corrective maintenance • Summary statement of software errors • Summary statement of hardware errors requiring a redesign with functional testing • Average delay of analysis of major anomalies (significant impact on operation) • Periodical correction plan listing the anomalies and the version number fix
Obsolescence management	Yearly report stating for each module and equipment the planned end of commercialization and production, and the proposed strategy to provide functional equivalent
Software evolution	Periodical assessment of the SAS technical evolution
System extension	FAT and SAT reports Average execution delay of system extension services (compliance with

Service	KPI
	technical expectations and planning)
Version control	Historical log of hardware/software/data configuration version upgrades for each IED and the SAS globally whether the upgrade is motivated by corrective maintenance or evolution

A quality assurance plan tracks poor performance, analyses the causes of dissatisfaction, and makes sure the same anomaly is not repeated.

8.13 Responsibilities of all parties

The different roles of parties involved in the life cycle of substation automation must be clear from the beginning.

8.14 Conclusion

Integrating a SAS is a complex task and is not just about assembling separate equipments, but providing global functionality. For that reason, the System Integrator has a great added value and his role is not limited to the procurement process but transformed after the FAT to the role of the System Maintainer.

9. Summary

The standard IEC 61850 was issued in 2005 (last of the 14 parts i.e. IE C 61850-10 in May 2005) and has quickly been adopted in commercial Substation Automation projects.

IEC 61850 has a lot of benefits for the utilities. The benefits corresponding to the goals of the standard development are:

- **Interoperability** allows building Substation Automation systems with devices from different suppliers as along as they are compliant with the standard. This supports the optimization of SA systems regarding functionality and cost. It facilitates also the life cycle maintenance of such systems because with help of future compliant IEDs replacing or complementing the existing ones.
- By the **free allocation of functions to devices** the utilities may get solutions according to their philosophies world-wide that were restricted in previous technologies. This point is very important for the future evolution of Substation Automation systems and the related development of IEDs.
- The fact that the standard is **future proof** because of its split between the Data Model with its abstract Services and the communication system represented by the selected stack, the utility's investments are safeguarded for the future.

There are three additional points providing benefits for the utilities:

- The use of **Ethernet** for the communication allows benefiting from the widespread investment in this communication technology that will also provide even higher speeds in the future.
- Systems engineered with the **Substation Configuration description Language** (SCL) allow the user to control interoperability even in the most complex configurations. It simplifies engineering with appropriate tools and supports reusability of system elements. Last, but not least, the System Configuration Description file (SCD file based on SCL) is the backbone for the complete SA documentation and facilitates maintenance over the complete life cycle.
- The fact, that IEC 61850 is being extended for use between substation, between substation and Network Control Centers, and in **other application domains** like hydro power plants, wind power parks, and for distributed energy resources supports that IEC 61850 is the right and future proof direction for the utilities.

There are special impacts of IEC 61850 on the utilities, the procurement process and the project organization

- To exploit the benefits of IEC 61850, the proper **know-how** has to be established in the utilities according the roles of the utility people. This means training and reconsideration of the SA system designs used up to now.
- Building multi-vendor systems means a clear definition of **roles and responsibilities** from the early beginning. Most important are the role of the System Integrator and, later, the role of the System Maintainer.
- The highly structured nature of IEC 61850 requires that all roles have appropriate **tools**. This is in many cases a matter of investing time and cost in new support systems.
- The benefits are fully exploited only if all functions in the SA system like control, protection and monitoring are handled in a consistent system approach. This and different roles taken by the utilities may have an impact also on the **organization of the utility**.
- IEC 61850 will provide an opportunity to **replace the large amount of copper** based wiring and connections throughout the substation by serial communication links which will improve installation, commissioning and maintenance processes.

- There is an opportunity to review the choice of, or at least the type of **interface with primary equipment** and associated monitoring systems which will significantly increase the benefits provided to the utility from concept stage through the whole of life operation.
- **Operational procedures** such as for example isolation, must be reviewed to cater for the Ethernet based technology
- **Training** of technical maintenance and support staff will need to be provided in all areas of substation, IT and telecommunications departments

This report outlines many issues that must be dealt with by any user contemplating a move to IEC 61850 based systems. Daunting as they may seem initially, this report will provide a structured means for the utility to develop an appropriate implementation strategy that will yield significant benefits both in the initial projects and ongoing life of the systems.

10. Definition of terms and acronyms

Term	Description
ACSI	Abstract Communication Service Interface: – refer Chapter 2
Bay level	The part of the SA system relevant to the monitoring, protection and control of a particular segment of the substation such as a line, transformer, circuit breaker etc.
CBM	Circuit Breaker Monitoring
Data model	The structure of information to be exchanged for functions in a dedicated application domain as in Substation Automation: - refer chapter 2. It may be also extended to cover many domains or a meta-domain like the overall power system management
DNP	A communication protocol
FAT	Factory Acceptance Test(ing): a test program conducted in the factory prior to shipping to site designed to test directly or through simulation that the system behaves as specified (functionality, performance, etc.)
GOOSE	Generic Object Oriented Substation Event: a time-critical message sent over the network by exception e.g. in response to a change of state, to crossing a limit, or change of data attributes. This message is used between IEDs e.g. for interlocking, blocking, starts or trips
HMI	Human-Machine Interface: the system for enabling an operator to view information and initiate controls or actions. This is typically a screen, keyboard and mouse connected to a computer linked to the network
ICD	IED Capability Description file: - refer chapter 2
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device: a device with a specific system function incorporating mainly a programmable microprocessor with communication facilities.
Interchangeability	The ability to replace one device with another e.g. from another vendor using the same configuration definition with little requirement to reconfigure the new device
Interoperability	The ability for IEDs from one or several manufacturer to exchange information and use the information for the their own functions
ISO	International Organization for Standardization
ISO/OSI	The Open System Interconnection model of ISO which defines seven layers for hierarchical rule sets for coding and decoding information to be send over serial communication links
LAN	Local Area Network: a communication system connecting IEDs in a single location or restricted area. The most common

Term	Description
	realization is based on Ethernet
LN	Logical Node – refer Chapter 2
LON	A communication protocol
MICS	Model Implementation Conformance Statement - refer Chapter 2
Modbus	A communication protocol
NCC	Network Control Centre: the central control function/place for the power system
NWIP	New Work Item Proposal - refer Chapter 2
PICS	Protocol Implementation Conformance Statement: - refer Chapter 2
PIXIT	Protocol Implementation Extra Information for Testing - refer Chapter 2
Process level	The part of the SA system representing the interface to the primary equipment incorporating instrument transformer measurements, circuit breaker and isolator status, trip signals, equipment condition monitoring information etc
Profibus	A communication protocol
RTU	Remote Terminal Unit: device located in the substation which collects status and value information from the substation and passed to the NCC, issues control commands received from the NCC and may incorporate some automatic control programs. These functions are also provided by the SA system (SAS) which could be seen as fully distributed RTU. Reverse, the RTU could be seen as smallest SA system solution if missing functions like protection are provided by serial inked IEDs.
SA	Substation Automation: the collation of control, protection and monitoring functions into a complete entity to provide substation wide operational systems
SAS	Substation Automation System: A collection of IEDs and communication system arranged and connected so as to provide the SA
SAT	Site Acceptance Test(ing): a test program conducted on site after installation designed to test directly that the system behaves as specified (functionality, performance, etc.)
SCADA	Supervisory Control and Data Acquisition: the system allowing the operation and monitoring of the power system remotely from NCC. It is comprising of RTU or SA and NCC elements
SCL	System Configuration description Language – refer chapter 2
SCSM	Specific Communication Service Mapping -refer Chapter 2
SSD	System Specification Description file - refer chapter 2
Station Level	The part of the SA system covering the control and monitoring

Term	Description
	and may be protection of the complete substation commonly realized by a station computer, operator's workplace (HMI) and the gateway to NCC if applicable
SV	Sampled Value: a measurement of an analogue quantity at an instant in time. In the context of IEC 61850 the term is used as SV service which provides a stream of sampled data
TCP/IP	The level 3 and 4 of the ISO/OSI model (transport control protocol/internet protocol) which allows the addressing and the end-to-end control of messages in networks. Since this is the core functionality of a communication network, the de-facto standard TCP/IP is very common as in Ethernet based networks and in the Internet
Tissue	Technical Issue: a proposal for a change or addition to the IEC 61850 standard
TSO	Transmission System Operator
VLAN Virtual LAN	A logical LAN subset operated as an independent entity within the physical LAN in order to segregate operation and access from other parts of the system despite using the same physical connections.
WAN	Wide Area Network: a communication system that connects multiple geographically dispersed LANs so as to be considered separate locations
XML	eXtensible Mark Up Language: – refer chapter 2

11. Bibliography

11.1 Standards

[1] IEC 61850-1: Communication networks and systems in substations – Part 1: Introduction and Overview

[2] IEC TS 61850-2: Communication networks and systems in substations – Part 2: Glossary

[3] IEC 61850-3: Communication networks and systems in substations – Part 3: General requirements

[4] IEC 61850-4: Communication networks and systems in substations – Part 4: System and project management

[5] IEC 61850-5: Communication networks and systems in substations – Part 5: Communication requirements for functions and device models

[6] IEC 61850-6: Communication networks and systems in substations – Part 6: Configuration description language for communication in electrical substations related to IEDs

[7] IEC 61850-7-1: Communication networks and systems in substations – Part 7-1: Basic communication structure for substation and feeder equipment – Principles and models

[8] IEC 61850-7-2: Communication networks and systems in substations – Part 7-2: Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)

[9] IEC 61850-7-3: Communication networks and systems in substations – Part 7-3: Basic communication structure for substation and feeder equipment – Common data classes

[10] IEC 61850-7-4: Communication networks and systems in substations – Part 7-4: Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes

[11] IEC 61850-8-1: Communication networks and systems in substations – Part 8-1: Specific Communication Service Mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3

[12] IEC 61850-9-1: Communication networks and systems in substations – Part 9-1: Specific Communication Service Mapping (SCSM) – Sampled values over serial unidirectional multidrop point to point link

[13] IEC 61850-9-2: Communication networks and systems in substations – Part 9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3

[14] IEC 61850-10: Communication networks and systems in substations – Part 10: Conformance Testing

[15] IEC 60870-5-101: Telecontrol equipment and systems – Part 5-101: Transmission protocols – Companion standard for basic telecontrol tasks

[16] IEC 60870-5-103: Telecontrol equipment and systems – Part 5-103: Transmission protocols – Companion standard for the informative interface of protection equipment

[17] IEC 60870-5-104: Telecontrol equipment and systems – Part 5-104: Transmission protocols – Network access for IEC 60870-5-101 using standard transport profiles

[18] IEC 60870-6: Telecontrol equipment and systems – Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations

[19] IEC 61346: Industrial systems, installations and equipment and industrial products – Structuring principles and reference designations

[20] IEEE Std C37.2:1996, IEEE Standard Electrical Power System Device Function Numbers and Contact Designations

11.2 Standard Drafts

Note: Available only from the allocated IEC WGs or from the allocated National Committees of IEC. It may be assumed that all listed Drafts will be available as Standards soon.

[21] IEC 61400-25 Ed.1: Wind turbines – Part 25: Communications for monitoring and control of wind power plants

[22] Amendment 1 to IEC 61850-7-4 Ed. 1 (2003): Communication networks and systems in substations - Part 7-4: Basic communication structure for substation and feeder equipment - Compatible logical node classes and data classes (Addition of power quality monitoring)

[23] Amendment 2 to IEC 61850-7-4 Ed. 1 (2003): Communication networks and systems in substations - Part 7-4: Basic communication structure for substation and feeder equipment - Compatible logical node classes and data classes (inclusion of clarifications, corrections and extensions for statistical data)

[24] IEC 61850-7-420 Ed.1: Communication networks and systems in substations – Part 7-420: Communication systems for distributed energy resources

[25] IEC TR 62210: Power system control and associated communications – Data and communication security

[26] IEC 62344 Ed1: Hydroelectric power plants – Communications for monitoring and control (to be renamed finally into a IEC 61850 part)

[27] IEC 62350 Ed.1: Communication networks and systems in substations – Part 7-420: Communication systems for distributed energy resources (was renamed as IEC 61850 part → see [22])

[28] IEC 62351-3 TS Ed.1: Data and communication security – Part 3: Profiles including TCP/IP

[29] IEC 62351-4 TS Ed.1: Data and communication security – Part 4: Profiles including MMS

[30] IEC 62351-5 TS Ed.1: Data and communication security – Part 5: Security for IEC 60870-5 and derivates

[31] IEC 62351-6 TS Ed.1: Data and communication security – Part 5: Security for IEC 61850 profiles

[32] IEC 62351-7 TS Ed.1: Data and communication security – Part 6: Network and System Data Objects for End-to-End Network Management and System Security

11.3 Cigre Reports

[33] Cigre Technical Report, Ref. No. 180, Communication requirements in terms of data flow within substations. SC 34 WG 34.03, 2001, 120 pages

[34] K.P. Brand et. al., Communication requirements in terms of data flow within substations – Results of WG34.03 and standardization within IEC, Electra 173, 77-85 (1997) – Summary of [33]

[35] Cigre Technical Report, Ref. No. 246, The Automation of new and existing Substations: Why and How. SC B5 WG B5.07, 2004, 120 pages

[36] W.Baass et al., – The Automation of new and existing Substations: Why and How, Electra 213, 53-57 (2004) - Summary of [35]

[37] Cigre Technical Report, Ref. No. xxx, Guidelines for the Specification & Evaluations of S/S Automation Systems SC B5 WG B5.18, 2007, nnn pages (will be published in 2007)

[38] Summary of [37] – will be published in Electra 2007

[39] Cigre Technical Report, Ref. No. 236, Conformance Testing Guidelines for Communication in Substations. SC B5 WG B5.01, 2003, 30 pages

[40] K.P. Brand et al., Conformance Testing Guidelines for Communication in Substations, Electra 210, 55-59 (2003) – Summary of [39]

11.4 Books

[41] K.P.Brand, V. Lohmann, W.Wimmer, SUBSTATION AUTOMATION HANDBOOK - Comprehensive description of Substation Automation and the coordination with Network Operation to obtain both performance and cost benefits by enabling enhanced Power System Management, ISBN 3-85759-951-5, 2003, http://www.uac.ch

11.5 Internet URL

[42] IEC International Electrotechnical Commission, www.iec.ch

[43] UCA International Users Group, www.ucainternational.org

11.6 Others

[44] K. Schwarz et al: Offene Kommunikation nach IEC 61850 für die Schutz und Stationsleittechnik – etz-Report 34 – VDE VERLAG, Berlin & Offenbach, 2004 (in German)

[45] H. Schubert, G. Wong, "Towards Seamless Communications in Substations", IEE Power Engineer, 17, 4, Aug.-Sept. 2003, p 20-23

[46] L. Hossenlopp, Substation Automation beyond communication Standardization (Colloquium Paper), Electra 211, 22-26 (2003)

[47] H. Schubert, G. Wong, "IEC 61850 cuts out substation confusion", Modern Power Systems, April 2004, p. 47-51

[48] K.P. Brand, C. Brunner, W. Wimmer, Design of IEC 61850 based Substation Automation Systems according to customer requirements, Paper B5-103 of the B5 Session at CIGRE Plenary Meeting, Paris, 2004, 8 pages

[49] K.P.Brand, M.Janssen, The specification of IEC 61850 based Substation Automation Systems. Paper presented at the DistribuTech 2005, January 25-27, in San Diego

[50] G. Gilchrist, Power-assisted configuration using IEC 61850-6 SCL. Paper presented at the DistribuTech 2005, January 25-27, in San Diego

[51] L. Andersson, K.P. Brand, W. Wimmer, The Impact of the coming Standard IEC 61850 on the Life-cycle of Open Communication Systems in Substations. Paper presented at the Distribution 2001 – Distribution and Transmission, Nov 11-14, 2001, in Brisbane, Australia,

[52] S.Laederach, W.Baass, K.P.Brand, P.Reinhardt, Experience with IEC 61850 in the refurbishment of an important European 380 kV substation, Paper B5-109 of the B5 Session at CIGRE Plenary Meeting, Paris, 2006, 8 pages

[53] IEC 61970-301: Energy management system application program interface (EMS-API) – Part 301: Common Information Model (CIM) Base

