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Acceptable Functional Integration In HV Substations

Working Group
B5.13

February 2010

WG B5.13

Acceptable Functional Integration in HV Substations

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ISBN: 978-2-85873-091-9

Preface

In 2004, CIGRE Study Committee B5 (Power System Protection and Local Control) instigated the formation of a working group to look into the state of the art of Acceptable Functional Integration in HV Substations.

As background of the work of the WG it can be put forward that integrating functions to get cost reduction is one of the most attractive advantages of protection and control digital devices and has been pushed by digital technology development. Integration of multiple protective functions in one single digital device is accepted by many users nowadays for all power system components (generators, transmission lines, transformers and so on). Integration of control, monitoring and recording functions in protection devices has also been quite welcome by the different users.

Bearing in mind reliability and maintenance constraints and the conservative nature of protection specialists and operations personnel, the acceptable degree of Functional Integration for different types of installations must be identified.

Scope

The scope of work was thus defined as:

WG B5.13 shall evaluate how far Functional Integration may be applied to different types of substations aiming to achieve cost reduction, but preserving, and preferably improving the functionality and high reliability standards expected from multifunctional control and protection devices.

Dependability and security associated with each single function shall be taken into consideration in the determination of acceptable degree of integration.

The constraints and opportunities related to maintenance and operations should also be addressed.

Three main areas shall be focused on:

1. Combination of different protection functions;
2. Integration of control and protection functions;
3. Limitations, preferences, reliability and Functional Integration issues.

Deliverables: technical brochure with summary in Electra.

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1 Introduction – why and what

The introduction of microprocessor based relays about two decades ago resulted in a process of ever increasing expansion of the complexity of the functionality of different types of protection relays and other Intelligent Electronic Devices. This was due to the fact that there were many components in an IED that are similar and in some cases identical between substation protection, control, monitoring and recording devices.

The new microprocessor technology was initially used by manufacturers of devices required by the different domains in the substation. Protection relays manufacturers started implementing protection functions by emulating the principles of electromechanical or solid state relays using numerical methods.

Different types of logic schemes realized by hardwiring auxiliary relays were replaced by ladder diagrams in Programmable Logic Controllers.

Digital meters with LED displays took the place of analog meters.

Oscilloperturbographs were replaced by digital disturbance or transient recorders combined with printers to replicate their functionality.

The fact that the first generation of microprocessor based devices were with functionality dedicated to a specific domain was, among other reasons, due to the fact that the technology at the time was imposing limitations on how much can be done. At the same time the electric power industry for decades has been operating based on the principle “individual devices for individual functions”. In short, there were technological and historical reasons for the functional separation.

The continuous improvements in the capabilities of microprocessors, increase in the available memory chips, advancements in communications technology and the changing utility environment put pressure on the different manufacturers to start adding more and more features in their new generations of devices.

Both vendors and users realized that this new technology allows the development and application of functions that were impossible in the world of electromechanical devices. And this process occurred simultaneously from several directions. Protection relay manufacturers started adding fault locators, measurements and recording capabilities. That was followed by standard protection schemes and programmable scheme logic.

At the same time manufacturers of measuring devices were expanding the measuring capabilities to include demand, harmonics, sequence components and energy. Adding transient, disturbance and trend recording capabilities was also turning these devices into much more than a meter, but rather a component of a distributed monitoring and recording system.

Remote Terminal Units (RTU) were also making a transformation by adding programmable scheme logic and recording capabilities, as well as providing event logs.

The advancements in communications and the acceptance of standard international or industry protocols resulted in the wide spread of substation automation systems and further expanded the functionality of substation IEDs.

The new international standard for substation communications IEC 61850 is in the process of changing completely the ways protection, control, monitoring and recording has been done in the substation. There are several important features in the standard that need to be taken into consideration when discussing its impact on Functional Integration:

Substation bus and high-speed peer-to-peer communications

Process bus and distributed applications based on transmission of sampled measured values

Definition of distributed functions

The new concept of modeling any device or function in the substation as a component of a complex system with a functional hierarchy, regardless of the location of an individual functional element within a specific physical device will have significant impact on the levels of Functional Integration in the substation protection, control, monitoring and recording systems of the future.

All of the above described changes and trends in the industry are being considered in this document in order to determine the state-of-the-art of Functional Integration today and based on the acceptance by the industry to provide some guidelines on the acceptable levels of integration in future substation protection, control, monitoring and recording systems.

The report also covers the impact of Functional Integration on refurbishment, operation and maintenance of Substation Automation Systems and its relation with standardisation and customisation.

An industry survey covering the two main points of view of Functional Integration – the users' and the manufacturers' – is a very important part of the report. It is providing an insight into the perception of acceptability of Functional Integration and gives an idea of what might be the trends for the future.

2 Requirements for the protection and control of power systems

The design of a protection and control system must always be based on basic requirements of the power system. Generally accepted design principles that fulfil these requirements have been established and used for a long time. A conventional protection and control design can typically be characterised as follows:

- The protection and control system consists of two basic levels, the "**bay level"** and the "**station level"**. Some primary equipments cannot be clearly associated to one of these level (e.g. transformer protections, busbar protection). For this reason, the term "**equipment level**" for the control and protection function to any primary equipment of the substation can be used. Depending on the definition and on the utility, these definitions may overlap and there is no clear consensus on these terms in the industry.
- Distributed functionality. The functions are allocated and performed at lowest possible level, most distributed. In other words, all functions that can be performed at equipment level have to be kept at this level.
- Equipment protection and control system is mainly aimed for one primary substation device, e.g. one line, one transformer or one busbar. Traditionally one protection and control system has consisted of several protection and control equipments. However, increased performance and capacity of IEDs has led to solutions where all functionalities for an equipment are integrated in one IED, an equipment IED. Today many utilities have accepted integrated protection and control object IEDs but some utilities still require separate IEDs for protection and control.

For the physical layout of the protection and control system it is suitable also to consider the bay level in a station. The equipment level is often the same as the bay level, e.g. a line protection is normally allocated to the bay level. There are also examples where the protection for one primary equipment is allocated to the station level. The busbar protection is such an example.

With these basic principles it has been possible to design robust and reliable conventional protection and control systems with high dependability and security.

The improvements of performances and capacities of modern computers in combination with inputs via process busses make it today possible to integrate and perform protection and control functions for several objects in one IED. The free allocation of functionalities supported by IEC 61850 may considerably change the structure and design of the protection and control system. Functional Integration tends to raise the level where certain functions are allocated. E.g. there may be no dedicated IED on equipment level, resulting in an implementation on bay level.

Trial installations of totally integrated protection and control (P&C) systems exist where all P&C functions for a complete station are integrated in one centralized station computer. The basic requirements of the power system are still the same and must be fulfilled.

2.1 Main groups of functions

Protection and control functions can be divided in many different groups and the requirements are different for different categories of functions. When discussing the power system requirements it is suitable to divide the functions in the following two main groups of functions, the fault clearance functions and the control and monitoring functions. The different types of functions are defined in a more specific way in section 3.2.

2.1.1 Fault clearance functions

In most cases when we are talking about protection functions we in fact are thinking of fault clearance functions. To perform successful clearing of power system faults the fault clearance functions are dependent not only on protection equipments but also on other equipments included in the fault clearance system.

The fault clearance functions include all functions for automatic clearing of power system faults. They include basically the functions performed by the protection devices.

2.1.2 Control and monitoring functions

Control functions include all other functions needed for operation of the system. Both manual and automatic functions for the optimisation of operation, voltage and frequency control are included. Functions for restoration of the operation after a disturbance are also control functions. Functions for acquisition, storage, transmission and presentation of information to enable the analyses of network and equipment performance and behaviour during both non-system and system fault conditions are examples of monitoring functions. Alarm and supervision are other examples of control and monitoring functions.

2.2 Requirements on the fault clearance system

2.2.1 General Aspects

The fault clearance system in the station must fulfil specific requirements originating from personal safety, power system reliability and consequences of faults in the power system.

There are often safety regulations that have to be met. The aim of such regulations is to minimise the risk of personal injuries due to different faults in the power system. These regulations often state maximum allowed fault duration and sensitivity of the protective relays.

A fault in the power system can result in an interruption of supply. The degree of the risk of outages and the duration of an outage is influenced by the design of the power system and its protection. The allowed consequences of combinations of different faults in the power system and specified performance of the protection must be clearly determined and defined in specifications or rules. The decision, what is an acceptable consequence of a fault, is strategic. It can be based on an economic evaluation of the cost of loss of energy supply. These rules are mainly applied in the planning of the primary power system and in the design of the protection system.

The fault clearance time has influence on transient stability in the power system, thermal and mechanical stress on equipment in the power system and personal safety.

Selectivity is defined as the ability of a protection system to detect a fault in a specified zone of a network and to trip the appropriate circuit breakers to clear this fault with a minimum of disturbance to the rest of the network. The consequences of unselective tripping can vary for different power systems and for different fault locations in the power system. One consequence can be that more loads than necessary are interrupted. This will normally lead to minor consequences, if operation can be restored in a short time. A more serious case is when an unselective fault clearance will cause a partial or total black out in the power system. In this case the unselective tripping of a fault will cause a disturbance with unacceptable consequence.

The requirements can be expressed as follows. The fault clearance system shall perform with high:

- Reliability
- Speed
- Selectivity
- Sensitivity

All these requirements are important, but for the purpose of this report, regarding acceptable Functional Integration, we will from now on limit our study to the reliability issue. The reliability is probably the most fundamental and important property of the fault clearance system.

The *reliability of protection* includes *dependability of protection* and *security of protection.*

According to IEC 60050-448, dependability is the probability for a protection of not having a failure to operate under given conditions for a given time interval. In other words a protection function with high dependability will have a high probability to operate correctly when wanted.

According to IEC 60050-448, security is the probability for a protection of not having an unwanted operation for a given time interval. A function with high security will have a low probability to operate when unwanted.

By definition the protection system consists of instrument transformers, protection equipment, auxiliary supply, telecommunication system, tripping circuit including the circuit breaker trip coil and all the necessary wiring. The fault clearance system (Figure 2-1) is the protection system together with the circuit breaker mechanism. It is important to have in mind that all components have to operate properly to guarantee a reliable fault clearance of a power system fault. Independent of the high performance and quality the protection equipment may have, it is of no use if any of the other components in the fault clearance system fails.

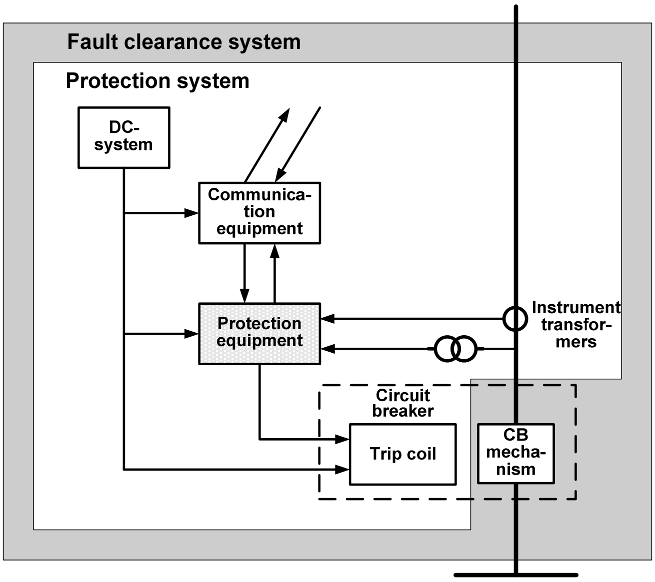

Figure 2-1: The fault clearance system for one primary equipment

The protection equipment may comprise electromechanical, static and digital relays. Numerical protection IEDs with higher degree of Functional Integration are now replacing the old types of relays but the principles to achieve a reliable fault clearing remain the same.

When integrating protection and control functions for more than one primary equipment in the same IED, the fault clearance system will change from representing one single object to be representing two or several objects. In case of a totally integrated protection and control (P&C) system there will be one fault clearance system (Figure 2-2) for the complete station. The requirements on fault clearance of the power system will remain the same and the same principles for a reliable fault clearance will still be valid. Special attention must be paid to I/O units, the process bus and the DC supply to these components. The principles for a reliable fault clearance will be discussed in the following section.

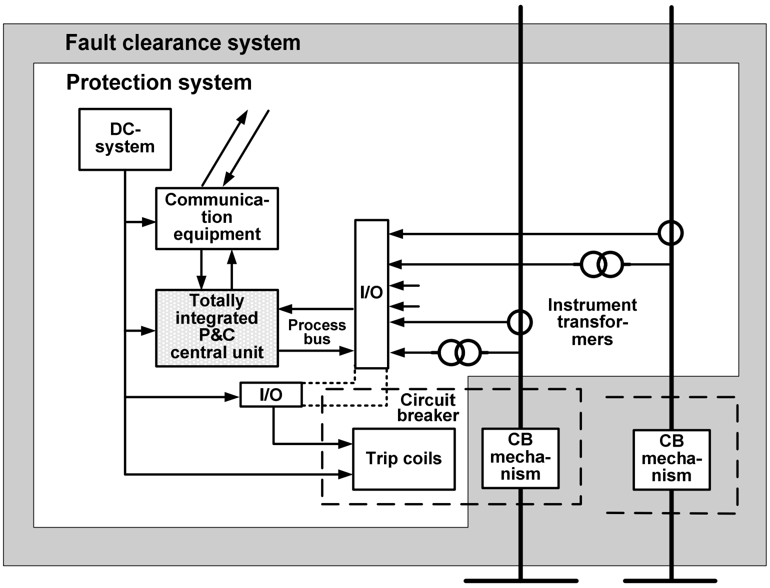

Figure 2-2: Fault clearance system for a substation with a totally integrated P&C system

2.2.2 The single-failure criterion

We cannot assume that all components in the fault clearance system always will operate correctly. It is well known that protection equipments and circuit breakers sometimes can fail or that loss of input from voltage and current transformers can occur. Interruption of the DC supply or of a tripping circuit may also happen. It is normally not accepted that these kinds of faults in the fault clearance system result in a failure to trip in case of a power system fault.

As each of the components in the fault clearance system has a low risk of failure it has become a common practice among utilities to apply the single-failure criterion in the planning and designing of the fault clearance system.

The single-failure criterion requires that the failure of any one component in a fault clearance system should not result in a complete failure to clear a power system fault. It is a commonly accepted design principle that the basic power system requirements, regarding dependability, are fulfilled if the single-failure criterion has been applied.

The practical application of the single-failure criterion means that the performance of the fault clearance system has to be studied during different conditions and power system faults must be possible to clear, in an acceptable way, even if there is one failure in the fault clearance system. The following shows examples of failures that shall be considered:

- Loss of input from voltage and current transformers
- Failure to operate of a protection equipment or a protection function
- Interruption of the DC supply
- Interruption of the tripping circuit
- Failure to operate of a circuit breaker

In case of higher Functional Integration the study must be applied to the corresponding fault clearance system. For example in a totally integrated P&C system also the following faults must be considered:

- Failure in the totally integrated P&C central unit
- Failure in any of the I/O units
- Failure in the communication between the central unit and I/O units (process bus)
- Interruption of the DC supply to any of the I/O units or the process bus equipment

It is obvious that a redundancy is required to fulfil the single-failure criterion. This redundancy can be achieved by a second main protection or some kind of backup protection in separated devices.

2.2.3 Backup protection and impact on Functional Integration

The standard IEC 60050-448 (1995) defines *main protection* and *backup protection* as follows:

Main protection is:

"Protection expected to have priority in initiating fault clearance or an action to terminate an abnormal condition in a power system.

Note. - For a given item of plant, two or more main protections may be provided."

Backup protection is:

"Protection which is intended to operate when a system fault is not cleared, or abnormal condition not detected, in the required time because of failure or inability of other protection to operate or failure of the appropriate circuit-breakers to trip.

Note. - In the USA, the term "backup protection" designates a form of protection that operates independently of specified devices in the main protection system. The backup protection may duplicate the main protection or may be intended to operate only if the main protection system fails or is temporarily out of service."

The main protection and the backup protection may be located in different substations (remote backup), or in the same substation (local backup). In case of local backup, we distinguish between substation local backup and circuit local backup.

A **circuit local backup protection** senses the same current and voltage as the main protection and trips the same circuit breaker, often via a separate trip coil. Often, a second protection on the same circuit has the same performance as the main protection and not a circuit local backup protection. In such case this protection in fact is a second main protection. If the second protection has a limited or time delayed performance, then it is a circuit local backup protection.
These terms are not always used in this sense by all vendors and utilities, who might designate the second main protection as a backup protection.

A **substation local backup protection** is achieved from protection systems that are main protection for other primary equipments and may use other analogue signals than the main protection. Backup protection tripping is time delayed and more equipments will be switched off than from a successful tripping of the main protection.

Above we concluded that it is necessary with backup protection to fulfil the single-failure criterion. The conditions of the connected power system and the required performance of backup operations decide the type and design of the backup protection. For example interconnected transmission lines often need circuit local backup protection system but sometimes it can also be sufficient with a combination of remote backup and substation local backup protection. In most substations the backup protection is achieved with combinations of different backup principles.

Figure 2-3 shows an example of a principle design of a totally integrated P&C system where all the protection and control functions of the substations are integrated in one single device which is duplicated. In this example, the I/O and analogue circuits are also duplicated on the transmission side, but not at the distribution side. In this example, P&C System 1 provides protection and control for both transmission and distribution and P&C System 2 provides the second main protection for the transmission side. Failure of P&C System 1 will result in delayed fault clearing by P&C System 2 for distribution faults.

The principles regarding dependability of protection systems are based on power system requirements, which the utilities in general wish to preserve. As a consequence, Functional Integration must meet these general requirements. A second main protection must never be integrated in the same equipment as the main protection and in systems with just one main protection, backup protection must not be integrated in the same equipment as the main protection.

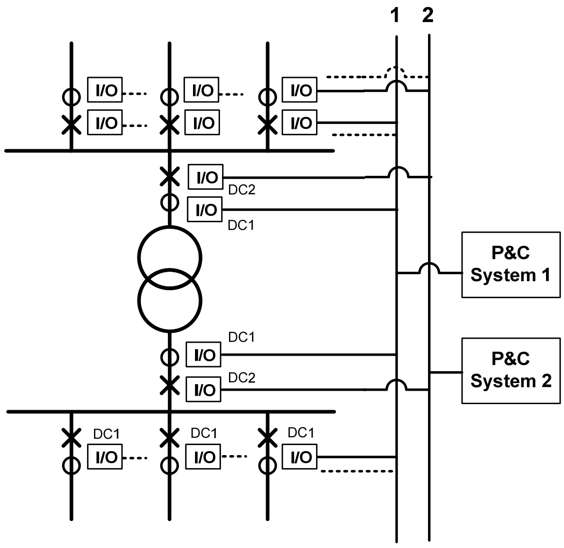

Figure 2-3: Example of a totally integrated P&C system

2.3 Requirements on control and monitoring functions

All hardware and software components of a conventional Substation Automation system are designed and manufactured in such a way that they meet high availability requirements. This means a high reliability (long MTBF times) as well as short down times (low MTTR) in case of a failure.

Short outage times are achieved by means of extensive diagnostic functions covering individual device modules (e.g. circuit board) with associated reporting, modular hardware design, and fast reconfiguration and restart after repair.

A typical structure of a conventional control system is shown in Figure 2-4. As much as possible of the control functionality is allocated in the bay level units.

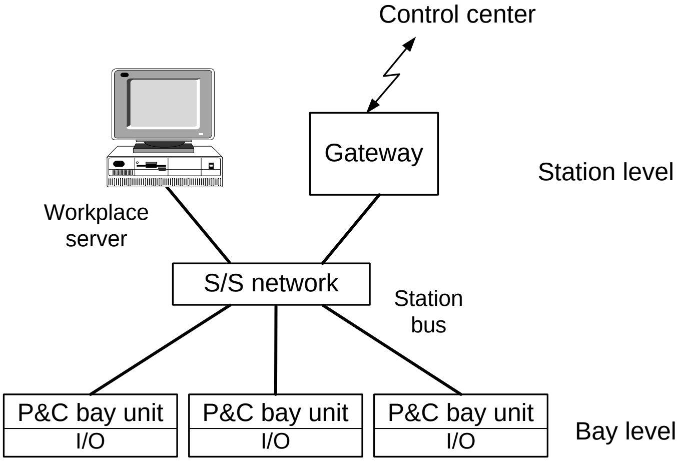

Figure 2-4: Typical structure of a conventional control system

There are no general accepted requirements on backup or redundancy of the control functionalities in a substation. Each utility may have its own set of requirements for this aspect. However, the basic distributed architecture of the control functions in a conventional system allows a very high availability and dependability even if no explicit redundancy is used. If the connection to control centre uses separate hardware instead of the same hardware as the workplace server at station level operation, a backup is established for one part of the station level. The station bus communication system connects bay and station level devices. The reliability of this system depends on the chosen architecture and on its components.

A control system should be designed according to principles that will assure that there is no single point of failure for the complete system. Depending on the architecture and on the level of integration of control functions in the devices used on bay or station level, complete or partial backup of control and system functions can be achieved (e.g. duplicated autorecloser).

Redundant control units require normally two separate systems to handle events and acquisition of service values. If redundancy is needed, then a functional redundancy, e.g. circuit breaker control with use of protection devices, is mostly sufficient. Further a direct control possibility at the switchgear itself or a back-up panel can already provide means for emergency control.

A prerequisite to really achieve higher availability is that even inactive redundant hardware parts (spares, standby parts etc.) are regularly supervised and repaired in case of a failure.

3 Functions in Protection and Control System

This section intends to provide a list of the functions used in protection and control systems and to give a classification of their types in order to better understand the implications of their integration in substation devices.

The impact of the modelling concepts defined in IEC 61850 is taken into consideration in the following sections.

3.1 Definitions

3.1.1 Basic function

A basic function is the simplest function that can be described with its configuration and behaviour. It has its own interface with the substation environment or with other functions.

Basic functions can be of two main different types:

- Interface - provides the analogue or binary interface with the substation instrument primary equipment and other substation systems (communications, HMI, etc.). It may provide a continuous output (for example sampled analogue values) or an output when it detects a change of state.
- Processing - process the values from any interface function and produce a measurement, protection operation or other necessary action.

Examples of basic functions are a current analogue input module, a ground overcurrent protection element, a directional element.

A basic function corresponds to a logical node in IEC 61850.

3.1.2 Complex functions

A complex function is one that produces an output as the result of operation or non-operation of two or more basic functions. An example of a complex function is a ground directional overcurrent protection element. The overcurrent element can be configured to be directional, or non-directional.

If it is directional with a forward direction selected as the operating direction, this complex function will produce an operate output when both the overcurrent and directional element have operated.

A combination of an interface function and a processing function is also a complex function. An example is an analogue interface current module and an overcurrent protection element.

A complex function can be local or distributed (see section 5.2). It is local when all its components are within the same physical device and it is distributed when at least one of its components is located in a different physical device.

Electromechanical protection and control systems have distributed nature. In many cases a single function is located in a dedicated device – for example a single phase overcurrent relay.

Modern microprocessor based multifunctional IEDs are characterized by a high level of Functional Integration, i.e. they contain multiple local complex functions. At the same time they may be part of distributed complex functions based on exchange of signals with other devices in the system.

3.2 *Types of function*

Within a substation automation system, several categories of functions are identifiable. Some functions can be considered as belonging to one or another, or more than one category, depending, for instance, on the goal of the analysis, or on its depth of detail; although functions classification has not a unique solution, a list of categories will be defined and each function will be associated only to one of them.

This classification doesn't intend to go into deep details, both because there is already a lot of specific documentation on this subject, and because who is reading this document probably knows almost everything about substation systems functionality.

Our description will be oriented to Functional Integration, so, for each function, we will give some indications about the typical implementation (e.g. function integrated with or separated from).

A first distinction can be made between primary functions, directly acting on the process, like **protection, control, automation, monitoring, supervision,** and support functions, that operate in background or only in specific phases, like **configuration and time synchronisation.**

Another classification can be made considering the level of distribution of a function: there are functions involving devices of a single bay (e.g. overcurrent protection), functions involving devices of more bays in the same substation (e.g. busbar protection, breaker failure) and functions involving devices in different substation (e.g. teleprotection, WAMS, distributed load shedding).

3.2.1 Protection functions

Protection functions operate directly on the process, in order to isolate the faults occurring on the grid or in the plant.

The task of any protection function is to monitor values from the power network or switchgear (voltage, current, temperature, etc.). If the actual value exceeds a predefined first boundary, the protection function goes into an alert state (alarm, start). If a second boundary is crossed (fault indicator), a trip is issued which switches off the protected object (cable, line, transformer, switchgear, etc.). The behaviour of any protection function, i.e. the protection algorithm, is controlled by a set of parameters which may be changed by the protection engineer.

Some examples of protection devices are listed below.

Examples include:

- distance protection
- line differential protection
- transformer differential protection
- overcurrent protection

Still associated to this category are the so-called protection related automation functions such as autoreclosing.

Protection function schemes can involve different installations at the same time: an example of this is given by the teleprotection function, that coordinates the operation of two or more distance protections, located at the different terminals of a line feeder, by means of a communication link; another example is given by the line differential protection.

Protection schemes can involve all the bays of the same voltage level in a substation: e.g. busbar differential protection.

3.2.1.1 Line Protection

Line protection may include one or more of the following functions :

- Distance protection. Normally the distance protection is a stand-alone device. It can be redundant in the higher voltage level : main one and main two operate on the fault with the same authority. Distance protection functions can be integrated in line differential relays and used for remote backup or in case of failure of the communication channel.

- Teleprotection. In conventional systems, the protection device and the communication are implemented in separate devices. The present transmission line protection devices may integrate the communication with the protection functions.
- Differential protection. The line differential protection is typically a stand-alone device. With the advancement of technology, it is becoming a main protection function with distance, overcurrent and other additional protection functions integrated in the same device.

3.2.1.2 Automatic reclosing

Before the introduction of digital protections relays, automatic reclosing was implemented in a dedicate device. Now it is often integrated in the line protection. The enabling of the reclosing functions, if it is implemented in redundant devices, has to be taken into consideration.

3.2.1.3 Busbar protection

The most common busbar protection is busbar differential protection. It usually consists of one central unit and may have as many remote units as the number of bays connected to the busbar. In the latter case, the remote units may also provide circuit breaker failure protection at the bay level.

Recent developments tend to expand the functions integrated in the remote units to distance and overcurrent functions.

Considering the big number of bays that can be treated by this protection, it should be possible to use a single busbar differential protection for the whole substation and for all the different voltage levels present in it. In this case, it is implemented as a multizone differential protection. This practice is not widely adopted.

3.2.1.4 Transformer protection

Transformer differential protection is usually a stand-alone device used as the main protection of the transformer. In more recent transformer protections, additional functions have been integrated. These include :

- Distance protection both on the primary and secondary windings,
- Overcurrent protection against one-phase fault or overload,
- Thermal overload protection,
- Overexcitation protection.

Separate devices are still used for non-electric types of transformer protection :

- Buchholz relay,
- Oil pressure control,
- Fire detection.

The level of integration can change considerably from one manufacturer to another and from one user to another, as well as the type of protection adopted.

3.2.1.5 Circuit breaker protection

Mechanical behaviour of the breaker is monitored during each switching operation. Possible breaker internal faults are:

- Discordant position between the switch poles over a determined time: in this case the breaker must be opened;
- Abnormal condition of the switch poles motion mechanism: in this case the breaker has to be locked.

This function can be integrated in any IED on the bay level.

3.2.1.6 Breaker failure protection

The circuit breaker failure protection was initially a stand-alone device. With the advancement of technology, it is becoming integrated in any protection device. This is advantageous since initiating and resetting the breaker failure protection can be done by functions that are not related to short-circuit faults. E.g, in case of tripping the circuit breaker by an overvoltage criterion combined with low level of load current, the reset criterion should not be an undercurrent threshold. In this case, the integration of the breaker failure function in an protection IED is advantageous.

3.2.2 Control Functions

Control functions can de defined in several different ways. In the context of this document, control functions are associated with operator actions related to switchgear and process control. The control functions are performed by means of a Human Machine Interface at different levels (bay, station, remote control center). Control functions allow the user to operate in safety conditions each part of the substation (HV/MV equipment, auxiliary equipment, etc.) through commands, to visualize the process through the HMI, to check events and alarms regarding the plant and the network. They support the user in the execution of commands, both in normal and in perturbed state.

Traditionally, control functions have been implemented using different devices or systems. They are nowadays integrated in every IED via the IED HMI or communication.

3.2.3 Automation Functions

Automation Functions are sequences of actions performed automatically, after some trigger impulse has started them. They may be triggered either by an operator or by the process condition supervision.

Each automatic function should have its own safety check and reside on the top of underlying interlocking and protection functions.

An example of automation is given by the sequences of commands: typical switching sequences contain a number of switching steps necessary to put a switchyard into the required operational state. The operator starts the sequence with a command and all the switching steps are performed autonomously, in sequence.

Similar to the control functions, automation functions have been traditionally implemented using different devices or systems. They can nowadays be integrated in every IED via the IED HMI or communication.

As an example, the load shedding function may be implemented at bay level, station level and/or at remote centre level, depending of utility philosophy and specific application. Today, load shedding functions can be implemented as distributed or centralised functions. In the case of distributed implementation, it is an integrated function in individual IEDs.

3.2.4 Monitoring and Recording Functions

Monitoring and recording functions can be implemented as independent or interrelated functions. Monitoring functions provide data in order to make diagnostic investigations on particular power network events and/or on the HV equipment, in order to analyse the faults, in the first case, and to prevent them, optimising maintenance, too, in the second case.

Examples are:

- Transient recording,
- Recording of fundamental and / or harmonic signals (Power quality, system disturbance),
- Sequence of events recording,
- Line fault location,
- GIS plant monitoring,
- Transformer / circuit breaker monitoring,
- Power quality monitoring and recording,
- Voltage and current circuit monitoring

3.2.5 Supervision Functions

The supervision functions allow the operator to visualize real-time data on the HV/MV and auxiliary equipment in the substation. These data include:

- equipment state: positions (open, close) , operating condition (normal, faulty);
- events: state change;
- alarms: indication of abnormal condition ;
- measured values: root-mean-square value or mean value of the main electrical parameters;
- data archiving

Similar to the control functions, supervision functions have been traditionally implemented using different devices or systems. They are nowadays integrated in every IED via the IED HMI or communication.

3.2.6 Auxiliary Functions

Auxiliary functions allow the substation automation system operation and its management. Some of them are dedicated to the system set up, typical activity occurring during substation commissioning or extension or modification.

Some are auxiliary functions, fundamental for the system life and operation.

Examples include:

- time synchronization,
- self monitoring and diagnostics of the devices,

One can consider that time synchronisation is a distributed function implemented partly in each IED and using in many cases an individual clock device (GPS). The self monitoring of the system is a distributed function implemented in each device.

3.3 Device definition - common elements shared by IED functions

The multifunctional devices that are subject to this report are implemented on a hardware platform that includes multiple modules that are shared by all the functions of the IED. The increase in the level of Functional Integration has to be considered under the point of view of a single mode failure of one of these shared elements and its impact on the availability and reliability of the systems. These shared elements include :

- Power supply
- Analogue and Binary I/O
- Time synchronization
- Signal Processing and CPU
- Base software (operating system, device supervision, ..)
- Application software (protection and control functions, fault recording, …)
- Communication ports

On the other hand, the fact that some resources are shared by the functions implemented in the IED is an advantage if this allows to reduce the effort of configuration, improves ergonomics and limits the risk of contradictory or incoherent parameters. The elements concerned by this consideration include :

- HMI
- Setting groups
- Programmable Scheme Logic

4 Substation topology

In this section the impact of the different possible substation topologies on Functional Integration is analysed. The actual state of the art consists of using one or more dedicated devices for one HV equipment. Depending on the topology, it can be envisioned to integrate the protection and control of several HV elements in one single device, with the potential of covering a voltage level or a complete substation. This may introduce additional constraints for the maintenance of the HV equipments which could be unacceptable for the users in some cases.

Transmission substations, as well as distribution substations, can be different for voltage level, size, number of feeders, number of transformers.

Considering voltage level:

- A distribution substation is usually equipped with feeders in the voltage range of 30 kV and under, but it can include incoming feeders at a transmission voltage level.
- A transmission substation is usually equipped with feeders in the range of 100 kV and above, but it can include a distribution-level section.

Differences can also be found in the technical features of the substations, and some of them are usually related to the size of the plant, like:

- Busbar arrangement (double busbar, single busbar, one and a half breaker, double breaker);

Architecture (station level, bay level, switchgear level). Figure 4-1 shows the more common busbar arrangements.

Functional requirements, in principle are independent from substation size. There is thus no particular impact of the substation size on Functional Integration. Functional Integration is not impacted either by the substation topology as far as functions associated to a primary equipment are concerned.

The main impact of substation topology on Functional Integration concerns the functions on substation level. In cases of complex topologies, Functional Integration may be beneficial since it allows to implement all control functions concerning several associated circuit breakers or switches in one single device. E.g, in the case of a double bus – one and a half breaker Figure 4-1 d), it may be advantageous to integrate all the control functions of one diameter in one device. This avoids the problems related to treating this topology with one IED per switch or breaker requiring multiple interfaces between the IEDs.

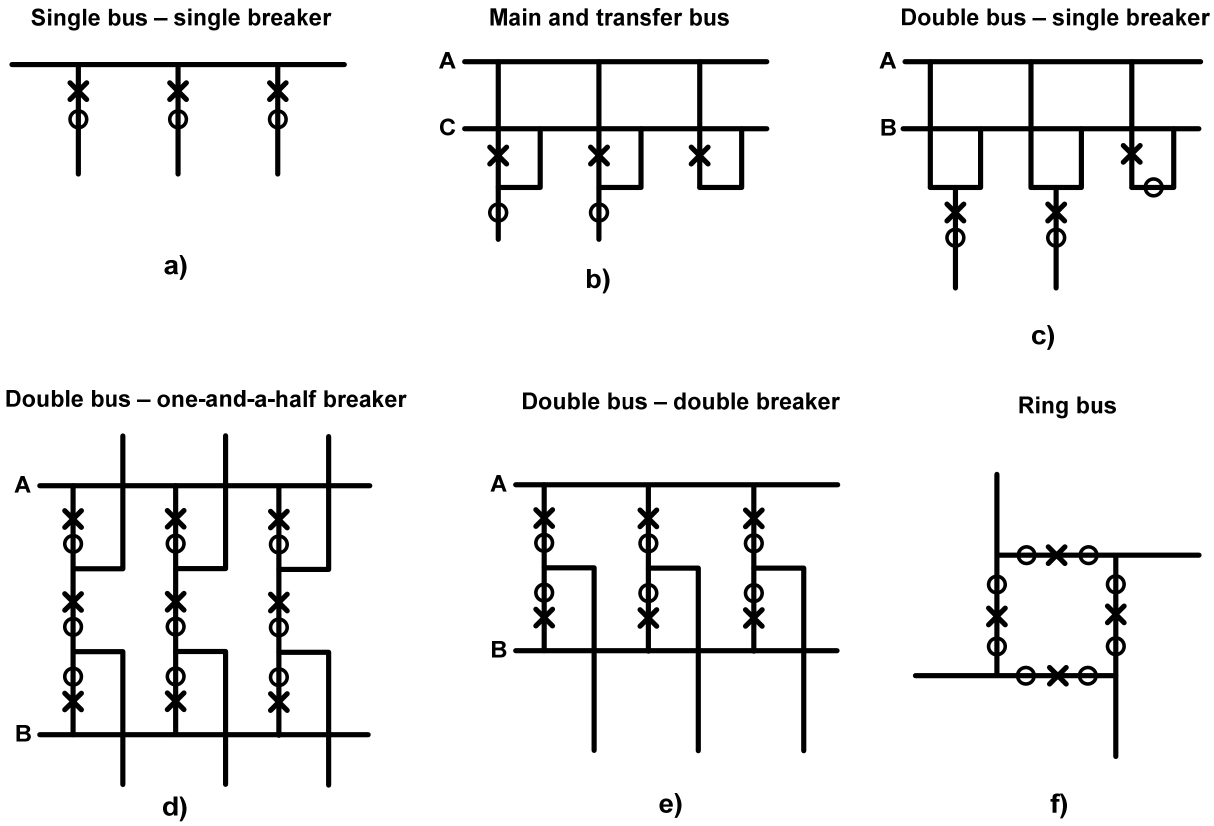

Figure 4-1 Examples for Busbar Topologies

5 Impact of IEC 61850 on Functional Integration

IEC 61850 is an approved international standard for communications in substations that is creating opportunities for a significant change in electric power systems protection and control. It represents the next step in integration of multifunctional Intelligent Electronic Devices (IEDs) based on the development and implementation of advanced distributed protection and control applications.

According to the names of the different parts of IEC 61850 it is a standard for communication networks and systems in substations. It was developed with the goal of meeting the requirements of all different functions and applications in the substation, such as:

- Protection
- Control
- Automation
- Measurements
- Monitoring
- Recording

At the same time it supports different tasks related to the above listed substation functions, such as:

- Engineering
- Operations
- Commissioning
- Testing
- Maintenance
- Event analysis

- Security

IEC 61850 was developed on the basis of some key requirements:

- It should be technology independent
- It should be flexible
- It should be expandable

By meeting the above requirements the standard allows us to meet the changing needs of the electric power industry and take advantage of the developments in computers, communications and sensors technology.

The IEC 61850 standard defines not only how to communicate over the substation local area network, but also what to communicate. It provides an abstract model of the substation equipment and functions that can be used as the foundation of the development of different tools.

The standard also addresses the substation integration and automation engineering process and specifies the conformance testing for intelligent electronic devices (IEDs) that support it.

It needs to be well understood that the IEC 61850 standard does not specify individual implementations, communication architectures or products. It also does not attempt to describe any details of the functionality of the different devices, such as algorithms, but focuses only on the specification of the externally visible functionality of primary or secondary equipment, functions or implementations in substation protection, control and automation systems.

5.1 The IEC 61850 model

The IEC 61850 object model is designed to represent in a consistent way substation devices with different levels of Functional Integration.

IEC 61850 defines not only the object models of IEDs and functions in a substation automation system, but also the communications between the components of the system and the different system requirements. It is very important to understand that the fact that one can model a function in a device or substation automation system does not mean that the standard attempts to standardize the functions. This is especially true for the distance elements. There are so many different algorithms and characteristics, as well as preferences and opinions, that this will be an extremely difficult task. Instead, the model represents the communications visible attributes and behaviour of the device.

It is important to also remember that the changing technology introduces new methods for interface between the instrument transformers or sensors in the substation and the distance or other protection relays. They need to be able to interface with conventional and non-conventional sensors in order to allow the implementation of the system in different substation environments.

A simplified diagram with the communications architecture of an IEC 61850 Process Bus based substation automation system is shown in Figure 5-1.

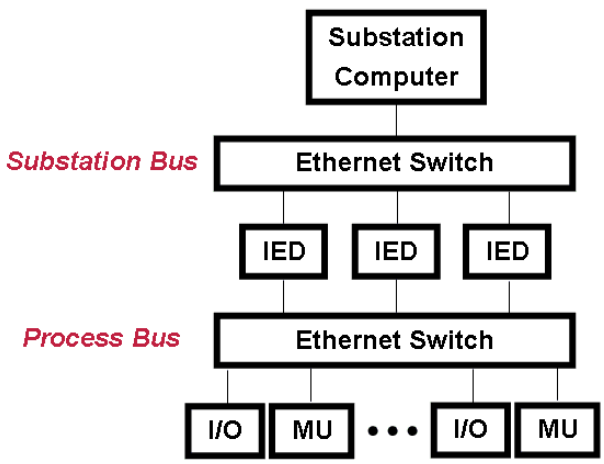

Figure 5-1 Simplified IEC 61850 based communications architecture

The Merging Unit (MU) multicasts sets of measured sampled values to multiple IEDs in the substation over the substation local area network. In some cases it is called the “process bus”. Status information for breakers and switches is available through an input/output unit (I/O). In some cases the merging unit and the input/output unit can be combined in a single device.

The receiving devices then process the data, make decisions and take action based on their functionality. The action of protection and control devices in this case will be to operate their relay outputs or to send a high-speed peer-to-peer communications message to other IEDs in order to trip a breaker or initiate some other control function, such as breaker failure protection, reclosing, etc..

The modelling of complex multifunctional IEDs from different vendors that are also part of distributed functions requires the definition of basic elements that can function by themselves or communicate with each other. These communications can be between the elements within the same physical device or in the case of distributed functions (such as substation protection schemes) between multiple devices over the substation local area network. The basic functional elements defined in IEC 61850 are the Logical Nodes.

A Logical Node is “the smallest part of a function that exchanges data”. It is an object that is defined by its data and methods. When instantiated, it becomes a Logical Node Object. Multiple instances of different logical nodes become components of different protection, control, monitoring and other functions in a substation automation system. These instances are used to represents individual zones or steps in a protection function.

A multifunctional protection IED has a complex functional hierarchy that needs to be modelled according to the definitions of the IEC 61850 model. It has two main groups of functions – protection and non-protection.

Each device sub-function then can be split in functional elements. Functional elements can be defined as the smallest functional unit that can exist by itself and also can exchange signals or information with other elements within a device or a system.

An example of a protection function is a distance protection. Phase distance and ground distance are subfunctions of the distance protection functions. The zones used in each of these subfunctions are functional elements. Each functional element (zone) may have multiple settings (impedance or time delay). Each setting may have multiple attributes (value, minimum, maximum, step, etc.)

Figure 5-2 shows an example of the functional hierarchy of a multifunctional IED. FGN in this figure indicates a Functional Grouping, DO a Data Object and DA a Data Attribute.

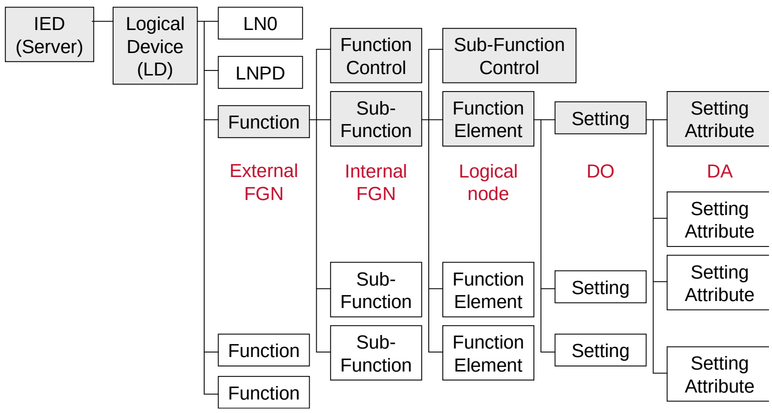

Figure 5-2 IED functional hierarchy

The modelling of complex protection devices depends not only on their functionality, but also on the configuration of the substation where they are installed. The model will be different if the transmission line is connected to a bus with a single breaker compared to the case of a breaker-and-a-half or ring bus.

Figure 5-3 shows a distance relay connected to a segment of a breaker-and-a-half bay. In this case the transmission line protection relay will need the currents from current transformers on each breaker and voltages from voltage transformers on the protected line.

If the relay also performs reclosing functions, it will need additional voltage measurements to perform synchrocheck.

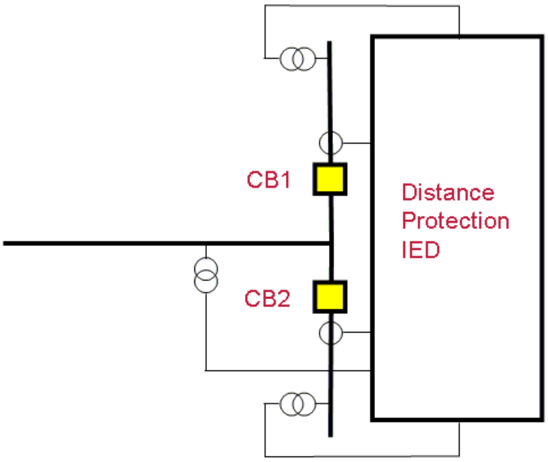

Figure 5-3 Distance relay connected to a segment of a breaker-and-a-half bay

The modelling of multifunctional devices needs to reflect the functional and modelling hierarchy described earlier.

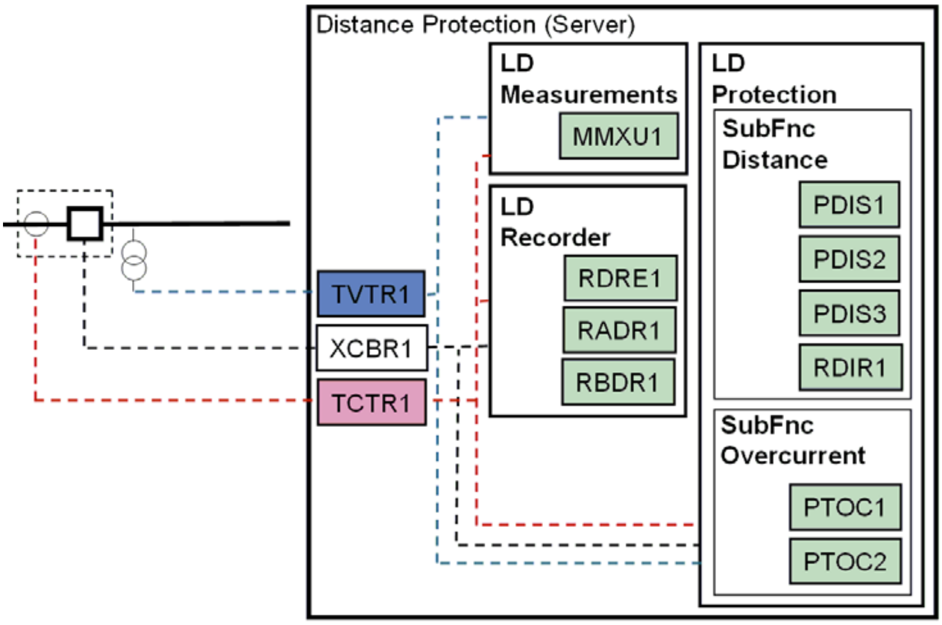

Figure 5-4 Distance protection relay – simplified object model

If we go further down in the functional hierarchy from Figure 5-2, the Protection Logical Device will include multiple protection functions. When a protection function is Disabled, it means that all Functional elements (Logical Nodes) included in it become Disabled as well.

The functional hierarchy becomes more complicated in the case of an advanced distance protection relay connected to a breaker-and-a-half or ring bus. One approach to the modelling will be to have a logical device for Protection, Measurements and Recording and then if necessary different functional groupings for the line and per breaker, and further down the functional hierarchy.

Another way of modelling this device is to use a Logical Device for each different physical interface and for some line level functions. Then each of these Logical Devices will include Protection, Measuring and Monitoring functions. A Line level LD will also contain the Disturbance recorder function.

Implementation agreements on the use of Logical Devices can significantly improve the chances for development of tools that will support the shift from manual to automatic execution of different engineering tasks.

XCBR1 in Figure 5-4 is the logical node that models the breaker that the relay is connected to. TCTR and TVTR are the logical nodes that represent the analogue input module of the distance relay that converts the signals to sampled values transmitted over the device internal data bus for recording (represented by the logical nodes RDRE1, RADR1 and RBDR1) or processing by the measurements (MMXU1) and protection PDISi, PTOCj functional elements. Each of these logical nodes has data object hierarchy as defined in IEC 61850 and described in more detail below.

Logical nodes typically include not only data, but also data sets, different control blocks, logs and others as defined by the standard.

5.2 Distributed functions in IEC 61850

The selection of IEC 61850 as the communications protocol used for substation communications is one of the critical factors that affect the design of the substation protection and control system. It allows the development of distributed function resulting in improved performance and reduced costs. A function can be divided into sub-functions and functional elements.

A "distributed function" is one that requires exchange of data between two or more logical nodes located in different physical devices. The exchange of data is not only between functional elements, but also between different levels of the substation functional hierarchy.

IEC 61850 defines interfaces that may use dedicated or shared physical connections - the communications links between the physical devices. The allocation of functions between different physical devices defines the requirements for the physical interfaces, and in some cases may be implemented into more than one physical LANs.

The functions in the substation can be distributed between IEDs on the same, or on different levels of the substation functional hierarchy – Station, Bay or Process..

These levels and the logical interfaces are shown by the logical interpretation of Figure 5-5. The logical interfaces of specific interest to protection applications shown above are defined as:

IF4: CT and VT instantaneous data exchange (samples) between process and bay level

IF8: direct data exchange between the bays especially for fast functions like interlocking using Generic Object Oriented Substation Event (GOOSE) messages.

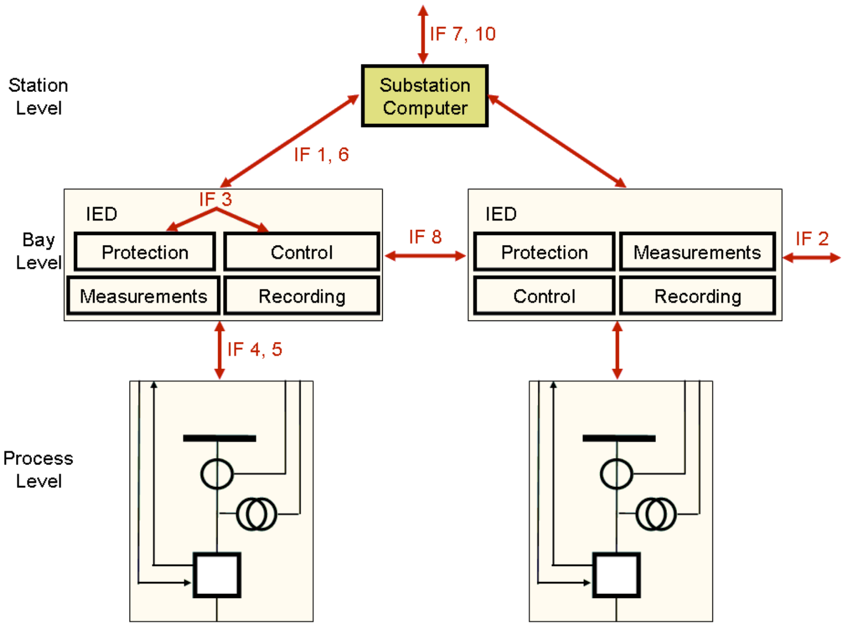

Figure 5-5 Logical interfaces in Substation Automation Systems

The first one is used typically for Process bus applications, while the second defines Substation bus communications.

5.3 Distributed functions based on sampled analogue values

A distributed function can also be based on sampled measured values. In this case the analogue signals that are usually hardwired from the secondary of the instrument transformers into the analogue inputs of the IED are replaced by an Ethernet message that contains one or more sets of samples from a Merging Unit connected to the instrument transformers. The instrument transformers can be either conventional or non-conventional.

The Merging Units are defined as interface unit that accepts multiple analogue CT/VT and binary inputs and produces multiple time synchronized serial unidirectional multi-drop digital point to point outputs to provide data communication via the logical interfaces 4.

The information exchange for sampled values is also based on a publisher/subscriber mechanism. The publisher writes the values in a local buffer at the sending side, while the subscriber reads the values from a local buffer at the receiving side. A time stamp is added to the values, so that the subscriber can check the timeliness of the values and use them to align the samples for further processing. The communication system shall be responsible to update the local buffers of the subscribers. A sampled Value Control (SVC) in the publisher is used to control the communication procedure.

There is a difference between conventional multifunctional IED set of functions and the same function's distributed implementation based on merging units and sampled measured values based IEDs. In the first case all sampled measured values exchanged between the Txxx logical nodes and protection and recording logical nodes are sampled at the same moment in time using a sample-hold type method and transmitted over the internal IED data bus for use by the different function modules. In the distributed applications (especially if there are multiple merging units involved) the sampling may occur at different times.

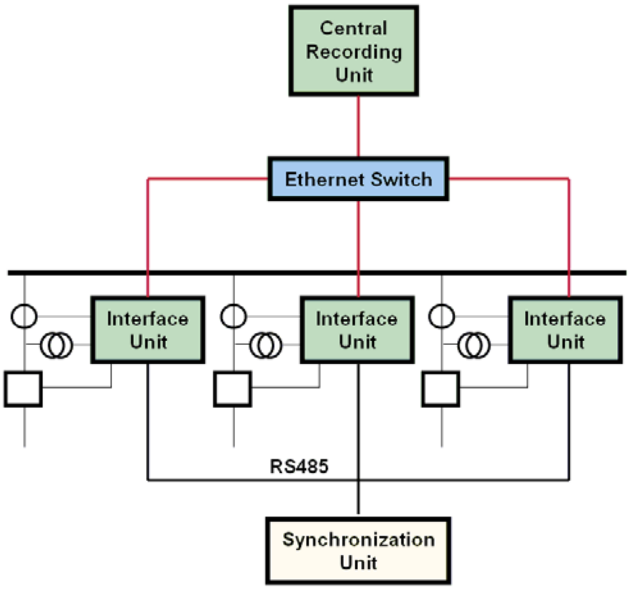

Figure 5-6 Waveform recording system architecture

A good example of a distributed Sampled Measured Values (SMV) application is the distributed waveform recording system that includes three types of devices – recording, interface and synchronization.

The synchronization device (or synchronizer) is used to ensure that the waveform recording system meets the requirements for time-synchronization accuracy better than 1 microsecond.

A good example of a distributed protection application based on sampled analogue values from multiple merging units is a distributed bus differential protection application.

5.4 Analysis of IED operation

The analysis of protective relays operation is based on the different reporting functions in these IEDs, such as Event reports, Fault records and Waveform records. In many cases the fault records are included in the event report.

Event reports in IEC 61850 are based on Report Control Blocks that control the procedures required for reporting values of event data from one or more logical nodes to one client. Instances of report control are configured in the IED at configuration time.

IEC 61850 defines two classes of report control:.- Buffered Report Control Block (BRCB) and Unbuffered Report Control Block (URCB).

Buffered Report Control Blocks are used for sequence of event purposes. They define internal events (caused by trigger options data-change, quality-change, and data-update) that issue immediate sending of reports or buffer the events for transmission. This prevents from data being lost in case of loss of connection.

Unbuffered Report Control Blocks are quite similar to the BCRB. However they don't buffer the data, so event information may be lost in the case of communication problems. Obviously the unbuffered report control block does not support sequence of events reporting in case of loss of communications.

Waveform records are typically saved as a file or set of files (according to the COMTRADE specifications). Retrieval of such files requires file transfer support in the communications protocol. IEC 61850 supports file transfer, so it can be used to support the waveform records extraction function.

This operation helps to eliminate the traditional substation anunciator function (alarm panel, centralised event recorder, …) which is now distributed in the different elements, independent on their level of integration. This also allows a redundant distribution of these elements in any device on substation level if required.

5.5 IEC 61850 Control Model

Protection functions are not sufficient to perform all tasks given to an advanced protection IED. It has to be able to adapt to the changing power system conditions and substation configuration in order to ensure optimal performance in all cases. At the same time it has to ensure the fastest possible restoration of the system in order to reduce the effect of the fault on the system, substation and customer equipment.

IEC 61850 defines a Control model that includes a specification of services and behaviour, such as: Controllable single point (SPC), Controllable double point (DPC) and Controllable integer status (ISC)

The behaviour of a control object is dependent on the application. Each behaviour is defined by a state machine. Four cases are used to specify the behaviour: - Direct control with normal security, SBO (Select Before Operate) control with normal security, Direct control with enhanced security and SBO control with enhanced security.

The 61850 control model supports all substation control functions regardless of the level of Functional Integration of the devices.

5.6 Substation Configuration Language

One of the key advantages of IEC 61850 based systems is the availability of the Substation Configuration Language (SCL) that allows interoperability and a seamless integration process. In the context of the new standard, it plays a very important role in the integration of numerous multifunction devices from different vendors in one substation protection and control system. It represents the functional hierarchy and the interfaces with the primary substation equipment and other IEDs in the system.

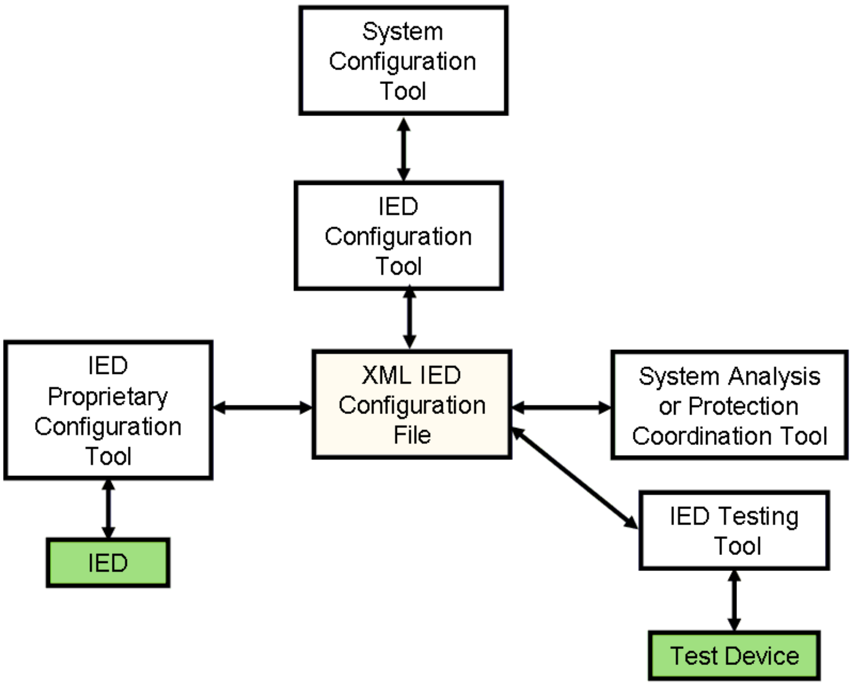

Figure 5-7 SCL based configuration process

The SCL is basically a system specification of the substation equipment connections in a single line diagram. It also documents the allocation of Logical Nodes to devices and equipment of the single line to define functionality, access point connections, and sub network access paths for all possible clients.

What is of specific interest for protection and control applications is that it allows the development of engineering tools for configuration, protection coordination and testing that use a common standard data format.

The overall functionality of any IEC 61850 compliant device is available in a file that describes its capabilities. This file has the extension “ICD” meaning IED Capability Description. The system specification tool supplies to the system configuration tool information such as the single line diagram of the substation and the required logical nodes. The file extension for this file is “SSD” meaning System Specification Description.

The system configuration tool then provides information to the IED configuration tools regarding all IEDs, communication configuration and substation description sections. This information is in a file with the “SCD” extension meaning Substation Configuration Description. This information also needs to be provided to the other tools in order to allow them to configure the set of functions to be performed.

The Standard IED configuration tool sends information to the IED upon its instantiation within a SAS project. The communication section of the file contains the current address of the IED. The substation section related to this IED may be present and then shall have name values assigned according to the project specific names. This file has an extension of “CID” meaning Configured IED Description. Currently there is ongoing work to expand the content of this file to include all settings, thus providing the required configuration data for both the IED itself, and also for the different functional tools.

6 Levels of integration

Multifunctional devices can be characterized based on their levels of Functional Integration. While there are some generic devices that can be configured as devices with different functionality depending on their use, the typical IEDs include a set of principal functions and some additional functions.

6.1 Simple devices with limited Functional Integration

The simplest protection devices have a limited number of analogue inputs (current or voltage only) and cover a set of basic protection functions, for example phase and ground overcurrent. This type of devices may have a very limited set of additional functions, such as measurements and fault or event recording.

Waveform recording may not exist, or can be very limited and with a low sampling rate.

No control and automation functions are available.

Programmability can be limited to assignments of binary inputs and relay outputs to a specific protection related function.

6.2 Typical devices with average Functional Integration

More advanced devices expand the number of analogue signals and combine both voltage and current inputs, which allows the implementation of more advanced protection functions, such as directional overcurrent and distance.

Such devices may also have communications capabilities that support not only remote interface with the device, but also communications based (line differential) or communications aided (permissive, blocking, etc.) protection functions.

The primary protection functions are supported by local backup protection functions (for example breaker failure protection).

Such devices include local and remote control capabilities, as well as automatic functions such as autoreclosing.

Basic monitoring functions, such as voltage transformer supervision or trip circuit supervision are also available.

Transient recording is typically available, combined with event recording and fault location.

Measurements cover phase and sequence components of the currents and voltages, as well as many other power system parameters (active and reactive power, etc.)

6.3 Advanced devices with high levels of Functional Integration

Advanced devices with high levels of Functional Integration may further expand the number of analogue signals – for example if the device is protecting a transmission line connected to the substation with a breaker-and-a-half scheme, there will be two separate three phase inputs that provide better performance for cases of CT saturation or integrated breaker failure protection. Additional inputs may be available for mutual current compensation.

Such devices may also have Ethernet communications capabilities that support high-speed peer-to-peer communications and distributed functions integration.

The primary protection functions are supported by local backup protection functions (for example breaker failure protection). Load shedding functions are typically supported as well.

Such devices include not only local and remote control capabilities, but also more advanced automatic functions such as autoreclosing with synchrocheck, single pole reclosing. .

A broad range of monitoring functions, such as current transformer supervision or breaker monitoring may also be available.

Other forms of system event recording can be available in addition to the transient recording. Double-ended fault location may be supported.

Measurements cover phase and sequence components of the currents and voltages, as well as many other power system parameters (active and reactive power, etc.). Demand measurements may also be supported.

Phasor measurements are a new addition in devices with high levels of Functional Integration.

Metering can also be supported when non-conventional instrument transformers are used or if the device has separate inputs for protection and metering.

6.4 Highly integrated P&C system

In some existing solutions, functionalities concerning protection and control of several objects of the substation are integrated within one single device. E.g. several distribution feeders are protected by a single protection IED. One can consider that this represents an intermediate step between the typical multifunctional device and the totally integrated protection and control system.

The redundancy and the reliability of all functions of such a P&C system have to be ensured in order to meet the requirements stated in paragraph 2.2 and 2.3.

The following of this chapter will deal with totally integrated P&C systems and different degree of redundancy.

6.4.1 Totally integrated P&C system

The same requirement on backup of the control functionalities is valid for a totally integrated P&C as for a conventional system. Figure 6-1 shows the principle structure of a totally integrated P&C system. This corresponds to the highest possible level of Functional Integration which can be achieved for a substation P&C system. Because all functions are located within the same physical device, the reliability and redundancy of the system, if required, has to be achieved using redundant devices with the same functionality (see section 6.4.2).

The main computer corresponds to the server, gateway and S/S network in the conventional system and the I/O hardware corresponds to the I/O part of the P&C bay units. The difference to a conventional system is that all functions are allocated in the main computer. This will result in complete loss of protection and control functionalities in case of e.g. extensions and modifications of the main software during normal operation of the substation. The risk of failures that give complete losses of the functionalities will also increase. From the protection point of view it is necessary that there are sufficient remote backup functions. As there are no generally accepted requirements on backup of the control functionalities this most basic totally integrated P&C system may be acceptable for some kind of the smallest substations. However, in most substations the decrease of the availability and dependability compared to a conventional P&C system is not acceptable and duplication of main computers is necessary. The importance of the substation will decide the necessary degree of redundancy.

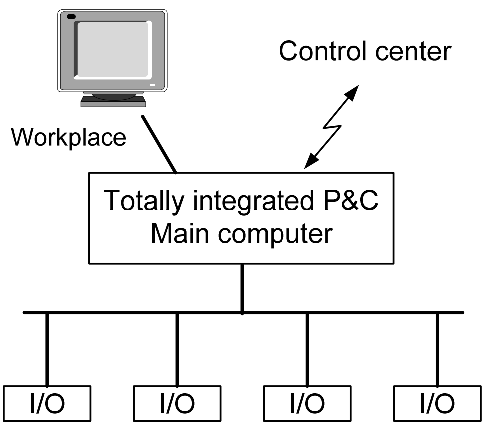

Figure 6-1: Principle structure of a most basic totally integrated P&C system

6.4.2 Redundant main computers

To improve the dependability and availability there must be some kind of back-up for the main computers. The following defines three ways how back-up can be provided on station level in a system:

- **Cold standby**: A standby hardware device exists. It is physically connected and pre-configured but may at the moment be used for other purpose. In case of a failure the appropriate software is started manually. Start up time is in the order of 5 to 10 minutes. Archived data on the replaced part, which has not been secured, is probably lost.

- **Hot standby:** A standby part constantly supervises the active (hot) component. In case of a failure it takes over automatically. No time stamped events are lost, no archived data is lost, and commands are usable after 1 – 5 sec. When the failure is repaired and the system is put to standby mode again, its archive and configuration data is automatically updated.
- **Duplicated central units:** Two devices are running in parallel (hot). This means that commands are always usable at least on one of them.

A cold standby solution is normally not suitable in unmanned substations, because immediate manual work by maintenance people must be done.

If there are two active systems, they may supervise each other and give an alarm if the other system fails. In this case, the control is only enabled in one system (unique point of control), but the protections are active in both systems.

In case that under no circumstances time stamped events shall be lost, a hot standby system is needed.

In case that configuration and archive consistency is not so important, duplicated central units can be applied. This allows to have different configurations on both units, e.g. for testing configuration changes/extensions or new functions only on one unit, while operation is performed by the other unit. The process database on both units is always up to date, so that in case of a shut down of one unit the other one can continue commanding without interruption.

The solution with duplicated central units gives an improved backup on station level, which means no loss of functionalities during work on one computer and no risk of complete loss of functionalities. This solution is here recommended before a hot standby solution, because the duplicated central units can have different configurations, which give possibilities for more flexible solutions compared with a hot standby solution. A hot standby solution is also more complex and by that more costly.

In case local backup functions are necessary for fulfilling the requirements on the fault clearance system these functions must be allocated in duplicated central units running in parallel.

6.4.3 Redundant process busses

Figure 6-2 shows a principle design of a duplicated system with two separate main computers connected to single I/O units in each bay. The main computer is connected to the I/O units via a process bus containing switches. The process busses in system 1 and system 2 must be strictly separated. This design of a totally integrated P&C system may have a higher availability and reliability than the control and monitoring system shown in Figure 2-4. Except for the I/O units all parts including the application software are duplicated.

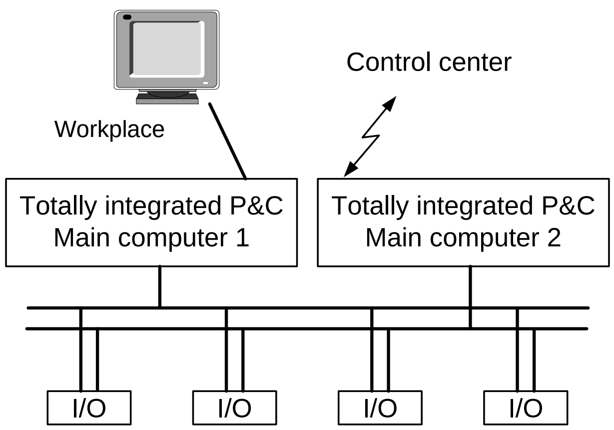

Figure 6-2: Totally integrated P&C system with duplicated main units and redundant process busses

6.4.4 Completely redundant system

By duplicating the I/O units according to Figure 6-3, the totally integrated P&C system fulfils the most demanding requirements including a complete backup of the functionality also on the bay level. This high level of backup is very seldom required in conventional control systems. Redundant I/O units are not always required for control functions which are not critical.

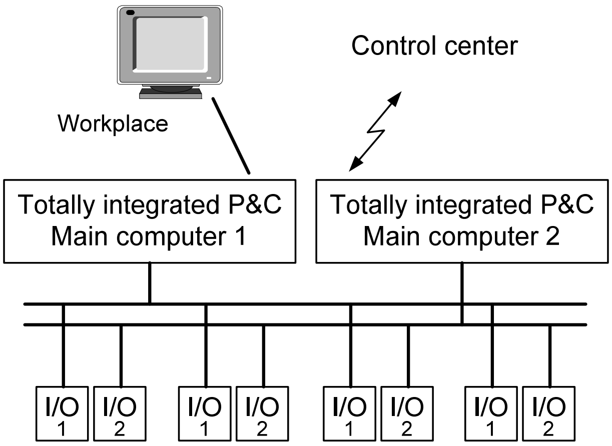

Figure 6-3: Duplicate structure of a totally integrated P&C system

6.4.5 Other control functions

With duplicated central units the management of common resources like disturbance recording, control centre connections, event log printers, automatic restoration etc. may be different (although equivalent) even if both systems are operating, and holes in one archive during shut down are not automatically filled on system start up. Event lists are different, because e.g. commands and alarm acknowledges are logged only on the executing system, and operational parameters like measurement limits and dead band may be different if they are interactively changed during operation of the system.

These improper differences should not give any impact on the normal control functionality, but can have some importance at analysis work after a disturbance.

6.4.6 Conclusions regarding application of totally integrated solutions

Mostly totally integrated P&C systems must have duplicated main computers. The main reason for this is to minimize the risk of a complete loss of the protection and control functionalities in a station. Another reason is that it must be possible to shortly take one of the systems out of operation to be able to e.g. perform upgrades or implement new functionalities. Major system changes and tests should be carried out on a separate system.

Methods to automatically perform supervision, maintenance and testing should be implemented in the systems. However, if the risk of a failure of the central unit while the other unit is out of operation still cannot be accepted, the central units may even have to be triplicated. This is especially the case if the protection provided by remote backup is not sufficient from e.g. the sensitivity or system stability point of view.

By duplication of the main computers, the process busses and the I/O units all requirements are possible to achieve for the most demanding cases. It is also possible to design the system with single I/O units with duplicated communication ports but still maintaining practically the same dependability. This is possible due to the fact that all measured currents and voltages are available in each of the main computers and in case of a failure in one I/O it is possible to calculate the missing quantities. In this case the commands for emergency control also must be able to perform another way e.g. direct control at the switchgear itself or from a back-up panel. However, in a totally integrated P&C system for the most demanding cases a duplication of the I/O units can be an interesting alternative compared to other backup solutions.

7 Advantages and disadvantages, constraints and limitations

The obvious advantage of a higher degree of integration of functions in a substation automation system is a reduction of the number of equipments and devices and, subsequently, a simplification in wiring and a reduction of the number of cubicles. All these factors contribute to an overall cost reduction of the control system. Moreover, the integration of functions in a small number of devices facilitates configuration or at least the control of consistency of their settings and parameters. Depending on the way of implementation, operators also have a higher degree of flexibility for addition, modifications or adaptations of the different functions after commissioning.

But there are also some potential drawbacks : a higher Functional Integration implies an incidence on the reliability and the performance of the overall system compared to a less integrated system using equipment of the same technology. Also, different functions share more common elements. The question which functions have to be independent (not sharing common elements) and to which extent becomes an important issue (see sections 3.3 and 11.2) and may challenge long established utility customs (e.g. separation of protection and control functions). In some cases, maintenance operation on bays with HV equipment in service are required. They can be more difficult or impossible if the degree of integration is too high.

For each case or type of substation, the advantages and drawbacks have to be carefully analysed by the utilities and by the manufacturers before deciding the extent of Functional Integration for a given substation automation system (see sections 3 and 3.3). They have to be translated into explicit requirements in the corresponding specifications for the SAS (see section 11).

Table 7-1 below discusses the advantages and disadvantages of Functional Integration for different issues :

Table 7-1 Advantages and disadvantages, constraints and limitations of Functional Integration

Issue	Advantage	Disadvantage or constraint
Hardware	Optimised use of hardware. Limited number of equipments to install.	Functions share common hardware elements. Limitation of number of different functions in one device by hardware capability.
Software	Software development and maintenance for a limited number of platforms.	Software has to be adapted to enable simultaneous implementation and execution of different functions.
Configuration	Allocation in one device facilitates configuration and consistency check.	Configuration tool more difficult due to increased number of functions and parameters.
Functionality	Simpler to add in an existing SAS.	Acceptance of shared resources with other functions for each functionality.
Performance	/	Limitation by hardware
Cost and other economical issues – installation and maintenance	Overall installation cost reduction due to decreased number of devices and less wiring. Reduction of number of different hardware spare-parts.	Higher constraints for maintenance and spare-part management (software versions).
Maintenance and operations	/	Constraints due to shared common elements between functions if live maintenance is required. Safety issues to be verified for live maintenance operation.
Security	/	Evaluation of integration versus risk has to be performed.
Flexibility	Higher flexibility for function allocation, addition or modification.	/
Installation and commissioning	Facilitated by limited number of devices, settings and simpler configuration.	/

Training	Limited number of hardware devices.	Integration issues have to be discussed
Communications	Limited number of communication interfaces on bay level.	Potential higher solicitation of the local bus on station and bay level.
Refurbishment/ Existing installations	Higher flexibility facilitates complete or partial refurbishment of SAS	On-shelf solution difficult if legacy hardware has to be integrated or interfaced.
Greenfield installation	Optimised use of hardware	/

8 Customisation, levels of functional complexity and flexibility – how are they all affected by integration?

8.1 The standardisation and customisation concepts

Big utilities' philosophy is often based on the principle of **standardisation** of substation design. The concept of standardisation involves many issues, such as substation topology, substation control system architecture and technology, substation and system operation and maintenance procedures, even purchasing procedures specific to that particular utility.

Utilities introduced standardisation to satisfy the need of common procedures to be applied to the whole process, from planning to substation operation in order to improve the efficiency, save of the value of investments and asset and to reduce costs.

Standardisation involves devices, functions and installations: the first two are more affected by Functional Integration. It means conformance of all parts the substation and its protection and control system to a list of references defined by the utilities (custom references):

- same topology,
- same control system,
- same operation and maintenance procedures,
- same spare parts,
- etc.

The other important principle is **customisation** of commercially available off-the-shelf products. It is typical of those companies who are focused on their business from many years and have a consolidated tradition for their processes, procedures, in every field.

Customisation means definition of specific criteria and, with reference to our subject, translation of these criteria in requirements for the technical specification. This involves the ability of the devices to be more and more flexible.

Concerning control systems, users are generally interested in maintaining the legacy, "well established", customised functionality, just implementing it with what technology offers today. This implies a strong specification activity for the utility in order to obtain customised off-the-shelf components. Depending on the case, the customisation can be made by the utility, by the vendor or in collaboration between the two parts.

This legacy way of doing things may be an obstacle to taking full advantage of the technical evolution.

Due to the complexity of the process, it is almost impossible to modify a product to meet all specific requirements of every single customer. Manufacturers try to compensate by offering products with a very high level of Functional Integration that can be adapted to a specific application. This results in flexible and complex products with high requirements for engineering by the users. The fulfilment of customer requirements involves for the manufacturer not only extra cost for the development, but also the need of specific software release, with consequent maintenance and post sale assistance. Sometimes the new solutions introduce the risk for the first customer to do a heavy debug work.

For the users, the standardisation and customisation of protection and control systems are easier to apply and maintain along the years as long as the technology associated is still available (same devices, same wiring, same interfaces, some tools, same skills of personnel). Such a long-term standardisation is sometimes applied to high voltage equipment and components, but it's not verified in the field of substation control systems, where the result of this is a series of compromises between what the utility asks for and what manufacturers produce.

The consequences are installations of substation that are different from each other. These differences don't depend only on the specific manufacturer, but are also visible in substations made by the same vendor, who, from time to time, makes some modifications in its products for different reasons. This fact may have a negative impact on standardisation.

8.2 Functional Integration versus standardisation and customisation

Functional Integration has a big influence on customisation and standardisation required by the utility. Devices with a high level of Functional Integration may contribute to the optimisation of the architecture of protection and control systems (e.g. transient recording, sequence of events, fault locator). These functions can be reorganised, bringing a reduction in the total number of devices.

A positive aspect of Functional Integration is given by the multiple possibilities for configuration of the same device for different applications. It consists in implementing multiple protection functions in the same device (e.g. distance and busbar differential, or distance and overcurrent, or distance and line differential). This creates new opportunities, for instance a line feeder can be protected with distance and differential protection with only one device.

Another subject for which Functional Integration could open new roads is the distinction between voltage levels or types of substation, made my many utilities. For example :

- in a small and unmanned substation a double level (station–bay) architecture may not be required. It could be acceptable to concentrate all functions at one level with integrated protection and control functions.
- for an important substation or a higher voltage level, it can be required to have two devices each one with protection and control or a single control device and another device with two protection functions. In order to enable utility-wide standardisation, these devices could be of the same type as the one installed in the smaller substation.

Further to the previous discussion, combined implementation of protection and control functions can also be considered (cf §6). The utilities have to take into account :

- the redundancy of the devices: two devices have implemented in each of them control and protection functions. Control functions are normally enabled in main device and, only in case of fault of this one, in the main two. In this case there is backup for both protection and control functions.
- the redundancy of protection principles: for instance a device capable of acting as distance and overcurrent or differential protection is intrinsically redundant.
- the flexibility: the same device could be used for one function (distance protection) ore for another one (eg. differential protection), just by changing its configuration.

As far as standardisation and customisation are concerned, the possible drawbacks of Functional Integration are :

- risk of reduction in availability (more functions concentrated in few components/devices).
- risk of reduction in performances : more functions in the same hardware/software can mean functions with reduced performance, (e.g. digital fault recorder dedicated device versus transient recorder function integrated in a protection device) .
- evolution of standardisation (new systems with strong Functional Integration are different from the old operating one).
- possible degradation of customisation: more functions in the same hardware with reduced capability. In some cases, a given parameter may be used by different functions reducing thus the flexibility of configuration.

- possible degradation of integrated functions compared to stand-alone functions (e.g. integration of a protection device and a line differential protection device: in case of fault of the communication system of the second one, the device switches to distance mode which may be inferior to the performance of a conventional distance relay).

As of today, there is no indication that in the efforts of the utilities to obtain standardised and customised SAS will facilitate Functional Integration. As a matter of fact, standardisation and customisation requirements often impose constraints on the architecture and the implementation which probably limit a high degree of Functional Integration.

It is also difficult to specify these aspects without taking into account the real characteristics and performance of the hardware used. This makes common rules applicable to different vendors difficult to establish while the Functional Integration has not obtained a high level.

This problem will disappear as soon as all functions of at least one bay can be integrated in one device which is duplicated.

9 Organisational Requirements of Functional Integration

Functional Integration may imply "cultural" changes in the utilities and require organisation structures (both for utilities and vendors) which enable coordination of protection, control, monitoring and recording activities for development, engineering and operation.

The context of Functional Integration is the massive introduction of digital technologies that are developing and changing quickly. This will require personnel to learn, maintain the competence and be efficient in a huge variety of new concepts and tools across different disciplines (e.g. protection and IT systems). Furthermore, this will require ongoing training as new tools and technology are introduced.

In addition to this, another difficulty is introduced by Functional Integration since there may be interdependency between different functions. Their enabling or disabling may affect the behaviour of the system under certain conditions. This may have an impact on the organisation of the type acceptance and commissioning process.

The users thus have to acquire a deeper understanding of all these items in order to be able to configure and to operate a digital SAS with a high level of Functional Integration. This represents a major change with respect to the skills required for maintenance and operation of a conventional control system.

The integration of communication functions in the multifunctional substation devices requires a new set of skills in order to be able to configure, commission, maintain and test such devices and systems. Testing of a system with a high level of Functional Integration also requires a different set of skills and tools as well as new methods that will allow the testing of all components as well as a system as a whole (cf. §16).

Functional Integration potentially also has an impact on substation configuration. The advantage is that in an integrated context, common parameters can be shared allowing to reduce the work of entering the different values and checking the consistency of the parameters of different functions. As mentioned in §8.2, this may reduce the flexibility of defining different values for corresponding parameters of two integrated functions. In this context, it can be pointed out that particular care has to be taken by the vendors for designing the user interface if many functions are in one IED in order to guarantee a certain user-friendliness.

On the other hand, the impact of Functional Integration on system administration is not very significant since the way of administrating the system databases, fault reports, event- and fault recordings etc. is not directly related to the level of Functional Integration of the system. The associated workload does not depend on the number of devices but on the number of functions.

The above listed requirements imply that some utility personnel may have to change their attitude towards new technologies. A typical example of this is given by the introduction of the autorecloser function into the protection device: all new protections have an integrated recloser. In case of redundant distant protections, two reclosers are thus available. A solution adopted by many utilities consists in making both protections initiate the recloser function of the main 1 protection (with recloser in back up protection disabled). In case of failure of the first protection device, the second recloser is enabled with reclosing initiated only by the second protection. This solution, before being adopted had to overcome the fear of many users of “two recloser working at the same time” or “only one protection acting on its recloser”.

Transient recording and sequence of event recording are available both in dedicated devices and integrated in protection devices. The integrated version may have lower performance than the dedicated one, and this may be an obstacle for the acceptance of the integrated solution.

10 Impact of Functional Integration on communication constraints

Communication and data exchanges for different functions and applications in the substation require good understanding of their impact on the overall performance of the system. As discussed earlier in the report (§2.1), the following are the typical functions supported in multifunctional IEDs:

- Protection
- Control
- Automation
- Measurements
- Monitoring
- Recording

The device needs to meet specific requirements and ensure that data exchange related to any of the above functions does not degrade the performance of the system under critical conditions.

The different distributed functions impose different performance requirements that have to be considered in the design process of substation protection, control, monitoring and recording systems. IEC 61850 defines performance requirements for the typical substation functions. The transfer time definition is based on Figure 1 below:

The performance classes for protection and control are defined according to the required functionality and are independent from the size of the substation. They are higher, because of the effect of the fault clearing time on the stability of the system or on sensitive loads. IEC 61850 defines three Performance Classes for such applications:

- P1 - applies typically to the distribution level of the substation or in cases where lower performance requirements can be accepted.
- P2 - applies typically to the transmission level or if not otherwise specified by the user.
- P3 - applies typically to transmission level applications with high requirements, such as bus protection.

The transfer time is

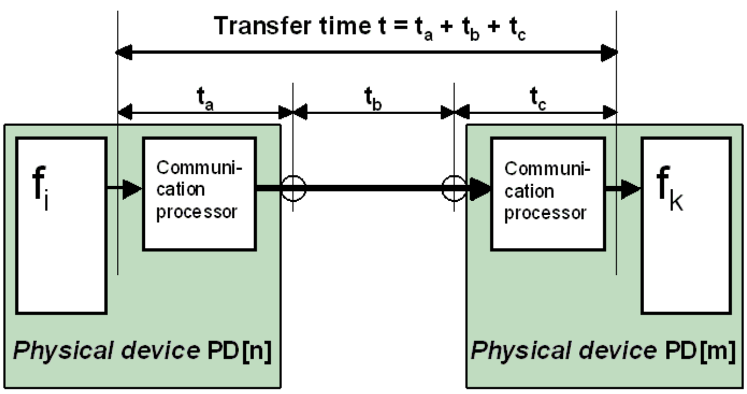

Figure 10-1Transfer time definition

Where:

t_a - time from the moment the sending IED (PD[n] in Figure 10-1) puts the data content on top of its transmission stack until the message is sent on the network

t_b - the time over the network

t_c - the time from the moment the receiving IED (PD[m] in Figure 10-1) gets the message from the network until the moment it extracts the data from its transmission stack

The overall performance requirements also depend on the message type. Since Trip is the most important fast message in the substation, it has more demanding requirements compared to all other fast messages. The same performance may be requested for interlocking, intertrips and logic discrimination between protection functions. For Performance Class P1, the total transmission time shall be in the order of half a cycle. Therefore, 10 ms is defined.

For Performance Class P2/3, the total transmission time shall be below the order of a quarter of a cycle. Therefore, 3 ms is defined.

The performance of the multifunctional IED is also dependent on its architecture. The behaviour will be different if the device has a single network interface or multiple interface cards.

The support of priority tagging in IEC 61850 GOOSE (see section 5.2) and Sampled Measured Values (see section 5.3) communications allows the faster processing of these messages, even in cases when other functions, such as measuring or extraction of disturbance records is being performed. This will allow the system to meet the performance requirements even in cases of communication constraints.

The use of distributed functions as defined earlier in the document results in higher requirements for the communications exchange between the different devices included in the system.

As far as Functional Integration is concerned, the allocation of functions has thus a significant impact on the overall performance of the different functions due to the communication time between them. If a function is implemented in a single device, it will perform faster due to the fact that it does not require communications with other devices. On the other hand, in distributed applications, the communication processors and the transmission time over the network have to be taken into consideration in the design of the system.

A similar statement can be made for the reliability and availability of the functions that also depend on the communication. When multiple devices are involved in the implementation of a distributed function, the reliability may be degraded. This also has to be taken into account in the design of system.

In cases of high communication constraints it will be beneficial to increase the level of Functional Integration.

11 Impact of Functional Integration on system specification documentation

As far as the specification of Substation Automation Systems (SAS) are concerned, Functional Integration implies generally to abandon –or at least to strongly restrict – in the reference documents any constructive characteristic and detailed demands of functional allocation in different bay equipments of the SAS. E.g., a detailed description of the different equipments in a cubicle, the position and type of switches, the way the wiring has to be arranged in the cubicle, etc. represent such a description of constructive characteristics.

In order to take full advantage of the possibilities of Functional Integration and in order to be able to accept solutions closer to manufacturers' off-the-shelf solutions, the constructive specifications and the demands concerning functional allocation have to be substituted by a more functional approach. This should result in optimised – and thus cheaper- substation control systems.

In order to obtain a functional specification respecting the basic requirements, the following steps can been undertaken :

1. Analysis of the different constructive characteristics of the existing cubicles in order to clearly identify the underlying basic requirements. Analyses of the reasons underlying the demand for a particular allocation of functions in the substation or in a bay.

2. Definition of functional specifications which guarantee the respect of these basic requirements without implying a predefined constructive solution.

3. This procedure will lead to different constructive solutions depending on the manufacturer. It will, in turn, be necessary to adapt to the solution of each manufacturer the operation and maintenance manuals used by the operation staff individually.

11.1 Analysis of the constructive characteristics

The first step of the analysis has to be the identification of the different constructive characteristics for the substation control system. Examples concerning the constructive characteristics of a cubicle for a line bay are listed in Table 11-1 below.

Specifications of control bays often contain a detailed description of the constructive characteristics of these items. The results are standardised bays adapted to existing maintenance and repair procedures and compatible with the constraints due to safety regulations.

For each of the above listed items, the origin and the importance of the demand have to be identified. These impacts can be evaluated for the maintenance operation, for the everyday operation of the substation and of the bay and for the overall engineering of the bay.

Table 11-1 Constructive characteristics identified for control bays

#	Constructive Characteristic Item
1	The mode of connection of equipment within the bays and inter-bay circuits. These include connection of supply, of the vt and ct circuits, of the command and trip circuits and the earthing of the equipment.
2	The wiring board on bay level.
3	The cabling of the bays using standard cable trees for the different circuits and the existence of standard connectors for these cable trees.
4	Dedicated switches allowing disconnection of the bay from voltage sources necessary for maintenance and repair operation in accordance with safety regulations.
5	Other switches (e.g inter-bay circuit, differential busbar protection circuits) facilitating maintenance and repair operation within the bay or on this equipment.
6	Decoupling, marshalling and other electromechanical relays on bay level.
7	Use of different supply polarities in order to reduce the common mode on supply level.
8	Identification of connectors and pins and a system to avoid incorrect reconnections.
9	Dedicated interface with primary equipment.
10	Dedicated boards for different functionalities integrated in the bays.
11	Use of fuses in voltage circuits and use of switches to shunt current circuits.
12	Specification of dimensions and mechanical characteristics of bay structure.
13	Ergonomic considerations (position and colour of equipment, etc.)
	Etc…

11.2 Analysis of demands concerning a particular functional allocation

Since a higher Functional Integration is envisaged, a modification of the technology of the bays and of its individual equipment with respect to the conventional systems used at the utilities has to be accepted. As a consequence, it is also necessary to determine which differences in terms of operation, test and maintenance can be accepted by the network operators and maintenance staff.

In terms of functional specification, these constraints may lead to requirements concerning a constructive and functional separation between certain functionalities. This includes a prohibition of implementation of these functionalities in the same module or equipment and an independence in their alimentation and connection to HV equipment. The extent and severity of this prohibition has to be adapted to the context of each SAS and may also take into account the security and reliability philosophy of the utility. In any case, existing separation between functionalities in conventional substation automation systems can be analysed and included in the functional specification if they are justified.

Typical examples of requirements of this type are:

1. Separation between main and back-up protection for one line (see section 2.2),
2. Separation between protection and control functions (see section 3).
3. Separation of functionalities of two neighbour bays.
4. Separation of functionalities between bay and substation level.
5. Separation between remote control and local control on substation level.

Concerning points 3 and 4, the extent of the requirements concerning these separations should however be closely examined and justified since an optimised allocation may be possible without operational or safety drawback.

Concerning point 5, the underlying general requirement is to not depend on one single device for the remote and local control of the substation. In case of a failure in this device, neither remote nor local control operation would be possible. The scope "local control" may also include the event- and wave recorder depending on the needs of the utility.

The user also may specifically require to allocate all functionalities of a given type in one single device. This may for example be justified for the line recloser automaton of a given bay.

11.3 Definition of corresponding functional specification

The functional specifications for the digital control systems be established based on the analysis described above. It is thus possible to identify functional specifications compatible with the identified constraints while limiting the extent of constructive demands. The functional specifications obtained with this approach include constraints regarding reliability, availability, maintenance, repair, safety, operation, test and installation of the substation control equipment. The definition of functional requirements for a major part of these constraints is possible.

The main spirit of the specification should thus be a response to the question "What are the facilities the control system has to provide ?" instead of "How do we want the control system to be built ?".

Special care has to be taken in checking that all basic requirements have been completely covered by the functional specification in order to make sure that the solution complying with them can be inserted with no major problem in the operational context of the utility's networks and substations.

Major differences in the specification of the digital control system include the wiring- and relay boards used in the conventional bays whose functions can be easily integrated in a digital system. The accepted higher level of integration also calls for a different approach regarding maintenance, test and repair operations, which has to be taken into account in the specifications.

11.4 Examples for the application of functional specification

In this paragraph are given some examples of the approach described above aiming at higher Functional Integration and the resulting functional specifications.

11.4.1 Dispositions for maintenance operations

Table 11-2 below gives examples of items that can be connected to constraints related to maintenance operations.

Table 11-2 Constructive items with respect to maintenance related constraints

#	Item	Maintenance related constraint
1	Connectors as bay-equipment interface	Simple, safe and secure connection and reconnection for maintenance and repair. Avoid

		reconnection errors. Guarantee electric continuity after reconnection.
2	Wiring board on bay level	Facilitates error research
3	Standard cable trees and connectors	Facilitates connection of test equipment
4	Switches for disconnection of the bay from voltage sources	Visible and securable separation required by safety regulations and operational procedures.
5	Other switches	Facilitate maintenance and repair operation
6	Electromechanical relay board	None
7	Different supply polarities	None
8	Identification of connectors and pins	Avoid reconnection errors. Guarantee coherence between (standard) schemes and bay circuits.
9	Interface with primary equipment	Special disposition for command, voltage and current circuits.
10	Boards for different functionalities	Facilitate maintenance and ergonomic reasons.
11	Use of fuses and switches to shunt current circuits	Visible and securable separation required by safety regulations and operational procedures.
12	Dimensions and mechanical characteristics	Facilitate access to the bay and its equipment
13	Ergonomic considerations	Facilitate maintenance
	Etc.	

The next step is to formulate functional requirements for the digital control systems in order to meet the maintenance-related constraints listed in Table 2.

For example, in order to obtain satisfying ergonomic condition for the maintenance- and repair operations as aimed at via items 12 and 13, the following requirement can be formulated :

- **Facility of maintenance and repair operations**
  The constructive dispositions of the control system including integrated equipment of third manufacturers allow maintenance and repair operations to be conducted under satisfying ergonomic conditions. This includes
  - good accessibility to all parts which may have to be disconnected or dismounted,
  - position of the HMI of the bay allowing its easy use by a standing operator,
  - an arrangement allowing maintenance operation on neighbour or opposite bays under satisfying conditions.

11.4.2 Conformity with safety regulations for operation in electric installations

Table 11-3 below indicates items connected to constraints related to safety and operation issues.

Table 11-3 Constructive items with respect to safety related constraints

#	Item	Safety and operation related constraint
1	Connectors as bay- equipment interface	Earthing : has to comply with safety regulations
2	Wiring board on bay level	None
3	Standard cable trees and connectors	None
4	Switches for disconnection of the bay from voltage sources	Visible and securable separation required by safety regulations and operational procedures
5	Other switches	Idem
6	Electromechanical relay board	None

7	Different supply polarities	Facilitates monitoring of the control system
8	Identification of connectors and pins	Have to comply with safety regulations
9	Interface with primary equipment	None
10	Boards for different functionalities	Some safety-related functions are implemented on specific boards. Defined behaviour of the bay in case of equipment malfunction.
11	Use of fuses and switches to shunt current circuits	Visible and securable separation required by safety regulations and operational procedures
12	Dimensions and mechanical characteristics	None
13	Ergonomic considerations	Contribute to avoid maloperations
	Etc…	

The requirements in table 3 can be treated in a similar way as described in §11.4.1 above in order to obtain the functional requirements to be written in the specification.

11.5 General considerations concerning the establishment of specifications

The integration of functions calls in most cases for an approach to obtain a functional specification of a digital substation automation system based on an analysis of the requirements. These requirements have led in the past to adopt specific constructive solutions for standard control equipment based on static or electromechanic technology. The results of the analysis can be used to establish functional requirements compatible and adapted to digital automation systems allowing a higher degree of Functional Integration.

A complete and careful validation of the thus obtained functional requirements is required. This also may include the validation by representatives of the operation staff.

The approach and the examples in the previous section show that it is possible to identify functional specifications compatible with the identified constraints without including specific constructive demands. They also include the identification of the prohibition of common elements shared by certain functions. Examples have been given for constraints related to maintenance, test, safety and engineering. In some cases, it is possible to cover the function of a set of existing constructive characteristics by one single relatively simple requirement.

This in turn raises the question of how to test and qualify a digital automation system with respect to such a relatively general requirement such as "accessibility has to be good". For this, the utilities will somehow have to rely on the manufacturers' "common sense" and on a mutual open attitude in the design, test and qualification phase, which, in general, is the case. In any case, even the most detailed constructive specification will not be enough to avoid all problems without a sensible and trustworthy collaboration between partners.

For some utilities, there will be a step-by-step integration process of the substation automation system in order to improve acceptability among maintenance and operation staff. In addition, cost reduction should be achieved bearing in mind that the overall reliability of the substation automation system (and thus of the network) has, in any case, to be maintained on the present level or, if possible, improved (cf refurbishment, remote control availability,...). Moreover, some features require a migration process in the case of existing substations and therefore have to be introduced over a long period of time (e.g. connection of voltage transforms and current transformers to the protection relays and the substation automation system by digital links respecting international communication standards).

12 Environmental impact on distributed and integrated solutions

SAS specifications include requirements describing the environmental conditions of the operation of the substation (temperature, EMC, vibrations, voltage supply etc...). These requirements have to be met by the hardware design of each equipment. The number of functions integrated in this equipment does not influence on its hardware characteristics.

In particular, the communication equipment used in substation protection and control systems needs to meet the same environmental withstand requirement as the protection and control devices.

In the case of distributed functions, each piece of hardware necessary for the implementation of its subfunctions – and for the communication between all of them – has to respect the environmental requirements. This means that Functional Integration does not pose any particular constraints for this type of requirements.

As far as distributed functions are concerned, the conformance of several equipments has to be verified. For a given requirement, the distributed functions attains only the level of the weakest component it is implemented in.

Beyond the environmental requirements, there may be particular constraints concerning the available space or power consumption, which may require to consider a higher Functional Integration. The constraints related to these aspects can be mitigated by application of a higher level of Functional Integration.

13 Impact of Functional Integration on maintenance

As a consequence of this Functional Integration, maintenance methods may have to be adapted with respect to the procedures applied to conventional bays and systems.

Maintenance in conventional bays is organised on the base of "one equipment = one function". In a digital SAS, one function can either be implemented together with other functions in the same equipment (Functional Integration) or it can be distributed over several equipments (e.g. cb failure protection). Maintenance operation has thus to take into account the implementation of the functions and cannot, in some cases, be organised, as it is done in conventional substation automation systems, as almost independent procedure for each functionality.

Maintenance consists in repair or replacement operation or in periodic verifications. In any case, the testing of a function in the context of a SAS in operation is required. The requirements for these tests are very different from those of the system tests performed in Type Tests, Factory Tests or during Commissioning (cf. §15). The particularity is related to the constraints related to the operation of the substation which has to be maintained during maintenance and test procedures.

13.1 Consequences of Functional Integration

Replacement or repair operation is performed on equipment level. This means that, in case of Functional Integration, several functionalities may be concerned and not available during the procedure. These aspects have to be taken into account by proper definition of acceptable and unacceptable common modes as described in section §3.

As far as testing is concerned, a test of a given function in the case of Functional Integration may lead to the unavailability of the other functions implemented in the same equipment (cf. §15). If this is unacceptable or too onerous, alternative test procedures have to be considered. One possibility is to perform a set of test verifying each elementary function of the equipment concerning the function to be tested : binary and analogue inputs, information coming from the local communication network, proper configuration of the equipment, proper operation of the CPU, binary and analogue outputs, information sent to the local communication network. A consistent subset of these tests thus can cover all aspects of a complete unitary test of the function without having the same impact on the availability of the other functions implemented in the same equipment.

13.2 Consequences for Distributed Functions

As mentioned above, replacement or repair operation is performed on equipment level. Distributed Functions are in most cases also functions concerned by Functional Integration if they are implemented in several equipments together with other functions. In the case of a distributed function, there are two possible cases :

- One of the equipments in which a part of the distributed function is implemented has to be repaired or exchanged. This case corresponds to the configuration described in §13.1 above. The distributed function may be in a degraded mode or it may be included in the functions unavailable during repair procedure.

- All equipments concerned by the distributed function have to be exchanged or repaired. Beside the impact on the other functions implemented in each unitary equipment, which is covered by §13.1 above, this may lead to an unavailability of the distributed function during the complete migration period. This can occur if the previous distributed function has to be replaced by a completely new configuration or algorithm or is subject to an upgrade of a new, not downward compatible hardware or software version.

Like in the case of Functional Integration, the test procedure consists thus in performing successive elementary tests on one or on a limited number of parts of the digital SAS. These tests have to be designed with the aim to prove that, if all tests are passed successfully, the target functions works correctly.

Figure 13-1 illustrates the approach for the Overlapping Partial Testing of a function implemented in two different equipments and using the substation communication bus.

Taking into account the severe constraints for availability of a significant part of a substation at any given time the only – and last- possibility for a complete unit test of some distributed functions is perhaps at the commissioning of the digital SAS of the substation. This is due to the fact that afterwards it will not possible to put simultaneously all concerned equipments in maintenance mode. One example for this situation is a circuit breaker failure protection implemented in the bay controllers. If the test of this protection scheme requires to disable all bay controllers of the busbar, this might be not acceptable for the operation of the substation.

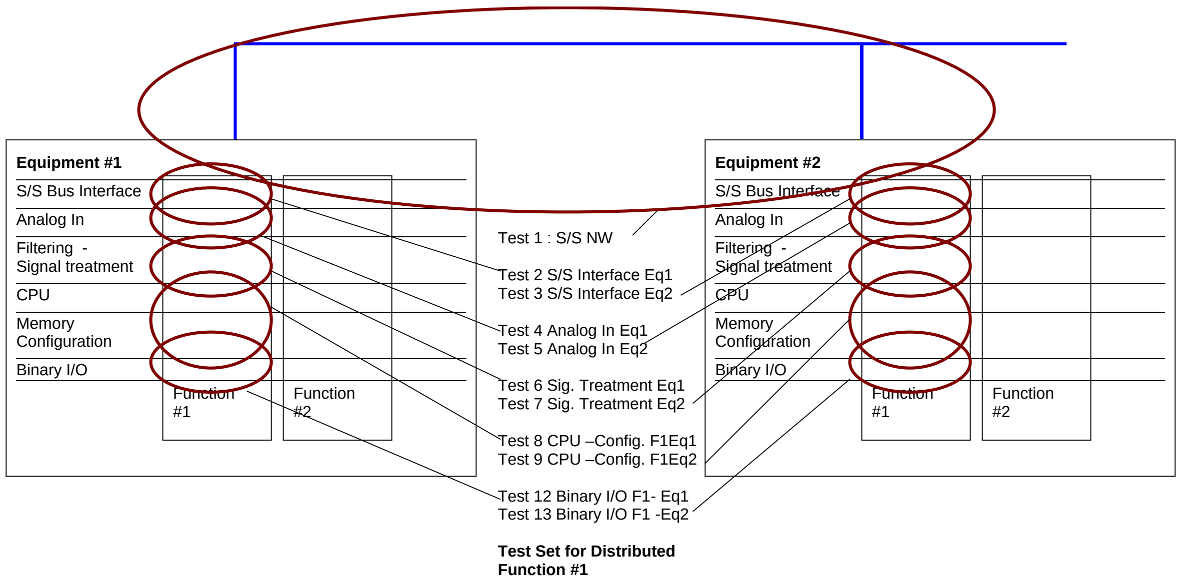

Figure 13-1 Principle of Overlapping Partial Testing of a function

14 Impact of Functional Integration on the refurbishment of substations

Modern substation automation systems are based on the integration of multifunctional IEDs from different manufacturers. Requirements that they support IEC 61850 – the new international standard for substation communications are seen more and more around the world. Such systems not only support features available in the communications protocols currently used in substations, but they allow different distributed applications, such as protection, monitoring or event and disturbance recording. This results in significant improvement in the efficiency of use of new technology in the substation.

The existence of numerous substations with an installed base of millions of electromechanical or solid-state relays that are still meeting the protection requirements of the user presents a challenge to the industry. On top of that, many of the substations have been upgraded in the last several years with microprocessor based relays that do not support IEC 61850. The replacement of all these legacy products will be very time consuming and costly. The upgrade process requires careful consideration of all available options and the development of a migration path that will allow smooth transition into the IEC 61850 based distribution protection and automation world.

A successful refurbishment strategy can be developed only based on a proper definition of functional and performance requirements, good understanding of the capabilities of existing and new devices, as well as the acceptable levels of application of communications based solutions. Knowledge of IEC 61850, adequate substation local area network architecture selection and decisions on which components of such solution should be implemented at different stages of the refurbishment process also play an important role.

The Process Bus offers significant advantages and can be successfully used especially in the refurbishment of old substations that require replacement of copper cables with failing insulation.

The Station Bus is used for IED to IED communications in a peer-to-peer mode, as well as for interface between the IEDs and the substation level HMI and other applications in a Client – Server mode.

The Station Bus also allows the replacement of copper control cables with fiber. It leads to improvements in the functionality and reduction of the engineering, commissioning and maintenance costs.

The last 15 – 20 years have seen the gradual replacement of electromechanical and solid state relays with simple or more complex IEDs. The integration of IEDs is based on proprietary, semi-standard and standard communication protocols. The definition of hierarchical object models in IEC 61850 is one of the key benefits of IEC 61850 that allows seamless integration and interoperability. Legacy IEDs need to be modeled as well in order to be integrated into an IEC 61850 based distribution substation.

The highest level of complexity of modeling is in the case of integration of advanced legacy protection IEDs. This also changes the communications architecture in the substation, compared to the purely IEC 61850 communications architecture.

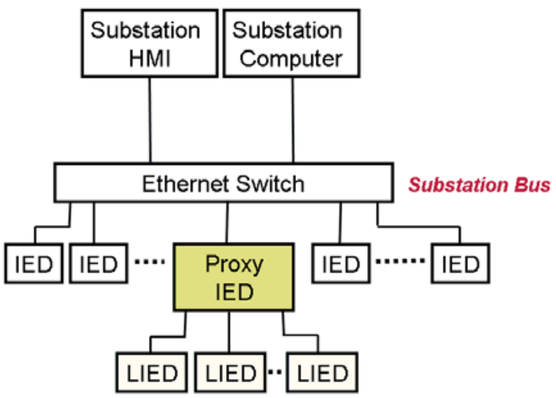

Figure 14-1 Communications architecture with legacy devices

The legacy IEDs (LIED) in Figure 14-1 are connected to a Proxy IED usually through serial communications over RS 232 or RS 485 using Modbus, DNP3, IEC 870-5-103 or other common protocol.

New IEDs with high level of Functional Integration can be used to replace many electromechanical and solid state devices, while at the same time multifunctional IEDs that can perform proxy functions are used to integrate legacy IEDs to be still used in the substation.

In many cases there will be no integration of existing equipment, but rather replacement of the existing protection, control, monitoring and recording devices with a limited number of multifunctional IEDs with high levels of Functional Integration. This will result in less space taken by a system with identical or expanded functionality. However, it is not expected to have significant impact on the time to complete the refurbishment process.

Depending of the specific requirements and constraints of different sites and utilities the benefits of Functional Integration for the refurbishment may vary significantly.

15 Testing of devices and systems with Functional Integration

Protection relays have changed dramatically in the last two decades from simple single function protection relays into multifunctional IEDs with primary transmission line protection functions based on classical or advanced operating principles. Testing of such devices requires the availability of a set of tools that will simplify the testing process, while at the same time will ensure the required high quality of that testing process. We use a multifunctional distance relay as an example in the following discussions on the issues related to testing of multifunctional protection IEDs.

Testing of distance protection relays and IEDs is one of the key requirements to ensure their correct operation under short circuit faults during abnormal system conditions. Since protection technology is becoming more and more complex, with protective relays evolving to multifunctional devices with integrated pre-programmed control logic and additional functions like measuring, fault and disturbance recording, programmable scheme logic, etc., ensuring that they are properly configured and implemented requires adequate testing of their functionality. At the same time the operation of the transmission systems close to their stability limit requires significant reduction in the fault clearing times that can be only achieved by using the advanced logic schemes available in modern transmission protection relays. In this case verification of the relay operating times through testing is critical.

The interaction of different logical and functional elements needs to be well understood, since there are differences between the implementation of some protection functions in electromechanical and microprocessor based distance protection relays. For example, a directional ground overcurrent protection is a single electromechanical device, while in the microprocessor-based relay it is achieved as a combination of an overcurrent and directional element.

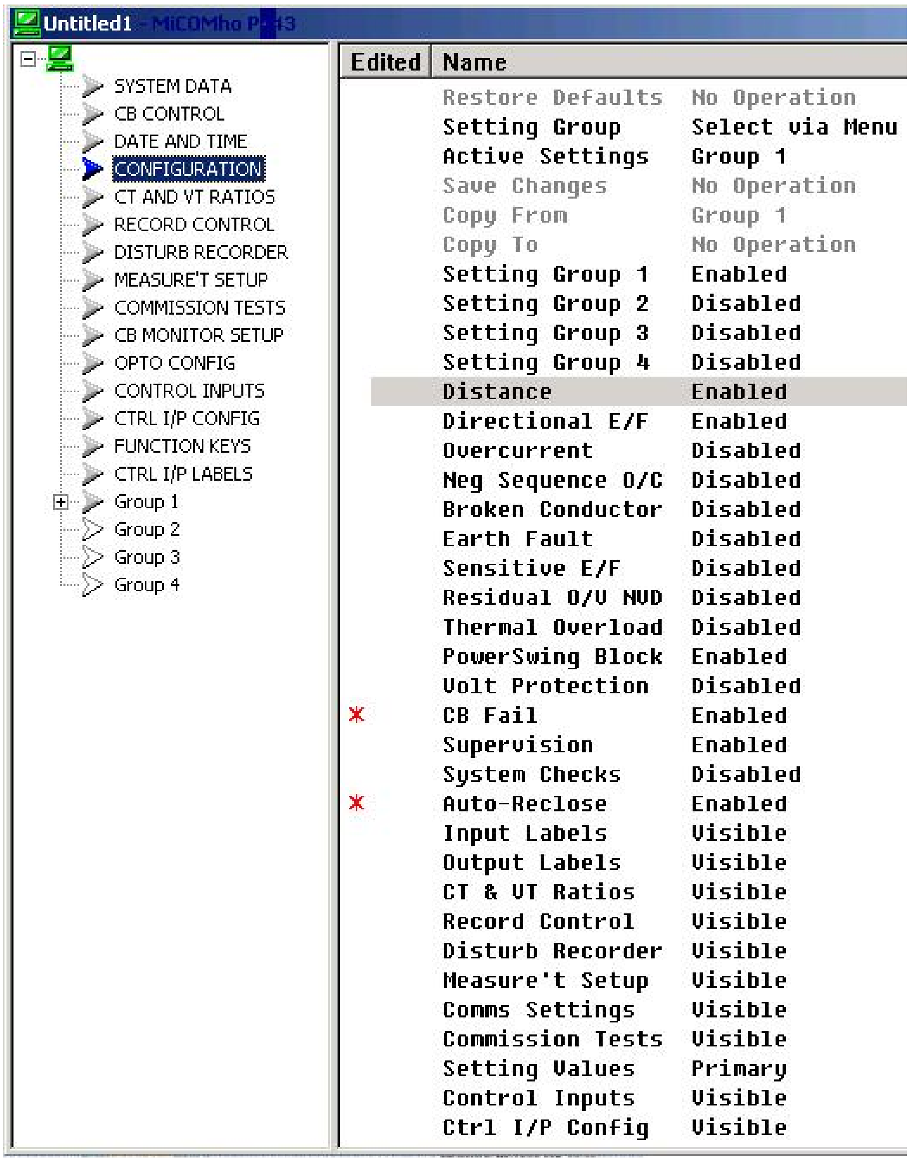

Figure 15-1 Example for a distance relay configuration

The testing of such devices is also dependent on the purpose of the test. For example if the testing is part of an evaluation procedure with the goal to accept a new IED for use in a utility's transmission system, this will require the isolation of each individual function through disabling of all other functions that may also operate under some of the tested conditions, thus making it difficult to determine which functional element actually operated during the test.

The same requirement may exist also during some commissioning tests. The difference in this case is that instead of testing all IED functions, now only the functions used for the specific application are being tested.

The typical commissioning, and especially maintenance tests will be targeted to determine the behaviour of the tested IED as a whole for the expected normal and abnormal system conditions.

The increased level of Functional Integration leads to new challenges of their testing the functions in such devices. The issues, which can be identified, are

- The fact that different functions can operate the same output means that a single function has to be enabled in order to test it specifically. This concerns the acceptance testing of a function.
- The testing has to verify that there is no interference between the different functions in the device. In order to do this, several or all functions in a device have to be enabled and a test

scenario has to be chosen in order to provoke a response from a limited number of functions. It has to be verified in this case that there is no undesired response from the other enabled functions. In this case it is important to monitor not only the overall behaviour of the tested device but also to observe the response of the individual functional elements.

- The integration of communication function in the devices, in the context of the introduction of IEC 61850 and / or the use of distributed functions requires from the test system to be able the test the response of a given function on the communication network. Before, only the wired binary relay outputs and inputs had to be taken into account for the test. This also represents a major change in the skills required by the personnel and a new type of testing tools.
- In the same time the criticality of the test is increasing because of the potential consequences of a misoperation in a system with high Functional integration.

Figure 15-1 shows an example for the configuration of a distance protection relay with the different available functions that can be enabled or disabled depending on the requirements of the specific application. This is something that needs to be carefully considered before, during and after the testing of a distance protection relay.

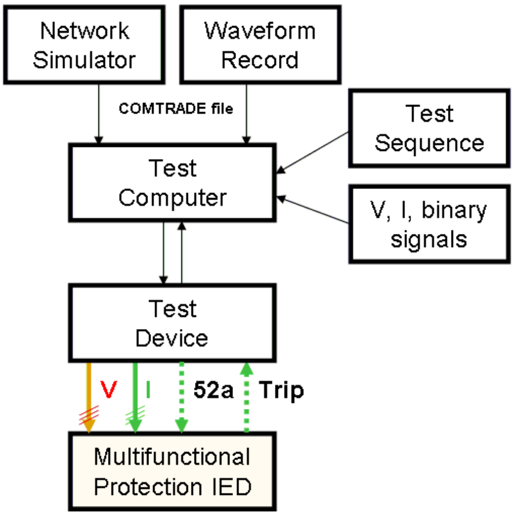

Figure 15-2 Example for a test system block diagram

When we analyse the complexity of modern multifunctional distance protection devices it is clear that their testing requires the use of advanced tools and software that can simulate the different system conditions and status of primary substation equipment and other multifunctional IEDs. The test system should be able to replay COMTRADE files from disturbance recorders or produced from electromagnetic transient analysis programs. It should be able to apply user defined current and voltage signals with settable phase angles, as well as execute a sequence of pre-defined pre-fault, fault and post-fault steps. A possible configuration of such a test system is shown in the example given in Figure 15-2.

The testing of the different IED elements has to start from the bottom of the functional hierarchy and end with the most complex logic schemes implemented in the device. Protective relays with such schemes operate based on the state of multiple monitored signals such as permissive or blocking signals, breaker status signals, and relay status signals. Time coordination of these signals and synchronization with the pre-fault and fault analogue signals is required in order to perform adequate testing of these types of schemes.

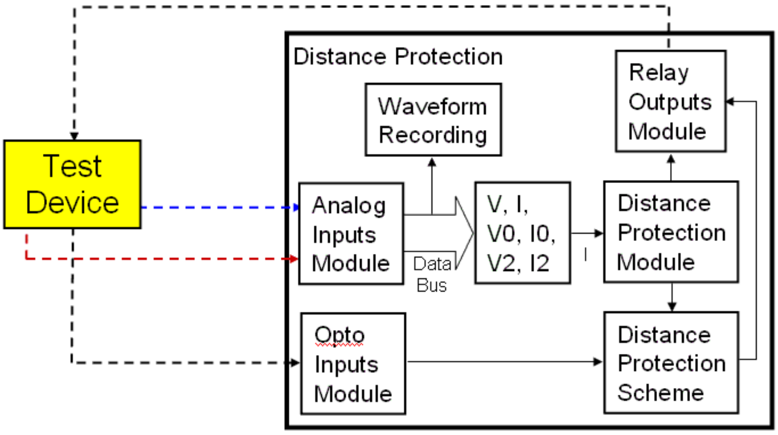

Figure 15-3 Testing of distance protection IED

Figure 15-3 shows in a simplified way the need for the test device to be able to properly simulate the distance protection environment from Figure 2, as well as to monitor the operation of the relay under the simulated conditions.

As can be seen from the figure, the testing should include any visible behaviour of the tested device or system.

15.1 Type- or Acceptance testing

The following steps have to be taken into account for the testing procedure for type- or acceptance testing :

- The analogue signal processing is the first critical step in the testing of a device because if any problems exist at this level, they will be reflected at any other step up the functional hierarchy.
- The testing of the measuring functions of the device is the next step. It can use the same set up, at least as the initial measurements test condition. This test does not require the use of device communications, since the measurements are normally available through the front panel user interface.
- Testing of the main protection functions. During the conventional testing of individual protection elements it is very important that they are the only enabled protection function (if all protection elements share the same relay output). If the IED has multiple relay outputs and different protection elements are mapped to different outputs, we need to make sure that the test device monitors the correct relay output during the test.
- The next step is the testing of the different protection schemes. The testing of protection schemes is the final step in the testing of a multifunctional protection relay and it is based on the assumption that all individual protection elements – distance, overcurrent, directional, faulted phase selection, etc. have already been tested and proven to be operating correctly.
- Test Results Analysis. The results from each test performed are automatically analysed by the test software. The analysis is based on an expert system comparing the operating time of a combination of monitored protection elements that have picked-up during the test.

15.2 Commissioning Tests

Commissioning tests of complete systems or of multifunctional devices have some similarities and some differences from the qualification testing described above.

The first key difference is that the relay testing covers only the functions that are being used.

The used functions are configured with the settings to be used for their specific application.

The tests should include not only the functionality of the relay itself, but also the complete analog and binary input and output circuits of the relay.

The main principle to follow in this, as well as any other test case is to define first the function to be tested. A “black box” approach is appropriate. This means that we need to identify:

- the boundary of the tested function
- its interface with the rest of the primary or secondary substation environment
- its behavior for different simulated inputs

The tested function does not have to be isolated as is done in the qualification tests. However, use of the event reporting or other available method to determine the start and operation of the function may be required if the visible interface is shared with other functions in the relay.

Injection at the initial stages of the commissioning testing can be directly to the inputs of the relay. Signals from other devices involved in a distributed function are simulated by the test equipment as well.

A limited number of tests designed to determine if the settings have been properly applied are required. There is no need to test the complete characteristic of a tested function. The test cases may be limited to some specific critical real-life fault or other abnormal conditions.

15.3 Maintenance Testing

Maintenance tests are limited only to specific functions that are used for the IED application.

Injection is limited only to cases when some specific fault conditions need to be simulated in order to perform the tests. These tests should include the complete output circuit to the controlled primary substation equipment.

Measuring functions performance may not require injection, since it can be estimated based on a comparison between the measurements of different devices connected to the same instrument transformers.

Testing of distributed functions can use the “black box” approach as well, Function and sub-function boundaries, interface and behaviour need to be identified keeping in mind the components of the system that are in service or out of service.

Synchronized operation of multiple test devices may be required for the testing of complex distributed functions that involve multiple multifunctional IEDs.

16 Survey results and their analysis

The results of the questionnaire are summarised in the restitution given in appendix 2 of this guide. This chapter gives the analysis and the conclusions by the WG regarding the responses given by utilities and vendors. The detailed restitution and the questions of the questionnaire are given in §20 (Appendix 2) of this document.

16.1 Utilities

The restitution of the survey for utilities is based on 29 responses from utilities, 7 from Europe, 8 from South America, 8 from Asia/ Australia and 6 from North America. The average response rate is estimated at between 20 to 50 % of directly solicited answers.

Question 1 concerned the utility profile. The samples of all types of companies (sizes, activities) were represented in the responses received. Some companies have only generation activity.

Question 2 concerned the use of the devices with communications capabilities and/or based on microprocessor technology in the utilities. The expected response is yes if at least some devices are in service, but not necessarily generalised over the utility.
The result of the survey is that IEDs seem generally to be widely accepted. They were first used for protection and recording. Other applications, especially measurement lag a little bit behind. Possible reasons for this fact are the accuracy of protection core of CTs which does not allow to use protection IED as measurement device.

The fact that 97% of the utilities state that they use IED's as control devices can be related to the interpretation by utilities of the term "Control IED". They probably include protection relays with autoreclose, Programmable Logic and, possibly, RTU’s.

Question 3 concerned the multifunctional IEDs in use within the utilities. With regard to the responses received, it is not clear whether the integration of, e.g., the autorecloser function in the digital protection is interpreted by all utilities as a "multifunctional IED". In many cases, utilities may actually operate multifunctional IED corresponding to the above definition without being aware of it. Multifunctional IED seem to be generally accepted, although there are several restrictions depending on the utility philosophy. They may at this moment not be generalised in all utilities.

Question 4 asked for the levels of Functional Integration accepted by the utilities. It turns out that the integration of protection and control even at higher voltage levels seems to be accepted by the majority of utilities having responded under the condition that the IEDs are duplicated. One utility even states that the fact that protections are redundant (at least two different independent IEDs) is a favourable condition for Functional Integration of control and other function in protection IED. Apart transformer protection, there is unanimity that one IED should not cover two voltage levels.

An unexpected result of the survey was the indication of a lower percentage of Functional Integration in distribution level. This can be explained by the fact that some utilities did not fill in the line since they have no distribution network, contributing thus to decrease the overall percentage. Some of the other possible reasons may be a simpler functionality, tighter development budget, poorer communication between many devices scattered in distribution systems and, therefore, less benefit of integration.

There seems to be no significant difference in the point of view of the responding utilities concerning application for transmission level as opposed to distribution level. This is at least the interpretation which can be deduced from the obtained answers, which might be different to the perception the WG members had before.

Questions 5 asked to fill in a matrix defining the integration of which functions integrated in same IED is acceptable. Some conclusions are:

The most common requirement is a separation between Main 1 and Main 2 protection. Integration of Main 1 and Main 2 protection is avoided at any voltage level by most utilities. In the majority view, Main 1 protection may be integrated with other protection functions and autorecloser although some reservations are formulated. The majority of utilities does not accept either to integrate Main 1 protection and back-up protection in one device. The 50% acceptance of integration of back-up protection with Main 1 protection comes, presumably, from the signification of the term "back-up protection" which is understood in different ways by the responding utilities. It is also interesting to note that integration of Main 1 protection and control functions are accepted by half of the utilities.

The Main 2 protection is integrated more easily than Main1 protection, even with back-up protection. As mentioned above, the meaning of local back up in addition to Main 2 is not clear here. It may refer to circuit breaker failure or to cover a possible failure of Main 2 protection, e.g. loss of communication for a differential relay.

Integration of autorecloser and main protection is broadly accepted (between 60% and 67%), but curiously integration of back-up or overload protection with the autorecloser has a lower acceptance.

Almost everybody likes the fault recording capabilities of digital relays and their integration is commonly accepted with any protection function, even with the Main 1 protection, the most "untouchable" of all functions. The most popular function whose integration with whatever other function is readily accepted, is event recording. Waveform recording, fault location (where applicable) also have high scores in this field.

Integration of main protection and manual control (local or remote) functions is not very popular, (score of about 30%). The integration of other protection functions and remote monitoring or automatic control is more widely accepted.

Another remarkable figure is the fact that 60% of the utilities consider that an integration of metering function and the overload protection is not acceptable, whereas this figure is lower for the integration of metering and other protection functions. A possible explanation is the understanding of "metering" in this context : if metering is understood as remote monitoring of the line load (and not as revenue metering), it is clear that an integration with the overload protection, which also prevents overload situations, is not desirable. In general, integration of metering and other recording functions is not well accepted by the utilities.

70% of the utilities stated that integration of load shedding and remote measurement or event recording is not acceptable. Since the WG does not see any technical reasons for this figure, it is assumed that there are cultural or organisational reasons.

Question 6 asks which other constraints impact the Functional Integration. More than 80% of the utilities accept the principle of Functional Integration, but only 40% state that there are rules. This means that the subject has not been studied in detail by one utility out of two, else there would be rules.

The rules originate from reliability requirements, design and maintenance standards, resources, experience and costs. Several examples of rules listed are very good representation of main reservations to integration from the reliability perspective. Two different solutions are characteristic for setting the protection rules : a duplicated main protection in two separate devices is typical for a transmission application and one main protection with remote or station level back-up is typical for distribution applications. The latter allow a higher degree of integration than the former.

The protection and control separation is a practice- and resource related rule of apparently decreasing importance. The rules overlap differently in various networks.

Question 7 asks for constraints which are explicitly identified in the specifications of the utilities. The following items are covered :

- Maintenance : 62% of the utilities state that there is no constraint of maintenance on Functional Integration. This the WG considers this score surprising and reflects the approach of maintaining conventional electromechanic or solid-state devices. The comments received by utilities focus on the requirement of continuous network operation during maintenance.
- Network operation : 62% of the utilities state that there is no constraint of network operation on Functional Integration. The WG considers that the level of Functional Integration should not have any impact on network operation.
- Safety of staff : 66% of the utilities state that there is no constraint of staff safety on Functional Integration. The WG considers that the constraints due to safety preparation and hand-over procedure in order to prevent electrical hazard can induce an additional constraint in Functional Integration if repair operation has to be performed on devices which are not completely shut off.

In general, the average level of constraints identified in specifications is very low (only 20 to 25 % of the utilities identify any constraint). There is probably a deficit in the detail of present specifications in most utilities. A growing degree of Functional Integration might oblige utilities to take into account these points in their specification updates.

The use of standardisation should allow for different applications to be implemented depending on the specific case. Standardisation in general (with or without Functional Integration) should take into account this requirement. Standardisation should only be applied to "common" cases and should not try to cover all possible specific cases.

Question 8 asked for plans of the utilities to change policy or specifications. 55% of them answered that there are no such plans. This does not mean that this percentage of utilities does not accept Functional Integration. In some cases, Functional Integration is part of the policy, but it is not envisaged to modify it in near future.

Considering the globally conservative attitude of protection and control staff, a score of 41% stating that evolution of policy is possible, is remarkable. This may reflect the general tendency of the industry for rapid changes.

The level of acceptance of a higher degree of Functional Integration will depend, on one hand, on the acceptance of the principle by the operating staff and, on the other hand, on the ability of the utilities to make the allocation and integration of functions independent of their internal organisation.

Question 9 asks if there is an impact of IEC 61850 on Functional Integration. The low percentage of affirmative responses reflects the fact that many utilities are in a waiting position and require more information about the standard in order to make argumented decisions. There is also a need for a better understanding of the impact of IEC 61850 on substation functions and their integration.

The IEC 61850 process bus creates the possibility of the integration of many different functions in a single device. In parallel, the definition of distributed applications reduces the Functional Integration in systems with station bus.

The communication from substation to the control centre and between substations have been up to now out of scope of the standard. Two new work item proposals address these subjects.

The use of an IEC 61850-device to provide an interface with legacy protocols represents a formal Functional Integration of communication functions in that device. If the IEC 61850 device fails, the interfaced functions are no longer available.

Question 10 concerns the acceptable level of Functional Integration. A large majority of the utilities accepts a partial Functional Integration. The integration of the protection for several substation components in one device or the complete integration of protection and control of a substation in one device is considered to be not acceptable by almost all of the responders.

Acceptance of integration is easier for lower voltage levels (distribution) and if there are redundant devices.

Question 11 asks for advantages related to Functional Integration. A large majority of the respondent utilities see an advantage of Functional Integration for system cost reduction and simplification of installation. Most of the respondents perceive advantages for engineering, application flexibility, commissioning, maintenance and addition of functions. In general, no advantages were associated with training and operation.

Utilities perceive potential cost savings because new functions can be implemented in existing IEDs (programmable scheme logic, software modification). These modifications may not induce hardware costs, but they still require engineering, software development, testing, update of documentation and commissioning. They are therefore not free from costs, but still have benefits for the utility if no hardware and wiring changes are necessary.

Some respondents point out the possibility that increased integration reduces the flexibility. The problem is in practice more a possible limitation of the performance than a reduction of flexibility which in principle benefits from Functional Integration.

Advantages and drawbacks are perceived for the training. On one hand, the skill level has to be higher, but on the other hand a reduced number of different devices using the same philosophy allows an optimisation of the training program.

The exact meaning of "setting" and of "configuration" has to be defined because it obviously can have different significations depending on the vendor or on the utility. The same holds for "maintenance" and "refurbishment".

Some utilities have a tendency to mix digital technology and Functional Integration. For example, remote access or improved HMI are more related to the use of digital technology than to Functional Integration.

One utility pointed out that, at the moment, the management of firmware and software, of the setting information and of test results represents a considerable maintenance workload. Functional Integration may improve the situation by reducing the number of different IED to manage, but might require more intensive management for a given device.

A majority of the utilities does not see an advantage of Functional Integration related to site expansion. This is true if independent bays are used, but such an advantage is evident if the control system of the complete substation is completely integrated.

One utility states that Functional Integration should lead to higher performance for the same cost. Most users try to obtain the same level of performance with reduced cost by Functional Integration.

No comments of the utilities associated to combining devices of different manufacturers or implementing functions delivered by one manufacturer in the device of another have been made in the questionnaire.

Question 12 asks whether the utilities have a separate protection and control department. This is the case for about 50% of the utilities. The WG expected more utilities to have different departments for protection and control.

Question 13 concerns outsourcing. No clear tendency can be seen. A partial outsourcing of all types of activity related to protection and control is used by a majority of the utilities. Very few utilities outsource completely engineering and configuration. Half of the utilities have the installation outsourced and almost all of them outsource it at least partially.

16.2 Vendors

The summary of the vendor questionnaire is based on 20 responses (9 Europe, 7 Asia / Australia, 2 North America).

Question 1 concerns the profile of the vendors. Most of them have a profile including the fabrication of protection, control, monitoring and recording devices. As far as metering is concerned, only one third of the responding vendors offer devices with metering functions. This is probably due to special approval process required by regulation authorities. In addition, metering is often separate from the control system. Utilities often do not have the choice to integrate metering with the rest of the protection and control system. The evolution of the technology may lead to an evolution of the regulation in this point, replacing separate physical devices by access control.

Metering also requires a different accuracy of conventional instrument transformers and needs therefore separate current circuits. On the other hand, an integration of this functionality would make sense, using maybe separate inputs or merging units.

Only three of the responding vendors had a limited range of products (for example no protections). All other vendors offer practically all of the mentioned devices.

Question 2 asked for the types of IEDs manufactured. Integration of multiple functions, including combination of protection and control, represents a standard offer of most vendors. All vendors that have protection functions typically have integrated solutions. The range of 75% to 80% of vendors proposing integrated devices with protection or control functions can be explained by the particular vendors who do not offer protection IEDs.

The vendors perceive the requirement of some customers to separate protection and control functions as a limitation to Functional Integration. If a vendor decides to integrate protection and control functions in one device, he has to make sure that the design guarantees a satisfying performance of all functions integrated in the IED.

Question 3 concerns specific integration criteria for IEDs. Seen from the vendor side, there seems to be no clear policy among different utilities for the integration criteria depending on different voltage levels or applications. As mentioned in the comments above, some customers may accept a higher integration in lower voltage level, some not at all and some accept a higher integration everywhere. Vendors basically have to meet the customer requirements, but they try to use the same hardware and software base to meet this great variety of requirements. The same hardware platform may be used for the IEDs of all voltage levels.

Questions 5 asked which functions are currently used in the same time in the same IED.

- Protection : Most protections IEDs also contain possibilities for local and remote control applications. It can however be noted that general control functions can be implemented only in about 2/3 of the cases. Most other functionalities, except metering and phasor measurements are implemented in a great majority of the protection IEDs. It is however surprising to note that waveform recording is not performed by about 1/3 of the protection IEDs.
- Control : Only about half of the control IEDs can also perform main- or tele- protection functions. Most of the other functionalities are implemented in the control IEDs, although with a lower percentage than in the pure protection IEDs. Significant exceptions are the fault locator and the phasor measurements that are possible with about half of the control IEDs in the responses obtained.
- Monitoring : Monitoring IEDs are usually also able to perform control functions but no protection functions .
- Recording : Only about one third of the specific recording IEDs also offer protection and control functions. On the other hand, recording IEDs are often associated with measurement and monitoring functions. For the recoding functions, no differentiation is made by the vendors between the different voltage levels.
- Measurement : As for the recording IEDs, only about one third of the specific measurement IEDs also offer protection and control functions. On the other hand, measurement IEDs are often associated with recording, metering and monitoring functions.

Question 6 concerns explicit or implicit constraints identified for the degree of Functional Integration.

- User requirements : User requirements are perceived as a very important constraint by the vendors. Even when the integration of function is available in an IED, the users can disable them. The users have thus a choice of accepting or not the Functional Integration.
  Only 40% of the utilities responding to the survey explicitly sated that there are rules or limitation for Functional Integration, whereas 68% of the vendors identify these requirements as important constraints. The explanation of this difference may be that the vendors try to offer a solution generally accepted by the market and that some rules associated to customer requirements are implicitly accepted by the vendors (example : integration of main 1 and main 2 protection).
- Industry regulations : There seems to be no general industrial regulations having an impact on Functional Integration. Each user has its own set of requirements.
- Reliability requirements : There are few formal requirements identified directly as a reliability issue for an IED. As a matter of fact, a system using IED often allows improvement of overall system reliability because of the redundancy of functionalities. A distinction has to be made between the reliability of an IED and the overall system reliability.
- Design Philosophy : A distinction has to be made between the design philosophy on IED level and the implementation philosophy in a given system. In this context, the vendors state that the requirements associated to the design philosophy of the IEDs do not represent a limitation for the Functional Integration.

- Technological Limitations : The vendors identify technological limitations due to CPU capacity. But these limits do not represent a constraint in Functional Integration at this point in time since the customer- and reliability requirements do not allow to attain this level of integration for other reasons.
  There are although already some limitation of Functional Integration associated to the number of I/O of one IED and to its communication capabilities or to the number of functions implemented in a given device.
- Economical issues : Half of the vendors associate Functional Integration to higher costs. Functional integration seems to be associated to an increased modularity of the IEDs, both on the hardware and software level. This modularity leads to higher costs in spite of the fact that Functional Integration is generally considered by the customers as a way to optimise costs. The comments received by the vendors reflect more there feeling about the costs supported by the customers than their internal costs.

Vendors in general perceive the customer requirements and limitations as a major constraint for Functional Integration. Without these constraints, Functional Integration could be higher. Often, vendors offer solutions that allow a variable degree of Functional Integration allowing to adapt to specific customer requirements.

Except user requirements, there is no other constraint identified by a majority of vendors. Vendors identify the constraints based on the experience they have with past systems and on their general knowledge of their particular customers and their particular market.

More the vendors think about possible constraints for Functional Integration, more they seem to identify. Technological limitations and economical issues are important constraints for about half of the vendors. The former constraint seems to apply more to smaller vendors (less R&D capability) and the latter more to larger vendors (global market, less "specific" customers".

The economic pressure can go into both directions: there is no unanimous opinion among the vendors whether economic pressure would in general favour or hinder Functional Integration.

Industry regulations, reliability requirements and design philosophy do not seem to impose constraints for a majority of the vendors.

One vendor indicates that the customers sometimes try to find reliability requirements in order to prevent change in the existing design philosophy of a control system. Such a change has to be carefully studied, which is often impossible due to lack of time.

Question 7 asks if there are plans to change the strategy concerning Functional Integration. The almost unanimous response by all vendors was that a change which will take place or has already taken place to adopt a strategy with higher Functional Integration. The low percentage of affirmative responses is due to the fact that many vendors consider that they already have adapted their strategy aiming at higher Functional Integration.

Question 8 concerned the influence of IEC 61850 on the integration strategy. In general, the vendors state IEC 61850 has a very high influence on their product integration strategy. Only very few vendors consider that IEC 61850 has no impact on their integration strategy. These vendors do not offer IEC 61850 based products at this moment.

Question 9 asked whether IEDs with IEC 61850-9-2 (or other digital) Sampled Analogue Values Process bus interface is being manufacturing. All major manufacturers of protection and control devices are in various stages of implementing the IEC 61850 process bus interface.

Question 10 concerned the degree of Functional Integration of IEDs manufactured. The main focus is presently on the Functional Integration on the bay level and communication between the bays. Functional Integration covering all functions related to several HV equipments in one IED is only identified as aim by half of the vendors. At this point in time, there are very few manufacturers offering an integrated solution for a complete substation automation system. It is not clear how the size of the concerned substation would affect these offers.

Questions 11 asked the vendors how they perceive the acceptance of Functional Integration by the users. There is a good correspondence between the response of the vendors and the acceptation stated by the utilities :

1. IED covering all functions related to a single substation component accepted by utilities : vendors 82%, utilities 88%,
2. Integration of the functions related to several substation components accepted by the utilities : vendors 27%, utilities 28 %,
3. Completely Integrated Substation System accepted by utilities : vendors 9%, utilities 4%.

There is a very clear opinion among the vendors that utilities would accept a "conventional" Functional Integration. Only a minority of the vendors believe that this acceptation would extend to the integration of the functions related to several substation components. Even in these cases, they think that this FI is restricted to some components but not to all components of the S/S. This subject seems to be under discussion and the position of some utilities is changing.

The fact that almost a third of the utilities accept an integration of the functions related to several substation components shows that there is a clear trend for acceptance of a higher level of Functional Integration by the utilities. A complete Functional Integration is considered by most vendors as being unacceptable for the utilities. It has to be pointed out that some vendors estimate that a complete integration may be acceptable, but not an integration of the functions related to several substation components.

Question 12 asked for advantages related to integration for the vendors themselves.

- Overall cost reduction (vendors : 82% - utilities : 88%) : Both vendors and utilities think that Functional Integration may lead to cost reduction for themselves on the system level. On the other hand, in question 6, half of the vendors identified economical issues as a constraint for Functional Integration, but this may refer more to the costs associated to the IED level.
  There is thus a benefit from the point of view of the system integrator, but the manufacturers of IEDs have to take into account the increased costs of one single IED due to Functional Integration.
- R&D : The figure of affirmative responses (55%) is surprisingly low, the WG would have expected the vendors to see a more general benefit on the R&D efforts related to Functional Integration. It seems that the case is different for smaller vendors and for bigger vendors. The latter are able to distribute the R&D costs on a higher number of IEDs of a limited product range, which may lead to an optimisation of the R&D effort. On the other hand, Functional Integration may represent a significant R&D effort for smaller vendors.
  A limitation of the number of platforms should reduce both the cost of software development and of testing for a given functionality.

- Engineering : 64% of the vendors replied that Functional Integration presents an advantage in the field of engineering. The correspondent figure from the utility questionnaire was 60%. Vendors and utilities have thus the same perception and there is a consensus between major vendors of protection and control equipment that global engineering cost is reduced because of reduction in wiring, number of devices and standardisation.
- Application flexibility : There is a consensus among the major manufacturers of protection and control devices that Functional Integration improves the application flexibility. The utilities (60%) share this point of view. Smaller vendors who do not offer a complete product range do probably not experience a benefit in this field.
- Installation: The utilities (88%) were even more affirmative than the vendors (68%) that Functional Integration will be beneficial for the installation of the digital SAS. The mentioned points include improvements in space, wiring and configuration. Utilities normally look more on the system level whereas some vendors focus more on the context of a single IED.
- Commissioning : the perception of vendors (55%) and utilities (52%) is almost the same when asked whether Functional Integration presents advantages for commissioning. The fact that only half of the vendors responds affirmative is maybe related to the commissioning process of a multifunctional IED per se being more complicated since functions have to be enabled / disabled several times in the commissioning procedure. Testing becomes more complicated, but at the same time automatic testing tools become available which can simplify this process. The standardisation of protection and control schemes can further improve this point.
- Training : The utilities (12% of affirmative responses) are even more pessimistic than the vendors (41%) when being asked if Functional Integration would have a positive impact on Training. It is a general shared opinion that training costs will increase associated to Functional Integration due to the higher skill required for the operators. On the other hand, a reduction of the number of different configuration tools and IEDs within the utility may somewhat counterbalance this effect.
- Configuration : The overall configuration of the system should be simplified by Functional Integration thanks to the fact that many functionalities are implemented within one IED, thus sharing configuration data.
  On the overall system level, Functional Integration leads to a decrease of the engineering effort but may lead to an increase of the configuration needs at the IED level. This perception may be reflected in the responses.
- Maintenance: Only 64% of the vendors think that Functional Integration will lead to advantages for them on the level of maintenance. In this, they are a little bit more optimistic than the utilities (56%) on this point, maybe because utilities do not adapt their maintenance strategies to the possibilities of the system. Utilities also evaluate the maintenance requirements on the system level and not restricted to the level of one single IED. Probably Functional Integration allows some savings in maintenance, but features like self-monitoring and monitoring of different circuits cannot take care of all maintenance needs in the substation.
- Refurbishment : There is a consensus between the major vendors of protection and control devices that Functional Integration has benefits for them related to refurbishment, as compared to 40% of the utilities. This definitely depends on the context and on the scope of the refurbishment. It is clear that Functional Integration is more interesting for the complete refurbishment of a control system of a substation. Furthermore, an improvement of the functionalities is possible when doing the refurbishment. This advantage should be taken into account when planning and evaluating the refurbishment.
- Site expansion : Half of the vendors see a benefit for themselves related to Functional Integration for the site expansion, as opposed to only 36% of the utilities. The benefits depend of course on the context and on the scope of the site expansion. One should expect advantages for the site expansion using functional integrated IEDs.
- Addition of functions : Advantages for the vendors related to the implementation of additional functions are expected. There are limitations due to the hardware when adding functions later on and there is a commercial issue between vendors and utilities related to the cost of the software of this added functionality.

Adding a functionality may require a change of the software and considerable testing and certification efforts.

Question 13 asks the vendors which are the benefits for customers among items identified in the previous question. Most vendors think that all the benefits identified for them in Q12 related to Functional Integration will also benefit the customers to some extent. The main benefit is cost reduction, but the space reduction due to Functional Integration is also seen as an important item for the clients.

Question 14 asks the vendors which problems might appear for customers related to Functional Integration. Half of the vendors (including the major ones which agree on this point) perceive potential problems for their clients related to higher Functional Integration. The main problems identified in the responses concern training required by the growing complexity of the system and of the devices. Potential adverse consequences due to common mode failures are also mentioned.
Some vendors think that the basic philosophy of the utilities has to adapt (the expression of "paradigm change" is employed by one vendor).

17 The Future of Functional Integration

IEC 61850 allows not only the development of a new range of protection and control devices that can perform local and distributed functions in applications that result in significant benefits compared to conventional hard wired solutions, but leads to a future of Functional Integration that may include a single device performing all substation functions.

This will be the case of a complete implementation of IEC 61850 – with interface devices installed in the substation yard at the breakers, providing both analogue and binary signals over the substation LAN to several central units performing all required substation protection, control, monitoring and recording functions.

Reliability of the system is achieved using multiple substation devices, that may even operate in a voting mode.

Such an approach results in a different level of Functional Integration when issues related to commissioning, configuration and maintenance have to be considered in a different way compared to the case of multiple IEDs (see section 6.4.1).

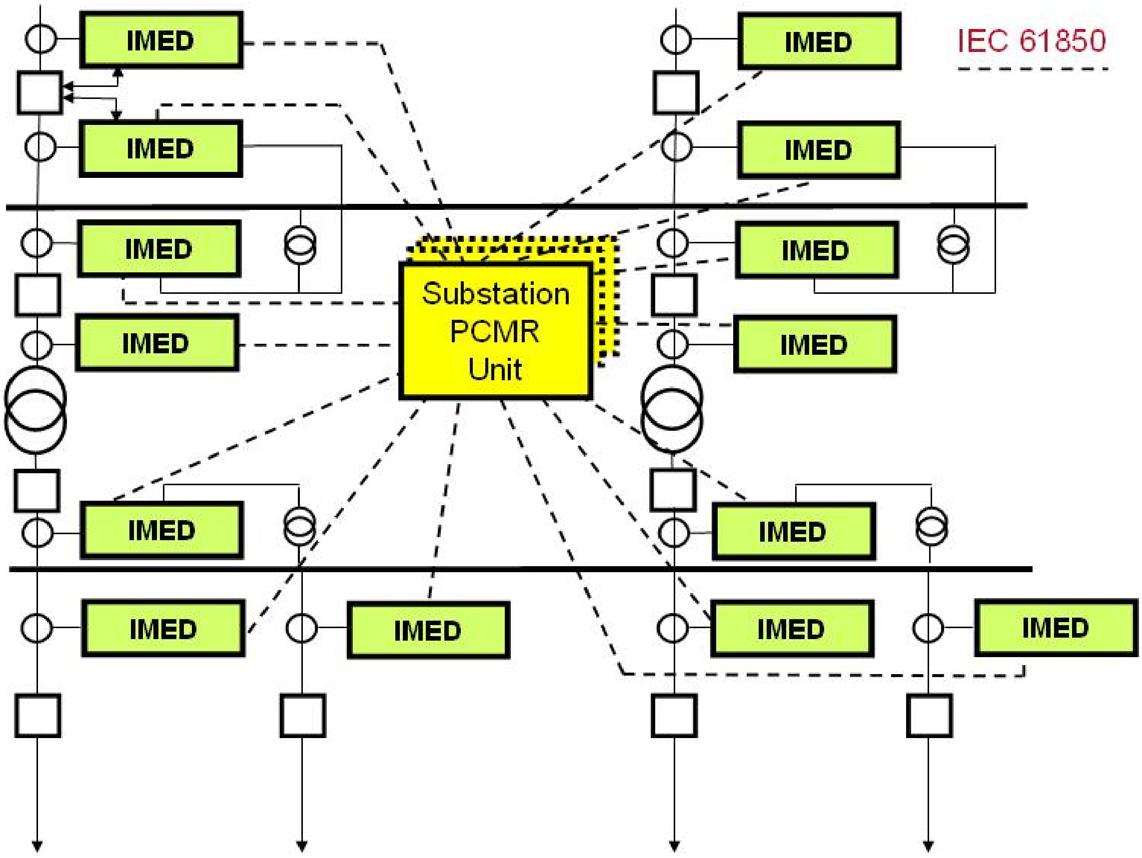

Figure 17-1 Totally integrated solution of a substation protection and control system

18 Conclusions

Functional Integration as a concept is widely accepted both by utilities and vendors. One of the more sensible points towards Functional Integration is the acceptance of integration of protection and control functions in one IED. The acceptable degree of Functional Integration is difficult to establish at this point in time and the philosophy and practices in the industry are in a process of evolution.

The Working Group believes that in the future totally integrated systems will be feasible in the future and will appear and be accepted by the industry as a result of a significant paradigm shift. This is due to the fact that such system will fulfil all requirements concerning reliability and availability of power system and simplify their engineering and maintenance. These latter aspects have to be taken into account in a more precise way in the specifications of the utilities than it is commonly done today.

Some of the problems identified in the context of Functional Integration, as utility standardisation and customisation, acceptable common failure modes, testing and maintenance issues become less pronounced when increasing the degree of Functional Integration.

The increasing acceptance of IEC 61850 standard and the shift of the focus from devices to functions and their free allocation will also facilitate increased Functional Integration and its acceptance. This will probably lead to totally integrated protection and control systems in the future.

Functions and Requirements - The new concept introduced by IEC 61850 of modelling any device or function in the substation as a component of a complex system with a functional hierarchy, regardless of the location of an individual functional element within a specific physical device will have significant impact on the levels of Functional Integration in the substation protection, control, monitoring and recording systems of the future.

All of the above described changes and trends in the industry are considered in this report in order to determine the state-of-the-art of Functional Integration today. Based on the acceptance by the industry it provides some guidelines on the acceptable levels of integration in future substation protection, control, monitoring and recording systems.

In order to establish a clear understanding from the readers of what was considered by the members of the working group by substation protection, automation and control functions, the first few chapters of the report define protection and non-protection functions and the requirements for their implementation in modern substations. The report also considers simple and complex, as well as centralised and distributed functions. Device definitions, substation topology, IEC 61850 and their impact on Functional Integration are also analysed in detail.

Different levels of Functional Integration starting from devices with limited integration and ending with totally integrated protection and control systems are described.

Advantages and Disadvantages - The analysis of substation functions, the requirements and methods for their integration in modern IEDs shows some clear advantages of a higher degree of integration of functions in a substation automation system. These include, but are not limited to a reduction of the number of devices and consequently simplification in wiring and reduction in the number of cubicles. All these factors contribute to a reduction in the overall cost of the control system. Moreover, the integration of functions in a small number of devices facilitates improvements in the efficiency and quality of the engineering process. Depending on the way of implementation, operators also have a higher degree of flexibility for addition, modification or adaptation of the different functions after commissioning.

A higher Functional Integration may have impact on the reliability and the performance of the overall system compared to a less integrated system. Depending on the equipment and on the architecture, there may be advantages or drawbacks for the reliability of the system.

Some potential disadvantages include the fact that different functions share more common elements. The question which functions have to be independent (not sharing common elements) and to which extent becomes an important issue and may challenge long established utility practices (e.g. separation of protection and control functions). For example, maintenance operation on bays with HV equipment in service may impacted. They can be more difficult or impossible if the degree of integration is too high. This may require to completely reconsider the way maintenance is performed.

For each case or type of substation, the advantages and drawbacks have to be carefully analysed by the utilities and by the manufacturers before deciding the extent of Functional Integration for a given substation automation system. They have to be translated into specific requirements in the corresponding specifications for the SAS. The survey shows that these considerations are not a common practice today in the industry.

Customisation and Standardisation - Big utilities' often base their philosophy on the principle of standardisation of substation design. This concept involves many issues, such as substation topology, substation system architecture and technology, substation and system operation and maintenance procedures, even purchasing procedures specific to that particular utility. Standardisation allows improvements in the efficiency of engineering, operations and maintenance and related cost savings.

Standardisation involves devices, functions and installations, with the first two being more affected by Functional Integration. It means conformance of all parts of the substation and its protection and control system to a list of references defined by the utilities such as topology, operation and maintenance procedures, spare part management, etc.

The other important principle is customisation of commercially available off-the-shelf products. It is typical of those companies who are focused on their business from many years and have a consolidated tradition for their philosophy and processes in every field.

Customisation means definition of specific criteria and translation of these criteria in requirements for the technical specification. This involves the ability of the devices to be more and more flexible.

Concerning control systems, users are generally interested in maintaining the legacy, "well established", customised functionality, just implementing it with what technology offers today. This implies a strong specification activity for the utility in order to obtain customised off-the-shelf components. Depending on the case, the customisation can be made by the utility, by the vendor or in collaboration between the two parts.

As of today, there is no indication that in the efforts of the utilities to obtain standardised and customised SAS will facilitate Functional Integration. As a matter of fact, standardisation and customisation requirements often impose constraints on the architecture and the implementation which probably limit a high degree of Functional Integration.

It is also difficult to specify these aspects without taking into account the real characteristics and performance of the hardware used. This makes common rules applicable to different vendors difficult to establish while the Functional Integration has not obtained a high level.

This problem will disappear as soon as all functions of at least one bay can be integrated in one device which is duplicated.

Organisational requirements - Functional Integration may imply "cultural" changes in the utilities and require organisation structures (both for utilities and vendors) which enable coordination of protection, control, monitoring and recording activities for development, engineering and operation.

The context of Functional Integration is the massive introduction of digital technologies that are developing and changing quickly. This requires personnel to learn, maintain the competence and be efficient in a huge variety of new concepts and tools across different disciplines (e.g. protection and IT systems). Furthermore, this requires ongoing training as new tools and technology are introduced.

In addition to this, another difficulty is introduced by Functional Integration since there may be interdependency between different functions. Their enabling or disabling may affect the behaviour of the system under certain conditions. This may have an impact on the organisation of the type acceptance and commissioning process.

The users thus have to acquire a deeper understanding of all these items in order to be able to configure and to operate a digital SAS with a high level of Functional Integration. This represents a major change with respect to the skills required for maintenance and operation of a conventional control system.

The integration of communication functions in the multifunctional substation devices requires a new set of skills in order to be able to configure, commission, maintain and test such devices and systems. Testing of a system with a high level of Functional Integration also requires a different set of skills and tools, as well as new methods that will allow the testing of all components as well as a system as a whole.

The expression "Paradigm Change" for theses challenges on several levels (organisation, operation, specification) was used by one of the respondents to the survey in this context.

Impact on Maintenance - Functional Integration also requires adaptation of maintenance methods with respect to the procedures applied to conventional bays and systems. While in conventional bays it is organised on the basis of "one equipment = one function", in a digital SAS, one function can either be implemented together with other functions in the same equipment (Functional Integration) or it can be distributed over several equipments (for example breaker failure protection). Maintenance operation has thus to take into account the implementation of the functions and cannot, in some cases, be organised, as it is done in conventional substation automation systems, as almost independent procedure for each functionality.

Impact on Refurbishment - Modern substation automation systems are based on the integration of multifunctional IEDs from different manufacturers. Requirements that they support IEC 61850 – the new international standard for substation communications - are seen more and more around the world. Such systems not only support features available in the communications protocols currently used in substations, but they allow different distributed applications, such as protection, monitoring or event and disturbance recording. This results in significant improvement in the efficiency of use of new technology in the substation.

The existence of numerous substations with an installed base of millions of electromechanical or solid-state relays that are still meeting the protection requirements of the user presents a challenge to the industry. On top of that, many of the substations have been upgraded in the last several years with microprocessor based relays that do not support IEC 61850. The replacement of all these legacy products will be very time consuming and costly. The upgrade process requires careful consideration of all available options and the development of a migration path that will allow smooth transition into the IEC 61850 based distribution protection and automation world through the use of multifunctional devices with high level of Functional Integration.

Impact on Testing - Testing is one of the key requirements to ensure correct operation of a protection and control system. Since technology is becoming more and more complex, with IEDs evolving to multifunctional devices with integrated pre-programmed control logic and additional functions like measuring, fault and disturbance recording, programmable scheme logic, etc., ensuring that they are properly configured and implemented requires adequate testing of their functionality.

The interaction of different logical and functional elements in devices with high level of Functional Integration needs to be well understood, since there are differences between the implementation of some protection functions in electromechanical and microprocessor based distance protection relays. Methods for testing of individual functional elements, complex functions, a devices as a whole and distributed applications should be developed and applied, taking into consideration the possible overlapping of functions operation for the same system event.

Survey - One of the primary tasks of working group B5-13 was to prepare and perform an industry survey on the acceptable level of Functional Integration.

The questions in the utility survey were formed in a way that provides good understanding of what IEDs are used, what is the acceptance of integration of protection and non-protection functions and the constraints that impact the level of acceptance. Another group of questions are related to the impact of IEC 61850, utility organization, engineering practices and perception of the benefits of functional integration.

The questions in the manufacturers' survey were formed in a way that provides good understanding of what IEDs are developed and made available on the market, what is the acceptance of integration of protection and non-protection functions in the devices and the constraints that impact the level of acceptance. Another group of questions are related to the impact of vendor's organization, outsourcing and perception of the benefits of functional integration.

The report includes the results from the survey based on 29 responses from utilities (7 from Europe, 8 from South America, 8 from Asia/ Australia and 6 from North America) and 20 responses from vendors (9 Europe, 7 Asia / Australia, 2 North America). Given the space available for this article, it was not possible to give a detailed account of all answers.

Multifunctional IED seem to be generally accepted by utilities, although there are several restrictions depending on the utility philosophy. The majority uses integration of protection and control functions even at higher voltage under the condition that the IEDs are duplicated. Integration of Main 1 and Main 2 protection is avoided at any voltage level by most utilities.

A low percentage of affirmative responses related to the impact of IEC 61850 reflects the fact that many utilities are in a waiting position and require more information about the standard in order to make a decision. The advantages of Functional Integration are in engineering, application flexibility, commissioning, maintenance and addition of functions.

Most of the manufacturers responding to the survey were producing multifunctional IEDs with integrated protection, control and auxiliary functions. The biggest impact on the integration is users' requirements.

There is a significant difference in the impact of IEC 61850. Majority of manufacturers already have or are in the process of development of devices supporting the standard, including process bus.

There is a consensus among the major manufacturers of protection and control devices that Functional Integration reduces costs and space requirements, while at the same time it improves the application flexibility. The main problems identified concern training required by the growing complexity of the system and of the devices.

19 Appendix 1 - Glossary

Bay (IEC 61850)	A substation consists of closely connected subparts with some common functionality. Examples are the switchgear between an incoming or outgoing line and the busbar, the bus coupler with its circuit breaker and related isolators and earthing switches, the transformer with its related switchgear between the two busbars representing the two voltage levels, the diameter in a 1 ½ breaker arrangement, etc. These subparts comprise very often a device to be protected like a transformer or a line end, and the control of its switchgear has some common restrictions like mutual interlocking or well-defined operation sequences. The identification of such sub-parts is important for maintenance purposes (what parts may be switched off at the same time with a minimum impact on the rest of the substation) or for extension plans (what has to be added if a new line shall be linked in). These subparts are called “bays” and managed by de-vices with the generic names “bay controller” and “bay protection”. They represent an additional control level below the overall station level that is called “bay level”.
Bay controllers	Bay controllers are devices with control and monitoring functions without protective functions.
Configuration **Configuration** (of a system or device) **(IEC 61850)**	**Configuration** (of a system or device) **(B5/WG18, IEC 61850)** is a step in system design: selecting functional units, assigning their locations and defining their interconnections. Configuration of an Intelligent Electronic Device determines the logic and assignment of interface points of the device with external systems. It may be partly pre-determined by the factory supplied hardware and firmware. Typically, the device configuration can be customized by modification of the **Configuration File** loaded into the device. The configuration file may be integrated with the setting file into one **Configuration and Settings File**. **Configuration** (of a system or device) **(IEC**
Configuration list (IEC 61850)	An overview of all compatible hardware and software versions of components and IEDs including the software versions of relevant supporting tools operating together in a SASproduct family. Additionally the configuration list contains the supported transmission protocols for communication with IEDs of other manufacturers.
Conformance test (IEC 61850)	Check of data flow on serial links in accordance with the standard conditions concerning access organization, formats and bit sequences, time synchronization, timing, signal form and level, reaction to errors. The conformance test can be carried out and certified for the standard or specially described parts of the standard. The conformance test should be carried out by a certified organization.
Function (IEC 61850)	Tasks, which are performed by the substation automation system. Generally, a function consists of logical nodes, which exchange data, with each other. Depending on the function definition functions itself exchange data with other functions. A function is called distributed when two or more logical nodes that are located in different physical devices perform it.

GOOSE message	GOOSE-messages (Generic Object Oriented Substation Event) according to IEC 61850 are data packets which are cyclically transferred via the Ethernet-communication system in case of event-controlled. They serve to the direct information exchange of the device to each other. The cross-communication between the bay devicesis implemented via this mechanism.
Hub	Basic networking device that connects multiple computers together.
IEC 61850	International communication standard for communication in substations. The objective of this standard is the interoperability of devices from different manufacturers on the station bus. An Ethernet network is used for data transfer.
IED (Intelligent Electronic Device) (IEC 61850)	Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers). An entity capable of executing the behaviour of one or more specified Logical Nodes in a particular context and delimited by its interfaces.
Interchangeability (IEC 61850)	The ability to replace a device from the same vendor, or from different vendors, utilizing the same communication interface and as a minimum, with the same functionality, and with no impact on the rest of the system.
Interface (IEC 61850)	A shared boundary between two functional units, defined by functional characteristics, signal characteristics, or other characteristics as appropriate.
Interoperability (IEC 61850)	The ability of two or more IEDs from the same vendor, or different vendors, to exchange information and use that information for correct co-operation.
LAN	Acronym for Local-Area Network. A LAN is a network that has networking equipment and/or computers in close proximity to each other capable of communicating, sharing resources and information.
Maintenance	Maintenance means the act of keeping the system in proper condition. Maintenance may include replacement of some elements of the installation but does not significantly enhance its functional specification.
MTBF	Acronym that stands for Mean Time Between Failure. The probable length of time that a component taken from a particular batch will survive if operated under the same conditions as a sample from that particular batch. This measure of product reliability has been rendered largely meaningless. MTBF figures do not require certification of any kind and are frequently generated by marketing departments rather than engineering groups.
Parameters (IEC 61850)	Variables, which define the behaviour of partial functions of the SAS and its IEDs within a given range of values.
Process bus (IEC 61850)	Communication interface between the different IEDs and the process.
Protection **Main 1 and Main 2 protection**	According to CEI/ IEC 60050 IEC 60050-448-11-13 main protection : Protection expected to have priority in initiating fault clearance or an action to terminate an abnormal condition in a power system. Note,-For a given item of plant, two or more main protections may be provided."
Backup protection	IEC 60050-448-11-14 backup protection = Protection which is intended to operate when a system fault is not cleared, or abnormal condition not detected, in the required time because

	of failure or inability of other protection to operate or failure of the appropriate circuit breaker(s) to trip. Note, - In the USA, the term “backup protection” designates a form of protection that operates independently of specified devices in the main protection system. The backup protection may duplicate the main protection or may be intended to operate only if the main protection system fails or is temporarily out of service.
Redundancy	Duplicating devices to the extent that if one were to fail there would be an identical unit to replace the failed unit. Often employed in mission critical networking systems as "mirrored" or "redundant" servers where both machines are performing identical tasks. If one of these servers fails, the application will not cease functioning.
Refurbishment	Refurbishment often includes partial or complete replacement of the installation or the system and enhancement of the characteristics usually takes place.
RTU - Remote Terminal Unit (IEC 61850)	Typically an outstation in a SCADA system. An RTU acts as an interface between the communication network and the substation equipment.
SAS	Substation Automation System
SAS-installation (IEC 61850)	The concrete instance of a substation automation system consisting of different interoperable IEDs of one or more manufacturers.
SAS-parameter set (IEC 61850)	All parameter values needed for the definition of the behavior of the overall SAS and its adaptation to the substation conditions. The SAS-parameter set includes the IED-parameter sets of all participating IEDs.
Settings	**Settings** for an Intelligent Electronic Device (IED) is a set of numerical and/or logical values that determine the operating characteristics of the device. Settings are applicable to a given configuration and sometimes include some elements of configuration. Settings are formatted in a file compatible with the device application software. **Setting** of a device means loading of a Settings File into the device thereby applying the desired characteristics and set points. Setting is sometimes understood as applying both configuration and settings to the device.
Switch	A network device that cross connects stations or LAN segments. Also known as a "frame switch," switches are available for Ethernet, Fast Ethernet, Token Ring and FDDI. ATM switches are generally considered in a category by themselves. Network switches are increasingly replacing shared media hubs in order to increase bandwidth. For example, a 16-port 100BaseT hub shares the total 100 Mbps bandwidth with all 16 attached nodes. By replacing the hub with a switch, each sender/receiver pair has the full 100 Mbps capacity. Each port on the switch can give full bandwidth to a single server or client station or it can be connected to a hub with several stations.
System (IEC 61850)	A set of interrelated elements considered in a defined context as a whole and separated from its environment. The logical system is a union of all communicating functions performing some overall task like “management of a substation”. The physical system is composed of all devices and the interconnecting physical communication network (commonly fibre optics). The boundary of a system is given by its logical or physical interfaces. Examples are industrial systems, management systems, information systems, etc. Within the

	scope of this standard, system refers to substation automation systems always if not mentioned otherwise.
System parameters	Data, which define the co-operation of IEDs in the SAS. They are especially important in the definitions for: • configuration of the SAS • communication between IEDs • marshalling of data between IEDs • processing and visualization of data from other IEDs e.g. at the station level.
System test	Check of correct behavior of the IEDs and of the overall SAS under various application conditions. The system test marks the final stage of the development of IEDs as part of a SAS-product family.
Test equipment	All tools and instruments which simulate and verify the input/outputs of the operating environment of the SAS such as switchgear, transformers, network control centers or connected telecommunication units on the one side, and the serial links between the IEDs of the SAS on the other.
Type test (IEC 61850)	Verification of correct behavior of the IEDs of the SAS by use of the system tested software under the environmental test conditions corresponding to the terminology given in IEC61850-2 should be used.

20 Appendix 2 Restitution of the questionnaire

20.1 Utilities

Based on 29 responses from utilities, 7 from Europe, 8 from South America, 8 from Asia/ Australia and 6 from North America.

Average response rate estimated at between 20 to 50 % of directly sollicitated answers.

Q1. What is your maximum system voltage level : 132 to 765 kV
What is your minimum system voltage level : 0,24 kV to 138 kV
240 V being the voltage level of LV distribution to final user. Complete distribution network is covered.

pure distribution and S-Transmission companies (max system voltage level < 150 kV): 4
pure transmission companies (min voltage level > 100 kV) : 5
pure generation : 3
mixed companies : 17

What is the approximate number of substations above 50 kV: 3 to 4000, medium 591
Does your activity include transmission of electric energy? 79 % Yes
Does your activity include distribution of electric energy? ? 66 % Yes

Q2. IEDs (devices with communications capabilities and/or based on microprocessor technology) in use in your company:

Protection devices	100% Yes
Control (supervision, automation) devices	97% Yes
Monitoring (breaker, transformer, power quality) devices	90% Yes
Recording devices (transient, disturbance, trend, event)	100% Yes
Measuring devices (system parameters – I, A, P, Q, f)	79% Yes
Metering (energy, billing metering) devices	83% Yes

Other devices identified in the answers :

- Voltage regulation/ Transformer Tapchanger control. These devices may have been classified as "control" by other utilities.
- Load Shedding

Q3. Do you use multifunctional IEDs (more than one functionality implemented which may or may not include a protection function): 90 % Yes

If Yes, do you use more than one of the available functions 90 % Yes
(all companies responding in an affirmative way to the former question)

Comments made by utilities : only few cases concerned in the case of some utilities.

Applications identified by the utilities :

- combination of protection and RTU,
- use of integration tables,
- combination of protection and control,
- disturbance record,
- control and measuring, autoreclose and synchrocheck integrated,

- event recorder,
- remote control.

Q4. Do you accept the integration of several functions in a single IED for applications at different levels of the system:

Transmission	86 %Yes , 3% No
Sub-transmission	83 % Yes, 7% No
Distribution	72 %Yes, 3% No

Comments made by utilities :

- IED used for generator protection,
- duplication for important applications,
- more efficient and cost effective approach with better event analysis.
- Protection redundancy exists on transmission and sub-transmission, therefore functional integration should address protection.
- Multifunctional IEDs at one level and on transformers, but no integration functions of different levels or bays, less integration of P&C at the higher voltage.
- Integration of protection and autoreclose at 380/220 kV,
- different IED for different voltage levels
- Different philosophies apply at different levels

Q5. In a multifunctional relay with the following functions, which functions do you currently use in the same time in the same IED? Please enter one answer among the choices listed below in each field in the table below (do not enter in the grey fields):
Y : Integration acceptable on all system levels
S : Integration acceptable on sub-transmission level and below
D : Integration acceptable on distribution level only
N : Integration option not acceptable on any system level
? : no opinion

Comments : Some of the matrices received as answer for Q5 were only partially completed. The following approach was used for the elaboration of the statistics :
Each line was considered separately, giving the existing combinations between one given functionality and the others. If one line was not completed, it was not taken into account. If one line was partially completed, the cases left blank were counted as "?".
As a consequence the number of responses representing 100% is not the same for each line.

		Protection Functions				Reclose		Control functions							Recording			
	Response	Main 2 Protection	Local Backup Protection	Overload Protection	Other Protection Functions	Autoreclosing	Synchrocheck	Remote Control Interface	Local Control HMI	Remote Monitoring	Remote Measurements (V,I,P,Q, phasor)	Load Shedding	Other Control Functions	Metering	Event Recording	Waveform (Transient) Recording	Disturbance Recording	Fault Locator
Main 1 Protection	Y %	10%	**50%**	**60%**	**67%**	**57%**	**57%**	30%	27%	**50%**	**43%**	**37%**	**40%**	30%	**83%**	**73%**	**80%**	**77%**
	S %	3%	0%	7%	3%	10%	10%	10%	17%	3%	7%	0%	13%	0%	0%	3%	0%	0%
	D %	7%	3%	3%	7%	7%	3%	13%	13%	3%	10%	20%	7%	0%	0%	0%	0%	0%
	N %	**67%**	33%	10%	10%	7%	17%	27%	30%	30%	23%	23%	20%	**40%**	10%	7%	10%	7%
	? %	13%	13%	20%	13%	20%	13%	20%	13%	13%	17%	20%	20%	**30%**	7%	17%	10%	17%
Main 2 Protection	Y %		**65%**	**69%**	**73%**	**62%**	**54%**	31%	27%	**54%**	**46%**	38%	38%	31%	**85%**	**81%**	**81%**	**85%**
	S %		0%	8%	4%	12%	8%	12%	19%	4%	8%	0%	15%	0%	0%	4%	0%	0%
	D %		0%	0%	4%	0%	0%	4%	4%	0%	4%	15%	4%	4%	0%	0%	0%	0%
	N %		27%	12%	12%	15%	27%	**38%**	27%	27%	23%	23%	19%	**38%**	15%	8%	12%	8%
	? %		8%	12%	8%	12%	12%	15%	23%	15%	19%	23%	23%	27%	0%	8%	8%	8%
Local Backup Protectio	Y %			**48%**	**52%**	**43%**	**43%**	**33%**	**33%**	**43%**	**38%**	24%	33%	29%	**67%**	**62%**	**62%**	**62%**
	S %			5%	0%	10%	10%	10%	14%	10%	10%	0%	14%	0%	0%	5%	0%	0%
	D %			0%	5%	5%	0%	5%	0%	19%	0%	10%	5%	5%	0%	0%	0%	0%
	N %			19%	19%	14%	14%	24%	24%	19%	14%	**33%**	10%	**38%**	10%	5%	14%	14%
	? %			29%	24%	29%	33%	29%	29%	10%	38%	33%	**38%**	29%	24%	29%	24%	24%
Overload Protection	Y %				**53%**	40%	40%	33%	33%	47%	47%	27%	**40%**	20%	**60%**	**60%**	**60%**	**60%**
	S %				0%	7%	7%	7%	13%	13%	7%	0%	7%	0%	7%	7%	0%	0%
	D %				7%	7%	7%	7%	7%	0%	0%	20%	7%	7%	0%	0%	0%	0%
	N %				33%	40%	40%	**40%**	**40%**	27%	**27%**	**40%**	27%	**60%**	13%	13%	27%	20%
	? %				7%	7%	7%	13%	7%	13%	20%	13%	20%	13%	20%	20%	13%	20%

		Protection Functions				Reclose		Control functions							Recording			
	Response	Main 2 Protection	Local Backup Protection	Overload Protection	Other Protection Functions	Autoreclosing	Synchrocheck	Remote Control Interface	Local Control HMI	Remote Monitoring	Remote Measurements (V,I,P,Q, phasor)	Load Shedding	Other Control Functions	Metering	Event Recording	Waveform (Transient) Recording	Disturbance Recording	Fault Locator
Other Protection Functions	Y %					**52%**	**52%**	**52%**	26%	26%	**37%**	22%	**37%**	22%	**63%**	**59%**	**56%**	**56%**
	S %					4%	4%	7%	11%	11%	4%	0%	4%	0%	4%	4%	0%	0%
	D %					4%	4%	4%	4%	4%	4%	19%	4%	4%	4%	4%	4%	4%
	N %					15%	15%	33%	**30%**	**30%**	30%	**30%**	26%	**52%**	7%	7%	19%	19%
	? %					26%	26%	4%	**30%**	**30%**	26%	30%	30%	22%	22%	26%	22%	22%
Auto-reclosing	Y %						**71%**	**38%**	29%	33%	**38%**	10%	**38%**	19%	**86%**	**71%**	**71%**	**57%**
	S %						0%	7%	7%	11%	4%	0%	4%	0%	0%	4%	0%	0%
	D %						0%	4%	0%	0%	0%	19%	4%	4%	0%	0%	0%	0%
	N %						15%	30%	**37%**	33%	33%	**44%**	30%	**41%**	7%	7%	15%	22%
	? %						14%	21%	27%	22%	25%	28%	25%	**37%**	7%	17%	14%	21%
Synchro-check	Y %							**38%**	**48%**	**48%**	**48%**	10%	**48%**	19%	**76%**	**62%**	**62%**	**62%**
	S %							10%	10%	10%	10%	0%	5%	0%	0%	5%	0%	0%
	D %							5%	0%	0%	0%	14%	5%	5%	0%	0%	0%	0%
	N %							29%	29%	24%	33%	**57%**	24%	**52%**	14%	14%	24%	33%
	? %							19%	14%	19%	10%	19%	19%	24%	10%	19%	14%	5%
Remote Control Interface	Y %								**41%**	**55%**	**55%**	18%	**36%**	14%	**45%**	32%	36%	**36%**
	S %								0%	0%	14%	0%	5%	0%	0%	5%	0%	0%
	D %								5%	5%	5%	5%	9%	5%	5%	5%	5%	5%
	N %								32%	9%	18%	**45%**	23%	**50%**	32%	**36%**	**41%**	**36%**
	? %								23%	32%	9%	32%	27%	32%	18%	23%	18%	23%

	Response	Protection Functions				Reclose		Control functions							Recording			
	Response	Main 2 Protection	Local Backup Protection	Overload Protection	Other Protection Functions	Autoreclosing	Synchrocheck	Remote Control Interface	Local Control HMI	Remote Monitoring	Remote Measurements (V,I,P,Q, phasor)	Load Shedding	Other Control Functions	Metering	Event Recording	Waveform (Transient) Recording	Disturbance Recording	Fault Locator
Local Control HMI	Y %									**61%**	**56%**	17%	**39%**	11%	39%	28%	33%	39%
	S %									0%	6%	0%	6%	0%	0%	6%	0%	0%
	D %									0%	0%	6%	6%	6%	0%	0%	0%	0%
	N %									28%	28%	**56%**	28%	**67%**	**50%**	**50%**	**56%**	**50%**
	? %									11%	11%	22%	22%	17%	11%	17%	11%	11%
Remote Monitor-ing	Y %										**65%**	15%	**45%**	20%	**50%**	**45%**	**45%**	**45%**
	S %										0%	0%	5%	0%	0%	5%	0%	0%
	D %										0%	5%	0%	5%	0%	0%	0%	0%
	N %										10%	**55%**	35%	**55%**	35%	35%	**45%**	**45%**
	? %										25%	25%	15%	20%	15%	15%	10%	10%
Remote Measure-ments (V,I,P,Q, phasor)	Y %											15%	35%	25%	**60%**	**50%**	45%	45%
	S %											0%	10%	0%	5%	10%	0%	0%
	D %											5%	0%	0%	0%	0%	0%	0%
	N %											**70%**	**45%**	**60%**	30%	30%	**55%**	**50%**
	? %											10%	10%	15%	5%	10%	0%	5%
Load Shedding	Y %													32%	11%	26%	21%	21%
	S %													0%	0%	0%	5%	0%
	D %													11%	11%	11%	5%	11%
	N %													**53%**	**74%**	**58%**	**63%**	**63%**
	? %													5%	5%	5%	5%	5%

		Protection Functions				Reclose		Control functions							Recording			
	Response	Main 2 Protection	Local Backup Protection	Overload Protection	Other Protection Functions	Autoreclosing	Synchrocheck	Remote Control Interface	Local Control HMI	Remote Monitoring	Remote Measurements (V,I,P,Q, phasor)	Load Shedding	Other Control Functions	Metering	Event Recording	Waveform (Transient) Recording	Disturbance Recording	Fault Locator
Other Control Functions	Y %														28%	**50%**	**44%**	28%
	S %														0%	6%	11%	0%
	D %														6%	6%	6%	6%
	N %														**61%**	28%	28%	**56%**
	? %														6%	11%	11%	11%
Metering	Y %														30%	25%	15%	10%
	S %														0%	0%	0%	0%
	D %														5%	5%	5%	5%
	N %														**60%**	**60%**	**70%**	**75%**
	? %														5%	10%	10%	10%
Event Recording	Y %															**77%**	**77%**	**82%**
	S %															5%	0%	0%
	D %															0%	0%	0%
	N %															14%	23%	14%
	? %															5%	0%	5%
Waveform (Transient) Recording	Y %																**76%**	**81%**
	S %																0%	0%
	D %																0%	0%
	N %																24%	19%
	? %																0%	0%

		Protection Functions				Reclose		Control functions							Recording			
	Response	Main 2 Protection	Local Backup Protection	Overload Protection	Other Protection Functions	Autoreclosing	Synchrocheck	Remote Control Interface	Local Control HMI	Remote Monitoring	Remote Measurements (V,I,P,Q, phasor)	Load Shedding	Other Control Functions	Metering	Event Recording	Waveform (Transient) Recording	Disturbance Recording	Fault Locator
Disturb-ance Recording	Y %																	**76%**
	S %																	0%
	D %																	0%
	N %																	24%
	? %																	0%

Q6. Are there rules, regulations or global philosophies applied in the utility which may prevent integration of several functions in one device?

48% explicitly state that there is some kind of rule.

Examples of rules given by the utilities :

- No integration of protection and control
- Integration tables are given in specifications
- Two independent protection above a given voltage level, backup can then be integrated
- Control implemented in only one protection to avoid conflict
- cultural philosophies
- No integration of Main 1 with Main 2 protection
- No total control loss for a single point failure rule stipulates segregation of remote control from local control
- Safety requires local control availability, interlocks and fail-safe designs
- One device / bay envisageable if performance can be maintained
- Change in minds of field staff is another problem
- n-1 criterion

Q7. Are there constraints (explicit or implicit) identified in your specifications concerning the degree of functional integration?

Maintenance 28 % Yes, 62% No

Comments by utilities concerning maintenance constraints in specifications :

- Safety
- Continuity of service during maintenance
- Independent backup protection must be active during maintenance
- Maintenance is done with the primary plant in service hence one protection must be active. If main 1 and main 2 separated, maintenance is possible on each device.
- At transmission level require ability to maintain 1 Main protection while other is still in service and line is still in service

Network operation 24% Yes 62% No

Comments of the utilities concerning the network operation :

- different modes of operation
- system reliability

- Control Logic (eg auto reclose OFF) should be contained in non volatile memory
- Maximizing of primary plant availability even when servicing secondary systems
- Continue to operate feeder or transformer while at same time testing/maintaining 1 Main protection (Transmission)

Safety of staff 24% Yes 66% No

Comments of the utilities concerning the safety of the staff :

- electrical hazard and consignation
- Control Logic (eg auto reclose OFF) should be contained in non volatile memory
- Local control, including disabling the remote, must be available
- no risks for workers
- Defined level of protection required when plant is in service

Other comments by utilities :

- Design standardization limits the freedom of use of functions in individual applications

Q8. Do you plan to change your policy or your specifications concerning functional integration in the future? 41% Yes 55% No

Reasons or comments given by utilities :

- economic reasons
- take better advantage of vendor offer
- define integration policy
- current trend of vendors and utilities
- review possible with experiences of new systems
- no needs of changing specification results from experience
- system reliability
- introduce more integrated protection and control
- no fundamental change. Some rules will not change in the near future. The policy is liberal already and is believed appropriate.
- possible if more simple, cheaper while conserving performances and reliability.
- Change of mentality required

- development of new function
- Re-consideration given to level of functional integration when considering new technologies such as IEC 61850 and when experience gained in field with combining various functions.

Q9. How does the new IEC 61850 standard influence on this question?

Influence : 31%, No influence 41%, no opinion : 28%

Comments made by utilities :

- system already compliant
- reduce wiring and aux components.
- Integration of different protocols
- More information required in order to decide
- asked for all new relays in order to prepare S/S automation
- currently no influence on specifications
- No official position of company established
- used in new specs.
- Economic issues yet not investigated
- not taken into account in new projects
- change probable. Vendors offer it and it is accepted
- SCADA using DNP3. IEC 61850 to be considered later. Continue with DNP3 until measurable benefit
- The effect of the standard on the redundancy and safety policy will not be significant in the near future. The standard will be introduced without compromising the policy rules.
- Currently in the process of investigating and considering this aspect

Q10. Is functional integration in the following cases acceptable:

1. Partial integration (multifunctional IED protecting a single substation component (Line, Transformer, etc.)) 90% Acceptable 10% Not acceptable

   Comments of utilities : for dual systems, distribution only, only if IED redundant

2. Integration of the protection of several substation components (Line, Transformer, etc.) in a single multifunctional IED 34% Acceptable 66% Not acceptable

Comments of utilities : partly accepted in distribution

3. Complete functional integration (Completely Integrated Substation System in a single computer based device) 7% Acceptable 90 % Not acceptable

Q11. Advantages related to integration (or to further or future integration), according to utility experience, expectation and opinion:

Item	Yes	No	Comments
System cost reduction	90%	3%	• less devices, panels, components, spare parts, wiring, auxiliary devices, • cost reduction (outage, contract, maintenance, operation, engineering) • less civil engineering and reduction of size of control room
Engineering	62%	31%	• limited number of relay types • Standardisation of architecture and design, use of templates • project simplification • implement new functions with little impact on hardware • reduction of total time spent in the project • efficiency improvement expected • improved reliability with less components in circuitry • less cabling and less schematics • simplified scheme designs
Application flexibility	59%	34%	• easier addition, modification and removal of functions • use programmable logic to create functions and extend logic • limitation of number of additional equipment • supplier options permitted • implementation of control functions • change project keeping the same equipment • installation is simpler and more cost effective • modifications in software, future functions at no cost • adaptability of spares to applications • integration has probable drawbacks on flexibility • Fewer standardized hardware devices required for required overall functionality

Item	Yes	No	Comments
Installation	86%	10%	• less cubicles, interfaces, components, panels and wiring • FAT, • simpler installation and reduction of total installation time • space and cost reduction
Commissionin g	48%	48%	• cost reduction (time,…) • reduction of space and wiring • reduced test time (established test plans with standard logic and protection applications) • simplify executive panel (HMI) • simplification and improvement of efficiency • Same number of functional elements to test – just method different
Training	17%	66%	• Higher skill levels are required for settings and field staff • training on one device can be faster than training on two. • Functions integrated in one device share same base philosophy • Depends on number of suppliers products purchased. Standardized solutions generally mean less training needed (fewer number of devices)
Configuration	38%	48%	• integrated configuration and setting tools (single tool for multiple functions). • advantages if standard templates and standard solutions are available • programming logic • Relay configuration generally more complex - but this only needs to be done once for a particular application type
Operation	34%	48%	• improved HMI • indication of problems during operation obtained • Standard solutions ready to load • Generally not seen as affecting network operation

Item	Yes	No	Comments
Maintenance	59%	31%	• less hardware problems • module change facilitated • less equipment needing periodic maintenance • less equipment to verify • less or no maintenance • remote access • reduction of number of spare parts • self monitoring, trip circuit supervision, event and fault record facilities • reduction of the number of different IEDs • space and cost reduction expected • efficiency improvement • Management of firmware, and software, setting information and test results, with a number of different relay manufacturers, makes a considerable maintenance workload for new devices. • Firmware upgrades for in-service relays on manufacturers recommendation adds to the workload and management complexity • Fewer devices to maintain and due to increased level of self-checking, interval is extended
Refurbishment	38%	52%	• reduce number and amount of spare components • Make the panels and wiring inside them cleaner • reduction of the number of different IEDs • cost reduction expected • once established, easier to upgrade single items of equipment • replacing an integrated relay will generally incur less circuitry changes • A number of existing devices can be replaced by a single hardware device. Complexity of engineering the refurbishment not simplified, however.
Site expansion	41%	45%	• facilitated • depends on configuration and type of modification • once established, easier to upgrade single items of equipment • simple engineering of repeatable or similar installations • additional integration • if space is limited

Item	Yes	No	Comments
Addition of functions	59%	34%	• possible without hardware change • implementing new control, protection and automated functions • higher performance for same cost • inbuilt functions can be switched on as required but it is only advantageous if functions are already available and only need to be activated. • Feasible • Where applicable, additional (non-protection) functions can improve overall performance by improving monitoring and providing better quality information

Q12. Do you have separate protection, control, etc. departments in your company structure and which one do you work for? 52% Yes, 41% No

Q13. Do you outsource any of the following?

	Yes	No	Partially
Engineering	10%	31%	59%
Configuration	14%	38%	41%
Installation	45%	10%	41%
Training	41%	10%	48%
Maintenance	21%	41%	38%

Comments received by utilities :

- concerns Protection and Control
- outsourcing of Protection and Control systems not a good solution
- Skills availability is a general problem

20.2 Vendors

Based on 20 responses (9 Europe, 7 Asia / Australia, 2 North America)

Q1. Types of IEDs (devices with communications capabilities and/or based on microprocessor technology) manufactured by your company:

Protection devices	2% Yes
Control (supervision, automation) devices	86% Yes
Monitoring (breaker, transformer, power quality) devices	77% Yes
Recording devices (transient, disturbance, trend, event)	68% Yes
Measuring devices (system parameters – I, A, P, Q, f)	77% Yes
Metering (energy, billing metering) devices	2% Yes

Comments received in the questionnaire :
Metering : integration is possible, however no Utilities will accept this at present

Others devices manufactured by some vendors ;: switches, multiplexers, teleprotection and communication equipment.

Q2. Do you manufacture IEDs with:

Multiple protection functions:	73% Yes
Multiple control functions:	7% Yes
Protection and control functions:	82% Yes
Protection, control and other functions:	77% Yes

Comments received in the questionnaire :
Protection, control (supervision, automation) and Measuring functions are integrated in a IED. The utilities require these functions. Vendors have by now a huge experience of manufacturing IEDs integrating multiple functions.
Based on the customer requests and customer availability to integrate more functions in one unit we always try to integrate as much functions as possible
Separation between Control and Protection functions is a limit for integration.

Q3. Regarding question 2, do you apply specific integration criteria for IEDs designed for different voltage levels: 32 %Yes 55% No

Comments received in the questionnaire :

- IEDs which include protection, control and metering are usually used in Low Voltage systems
- we have to comply with national standards and meet the specific requirements of customers
- Low end for Industrial and Distribution is a lower cost platform, however some Utilities will accept this up to 500kV. Conversely, some Utilities want the high end solution down to 35kV
- Typically higher voltage level IED’s have multiple criteria to be satisfied before a trip output

- The basic technology integration is the same whatever the voltage level.
- In principle No but in practice factors like application practice, user acceptance, marketing positioning, total IED capacity etc, influence the types and numbers of functions that are integrated in the same IED. These factors can of course be different depending on voltage levels. Main focus is a uniform hardware; some variations are possible with different software implementations (algorithms and functions)
- Specific integration criteria differ according to the voltage levels. At the higher voltage level, there can be limitations for functional integration applications taking account of bad influences in the case of system failure. On the contrary, at the lower voltage level, integration applications are comparatively easy because cost requirement is dominant. Specific integration applications are sometimes affected by customer's organization; e.g. different functions belong to different department cannot be integrated. "
- we suggest always the integration on all voltage levels. However we have to follow customer requests in many cases are mandatory i.e. independent tripping circuit, independent back up protection, protection independent from control IED etc.

Q5. Which functions do you currently use in the same time in the same IED?

Please enter one answer in each field in the table below using one column for each IED. The main function of the IED is indicated in the head of the column. You may add there the reference of the device you describe. You may replace "Other n" by a functional description if you wish to use these columns.

Y : Integration implemented in IEDs designed for all system levels
S : Integration implemented in IEDs designed for sub-transmission level and below
D : Integration implemented in IEDs designed for distribution level only
N : Integration not implemented in IEDs designed for any system level
? : no opinion

Comments :

- Only answers with the corresponding column of the IED completed (even partially have been taken into account. The percentage indicates the percentage of the indicated answer with respect of the number of individual answers received for each IED type.
- Some vendors used "T" in order to indicate that this implementation was used for transmission level. These answers were counted as "Y". Blank cases in cases of partially completed columns were counted as "?".
- In order to give an overview over the overall implementation practice, the positive answers (i.e. Y, S, D) were added in a separate column.
- Some vendors identified several different types of protection. These were taken into account as a separate column (i.e. answer) each.

- As far as the recording is concerned, some vendors differentiated event recording and waveform recording. As this difference was not explicitly proposed in the questionnaire, all answers were used for the table "recording".
- Only 2 vendors identified devices not identified in the initial tables. Since these are unique answers, it was not possible to represent them in a table with calculated percentages as below.

	Main function of IED : **protection**					
Other functions implemented in the IED	**%Y**	**%S**	**%D**	**%[Y,S, D]**	**%N**	**%?**
Main protection function	90%	0%	5%	95%	0%	5%
Teleprotection	75%	10%	5%	**90%**	5%	5%
Other Protection functions	80%	0%	5%	**85%**	10%	5%
Local Control HMI	65%	5%	10%	**80%**	20%	0%
Remote Control	60%	0%	10%	**70%**	20%	10%
Autoreclosing	85%	0%	5%	**90%**	5%	5%
Synchrocheck	70%	10%	10%	**90%**	0%	10%
Control	55%	0%	10%	65%	**30%**	5%
Measurements	60%	0%	20%	**80%**	15%	5%
Monitoring	60%	0%	20%	**80%**	20%	0%
Metering	30%	0%	5%	35%	55%	10%
Programmable Scheme Logic	80%	0%	0%	**80%**	20%	0%
Fault Locator	75%	10%	0%	**85%**	10%	5%
Event recording	85%	0%	5%	**90%**	5%	5%
Load-shedding	45%	0%	30%	**75%**	10%	15%
Overload protection	75%	0%	20%	**95%**	0%	5%
Power Swing	55%	20%	5%	**80%**	10%	10%
Other protection (V, f, df/dt, etc.)	65%	0%	20%	**85%**	5%	10%
Waveform (Transient) Recording	55%	0%	5%	60%	**35%**	5%
Disturbance Recording	65%	10%	5%	**80%**	15%	5%
Phasor Measurements	35%	0%	5%	40%	**50%**	10%

	Main function of IED : **Control**					
Other functions implemented in the IED	**%Y**	**%S**	**%D**	**%[Y,S, D]**	**%N**	**%?**
Main protection function	25%	5%	10%	40%	**45%**	15%
Teleprotection	20%	0%	5%	25%	**60%**	15%
Other Protection functions	40%	0%	20%	**60%**	30%	10%
Local Control HMI	95%	0%	5%	**100%**	0%	0%
Remote Control	90%	0%	5%	**95%**	5%	0%
Autoreclosing	55%	0%	10%	**65%**	20%	15%
Synchrocheck	75%	0%	10%	**85%**	5%	10%
Control	95%	0%	5%	**100%**	0%	0%
Measurements	80%	0%	10%	**90%**	0%	10%
Monitoring	85%	0%	10%	**95%**	5%	0%
Metering	40%	0%	10%	50%	35%	15%
Programmable Scheme Logic	65%	0%	5%	**70%**	20%	10%
Fault Locator	30%	0%	0%	30%	**55%**	15%
Event recording	75%	0%	10%	**85%**	10%	5%
Load-shedding	45%	0%	15%	**60%**	25%	15%
Overload protection	50%	0%	10%	**60%**	30%	10%
Power Swing	20%	10%	5%	35%	50%	15%
Other protection (V, f, df/dt, etc.)	50%	0%	10%	**60%**	30%	10%
Waveform (Transient) Recording	50%	5%	5%	**60%**	30%	10%
Disturbance Recording	50%	0%	5%	55%	35%	10%
Phasor Measurements	30%	0%	5%	35%	**50%**	15%

	Main function of IED : **Monitoring**					
Other functions implemented in the IED	**%Y**	**%S**	**%D**	**%[Y,S, D]**	**%N**	**%?**
Main protection function	24%	0%	12%	35%	**53%**	12%
Teleprotection	18%	0%	6%	24%	**65%**	12%
Other Protection functions	29%	0%	24%	**53%**	41%	6%
Local Control HMI	82%	0%	6%	**88%**	12%	0%
Remote Control	65%	0%	6%	**71%**	29%	0%
Autoreclosing	24%	0%	12%	35%	**53%**	12%
Synchrocheck	35%	0%	12%	**47%**	41%	12%
Control	71%	0%	12%	**82%**	18%	0%
Measurements	76%	0%	12%	**88%**	6%	6%
Monitoring	88%	0%	12%	**100%**	0%	0%
Metering	24%	0%	12%	35%	41%	**24%**
Programmable Scheme Logic	53%	0%	6%	**59%**	35%	6%
Fault Locator	18%	0%	0%	18%	**71%**	12%
Event recording	65%	0%	12%	**76%**	18%	6%
Load-shedding	12%	0%	18%	29%	**59%**	12%
Overload protection	35%	0%	12%	47%	47%	6%
Power Swing	18%	0%	6%	24%	**65%**	12%
Other protection (V, f, df/dt, etc.)	18%	0%	12%	29%	**59%**	12%
Waveform (Transient) Recording	47%	0%	6%	**53%**	35%	12%
Disturbance Recording	35%	0%	6%	41%	**47%**	12%
Phasor Measurements	41%	0%	6%	**47%**	41%	12%

	Main function of IED : **Recording**					
Other functions implemented in the IED	**%Y**	**%S**	**%D**	**%[Y,S, D]**	**%N**	**%?**
Main protection function	35%	0%	0%	35%	**59%**	6%
Teleprotection	35%	0%	0%	35%	**59%**	6%
Other Protection functions	35%	0%	0%	35%	**59%**	6%
Local Control HMI	59%	0%	0%	**59%**	41%	0%
Remote Control	53%	0%	0%	**53%**	47%	0%
Autoreclosing	35%	0%	0%	35%	**59%**	6%
Synchrocheck	35%	0%	0%	35%	**59%**	6%
Control	41%	0%	0%	41%	**59%**	0%
Measurements	76%	0%	0%	**76%**	12%	12%
Monitoring	71%	0%	0%	**71%**	29%	0%
Metering	41%	0%	0%	41%	41%	**18%**
Programmable Scheme Logic	59%	0%	0%	**59%**	41%	0%
Fault Locator	65%	0%	0%	**65%**	29%	6%
Event recording	82%	0%	6%	**88%**	6%	6%
Load-shedding	29%	0%	6%	35%	**59%**	6%
Overload protection	35%	0%	0%	35%	**59%**	6%
Power Swing	35%	0%	0%	35%	**59%**	6%
Other protection (V, f, df/dt, etc.)	35%	0%	0%	35%	**59%**	6%
Waveform (Transient) Recording	82%	0%	0%	**82%**	12%	6%
Disturbance Recording	82%	0%	0%	**82%**	12%	6%
Phasor Measurements	59%	0%	0%	**59%**	35%	6%

	Main function of IED : **Measuring**					
Other functions implemented in the IED	**%Y**	**%S**	**%D**	**%[Y,S, D]**	**%N**	**%?**
Main protection function	19%	0%	6%	25%	**63%**	13%
Teleprotection	19%	0%	0%	19%	**69%**	13%
Other Protection functions	19%	0%	19%	38%	**50%**	13%
Local Control HMI	69%	0%	0%	**69%**	25%	6%
Remote Control	50%	0%	0%	**50%**	44%	6%
Autoreclosing	19%	0%	6%	25%	**63%**	13%
Synchrocheck	31%	0%	6%	38%	**50%**	13%
Control	44%	0%	6%	**50%**	44%	6%
Measurements	81%	0%	6%	**88%**	0%	13%
Monitoring	63%	0%	6%	**69%**	25%	6%
Metering	50%	0%	6%	**56%**	31%	13%
Programmable Scheme Logic	44%	0%	6%	**50%**	38%	13%
Fault Locator	25%	0%	0%	25%	**69%**	6%
Event recording	63%	0%	6%	**69%**	**19%**	13%
Load-shedding	13%	0%	13%	25%	**56%**	19%
Overload protection	19%	0%	6%	25%	**56%**	19%
Power Swing	19%	0%	6%	25%	**63%**	13%
Other protection (V, f, df/dt, etc.)	19%	0%	6%	25%	**63%**	13%
Waveform (Transient) Recording	56%	0%	0%	**56%**	31%	13%
Disturbance Recording	44%	0%	0%	44%	44%	13%
Phasor Measurements	63%	0%	0%	**63%**	25%	13%

Q6. Are there constraints (explicit or implicit) identified concerning the degree of functional integration regarding:

User requirements 68% Yes

Comments given in the questionnaire :

- every user has its own special requirements we have to meet
- Some Utilities will not accept integration of Protection and Control and ask for a separation between Control and Protection functions. The reasons are diversified e.g. tradition, risk of common failure, policies depending voltage level, etc
- Users often specify a specific function only
- Typically transmission users do not combine multiple main protections or protection and control in one IED due to fear of common mode failure
- Depending on the specific requirements or exploration strategies of each market/ customer.
- Main1 and Main2 (back-up) protection must not be integrated in the same IED due to the risk of common mode failure.
- Both yes and no, depends on the user.
- technically possible degree of integration may not be acceptable for the user"
- User requirements are the most important factor for deciding the degree of the functional integration in many case integration is considered as a loss of reliability and the integration is not accepted. In many cases the customer doesn't accept any integration because it is considered a risk (change in his approach) many smaller users are waiting to follow on big utilities changes
- Dependability, different algorithm & platforms

Industry regulations 23%Yes

Comments given in the questionnaire :

- every user has its own special requirements we have to meet
- Some Countries/ Utilities will not accept Software Interlocking
- The regulations normally include definitions about the requirements and the functionality necessary for each industry.

Reliability requirements 36% Yes

Comments given in the questionnaire :

- in IEDs designed for sub-transmission level, the protection doesn't integrate with monitoring, control functions etc
- there are quite some differences for application indoors and outdoors

- Main1 and Main2 (back-up) protection must not be integrated in the same IED due to the risk of common mode failure.
- But the user can duplicate the devices, if redundancy is required
- Usually it is not a real reliability requirement as MTBF or lambda calculation but the final customer willing not to integrate functions in a single IED because he is used to do in such away and he doesn't want to take any risk (eng inertia)

Design philosophy 36% Yes

Comments given in the questionnaire :

- obviously the hardware and software platforms have some constraints on the functions
- Some Utilities will not accept integration of Protection and Control
- Design of an IED for a particular function say feeder protection and control typically bunches the functions related to feeders even though others can be added.
- Different users can have different philosophy that have been established during long time. Even though there can be an acceptance for a high degree of integration of functions for the same object it can be more difficult to accept integration of functions for several objects in the same IED.
- Devices should be identically in the design and handling, this includes also an identical functionality.
- Functional integration is often avoided for important protection devices such as that applied to EHV power systems, because functional integration enlarges bad-influences in the case of system hardware failure.
- the inertia is very high and due to lack of time few end user want to invest on his own philosophy.

Technological limitations 41% Yes

Comments given in the questionnaire :

- the capacity, the speed, the reliability of the elements have some limitations on the functions Some accuracy limitations with a few Utilities for measurements e.g. PQ
- Normally manufacturers have a library of functions and the limit of functionality is reached by number of functions vs CPU usage, I/O cards that can be added and size of the box.
- Obviously, the, non frequent, technological limitations may affect to the integration definitions.
- Feature trends are: higher CPU performance, better ADC's (speed and resolutions), higher capacity of memories.

- small manufacturers wants to keep the system as it is with no integration reducing the risk of market share erosion. In some countries the small manufactures has strong local influences.

Economical issues 50% Yes

Comments given in the questionnaire :

- price of IEDs
- users want to have more functions with less cost.
- more or less pronounced depending on the utility.
- This is one of the main drivers due to the different integration levels have different costs and it doesn't make sense create something that the market cannot buy.
- Optimisation of internal cost and minimization of variants; reduction of the overall costs by the user via near identical devices
- In general, functional integration is an effective means for total system cost reduction.
- It is not really clear on final customer side which are the economical advantages because some of the integration. Advantages can be detected after the installation i.e. during the operation and for the troubleshooting.
- Modularity has a cost

General comments received :

- From the technology point of view will get a higher degree of integration; the manufacturer must find the right balance between high functionality and a clear and "easy" handling / operation & responsibilities
- the main utilities have to be more confident to integrate functions and to achieve on it.

Q7. Do you plan to change your strategy concerning functional integration in the future?

36 % Yes

Reasons to change ?

- Marketing Strategy
- The needs of the users are changing
- Increase integration flexibility
- We will offer more single-function products as specified
- We need some strategy to develop the integrated system for more effective power utility operation in the future
- We believe that trust in IED based technology will increase and integration levels will also increase and at the same time

- Adaptation to the future standards.   We will continue to increase the functional integration because:
  - Improved performance and capacity of microprocessors make it possible to increase the integration.
  - We believe that trust in IED based technology will increase and higher degree of integration will be accepted.
  - Increased functional integration will be a possibility to continue decreasing the cost per function.
- The most strong incentive for the functional integration is user requirements, where remarkable changes are not predicted for the present.
- we will launch in Europe a new platform to integrate all functions on all levels especially on HV and EHV levels
- Competition drives towards more functions in one device

Reasons not to change

- No change : the correct strategy is applied

Q8. How does the new IEC 61850 or other new industry standards influence on your integration strategy?

59% of the vendors indicate that this standard will or already has influenced their integration strategy.

The following comments have been received in the questionnaire :

- We are doing the new products if users like to use this kind of standards   It was the prime mover in increasing integration flexibility
- IEC 61850 appears to discourage integrated products
- A lot of influence by IEC 61850 expected
- New suite of products and systems based on IEC 61850 in preparation or released. These terminals embrace the open philosophy and interoperability.
- requirements placed by IEC 61850
- The IEC61850 standard defines a new philosophy to manage the information in the electric substations, so new integration procedures should be defined. Provided that this standard is very open, the final integration methodology will depend on the final requirements of each customer.
- Our integration strategy is very influenced by IEC61850
- It helps clarifying the protocol maze. Too much time and effort was being wasted in adapting modern IEDs to old legacy protocols.
- The support of free allocation of functions will facilitate integration of functions for different objects in the same IED.
- IEC 61850 offers the possibilities of more distributed functions in the IED's. Some functions from the central station will be integrated in the IED's. Finally we get a higher degree of integration.
- Integration strategy is not, in general, influenced by industry standards because the strategy is primary influenced by user requirements especially in terms of performances, cost and operational convenience.
- fundamental

- Integration of this interface into the devices products are based on IEC61850
- Not significant at this time
- implementation and progress of IEC 61850 will be monitored and will implementation will be launched when business needs indicate

Q9. Do you manufacture (or plan to) IEDs with IEC 61850-9-2 (or other digital) Sampled Analog Values Process bus interface ?   59% Yes

Comments received by vendors :

- In the moment open, depends on the market situation (lower total costs and a finalized and tested standard (operation with different and distributed merging units)

Q10. Do you manufacture IEDs with the following types of functional integration:

1. Typical integration (IED covering all functions related to a single substation component (Line, Transformer, etc.))   77 % Yes
2. Integration of the functions related to several substation components (Line, Transformer, etc.) in a single multifunctional IED   55% Yes
3. Complete functional integration (Completely Integrated Substation System – system covering all substation functions - in a single computer based device)   9% Yes

Comments received :

- Because we haven't seen the market for this at present. Don't see any technical problem though.
- Regarding answer for 2. above, a typical example is transformer feeder protection & control"
- Regarding 2. E.g. protection of several feeders, protection of one transformer and some feeders, main protection for a transformer and back-up protection for another transformer, etc
- Questions not 100% clear: Main focus is on the functional integration on the bay level and communication between the bays

Q11. Do you see a difference in the acceptance by users of functional integration in the following cases: Yes / No

1. Typical integration (IED covering all functions related to a single substation component (Line, Transformer, etc.))   82% Accepted
2. Integration of the functions related to several substation components (Line, Transformer, etc.) in a single multifunctional IED   27% Accepted

3. Complete functional integration (Completely Integrated Substation System – system covering all substation functions - in a single computer based device)
9% Accepted

Comments received :

- Because several substation components in a single multifunction IED will result in complex of fault
- Answers above are majority views. There are always Utilities that are exceptions.
- Utilities are conservative
- Regarding question 2 : there is acceptance in certain special cases
- Regarding 2: The possibilities of this kind of integration are relatively new and it is in general not accepted. However we can feel an interest and curiosity for these kinds of solutions so probably there will be an acceptance from some users in a near future. For some special cases there already is an acceptance.
- Regarding 3: It is not accepted but in a trial installation of a completely Integrated SA system in a 130/40 kV h as been commissioned by one vendor. The station is in full operation.
- Difference in acceptance of functional integration between users and manufacturers are quite small because user requirements are the most strong incentive to make up manufacturer's design concept.
- Only industries when they must not follow the local network requirements accept the integration. The utilities accept the integration only on MV
- Depends on reliability. Integration of function related to several S/S components accepted only for some functions

Q12. Advantages related to integration (or to further or future integration) for you as a vendor, according to your experience, expectation and opinion:

Overall cost reduction: 82 %Yes

Comments given in the questionnaire :

- Evident
- Space reduction, can install new before removing existing equipment at refurbishments
- Less hardware, engineering and cabling
- Basically due to reduction of installation and works
- the amount of IED's is reduced
- More cost efficiency solutions, extensions will be easier, upgrading will be easier (mostly SW) : less devices, less spare parts, uniform devices, uniform functionality, same handling and operation Overall cost reduction, as well as system size reduction, is the biggest advantage derived from the functional integration.
- less: units, eng, wiring , panels, installation, testing during FAT and SAT , maintenance
- Using common main processor for multiple protection devices

- reduced equipment cost

R&D: 55 % Yes

Comments given in the questionnaire :

- reduction of the expenses on human resources
- Re-use of existing algorithms and configuration
- Working with one platform Hardware and a suite of modular functions that can be added at will
- the amount of designs is reduced
- Simpler R&D efforts, smaller product ranges
- More standardized HW and base SW together with a complete suite of freely allocatable application SWs (functions) will make the product development more effective.
- less hardware components, less variants in hard- and software developments concentrated on a single product/platform
- ease of design in one device

Engineering: 64% Yes

Comments given in the questionnaire :

- makes engineering easier
- Re-use of existing configuration
- Computer aided tools can be used for IED programming
- Less devices are necessary making the substation engineering easier
- Reusability of HW & SW
- The engineering can be more efficient with computer aided tools that is used for programming of IEDs including functions for several objects. uniform devices allows a standardized engineering, (same interfaces, identically product philosophy, less variants,..)
- Engineering works will be simplified because interfaces among functions are packed in a single IED
- reducing the wiring faster eng. less hours. Only one unit to be programmed. Easier link between the functions,
- less hw engineering
- simplifies installation design

Application flexibility: 59% Yes

Comments given in the questionnaire :

- all applications can be configured
- Easy to reconfigure without additional hardware
- Functions and modules can be added as required, limited only by physical constraints e.g. I/O, IED size

- Using integrated systems allows easier adaptations to the future changes in substations.
- Easy changes of functions are allowed with no change of engineering or wiring
- Applications used at all voltage levels
- Functions and modules can be added as required, limited only by physical constraints of the IED e.g. numbers of I/O, CPU capacity   Easier with identical devices and software packages
- There can be both sides. Operational flexibility will be improved because protection functions are easily changed and their co-operations are also easily adjusted by using PC. However in the case of partial refurbishment of protection scheme, functional integration sometimes makes it complicated to change software and hardware.
- having all integrated any change affect few units i.e. in case of changes they can be done very easily during FAT or SAT
- Common platform with customized protection modules does not require re-design of any one device
- simplifies and improves flexibility

Installation: 68% Yes

Comments given in the questionnaire :

- the architecture is explicit
- Space reduction, can install new before removing existing equipment at refurbishments
- Smaller size, profile and standardized boxes. Customization in physical attributes avoided.
- Integrated systems reduces the installation jobs to install the control and protection systems.
- The need of Measurement transformers or their windings is eliminated and the wiring is reduced as well
- Less installation on site. The installation will be limited to connecting the analog inputs and the binary outputs. The rest of the installation will be done in SW configurations and the complete functionality can be tested in advance.
- Identically design of the products, standardization of the interfaces
- Installation works will be also simplified because total system size is reduced.
- reduced space reduce transportation cost (less cubicles) less wiring among different cubicles less wiring to field
- Pre-wiring done in logic, less space required
- simplifies

Commissioning: 55% Yes

Comments given in the questionnaire :

- makes commissioning easier Easier FAT
- Typically software tools can follow entire current flows within IED to check if configuration and even settings are correct thus reducing work, time and cost
- The amount of commissioning tests is reduced
- The commissioning on site can be done faster and more cost efficient. Software tools can follow entire current flows within IED to check if configuration and even settings are correct thus reducing work, time and cost. The complete functionality can be tested in factory and the commissioning will be focused on the interfaces to the power system process (analog inputs and binary outputs).
- Identically design of the products, standardization of the interfaces
- less units to test= less time +less risk of mistest
- Factory pre-test of scheme and logic
- greatly simplifies

Training: 41 %Yes

Comments given in the questionnaire :

- Less people
- All platform, configuration, etc is the same
- Instead of specific device based training programs, an IED family based program can be made for bigger utilities
- As the number of devices is fewer the training is easier.
- Less number of IEDs
- Instead of specific device based training programs, an IED family based program and general application training can be made for users.
- Y/N : 50/50 :Training may be reduced because of reduced variance in equipment. On the other hand, people have to be trained in both, protection & control
- less units to train on = less time
- one device – less confusion – simplifies training

Configuration: 50% Yes

Comments given in the questionnaire :

- All configuration is the same
- Can be done graphically with software complying to IEC 61131 thus ensuring correctness, uniformity and advanced aspects such as on line debugging etc as against complex equations
- By sharing the same configuration tool the probability of errors and the configuration time are smaller

- See answers regarding engineering.
- Always the same principle
- In many cases, size of the total system or each devices are reduced.
- less units to configure = less time
- the operator are not stressed to know different SW different way to approach the problem
- common user interface
- consistent interface

Maintenance: 64% Yes

Comments given in the questionnaire :

- Virtually no maintenance because of self-diagnosis and you can configure Trip Testing to exercise the IED
- Reduced due to common hardware platforms between IED's same I/O, same Power supply cards, same CPU cards etc..
- The fewer devices are installed the fewer spare parts needed and the maintenance is easier
- Less number of parts to be kept in inventory
- Reduced due to common hardware platforms between IED's, the same I/O, the same Power supply cards, the same CPU cards etc. Increased integration requires new malignance philosophies. It is not recommendable or suitable to continue to maintain (test) more integrated system in the same way as electromechanical or other traditional protection and control equipment. The future integrated systems will have much more advanced and improved self-supervision capabilities.
- Less spare parts and components
- Maintenance works will be also simplified because number of the target IEDs will be reduced, where self-supervision, combined with functional integration, plays great role in reducing the maintenance works.
- less units to maintain means less spare parts to manage
- reduces and simplifies maintenance

Refurbishment: 50% Yes

Comments given in the questionnaire :

- Space reduction, can install new before removing existing equipment at refurbishments
- The next step would be refurbishment of technology related parts only e.g. CPU and communications modules where technology moves rapidly. The others (I/O, PSU etc) can remain till the next generation evolves
- Less space needed
- The refurbishment will be more cost efficient. The next step would be refurbishment of technology related parts only e.g. CPU and

communications modules where technology moves rapidly. The others (I/O, PSU etc) can remain till the next generation evolves.

- Less components
- integrating more functions
- many functions can use the same cable thus during the refurbishment even the renew of all wiring can be reduced, save a lot of money to replace the existing
- modular
- eliminates - replace only

Site expansion: 50 %Yes

Comments given in the questionnaire :

- Space reduction, so often no increase in buildings required
- By choosing IED that can cover the whole future configuration (e.g. busbar protection) and activating only presently available bays, you can easily cover for the future, NOW"
- Using integrated systems allows easier adaptations to the future changes in substations and cost effective solutions.
- Less space needed
- Extensions will be easy and cost efficient. The I/Os for the new object are the only necessary HW to install. The rest of the extension will be taken care of by SW implementations. By choosing IED that can cover the whole future configuration (e.g. busbar protection) and activating only presently available bays, you can easily cover for the future.
- Depends on the kind of expansion
- yes using IEC61850
- modular
- reduces cost and space required for expansion – makes expansion possible in some cases

Addition of functions: 59% Yes

Comments given in the questionnaire :

- IEDs are modular, new firmware and/or software can be added
- Yes, Typically it has been related to acceptance testing and taking over as today the level of integration and the types of testing of integrated terminals vary between suppliers and users.
- Using integrated systems allows easier adaptations to the future changes in substations.
- As they are multifunctional devices, a new feature can be easily added by loading a new software configuration
- Platforms are more powerful

- Easily done by adding SW without changing or adding any HW. This can be done locally or remote. Only of a new loading of a new firmware version necessary
- the additional functions can be easily integrated in the units using the advantages listed above
- modular

Q13. Which of the above do you think are also benefits to your customers?

Answers received :

- Overall cost reduction in engineering
- cost saving, maintenance reduction, installation reduction
- Almost all
- ALL, vendors cost reductions mean that the solution is more cost effective to customer in a competitive environment Reduced cost of installation & wiring. However each function must be tested and commissioned in its own right, often involving different people overall cost reduction all of Q12 above
- The same that the ones for us like vendors.
- Overall cost reduction, Engineering, Application Flexibility, Installation, Commissioning, Training, Configuration, Maintenance, Additional Functions
- All above but engineering (HW & SW)
- All of them.
- Overall costs, application flexibility, installation, maintenance
- All of the above items marked “Yes” are also benefits to the customers.
- nowadays the cost reduction is the main sensible (the cost reductions has to consider not only the purchase but the total life of the system 15-20years considering the maintenance and the troubleshooting) the most imp tech aspects are: flexibility, maintenance, configuration, installation
- Space reduction
- Cost savings for installation, training, spare parts and lower cost for multifunctional device
- all

Q14. Do you think that functional integration presents any problems to your customers?

55 % Yes

Answers received :

- Training
- It needs more competent engineers to use these devices
- NO, some retraining required, however the vast majority of engineers prefer new technology. Still a few Utilities that keep Protection and Control separate, however most accept integration. Next step, integrate Tariff Metering??

- In some utilities different functions (protection, control, monitoring, communications) are handled by different departments. It’s easier to deal with each separately.
- The higher the voltage level of substation, the more troublesome
- Yes, Typically it has been related to acceptance testing and taking over as today the level of integration and the types of testing of integrated terminals vary between suppliers and users."
- No, only some small investment in new solutions training may be necessary.
- It is a change in their mental model: a paradigm shift specially for the older generations, plus internal organizational changes
- Yes. The systems must be designed in such a way that the users are convinced that all power system requirements and the dependability of the protection are fulfilled. Operation and maintenance are other important issues and new philosophies and methods must be developed and established among the users.
- Additional training, complexity, changing of internal responsibility (universal engineers or technicians)
- Main disadvantage of functional integration is larger bad-influence on various functions in the case of hardware failure. Decision of users for introducing functional integration is based on trade-off judgment between cost reduction and bad-influence with the hardware failure. In functional integrated IEDs, setting works are more complicated and troublesome. That may also be disadvantage for the customers.
- they want to rethink the tech approach not at all. Integration is an advantage
- Yes for instance due to their organization
- Yes, more complex device requires learning a new device – possible confusion if un-needed features are not properly “hidden” from user